Intergovernmental Panel on Climate Change

2006 IPCC Guidelines for National Greenhouse Gas Inventories

Volume 2

Energy

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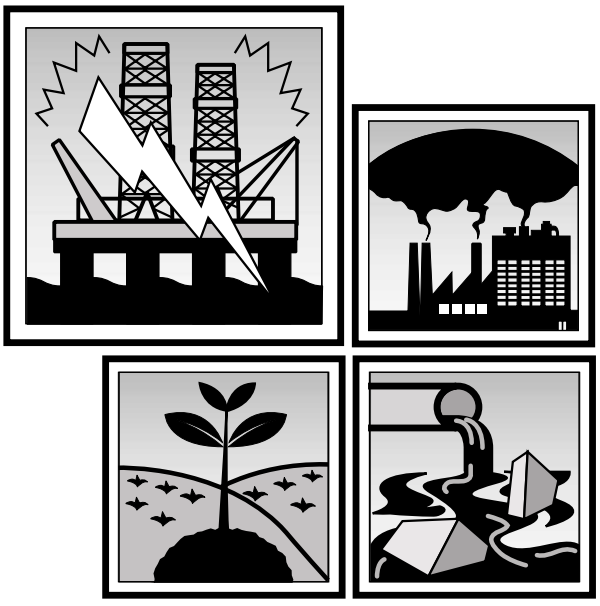

IPCC National Greenhouse Gas Inventories Programme

IGES

A report prepared by the Task Force on National Greenhouse Gas Inventories (TFI) of the IPCC and accepted by the Panel but not approved in detail

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CHAPTER 1

INTRODUCTION

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1 INTRODUCTION

1.1 INTRODUCTION

Energy systems are for most economies largely driven by the combustion of fossil fuels. During combustion the carbon and hydrogen of the fossil fuels are converted mainly into carbon dioxide (CO_2) and water (H_2O), releasing the chemical energy in the fuel as heat. This heat is generally either used directly or used (with some conversion losses) to produce mechanical energy, often to generate electricity or for transportation. The energy sector is usually the most important sector in greenhouse gas emission inventories, and typically contributes over 90 percent of the CO_2 emissions and 75 percent of the total greenhouse gas emissions in developed countries. CO_2 accounts typically for 95 percent of energy sector emissions with methane and nitrous oxide responsible for the balance. Stationary combustion is usually responsible for about 70 percent of the greenhouse gas emissions from the energy sector. About half of these emissions are associated with combustion in energy industries mainly power plants and refineries. Mobile combustion (road and other traffic) causes about one quarter of the emissions in the energy sector.

1.2 SOURCE CATEGORIES

The energy sector mainly comprises:

- exploration and exploitation of primary energy sources,
- conversion of primary energy sources into more useable energy forms in refineries and power plants
- transmission and distribution of fuels
- use of fuels in stationary and mobile applications.

Emissions arise from these activities by combustion and as fugitive emissions, or escape without combustion.

For inventory purposes, *fuel combustion* may be defined as *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.* This definition aims to separate the combustion of fuels for distinct and productive energy use from the heat released from the use of hydrocarbons in chemical reactions in industrial processes, or from the use of hydrocarbons as industrial products. It is *good practice* to apply this definition as fully as possible but there are cases where demarcation with the industrial processes and product use (IPPU) sector is needed. The following principle has been adopted for this:

Combustion emissions from fuels obtained directly or indirectly from the feedstock for an IPPU process will normally be allocated to the part of the source category in which the process occurs. These source categories are normally 2B and 2C. However, if the derived fuels are transferred for combustion in another source category, the emissions should be reported in the appropriate part of Energy Sector source categories (normally 1A1 or 1A2). Please refer to Box 1.1 and section 1.3.2 in chapter 1 of the IPPU Volume for examples and further details.

When the total emissions from the gases are calculated, the quantity transferred to the energy sector should be noted as an information item under IPPU source category and reported in the relevant energy sector source category to avoid double counting.

Typically, only a few percent of the emissions in the energy sector arise as *fugitive emissions* from extraction, transformation and transportation of primary energy carriers. Examples are leakage of natural gas and the emissions of methane during coal mining and flaring during oil/gas extraction and refining[1]. In some cases where countries produce or transport significant quantities of fossil fuels, fugitive emissions can make a much larger contribution to the national total. Combustion and fugitive emissions from production, processing and handling of oil and gas should be allocated according to the national territory of the facilities including offshore areas (see Chapter 8 - section 8.2.1 in Vol. 1). These offshore areas may be an economic zone agreed upon with other countries.

[1] Note that the combustion emissions due to transport of energy carriers by ship, rail and road are included in the mobile combustion processes.

Figure 1.1 shows the structure of activities and *source categories* within the energy sector. This structure is based on the coding and naming as defined in *the 1996 IPCC Guidelines and the Common Reporting Format (CRF)* used by the UNFCCC. The technical chapters of this Volume follow this source category structure.

1.3 METHODOLOGICAL APPROACHES

1.3.1 Emissions from fossil fuel combustion

There are three Tiers presented in the *2006 IPCC Guidelines* for estimating emissions from fossil fuel combustion. In addition a Reference Approach is presented. It can be used as an independent check of the sectoral approach and to produce a first-order estimate of national greenhouse gas emissions if only very limited resources and data structures are available to the inventory compiler.

The *2006 IPCC Guidelines* estimate carbon emissions in terms of the species which are emitted. During the combustion process, most carbon is immediately emitted as CO_2. However, some carbon is released as carbon monoxide (CO), methane (CH_4) or non-methane volatile organic compounds (NMVOCs). Most of the carbon emitted as these non-CO_2 species eventually oxidises to CO_2 in the atmosphere. This amount can be estimated from the emissions estimates of the non-CO_2 gases (See Volume 1, Chapter 7).

In the case of fuel combustion, the emissions of these non-CO_2 gases contain very small amounts of carbon compared to the CO_2 estimate and, at Tier 1, it is more accurate to base the CO_2 estimate on the total carbon in the fuel. This is because the total carbon in the fuel depends on the fuel alone, while the emissions of the non-CO_2 gases depend on many factors such as technologies, maintenance etc which, in general, are not well known. At higher tiers, the amount of carbon in these non-CO_2 gases can be accounted for.

Since CO_2 emissions are independent of combustion technology whilst CH_4 and N_2O emissions are strongly dependent on the technology, this chapter only provides default emission factors for CO_2 that are applicable to all combustion processes, both stationary and mobile. Default emission factors for the other gases are provided in subsequent chapters of this volume, since combustion technologies differ widely between source categories within the source sector "Combustion" and hence will vary between these subsectors.

1.3.1.1 TIERS

TIER 1

The Tier 1 method is fuel-based, since emissions from all sources of combustion can be estimated on the basis of the quantities of fuel combusted (usually from national energy statistics) and average emission factors. Tier 1 emission factors are available for all relevant direct greenhouse gases.

The quality of these emission factors differs between gases. For CO_2, emission factors mainly depend upon the carbon content of the fuel. Combustion conditions (combustion efficiency, carbon retained in slag and ashes etc.) are relatively unimportant. Therefore, CO_2 emissions can be estimated fairly accurately based on the total amount of fuels combusted and the averaged carbon content of the fuels.

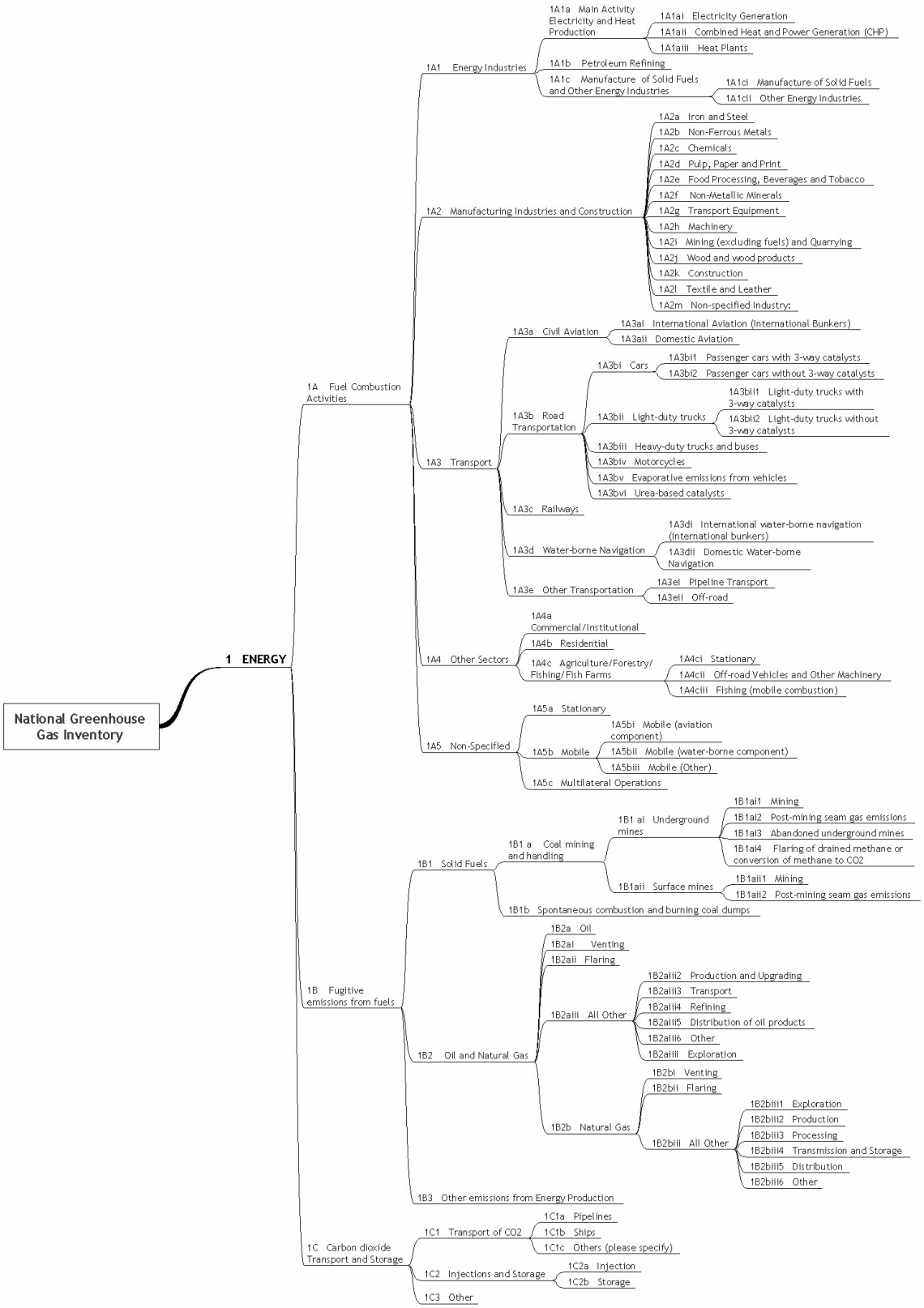
However, emission factors for methane and nitrous oxide depend on the combustion technology and operating conditions and vary significantly, both between individual combustion installations and over time. Due to this variability, use of averaged emission factors for these gases, that must account for a large variability in technological conditions, will introduce relatively large uncertainties.

TIER 2

In the Tier 2 method for energy, emissions from combustion are estimated from similar fuel statistics, as used in the Tier 1 method, but country-specific emission factors are used in place of the Tier 1 defaults. Since available country-specific emission factors might differ for different specific fuels, combustion technologies or even individual plants, activity data could be further disaggregated to properly reflect such disaggregated sources. If these country-specific emission factors indeed are derived from detailed data on carbon contents in different batches of fuels used or from more detailed information on the combustion technologies applied in the country, the uncertainties of the estimate should decrease, and the trends over time can be better estimated.

If an inventory compiler has well documented measurements of the amount of carbon emitted in non-CO_2 gases or otherwise not oxidised, it can be taken into account in this tier in the country-specific emission factors. It is *good practice* to document how this has been done.

Figure 1.1 Activity and source structure in the Energy Sector



TIER 3

In the Tier 3 methods for energy, either detailed emission models or measurements and data at individual plant level are used where appropriate. Properly applied, these models and measurements should provide better estimates primarily for non-CO_2 greenhouse gases, though at the cost of more detailed information and effort.

Continuous emissions monitoring (CEM) of flue gases is generally not justified for accurate measurement of CO_2 emissions only (because of the comparatively high cost) but could be undertaken particularly when monitors are installed for measurement of other pollutants such as SO_2 or NO_x. Continuous emissions monitoring is particularly useful for combustion of solid fuels where it is more difficult to measure fuel flow rates, or when fuels are highly variable, or fuel analysis is otherwise expensive. Direct measurement of fuel flow, especially for gaseous or liquid fuels, using quality assured fuel flow meters may improve the accuracy of CO_2 emission calculations for sectors using these fuel flow meters. When considering using measurement data, it is *good practice* to assess the representativeness of the sample and suitability of measurement method. The best measurement methods are those that have been developed by official standards organisations and field-tested to determine their operational characteristics. For further information on the usage of measured data, check Chapter 2, Approaches to Data Collection in Volume 1.

It should be noted that additional types of uncertainties are introduced through the use of such models and measurements should therefore be well validated, including a comparison of calculated fuel consumption with energy statistics, thorough assessments of their uncertainties and systematic errors, as described in Volume 1, Chapter 6.

If an inventory compiler has well documented measurements of the amount of carbon emitted in non-CO_2 gases or otherwise not oxidised, it can be taken into account in this tier in the country-specific emission factors. It is *good practice* to document how this has been done. If emission estimates are based on measurements then they will already include the direct emissions of CO_2 only.

1.3.1.2 SELECTING TIERS: A GENERAL DECISION TREE

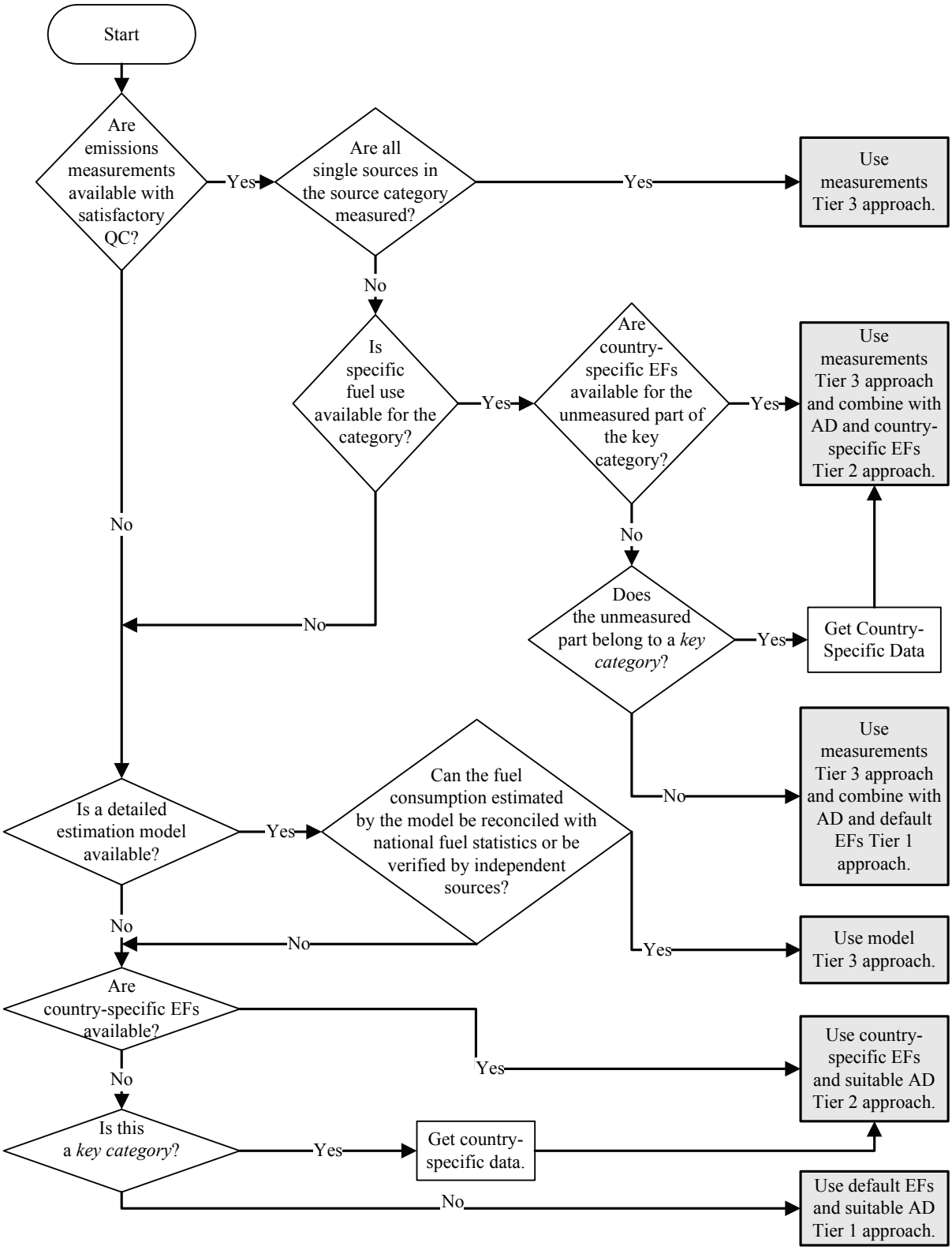
For each source category and greenhouse gas, the inventory compiler has a choice of applying different methods, as described in the Tiers for the source category and gas. The inventory compiler could use different tiers for different source categories, depending on the importance of the source category within the national total (cf. *key categories* Chapter 4 of Volume 1) and the availability of resources in terms of time, work force, sophisticated models, and budget. To perform a *key category* analysis, data on the relative importance of each source category already calculated is required. This knowledge could be derived from an earlier inventory, and updated if necessary.

Figure 1.2 presents a generalized decision tree for selecting Tiers for fuel combustion. This decision tree applies in general for each of the fuel combustion activities and for each of the gases.

The measurements referred to in this decision tree should be considered as continuous measurements. Continuous measurements are becoming more widely available and this increase in availability is in part driven by regulatory pressure and emissions trading. The decision tree allows available emission measurements to be used (Tier 3) in combination with a Tier 2 or Tier 1 estimate within the same activity. Measurements will typically be available only for larger industrial sources and hence only occur in stationary combustion. For CO_2, particularly for gaseous and liquid fuels, such measurements should in most cases preferably be used to determine the carbon content of the fuel before combustion, whereas for other gases stack measurements could be applied. For some inhomogeneous solid fuels, stack measurements might provide more precise emission data.

Particularly for road transport, using a Tier 2 or Tier 3 technology-specific method for estimating N_2O and CH_4 emissions will usually bring large benefits. However, for CO_2 in general, a Tier 1 method based on fuel carbon and fuel amount used will often suffice. This means that the generalized decision tree might result in different approaches for different gases for the same source category. Since emission models and technology-specific methods for road transport might be based on vehicle kilometres travelled rather than on fuel used, it is *good practice* to show that the activity data applied in such models and higher tier methods are consistent with the fuel sales data. These fuel sales data are likely to be used to estimate CO_2 emissions from road transport. The decision tree allows the inventory compiler to use sophisticated models in combination with any other Tier methodology, including measurements, provided that the model is consistent with the fuel combustion statistics. In cases where a discrepancy between fuel sales and vehicle kilometres travelled is detected, the activity data, used in the technology-specific method should be adjusted to match fuel sales statistics, unless it can be shown that the fuel sales statistics are inaccurate.

Figure 1.2 Generalised decision tree for estimating emissions from fuel combustion



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.

1.3.1.3 RELATION TO OTHER INVENTORY APPROACHES

The *IPCC Guidelines for National Greenhouse Gas Inventories* are specifically designed for countries to prepare and report inventories of greenhouse gases. Some countries may also be required to submit emission inventories of various gases from the Energy Sector to United Nations Economic Commission for Europe (UNECE) Long Range Transboundary Air Pollution (LRTAP) Convention[2]. The UNECE has adopted the joint European Monitoring Evaluation Programme (EMEP)/CORINAIR Emission Inventory Guidebook [3] for inventory reporting.

Countries which are Parties to different Conventions have to use the appropriate reporting procedures when reporting to a specific Convention. The IPCC approach meets UNFCCC needs for calculating national totals (without further spatial resolution) and identifying sectors within which emissions occur, whereas the EMEP/CORINAIR approach is technology based and includes spatial allocation of emissions (point and area sources).

Both systems follow the same basic principles:

- complete coverage of anthropogenic emissions (CORINAIR also considers natural emissions);
- annual source category totals of national emissions;
- clear distinction between energy and non-energy related emissions;
- transparency and full documentation permitting detailed verification of activity data and emission factors.

Considerable progress has been made in the harmonisation of the IPCC and EMEP/CORINAIR approaches. UNECE LRTAP reporting now has accepted a source category split that is fully compatible with the UNFCCC split as defined in the Common Reporting Framework (CRF). Differences only occur in the level of aggregation for some specific sources. Such differences only occur in the energy sector in the transport source categories, where UNECE LRTAP requires further detail in the emissions from road transport.

The CORINAIR programme has developed its approach further to include additional sectors and sub-divisions so that a complete CORINAIR inventory, including emission estimates, can be used to produce reports in both the UNFCCC/IPCC or EMEP/CORINAIR reporting formats for submission to their respective Conventions. Minor adjustments based on additional local knowledge may be necessary to complete such reports for submission.

One significant difference between the approaches that remain is the spatial allocation of road transport emissions: while CORINAIR, with a view to the input requirements of atmospheric dispersion models, applies the principle of territoriality (emission allocation according to fuel consumption), the *2006 IPCC Guidelines* follow what is usually the most accurate data: fuel sales (usually fuel sales are more accurate than vehicle kilometres). In the context of these IPCC Guidelines, countries with a substantial disparity between emissions as calculated from fuel sales and from fuel consumption have the option of estimating true consumption and reporting the emissions from consumption and trade separately using appropriate higher tier methods. National totals must be consistent with fuel sales.

Since both approaches are now generally well harmonised, the *2006 IPCC Guidelines* will concentrate on emissions of direct greenhouse gases, CO_2, CH_4 and N_2O with some advice on NMVOCs where these are closely linked to emissions of direct greenhouse gases (non-energy use of fuels, CO_2 inputs to the atmosphere from oxidation of NMVOCs). Users are referred to the EMEP/CORINAIR Emission Inventory Guidebook for emission estimation methods for indirect greenhouse gases and other air pollutants.

1.3.2 Fugitive emissions

This volume provides methodologies for the estimation of fugitive emissions of CO_2, CH_4 and N_2O. Methodologies for estimating fugitive emissions from the Energy Sector are very different from those used for fossil fuel combustion. Fugitive emissions tend to be diffuse and may be difficult to monitor directly. In addition, the methods are quite specific to the type of emission release. For example, methods for coal mining are linked

[2] There are 49 parties to the UNECE Convention on Long-range Transboundary Air Pollution including USA, Canada, most of Europe including Russia, Armenia and Georgia and some central Asian countries such as Kazakhstan and Kyrgyzstan.

[3] See EEA 2005.

to the geological characteristics of the coal seams, whereas methods for fugitive leaks from oil and gas facilities are linked to common types of equipment.

There can be anthropogenic emissions associated with the use of geothermal power. At this stage no methodology to estimate these emissions is available. However if these emissions can be measured, they should be reported in source category 1.B.3 "Other emissions from energy production".

1.3.3 CO_2 capture and storage

According to the IPCC Third Assessment Report, over the 21st century substantial amounts of CO_2 emissions need to be avoided to achieve stabilization of atmospheric greenhouse gas concentrations. CO_2 capture and storage (CCS) will be one of the options in the portfolio of measures for stabilization of greenhouse gas concentrations while the use of fossil fuels continues. Chapter 5 of this volume presents an overview of the CCS system and provides emission estimation methods for CO_2 capture, CO_2 transport, CO_2 injection and underground CO_2 storage. It is *good practice* for inventory compilers to ensure that the CCS system is handled in a complete and consistent manner across the entire Energy Sector.

1.4 DATA COLLECTION ISSUES

1.4.1 Activity data

In the Energy sector, the activity data are typically the amounts of fuels combusted. Such data are sufficient to perform a Tier 1 analysis. In higher Tier approaches additional data are required on fuel characteristics and the combustion technologies applied.

In order to ensure transparency and comparability, a consistent classification scheme for fuel types need to be used. This section provides:

1. definitions of the different fuels
2. the units in which to express the activity data
3. guidance on possible sources of activity data and
4. guidance on time series consistency

A clear explanation of energy statistics and energy balances is provided in the "Energy Statistics Manual" of the International Energy Agency (IEA)[4].

1.4.1.1 FUEL DEFINITIONS

Common terms and definitions of fuels are necessary for countries to describe emissions from fuel combustion activities, consistently. A list of fuel types based primarily on the definitions of the International Energy Agency (IEA) is provided below. These definitions are used in the *2006 IPCC Guidelines.*

[4] OECD/IEA Energy Statistics Manual (2004), OECD/IEA, Paris. This publication can be downloaded for free at www.iea.org .

TABLE 1.1
DEFINITIONS OF FUEL TYPES USED IN THE *2006 IPCC GUIDELINES*

English Description		Comments
LIQUID (Crude oil and petroleum products)		
Crude Oil		Crude oil is a mineral oil consisting of a mixture of hydrocarbons of natural origin, being yellow to black in colour, of variable density and viscosity. It also includes lease condensate (separator liquids) which are recovered from gaseous hydrocarbons in lease separation facilities.
Orimulsion		A tar-like substance that occurs naturally in Venezuela. It can be burned directly or refined into light petroleum products.
Natural Gas Liquids (NGLs)		NGLs are the liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities, or gas processing plants. NGLs include but are not limited to ethane, propane, butane, pentane, natural gasoline and condensate. They may also include small quantities of non-hydrocarbons.
Gasoline	Motor Gasoline	This is light hydrocarbon oil for use in internal combustion engines such as motor vehicles, excluding aircraft. Motor gasoline is distilled between 35ºC and 215ºC and is used as a fuel for land based spark ignition engines. Motor gasoline may include additives, oxygenates and octane enhancers, including lead compounds such as TEL (Tetraethyl lead) and TML (Tetramethyl lead).
	Aviation Gasoline	Aviation gasoline is motor spirit prepared especially for aviation piston engines, with an octane number suited to the engine, a freezing point of -60ºC, and a distillation range usually within the limits of 30ºC and 180ºC.
	Jet Gasoline	This includes all light hydrocarbon oils for use in aviation turbine power units. They distil between 100ºC and 250ºC. It is obtained by blending kerosenes and gasoline or naphthas in such a way that the aromatic content does not exceed 25 percent in volume, and the vapour pressure is between 13.7 kPa and 20.6 kPa. Additives can be included to improve fuel stability and combustibility.
Jet Kerosene		This is medium distillate used for aviation turbine power units. It has the same distillation characteristics and flash point as kerosene (between 150ºC and 300ºC but not generally above 250ºC). In addition, it has particular specifications (such as freezing point) which are established by the International Air Transport Association (IATA).
Other Kerosene		Kerosene comprises refined petroleum distillate intermediate in volatility between gasoline and gas/diesel oil. It is a medium oil distilling between 150ºC and 300ºC.
Shale Oil		A mineral oil extracted from oil shale.
Gas/Diesel Oil		Gas/diesel oil includes heavy gas oils. Gas oils are obtained from the lowest fraction from atmospheric distillation of crude oil, while heavy gas oils are obtained by vacuum redistillation of the residual from atmospheric distillation. Gas/diesel oil distils between 180ºC and 380ºC. Several grades are available depending on uses: diesel oil for diesel compression ignition (cars, trucks, marine, etc.), light heating oil for industrial and commercial uses, and other gas oil including heavy gas oils which distil between 380ºC and 540ºC and are used as petrochemical feedstocks.
Residual Fuel Oil		This heading defines oils that make up the distillation residue. It comprises all residual fuel oils, including those obtained by blending. Its kinematic viscosity is above 0.1cm^2 (10 cSt) at 80ºC. The flash point is always above 50ºC and the density is always more than 0.90 kg/l.
Liquefied Petroleum Gases		These are the light hydrocarbons fraction of the paraffin series, derived from refinery processes, crude oil stabilisation plants and natural gas processing plants comprising propane (C3H8) and butane (C4H10) or a combination of the two. They are normally liquefied under pressure for transportation and storage.

TABLE 1.1 (CONTINUED)
DEFINITIONS OF FUEL TYPES USED IN THE *2006 IPCC GUIDELINES*

English Description		Comments
LIQUID (Crude oil and petroleum products)		
Ethane		Ethane is a naturally gaseous straight-chain hydrocarbon (C2H6). It is a colourless paraffinic gas which is extracted from natural gas and refinery gas streams.
Naphtha		Naphtha is a feedstock destined either for the petrochemical industry (e.g. ethylene manufacture or aromatics production) or for gasoline production by reforming or isomerisation within the refinery. Naphtha comprises material in the 30ºC and 210ºC distillation range or part of this range.
Bitumen		Solid, semi-solid or viscous hydrocarbon with a colloidal structure, being brown to black in colour, obtained as a residue in the distillation of crude oil, vacuum distillation of oil residues from atmospheric distillation. Bitumen is often referred to as asphalt and is primarily used for surfacing of roads and for roofing material. This category includes fluidised and cut back bitumen.
Lubricants		Lubricants are hydrocarbons produced from distillate or residue; they are mainly used to reduce friction between bearing surfaces. This category 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.
Petroleum Coke		Petroleum coke is defined as a black solid residue, obtained mainly by cracking and carbonising of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent) and has a low ash content. It is used as a feedstock in coke ovens for the steel industry, for heating purposes, for electrode manufacture and for production of chemicals. The two most important qualities are "green coke" and "calcinated coke". This category also includes "catalyst coke" deposited on the catalyst during refining processes: this coke is not recoverable and is usually burned as refinery fuel.
Refinery Feedstocks		A refinery feedstock is a product or a combination of products derived from crude oil and destined for further processing other than blending in the refining industry. It is transformed into one or more components and/or finished products. This definition covers those finished products imported for refinery intake and those returned from the petrochemical industry to the refining industry.
Other Oil	Refinery Gas	Refinery gas is defined as non-condensable gas obtained during distillation of crude oil or treatment of oil products (e.g. cracking) in refineries. It consists mainly of hydrogen, methane, ethane and olefins. It also includes gases which are returned from the petrochemical industry.
	Waxes	Saturated aliphatic hydrocarbons (with the general formula C_nH_{2n+2}). These waxes are residues extracted when dewaxing lubricant oils, and they have a crystalline structure with carbon number greater than 12. Their main characteristics are that they are colourless, odourless and translucent, with a melting point above 45ºC.
	White Spirit & SBP	White spirit and SBP are refined distillate intermediates with a distillation in the naphtha/kerosene range. They are sub-divided as: i) Industrial Spirit (SBP): Light oils distilling between 30ºC and 200ºC, with a temperature difference between 5 percent volume and 90 percent volume distillation points, including losses, of not more than 60ºC. In other words, SBP is a light oil of narrower cut than motor spirit. There are 7 or 8 grades of industrial spirit, depending on the position of the cut in the distillation range defined above. ii) White Spirit: Industrial spirit with a flash point above 30ºC. The distillation range of white spirit is 135ºC to 200ºC.
	Other Petroleum Products	Includes the petroleum products not classified above, for example: tar, sulphur, and grease. This category also includes aromatics (e.g. BTX or benzene, toluene and xylene) and olefins (e.g. propylene) produced within refineries.

TABLE 1.1 (CONTINUED)
DEFINITIONS OF FUEL TYPES USED IN THE *2006 IPCC GUIDELINES*

English Description		Comments
SOLID (Coal and coal products)		
Anthracite		Anthracite is a high rank coal used for industrial and residential applications. It has generally less than 10 percent volatile matter and a high carbon content (about 90 percent fixed carbon). Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg) on an ash-free but moist basis.
Coking Coal		Coking coal refers to bituminous coal with a quality that allows the production of a coke suitable to support a blast furnace charge. Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg) on an ash-free but moist basis.
Other Bituminous Coal		Other bituminous coal is used for steam raising purposes and includes all bituminous coal that is not included under coking coal. It is characterized by higher volatile matter than anthracite (more than 10 percent) and lower carbon content (less than 90 percent fixed carbon). Its gross calorific value is greater than 23 865 kJ/kg (5 700 kcal/kg) on an ash-free but moist basis.
Sub-Bituminous Coal		Non-agglomerating coals with a gross calorific value between 17 435 kJ/kg (4 165 kcal/kg) and 23 865 kJ/kg (5 700 kcal/kg) containing more than 31 percent volatile matter on a dry mineral matter free basis.
Lignite		Lignite/brown coal is a non-agglomerating coal with a gross calorific value of less than 17 435 kJ/kg (4 165 kcal/kg), and greater than 31 percent volatile matter on a dry mineral matter free basis.
Oil Shale and Tar Sands		Oil shale is an inorganic, non-porous rock containing various amounts of solid organic material that yields hydrocarbons, along with a variety of solid products, when subjected to pyrolysis (a treatment that consists of heating the rock at high temperature). Tar sands refers to sand (or porous carbonate rocks) that are naturally mixed with a viscous form of heavy crude oil sometimes referred to as bitumen. Due to its high viscosity this oil cannot be recovered through conventional recovery methods.
Brown Coal Briquettes		Brown coal briquettes (BKB) are composition fuels manufactured from lignite/brown coal, produced by briquetting under high pressure. These figures include dried lignite fines and dust.
Patent Fuel		Patent fuel is a composition fuel manufactured from hard coal fines with the addition of a binding agent. The amount of patent fuel produced may, therefore, be slightly higher than the actual amount of coal consumed in the transformation process.
Coke	Coke Oven Coke and Lignite Coke	Coke oven coke is the solid product obtained from the carbonisation of coal, principally coking coal, at high temperature. It is low in moisture content and volatile matter. Also included are semi-coke, a solid product obtained from the carbonisation of coal at a low temperature, lignite coke, semi-coke made from lignite/brown coal, coke breeze and foundry coke. Coke oven coke is also known as metallurgical coke.
	Gas Coke	Gas coke is a by-product of hard coal used for the production of town gas in gas works. Gas coke is used for heating purposes.
Coal Tar		The result of the destructive distillation of bituminous coal. Coal tar is the liquid by-product of the distillation of coal to make coke in the coke oven process. Coal tar can be further distilled into different organic products (e.g. benzene, toluene, naphthalene) which normally would be reported as a feedstock to the petrochemical industry.
Derived Gases	Gas Works Gas	Gas works gas covers all types of gases produced in public utility or private plants, whose main purpose is manufacture, transport and distribution of gas. It includes gas produced by carbonization (including gas produced by coke ovens and transferred to gas works gas), by total gasification with or without enrichment with oil products (LPG, residual fuel oil, etc.), and by reforming and simple mixing of gases and/or air. It excludes blended natural gas, which is usually distributed through the natural gas grid.
	Coke Oven Gas	Coke oven gas is obtained as a by-product of the manufacture of coke oven coke for the production of iron and steel.
	Blast Furnace Gas	Blast furnace gas is produced during the combustion of coke in blast furnaces in the iron and steel industry. It is recovered and used as a fuel partly within the plant and partly in other steel industry processes or in power stations equipped to burn it.
	Oxygen Steel Furnace Gas	Oxygen steel furnace gas is obtained as a by-product of the production of steel in an oxygen furnace and is recovered on leaving the furnace. The gas is also known as converter gas, LD gas or BOS gas.

TABLE 1.1 (CONTINUED)
DEFINITIONS OF FUEL TYPES USED IN THE *2006 IPCC GUIDELINES*

English Description		Comments
GAS (Natural Gas)		
Natural Gas		Natural gas should include blended natural gas (sometimes also referred to as Town Gas or City Gas), a high calorific value gas obtained as a blend of natural gas with other gases derived from other primary products, and usually distributed through the natural gas grid (eg coal seam methane). Blended natural gas should include substitute natural gas, a high calorific value gas, manufactured by chemical conversion of a hydrocarbon fossil fuel, where the main raw materials are: natural gas, coal, oil and oil shale.
OTHER FOSSIL FUELS		
Municipal Wastes (non-biomass fraction)		Non-biomass fraction of municipal waste includes waste produced by households, industry, hospitals and the tertiary sector which are incinerated at specific installations and used for energy purposes. Only the fraction of the fuel that is non-biodegradable should be included here.
Industrial Wastes		Industrial waste consists of solid and liquid products (e.g. tyres) combusted directly, usually in specialised plants, to produce heat and/or power and that are not reported as biomass.
Waste Oils		Waste oils are used oils (e.g. waste lubricants) that are combusted for heat production.
PEAT		
Peat [5]		Combustible soft, porous or compressed, sedimentary deposit of plant origin including woody material with high water content (up to 90 percent in the raw state), easily cut, can contain harder pieces of light to dark brown colour. Peat used for non-energy purposes is not included.
BIOMASS		
Solid Biofuels	Wood/Wood Waste	Wood and wood waste combusted directly for energy. This category also includes wood for charcoal production but not the actual production of charcoal (this would be double counting since charcoal is a secondary product).
	Sulphite Lyes (Black Liquor)	Sulphite lyes is an alkaline spent liquor from the digesters in the production of sulphate or soda pulp during the manufacture of paper where the energy content derives from the lignin removed from the wood pulp. This fuel in its concentrated form is usually 65-70 percent solid.
	Other Primary Solid Biomass	Other primary solid biomass includes plant matter used directly as fuel that is not already included in wood/wood waste or in sulphite lyes. Included are vegetal waste, animal materials/wastes and other solid biomass. This category includes non-wood inputs to charcoal production (e.g. coconut shells) but all other feedstocks for production of biofuels should be excluded.
	Charcoal	Charcoal combusted as energy covers the solid residue of the destructive distillation and pyrolysis of wood and other vegetal material.

[5] Although peat is not strictly speaking a fossil fuel, its greenhouse gas emission characteristics have been shown in life cycle studies to be comparable to that of fossil fuels (Nilsson and Nilsson, 2004; Uppenberg *et al*., 2001; Savolainen *et al*., 1994). Therefore, the CO_2 emissions from combustion of peat are included in the national emissions as for fossil fuels.

TABLE 1.1 (CONTINUED)
DEFINITIONS OF FUEL TYPES USED IN THE *2006 IPCC GUIDELINES*

English Description		Comments
Liquid Biofuels	Biogasoline	Biogasoline should only contain that part of the fuel that relates to the quantities of biofuel and not to the total volume of liquids into which the biofuels are blended. This category includes bioethanol (ethanol produced from biomass and/or the biodegradable fraction of waste), biomethanol (methanol produced from biomass and/or the biodegradable fraction of waste), bioETBE (ethyl-tertio-butyl-ether produced on the basis of bioethanol: the percentage by volume of bioETBE that is calculated as biofuel is 47 percent) and bioMTBE (methyl-tertio-butyl-ether produced on the basis of biomethanol: the percentage by volume of bioMTBE that is calculated as biofuel is 36 percent).
	Biodiesels	Biodiesels should only contain that part of the fuel that relates to the quantities of biofuel and not to the total volume of liquids into which the biofuels are blended. This category includes biodiesel (a methyl-ester produced from vegetable or animal oil, of diesel quality), biodimethylether (dimethylether produced from biomass), fischer tropsh (fischer tropsh produced from biomass), cold pressed bio oil (oil produced from oil seed through mechanical processing only) and all other liquid biofuels which are added to, blended with or used straight as transport diesel.
	Other Liquid Biofuels	Other liquid biofuels not included in biogasoline or biodiesels.
Gas Biomass	Landfill Gas	Landfill gas is derived from the anaerobic fermentation of biomass and solid wastes in landfills and combusted to produce heat and/or power.
	Sludge Gas	Sludge gas is derived from the anaerobic fermentation of biomass and solid wastes from sewage and animal slurries and combusted to produce heat and/or power.
	Other Biogas	Other biogas not included in landfill gas or sludge gas.
Other non-fossil fuels	Municipal Wastes (biomass fraction)	Biomass fraction of municipal waste includes waste produced by households, industry, hospitals and the tertiary sector which are incinerated at specific installations and used for energy purposes. Only the fraction of the fuel that is biodegradable should be included here.

1.4.1.2 CONVERSION OF ENERGY UNITS

In energy statistics and other energy data compilations, production and consumption of solid, liquid and gaseous fuels are specified in physical units, e.g. in tonnes or cubic metres. To convert these data to common energy units, eg joules, requires calorific values. To convert tonnes to energy units, in this case terajoules, requires calorific values. These Guidelines use net calorific values (NCVs), expressed in SI units or multiples of SI units (for example TJ/Mg). Some statistical offices use gross calorific values (GCV). The difference between NCV and GCV is the latent heat of vaporisation of the water produced during combustion of the fuel. As a consequence for coal and oil, the NCV is about 5 percent less than the GCV For most forms of natural and manufactured gas, the NCV is about 10 percent less. The Box 1.1 below provides an algorithm for the conversion if fuel characteristics (moisture, hydrogen and oxygen contents) are known. For common biomass fuels default conversion from NCV to GCV especially bark, wood and wood waste are derived in the Pulp and Paper Greenhouse Gas Calculation Tools available via the WRI/WBCSD Greenhouse Gas Protocol web site[6].

If countries use GCV, they should identify them as such. For further explanations of this issue and how to convert from the one into the other, please consult the IEA's Energy Statistics Manual (OECD/IEA, 2004).

[6] See page 9 of "Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.1, July 8, 2005" page 9 available at http://www.ghgprotocol.org/includes/getTarget.asp?type=d&id=MTYwNjQ

BOX 1.1
CONVERSION BETWEEN GROSS AND NET CALORIFIC VALUES

Units: MJ/kg - Megajoules per kilogram; 1 MJ/kg = 1 Gigajoule/tonne (GJ/tonne)

Gross CV (GCV) or 'higher heating value' (HHV) is the calorific value under laboratory conditions.

Net CV (NCV) or 'lower heating value' (LHV) is the useful calorific value in boiler plant. The difference is essentially the latent heat of the water vapour produced.

Conversions - Gross/Net (per ISO, for As Received* figures) in MJ/kg:

$$Net\,CV = Gross\,CV - 0.212H - 0.0245M - 0.008Y$$

where M is percent Moisture, H is percent Hydrogen, Y is percent Oxygen (from ultimate analysis which determines the amount of carbon, hydrogen, oxygen, nitrogen and sulphur) As Received (i.e. includes Total Moisture (TM)).

Source: World Coal Institute (http://www.worldcoal.org/pages/content/index.asp?PageID=190), which provides more details.

Default NCV values to convert from units of 10^3 tonnes to units of terajoules are in Table 1.2. These values are based on a statistical analysis of three data sources:

1. **Annual greenhouse gas inventory submissions of Annex I Parties**: UNFCCC Annex-1 countries' national submissions in 2004 on 2002 emissions (Table-1A(b) of the CRF). This dataset contains Net Calorific Values (NCVs), Carbon Emission Factor (CEF) and Carbon Oxidation Factor (COF) for individual fuels for more than 33 Annex 1 countries.
2. **Emission Factor Database**: The IPCC Emission Factor Database (EFDB), version-1, as of December 2003 contains all default values included in the *1996 IPCC Guidelines* and additional data accepted by the EFDB editorial board. The EFDB contains country-specific data for NCV and CEF including developing countries.
3. **IEA Database**: International Energy Agency NCV database for all fuels, as of November 2004. The IEA database contains country-specific NCV data for many countries, including developing countries.

The statistical analysis performed on these datasets has been described in detail in a separate document (Kainou, 2005). The same data set was used to compile a table of default values and uncertainty ranges.

1.4.1.3 ACTIVITY DATA SOURCES

Fuel statistics collected by an officially recognised national body are usually the most appropriate and accessible activity data. In some countries, however, those charged with the task of compiling inventory information may not have ready access to the entire range of data available within their country and may wish to use data specially provided by their country to the international organisations.

There are currently two main sources of international energy statistics: the International Energy Agency (IEA), and the United Nations (UN). Both international organisations collect energy data from the national administrations of their member countries through systems of questionnaires. The data gathered are therefore "official" data. To avoid duplication of reporting, where countries are members of both organisations, the UN receives copies of the IEA questionnaires for the OECD member countries rather than requiring these countries to complete the UN questionnaires. When compiling its statistics of non-OECD member countries, the IEA, for certain countries, uses UN data to which it may add additional information obtained from the national administration, consultants or energy companies operating within the countries. Statistics for other countries are obtained directly from national sources. The number of countries covered by the IEA publications is fewer than that of the UN. [7]

[7] Approximately 130 countries (of about 170 UN Member countries) are included in the IEA data, and represent about 98 per cent of worldwide energy consumption and nearly all energy production.

TABLE 1.2
DEFAULT NET CALORIFIC VALUES (NCVS) AND LOWER AND UPPER LIMITS OF THE 95% CONFIDENCE INTERVALS [1]

Fuel type English description		Net calorific value (TJ/Gg)	Lower	Upper
Crude Oil		42.3	40.1	44.8
Orimulsion		27.5	27.5	28.3
Natural Gas Liquids		44.2	40.9	46.9
Gasoline	Motor Gasoline	44.3	42.5	44.8
	Aviation Gasoline	44.3	42.5	44.8
	Jet Gasoline	44.3	42.5	44.8
Jet Kerosene		44.1	42.0	45.0
Other Kerosene		43.8	42.4	45.2
Shale Oil		38.1	32.1	45.2
Gas/Diesel Oil		43.0	41.4	43.3
Residual Fuel Oil		40.4	39.8	41.7
Liquefied Petroleum Gases		47.3	44.8	52.2
Ethane		46.4	44.9	48.8
Naphtha		44.5	41.8	46.5
Bitumen		40.2	33.5	41.2
Lubricants		40.2	33.5	42.3
Petroleum Coke		32.5	29.7	41.9
Refinery Feedstocks		43.0	36.3	46.4
Other Oil	Refinery Gas [2]	49.5	47.5	50.6
	Paraffin Waxes	40.2	33.7	48.2
	White Spirit and SBP	40.2	33.7	48.2
	Other Petroleum Products	40.2	33.7	48.2
Anthracite		26.7	21.6	32.2
Coking Coal		28.2	24.0	31.0
Other Bituminous Coal		25.8	19.9	30.5
Sub-Bituminous Coal		18.9	11.5	26.0
Lignite		11.9	5.50	21.6
Oil Shale and Tar Sands		8.9	7.1	11.1
Brown Coal Briquettes		20.7	15.1	32.0
Patent Fuel		20.7	15.1	32.0
Coke	Coke Oven Coke and Lignite Coke	28.2	25.1	30.2
	Gas Coke	28.2	25.1	30.2
Coal Tar [3]		28.0	14.1	55.0
Derived Gases	Gas Works Gas [4]	38.7	19.6	77.0
	Coke Oven Gas [5]	38.7	19.6	77.0
	Blast Furnace Gas [6]	2.47	1.20	5.00
	Oxygen Steel Furnace Gas [7]	7.06	3.80	15.0
Natural Gas		48.0	46.5	50.4
Municipal Wastes (non-biomass fraction)		10	7	18
Industrial Wastes		NA	NA	NA
Waste Oil [8]		40.2	20.3	80.0
Peat		9.76	7.80	12.5

TABLE 1.2 (CONTINUED)
DEFAULT NET CALORIFIC VALUES (NCVS) AND LOWER AND UPPER LIMITS OF THE 95% CONFIDENCE INTERVALS [1]

Fuel type English description		Net calorific value (TJ/Gg)	Lower	Upper
Solid Biofuels	Wood/Wood Waste [9]	15.6	7.90	31.0
	Sulphite lyes (black liquor) [10]	11.8	5.90	23.0
	Other Primary Solid Biomass [11]	11.6	5.90	23.0
	Charcoal [12]	29.5	14.9	58.0
Liquid Biofuels	Biogasoline [13]	27.0	13.6	54.0
	Biodiesels [14]	27.0	13.6	54.0
	Other Liquid Biofuels [15]	27.4	13.8	54.0
Gas Biomass	Landfill Gas [16]	50.4	25.4	100
	Sludge Gas [17]	50.4	25.4	100
	Other Biogas [18]	50.4	25.4	100
Other non-fossil fuels	Municipal Wastes (biomass fraction)	11.6	6.80	18.0

Notes:

[1] The lower and upper limits of the 95 percent confidence intervals, assuming lognormal distributions, fitted to a dataset, based on national inventory reports, IEA data and available national data. A more detailed description is given in section 1.5.

[2] Japanese data; uncertainty range: expert judgement

[3] EFDB; uncertainty range: expert judgement

[4] Coke Oven Gas; uncertainty range: expert judgement

[5-7] Japan and UK small number data; uncertainty range: expert judgement

[8] For waste oils the values of "Lubricants" are taken

[9] EFDB; uncertainty range: expert judgement

[10] Japanese data ; uncertainty range: expert judgement

[11] Solid Biomass; uncertainty range: expert judgement

[12] EFDB; uncertainty range: expert judgement

[13-14] Ethanol theoretical number; uncertainty range: expert judgement;

[15] Liquid Biomass; uncertainty range: expert judgement

[16 -18] Methane theoretical number uncertainty range: expert judgement;

In general, the IEA and UN data for a country can be obtained free of charge by that country's national inventory agencies by contacting stats@iea.org or energy_stat@un.org.

Two types of fuels deserve special attention:

Biomass:

Biomass data are generally more uncertain than other data in national energy statistics. A large fraction of the biomass, used for energy, may be part of the informal economy, and the trade in these type of fuels (fuel wood, agricultural residues, dung cakes, etc.) is frequently not registered in the national energy statistics and balances.

The AFOLU Volume 4 Chapter 4 (Forest Land) provides an alternative method to estimate activity data for fuel wood use.

Where data from energy statistics and AFOLU statistics are both available, the inventory compiler should take care to avoid any double counting, and should indicate how data from both sources have been integrated to obtain the best possible estimate of fuel wood use in the country. CO_2 emissions from biomass combustion are not included in national totals, but are recorded as an information item for cross-checking purposes as well as avoiding double counting. Note that peat is not treated as biomass in these guidelines, therefore CO_2 emissions from peat are estimated.

Waste:

Waste incineration may occur in installations where the combustion heat is used as energy in other processes. In such cases, this waste must be treated as a fuel and the emissions should be reported in the energy sector. When waste is incinerated without using the combustion heat as energy, emissions should be reported under waste incineration. Methodologies in both cases are provided in Volume 5 Chapter 5. CO_2 emissions from combustion

of biomass in waste used for energy are not included in national totals, but are recorded as an information item for cross-checking purposes.

1.4.1.4 TIME SERIES CONSISTENCY

Many countries have long time series of energy statistics that can be used to derive time series of energy sector greenhouse gas emissions. However, in many cases statistical practices (including definitions of fuels, of fuel use by sectors) will have changed over time and recalculations of the energy data in the latest set of definitions is not always feasible. In compiling time series of emissions from fuel combustion, these changes might give rise to time series inconsistencies, which should be dealt with using the methods provided in Time Series Consistency Chapter 5 of Volume 1 of the *2006 IPCC Guidelines*.

1.4.2 Emission factors

1.4.2.1 CO_2 EMISSION FACTORS

Combustion processes are optimized to derive the maximum amount of energy per unit of fuel consumed, hence delivering the maximum amount of CO_2. Efficient fuel combustion ensures oxidation of the maximum amount of carbon available in the fuel. CO_2 emission factors for fuel combustion are therefore relatively insensitive to the combustion process itself and hence are primarily dependent only on the carbon content of the fuel.

The carbon content may vary considerably both among and within primary fuel types on a per mass or per volume basis:

- For natural gas, the carbon content depends on the composition of the gas which, in its delivered state, is primarily methane, but can include small quantities of ethane, propane, butane, and heavier hydrocarbons. Natural gas flared at the production site will usually contain far larger amounts of non-methane hydrocarbons. The carbon content will be correspondingly different.
- Carbon content per unit of energy is usually less for light refined products such as gasoline than for heavier products such as residual fuel oil.
- For coal, carbon emissions per tonne vary considerably depending on the coal's composition of carbon, hydrogen, sulphur, ash, oxygen, and nitrogen.

By converting to energy units this variability is reduced.

A small part of the fuel carbon entering the combustion process escapes oxidation. This fraction is usually small (99 to 100 percent of the carbon is oxidized) and so the default emission factors in Table 1.4 are derived on the assumption of 100 percent oxidation. For some fuels, this fraction may in practice not be negligible and where representative country-specific values, based on measurements are available, they should be used. In other words: the fraction of carbon oxidised is assumed to be 1 in deriving default CO_2 emission factors.

Table 1.3 gives carbon contents of fuels from which emission factors on a full molecular weight basis can be calculated (Table 1.4). These emission factors are default values that are suggested only if country-specific factors are not available. More detailed and up-to-date emission factors may be available at the IPCC EFDB.

Note that CO_2 emissions from biomass fuels are not included in the national total but are reported as an information item. Net emissions or removals of CO_2 are estimated in the AFOLU sector and take account of these emissions. Note that peat is treated as a fossil fuel and not a biofuel and emissions from its combustion are therefore included in the national total.

The data presented in Table 1.3 is used to calculate default emission factors for each fuel on a per energy basis. If activity data are available on a per mass basis, a similar approach can be applied to these activity data directly. Obviously the carbon content then should be known on a per mass basis.

TABLE 1.3
DEFAULT VALUES OF CARBON CONTENT

Fuel type English description	Default carbon content [1] (kg/GJ)	Lower	Upper
Crude Oil	20.0	19.4	20.6
Orimulsion	21.0	18.9	23.3
Natural Gas Liquids	17.5	15.9	19.2
Motor Gasoline	18.9	18.4	19.9
Aviation Gasoline	19.1	18.4	19.9
Jet Gasoline	19.1	18.4	19.9
Jet Kerosene	19.5	19	20.3
Other Kerosene	19.6	19.3	20.1
Shale Oil	20.0	18.5	21.6
Gas/Diesel Oil	20.2	19.8	20.4
Residual Fuel Oil	21.1	20.6	21.5
Liquefied Petroleum Gases	17.2	16.8	17.9
Ethane	16.8	15.4	18.7
Naphtha	20.0	18.9	20.8
Bitumen	22.0	19.9	24.5
Lubricants	20.0	19.6	20.5
Petroleum Coke	26.6	22.6	31.3
Refinery Feedstocks	20.0	18.8	20.9
Refinery Gas [2]	15.7	13.3	19.0
Paraffin Waxes	20.0	19.7	20.3
White Spirit & SBP	20.0	19.7	20.3
Other Petroleum Products	20.0	19.7	20.3
Anthracite	26.8	25.8	27.5
Coking Coal	25.8	23.8	27.6
Other Bituminous Coal	25.8	24.4	27.2
Sub-Bituminous Coal	26.2	25.3	27.3
Lignite	27.6	24.8	31.3
Oil Shale and Tar Sands	29.1	24.6	34
Brown Coal Briquettes	26.6	23.8	29.6
Patent Fuel	26.6	23.8	29.6
Coke Oven Coke and Lignite Coke	29.2	26.1	32.4
Gas Coke	29.2	26.1	32.4
Coal Tar [3]	22.0	18.6	26.0
Gas Works Gas [4]	12.1	10.3	15.0
Coke Oven Gas [5]	12.1	10.3	15.0
Blast Furnace Gas [6]	70.8	59.7	84.0
Oxygen Steel Furnace Gas [7]	49.6	39.5	55.0
Natural Gas	15.3	14.8	15.9

TABLE 1.3 (CONTINUED)
DEFAULT VALUES OF CARBON CONTENT

Fuel type English description	Default carbon content [1] (kg/GJ)	Lower	Upper
Municipal Wastes (non-biomass fraction)[8]	25.0	20.0	33.0
Industrial Wastes	39.0	30.0	50.0
Waste Oils [9]	20.0	19.7	20.3
Peat	28.9	28.4	29.5
Wood/Wood Waste [10]	30.5	25.9	36.0
Sulphite lyes (black liquor) [11]	26.0	22.0	30.0
Other Primary Solid Biomass [12]	27.3	23.1	32.0
Charcoal [13]	30.5	25.9	36.0
Biogasoline [14]	19.3	16.3	23.0
Biodiesels [15]	19.3	16.3	23.0
Other Liquid Biofuels [16]	21.7	18.3	26.0
Landfill Gas [17]	14.9	12.6	18.0
Sludge Gas [18]	14.9	12.6	18.0
Other Biogas [19]	14.9	12.6	18.0
Municipal Wastes (biomass fraction) [20]	27.3	23.1	32.0

Notes:

[1] The lower and upper limits of the 95 percent confidence intervals, assuming lognormal distributions, fitted to a dataset, based on national inventory reports, IEA data and available national data. A more detailed description is given in section 1.5

[2] Japanese data; uncertainty range: expert judgement;

[3] EFDB; uncertainty range: expert judgement

[4] Coke Oven Gas; uncertainty range: expert judgement

[5] Japan & UK small number data; uncertainty range: expert judgement

[6] 7. Japan & UK small number data; uncertainty range: expert judgement

[8] Solid Biomass; uncertainty range: expert judgement

[9] Lubricants ; uncertainty range: expert judgement

[10] EFDB; uncertainty range: expert judgement

[11] Japanese data; uncertainty range: expert judgement

[12] Solid Biomass; uncertainty range: expert judgement

[13] EFDB; uncertainty range: expert judgement

[14] Ethanol theoretical number; uncertainty range: expert judgement

[15] Ethanol theoretical number; uncertainty range: expert judgement

[16] Liquid Biomass; uncertainty range: expert judgement

[17-19] Methane theoretical number; uncertainty range: expert judgement

[20] Solid Biomass; uncertainty range: expert judgement

TABLE 1.4
DEFAULT CO_2 EMISSION FACTORS FOR COMBUSTION [1]

Fuel type English description		Default carbon content (kg/GJ)	Default carbon oxidation factor	Effective CO_2 emission factor (kg/TJ) [2]		
				Default value [3]	95% confidence interval	
		A	B	C=A*B*44/ 12*1000	Lower	Upper
Crude Oil		20.0	1	73 300	71 100	75 500
Orimulsion		21.0	1	77 000	69 300	85 400
Natural Gas Liquids		17.5	1	64 200	58 300	70 400
Gasoline	Motor Gasoline	18.9	1	69 300	67 500	73 000
	Aviation Gasoline	19.1	1	70 000	67 500	73 000
	Jet Gasoline	19.1	1	70 000	67 500	73 000
Jet Kerosene		19.5	1	71 500	69 700	74 400
Other Kerosene		19.6	1	71 900	70 800	73 700
Shale Oil		20.0	1	73 300	67 800	79 200
Gas/Diesel Oil		20.2	1	74 100	72 600	74 800
Residual Fuel Oil		21.1	1	77 400	75 500	78 800
Liquefied Petroleum Gases		17.2	1	63 100	61 600	65 600
Ethane		16.8	1	61 600	56 500	68 600
Naphtha		20.0	1	73 300	69 300	76 300
Bitumen		22.0	1	80 700	73 000	89 900
Lubricants		20.0	1	73 300	71 900	75 200
Petroleum Coke		26.6	1	97 500	82 900	115 000
Refinery Feedstocks		20.0	1	73 300	68 900	76 600
Other Oil	Refinery Gas	15.7	1	57 600	48 200	69 000
	Paraffin Waxes	20.0	1	73 300	72 200	74 400
	White Spirit & SBP	20.0	1	73 300	72 200	74 400
Other Petroleum Products		20.0	1	73 300	72 200	74 400
Anthracite		26.8	1	98 300	94 600	101 000
Coking Coal		25.8	1	94 600	87 300	101 000
Other Bituminous Coal		25.8	1	94 600	89 500	99 700
Sub-Bituminous Coal		26.2	1	96 100	92 800	100 000
Lignite		27.6	1	101 000	90 900	115 000
Oil Shale and Tar Sands		29.1	1	107 000	90 200	125 000
Brown Coal Briquettes		26.6	1	97 500	87 300	109 000
Patent Fuel		26.6	1	97 500	87 300	109 000
Coke	Coke oven coke and lignite Coke	29.2	1	107 000	95 700	119 000
	Gas Coke	29.2	1	107 000	95 700	119 000
Coal Tar		22.0	1	80 700	68 200	95 300
Derived Gases	Gas Works Gas	12.1	1	44 400	37 300	54 100
	Coke Oven Gas	12.1	1	44 400	37 300	54 100
	Blast Furnace Gas [4]	70.8	1	260 000	219 000	308 000
	Oxygen Steel Furnace Gas [5]	49.6	1	182 000	145 000	202 000

TABLE 1.4 (CONTINUED)
DEFAULT CO_2 EMISSION FACTORS FOR COMBUSTION [1]

Fuel type English description		Default carbon content (kg/GJ)	Default carbon oxidation Factor	Effective CO_2 emission factor (kg/TJ) [2]		
				Default value	95% confidence interval	
		A	B	C=A*B*44/ 12*1000	Lower	Upper
Natural Gas		15.3	1	56 100	54 300	58 300
Municipal Wastes (non-biomass fraction)		25.0	1	91 700	73 300	121 000
Industrial Wastes		39.0	1	143 000	110 000	183 000
Waste Oil		20.0	1	73 300	72 200	74 400
Peat		28.9	1	106 000	100 000	108 000
Solid Biofuels	Wood/Wood Waste	30.5	1	112 000	95 000	132 000
	Sulphite lyes (black liquor)[5]	26.0	1	95 300	80 700	110 000
	Other Primary Solid Biomass	27.3	1	100 000	84 700	117 000
	Charcoal	30.5	1	112 000	95 000	132 000
Liquid Biofuels	Biogasoline	19.3	1	70 800	59 800	84 300
	Biodiesels	19.3	1	70 800	59 800	84 300
	Other Liquid Biofuels	21.7	1	79 600	67 100	95 300
Gas biomass	Landfill Gas	14.9	1	54 600	46 200	66 000
	Sludge Gas	14.9	1	54 600	46 200	66 000
	Other Biogas	14.9	1	54 600	46 200	66 000
Other non-fossil fuels	Municipal Wastes (biomass fraction)	27.3	1	100 000	84 700	117 000

Notes:

[1] The lower and upper limits of the 95 percent confidence intervals, assuming lognormal distributions, fitted to a dataset, based on national inventory reports, IEA data and available national data. A more detailed description is given in section 1.5

[2] TJ = 1000GJ

[3] The emission factor values for BFG includes carbon dioxide originally contained in this gas as well as that formed due to combustion of this gas.

[4] The emission factor values for OSF includes carbon dioxide originally contained in this gas as well as that formed due to combustion of this gas

[5] Includes the biomass-derived CO_2 emitted from the black liquor combustion unit and the biomass-derived CO_2 emitted from the kraft mill lime kiln.

1.4.2.2 OTHER GREENHOUSE GASES

Emission factors for non-CO_2 gases from fuel combustion are strongly dependent on the technology used. Since the set of technologies, applied in each sector varies considerably, so do the emission factors. Therefore it is not useful to provide default emission factors for these gases on the basis of fuels only. Tier 1 default emission factors are therefore provided in the subsequent chapters for each subsector separately.

1.4.2.3 INDIRECT GREENHOUSE GASES

This volume will not present guidance on the estimation of emissions of indirect greenhouse gases. For information on these gases, the user is referred to guidance provided under other conventions (see also section 1.3.1.3 Relation to other inventory approaches). Default methods for estimating these emissions are provided in the EMEP/CORINAIR Guidebook. Chapter 7 of Volume 1 provides full details on how to link to this information.

1.5 UNCERTAINTY IN INVENTORY ESTIMATES

1.5.1 General

A general treatment of uncertainties in emission inventories is provided in Chapter 3 of Volume 1 of the *2006 IPCC Guidelines*. A quantitative analysis of the uncertainties in the inventory need quantitative input values for both activity data and emission factors. This chapter will provide recommended default uncertainty ranges (95 percent confidence interval limits) to be used if further information is not available. The lower limit (marked as "lower" in the tables) is set at the 2.5 percent percentile of the probability distribution function and the upper limit (marked "upper" in the tables) at the 97.5 percentile.

All default values in this chapter are rounded to three significant digits, both for the default emission factor itself and for the lower and upper limits of the 95 percent confidence intervals. Although applying exact arithmetic could provide more digits, these are not considered as significant.

1.5.2 Activity data uncertainties

Activity data needed for emission estimates in the Energy Sector are largely derived from national and international energy balances and energy statistics. Such data are generally seen as quite accurate. Uncertainty information on the fuel combustion statistics or the energy balances could be obtained from the national or international institutions responsible.

If no further data are available, the recommended default uncertainty range for fossil fuel combustion data should be assumed to be plus or minus 5 percent. In other words:

- The value in the energy statistics or energy balance is interpreted as the point estimate for the activity data
- The lower limit value of the 95 percent confidence interval is 0.95 times the point estimate;
- The upper limit value of the 95 percent confidence interval is 1.05 times this value.

The "statistical difference", frequently given in energy balances, could also be used to obtain a feeling for the uncertainty in the data. The "statistical difference" is calculated from the difference between data derived from the supply of fuels and data derived from the demand of fuels. The year-to-year variation in its value reflects the aggregated uncertainty in all underlying fuel data including their inter relationships. Hence, the variation of the "statistical difference" will be an indication of the combined uncertainty of all supply and demand data for a specific fuel. Recalling that the uncertainties are expressed in percentage terms, the uncertainties in the fuel combustion data for specific sectors or applications will usually be higher than the uncertainty suggested by the "statistical difference". The recommended default uncertainty range is based on this line of thought. However, if a "statistical difference" is zero, the balance is immediately suspect and should be treated as though a "statistical difference" had not been given. In these instances, the data quality should be examined for QA/QC purposes and subsequent improvements made if appropriate.

Since data on biomass as fuel are not as well developed as for fossil fuels, the uncertainty range for biomass fuels will be significantly higher. A value of plus or minus 50 percent is recommended.

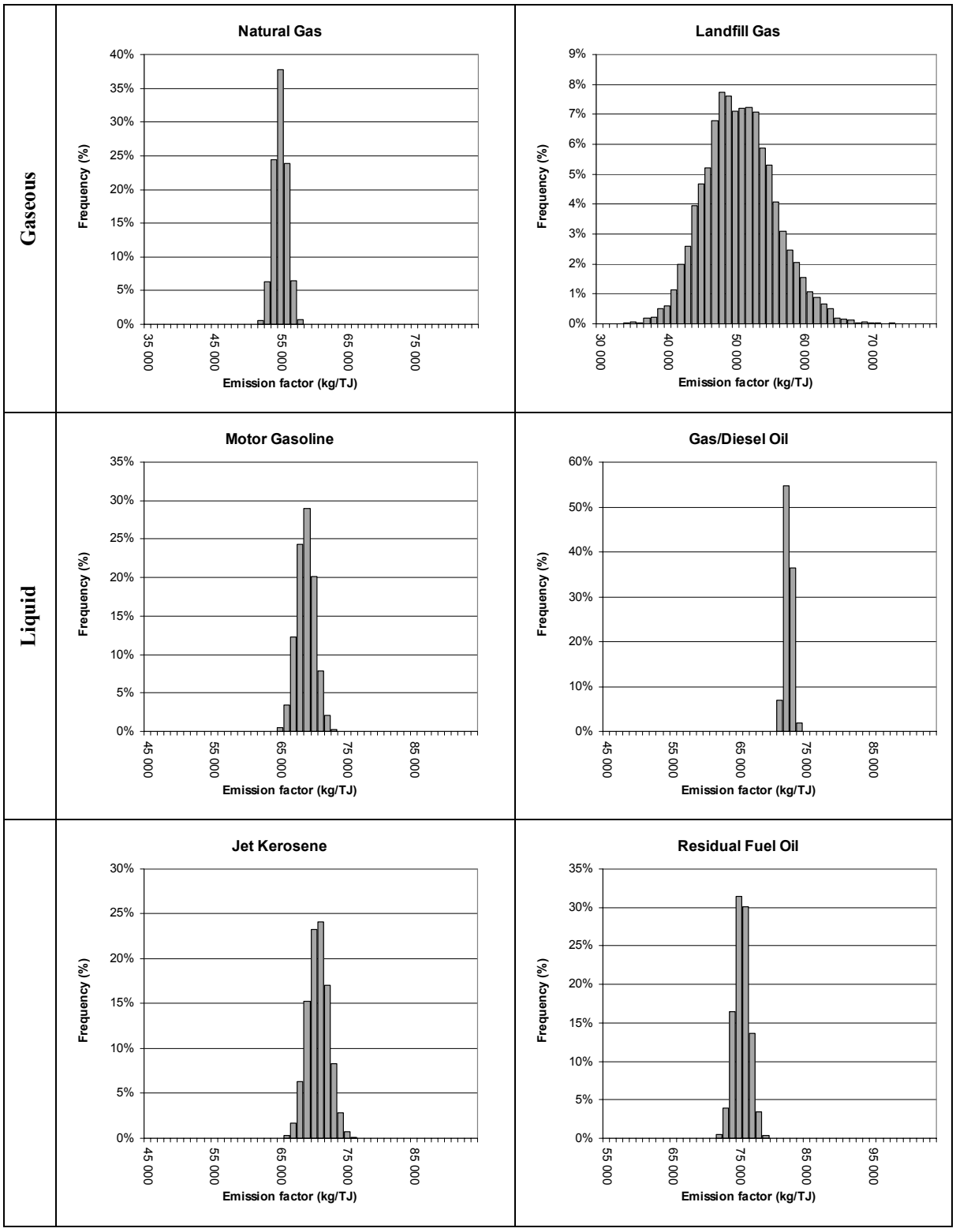
1.5.3 Emission factor uncertainties

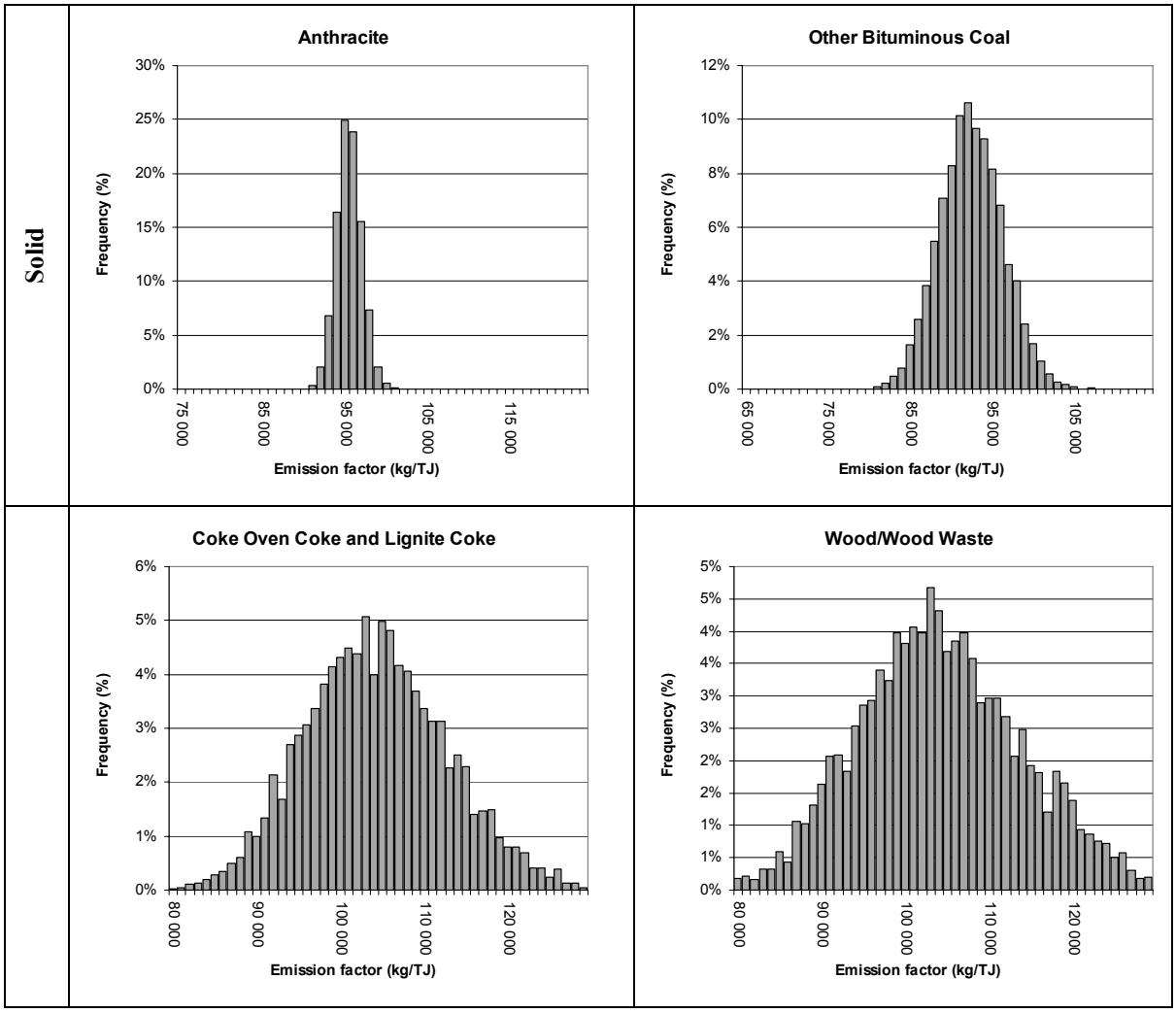
The default emission factors, derived in this chapter are based on a statistical analysis of available data on fuel characteristics. The analysis provides lower and upper limits of the 95 percent confidence intervals as provided in Table 1.2 for net calorific values and Table 1.3 for carbon contents of fuels.

The uncertainty ranges, provided in Table 1.4 are calculated from this information, using a Monte Carlo analysis (5 000 iterations). In this analysis, lognormal distributions, fitted to the provided lower and upper limits of the 95 percent confidence intervals were applied for the probability distribution functions.

For a few typical examples, the resulting probability distribution functions for the default final effective CO_2 emission factors are given below in Figure 1.3.

Figure 1.3 Some typical examples of probability distribution functions (PDFs) for the effective CO_2 emission factors for the combustion of fuels.





The uncertainty information as presented in Table 1.4 can also be used when comparing country-specific emission factors with the default ones. Whenever a national specific emission factor falls within the 95 percent confidence interval, it could be regarded as consistent with the default value. In addition, one would expect the uncertainty range of country-specific values for application in that country to be smaller than the range provided in Figure 1.3. Uncertainties in emission factors for non-CO_2 emission factors are treated in the subsequent chapters for the different source categories separately.

1.6 QA/QC AND COMPLETENESS

1.6.1 Reference Approach

As carbon dioxide emissions from fuel combustion dominate greenhouse gas emissions in many countries, it is worthwhile to use an independent check providing a quick and easy alternative estimate of these emissions. The Reference Approach provides a methodology for producing a first-order estimate of national greenhouse gas emissions based on the energy supplied to a country, even if only very limited resources and data structures are available to the inventory compiler. Since the Reference Approach is a top-down approach and in that respect is relatively independent of the bottom-up approach as described in the Tier 1, 2 and 3 methods of this chapter, the Reference Approach can be seen as a verification cross-check. As such it is part of the required QA/QC for the energy sector. The Reference Approach is described in full detail in Chapter 6 of this Volume.

The Reference Approach requires statistics on the production of fuels, on their external trade, as well as on changes in their stocks. It also requires a limited amount of data on the consumption of fuels used for non-energy purposes where carbon may need to be excluded.

The Reference Approach is based on the assumption that, once carbon is brought into a national economy in the form of a fuel, it is either released into the atmosphere in the form of a greenhouse gas, or it is diverted (e.g., in increases of fuel stocks, stored in products, left unutilised in ash) and does not enter the atmosphere as a

greenhouse gas. In order to calculate the amount of carbon released into the atmosphere, it is not necessary to know exactly how the fuel was used or what intermediate transformations it underwent. In view of this, the methodology may be described as *top-down* in contrast to the *bottom-up* methodologies applied in a sectoral approach.

1.6.2 Potential double counting between sectors

1.6.2.1 NON-ENERGY USE OF FUELS

For a number of applications, mainly in larger industrial processes, fossil hydrocarbons are not only used as energy sources, but also have other uses e.g. feedstocks, lubricants, solvents, etc. The sectoral approaches (Tier 1, 2 and 3) are therefore based on fuel combustion statistics.

Hence, the use of fuel combustion statistics rather than fuel delivery statistics is key to avoid double counting in emission estimates. When activity data are not quantities of fuel combusted but are instead deliveries to enterprises or main subcategories, there is a risk of double counting emissions from the IPPU (Chapter 5) or Waste Sectors.

In some types of non-energy use of fossil hydrocarbons, emissions of fossil carbon containing substances might occur. Such emissions should be reported under the IPPU sector where they occur. Methods to estimate these emissions are provided in Volume 3, Industrial Processes and Product Use.

1.6.2.2 WASTE AS A FUEL

Some waste incinerators also produce heat or power. In such cases the waste stream will show up in national energy statistics and it is *good practice* to report these emissions under the energy sector. This could lead to double counting when in the waste sector the total volume of waste is used to estimate emissions. Only the fossil fuel derived fraction of CO_2 from waste is included in national total emissions. For details please see Volume 5 (Waste)-Chapter 5 (Incineration and Open Burning of Waste) where methodological issues to estimate emissions are discussed.

1.6.3 Mobile versus stationary combustion

For most sources the distinction between mobile and stationary combustion is quite clear. In energy statistics, this however is not always the case. In some industries it might occur that fuels are in part used for stationary equipment and in part for mobile equipment. This could for example occur in agriculture, forestry, construction industry etc. When this occurs and a split between mobile and stationary is not feasible, the emissions could be reported in the source category that is expected to have the largest part of the emissions. In such cases, care must be taken to properly document the method and choices.

1.6.4 National boundaries

Mobile sources, while moving across national borders, might carry part of the fuel sold in one country for use in a second country. To estimate these emissions, however, the principle of using fuel sold to estimate the emissions should prevail over a strict application of the national territory for several reasons:

- data on fuels moving across borders in vehicle fuel tanks is unlikely to be available at all, and if it were it is likely to be much less accurate than national fuel sales data
- it is important that emissions from fuel sold appear in only one county's inventory. It would be nearly impossible to ensure consistency between neighbouring countries
- in most cases the net effect of trans-boundary traffic will be small since most vehicles will in the end return to their own country with fuel in their tanks. Only in cases of "fuel tourism[8]" this might not be the case.

[8] People living near national borders might have an incentive to buy gasoline in one country for use in the other country if gasoline prices differ between these countries. In some regions this effect is substantial. See: Fuel tourism in border regions, Silvia Banfi, Massimo Filippini, Lester C. Hunt, CEPE, Centre for Energy Policy and Economics, Swiss Federal Institutes of Technology, 2003, http://e-collection.ethbib.ethz.ch/show?type=incoll&nr=888

Other advice on boundary issues associated with bunker fuels and carbon capture and storage is provided in subsequent chapters, consistent with the principles set out in Volume 1, Chapter 8.

1.6.5 New sources

The *2006 IPCC Guidelines* include, for the first time, methods for estimating emissions from carbon dioxide capture and storage (Chapter 5) so that the effect of these technologies on reducing emissions overall can be properly reflected in national inventories. The Guidelines also include new methods for estimation emissions from abandoned coal mines (Section 4.1), to complement the methods for working mines which were already included in the *1996 IPCC Guidelines and GPG2000*.

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CHAPTER 2

STATIONARY COMBUSTION

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2 STATIONARY COMBUSTION

2.1 OVERVIEW

This chapter describes the methods and data necessary to estimate emissions from Stationary Combustion, and the categories in which these emissions should be reported. Methods are provided for the sectoral approach in three tiers based on:

- Tier 1: fuel combustion from national energy statistics and default emission factors;
- Tier 2: fuel combustion from national energy statistics, together with country-specific emission factors, where possible, derived from national fuel characteristics;
- Tier 3: fuel statistics and data on combustion technologies applied together with technology-specific emission factors; this includes the use of models and facility level emission data where available.

The chapter provides default Tier 1 emission factors for all source categories and fuels. The IPCC Emission Factor Database[1] may be consulted for information appropriate to national circumstances, though the correct use of information from the database is the responsibility of greenhouse gas inventory compilers.

This chapter covers elements formerly presented in the 'Energy' chapter of the *GPG2000*. The organisation of the *IPCC 2006 Guidelines* is different from both the *IPCC 1996 Guidelines* and the *GPG2000*. The changes to the stationary combustion information are summarised below.

Content:

- A table detailing which sectors this chapter covers, and which IPCC source codes the emissions are to be reported under is included.
- Some of the emission factors have been revised, and some new factors have also been included. The tables containing the emission factors indicate which factors are new, and which have been revised from the *IPCC 1996 Guidelines* and *GPG2000*.
- The default oxidation factor is assumed to be 1, unless better information is available.
- In the Tier 1 sectoral approach, the oxidation factor is included with the emission factor, which simplifies the worksheet.
- Building on the *GPG2000*, this chapter includes extended information about uncertainty assessment of both the activity data and the emission factors.
- Some definitions have changed or been refined.
- A new section on carbon dioxide capture and storage has been added.

Structure:

- The methodology for estimating emissions is now subdivided into smaller sections for each Tier approach.
- The tables have been designed to present emission factors for CO_2, CH_4, and N_2O together, where possible.

2.2 DESCRIPTION OF SOURCES

In the Sectoral Approach, emissions from stationary combustion are specified for a number of societal and economic activities, defined within the IPCC sector 1A, Fuel Combustion Activities (see Table 2.1). A distinction is made between stationary combustion in energy industries (1.A.1), manufacturing industries and construction (1.A.2) and other sectors (1.A.4). Although these distinct subsectors are intended to include all stationary combustion, an additional category is available in sector 1.A.5 for any emissions that cannot be allocated to one of the other subcategories. Table 2.1 also indicates the mobile source categories in 1.A.4 and 1.A.5 that are treated in Chapter 3 of this Volume.

[1] Available at http://www.ipcc-nggip.iges.or.jp/efdb/main.php

TABLE 2.1
DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[2]

Code number and name				Definitions
1 ENERGY				All GHG emissions arising from combustion and fugitive releases of fuels. Emissions from the non-energy uses of fuels are generally not included here, but reported under Industrial Processes and Product Use.
1 A Fuel Combustion Activities				Emissions from the intentional oxidation of materials within an apparatus that is designed to raise heat and provide it either as heat or as mechanical work to a process or for use away from the apparatus.
1 A 1	*Energy Industries*			Comprises emissions from fuels combusted by the fuel extraction or energy-producing industries.
1 A 1	a	Main Activity Electricity and Heat Production		Sum of emissions from main activity producers of electricity generation, combined heat and power generation, and heat plants. Main activity producers (formerly known as public utilities) are defined as those undertakings whose primary activity is to supply the public. They may be in public or private ownership. Emissions from own on-site use of fuel should be included. Emissions from autoproducers (undertakings which generate electricity/heat wholly or partly for their own use, as an activity that supports their primary activity) should be assigned to the sector where they were generated and not under 1 A 1 a. Autoproducers may be in public or private ownership.
1 A 1	a	*i*	*Electricity Generation*	Comprises emissions from all fuel use for electricity generation from main activity producers except those from combined heat and power plants.
1 A 1	a	*ii*	*Combined Heat and Power Generation (CHP)*	Emissions from production of both heat and electrical power from main activity producers for sale to the public, at a single CHP facility.
		iii	*Heat Plants*	Production of heat from main activity producers for sale by pipe network.
1 A 1	b	Petroleum Refining		All combustion activities supporting the refining of petroleum products including on-site combustion for the generation of electricity and heat for own use. Does not include evaporative emissions occurring at the refinery. These emissions should be reported separately under 1 B 2 a.

[2] Methods for mobile sources occurring in sub-categories 1 A 4 and 1 A 5 are dealt with in Chapter 3 and the emissions are reported under Stationary Combustion.

TABLE 2.1 (CONTINUED)
DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[3]

Code number and name				Definitions
1 A 1	c	Manufacture of Solid Fuels and Other Energy Industries		Combustion emissions from fuel use during the manufacture of secondary and tertiary products from solid fuels including production of charcoal. Emissions from own on-site fuel use should be included. Also includes combustion for the generation of electricity and heat for own use in these industries.
1 A 1	c	*i*	*Manufacture of Solid Fuels*	Emissions arising from fuel combustion for the production of coke, brown coal briquettes and patent fuel.
1 A 1	c	*ii*	*Other Energy Industries*	Combustion emissions arising from the energy-producing industries own (on-site) energy use not mentioned above or for which separate data are not available. This includes the emissions from own-energy use for the production of charcoal, bagasse, saw dust, cotton stalks and carbonizing of biofuels as well as fuel used for coal mining, oil and gas extraction and the processing and upgrading of natural gas. This category also includes emissions from pre-combustion processing for CO_2 capture and storage. Combustion emissions from pipeline transport should be reported under 1 A 3 e.
1 A 2	*Manufacturing Industries and Construction*			Emissions from combustion of fuels in industry. Also includes combustion for the generation of electricity and heat for own use in these industries. Emissions from fuel combustion in coke ovens within the iron and steel industry should be reported under 1 A 1 c and not within manufacturing industry. Emissions from the industry sector should be specified by sub-categories that correspond to the International Standard Industrial Classification of all Economic Activities (ISIC). Energy used for transport by industry should not be reported here but under Transport (1 A 3). Emissions arising from off-road and other mobile machinery in industry should, if possible, be broken out as a separate subcategory. For each country, the emissions from the largest fuel-consuming industrial categories ISIC should be reported, as well as those from significant emitters of pollutants. A suggested list of categories is outlined below.
1 A 2	a	Iron and Steel		ISIC Group 271 and Class 2731
1 A 2	b	Non-Ferrous Metals		ISIC Group 272 and Class 2732
1 A 2	c	Chemicals		ISIC Division 24
1 A 2	d	Pulp, Paper and Print		ISIC Divisions 21 and 22
1 A 2	e	Food Processing, Beverages and Tobacco		ISIC Divisions 15 and 16
1 A 2	f	Non-Metallic Minerals		Includes products such as glass, ceramic, cement, etc.; ISIC Division 26
1 A 2	g	Transport Equipment		ISIC Divisions 34 and 35
1 A 2	h	Machinery		Includes fabricated metal products, machinery and equipment other than transport equipment; ISIC Divisions 28, 29, 30, 31 and 32.

[3] Methods for mobile sources occurring in sub-categories 1 A 4 and 1 A 5 are dealt with in Chapter 3 and the emissions are reported under Stationary Combustion.

TABLE 2.1 (CONTINUED)
DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[4]

Code number and name				Definitions
1 A 2	i	Mining (excluding fuels) and Quarrying		ISIC Divisions 13 and 14
1 A 2	j	Wood and Wood Products		ISIC Division 20
1 A 2	k	Construction		ISIC Division 45
1 A 2	l	Textile and Leather		ISIC Divisions 17, 18 and 19
1 A 2	m	Non-specified Industry		Any manufacturing industry/construction not included above or for which separate data are not available. Includes ISIC Divisions 25, 33, 36 and 37.
1 A 4	*Other Sectors*			Emissions from combustion activities as described below, including combustion for the generation of electricity and heat for own use in these sectors.
1 A 4	a	Commercial / Institutional		Emissions from fuel combustion in commercial and institutional buildings; all activities included in ISIC Divisions 41, 50, 51, 52, 55, 63-67, 70-75, 80, 85, 90-93 and 99.
1 A 4	b	Residential		All emissions from fuel combustion in households.
1 A 4	c	Agriculture / Forestry / Fishing / Fish farms		Emissions from fuel combustion in agriculture, forestry, fishing and fishing industries such as fish farms. Activities included in ISIC Divisions 01, 02 and 05. Highway agricultural transportation is excluded.
1 A 4	c	*i*	*Stationary*	Emissions from fuels combusted in pumps, grain drying, horticultural greenhouses and other agriculture, forestry or stationary combustion in the fishing industry.
1 A 4	c	*ii*	*Off-road Vehicles and Other Machinery*	Emissions from fuels combusted in traction vehicles on farm land and in forests.
1 A 4	c	*iii*	*Fishing (mobile combustion)*	Emissions from fuels combusted for inland, coastal and deep-sea fishing. Fishing should cover vessels of all flags that have refuelled in the country (include international fishing).

[4] Methods for mobile sources occurring in sub-categories 1 A 4 and 1 A 5 are dealt with in Chapter 3 and the emissions are reported under Stationary Combustion.

TABLE 2.1 (CONTINUED)
DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[5]

Code number and name				Definitions
1 A 5	*Non-Specified*			All remaining emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries that are not engaged in multilateral operations.
1 A 5	a	Stationary		Emissions from fuel combustion in stationary sources that are not specified elsewhere.
1 A 5	b	Mobile		Emissions from vehicles and other machinery, marine and aviation (not included in 1 A 4 c ii or elsewhere).
1 A 5	b	*i*	*Mobile (aviation component)*	All remaining aviation emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the country's military as well as fuel delivered within that country but used by the militaries of other countries that are not engaged in multilateral operations.
1 A 5	b	*ii*	*Mobile (water-borne component)*	All remaining water-borne emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the country's military as well as fuel delivered within that country but used by the militaries of other countries that are not engaged in multilateral operations.
1 A 5	b	*iii*	*Mobile (other)*	All remaining emissions from mobile sources not included elsewhere.
Multilateral operations (Information item)				Emissions from fuels used in multilateral operations pursuant to the Charter of the United Nations. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries.

The category "Manufacturing industries and Construction" has been subdivided using the International Standard Industrial Classification[6]. This industrial classification is widely used in energy statistics. Note that this table adds a number of industrial sectors in the category "Manufacturing Industries and Construction" to better align to the ISIC definitions and common practice in energy statistics.

Emissions from autoproducers (public or private undertakings that generate electricity/heat wholly or partly for their own use, as an activity that supports their primary activity, see Box 2.1) should be assigned to the sector where they were generated and not under 1 A 1 a.

[5] Methods for mobile sources occurring in sub-categories 1 A 4 and 1 A 5 are dealt with in Chapter 3 and the emissions are reported under Stationary Combustion.

[6] International Standard Industrial Classification of all Economic Activities, United Nations, New York. The publication can be downloaded from http://unstats.un.org/unsd/cr/.

BOX 2.1
AUTOPRODUCERS

An autoproducer of electricity and/or heat is an enterprise that, in support of its primary activity, generates electricity and/or heat for its own use or for sale, but not as its main business. This should be contrasted with main activity producers who generate and sell electricity and/or heat as their primary activity. Main activity producers were previously referred to as "Public" electricity and heat suppliers, although, as with autoproducers, they might be publicly or privately owned. Note that the ownership does not determine the allocation of emissions.

The *IPCC 2006 Guidelines* follow the *IPCC 1996 Guidelines* in attributing emissions from autoproduction to the industrial or commercial branches in which the generation activity occurred, rather than to 1 A 1 a. Category 1 A 1a is for main activity producers only.

With the complexity of plant activities and inter-relationships, there may not always be a clear separation between autoproducers and main activity producers. The most important issue is that all facilities be accounted under the most appropriate category and in a complete and consistent manner.

2.3 METHODOLOGICAL ISSUES

This section explains how to choose an approach, and summarises the necessary activity data and emission factors the inventory compiler will need. These sections are subdivided into Tiers as set out in Volume 1 General Guidance. The Tier 1 sections set out the steps needed for the simplest calculation methods, or the methods that require the least data. These are likely to provide the least accurate estimates of emissions. The Tier 2 and Tier 3 approaches require more detailed data and resources (time, expertise and country-specific data) to produce an estimate of emissions. Properly applied, the higher tiers should be more accurate.

2.3.1 Choice of method

In general, emissions of each greenhouse gas from stationary sources are calculated by multiplying fuel consumption by the corresponding emission factor. In the Sectoral Approach, "Fuel Consumption" is estimated from energy use statistics and is measured in terajoules. Fuel consumption data in mass or volume units must first be converted into the energy content of these fuels. All tiers described below use the amount of fuel combusted as the activity data. Section 1.4.1.2 of the Introduction chapter contains information on how to find and apply energy statistics data. Different tiers can be applied for different fuels and gases, consistent with the requirements of *key category* analysis and avoidance of double counting (see also the General Decision Tree in section 1.3.1.2).

2.3.1.1 TIER 1 APPROACH

Applying a Tier 1 emission estimate requires the following for each source category and fuel:

- Data on the amount of fuel combusted in the source category
- A default emission factor

Emission factors come from the default values provided together with associated uncertainty range in Section 2.3.2.1. The following equation is used:

EQUATION 2.1
GREENHOUSE GAS EMISSIONS FROM STATIONARY COMBUSTION

$$Emissions_{GHG,\,fuel} = Fuel\ \ Consumption_{fuel} \bullet Emission\ \ Factor_{GHG,\,fuel}$$

Where:

$Emissions_{GHG,fuel}$ = emissions of a given GHG by type of fuel (kg GHG)

$Fuel\ Consumption_{fuel}$ = amount of fuel combusted (TJ)

$Emission\ Factor_{GHG,fuel}$ = default emission factor of a given GHG by type of fuel (kg gas/TJ). For CO_2, it includes the carbon oxidation factor, assumed to be 1.

To calculate the total emissions by gas from the source category, the emissions as calculated in Equation 2.1 are summed over all fuels:

EQUATION 2.2
TOTAL EMISSIONS BY GREENHOUSE GAS

$$Emissions_{GHG} = \sum_{fuels} Emissions_{GHG,fuel}$$

2.3.1.2 TIER 2 APPROACH

Applying a Tier 2 approach requires:

- Data on the amount of fuel combusted in the source category;
- A country-specific emission factor for the source category and fuel for each gas.

Under Tier 2, the Tier 1 default emission factors in Equation 2.1 are replaced by country-specific emission factors. Country-specific emission factors can be developed by taking into account country-specific data, for example carbon contents of the fuels used, carbon oxidation factors, fuel quality and (for non-CO_2 gases in particular) the state of technological development. The emission factors may vary over time and, for solid fuels, should take into account the amount of carbon retained in the ash, which may also vary with time. It is *good practice* to compare any country-specific emission factor with the default ones given in Tables 2.2 to 2.5. If such country-specific emission factors are outside the 95 percent confidence intervals, given for the default values, an explanation should be sought and provided on why the value is significantly different from the default value.

A country-specific emission factor can be identical to the default one, or it may differ. Since the country-specific value should be more applicable to a given country's situation, it is expected that the uncertainty range associated with a country-specific value will be smaller than the uncertainty range of the default emission factor. This expectation should mean that a Tier 2 estimate provides an emission estimate with lower uncertainty than a Tier 1 estimate.

Emissions can be also estimated as the product of fuel consumption on a mass or volume basis, and an emission factor expressed on a compatible basis. For example, the use of activity data expressed in mass unit is relevant when the Tier 2 approach described in Chapter 5 of Volume 5 is used alternatively to estimate emissions that arise when waste is incinerated for energy purposes.

2.3.1.3 TIER 3 APPROACH

The Tier 1 and Tier 2 approaches of estimating emissions described in the previous sections necessitate using an average emission factor for a source category and fuel combination throughout the source category. In reality, emissions depend on the:

- fuel type used,
- combustion technology,
- operating conditions,
- control technology,
- quality of maintenance,
- age of the equipment used to burn the fuel.

In a Tier 3 approach this is taken into account by splitting the fuel combustion statistics over the different possibilities and using emission factors that are dependent upon these differences. In Equation 2.3, this is indicated by making the variables and parameters technology dependent. Technology here stands for any device, combustion process or fuel property that might influence the emissions.

EQUATION 2.3
GREENHOUSE GAS EMISSIONS BY TECHNOLOGY

$$Emissions_{GHG,fuel,technology} = Fuel\,Consumption_{fuel,technology} \bullet Emission\ Factor_{GHG,fuel,technology}$$

Where:

$Emissions_{GHG\ gas,fuel,\ technology}$ = emissions of a given GHG by type of fuel and technology (kg GHG)

$Fuel\ Consumption_{fuel,\ technology}$ = amount[7] of fuel combusted per type of technology (TJ)

$Emission\ Factor_{GHG\ gas,fuel,technology}$ = emission factor of a given GHG by fuel and technology type (kg GHG/TJ)

When the amount of fuel combusted for a certain technology is not directly known, it can be estimated by means of models. For example, a simple model for this is based on the penetration of the technology into the source category.

EQUATION 2.4
FUEL CONSUMPTION ESTIMATES BASED ON TECHNOLOGY PENETRATION

$$Fuel\ Consumption_{fuel,technology} = Fuel\ Consumption_{fuel} \bullet Penetration_{technology}$$

Where:

$Penetration_{technology}$ = the fraction of the full source category occupied by a given technology. This fraction can be determined on the basis of output data such as electricity generated which would ensure that appropriate allowance was made for differences in utilisation between technologies.

To calculate the emissions of a gas for a source category, the result of Equation 2.3 must be summed over all technologies applied in the source category.

EQUATION 2.5
TECHNOLOGY-BASED EMISSION ESTIMATION

$$Emissions_{GHG,fuel} = \sum_{technologies} Fuel\ Consumption_{fuel,technology} \bullet Emission\ \ Factor_{GHG,fuel,technology}$$

Total emissions are again calculated by summing over all fuels (Equation 2.2).

Application of a Tier 3 emission estimation approach requires:

- Data on the amount of fuel combusted in the source category for each relevant technology (fuel type used, combustion technology, operating conditions, control technology, and maintenance and age of the equipment).
- A specific emission factor for each technology (fuel type used, combustion technology, operating conditions, control technology, oxidation factor, and maintenance and age of the equipment).
- Facility level measurements can also be used when available.

Using a Tier 3 approach to estimate emissions of CO_2 is often unnecessary because emissions of CO_2 do not depend on the combustion technology. However, plant-specific data on CO_2 emissions are increasingly available and they are of increasing interest because of the possibilities for emissions trading. Plant-specific data can be based on fuel flow measurements and fuel chemistry or on flue gas flow measurements and flue gas chemistry data. Continuous emissions monitoring (CEM) of flue gases is generally not justified for accurate measurement of CO_2 emissions alone (because of the comparatively high cost) but could be undertaken particularly when monitors are installed for measurement of other pollutants such as SO_2 or NO_x. Continuous emissions monitoring is also particularly useful for combustion of solid fuels where it is more difficult to measure fuel flow rates, or when fuels are highly variable, or fuel analysis is otherwise expensive. Rigorous, continuous monitoring is required to provide a comprehensive accounting of emissions. Care is required when continuous emissions monitoring of some facilities is used but monitoring data are not available for a full reporting category.

Continuous emissions monitoring requires attention to quality assurance and quality control. This includes certification of the monitoring system, re-certification after any changes in the system, and assurance of continuous operation[8]. For CO_2 measurements, data from CEM systems can be compared with emissions estimates based on fuel flows.

[7] Fuel consumption could be expressed on a mass or volume basis, and emissions can be estimated as the product of fuel consumption and an emission factor expressed on a compatible basis.

[8] See for example: U.S. EPA (2005a).

If detailed monitoring shows that the concentration of a greenhouse gas in the discharge from a combustion process is equal to or less than the concentration of the same gas in the ambient intake air to the combustion process, then emissions may be reported as zero. Reporting these emissions as "negative emissions" would require continuous high quality monitoring of both the air intake and the atmospheric emissions.

2.3.1.4 DECISION TREES

The tier used to estimate emissions will depend on the quantity and quality of data that are available. If a category is key, it is *good practice* to estimate emissions using a Tier 2 or Tier 3 approach. The decision tree (Figure 2.1) below will help in selecting which tier should be used to estimate emissions from sources of stationary combustion.

To use a decision tree correctly, the inventory compiler needs to undertake a thorough survey of available national activity data and national or regional emission factor data, by relevant source category. This survey needs to be completed before the first inventory is compiled, and the results of the survey should be reviewed regularly. It is *good practice* to improve the data quality if an initial calculation with a Tier 1 approach indicates a *key source*, or if an estimate is associated with a high level of uncertainty. The decision tree and *key source* category determination should be applied to CO_2, CH_4 and N_2O emissions separately.

2.3.2 Choice of emission factors

This section provides default emission factors for CO_2, CH_4 and N_2O, and discusses provision of emission factors at higher Tiers. CO_2 emission factors for all Tiers reflect the full carbon content of the fuel less any non-oxidised fraction of carbon retained in the ash, particulates or soot. Since this fraction is usually small, the Tier 1 default emission factors derived in Chapter 1 of this Volume neglect this effect by assuming a complete oxidation of the carbon contained in the fuel (carbon oxidation factor equal to 1). For some solid fuels, this fraction will not necessarily be negligible, and higher Tier estimates can be applied. Where this is known to be the case it is *good practice* to use country-specific values, based on measurements or other well documented data. The Emission Factor Database (EFDB) provides a variety of well-documented emission factors and other parameters that may be better suited to national circumstances than the default values, although the responsibility to ensure appropriate application of material from the database remains with the inventory compiler.

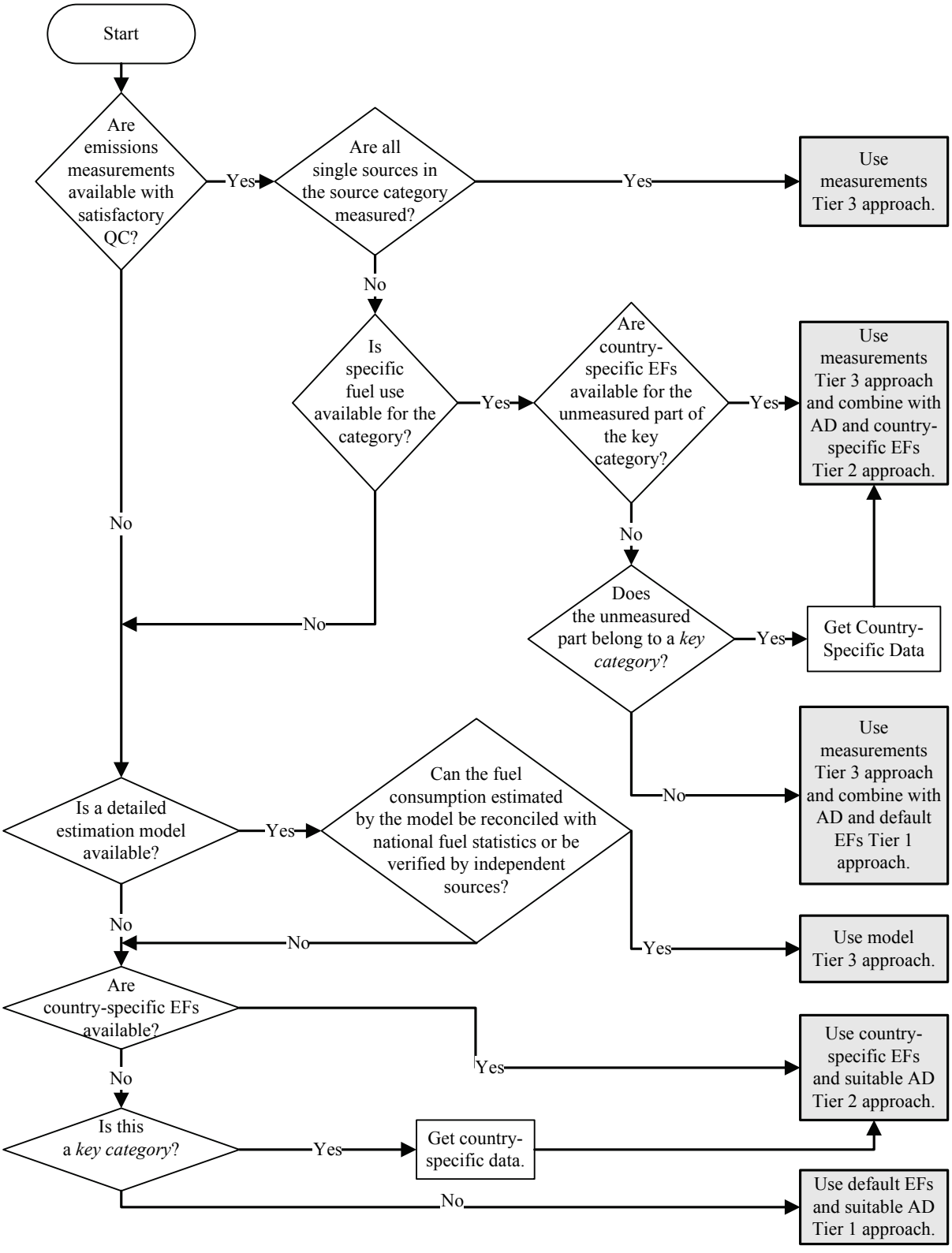
2.3.2.1 TIER 1

This section presents for each of the fuels used in stationary sources a set of default emission factors for use in Tier 1 emission estimates for the source categories. In a number of source categories, the same fuels are used. These will have the same emission factors for CO_2. The derivation of the CO_2 emission factors is presented in the Introduction chapter of this Volume. Emission factors for CO_2 are in units of kg CO_2/TJ on a net calorific value basis and reflect the carbon content of the fuel and the assumption that the carbon oxidation factor is 1.

Emission factors for CH_4 and N_2O for different source categories differ due to differences in combustion technologies applied in the different source categories. The default factors presented for Tier 1 apply to technologies without emission controls. The default emission factors, particularly those in Tables 2.2 and 2.3, assume effective combustion in high temperature. They are applicable for steady and optimal conditions and do not take into account the impact of start-ups, shut downs or combustion with partial loads.

Default emission factors for stationary combustion are given in Tables 2.2 to 2.5. The CO_2 emission factors are the same ones as presented in Table 1.4 of the Introduction chapter. The emission factors for CH_4 and N_2O are based on the IPCC 1996 Guidelines. These emission factors were established using the expert judgement of a large group of inventory experts and are still considered valid. Since not many measurements of these types of emission factors are available, the uncertainty ranges are set at plus or minus a factor of three. Tables 2.2 to 2.5 do not provide default emission factors for CH_4 and N_2O emissions from combustion by off-road machinery that are reported in the 1A category. These emission factors are provided in Section 3.3 of this Volume.

Figure 2.1 Generalised decision tree for estimating emissions from stationary combustion



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.

TABLE 2.2
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE ENERGY INDUSTRIES
(kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Crude Oil		73 300	71 100	75 500	r 3	1	10	0.6	0.2	2
Orimulsion		r 77 000	69 300	85 400	r 3	1	10	0.6	0.2	2
Natural Gas Liquids		r 64 200	58 300	70 400	r 3	1	10	0.6	0.2	2
Gasoline	Motor Gasoline	r 69 300	67 500	73 000	r 3	1	10	0.6	0.2	2
	Aviation Gasoline	r 70 000	67 500	73 000	r 3	1	10	0.6	0.2	2
	Jet Gasoline	r 70 000	67 500	73 000	r 3	1	10	0.6	0.2	2
Jet Kerosene		r 71 500	69 700	74 400	r 3	1	10	0.6	0.2	2
Other Kerosene		71 900	70 800	73 700	r 3	1	10	0.6	0.2	2
Shale Oil		73 300	67 800	79 200	r 3	1	10	0.6	0.2	2
Gas/Diesel Oil		74 100	72 600	74 800	r 3	1	10	0.6	0.2	2
Residual Fuel Oil		77 400	75 500	78 800	r 3	1	10	0.6	0.2	2
Liquefied Petroleum Gases		63 100	61 600	65 600	r 1	0.3	3	0.1	0.03	0.3
Ethane		61 600	56 500	68 600	r 1	0.3	3	0.1	0.03	0.3
Naphtha		73 300	69 300	76 300	r 3	1	10	0.6	0.2	2
Bitumen		80 700	73 000	89 900	r 3	1	10	0.6	0.2	2
Lubricants		73 300	71 900	75 200	r 3	1	10	0.6	0.2	2
Petroleum Coke		r 97 500	82 900	115 000	r 3	1	10	0.6	0.2	2
Refinery Feedstocks		73 300	68 900	76 600	r 3	1	10	0.6	0.2	2
Other Oil	Refinery Gas	n 57 600	48 200	69 000	r 1	0.3	3	0.1	0.03	0.3
	Paraffin Waxes	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
	White Spirit and SBP	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
	Other Petroleum Products	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
Anthracite		98 300	94 600	101 000	1	0.3	3	r 1.5	0.5	5
Coking Coal		94 600	87 300	101 000	1	0.3	3	r 1. 5	0.5	5
Other Bituminous Coal		94 600	89 500	99 700	1	0.3	3	r 1. 5	0.5	5
Sub-Bituminous Coal		96 100	92 800	100 000	1	0.3	3	r 1.5	0.5	5
Lignite		101 000	90 900	115 000	1	0.3	3	r 1. 5	0.5	5
Oil Shale and Tar Sands		107 000	90 200	125 000	1	0.3	3	r 1. 5	0.5	5
Brown Coal Briquettes		97 500	87 300	109 000	n 1	0.3	3	r 1. 5	0.5	5
Patent Fuel		97 500	87 300	109 000	1	0.3	3	n 1. 5	0.5	5
Coke	Coke Oven Coke and Lignite Coke	r 107 000	95 700	119 000	1	0.3	3	r 1. 5	0.5	5
	Gas Coke	r 107 000	95 700	119 000	r 1	0.3	3	0.1	0.03	0.3
Coal Tar		n 80 700	68 200	95 300	n 1	0.3	3	r 1. 5	0.5	5
Derived Gases	Gas Works Gas	n 44 400	37 300	54 100	n 1	0.3	3	0.1	0.03	0.3
	Coke Oven Gas	n 44 400	37 300	54 100	r 1	0.3	3	0.1	0.03	0.3
	Blast Furnace Gas	n 260 000	219 000	308 000	r 1	0.3	3	0.1	0.03	0.3
	Oxygen Steel Furnace Gas	n 182 000	145 000	202 000	r 1	0.3	3	0.1	0.03	0.3
Natural Gas		56 100	54 300	58 300	1	0.3	3	0.1	0.03	0.3

TABLE 2.2 (CONTINUED)
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE ENERGY INDUSTRIES
(kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	**Lower**	**Upper**	**Default Emission Factor**	**Lower**	**Upper**	**Default Emission Factor**	**Lower**	**Upper**
Municipal Wastes (non-biomass fraction)		**n** 91 700	73 300	121 000	30	10	100	4	1.5	15
Industrial Wastes		**n** 143 000	110 000	183 000	30	10	100	4	1.5	15
Waste Oils		**n** 73 300	72 200	74 400	30	10	100	4	1.5	15
Peat		106 000	100 000	108 000	**n** 1	0.3	3	**n** 1.5	0.5	5
Solid Biofuels	Wood / Wood Waste	**n** 112 000	95 000	132 000	30	10	100	4	1.5	15
	Sulphite lyes (Black Liquor)[a]	**n** 95 300	80 700	110 000	**n** 3	1	18	**n** 2	1	21
	Other Primary Solid Biomass	**n** 100 000	84 700	117 000	30	10	100	4	1.5	15
	Charcoal	**n** 112 000	95 000	132 000	200	70	600	4	1.5	15
Liquid Biofuels	Biogasoline	**n** 70 800	59 800	84 300	**r** 3	1	10	0.6	0.2	2
	Biodiesels	**n** 70 800	59 800	84 300	**r** 3	1	10	0.6	0.2	2
	Other Liquid Biofuels	**n** 79 600	67 100	95 300	**r** 3	1	10	0.6	0.2	2
Gas Biomass	Landfill Gas	**n** 54 600	46 200	66 000	**r** 1	0.3	3	0.1	0.03	0.3
	Sludge Gas	**n** 54 600	46 200	66 000	**r** 1	0.3	3	0.1	0.03	0.3
	Other Biogas	**n** 54 600	46 200	66 000	**r** 1	0.3	3	0.1	0.03	0.3
Other non-fossil fuels	Municipal Wastes (biomass fraction)	**n** 100 000	84 700	117 000	30	10	100	4	1.5	15

(a) Includes the biomass-derived CO_2 emitted from the black liquor combustion unit and the biomass-derived CO_2 emitted from the kraft mill lime kiln.
n indicates a new emission factor which was not present in the 1996 Guidelines
r indicates an emission factor that has been revised since the 1996 Guidelines

TABLE 2.3
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN MANUFACTURING INDUSTRIES AND CONSTRUCTION
(kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Crude Oil		73 300	71 100	75 500	r 3	1	10	0.6	0.2	2
Orimulsion		r 77 000	69 300	85 400	r 3	1	10	0.6	0.2	2
Natural Gas Liquids		r 64 200	58 300	70 400	r 3	1	10	0.6	0.2	2
Gasoline	Motor Gasoline	r 69 300	67 500	73 000	r 3	1	10	0.6	0.2	2
	Aviation Gasoline	r 70 000	67 500	73 000	r 3	1	10	0.6	0.2	2
	Jet Gasoline	r 70 000	67 500	73 000	r 3	1	10	0.6	0.2	2
Jet Kerosene		71 500	69 700	74 400	r 3	1	10	0.6	0.2	2
Other Kerosene		71 900	70 800	73 700	r 3	1	10	0.6	0.2	2
Shale Oil		73 300	67 800	79 200	r 3	1	10	0.6	0.2	2
Gas/Diesel Oil		74 100	72 600	74 800	r 3	1	10	0.6	0.2	2
Residual Fuel Oil		77 400	75 500	78 800	r 3	1	10	0.6	0.2	2
Liquefied Petroleum Gases		63 100	61 600	65 600	r 1	0.3	3	0.1	0.03	0.3
Ethane		61 600	56 500	68 600	r 1	0.3	3	0.1	0.03	0.3
Naphtha		73 300	69 300	76 300	r 3	1	10	0.6	0.2	2
Bitumen		80 700	73 000	89 900	r 3	1	10	0.6	0.2	2
Lubricants		73 300	71 900	75 200	r 3	1	10	0.6	0.2	2
Petroleum Coke		r 97 500	82 900	115 000	r 3	1	10	0.6	0.2	2
Refinery Feedstocks		73 300	68 900	76 600	r 3	1	10	0.6	0.2	2
Other Oil	Refinery Gas	n 57 600	48 200	69 000	r 1	0.3	3	0.1	0.03	0.3
	Paraffin Waxes	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
	White Spirit and SBP	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
	Other Petroleum Products	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
Anthracite		98 300	94 600	101 000	10	3	30	r 1.5	0.5	5
Coking Coal		94 600	87 300	101 000	10	3	30	r 1.5	0.5	5
Other Bituminous Coal		94 600	89 500	99 700	10	3	30	r 1.5	0.5	5
Sub-Bituminous Coal		96 100	92 800	100 000	10	3	30	r 1.5	0.5	5
Lignite		101 000	90 900	115 000	10	3	30	r 1.5	0.5	5
Oil Shale and Tar Sands		107 000	90 200	125 000	10	3	30	r 1.5	0.5	5
Brown Coal Briquettes		n 97 500	87 300	109 000	n 10	3	30	n 1.5	0.5	5
Patent Fuel		97 500	87 300	109 000	10	3	30	r 1.5	0.5	5
Coke	Coke Oven Coke and Lignite Coke	r 107 000	95 700	119 000	10	3	30	r 1.5	0.5	5
	Gas Coke	r 107 000	95 700	119 000	r 1	0.3	3	0.1	0.03	0.3
Coal Tar		n 80 700	68 200	95 300	n 10	3	30	n 1.5	0.5	5
Derived Gases	Gas Works Gas	n 44 400	37 300	54 100	r 1	0.3	3	0.1	0.03	0.3
	Coke Oven Gas	n 44 400	37 300	54 100	r 1	0.3	3	0.1	0.03	0.3
	Blast Furnace Gas	n260 000	219 000	308 000	r 1	0.3	3	0.1	0.03	0.3
	Oxygen Steel Furnace Gas	n 182 000	145 000	202 000	r 1	0.3	3	0.1	0.03	0.3
Natural Gas		56 100	54 300	58 300	r 1	0.3	3	0.1	0.03	0.3

TABLE 2.3 (CONTINUED)
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN MANUFACTURING INDUSTRIES AND CONSTRUCTION
(kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Municipal Wastes (non-biomass fraction)		**n** 91 700	73 300	121 000	30	10	100	4	1.5	15
Industrial Wastes		**n** 143 000	110 000	183 000	30	10	100	4	1.5	15
Waste Oils		**n** 73 300	72 200	74 400	30	10	100	4	1.5	15
Peat		106 000	100 000	108 000	**n** 2	0.6	6	**n** 1.5	0.5	5
Solid Biofuels	Wood / Wood Waste	**n** 112 000	95 000	132 000	30	10	100	4	1.5	15
	Sulphite lyes (Black Liquor)[a]	**n** 95 300	80 700	110 000	**n** 3	1	18	**n** 2	1	21
	Other Primary Solid Biomass	**n** 100 000	84 700	117 000	30	10	100	4	1.5	15
	Charcoal	**n** 112 000	95 000	132 000	200	70	600	4	1.5	15
Liquid Biofuels	Biogasoline	**n** 70 800	59 800	84 300	**r** 3	1	10	0.6	0.2	2
	Biodiesels	**n** 70 800	59 800	84 300	**r** 3	1	10	0.6	0.2	2
	Other Liquid Biofuels	**n** 79 600	67 100	95 300	**r** 3	1	10	0.6	0.2	2
Gas Biomass	Landfill Gas	**n** 54 600	46 200	66 000	**r** 1	0.3	3	0.1	0.03	0.3
	Sludge Gas	**n** 54 600	46 200	66 000	**r** 1	0.3	3	0.1	0.03	0.3
	Other Biogas	**n** 54 600	46 200	66 000	**r** 1	0.3	3	0.1	0.03	0.3
Other non-fossil fuels	Municipal Wastes (biomass fraction)	**n** 100 000	84 700	117 000	30	10	100	4	1.5	15

(a) Includes the biomass-derived CO_2 emitted from the black liquor combustion unit and the biomass-derived CO_2 emitted from the kraft mill lime kiln.
n indicates a new emission factor which was not present in the 1996 Guidelines
r indicates an emission factor that has been revised since the 1996 Guidelines

TABLE 2.4
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE COMMERCIAL/INSTITUTIONAL CATEGORY
(kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Crude Oil		73 300	71 100	75 500	10	3	30	0.6	0.2	2
Orimulsion		r 77 000	69 300	85 400	10	3	30	0.6	0.2	2
Natural Gas Liquids		r 64 200	58 300	70 400	10	3	30	0.6	0.2	2
Gasoline	Motor Gasoline	r 69 300	67 500	73 000	10	3	30	0.6	0.2	2
	Aviation Gasoline	r 70 000	67 500	73 000	10	3	30	0.6	0.2	2
	Jet Gasoline	r 70 000	67 500	73 000	10	3	30	0.6	0.2	2
Jet Kerosene		r 71 500	69 700	74 400	10	3	30	0.6	0.2	2
Other Kerosene		71 900	70 800	73 700	10	3	30	0.6	0.2	2
Shale Oil		73 300	67 800	79 200	10	3	30	0.6	0.2	2
Gas/Diesel Oil		74 100	72 600	74 800	10	3	30	0.6	0.2	2
Residual Fuel Oil		77 400	75 500	78 800	10	3	30	0.6	0.2	2
Liquefied Petroleum Gases		63 100	61 600	65 600	5	1.5	15	0.1	0.03	0.3
Ethane		61 600	56 500	68 600	5	1.5	15	0.1	0.03	0.3
Naphtha		73 300	69 300	76 300	10	3	30	0.6	0.2	2
Bitumen		80 700	73 000	89 900	10	3	30	0.6	0.2	2
Lubricants		73 300	71 900	75 200	10	3	30	0.6	0.2	2
Petroleum Coke		r 97 500	82 900	115 000	10	3	30	0.6	0.2	2
Refinery Feedstocks		73 300	68 900	76 600	10	3	30	0.6	0.2	2
Other Oil	Refinery Gas	n 57 600	48 200	69 000	5	1.5	15	0.1	0.03	0.3
	Paraffin Waxes	73 300	72 200	74 400	10	3	30	0.6	0.2	2
	White Spirit and SBP	73 300	72 200	74 400	10	3	30	0.6	0.2	2
	Other Petroleum Products	73 300	72 200	74 400	10	3	30	0.6	0.2	2
Anthracite		r 98 300	94 600	101 000	10	3	30	1.5	0.5	5
Coking Coal		94 600	87 300	101 000	10	3	30	1.5	0.5	5
Other Bituminous Coal		94 600	89 500	99 700	10	3	30	1.5	0.5	5
Sub-Bituminous Coal		96 100	92 800	100 000	10	3	30	1.5	0.5	5
Lignite		101 000	90 900	115 000	10	3	30	1.5	0.5	5
Oil Shale and Tar Sands		107 000	90 200	125 000	10	3	30	1.5	0.5	5
Brown Coal Briquettes		n 97 500	87 300	109 000	n 10	3	30	r 1.5	0.5	5
Patent Fuel		97 500	87 300	109 000	10	3	30	n 1.5	0.5	5
Coke	Coke Oven Coke and Lignite Coke	n 107 000	95 700	119 000	10	3	30	1.5	0.5	4
	Gas Coke	n 107 000	95 700	119 000	5	1.5	15	0.1	0.03	0.3

TABLE 2.4 (CONTINUED)
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE COMMERCIAL/INSTITUTIONAL CATEGORY
(kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Coal Tar		**n** 80 700	68 200	95 300	**n** 10	30	30	**n** 1.5	0.5	5
Derived Gases	Gas Works Gas	**n** 44 400	37 300	54 100	5	1.5	15	0.1	0.03	0.3
	Coke Oven Gas	**n** 44 400	37 300	54 100	5	1.5	15	0.1	0.03	0.3
	Blast Furnace Gas	**n** 260 000	219 000	308 000	5	1.5	15	0.1	0.03	0.3
	Oxygen Steel Furnace Gas	**n** 182 000	145 000	202 000	5	1.5	15	0.1	0.03	0.3
Natural Gas		56 100	54 300	58 300	5	1.5	15	0.1	0.03	0.3
Municipal Wastes (non-biomass fraction)		**n** 91 700	73 300	121 000	300	100	900	4	1.5	15
Industrial Wastes		**n** 143 000	110 000	183 000	300	100	900	4	1.5	15
Waste Oils		**n** 73 300	72 200	74 400	300	100	900	4	1.5	15
Peat		106 000	100 000	108 000	**n** 10	3	30	**n** 1.4	0.5	5
Solid Biofuels	Wood / Wood Waste	**r** 112 000	95 000	132 000	300	100	900	4	1.5	15
	Sulphite lyes (Black Liquor)[a]	**n** 95 300	80 700	110 000	**n** 3	1	18	**n** 2	1	21
	Other Primary Solid Biomass	**n** 100 000	84 700	117 000	300	100	900	4	1.5	15
	Charcoal	**n** 112 000	95 000	132 000	200	70	600	1	0.3	3
Liquid Biofuels	Biogasoline	**n** 70 800	59 800	84 300	10	3	30	0.6	0.2	2
	Biodiesels	**n** 70 800	59 800	84 300	10	3	30	0.6	0.2	2
	Other Liquid Biofuels	**n** 79 600	67 100	95 300	10	3	30	0.6	0.2	2
Gas Biomass	Landfill Gas	**n** 54 600	46 200	66 000	5	1.5	15	0.1	0.03	0.3
	Sludge Gas	**n** 54 600	46 200	66 000	5	1.5	15	0.1	0.03	0.3
	Other Biogas	**n** 54 600	46 200	66 000	5	1.5	15	0.1	0.03	0.3
Other non-	Municipal Wastes (biomass fraction)	**n** 100 000	84 700	117 000	300	100	900	4	1..5	15

(a) Includes the biomass-derived CO_2 emitted from the black liquor combustion unit and the biomass-derived CO_2 emitted from the kraft mill lime kiln.
n indicates a new emission factor which was not present in the 1996 Guidelines
r indicates an emission factor that has been revised since the 1996 Guidelines

TABLE 2.5
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE RESIDENTIAL AND AGRICULTURE/FORESTRY/FISHING/FISHING FARMS CATEGORIES (kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Crude Oil		73 300	71 100	75 500	10	3	30	0.6	0.2	2
Orimulsion		r 77 000	69 300	85 400	10	3	30	0.6	0.2	2
Natural Gas Liquids		r 64 200	58 300	70 400	10	3	30	0.6	0.2	2
Gasoline	Motor Gasoline	r 69 300	67 500	73 000	10	3	30	0.6	0.2	2
	Aviation Gasoline	r 70 000	67 500	73 000	10	3	30	0.6	0.2	2
	Jet Gasoline	r 70 000	67 500	73 000	10	3	30	0.6	0.2	2
Jet Kerosene		r 71 500	69 700	74 400	10	3	30	0.6	0.2	2
Other Kerosene		71 900	70 800	73 700	10	3	30	0.6	0.2	2
Shale Oil		73 300	67 800	79 200	10	3	30	0.6	0.2	2
Gas/Diesel Oil		74 100	72 600	74 800	10	3	30	0.6	0.2	2
Residual Fuel Oil		77 400	75 500	78 800	10	3	30	0.6	0.2	2
Liquefied Petroleum Gases		63 100	61 600	65 600	5	1.5	15	0.1	0.03	0.3
Ethane		61 600	56 500	68 600	5	1.5	15	0.1	0.03	0.3
Naphtha		73 300	69 300	76 300	10	3	30	0.6	0.2	2
Bitumen		80 700	73 000	89 900	10	3	30	0.6	0.2	2
Lubricants		73 300	71 900	75 200	10	3	30	0.6	0.2	2
Petroleum Coke		r 97 500	82 900	115 000	10	3	30	0.6	0.2	2
Refinery Feedstocks		73 300	68 900	76 600	10	3	30	0.6	0.2	2
Other Oil	Refinery Gas	n 57 600	48 200	69 000	5	1.5	15	0.1	0.03	0.3
	Paraffin Waxes	73 300	72 200	74 400	10	3	30	0.6	0.2	2
	White Spirit and SBP	73 300	72 200	74 400	10	3	30	0.6	0.2	3
	Other Petroleum Products	73 300	72 200	74 400	10	3	30	0.6	0.2	2
Anthracite		98 300	94 600	101 000	300	100	900	1.5	0.5	5
Coking Coal		94 600	87 300	101 000	300	100	900	1.5	0.5	5
Other Bituminous Coal		94 600	89 500	99 700	300	100	900	1.5	0.5	5
Sub-Bituminous Coal		96 100	92 800	100 000	300	100	900	1.5	0.5	5
Lignite		101 000	90 900	115 000	300	100	900	1.5	0.5	5
Oil Shale and Tar Sands		107 000	90 200	125 000	300	100	900	1.5	0.5	5
Brown Coal Briquettes		n 97 500	87 300	109 000	n 300	100	900	n 1.5	0.5	5
Patent Fuel		97 500	87 300	109 000	300	100	900	1.5	0.5	5
Coke	Coke Oven Coke and Lignite Coke	r 107 000	95 700	119 000	300	100	900	n 1.5	0.5	5
	Gas Coke	r 107 000	95 700	119 000	r 5	1.5	15	0.1	0.03	0.3
Coal Tar		n 80 700	68 200	95 300	n 300	100	900	n 1.5	0.5	5
Derived Gases	Gas Works Gas	n 44 400	37 300	54 100	5	1.5	15	0.1	0.03	0.3
	Coke Oven Gas	n 44 400	37 300	54 100	5	1.5	15	0.1	0.03	0.3
	Blast Furnace Gas	n 260 000	219 000	308 000	5	1.5	15	0.1	0.03	0.3
	Oxygen Steel Furnace Gas	n 182 000	145 000	202 000	5	1.5	15	0.1	0.03	0.3

TABLE 2.5 (CONTINUED)
DEFAULT EMISSION FACTORS FOR STATIONARY COMBUSTION IN THE RESIDENTIAL AND AGRICULTURE/FORESTRY/FISHING/FISHING FARMS CATEGORIES (kg of greenhouse gas per TJ on a Net Calorific Basis)

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Natural Gas		56 100	54 300	58 300	5	1.5	15	0.1	0.03	0.3
Municipal Wastes (non-biomass fraction)		**n** 91 700	73 300	121 000	300	100	900	4	1.5	15
Industrial Wastes		**n** 143 000	110 000	183 000	300	100	900	4	1.5	15
Waste Oils		**n** 73 300	72 200	74 400	300	100	900	4	1.5	15
Peat		106 000	100 000	108 000	**n** 300	100	900	**n** 1.4	0.5	5
Solid Biofuels	Wood / Wood Waste	**n** 112 000	95 000	132 000	300	100	900	4	1.5	15
	Sulphite lyes (Black Liquor)[a]	**n** 95 300	80 700	110 000	**n** 3	1	18	**n** 2	1	21
	Other Primary Solid Biomass	**n** 100 000	84 700	117 000	300	100	900	4	1.5	15
	Charcoal	**n** 112 000	95 000	132 000	200	70	600	1	0.3	3
Liquid Biofuels	Biogasoline	**n** 70 800	59 800	84 300	10	3	30	0.6	0.2	2
	Biodiesels	**n** 70 800	59 800	84 300	10	3	30	0.6	0.2	2
	Other Liquid Biofuels	**r** 79 600	67 100	95 300	10	3	30	0.6	0.2	2
Gas Biomass	Landfill Gas	**n** 54 600	46 200	66 000	5	1.5	15	0.1	0.03	0.3
	Sludge Gas	**n** 54 600	46 200	66 000	5	1.5	15	0.1	0.03	0.3
	Other Biogas	**n** 54 600	46 200	66 000	5	1.5	15	0.1	0.03	0.3
Other non-fossil fuels	Municipal Wastes (biomass fraction)	**n** 100 000	84 700	117 000	300	100	900	4	1.5	15

(a) Includes the biomass-derived CO_2 emitted from the black liquor combustion unit and the biomass-derived CO_2 emitted from the kraft mill lime kiln.
n indicates a new emission factor which was not present in the 1996 IPCC Guidelines.
r indicates an emission factor that has been revised since the 1996I PCC Guidelines.

2.3.2.2 TIER 2 COUNTRY-SPECIFIC EMISSION FACTORS

Good practice is to use the most disaggregated, technology-specific and country-specific emission factors available, particularly those derived from direct measurements at the different stationary combustion sources. When using the Tier 2 approach, two possible types of emission factors exist:

- National emission factors: These emission factors may be developed by national programmes already measuring emissions of indirect greenhouse gases such as NOx, CO and NMVOCs for local air quality;
- Regional emission factors.

Chapter 2 of Volume 1 provides general guidance for acquiring and compiling information from different sources, specific guidance for generating new data (Section 2.2.3) and generic guidance on emission factors (Section 2.2.4). When measurements are used to obtain emission factors, it is *good practice* to test a reasonable number of sources representing the average conditions in the country including fuel type and composition, type and size of the combustion unit, firing conditions, load, type of control technologies and maintenance level.

2.3.2.3 TIER 3 TECHNOLOGY-SPECIFIC EMISSION FACTORS

Due to the nature of the emissions of non-CO_2 greenhouse gases, technology-specific emission factors are needed for Tier 3. Tables 2.6 to 2.10 give, for example purposes, give representative emission factors for CH_4 and N_2O by main technology and fuel type. National experts working on detailed bottom-up inventories may use these factors as a starting point or for comparison. They show uncontrolled emission factors for each of the technologies indicated. These emission factor data, therefore, do not include the level of control technology that might be in place in some countries. For instance, for use in countries where control policies have significantly influenced the emission profile, either the individual factors or the final estimate will need to be adjusted.

2.3.3 Choice of activity data

For Stationary Combustion, the activity data for all tiers are the amounts and types of fuel combusted. Most fuels consumers (enterprises, small commercial consumers, or households) normally pay for the solid, liquid and gaseous fuels they consume. Therefore, the masses or volumes of fuels they consume are measured or metered. Quantities of carbon dioxide can normally be easily calculated from fuel consumption data and the carbon contents of the fuels, taking into account the fraction of carbon unoxidised.

The quantities of non-CO_2 greenhouse gases formed during combustion depend on the combustion technology used, and therefore detailed statistics on fuel combustion technology are needed to rigorously estimate emissions of non-CO_2 greenhouse gases.

The amount and types of fuel combusted are obtained from one, or a combination, of the sources in the list below:

- national energy statistics agencies (national energy statistics agencies may collect data on the amount and types of fuel combusted from individual enterprises that consume fuels)
- reports provided by enterprises to national energy statistics agencies (these reports are most likely to be produced by the operators or owners of large combustion plants)
- reports provided by enterprises to regulatory agencies (for example, reports produced to demonstrate how enterprises are complying with emission control regulations)
- individuals within the enterprise responsible for the combustion equipment
- periodic surveys, by statistical agencies, of the types and quantities of fuels consumed by a sample of enterprises
- suppliers of fuels (who may record the quantities of fuels delivered to their customers, and may also record the identity of their customers usually as an economic activity code).

TABLE 2.6
UTILITY SOURCE EMISSION FACTORS

		Emission factors[1] (kg/TJ energy input)	
Basic technology	**Configuration**	**CH_4**	**N_2O**
Liquid Fuels			
Residual Fuel Oil/Shale Oil Boilers	Normal Firing	**r** 0.8	0.3
	Tangential Firing	**r** 0.8	0.3
Gas/Diesel Oil Boilers	Normal Firing	0.9	0.4
	Tangential Firing	0.9	0.4
Large Diesel Oil Engines >600hp (447kW)		4	NA
Solid Fuels			
Pulverised Bituminous Combustion Boilers	Dry Bottom, wall fired	0.7	**r** 0.5
	Dry Bottom, tangentially fired	0.7	**r** 1.4
	Wet Bottom	0.9	**r** 1.4
Bituminous Spreader Stoker Boilers	With and without re-injection	1	**r** 0.7
Bituminous Fluidised Bed Combustor	Circulating Bed	1	**r** 61
	Bubbling Bed	1	**r** 61
Bituminous Cyclone Furnace		0.2	1.6
Lignite Atmospheric Fluidised Bed		NA	**r** 71
Natural Gas			
Boilers		**r** 1	**n** 1
Gas-Fired Gas Turbines >3MW		**r** 4	**n** 1
Large Dual-Fuel Engines		**r** 258	NA
Combined Cycle		**n** 1	**n** 3
Peat			
Peat Fluidised Bed Combustor[2]	Circulating Bed	**n** 3	7
	Bubbling Bed	**n** 3	3
Biomass			
Wood/Wood Waste Boilers[3]		**n** 11	**n** 7
Wood Recovery Boilers		**n** 1	**n** 1

Source: US EPA, 2005b except otherwise indicated. Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumptions on how to convert from gross to net calorific values.

[1] Source: Tsupari *et* al, 2006.

[2] Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific value for dry wood was 20 per cent lower than the gross calorific value (Forest Product Laboratory, 2004).

NA, data not available.

n indicates a new emission factor which was not present in the *IPCC 1996 Guidelines*

r indicates an emission factor that has been revised since the *IPCC 1996 Guidelines*

TABLE 2.7
INDUSTRIAL SOURCE EMISSION FACTORS

		Emission factors[1] (kg/TJ energy input)	
Basic technology	**Configuration**	**CH_4**	**N_2O**
Liquid Fuels			
Residual Fuel Oil Boilers		3	0.3
Gas/Diesel Oil Boilers		0.2	0.4
Large Stationary Diesel Oil Engines >600hp (447 kW)		**r** 4	NA
Liquefied Petroleum Gases Boilers		**n** 0.9	**n** 4
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		1	**r** 0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		14	**r** 0.7
Other Bituminous/Sub-bituminous Pulverised	Dry Bottom, wall fired	0.7	**r** 0.5
	Dry Bottom, tangentially fired	0.7	**r** 1.4
	Wet Bottom	0.9	**r** 1.4
Other Bituminous Spreader Stokers		1	**r** 0.7
Other Bituminous/Sub-bit. Fluidised Bed Combustor	Circulating Bed	1	**r** 61
	Bubbling Bed	1	**r** 61
Natural Gas			
Boilers		**r** 1	**n** 1
Gas-Fired Gas Turbines[2] >3MW		4	1
Natural Gas-fired Reciprocating Engines[3]	2-Stroke Lean Burn	**r** 693	NA
	4-Stroke Lean Burn	**r** 597	NA
	4-Stroke Rich Burn	**r** 110	NA
Biomass			
Wood/Wood Waste Boilers[4]		**n** 11	**n** 7

[1] Source: US EPA, 2005b except otherwise indicated. Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumptions on how to convert from gross to net calorific values.

[2] Factor was derived from units operating at high loads (80 percent load) only.

[3] Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants.

[4] Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific value for dry wood was 20 per cent lower than the gross calorific value (Forest Product Laboratory, 2004).

NA, data not available

n indicates a new emission factor which was not present in the IPCC 1996 Guidelines.

r indicates an emission factor that has been revised since the IPCC 1996 Guidelines .

TABLE 2.8
KILNS, OVENS, AND DRYERS SOURCE EMISSION FACTORS

Industry	Source	Emission factors[1] (kg/TJ energy input	
		CH_4	N_2O
Cement, Lime	Kilns - Natural Gas	1.1	NA
Cement, Lime	Kilns - Oil	1.0	NA
Cement, Lime	Kilns - Coal	1.0	NA
Coking, Steel	Coke Oven	1.0	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	1.1	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Oil	1.0	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Coal	1.0	NA

[1] Source: Radian, 1990. Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumptions on how to convert from gross to net calorific values.

NA, data not available.

There are a number of points of good practice that inventory compilers should follow when they collect and use fuel consumption data. It is *good practice* to use, where possible, the quantities of fuel combusted rather than the quantities of fuel delivered.[9] Agencies collecting emission data from companies under an environmental reporting regulation may request fuel combustion data on this basis. For further information on the general framework for the derivation or review of activity data, check Chapter 2, Approaches to Data Collection, in Volume 1.

Due to the technology-specific nature of emissions of non-CO_2 greenhouse gases, detailed fuel combustion technology statistics are needed in order to provide rigorous emission estimates. It is *good practice* to collect activity data in units of fuel used, and to disaggregate as far as possible into the share of fuel used by major technology types. Disaggregation can be achieved through a bottom-up survey of fuel consumption and combustion technology, or through top-down allocations based on expert judgement and statistical sampling. Specialised statistical offices or ministerial departments are generally in charge of regular data collection and handling. Including representatives from these departments in the inventory process is likely to facilitate the acquisition of appropriate activity data. For some source categories (e.g. combustion in the Agriculture Sector), there may be some difficulty in separating fuel used in stationary equipment from fuel used in mobile machinery. Given the different emission factors for non-CO_2 gases of these two sources, *good practice* is to derive shares of energy use of each of these sources by using indirect data (e.g. number of pumps, average consumption, needs for water pumping etc.). Expert judgement and information available from other countries may also be relevant.

Good practice for electricity autoproduction (self-generation) is to assign emissions to the source categories (or sub-source categories) where they were generated and to identify them separately from those associated with other end-uses such as process heat. In many countries, the statistics related to autoproduction are available and regularly updated, so activity data should not represent a serious obstacle to estimating non-CO_2 emissions.

Where confidentiality is an issue, direct discussion with the company affected often allows the data to be used. Otherwise aggregation of the fuel consumption or emissions with those from other companies is usually sufficient. For further information on dealing with restricted data sources or confidentiality issues, check Chapter 2, Approaches to Data Collection, in Volume 1.

[9] Quantities of solid and liquid fuels delivered to enterprises will, in general, differ from quantities combusted. This difference is normally the amount put into or taken from stocks held by the enterprise. Stock figures shown in national fuel balances may not include stocks held by final consumers, or may include only stocks held by a particular source category (for example electricity producers). Delivery figures may also include quantities used for mobile sources or as feedstock.

TABLE 2.9
RESIDENTIAL SOURCE EMISSION FACTORS

Basic technology	Configuration	Emission factors[1] (kg/TJ energy input)	
		CH_4	N_2O
Liquid Fuels			
Residual Fuel Oil Combustors		1.4	NA
Gas/Diesel Oil Combustors		0.7	NA
Furnaces		5.8	0.2
Liquefied Petroleum Gas Furnaces		1.1	NA
Other Kerosene Stoves[2]	Wick	**n** 2.2 – 23	1.2 – 1.9
Liquified Petroleum Gas Stoves[2]	Standard	**n** 0.9 – 23	0.7 – 3.5
Solid Fuels			
Anthracite Space Heaters		**r** 147	NA
Other Bituminous Coal Stoves[3]	Brick or Metal	**n** 267 – 2650	NA
Natural Gas			
Boilers and Furnaces		**n** 1	**n** 1
Biomass			
Wood Pits[4]		200	NA
Wood Stoves[5, 6]	Conventional	**r** 932	NA
	Non-catalytic	**n** 497	NA
	Catalytic	**r** 360	NA
Wood Stoves[7]		**n** 258 – 2190	4 – 18.5
Wood Fireplaces[6]		NA	**n** 9
Charcoal Stoves[8]		**n** 275 – 386	**n** 1.6 – 9.3
Other Primary Solid Biomass (Agriculture Wastes) Stoves[9]		**n** 230 – 4190	**n** 9.7
Other Primary Solid Biomass (Dung) Stoves[10]		**n** 281	**n** 27

[1] Source: US EPA, 2005b except otherwise indicated. Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumptions on how to convert from gross to net calorific values.

[2] Sources: Smith *et al.*, 1992, 1993; Smith *et al.*, 2000; Zhang *et al.*, 2000. Results of experimental studies conducted on a number of household stoves from China (CH_4), India and Philippines (CH_4 and N_2O).

[3] Source: Zhang *et al.*, 2000. Results of experimental studies conducted on a number of household stoves from China.

[4] Source: Adapted from Radian, 1990; *Revised IPCC 1996 Guidelines*.

[5] U.S. Stoves. Conventional stoves do not have any emission reduction technology or design features and, in most cases, were manufactured before July 1, 1986.

[6] Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific value for dry wood was 20 per cent lower than the gross calorific value (Forest Product Laboratory, 2004).

[7] Sources: Bhattacharya *et al.*, 2002; Smith *et al.*, 1992, 1993; Smith *et al.*, 2000; Zhang *et al.*, 2000. Results of experimental studies conducted on a number of traditional and improved stoves collected from: Cambodia, China, India, Lao PDR, Malaysia, Nepal, Philippines and Thailand. N_2O was measured only in the stoves from India and Philippines. The values represent ultimate emission factors that take into account the combustion, at later stages, of charcoal produced during earlier combustion stages.

[8] Sources: Bhattacharya *et al.*, 2002; Smith *et al.*, 1992, 1993; Smith *et al.*, 2000. Results of experimental studies conducted on a number of traditional and improved stoves collected from: Cambodia, India, Lao PDR, Malaysia, Nepal, Philippines and Thailand. N_2O was measured only in the stoves from India and Philippines.

[9] Sources: Smith *et al*, 2000; Zhang *et al.*, 2000. Results of experimental studies conducted on a number of household stoves from China (CH_4) and India (CH_4 and N_2O).

[10] Source: Smith *et al.*, 2000. Results of experimental studies conducted on a number of household stoves from India.

NA, data not available.

n indicates a new emission factor which was not present in the *IPCC 1996 Guidelines*

r indicates an emission factor that has been revised since the *IPCC 1996 Guidelines s*

TABLE 2.10
COMMERCIAL/INSTITUTIONAL SOURCE EMISSION FACTORS

Basic technology	Configuration	Emission factors[1] (kg/TJ energy input)	
		CH_4	N_2O
Liquid Fuels			
Residual Fuel Oil Boilers		1.4	0.3
Gas/Diesel Oil Boilers		0.7	0.4
Liquefied Petroleum Gases Boilers		**n** 0.9	**n** 4
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		**n** 1	**n** 0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		**n** 14	**n** 0.7
Other Bituminous/Sub-bit. Hand-fed Units		**n** 87	**n** 0.7
Other Bituminous/Sub-bituminous Pulverised Boilers	Dry Bottom, wall fired	**n** 0.7	**n** 0.5
	Dry Bottom, tangentially fired	**n** 0.7	**n** 1.4
	Wet Bottom	**n** 0.9	**n** 1.4
Other Bituminous Spreader Stokers		**n** 1	**n** 0.7
Other Bituminous/Sub-bit. Fluidised Bed Combustor	Circulating Bed	**n** 1	**n** 61
	Bubbling Bed	**n** 1	**n** 61
Natural Gas			
Boilers		**r** 1	**r** 1
Gas-Fired Gas Turbines >3MWa		**n** 4	**n** 1.4
Biomass			
Wood/Wood Waste Boilers[2]		**n** 11	**n** 7

[1] Source: US EPA, 2005b Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumptions on how to convert from gross to net calorific values.

[2] Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific value for dry wood was 20 per cent lower than the gross calorific value (Forest Product Laboratory, 2004).

n indicates a new emission factor which was not present in the IPCC 1996 Guidelines

r indicates an emission factor that has been revised since the IPCC 1996 Guidelines

2.3.3.1 TIER 1 AND TIER 2

The activity data used in a Tier 1 approach for combustion in the energy sector are derived from energy statistics, compiled by the national statistical agency. Comparable statistics are published by the International Energy Agency (IEA), based on national returns. If national data are not directly available to the national inventory compiler, a request could be sent to the IEA at stats@iea.org to receive the country's data free of charge.

Primary data on fuel consumption are normally collected in mass or in volume units. Because the carbon content of fuels is generally correlated with the energy content, and because the energy content of fuels is generally measured, it is recommended to convert values for fuel consumption into energy units. Default values for the conversion of fuel consumption numbers into conventional energy units are given in section 1.4.1.2.

Information on energy statistics and balances methodology is available in the "Energy Statistics Manual" published by the IEA. This manual can be downloaded free of charge from www.iea.org. Key issues about more important source categories are given below.

ENERGY INDUSTRIES

In energy industries, fossil fuels are both raw materials for the conversion processes, and sources of energy to run these processes. The energy industry comprises three kinds of activities:

1 Primary fuel production (e.g. coal mining and oil and gas extraction);

2 Conversion to secondary or tertiary fossil fuels (e.g. crude oil to petroleum products in refineries, coal to coke and coke oven gas in coke ovens);

3 Conversion to non-fossil energy vectors (e.g. from fossil fuel into electricity and/or heat).

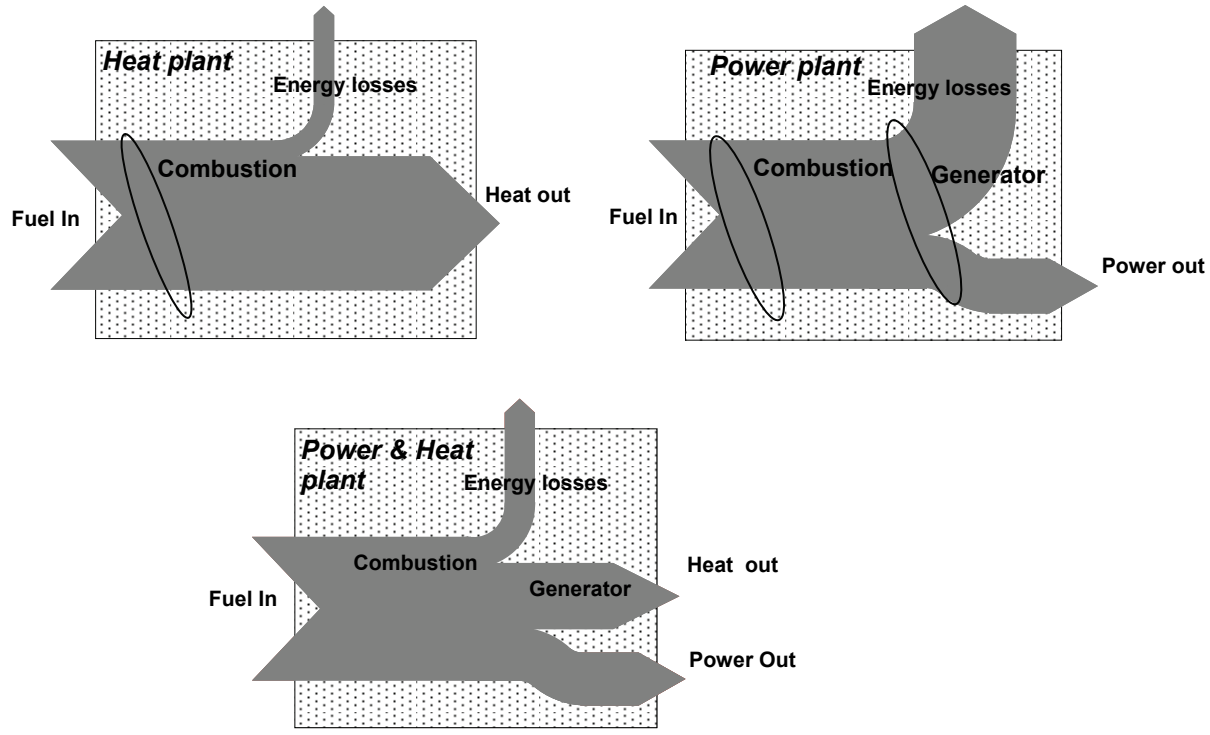
Emissions from combustion during production and conversion processes are counted under energy industries. Emissions from the secondary fuels produced by the energy industries are counted in the sector where they are used. When collecting activity data, it is essential to distinguish between the fuel that is combusted and the fuel that is converted into a secondary or tertiary fuel in Energy Industries.

MAIN ACTIVITY ELECTRICITY AND HEAT PRODUCTION

The main activity *electricity and heat production* (formerly known as public electricity and heat production) converts the chemical energy stored in the fuels to either electrical power (counted under *electricity generation*) or heat (counted under *heat production*) or both (counted under *combined heat and power, CHP*); see Table 2.1.

Figure 2.2 shows the energy flows. In conventional power plants, the total energy losses to the environment might be as high as 70 percent of the chemical energy in the fuels, depending on the fuel and the specific technology. In a modern high efficiency power plant, losses are down to about half of the chemical energy contained in the fuels. In a combined heat and power plant most of the energy in the fuel is delivered to final users, either as electricity or as heat (for industrial processes or residential heating or similar uses). The width of the arrows roughly represents the relative magnitude of the energy flows involved.

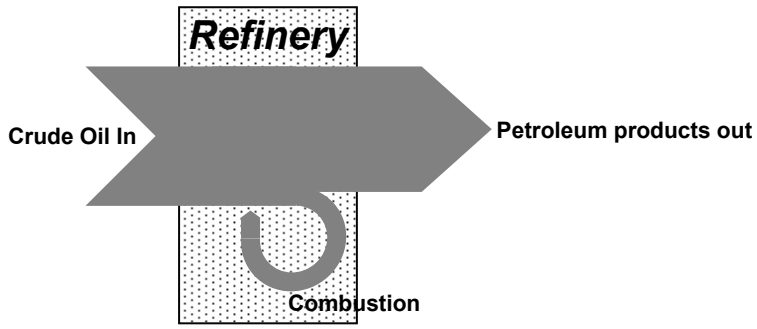
Figure 2.2 Power and heat plants use fuels to produce electric power and/or useful heat.



PETROLEUM REFINING

In a petroleum refinery, crude oil is converted to a broad range of products (Figure 2.3). For this transformation to occur, part of the energy content of the products obtained from crude oil is used in the refinery (See Table 2.1.). This complicates the derivation of activity data from energy statistics.

Figure 2.3 A refinery uses energy to transform crude oil into petroleum products.



In principle all petroleum products are combustible as fuel to provide the process heat and steam needed for the refining processes. The petroleum products include a broad range from the *heavy* products like tar, bitumen, heavy fuel oils via the *middle distillates* like gas oils, naphtha, diesel oils, kerosenes to *light* products like motor gasoline, LPG and refinery gas.

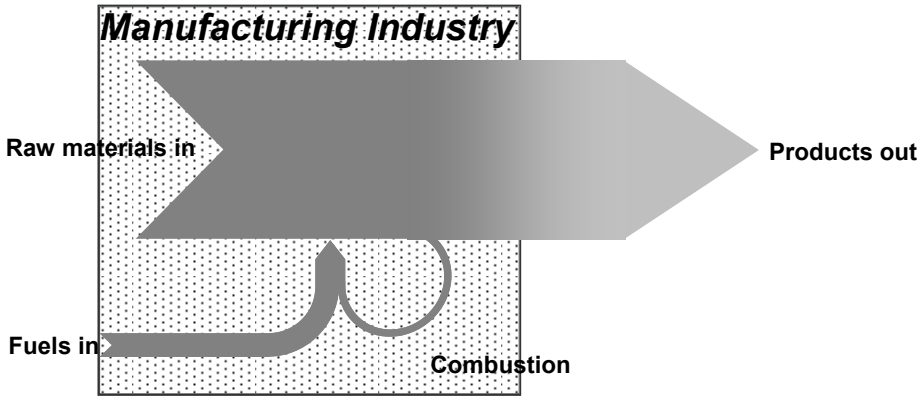
In many cases, the exact products and fuels used in refineries to produce the heat and steam needed to run the refinery processes are not easily derived from the energy statistics. The fuel combusted within petroleum refineries typically amounts to 6 to 10 percent of the total fuel input to the refinery, depending on the complexity and vintage of the technology. It is *good practice* to ask the refinery industry for fuel consumption in order to select or verify the appropriate values reported by energy statistics.

MANUFACTURING INDUSTRIES AND CONSTRUCTION

In manufacturing industries, raw materials are converted into products as is schematically presented in Figure 2.4. For construction, the same principle holds: the inputs include the building materials and the outputs are the buildings.

Manufacturing industries are generally classified according to the nature of their products. This is done via the International Standard Industrial Classification of economic activities that is used in Table 2.1 for convenient cross-referencing.

Figure 2.4 Fuels are used as an energy source in manufacturing industries to convert raw materials into products.[10]



[10] For some industries raw materials might include fossil fuel. Some fuel might be derived from by-products or waste streams generated in the production process.

Raw materials used in manufacturing industries can also include fossil fuels. Examples include production of petrochemicals (eg methanol), other bulk chemicals (eg ammonia) and primary iron where coke is an input. In some cases, the situation is more complicated, because the energy to drive the process might be directly delivered from the chemical reactions of the manufacturing processes. An example of this is the manufacture of primary iron and steel, where the chemical reaction between the coke and the iron ore produces gas and heat that are sufficient to run the process[11]. The reporting of emissions from gases obtained from processing feedstock and process fuels obtained directly from the feedstock (e.g. ammonia production) follows the principle stated in Section 1.2 of this Volume and detailed guidance given in the IPPU Volume. In summary, if the emissions occur in the IPPU source category which produced the gases emitted they remain as industrial processes emissions in that source category. If the gases are exported to another source category in the IPPU sector, or to the energy sector, then the fugitive, combustion or other emissions associated with them should be reported in the sector where they occur. Inventory compilers are reminded to discriminate between emissions from processes where the same fossil fuel is used both for energy and for feedstock purposes (e.g. synthesis gas production, carbon black production), and to report these emissions in the correct sectors.

Some countries may face some difficulties in obtaining disaggregated activity data or may have different definitions for industrial source categories. For example, some countries may include residential energy consumption of the workers in industry consumption. In this case, any deviations from the definitions should be documented.

2.3.3.2 TIER 3

Tier 3 estimates incorporate data at the level of individual facilities, and this type of information is increasingly available, because of the requirements of emissions trading schemes. It is often the case, that coverage of facility level data does not correspond exactly to coverage of classifications within the national energy statistics, and this can give rise to difficulties in combining the various sources of information. Methods for combining data are discussed in Chapter 2 of Volume 1 on General Guidance and Reporting.

2.3.3.3 AVOIDING DOUBLE COUNTING ACTIVITY DATA WITH OTHER SECTORS

The use of fuel combustion statistics rather than fuel delivery statistics is key to avoid double counting in emission estimates. Fuel combustion data, however, are very seldom complete, since it is not practical to measure the fuel consumption or emissions of every residential or commercial source. Hence, national inventories using this approach will generally contain a mixture of combustion data for larger sources and delivery data for other sources. The inventory compiler must take care to avoid both double counting and omission of emissions when combining data from multiple sources.

When activity data are not quantities of fuel combusted but are instead deliveries to enterprises or main subcategories, there is a risk of double counting emissions from the IPPU or Waste Sectors. Identifying double counting is not always easy. Fuels delivered and used in certain processes may give rise to by-products used as fuels elsewhere in the plant or sold for fuel use to third parties (e.g. blast furnace gas that is derived from coke and other carbon inputs to blast furnaces). It is *good practice* to coordinate estimates between the stationary source category and relevant industrial categories to avoid double counting or omissions. Some of the categories and subcategories where fossil fuel carbon is reported and between which double counting of fossil fuel carbon could, in principle, occur are summarized below.

- IPPU – Production of non-fuel products from energy feedstocks such as coke, ethane, gas/diesel oil, LPG, naphtha and natural gas.

  The production of synthesis gas (syngas), namely the mixture of carbon monoxide and hydrogen, through steam reforming or partial oxidation of energy feedstocks deserves particular attention since these processes produce CO_2 emissions. Synthesis gas is an intermediate in the production of chemicals such as ammonia, formaldehyde, methanol, pure carbon monoxide and pure hydrogen. Emissions from these processes should be accounted for in the IPPU sector. Note that CO_2 emissions should be counted at the point of emission if the gas is stored for only a short time (e.g. CO_2 used in the food and drink industry generated as a by product of ammonia production).

[11] The best available techniques reference documents (BREFs) of the European Integrated Pollution Prevention and Control Bureau (IPPC) for Iron and Steel (http://eippcb.jrc.es/) show that about one third of the heat requirement for the process comes from the blast furnace gas produced and combusted in the blast air heaters. Also the heat produced by the production of CO as the blast air passes over the coke is not strictly part of the reduction of the ore.

Synthesis gas is also produced by partial oxidation/gasification of solid and liquid fuel feedstocks in the relatively newer Integrated Gasification Combined Cycle (IGCC) technology for power generation. When synthesis gas is produced in IGCC for the purpose of generating power, associated emissions should be accounted for in 1A, fuel combustion.

In the production of carbides, CO_2 is released when carbon-rich fuels, particularly petroleum coke, are used as a carbon source. These emissions should be accounted for in the IPPU sector.

For further information, refer to Volume 3, which gives details of completeness check of carbon emissions from feedstock and other non-energy use.

- IPPU, AFOLU – Use of carbon as reducing agent in metal production

  The greenhouse gas emissions originating from the use of coal, coke, natural gas, prebaked anodes and coal electrodes as reducing agents in the commercial production of metals from ores should be accounted for in the IPPU sector. Wood chips and charcoal may also be used in some of the processes. In this case, the resulting emissions are counted in the AFOLU sector. By-product fuels (coke oven gas and blast furnace gas) are produced in some of these processes. These fuels may be sold or used within the plant. They may or may not be included in the national energy balance. Care should consequently be taken not to double count emissions.

- ENERGY, WASTE – methane from coal mine waste, landfill gas and sewage gas

  In these cases, it is important to ensure that the amounts of fuel accounted for in stationary combustion are the same as the quantities netted out from "Fugitive emissions from coal mining and handling", "Waste Incineration" and "Wastewater Treatment and Discharge" respectively.

- WASTE – Incineration of waste

  When energy is recovered from waste combustion, the associated greenhouse gas emissions are accounted for in the Energy sector under stationary combustion. Waste incineration with no associated energy purposes should be reported in the Waste source category; see Chapter 5 (Incineration and Open Burning of Waste) of Volume 5. It is *good practice* to assess the content of waste and differentiate between the part containing plastics and other fossil carbon materials from the biogenic part and estimate the associated emissions accordingly. The CO_2 emission from the fossil-carbon part can be included in the fuel category *Other fuels,* while the CO_2 emissions from the biomass part should be reported as an information item. For higher tier estimations, inventory compiler may refer to Chapter 5 of the Waste Volume. It is *good practice* to contact those responsible for recovering used oils in order to assess the extent to which used oils are burned in the country and estimate and report these emissions in the Energy sector if they are used as fuel.

- ENERGY – Mobile combustion

The main issue is to ensure that double counting of agricultural and off-road vehicles is avoided.

2.3.3.4 TREATMENT OF BIOMASS

Biomass is a special case:

- Emissions of CO_2 from biomass fuels are estimated and reported in the AFOLU sector as part of the AFOLU methodology. In the reporting tables, emissions from combustion of biofuels are reported as information items but not included in the sectoral or national totals to avoid double counting. In the emission factor tables presented in this chapter, default CO_2 emission factors are presented to enable the user to estimate these information items.
- For biomass, only that part of the biomass that is combusted for energy purposes should be estimated for inclusion as an information item in the Energy sector.
- The emissions of CH_4 and N_2O, however, are estimated and included in the sector and national totals because their effect is in addition to the stock changes estimated in the AFOLU sector.
- For fuel wood, activity data are available from the IEA or the FAO (Food and Agriculture Organisation of the United Nations). These data originate from national sources and inventory compilers can obtain a better understanding of national circumstances by contacting national statistical agencies to find the organisations involved.
- For agricultural crop residues (part of other primary solid biomass) and also for fuel wood, estimation methods for activity data are available in Chapter 5 of the AFOLU volume.

- In some instances, biofuels will be combusted jointly with fossil fuels. In this case, the split between the fossil and non-fossil fraction of the fuel should be established and the emission factors applied to the appropriate fractions.

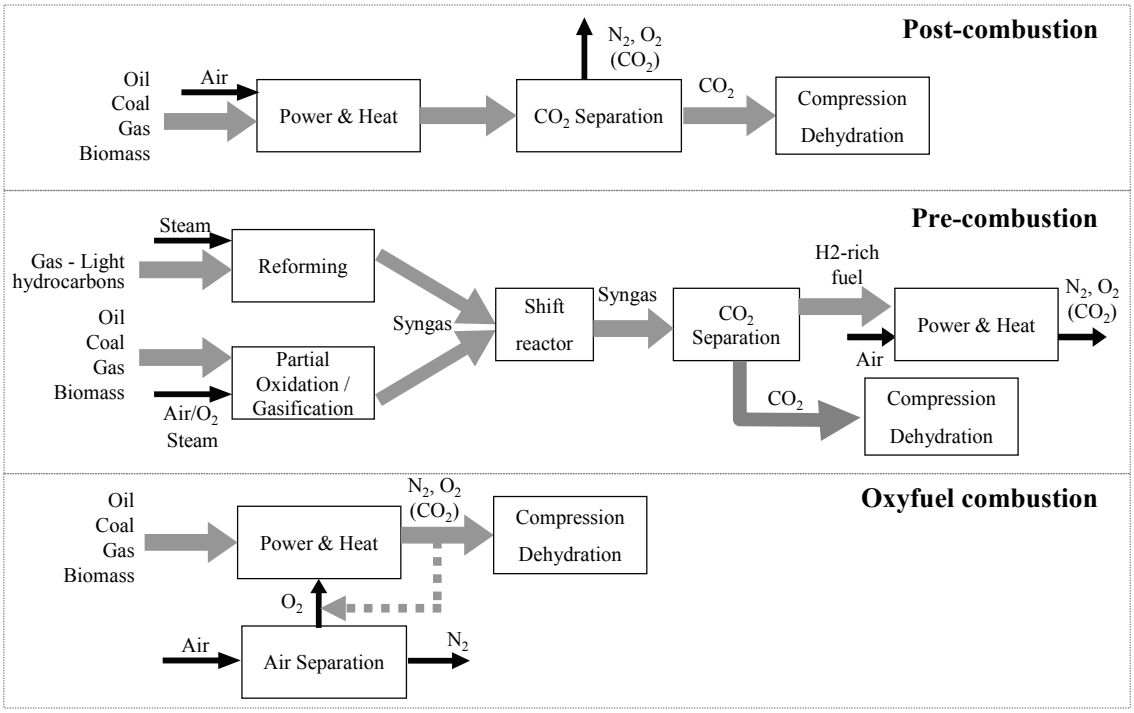
2.3.4 Carbon dioxide capture

Capture and storage removes carbon dioxide from the gas streams that would otherwise be emitted to the atmosphere, and transfers it for indefinite long term storage in geological reservoirs, such as depleted oil and gas fields or deep saline aquifers. In the energy sector, candidates for carbon dioxide capture and storage undertakings include large stationary sources such as power stations and natural gas sweetening units. This chapter deals only with CO_2 capture associated with combustion activities, particularly those relative to power plants. Fugitive emissions arising from the transfer of carbon dioxide from the point of capture to the geological storage, and emissions from the storage site itself, are covered in Chapter 5 of this Volume. Other possibilities also exist in industry to capture CO_2 from process streams. These are covered in Volume 3.

There are three main approaches for capturing CO_2 arising from the combustion of fossil fuels and/or biomass (Figure 2.5). Post-combustion capture refers to the removal of CO_2 from flue gases produced by combustion of a fuel (oil, coal, natural gas or biomass) in air. Pre-combustion capture involves the production of synthesis gas (syngas), namely the mixture of carbon monoxide and hydrogen, by reacting energy feedstocks with steam and/or oxygen or air. The resulting carbon monoxide is reacted with steam by the shift reaction to produce CO_2 and more hydrogen. The stream leaving the shift reactor is separated into a high purity CO_2 stream and H_2-rich fuel that can be used in many applications, such as boilers, gas turbines and fuel cells.

Oxy-fuel combustion uses either almost pure oxygen or a mixture of almost pure oxygen and a CO_2-rich recycled flue gas instead of air for fuel combustion. The flue gas contains mainly H_2O and CO_2 with excess oxygen required to ensure complete combustion of the fuel. It will also contain any other components in the fuel, any diluents in the oxygen stream supplied, any inert matter in the fuel and from air leakage into the system from the atmosphere. The net flue gas, after cooling to condense water vapour, contains from about 80 to 98 percent CO_2 depending on the fuel used and the particular oxy-fuel combustion process.

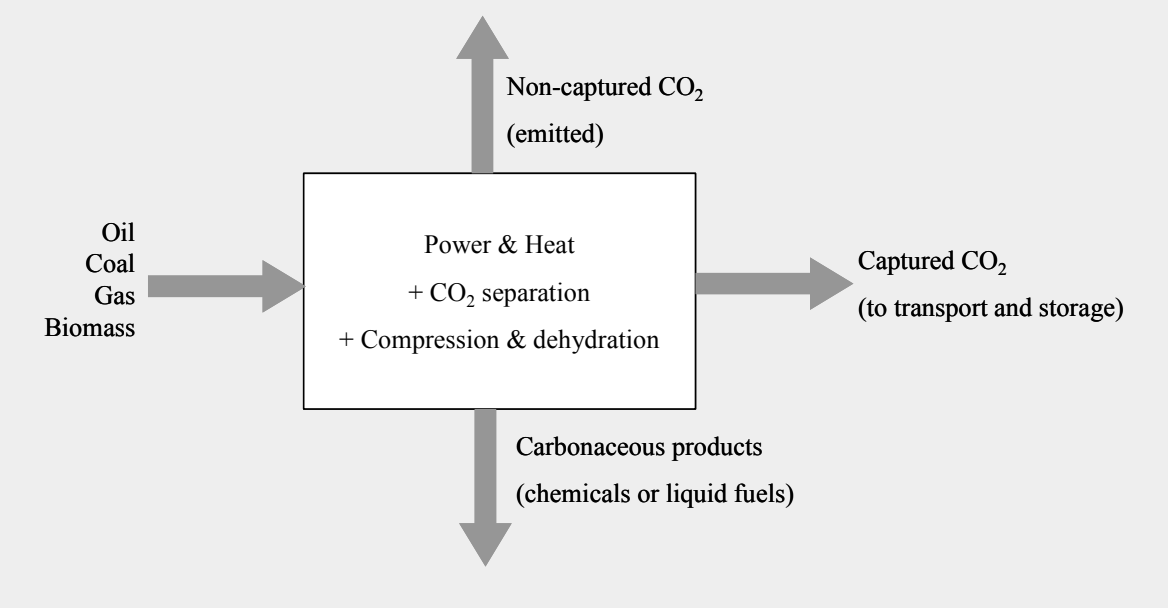
Figure 2.5 CO_2 capture systems from stationary combustion sources



Carbon dioxide capture has some energy requirements with a corresponding increase in fossil fuel consumption. Also the capture process is less than 100 percent efficient, so a fraction of CO_2 will still be emitted from the gas stream. Chapter 3 of the IPCC Special Report on CO_2 Capture and Storage (Thambimuthu *et al*., 2005) provides a thorough overview of the current and emerging technologies for capturing CO_2 from different streams arising in the energy and the industrial processes sectors.

The general scheme concerning the carbon flows in the three approaches for capturing CO_2 from streams arising in combustion processes is depicted in Figure 2.6. The system boundary considered in this chapter includes the power plant or other process of interest, the CO_2 removal unit and compression/dehydration of the captured CO_2 but does not include CO_2 transport and storage systems. This general scheme also contemplates the possibility that pre-combustion capture systems can also be applied to multi-product plants (also known as polygeneration plants). The type of polygeneration plant considered in this chapter employs fossil fuel feedstocks to produce electricity and/or heat plus a variety of co-products such as hydrogen, chemicals and liquid fuels. In those processes associated with post-combustion and oxyfuel combustion capture systems, no carbonaceous co-products are typically produced.

Figure 2.6 Carbon flows in and out of the system boundary for a CO_2 capture system associated with stationary combustion processes



The CO_2 capture efficiency of any system represented in Figure 2.6 is given in Equation 2.6. Table 2.11 summarises estimates of CO_2 capture efficiencies for post and pre-combustion systems of interest that have been recently reported in several studies. This information is provided for illustrative purposes only as it is *good practice* to use measured data on volume captured rather than efficiency factors to estimate emissions from a CO_2 capture installation.

EQUATION 2.6
CO_2 CAPTURE EFFICIENCY

$$Efficiency_{CO_2\ capture\ \ technology} = \frac{C_{captured\ \ CO_2}}{C_{fuel} - C_{products}} \bullet 100$$

Where:

$Efficiency_{CO_2\ capture\ \ technology}$ = CO_2 capture system efficiency (percent)

$C_{captured\ \ CO_2}$ = amount of carbon in the captured CO_2 stream (kg)

C_{fuel} = amount of carbon in fossil fuel or biomass input to the plant (kg)

$C_{products}$ = amount of carbon in carbonaceous chemical or fuel products of the plant (kg).

TABLE 2.11
TYPICAL CO_2 CAPTURE EFFICIENCIES FOR POST AND PRE-COMBUSTION SYSTEMS

Technologies	Efficiency (%)			References
Power plant / Capture system	**Average**	**Minimum**	**Maximum**	
Pulverised sub-bituminous/bituminous coal (250-760 MWe, 41-45% net plant efficiency)[1,2] / Amine-based post-combustion capture.	90	85	96	Alstom, 2001; Chen *et al*., 2003; Gibbins *et al*., 2005; IEA GHG, 2004; Parsons, 2002; Rao and Rubin, 2002; Rubin *et al*., 2005; Simbeck, 2002; Singh *et al*., 2003.
Natural gas combined cycle (380-780 MWe, 55-58% net plant efficiency, LHV)[1] / Amine-based post-combustion capture.	88	85	90	CCP, 2005; EPRI, 2002; IEA GHG, 2004; NETL, 2002; Rubin *et al*., 2005.
Integrated gasification combined cycle (400-830 MWe, 31-40% net plant efficiency)[1] / Physical solvent-based pre-combustion capture (Selexol)	88	85	91	IEA GHG, 2003; NETL, 2002; Nsakala *et al*., 2003; Parsons, 2002; Rubin *et al*., 2005; Simbeck, 2002.
Electricity + H_2 plant (coal, 2600-9900 GJ/hr input capacity)[1] / Physical solvent-based pre-combustion capture (mostly Selexol)	83	80	90	Kreutz *et al*., 2005, Mitretek, 2003; NRC, 2004; Parsons, 2002.
Electricity + dimethyl ether (coal, 7900-8700 GJ/hr input capacity)[1] / Physical solvent-based pre-combustion capture (Selexol or Rectisol)	64	32	97	Celik *et al*., 2005; Larson, 2003
Electricity + methanol (coal, 9900 GJ/hr input capacity)[1] / Physical solvent-based pre-combustion capture (Selexol)	60	58	63	Larson, 2003
Electricity + Fischer-Tropsch liquids (coal, 16000 GJ/hr input capacity)[1] / Physical solvent-based pre-combustion capture (Selexol)	91	-	-	Mitretek, 2001

[1] Reference plant without CO_2 capture system

[2] These options include existing plants with retrofitting post-combustion capture system as well as new designs integrating power generation and capture systems.

TIER 3 CO_2 EMISSION ESTIMATES

Because this is an emerging technology, it requires plant-specific reporting at Tier 3. Plants, with capture and storage will most probably meter the amount of gas removed by the gas stream and transferred to geological storage. Capture efficiencies derived from the measured data can be compared with the values in Table 2.11 as a verification cross-check.

Under Tier 3, the CO_2 emissions are therefore estimated from the fuel consumption estimated as described in earlier sections of this chapter minus the metered amount removed.

EQUATION 2.7
TREATMENT OF CO_2 CAPTURE

$$Emissions_s = \mathrm{Pr}oduction_s - Capture_s$$

Where:

s = source category or subcategory where capture takes place

Captures = Amount captured.

Productions = Estimated emissions, using these guidelines assuming no capture

$Emissions_s$ = Reported emission for the source category or sub-category

This method automatically takes into account any increase in energy consumption at the plant because of the capture process (since this will be reflected in the fuel statistics), and it does not require independent estimation of the capture efficiency, since the residual emissions are estimated more accurately by the subtraction. If the plant is supplied with biofuels, the corresponding CO_2 emissions will be zero (these are already included in national totals due to their treatment in the AFOLU sector), so the subtraction of the amount of gas transferred to long-term storage may give negative emissions. This is correct since if the biomass carbon is permanently stored, it is being removed from the atmosphere. The corollary of this is that any subsequent emissions from CO_2 transport, CO_2 injection and the storage reservoir itself should be counted in national total emissions, irrespective of whether the carbon originates from fossil sources or recent biomass production. This is why in sections 5.3 (CO_2 transport), 5.4 (Injection) and 5.5 (Geological Storage) no reference is made to the origin of the CO_2 stored in underground reservoirs. The metering for the amount removed should be installed in line with industrial practice and will normally be accurate to about 1 percent.

Quantities of CO_2 for later use and short-term storage should not be deducted from CO_2 emissions except when the CO_2 emissions are accounted for elsewhere in the inventory[12].

2.3.5 Completeness

A complete estimate of emissions from fuel combustion should include emissions from all fuels and all source categories identified within the *IPCC 2006 Guidelines*. Completeness should be established by using the same underlying activity data to estimate emissions of CO_2, CH_4 and N_2O from the same source categories.

All fuels delivered by fuel producers must be accounted for. Misclassification of enterprises and the use of distributors to supply small commercial customers and households increase the chance of systematic errors in the allocation of fuel delivery statistics. Where sample survey data that provide figures for fuel consumption by specific economic sectors exist, the figures may be compared with the corresponding delivery data. Any systematic difference should be identified and the adjustment to the allocation of delivery data may then be made accordingly.

Systematic under-reporting of solid and liquid fuels may also occur if final consumers import fuels directly. Direct imports will be included in customs data and therefore in fuel supply statistics, but not in the statistics of fuel deliveries provided by national suppliers. If direct importing by consumers is significant, then the statistical difference between supplies and deliveries will reveal the magnitude. Own use of fuels supplied by dedicated mines may occur in such sectors of manufacturing as iron and steel and cement, and is also a potential source of under-reporting. Once again, a comparison with consumption survey results will reveal which main source categories are involved in direct importing. Concerning biomass fuels, the national energy statistics agencies should be consulted about their use, including possible use of non-commercially traded biomass fuels.

Experience has shown that some activities such as change in producer stocks of fossil fuels and own fuel combustion by energy industries may be poorly covered in existing inventories. This also applies to statistics on biomass fuels and from waste combustion. Their presence should be specifically checked with statistical agencies, sectoral experts and organisations as well as supplementary sources of data included if necessary. Chapter 2 of Volume 1 covers data collection in general.

2.3.6 Developing a consistent time series and recalculation

Using a consistent method to estimate emissions is the main mechanism for ensuring time series consistency. However, the variability in fuel quality over time is also important to consider within the limits of the national fuel characterisation or the fuel types listed in Tables 2.2 to 2.5. This includes variation in carbon content, typically reflected in variation in the calorific values used to convert the fuels from mass or volume units to the energy units used in the estimation. It is *good practice* for inventory compilers to check that variations of calorific values over time are in fact reflected in the information used to construct the national energy statistics.

[12] Examples include urea production (Volume 3, section 3.2) and the use of CO_2 in methanol production (Volume 3, section 3.9) where the CO_2 due to the final products is accounted for.

Application of these *IPCC 2006 Guidelines* may result in revisions in some components of the emissions inventory, such as emissions factors or the sectoral classification of some emissions. For example, the component of emissions of CO_2 from non-fuel use of fossil fuels will move from the Energy Sector under the *IPCC 1996 Guidelines* to the IPPU sector under the *IPCC 2006 Guidelines*. Whereas the *IPCC 1996 Guidelines* for the energy sector estimated total potential emissions from fossil-fuel use and then subtracted the portion of the carbon that ended up stored in long-lived products, the *IPCC 2006 Guidelines* include all non-fuel uses in the IPPU sector. This should result in slightly decreased CO_2 emissions reported from the Energy sector and increased emissions reported in the IPPU sector. For further information on ensuring a consistent time series, check Chapter 5, Time Series Consistency, in Volume 1.

2.4 UNCERTAINTY ASSESSMENT

2.4.1 Emission factor uncertainties

For fossil fuel combustion, uncertainties in CO_2 emission factors are relatively low. These emission factors are determined by the carbon content of the fuel and thus there are physical constraints on the magnitude of their uncertainty. However, it is important to note there are likely to be intrinsic differences in the uncertainties of CO_2 emission factors of petroleum products, coal and natural gas. Petroleum products typically conform to fairly tight specifications which limit the possible range of carbon content and calorific value, and are also sourced from a relatively small number of refineries and/or import terminals. Coal by contrast may be sourced from mines producing coals with a very wide range of carbon contents and calorific values and is mostly supplied under contract to users who adapt their equipment to match the characteristics of the particular coal. Hence at the national level, the single energy commodity "black coal" can have a range of CO_2 emission factors.

Emission factors for CH_4 and especially N_2O are highly uncertain. High uncertainties in emission factors may be ascribed to lack of relevant measurements and subsequent generalisations, uncertainties in measurements, or an insufficient understanding of the emission generating process. Furthermore, due to stochastic variations in process conditions, a high variability of the real time emission factors for these gases might also occur (Pulles and Heslinga, 2004). Such variability obviously will also contribute to the uncertainty in the emission estimates. The uncertainties of emission factors are seldom known or accessible from empirical data. Consequently, uncertainties are customarily derived from indirect sources or by means of expert judgements. The *IPCC 1996 Guidelines* (Table A1-1, Vol. I, p. A1.4) suggest an overall uncertainty value of 7 per cent for the CO_2 emission factors of Energy.

The default uncertainties shown in Table 2.12 derived from the EMEP/CORINAIR Guidebook ratings (EMEP/CORINAIR, 1999) may be used in the absence of country-specific estimates.

TABLE 2.12
DEFAULT UNCERTAINTY ESTIMATES FOR STATIONARY COMBUSTION EMISSION FACTORS

Sector	CH_4	N_2O
Public Power, co-generation and district heating	50-150%	Order of magnitude*
Commercial, Institutional and Residential combustion	50-150%	Order of magnitude
Industrial combustion	50-150%	Order of magnitude

* i.e. having an uncertainty range from one-tenth of the mean value to ten times the mean value.
Source: IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)

While these default uncertainties can be used for the existing emission factors (whether country-specific or taken from the *IPCC Guidelines*), there may be additional uncertainties associated with applying emission factors that are not representative of the combustion conditions in the country. Uncertainties can be lower than the values in Table 2.12 if country-specific emission factors are used. It is *good practice* to obtain estimates of these uncertainties from national experts taking into account the guidance concerning expert judgements provided in Volume 1.

There is currently relatively little experience in assessing and compiling inventory uncertainties and more experience is needed to assess whether the few available results are typical and comparable, and what the main weaknesses in such analyses are. Some articles addressing uncertainty assessment of greenhouse inventories have recently appeared in the peer-reviewed literature. Rypdal and Winiwater (2001) evaluated the uncertainties in greenhouse gas inventories and compared the results reported by five countries namely Austria (Winiwarter and Rypdal, 2001), the Netherlands (van Amstel *et al*., 2000), Norway (Rypdal, 1999), UK (Baggott *et al*., 2005)

and USA (EIA, 1999). More recently, Monni *et al*. (2004) evaluated the uncertainties in the Finnish greenhouse gas emission inventory.

Tables 2.13 and 2.14 summarise the uncertainty assessments of emission factors for stationary combustion reported in the studies noted above. To complement this information, the approaches and emission factors used by each country as (reported in the corresponding 2003 National Greenhouse Gas Inventory submission to the UNFCCC) have been added to Tables 2.13 and 2.14. It can be seen that higher tier approaches and a higher number of country-specific (CS) emission factors were used for CO_2 as compared to CH_4 and N_2O. Conversely, lower tier approaches and greater reliance on default emission factors were used for N_2O. This information is provided primarily for illustrative purposes. These uncertainty ranges could be used as a starting point or for comparison by national experts working on uncertainty assessment.

TABLE 2.13
SUMMARY OF UNCERTAINTY ASSESSMENT OF CO_2 EMISSION FACTORS FOR STATIONARY COMBUSTION SOURCES OF SELECTED COUNTRIES

Country	95% confidence interval[1]	Distribution	2003 GHG inventory submission[2]		References
			Approach[3]	Emission factor[4]	
Oil					
Austria	± 0.5	Normal	C	CS	Winiwarter and Rypdal, 2001
Norway	± 3	Normal	C	CS	Rypdal, 1999
The Netherlands	± 2	-	T2, CS	CS, PS	Van Amstel *et al.*, 2000
UK	± 2	Normal	T2	CS	Baggott *et al.*, 2005
USA	± 2	-	T1	CS	EIA, 1999
Coal, coke, gas					
Austria	± 0.5	Normal	C	CS	Winiwarter and Rypdal, 2001
Norway	± 7	Normal	C	CS	Rypdal, 1999
The Netherlands	± 1-10	-	T2, CS	CS, PS	Van Amstel et al., 2000
UK	± 1-6	Normal	T2	CS	Baggott et al., (2005)
USA	± 0-1	-	T1	CS	EIA, 1999
Other fuels (mainly peat)					
Finland	± 5	Normal	T2, CS	D, CS, PS	Monni et al., 2004

[1] Data are given as upper and lower bounds of the 95 percent confidence interval, and expressed as percent relative to the mean value.

[2] The information in the columns is based on the 2003 National Greenhouse Gas Inventory submissions from Annex I Parties to the UNFCCC.

[3] Notation keys that specify the approach applied: T1 (IPCC Tier 1), T2 (IPCC Tier 2), T3 (IPCC Tier 3), C (CORINAIR), CS (Country-specific).

[4] Notation keys that specify the emission factor used: D (IPCC default), C (CORINAIR), CS (Country-specific), PS (Plant Specific).

TABLE 2.14
SUMMARY OF UNCERTAINTY ASSESSMENT OF CH_4 AND N_2O EMISSION FACTORS FOR STATIONARY COMBUSTION SOURCES OF SELECTED COUNTRIES

Country	95% confidence interval[1]	Distribution	2003 GHG inventory submission[2]		References
			Approach[3]	Emission factor[4]	
CH_4					
Austria	± 50	Normal	C, CS	CS	Winiwarter and Rypdal, 2001
Finland	-75 to +10	β	T1, T2, CS	CS, PS	Monni *et al.*, 2004
Norway	-50 to + 100	Lognormal	T2, CS	D, CS, PS	Rypdal, 1999
The Netherlands	± 25	-	T2, CS	CS, PS	Van Amstel *et al.*, 2000
UK	± 50	Truncated normal	T2	D, C, CS	Baggott *et al.*, 2005
USA	Order of magnitude	-	T1	D, CS	EIA, 1999
N_2O					
Austria	± 20	Normal	C, CS	CS	Winiwarter and Rypdal, 2001
Finland	-75 to +10	Beta	T1, T2, CS	CS, PS	Monni *et al.*, 2004
Norway	-66 to + 200	Beta	T1, T2	D, CS	Rypdal, 1999
The Netherlands	± 75	-	T1, CS	D, PS	Van Amstel *et al.*, 2000
UK	± 100 to 200	-	T2	D, C, CS	Baggott *et al.*, 2005
USA	-55 to + 200	-	T1	D, CS	EIA, 1999

[1] Data are given as upper and lower bounds of the 95 percent confidence interval, and expressed as percent relative to the mean value.

[2] The information in the columns is based on the 2003 National Greenhouse Gas Inventory submissions from Annex I Parties to the UNFCCC.

[3] Notation keys that specify the approach applied: T1 (IPCC Tier 1), T2 (IPCC Tier 2), T3 (IPCC Tier 3), C (CORINAIR), CS (Country-specific).

[4] Notation keys that specify the emission factor used: D (IPCC default), C (CORINAIR), CS (Country-specific), PS (Plant-Specific).

2.4.2 Activity data uncertainties

Statistics of fuel combusted at large sources obtained from direct measurement or obligatory reporting are likely to be within 3 percent of the central estimate. For some energy intensive industries, combustion data are likely to be more accurate. It is *good practice* to estimate the uncertainties in fuel consumption for the main sub-categories in consultation with the sample survey designers, because the uncertainties depend on the quality of the survey design and the size of sample used.

In addition to any systematic bias in the activity data as a result of incomplete coverage of consumption of fuels, the activity data will be subject to random errors in the data collection that will vary from year to year. Countries with good data collection systems, including data quality control, may be expected to keep the random error in total recorded energy use to about 2-3 percent of the annual figure. This range reflects the implicit confidence limits on total energy demand seen in models using historical energy data and relating energy demand to economic factors. Percentage errors for individual energy use activities can be much larger.

Overall uncertainty in activity data is a combination of both systematic and random errors. Most developed countries prepare balances of fuel supply and deliveries and this provides a check on systematic errors. In these circumstances, overall systematic errors are likely to be small. Experts believe that the uncertainty resulting from the two errors combined is probably in the range of ±5 percent for most developed countries. For countries with

less well-developed energy data systems, this could be considerably larger, probably about ±10 percent. Informal activities may increase the uncertainty up to as much as 50 percent in some sectors for some countries.

Uncertainty ranges for stationary combustion activity data are shown in Table 2.15. This information may be used when reporting uncertainties. It is *good practice* for inventory compilers to develop, if possible, country-specific uncertainties using expert judgement and/or statistical analysis.

TABLE 2.15
LEVEL OF UNCERTAINTY ASSOCIATED WITH STATIONARY COMBUSTION ACTIVITY DATA

Sector	Well developed statistical systems		Less developed statistical systems	
	Surveys	Extrapolation	Surveys	Extrapolation
Main activity electricity and heat production	Less than 1%	3-5%	1-2%	5-10%
Commercial, institutional, residential combustion	3-5%	5-10%	10-15%	15-25%
Industrial combustion (Energy intensive industries)	2-3%	3-5%	2-3%	5-10%
Industrial combustion (others)	3-5%	5-10%	10-15%	15-20%
Biomass in small sources	10-30%	20-40%	30-60%	60-100%

The inventory compiler should judge which type of statistical system best describes their national circumstances.
Source: IPCC *Good Practice Guidance* and Uncertainty Management in National Greenhouse Gas Inventories (2000)

2.5 INVENTORY QUALITY ASSURANCE/QUALITY CONTROL QA/QC

Specific QA/QC procedures to optimise the quality of estimates of emissions from stationary combustion are given in Table 2.16.

2.5.1 Reporting and Documentation

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates, as outlined in Chapter 8 of Volume 1. It is not practical to include all documentation in the inventory report. However, the inventory should include summaries of methods used and references to data sources such that the reported emissions estimates are transparent and steps in their calculation can be retraced. Some examples of specific documentation and reporting that are relevant to stationary combustion sources are discussed below.

For all tiers, it is *good practice* to provide the sources of the energy data used and observations on the completeness of the data set. Most energy statistics are not considered confidential. If inventory compilers do not report disaggregated data due to confidentiality concerns, it is *good practice* to explain the reasons for these concerns, and to report the data in a more aggregated form.

The current IPCC reporting format (spreadsheet tables, aggregate tables) tries to provide a balance between the requirement of transparency and the level of effort that is realistically achievable by most inventory compilers. *Good practice* involves some additional effort to fulfil the transparency requirements completely. In particular, if Tier 3 is used, additional tables showing the activity data that are directly associated with the emission factors should be prepared.

For country-specific CO_2 emission factors, it is *good practice* to provide the sources of the calorific values, carbon content and oxidation factors (whether the default factor of 100 percent is used or a different value depending on circumstances). For country- and technology-specific non-CO_2 greenhouse gas estimates, it may be necessary to cite different references or documents. It is *good practice* to provide citations for these references, particularly if they describe new methodological developments or emission factors for particular technologies or national circumstances. For all country- and technology-specific emission factors, it is *good practice* to provide the date of the last revision and any verification of the accuracy.

In those circumstances where double counting could occur, it is *good practice* to state clearly whether emission estimates have been allocated to the Energy or to other sectors such as AFOLU, IPPU or Waste, to show that no double counting has occurred.

2.6 WORKSHEETS

The four pages of the worksheets (Annex 1 of this Volume) for the Tier I Sectoral Approach should be filled in for each of the source categories indicated in Table 2.16. Only the amount of fuel combusted for energy purposes should be included in column A of the worksheets. When filling in column A of the worksheets, the following issues should be taken into account: 1) some fuels are used for purposes other than for combustion, 2) waste-derived fuels are sometimes burned for energy purposes, and 3) some of the fuel combustion emissions should be included in Industrial Processes. Table 1 in the Annex lists the main considerations that should be taken into consideration in deciding what fraction of consumption should be included in the activity data for each fuel.

TABLE 2.16
LIST OF SOURCE CATEGORIES FOR STATIONARY COMBUSTION

Code	Name
1A1a	Main Activity Electricity and Heat Production
1A1b	Petroleum Refining
1A1c	Manufacture of Solid Fuels and Other Energy Industries
1A2a	Iron and Steel
1A2b	Non-Ferrous Metals
1A2c	Chemicals
1A2d	Pulp, Paper and Print
1A2e	Food Processing, Beverages and Tobacco
1A2f	Non-Metallic Minerals
1A2g	Transport Equipment
1A2h	Machinery
1A2i	Mining (excluding fuels) and Quarrying
1A2j	Wood and Wood Products
1A2k	Construction
1A2l	Textile and Leather
1A2m	Non-specified Industry
1A4a	Commercial / Institutional
1A4b	Residential
1A4c	Agriculture / Forestry / Fishing / Fish Farms (Stationary combustion)
1A5a	Non-Specified Stationary

TABLE 2.17
QA/QC PROCEDURES FOR STATIONARY SOURCES

Activity	Calculations of CO_2 emissions from stationary combustion	Calculations of non- CO_2 emissions from stationary combustion
Comparison of emission estimates using different approaches	• The inventory compiler should compare estimates of CO_2 emissions from fuel combustion prepared using the Sectoral Approach with the Reference Approach, and account for any difference greater than or equal to 5 percent. In this comparative analysis, emissions from fuels other than by combustion, that are accounted for in other sections of a GHG inventory, should be subtracted from the Reference Approach.	• If a Tier 2 approach with country-specific factors is used, the inventory compiler should compare the result to emissions calculated using the Tier 1 approach with default IPCC factors. This type of comparison may require aggregating Tier 2 emissions to the same sector and fuel groupings as the Tier 1 approach. The approach should be documented and any discrepancies investigated. • If possible, the inventory compiler should compare the consistency of the calculations in relation to the maximum carbon content of fuels that are combusted by stationary sources. Anticipated carbon balances should be maintained throughout the combustion sectors.
Activity data check	• The national agency in charge of energy statistics should construct, if resources permit, national commodity balances expressed in mass units, and construct mass balances of fuel conversion industries. The time series of statistical differences should be checked for systematic effects (indicated by the differences persistently having the same sign) and these effects eliminated where possible. • The national agency in charge of energy statistics should also construct, if resources permit, national energy balances expressed in energy units and energy balances of fuel conversion industries. The time series of statistical differences should be checked, and the calorific values cross-checked with the default values given in the Introduction chapter. This step will only be of value where different calorific values for a particular fuel (for example, coal) are applied to different headings in the balance (such as production, imports, coke ovens and households). Statistical differences that change in magnitude or sign significantly from the corresponding mass values provide evidence of incorrect calorific values. • The inventory compiler should confirm that gross carbon supply in the Reference Approach has been adjusted for fossil fuel carbon from imported or exported non-fuel materials in countries where this is expected to be significant. • Energy statistics should be compared with those provided to international organisations to identify inconsistencies. • There may be routine collections of emissions and fuel combustion statistics at large combustion plants for pollution legislation purposes. If possible, the inventory compiler can use these plant-level data to cross-check national energy statistics for representativeness. • If secondary data from national organisations are used, the inventory compiler should ensure that these organisations have appropriate QA/QC programmes in place.	

TABLE 2.17(CONTINUED)
QA/QC PROCEDURES FOR STATIONARY SOURCES

Activity	Calculations of CO_2 emissions from stationary combustion	Calculations of non- CO_2 emissions from stationary combustion
Emission factors check and review	• The inventory compiler should construct national energy balances expressed in carbon units and carbon balances of fuel conversion industries. The time series of statistical differences should be checked. Statistical differences that change in magnitude or sign significantly from the corresponding mass values provide evidence of incorrect carbon content. • Monitoring systems at large combustion plants may be used to check the emission and oxidation factors in use at the plant. • Some countries estimate emissions from fuel consumed and the carbon contents of those fuels. In this case, the carbon contents of the fuels should be regularly reviewed.	• If country-specific emission factors are used, the inventory compiler should compare them to the IPCC defaults, and explain and document differences. • The inventory compiler should compare the emission factors used with site or plant level factors, if these are available. This type of comparison provides an indication of how reasonable and representative the national factor is.
Evaluation of direct measurements	• The inventory compiler should evaluate the quality control associated with facility-level fuel measurements that have been used to calculate site-specific emission and oxidation factors. If it is established that there is insufficient quality control associated with the measurements and analysis used to derive the factor, continued use of the factor may be questioned.	• If direct measurements are used, the inventory compiler should ensure that they are made according to good measurement practices including appropriate QA/QC procedures. Direct measurements should be compared to the results derived from using IPCC default factors.
CO_2 capture	• CO_2 capture should be reported only when linked with long-term storage. The captured amounts should be checked with amount of CO_2 stored. The reported CO_2 captured should not exceed the amount of stored CO_2 plus reported fugitive emissions from the measure. The amount of stored CO_2 should be based on measurements of the amount injected to storage.	Not applicable
External review	• The inventory compiler should carry out a review involving national experts and stakeholders in the different fields related to emissions from stationary sources, such as: energy statistics, combustion efficiencies for different sectors and equipment types, fuel use and pollution controls. In developing countries, expert review of emissions from biomass combustion is particularly important.	

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CHAPTER 3

MOBILE COMBUSTION

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3 MOBILE COMBUSTION

3.1 OVERVIEW

Mobile sources produce direct greenhouse gas emissions of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) from the combustion of various fuel types, as well as several other pollutants such as carbon monoxide (CO), Non-methane Volatile Organic Compounds (NMVOCs), sulphur dioxide (SO_2), particulate matter (PM) and oxides of nitrate (NOx), which cause or contribute to local or regional air pollution. This chapter covers *good practice* in the development of estimates for the direct greenhouse gases CO_2, CH_4, and N_2O. For indirect greenhouse gases and precursor substances CO, NMVOCs, SO_2, PM, and NOx, please refer to Volume 1 Chapter 7. This chapter does not address non-energy emissions from mobile air conditioning, which is covered by the IPPU Volume (Volume 3, Chapter 7).

Greenhouse gas emissions from mobile combustion are most easily estimated by major transport activity, i.e., road, off-road, air, railways, and water-borne navigation. The source description (Table 3.1.1) shows the diversity of mobile sources and the range of characteristics that affect emission factors. Recent work has updated and strengthened the data. Despite these advances more work is needed to fill in many gaps in knowledge of emissions from certain vehicle types and on the effects of ageing on catalytic control of road vehicle emissions. Equally, the information on the appropriate emission factors for road transport in developing countries may need further strengthening, where age of fleet, maintenance, fuel sulphur content, and patterns of use are different from those in industrialised countries.

TABLE 3.1.1
DETAILED SECTOR SPLIT FOR THE TRANSPORT SECTOR

Code and Name					Explanation
1 A 3	*TRANSPORT*				Emissions from the combustion and evaporation of fuel for all transport activity (excluding military transport), regardless of the sector, specified by sub-categories below. Emissions from fuel sold to any air or marine vessel engaged in international transport (1 A 3 a i and 1 A 3 d i) should as far as possible be excluded from the totals and subtotals in this category and should be reported separately.
1 A 3	a	Civil Aviation			Emissions from international and domestic civil aviation, including take-offs and landings. Comprises civil commercial use of airplanes, including: scheduled and charter traffic for passengers and freight, air taxiing, and general aviation. The international/domestic split should be determined on the basis of departure and landing locations for each flight stage and not by the nationality of the airline. Exclude use of fuel at airports for ground transport which is reported under 1 A 3 e Other Transportation. Also exclude fuel for stationary combustion at airports; report this information under the appropriate stationary combustion category.
1 A 3	a	*i*		*International Aviation (International Bunkers)*	Emissions from flights that depart in one country and arrive in a different country. Include take-offs and landings for these flight stages. Emissions from international military aviation can be included as a separate sub-category of international aviation provided that the same definitional distinction is applied and data are available to support the definition.
1 A 3	a	*ii*		*Domestic Aviation*	Emissions from civil domestic passenger and freight traffic that departs and arrives in the same country (commercial, private, agriculture, etc.), including take-offs and landings for these flight stages. Note that this may include journeys of considerable length between two airports in a country (e.g. San Francisco to Honolulu). Exclude military, which should be reported under 1 A 5 b.
1 A 3	b	Road Transportation			All combustion and evaporative emissions arising from fuel use in road vehicles, including the use of agricultural vehicles on paved roads.
1 A 3	b	*i*		*Cars*	Emissions from automobiles so designated in the vehicle registering country primarily for transport of persons and normally having a capacity of 12 persons or fewer.
1 A 3	b	*i*	1	Passenger cars with 3-way catalysts	Emissions from passenger car vehicles with 3-way catalysts.
1 A 3	b	*i*	2	Passenger cars without 3-way catalysts	Emissions from passenger car vehicles without 3-way catalysts.

TABLE 3.1.1 (CONTINUED)
DETAILED SECTOR SPLIT FOR THE TRANSPORT SECTOR

Code and Name					Explanation
1 A 3	b	*ii*		*Light duty trucks*	Emissions from vehicles so designated in the vehicle registering country primarily for transportation of light-weight cargo or which are equipped with special features such as four-wheel drive for off-road operation. The gross vehicle weight normally ranges up to 3500-3900 kg or less.
1 A 3	b	*ii*	1	Light duty trucks with 3-way catalysts	Emissions from light duty trucks with 3-way catalysts.
1 A 3	b	*ii*	2	Light duty trucks without 3-way catalysts	Emissions from light duty trucks without 3-way catalysts.
1 A 3	b	*iii*		*Heavy duty trucks and buses*	Emissions from any vehicles so designated in the vehicle registering country. Normally the gross vehicle weight ranges from 3500-3900 kg or more for heavy duty trucks and the buses are rated to carry more than 12 persons.
1 A 3	b	*iv*		*Motorcycles*	Emissions from any motor vehicle designed to travel with not more than three wheels in contact with the ground and weighing less than 680 kg.
1 A 3	b	*v*		*Evaporative emissions from vehicles*	Evaporative emissions from vehicles (e.g. hot soak, running losses) are included here. Emissions from loading fuel into vehicles are excluded.
1 A 3	b	*vi*		*Urea-based catalysts*	CO_2 emissions from use of urea-based additives in catalytic converters (non-combustive emissions)
1 A 3	c	Railways			Emissions from railway transport for both freight and passenger traffic routes.
1 A 3	d	Water-borne Navigation			Emissions from fuels used to propel water-borne vessels, including hovercraft and hydrofoils, but excluding fishing vessels. The international/domestic split should be determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship.
1 A 3	d	i		*International water-borne navigation (International bunkers)*	Emissions from fuels used by vessels of all flags that are engaged in international water-borne navigation. The international navigation may take place at sea, on inland lakes and waterways and in coastal waters. Includes emissions from journeys that depart in one country and arrive in a different country. Exclude consumption by fishing vessels (see Other Sector - Fishing). Emissions from international military water-borne navigation can be included as a separate sub-category of international water-borne navigation provided that the same definitional distinction is applied and data are available to support the definition.
1 A 3	d	ii		*Domestic water-borne Navigation*	Emissions from fuels used by vessels of all flags that depart and arrive in the same country (exclude fishing, which should be reported under 1 A 4 c iii, and military, which should be reported under 1 A 5 b). Note that this may include journeys of considerable length between two ports in a country (e.g. San Francisco to Honolulu).
1 A 3	e	Other Transportation			Combustion emissions from all remaining transport activities including pipeline transportation, ground activities in airports and harbours, and off-road activities not otherwise reported under 1 A 4 c Agriculture or 1 A 2. Manufacturing Industries and Construction. Military transport should be reported under 1 A 5 (see 1 A 5 Non-specified).
1 A 3	e	i		*Pipeline Transport*	Combustion related emissions from the operation of pump stations and maintenance of pipelines. Transport via pipelines includes transport of gases, liquids, slurry and other commodities via pipelines. Distribution of natural or manufactured gas, water or steam from the distributor to final users is excluded and should be reported in 1 A 1 c ii or 1 A 4 a.
1 A 3	e	ii		*Off-road*	Combustion emissions from Other Transportation excluding Pipeline Transport.
1 A 4	c	iii		Fishing (mobile combustion)	Emissions from fuels combusted for inland, coastal and deep-sea fishing. Fishing should cover vessels of all flags that have refuelled in the country (include international fishing).

TABLE 3.1.1 (CONTINUED)
DETAILED SECTOR SPLIT FOR THE TRANSPORT SECTOR

Code and Name				Explanation
1 A 5	a		*Non specified stationary*	Emissions from fuel combustion in stationary sources that are not specified elsewhere.
1 A 5	b		*Non specified mobile*	Mobile Emissions from vehicles and other machinery, marine and aviation (not included in 1 A 4 c ii or elsewhere). Includes emissions from fuel delivered for aviation and water-borne navigation to the country's military as well as fuel delivered within that country but used by the militaries of other countries that are not engaged in.
			Multilateral Operations (Memo item)	Multilateral operations. Emissions from fuels used for aviation and water-borne navigation in multilateral operations pursuant to the Charter of the United Nations. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries.

3.2 ROAD TRANSPORTATION

The mobile source category Road Transportation includes all types of light-duty vehicles such as automobiles and light trucks, and heavy-duty vehicles such as tractor trailers and buses, and on-road motorcycles (including mopeds, scooters, and three-wheelers). These vehicles operate on many types of gaseous and liquid fuels. In addition to emissions from fuel combustion, emissions associated with catalytic converter use in road vehicles (e.g., CO_2 emissions from catalytic converters using urea) [1] are also addressed in this section.

3.2.1 Methodological Issues

The fundamental methodologies for estimating greenhouse gas emissions from road vehicles, which are presented in Section 3.2.1.1, have not changed since the publication of the *1996 IPCC Guidelines* and the *GPG2000*, except that, as discussed in Section 3.2.1.2, the emission factors now assume full oxidation of the fuel. This is for consistency with the Stationary Combustion Chapter in this Volume. The method for estimating CO_2 emissions from catalytic converters using urea, a source of emissions, was not addressed previously.

Estimated emissions from road transport can be based on two independent sets of data: fuel sold (see section 3.2.1.3) and vehicle kilometres. If these are both available it is important to check that they are comparable, otherwise estimates of different gases may be inconsistent. This validation step (Figure 3.2.1) is described in sections 3.2.1.3 and 3.2.3. It is *good practice* to perform this validation step if vehicle kilometre data are available.

3.2.1.1 CHOICE OF METHOD

Emissions can be estimated from either the fuel consumed (represented by fuel sold) or the distance travelled by the vehicles. In general, the first approach (fuel sold) is appropriate for CO_2 and the second (distance travelled by vehicle type and road type) is appropriate for CH_4 and N_2O.

CO_2 EMISSIONS

Emissions of CO_2 are best calculated on the basis of the amount and type of fuel combusted (taken to be equal to the fuel sold, see section 3.2.1.3) and its carbon content. Figure 3.2.2 shows the decision tree for CO_2 that guides the choice of either the Tier 1 or Tier 2 method. Each tier is defined below.

[1] Urea consumption for catalytic converters in vehicles is directly related to the vehicle fuel consumption and technology.

Figure 3.2.1 Steps in estimating emissions from road transport

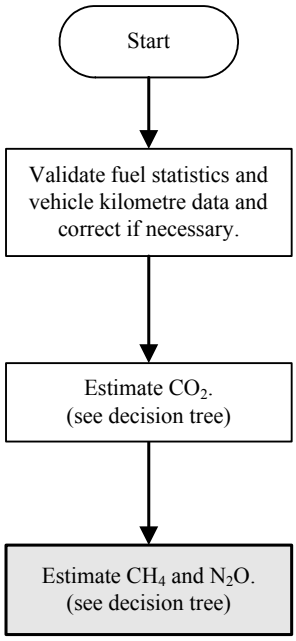
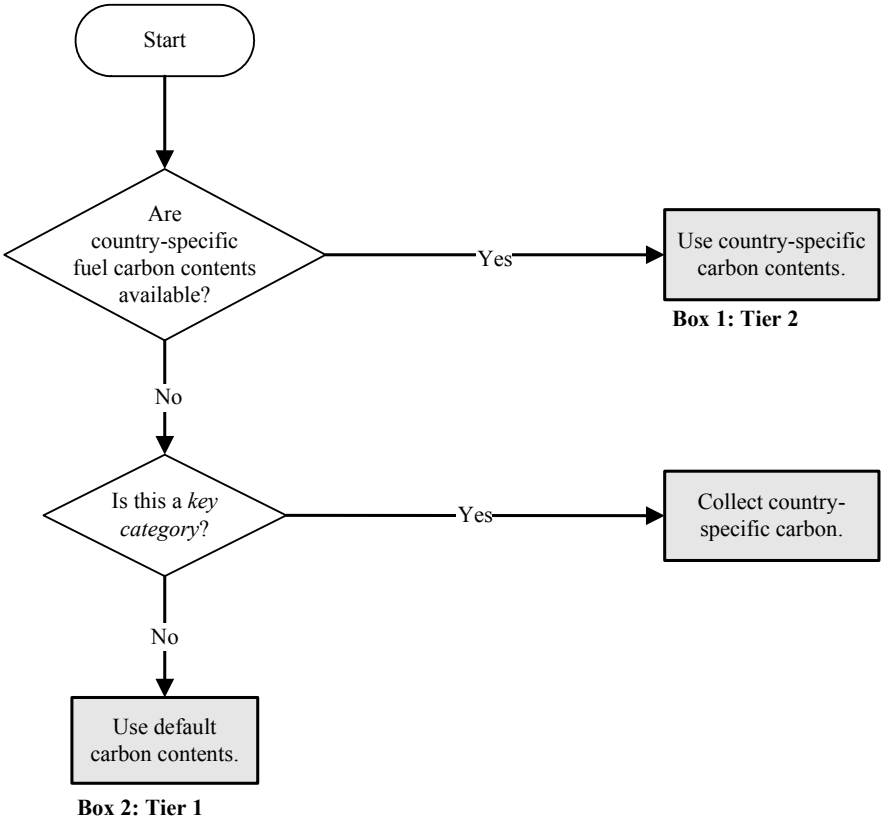


Figure 3.2.2 Decision tree for CO_2 emissions from fuel combustion in road vehicles



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.

The Tier 1 approach calculates CO_2 emissions by multiplying estimated fuel sold with a default CO_2 emission factor. The approach is represented in Equation 3.2.1.

EQUATION 3.2.1
CO_2 FROM ROAD TRANSPORT

$$Emission = \sum_a [Fuel_a \bullet EF_a]$$

Where:

Emission = Emissions of CO_2 (kg)

$Fuel_a$ = fuel sold (TJ)

EF_a = emission factor (kg/TJ). This is equal to the carbon content of the fuel multiplied by 44/12.

a = type of fuel (e.g. petrol, diesel, natural gas, LPG etc)

The CO_2 emission factor takes account of all the carbon in the fuel including that emitted as CO_2, CH_4, CO, NMVOC and particulate matter[2]. Any carbon in the fuel derived from biomass should be reported as an information item and not included in the sectoral or national totals to avoid double counting as the net emissions from biomass are already accounted for in the AFOLU sector (see section 3.2.1.4 Completeness).

The Tier 2 approach is the same as Tier 1 except that country-specific carbon contents of the fuel sold in road transport are used. Equation 3.2.1 still applies but the emission factor is based on the actual carbon content of fuels consumed (as represented by fuel sold) in the country during the inventory year. At Tier 2, the CO_2 emission factors may be adjusted to take account of un-oxidised carbon or carbon emitted as a non-CO_2 gas.

There is no Tier 3 as it is not possible to produce significantly better results for CO_2 than by using the existing Tier 2. In order to reduce the uncertainties, efforts should concentrate on the carbon content and on improving the data on fuel sold. Another major uncertainty component is the use of transport fuel for non-road purposes.

CO_2 EMISSIONS FROM UREA-BASED CATALYSTS

For estimating CO_2 emissions from use of urea-based additives in catalytic converters (non-combustive emissions), it is *good practice* to use Equation 3.2.2:

EQUATION 3.2.2
CO_2 FROM UREA-BASED CATALYTIC CONVERTERS

$$Emission = Activity \bullet \frac{12}{60} \bullet Purity \bullet \frac{44}{12}$$

Where:

Emissions = CO_2 Emissions from urea-based additive in catalytic converters (Gg CO_2)
Activity = amount of urea-based additive consumed for use in catalytic converters (Gg)
Purity = the mass fraction (= percentage divided by 100) of urea in the urea-based additive

The factor (12/60) captures the stochiometric conversion from urea ($CO(NH_2)_2$) to carbon, while factor (44/12) converts carbon to CO_2. On the average, the activity level is 1 to 3 percent of diesel consumption by the vehicle. Thirty two and half percent can be taken as default purity in case country-specific values are not available (Peckham, 2003). As this is based on the properties of the materials used, there are no tiers for this source.

CH_4 AND N_2O EMISSIONS

Emissions of CH_4 and N_2O are more difficult to estimate accurately than those for CO_2 because emission factors depend on vehicle technology, fuel and operating characteristics. Both distance-based activity data (e.g. vehicle-kilometres travelled) and disaggregated fuel consumption may be considerably less certain than overall fuel sold.

CH_4 and N_2O emissions are significantly affected by the distribution of emission controls in the fleet. Thus higher tiers use an approach taking into account populations of different vehicle types and their different pollution control technologies.

[2] Research on carbon mass balances for U.S. light-duty gasoline cars and trucks indicates that "the fraction of solid (unoxidized) carbon is negligible" USEPA (2004a). This did not address two-stroke engines or fuel types other than gasoline. Additional discussion of the 100 percent oxidation assumption is included in Section 1.4.2.1 of the Energy Volume Introduction chapter.

Although CO_2 emissions from biogenic carbon are not included in national totals, the combustion of biofuels in mobile sources generates anthropogenic CH_4 and N_2O that should be calculated and reported in emissions estimates.

The decision tree in Figure 3.2.3 outlines choice of method for calculating emissions of CH_4 and N_2O. The inventory compiler should choose the method on the basis of the existence and quality of data. The tiers are defined in the corresponding equations 3.2.3 to 3.2.5, below.

Three alternative approaches can be used to estimate CH_4 and N_2O emissions from road vehicles: one is based on vehicle kilometres travelled (VKT) and two are based on fuel sold. The Tier 3 approach requires detailed, country-specific data to generate activity-based emission factors for vehicle subcategories and may involve national models. Tier 3 calculates emissions by multiplying emission factors by vehicle activity levels (e.g., VKT) for each vehicle subcategory and possible road type. Vehicle subcategories are based on vehicle type, age, and emissions control technology. The Tier 2 approach uses fuel-based emission factors specific to vehicle subcategories. Tier 1, which uses fuel-based emission factors, may be used if it is not possible to estimate fuel consumption by vehicle type.

The equation for the Tier 1 method for estimating CH_4 and N_2O from road vehicles may be expressed as:

EQUATION 3.2.3
TIER 1 EMISSIONS OF CH_4 AND N_2O

$$Emission = \sum_{a} [Fuel_a \bullet EF_a]$$

Where:

Emissions = emission in kg

EF_a = emission factor (kg/TJ)

$Fuel_a$ = fuel consumed, (TJ) (as represented by fuel sold)

a = fuel type a (e.g., diesel, gasoline, natural gas, LPG)

Equation 3.2.3 for the Tier 1 method implies the following steps:

- Step 1: Determine the amount of fuel consumed by fuel type for road transportation using national data or, as an alternative, IEA or UN international data sources (all values should be reported in terajoules).
- Step 2: For each fuel type, multiply the amount of fuel consumed by the appropriate CH_4 and N_2O default emission factors. Default emission factors may be found in the next Section 3.2.1.2 (Emission Factors).
- Step 3: Emissions of each pollutant are summed across all fuel types.

The emission equation for Tier 2 is:

EQUATION 3.2.4
TIER 2 EMISSIONS OF CH_4 AND N_2O

$$Emission = \sum_{a,b,c} [Fuel_{a,b,c} \bullet EF_{a,b,c}]$$

Where:

Emission = emission in kg.

$EF_{a,b,c}$ = emission factor (kg/TJ)

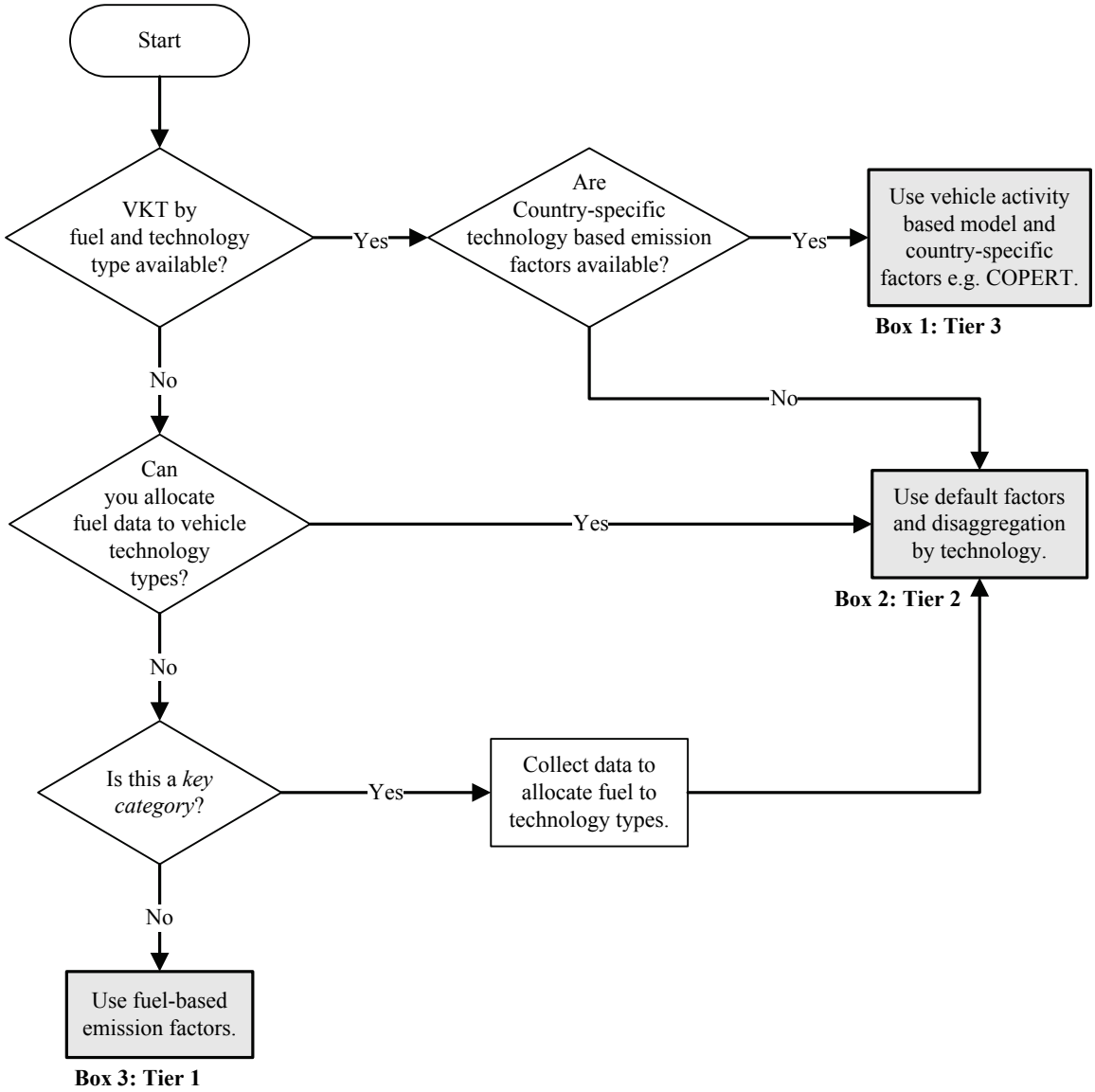
$Fuel_{a,b,c}$ = fuel consumed (TJ) (as represented by fuel sold) for a given mobile source activity

a = fuel type (e.g., diesel, gasoline, natural gas, LPG)

b = vehicle type

c = emission control technology (such as uncontrolled, catalytic converter, etc)

Figure 3.2.3 Decision tree for CH_4 and N_2O emissions from road vehicles



Notes:

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.

2.The decision tree and *key category* determination should be applied to methane and nitrous oxide emissions separately.

Vehicle type should follow the reporting classification 1.A.3.b (i to iv) (i.e., passenger, light-duty or heavy-duty for road vehicles, motorcycles) and preferably be further split by vehicle age (e.g., up to 3 years old, 3-8 years, older than 8 years) to enable categorization of vehicles by control technology (e.g., by inferring technology adoption as a function of policy implementation year). Where possible, fuel type should be split by sulphur content to allow for delineation of vehicle categories according to emission control system, because the emission control system operation is dependent upon the use of low sulphur fuel during the whole system lifespan[3]. Without considering this aspect, CH_4 may be underestimated. This applies to Tiers 2 and 3.

The emission equation for Tier 3 is:

EQUATION 3.2.5
TIER 3 EMISSIONS OF CH_4 AND N_2O

$$Emission = \sum_{a,b,c,d}[Distance_{a,b,c,d} \bullet EF_{a,b,c,d}] + \sum_{a,b,c,d} C_{a,b,c,d}$$

Where:

Emission = emission or CH_4 or N_2O (kg)

$EF_{a,b,c,d}$ = emission factor (kg/km)

$Distance_{a,b,c,d}$ = distance travelled (VKT) during thermally stabilized engine operation phase for a given mobile source activity (km)

$C_{a,b,c,d}$ = emissions during warm-up phase (cold start) (kg)

a = fuel type (e.g., diesel, gasoline, natural gas, LPG)

b = vehicle type

c = emission control technology (such as uncontrolled, catalytic converter, etc.)

d = operating conditions (e.g., urban or rural road type, climate, or other environmental factors)

It may not be possible to split by road type in which case this can be ignored. Often emission models such as the USEPA MOVES or MOBILE models, or the EEA's COPERT model will be used (USEPA 2005a, USEPA 2005b, EEA 2005, respectively). These include detailed fleet models that enable a range of vehicle types and control technologies to be considered as well as fleet models to estimate VKT driven by these vehicle types. Emission models can help to ensure consistency and transparency because the calculation procedures may be fixed in software packages that may be used. It is *good practice* to clearly document any modifications to standardised models.

Additional emissions occur when the engines are cold, and this can be a significant contribution to total emissions from road vehicles. These should be included in Tier 3 models. Total emissions are calculated by summing emissions from the different phases, namely the thermally stabilized engine operation (hot) and the warming-up phase (cold start) – Eq 3.2.5 above. Cold starts are engine starts that occur when the engine temperature is below that at which the catalyst starts to operate (light-off threshold, roughly 300°C) or before the engine reaches its normal operation temperature for non-catalyst equipped vehicles. These have higher CH_4 (and CO and HC) emissions. Research has shown that 180-240 seconds is the approximate average cold start mode duration. The cold start emission factors should therefore be applied only for this initial fraction of a vehicle's journey (up to around 3 km) and then the running emission factors should be applied. Please refer to USEPA (2004b) and EEA (2005a) for further details. The cold start emissions can be quantified in different ways. Table 3.2.3 (USEPA 2004b) gives additional emissions per start. This is added to the running emission and so requires knowledge of the number of starts per vehicle per year[4]. This can be derived through knowledge of the average trip length. The European model COPERT has more complex temperature dependant corrections for the cold start (EEA 2000) for methane.

[3] This especially applies to countries where fuels with different sulphur contents are sold (e.g. "metropolitan" diesel). Some control systems (for example, diesel exhaust catalyst converters) require ultra low sulphur fuels (e.g. diesel with 50 ppm S or less) to be operational. Higher sulphur levels deteriorate such systems, increasing emissions of CH_4 as well as nitrogen oxides, particulates and hydrocarbons. Deteriorated catalysts do not effectively convert nitrogen oxides to N_2, which could result in changes in emission rates of N_2O. This could also result from irregular misfuelling with high sulphur fuel.

[4] This simple method of adding to the running emission the cold start (= number of starts • cold start factor) assumes individual trips are longer than 4 km.

Both Equation 3.2.4 and 3.2.5 for Tier 2 and 3 methods involves the following steps:

- Step 1: Obtain or estimate the amount of fuel consumed by fuel type for road transportation using national data (all values should be reported in terajoules; please also refer to Section 3.2.1.3.)
- Step 2: Ensure that fuel data or VKT is split into the vehicle and fuel categories required. It should be taken into consideration that, typically, emissions and distance travelled each year vary according to the age of the vehicle; the older vehicles tend to travel less but may emit more CH_4 per unit of activity. Some vehicles may have been converted to operate on a different type of fuel than their original design.
- Step 3: Multiply the amount of fuel consumed (Tier 2), or the distance travelled (Tier 3) by each type of vehicle or vehicle/control technology, by the appropriate emission factor for that type. The emission factors presented in the EFDB or Tables 3.2.3 to 3.2.5 may be used as a starting point. However, the inventory compiler is encouraged to consult other data sources referenced in this chapter or locally available data before determining appropriate national emission factors for a particular subcategory. Established inspection and maintenance programmes may be a good local data source.
- Step 4: For Tier 3 approaches estimate cold start emissions.
- Step 5: Sum the emissions across all fuel and vehicle types, including for all levels of emission control, to determine total emissions from road transportation.

3.2.1.2 CHOICE OF EMISSION FACTORS

Inventory compilers should choose default (Tier 1) or country-specific (Tier 2 and Tier 3) emission factors based on the application of the decision trees which consider the type and level of disaggregation of activity data available for their country.

CO_2 EMISSIONS

CO_2 emission factors are based on the carbon content of the fuel and should represent 100 percent oxidation of the fuel carbon. It is *good practice* to follow this approach using country-specific net-calorific values (NCV) and CO_2 emission factor data if possible. Default NCV of fuels and CO_2 emission factors (in Table 3.2.1 below) are presented in Tables 1.2 and 1.4, respectively, of the Introduction Chapter of this Volume and may be used when country-specific data are unavailable. Inventory compilers are encouraged to consult the IPCC Emission Factor Database (EFDB, see Volume 1) for applicable emission factors. It is *good practice* to ensure that default emission factors, if selected, are appropriate to local fuel quality and composition.

TABLE 3.2.1
ROAD TRANSPORT DEFAULT CO_2 EMISSION FACTORS AND UNCERTAINTY RANGES [a]

Fuel Type	Default (kg/TJ)	Lower	Upper
Motor Gasoline	69 300	67 500	73 000
Gas/ Diesel Oil	74 100	72 600	74 800
Liquefied Petroleum Gases	63 100	61 600	65 600
Kerosene	71 900	70 800	73 700
Lubricants [b]	73 300	71 900	75 200
Compressed Natural Gas	56 100	54 300	58 300
Liquefied Natural Gas	56 100	54 300	58 300

Source: Table 1.4 in the Introduction chapter of the Energy Volume.

Notes:
[a] Values represent 100 percent oxidation of fuel carbon content.
[b] See Box 3.2.4 Lubricants in Mobile Combustion for guidance for uses of lubricants.

At Tier 1, the emission factors should assume that 100 percent of the carbon present in fuel is oxidized during or immediately following the combustion process (for all fuel types in all vehicles) irrespective of whether the CO_2

has been emitted as CO_2, CH_4, CO or NMVOC or as particulate matter. At higher tiers the CO_2 emission factors may be adjusted to take account of un-oxidised carbon or carbon emitted as a non-CO_2 gas.

CO_2 EMISSIONS FROM BIOFUELS

The use of liquid and gaseous biofuels has been observed in mobile combustion applications (see Box 3.2.1). To properly address the related emissions from biofuel combusted in road transportation, biofuel-specific emission factors should be used, when activity data on biofuel use are available. CO_2 emissions from the combustion of the biogenic carbon of these fuels are treated in the AFOLU sector and should be reported separately as an information item. To avoid double counting, the inventory compiler should determine the proportions of fossil versus biogenic carbon in any fuel-mix which is deemed commercially relevant and therefore to be included in the inventory.

There are a number of different options for the use of liquid and gaseous biofuels in mobile combustion (see Table 1.1 of the Introduction chapter of this Volume for biofuel definitions). Some biofuels have found widespread commercial use in some countries driven by specific policies. Biofuels can either be used as pure fuel or as additives to regular commercial fossil fuels. The latter approach usually avoids the need for engine modifications or re-certification of existing engines for new fuels.

To avoid double counting, over or under-reporting of CO_2 emissions, it is important to assess the biofuel origin so as to identify and separate fossil from biogenic feedstocks[5]. This is because CO_2 emissions from biofuels will be reported separately as an information item to avoid double counting, since it is already treated in the AFOLU Volume. The share of biogenic carbon in the fuel can be acknowledged by either refining activity data (*e.g.* subtracting the amount of non-fossil inputs to the combusted biofuel or biofuel blend) or emission factors (*e.g.* multiplying the fossil emission factor by its fraction in the combusted biofuel or biofuel blend, to obtain a new emission factor), but not both simultaneously. If national consumption of these fuels is commercially significant, the biogenic and fossil carbon streams need to be accurately accounted for thus avoiding double counting with refinery and petrochemical processes or the waste sector (recognising the possibility of double counting or omission of, for example, landfill gas or waste cooking oil as biofuel). Double counting or omission of landfill gas or waste cooking oil as biofuel should be avoided.

CH_4 AND N_2O

CH_4 and N_2O emission rates depend largely upon the combustion and emission control technology present in the vehicles; therefore default fuel-based emission factors that do not specify vehicle technology are highly uncertain. Even if national data are unavailable on vehicle distances travelled by vehicle type, inventory compilers are encouraged to use higher tiered emission factors and calculate vehicle distance travelled data based on national road transportation fuel use data and an assumed fuel economy value (see 3.2.1.3 Choice of Activity Data) for related guidance.

If CH_4 and N_2O emissions from mobile sources are not a *key category*, default CH_4 and N_2O emission factors presented in Table 3.2.2 may be used when national data are unavailable. When using these default values, inventory compilers should note the assumed fuel economy values that were used for unit conversions and the representative vehicle categories that were used as the basis of the default factors (see table notes for specific assumptions).

It is *good practice* to ensure that default emission factors, if selected, best represent local fuel quality/composition and combustion or emission control technology. If biofuels are included in national road transportation fuel use estimates, biofuel-specific emission factors should be used and associated CH_4 and N_2O emissions should be included in national totals.

Because CH_4 and N_2O emission rates are largely dependent upon the combustion and emission control technology present, technology-specific emission factors should be used, if CH_4 and N_2O emissions from mobile sources are a *key category*. Tables 3.2.3 and 3.2.5 give potentially applicable Tier 2 and Tier 3 emission factors from US and European data respectively. In addition, the U.S. has developed emission factors for some alternative fuel vehicles (Table 3.2.4). The IPCC EFDB and scientific literature may also provide emission factors (or standard emission estimation models) which inventory compilers may use, if appropriate to national circumstances.

[5] For example, biodiesel made from coal methanol with animal feedstocks has a non-zero fossil fuel fraction and is therefore not fully carbon neutral. Ethanol from the fermentation of agricultural products will generally be purely biogenic (carbon neutral), except in some cases, such as fossil-fuel derived methanol. Products which have undergone further chemical transformation may contain substantial amounts of fossil carbon ranging from about 5-10 percent in the fossil methanol used for biodiesel production upwards to 46 percent in ethyl-tertiary-butyl-ether (ETBE) from fossil isobutene (ADEME/DIREM, 2002). Some processes may generate biogenic by-products such as glycol or glycerine, which may then be used elsewhere.

BOX 3.2.1
EXAMPLES OF BIOFUEL USE IN ROAD TRANSPORTATION

Examples of biofuel use in road transportation include:

• Ethanol is typically produced through the fermentation of sugar cane, sugar beets, grain, corn or potatoes. It may be used neat (100 percent, Brazil) or blended with gasoline in varying volumes (5-12 percent in Europe and North America, 10 percent in India, while 25 percent is common in Brazil). The biogenic portion of pure ethanol is 100 percent.

• Biodiesel is a fuel made from the trans-esterification of vegetable oils (e.g., rape, soy, mustard, sun-flower), animal fats or recycled cooking oils. It is non-toxic, biodegradable and essentially sulphur-free and can be used in any diesel engine either in its pure form (B100 or neat Biodiesel) or in a blend with petroleum diesel (B2 and B20, which contain 2 and 20 per cent biodiesel by volume). B100 may contain 10 percent fossil carbon from the methanol (made from natural gas) used in the esterification process.

• Ethyl-tertiary-butyl-ether (ETBE) is used as a high octane blending component in gasoline (e.g., in France and Spain in blends of up to 15 percent content). The most common source is the etherification of ethanol from the fermentation of sugar beets, grain and potatoes with fossil isobutene.

• Gaseous Biomass (landfill gas, sludge gas, and other biogas) produced by the anaerobic digestion of organic matter is occasionally used in some European countries (e.g. Sweden and Switzerland). Landfill and sewage gas are common sources of gaseous biomass currently.

Other potential future commercial biofuels for use in mobile combustion include those derived from lignocellulosic biomass. Lignocellulosic feedstock materials include cereal straw, woody biomass, corn stover (dried leaves and stems), or similar energy crops. A range of varying extraction and transformation processes permit the production of additional biogenic fuels (e.g., methanol,dimethyl-ether (DME), and methyl-tetrahydrofuran (MTHF)).

It is *good practice* to select or develop an emission factor based on all the following criteria:

- Fuel type (gasoline, diesel, natural gas) considering, if possible, fuel composition (studies have shown that decreasing fuel sulphur level may lead to significant reductions in N_2O emissions[6])
- Vehicle type (i.e. passenger cars, light trucks, heavy trucks, motorcycles)
- Emission control technology considering the presence and performance (e.g., as function of age) of catalytic converters (e.g., typical catalysts convert nitrogen oxides to N_2, and CH_4 into CO_2). Díaz *et al* (2001) reports catalyst conversion efficiency for total hydrocarbons (THCs), of which CH_4 is a component, of 92 (+/- 6) percent in a 1993-1995 fleet. Considerable deterioration of catalysts with relatively high mileage accumulation; specifically, THC levels remained steady until approximately 60 000 kilometers, then increased by 33 percent to between 60 000 to 100 000 kilometres.
- The impact of operating conditions (e.g., speed, road conditions, and driving patterns, which all affect fuel economy and vehicle systems' performance)[7].
- Consideration that any alternative fuel emission factor estimates tend to have a high degree of uncertainty, given the wide range of engine technologies and the small sample sizes associated with existing studies[8].

The following section provides a method for developing CH_4 emission factors from THC values. Well conducted and documented inspection and maintenance (I/M) programmes may provide a source of national data for emission factors by fuel, model, and year as well as annual mileage accumulation rates. Although some I/M programmes may only have available emission factors for new vehicles and local air pollutants, (sometimes called regulated pollutants, e.g. NO_x, PM, NMVOCs, THCs), it may be possible to derive CH_4 or N_2O emission factors from these data. A CH_4 emission factor may be calculated as the difference between emission factors for THCs and NMVOCs. In many countries, CH_4 emissions from vehicles are not directly measured. They are a

[6] UNFCCC (2004)

[7] Lipman and Delucchi (2002) provide data and explanation of the impact of operating conditions on CH_4 and N_2O emissions.

[8] Some useful references on bio fuels are available in Beer *et al* (2000), CONCAWE (2002).

fraction of THCs, which is more commonly obtained through laboratory measurements. USEPA (1997) and Borsari (2005) and CETESB (2004 & 2005) provide conversion factors for reporting hydrocarbon emissions in different forms. Based on these sources, the following ratios of CH_4 to THC may be used to develop CH_4 emission factors from country-specific THC data[9]:

- 2-stroke gasoline: 0.9 percent,
- 4-stroke gasoline: 10-25 percent,
- diesel: 1.6 percent,
- LPG: 29.6 percent,
- natural gas vehicles: 88.0-95.2 percent,
- gasohol E22: 24.3-25.5 percent, and
- ethanol hydrated E100: 26.0-27.2 percent.

Some I/M programmes may collect data on evaporatives, which may be assumed to be equal to NMVOCs.[10] Recent and ongoing research has investigated the relationship between N_2O and NO_x emissions. Useful data may become available from this work[11].

Further refinements in the factors can be made if additional local data (e.g. on average driving speeds, climate, altitude, pollution control devices, or road conditions) are available, for example, by scaling emission factors to reflect the national circumstances by multiplying by an adjustment factor (e.g., traffic congestion or severe loading). Emission factors for both CH_4 and N_2O are established not just during a representative compliance driving test, but also specifically tested during running conditions and cold start conditions. Thus, data collected on the driving patterns in a country (based on the relationship of starts to running distances) can be used to adjust the emission factors for CH_4 and N_2O. Although ambient temperature has been shown to have impacts on local air pollutants, there is limited research on the effects of temperature on CH_4 and N_2O (USEPA 2004b). Please see Box 3.2.2 for information on refining emission factors for mobile sources in developing countries.

[9] Gamas et. al. (1999) and Díaz, et.al (2001) report measured THC data for a range of vehicle vintage and fuel types.

[10] IPCC (1997).

[11] For light motor vehicles and passenger cars, ratios N2O/NOx obtained in literature range around 0.10-0.25 (Lipmann and Delucchi, 2002 and Behrentz, 2003).

BOX 3.2.2
REFINING EMISSION FACTORS FOR MOBILE SOURCES IN DEVELOPING COUNTRIES

In some developing countries, the estimated emission rates per kilometre travelled may need to be altered to accommodate national circumstances, which could include:

•Technology variations - In many cases due to tampering of emission control systems, fuel adulteration, or simply vehicle age, some vehicles may be operating without a functioning catalytic converter. Consequently, N_2O emissions may be low and CH_4 may be high when catalytic converters are not present or operating improperly. Díaz *et al* (2001) provides information on THC values for Mexico City and catalytic converter efficiency as a function of age and mileage, and this also chapter provides guidance on developing CH_4 factors from THC data.

▪ Engine loading - Due to traffic density or challenging topography, the number of accelerations and decelerations that a local vehicle encounters may be significantly greater than that for corresponding travel in countries where emission factors were developed. This happens when these countries have well established road and traffic control networks. Increased engine loading may correlate with higher CH_4 and N_2O emissions.

▪ Fuel Composition - Poor fuel quality and high or varying sulphur content may adversely affect the performance of engines and conversion efficiency of post-combustion emission control devices such as catalytic converters. For example, N_2O emission rates have been shown to increase with the sulphur content in fuels (UNFCCC, 2004). The effects of sulphur content on CH_4 emissions are not known. Refinery data may indicate production quantities on a national scale.

Section 3.2.2 Uncertainty Assessment provides information on how to develop uncertainty estimates for emission factors for road transportation.

Further information on emission factors for developing countries is available from Mitra *et al*. (2004).

TABLE 3.2.2
ROAD TRANSPORT N_2O AND CH_4 DEFAULT EMISSION FACTORS AND UNCERTAINTY RANGES [a]

Fuel Type/Representative Vehicle Category	CH_4 (kg /TJ)			N_2O (kg /TJ)		
	Default	Lower	Upper	Default	Lower	Upper
Motor Gasoline -Uncontrolled [b]	33	9.6	110	3.2	0.96	11
Motor Gasoline –Oxidation Catalyst [c]	25	7.5	86	8.0	2.6	24
Motor Gasoline –Low Mileage Light Duty Vehicle Vintage 1995 or Later [d]	3.8	1.1	13	5.7	1.9	17
Gas / Diesel Oil [e]	3.9	1.6	9.5	3.9	1.3	12
Natural Gas [f]	92	50	1 540	3	1	77
Liquified petroleum gas [g]	62	na	na	0.2	na	na
Ethanol, trucks, US [h]	260	77	880	41	13	123
Ethanol, cars, Brazil [i]	18	13	84	na	na	na

Sources: USEPA (2004b), EEA (2005a), TNO (2003) and Borsari (2005) CETESB (2004 & 2005) with assumptions given below. Uncertainty ranges were derived from data in Lipman and Delucchi (2002), except for ethanol in cars.

(a) Except for LPG and ethanol cars, default values are derived from the sources indicated using the NCV values reported in the Energy Volume Introduction chapter; density values reported by the U.S. Energy Information Administration; and the following assumed representative fuel consumption values: 10 km/l for motor gasoline vehicles; 5 km/l for diesel vehicles; 9 km/l for natural gas vehicles (assumed equivalent to gasoline vehicles); 9 km/l for ethanol vehicles. If actual representative fuel economy values are available, it is recommended that they be used with total fuel use data to estimate total distance travelled data, which should then be multiplied by Tier 2 emission factors for N_2O and CH_4.

(b) Motor gasoline uncontrolled default value is based on USEPA (2004b) value for a USA light duty gasoline vehicle (car) – uncontrolled, converted using values and assumptions described in table note (a). If motorcycles account for a significant share of the national vehicle population, inventory compilers should adjust the given default emission factor downwards.

(c) Motor gasoline – light duty vehicle oxidation catalyst default value is based on the USEPA (2004b) value for a USA Light Duty Gasoline Vehicle (Car) – Oxidation Catalyst, converted using values and assumptions described in table note (a). If motorcycles account for a significant share of the national vehicle population, inventory compilers should adjust the given default emission factor downwards.

(d) Motor gasoline – light duty vehicle vintage 1995 or later default value is based on the USEPA (2004b) value for a USA Light Duty Gasoline Vehicle (Car) – Tier 1, converted using values and assumptions described in table note (a). If motorcycles account for a significant share of the national vehicle population, inventory compilers should adjust the given default emission factor downwards.

(e) Diesel default value is based on the EEA (2005a) value for a European heavy duty diesel truck, converted using values and assumptions described in table note (a).

(f) Natural gas default and lower values were based on a study by TNO (2003), conducted using European vehicles and test cycles in the Netherlands. There is a lot of uncertainties for N_2O. The USEPA (2004b) has a default value of 350 kg CH_4/TJ and 28 kg N_2O/TJ for a USA CNG car, converted using values and assumptions described in table note (a). Upper and lower limits are also taken from USEPA (2004b)

(g) The default value for methane emissions from LPG, considering for 50 MJ/kg low heating value and 3.1 g CH_4/kg LPG was obtained from TNO (2003). Uncertainty ranges have not been provided.

(h) Ethanol default value is based on the USEPA (2004b) value for a USA ethanol heavy duty truck, converted using values and assumptions described in table note (a).

(i) Data obtained in Brazilian vehicles by Borsari (2005) and CETESB (2004 & 2005). For new 2003 models, best case: 51.3 kg THC/TJ fuel and 26.0 percent CH_4 in THC. For 5 years old vehicles: 67 kg THC/TJ fuel and 27.2 percent CH_4 in THC. For 10 years old: 308 kg THC/TJ fuel and 27.2 percent CH_4 in THC.

TABLE 3.2.3
N_2O AND CH_4 EMISSION FACTORS FOR USA GASOLINE AND DIESEL VEHICLES

Vehicle Type	Emission Control Technology	N_2O		CH_4	
		Running (hot)	Cold Start	Running (hot)	Cold Start
		mg/km	mg/start	mg/km	mg/start
Light Duty Gasoline Vehicle (Car)	Low Emission Vehicle (LEV)	0	90	6	32
	Advanced Three-Way Catalyst	9	113	7	55
	Early Three-Way Catalyst	26	92	39	34
	Oxidation Catalyst	20	72	82	9
	Non-oxidation Catalyst	8	28	96	59
	Uncontrolled	8	28	101	62
Light Duty Diesel Vehicle (Car)	Advanced	1	0	1	-3
	Moderate	1	0	1	-3
	Uncontrolled	1	-1	1	-3
Light Duty Gasoline Truck	Low Emission Vehicle (LEV)	1	59	7	46
	Advanced Three-Way Catalyst	25	200	14	82
	Early Three-Way Catalyst	43	153	39	72
	Oxidation Catalyst	26	93	81	99
	Non-oxidation catalyst	9	32	109	67
	Uncontrolled	9	32	116	71
Light Duty Diesel Truck	Advanced and moderate	1	-1	1	-4
	Uncontrolled	1	-1	1	-4
Heavy Duty Gasoline Vehicle	Low Emission Vehicle (LEV)	1	120	14	94
	Advanced Three-Way Catalyst	52	409	15	163
	Early Three-Way Catalyst	88	313	121	183
	Oxidation catalyst	55	194	111	215
	Non-oxidation catalyst	20	70	239	147
	Heavy Duty Gasoline Vehicle - Uncontrolled	21	74	263	162
Heavy Duty Diesel Vehicle	All -advanced, moderate, or uncontrolled	3	-2	4	-11
Motorcycles	Non-oxidation catalyst	3	12	40	24
	Uncontrolled	4	15	53	33

Source: USEPA (2004b).

Notes:

[a] These data have been rounded to whole numbers.

[b] Negative emission factors indicate that a vehicle starting cold produces fewer emissions than a vehicle starting warm or running warming.

[c] A database of technology dependent emission factors based on European data is available in the COPERT tool at http://vergina.eng.auth.gr/mech0/lat/copert/copert.htm.

[d] Because of the total-hydrocarbon limits in Europe, the CH_4-emissions of European vehicles may be lower than the indicated values from USA (Heeb, et. al., 2003)

[e] These "cold starts" were measured at an ambient temperature of 68ºF to 86ºF (20°C to 30°C).

TABLE 3.2.4
EMISSION FACTORS FOR ALTERNATIVE FUEL VEHICLES (mg/km)

Vehicle Type Vehicle Control Technology	N_2O Emission Factor	CH_4 Emission Factor
Light Duty Vehicles		
Methanol	39	9
CNG	27 - 70	215 - 725
LPG	5	24
Ethanol	12 - 47	27 - 45
Heavy Duty Vehicles		
Methanol	135	401
CNG	185	5 983
LNG	274	4 261
LPG	93	67
Ethanol	191	1227
Buses		
Methanol	135	401
CNG	101	7 715
Ethanol	226	1 292

Sources: USEPA 2004c, and Borsari (2005) CETESB (2004 & 2005).

TABLE 3.2.5
EMISSION FACTORS FOR EUROPEAN GASOLINE AND DIESEL VEHICLES (mg/km), COPERT IV MODEL

Vehicle Type	Fuel	Vehicle Technology/ Class	N_2O Emission Factors (mg/km)				CH_4 Emission Factors (mg/km)			
			Urban		Rural	Highway	Urban		Rural	Highway
			Cold	Hot			Cold	Hot		
Passenger Car	Gasoline	pre-Euro	10	10	6.5	6.5	201	131	86	41
		Euro 1	38	22	17	8.0	45	26	16	14
		Euro 2	24	11	4.5	2.5	94	17	13	11
		Euro 3	12	3	2.0	1.5	83	3	2	4
		Euro 4	6	2	0.8	0.7	57	2	2	0
	Diesel	pre-Euro	0	0	0	0	22	28	12	8
		Euro 1	0	2	4	4	18	11	9	3
		Euro 2	3	4	6	6	6	7	3	2
		Euro 3	15	9	4	4	7	3	0	0
		Euro 4	15	9	4	4	0	0	0	0
	LPG	pre-ECE	0	0	0	0	80		35	25
		Euro 1	38	21	13	8				
		Euro 2	23	13	3	2				
		Euro 3 and later	9	5	2	1				
Light Duty Vehicles	Gasoline	pre-Euro	10	10	6.5	6.5	201	131	86	41
		Euro 1	122	52	52	52	45	26	16	14
		Euro 2	62	22	22	22	94	17	13	11
		Euro 3	36	5	5	5	83	3	2	4
		Euro 4	16	2	2	2	57	2	2	0
	Diesel	pre-Euro	0	0	0	0	22	28	12	8
		Euro 1	0	2	4	4	18	11	9	3
		Euro 2	3	4	6	6	6	7	3	2
		Euro 3	15	9	4	4	7	3	0	0
		Euro 4	15	9	4	4	0	0	0	0
Heavy Duty Truck & Bus	Gasoline	All Technologies	6		6	6	140		110	70
	Diesel	GVW<16t	30		30	30	85		23	20
		GVW>16t	30		30	30	175		80	70
		Urban Busses & Coaches	30		30	30	175		80	70
	CNG	pre-Euro 4	n.a.				5400			
		Euro 4 and later (incl. EEV)					900			
Power Two Wheeler	Gasoline	<50 cm^3	1		1	1	219		219	219
		>50 cm^3 2-stroke	2		2	2	150		150	150
		>50 cm^3 4-stroke	2		2	2	200		200	200

Notes:

[1] Personal Communication: Ntziachristos, L., and Samaras, Z., (2005), LAT (2005) and TNO (2002).

[2] The urban emission factor is distinguished into cold and hot for passenger cars and light duty trucks. The cold emission factor is relevant for trips which start with the engine at ambient temperature. A typical allocation of the annual mileage of a passenger car into the different driving conditions could be: 0.3/0.1/0.3/0.3 for urban cold, urban hot, rural and highway respectively.

[3] Passenger car emission factors are also proposed for light duty vehicles when no more detailed information exists.

[4] The sulphur content of gasoline has both a cumulative and an immediate effect on N_2O emissions. The emission factors for gasoline passenger cars correspond to fuels at the period of registration of the different technologies and a vehicle fleet of ~50 000 km average mileage.

[5] N_2O and CH_4 emission factors from heavy duty vehicles and power two wheelers are also expected to depend on vehicle technology. There is no adequate experimental information though to quantify this effect.

[6] N_2O emission factors from diesel and LPG passenger cars vehicles are proposed by TNO (2002). Increase in diesel N_2O emissions as technology improves may be quite uncertain but is also consistent with the developments in the after treatment systems used in diesel engines (new catalysts, SCR-DeNO_x).

3.2.1.3 CHOICE OF ACTIVITY DATA

Activity data may be provided either by fuel consumption or by vehicle kilometres travelled VKT. Use of adequate VKT data can be used to check top-down inventories.

FUEL CONSUMPTION

Emissions from road vehicles should be attributed to the country where the fuel is sold; therefore fuel consumption data should reflect fuel that is sold within the country's territories. Such energy data are typically available from the national statistical agency. In addition to fuel sold data collected nationally, inventory compilers should collect activity data on other fuels used in that country with minor distributions that are not part of the national statistics (i.e., fuels that are not widely consumed, including those in niche markets such as compressed natural gas or biofuels). These data are often also available from the national statistical agency or they may be accounted for under separate tax collection processes. For Tier 3 methods, the MOBILE or COPERT models may help develop activity data.

It is *good practice* to check the following factors (as a minimum) before using the fuel sold data:

- Does the fuel data relate to on-road only or include off-road vehicles as well? National statistics may report total transportation fuel without specifying fuel consumed by on-road and off-road activities. It is important to ensure that fuel use data for road vehicles excludes that used for off-road vehicles or machinery (see Off-Road Transportation Section 3.3). Fuels may be taxed differently based on their intended use. A Road-Taxed fuel survey may provide an indication of the quantity of fuel sold for on-road use. Typically, the on-road vehicle fleet and associated fuel sales are better documented than the off-road vehicle population and activity. This fact should be considered when developing emission estimates.
- Is agricultural fuel use included? Some of this may be stationary use while some will be for mobile sources. However, much of this will not be on-road use and should not be included here.
- Is fuel sold for transportation uses used for other purposes (e.g., as fuel for a stationary boiler), or vice versa? For example, in countries where kerosene is subsidized to lower its price for residential heating and cooking, the national statistics may allocate the associated kerosene consumption to the residential sector even though substantial amounts of kerosene may have been blended into and consumed with transportation fuels.
- How are biofuels accounted for?
- How are blended fuels reported and accounted for? Accounting for official blends (e.g. addition of 25 percent of ethanol in gasoline) in activity data is straightforward, but if fuel adulteration or tampering (e.g. spent solvents in gasoline, kerosene in diesel fuel) is prevalent in a country, appropriate adjustments should be applied to fuel data, taking care to avoid double counting.
- Are the statistics affected by fuel tourism?
- Is there significant fuel smuggling?
- How is the use of lubricants as an additive in 2-stroke fuels reported? It may be included in the road transport fuel use or may be reported separately as a lubricant (see Box 3.2.4.).

Two alternative approaches are suggested to separate non-road and on-road fuel use:

(1) For each major fuel type, estimate the fuel used by each road vehicle type from vehicle kilometres travelled data. The difference between this road vehicle total and the apparent consumption is attributed to the off-road sector; or

(2) The same fuel-specific estimate in (1) is supplemented by a similarly structured bottom-up estimate of off-road fuel use from a knowledge of the off-road equipment types and their usage. The apparent consumption in the transportation sector is then disaggregated according to each vehicle type and the off-road sector in proportion to the bottom-up estimates.

Depending on national circumstances, inventory compilers may need to adjust national statistics on road transportation fuel use to prevent under- or over-reporting emissions from road vehicles. It is *good practice* to adjust national fuel sales statistics to ensure that the data used just reflects on-road use. Where this adjustment is necessary it is *good practice* to cross-check with the other appropriate sectors to ensure that any fuel removed from on-road statistics is added to the appropriate sector, or vice versa.

As validation, and if distance travelled data are available (see below vehicle kilometres travelled), it is *good practice* to estimate fuel use from the distance travelled data. The first step (Equation 3.2.6) is to estimate fuel consumed by vehicle type i and fuel type j.

EQUATION 3.2.6
VALIDATING FUEL CONSUMPTION

$$Estimated\ Fuel = \sum_{i,j,t} [Vehicles_{i,j,t} \bullet Distance_{i,j,t} \bullet Consumption_{i,j,t}]$$

Where:

Estimated Fuel	=total estimated fuel use estimated from distance travelled (VKT) data (l)
$Vehicles_{i,j,t}$	= number of vehicles of type i and using fuel j on road type t
$Distance_{i,j,t}$	= annual kilometres travelled per vehicle of type i and using fuel j on road type t (km)
$Consumption_{i,j,t}$	= average fuel consumption (l/km) by vehicles of type i and using fuel j on road type t
i	= vehicle type (e.g., car, bus)
j	= fuel type (e.g. motor gasoline, diesel, natural gas, LPG)
t	= type of road (e.g., urban, rural)

If data are not available on the distance travelled on different road types, this equation should be simplified by removing the "t" the type of road. More detailed estimates are also possible including the additional fuel used during the cold start phase.

It is *good practice* to compare the fuel sold statistics used in the Tier 1 approach with the result of equation 3.2.6. It is *good practice* to consider any differences and determine which data is of higher quality. Except in rare cases (e.g. large quantities of fuel sold for off-road uses, extensive fuel smuggling), fuel sold statistics are likely to be more reliable. This provides an important quality check. Significant differences between the results of two approaches may indicate that one or both sets of statistics may have errors, and that there is need for further analysis. Areas of investigation to pursue when reconciling fuel sold statistics and vehicle kilometre travelled data are listed in Section 3 2.3, Inventory quality assurance/quality control (QA/QC).

Distance travelled data for vehicles by type and fuel are important underpinnings for the higher tier calculations of CH_4 and N_2O emissions from road transport. So it may be necessary to adjust the distance travelled data to be consistent with the fuel sold data before proceeding to estimating emissions of CH_4 and N_2O. This is especially important in cases where the discrepancy between the estimated fuel use (Eq 3.2.6) and the statistical fuel sold is significant compared to the uncertainties in fuel sold statistics. Inventory compilers will have to use their judgement on the best way of adjusting distance travelled data. This could be done pro rata with the same adjustment factor applied to all vehicle type and road type classes or, where some data are judged to be more accurate, different adjustments could be applied to different vehicle types and road types. An example of the latter could be where the data on vehicle travelled on major highways is believed to be reasonably well known and on the other hand rural traffic is poorly measured. In any case, the adjustments made for reasons of the choice of adjustment factor and background data as well as any other checks should be well documented and reviewed.

VEHICLE KILOMETRES TRAVELLED (VKT)

While fuel data can be used at Tier 1 for CH_4 and N_2O, higher tiers also need vehicle kilometres travelled (VKT) by vehicle type, fuel type and possibly road type as well.

Many countries collect, measure, or otherwise estimate VKT. Often this is done by sample surveys counting vehicle numbers passing fixed points. These surveys can be automatic or manual and count vehicle numbers by type of vehicle. There may be differences between the vehicle classification used in the counts and other data (e.g. tax classes) that also give data on vehicle numbers. In addition they are unlikely to differentiate between similar vehicle using different fuels (e.g. motor gasoline and diesel cars). Sometimes more detailed information is also collected (e.g. vehicle speeds as well as numbers) especially where more detailed traffic planning has been performed. This may only be available for a municipality rather than the whole country. From these traffic counts, transport authorities can make estimates of the total VKT travelled in a country. Alternatives ways to determine the mileage are direct surveys of vehicle owners (private and commercial) and use of administrative records for commercial vehicles, taking care to account for outdated registration records for scrapped vehicles (Box 3.2.3 provides an approach to estimate the remaining fleets).

Where VKT is estimated in a country it is *good practice* to use this data, especially to validate the fuel sold data (see section 3.2.1.4).

OTHER PARAMETERS.

If CH_4 or N_2O emissions from road transportation are a *key category*, it is *good practice* to obtain more information on parameters that influence emission factors to ensure the activity data is compatible with the applicable Tier 2 or Tier 3 emission factor. This will require more dissagregated activity data in order to implement Equation 3.2.3 or 3.2.5:

- the amount of fuel consumed (in terajoules) by fuel type (all tiers);
- for each fuel type, the amount of fuel (or VKT driven) that is consumed by each representative vehicle type (e.g., passenger, light-duty or heavy-duty for road vehicles) preferably with age categories (Tiers 2 and 3); and
- the emission control technology (e.g., three-way catalysts) (Tiers 2 and 3).
- It may also be possible to collect VKT data by type of road (e.g. urban, rural, highway)

If the distribution of fuel use by vehicle and fuel type is unknown, it may be estimated from the number of vehicles by type. If the number of vehicles by vehicle and fuel type is not known, it may be estimated from national statistics (see below).

Vehicle technology, which is usually directly linked to the model and year of vehicle, affects CH_4 and N_2O emissions. Therefore, for Tier 2 and Tier 3 methods, activity data should be grouped based on Original Equipment Manufacturer (OEM) emission control technologies fitted to vehicle types in the fleet. The fleet age distribution helps stratify the fleet into age and subsequently technology classes. If the distribution is not available, vehicle deterioration curves may be used to estimate vehicle lifespan and therefore the number of vehicles remaining in service based on the number introduced annually (see Box 3.2.3).

In addition, if possible, determine (through estimates or from national statistics) the total distance travelled (i.e., VKT) by each vehicle technology type (Tier 3). If VKT data are not available, they can be estimated based on fuel consumption and assumed national fuel economy values. To estimate VKT using road transport fuel use data, convert fuel data to volume units (litres) and then multiply the fuel-type total by an assumed fuel economy value representative of the national vehicle population for that fuel type (km/l).

If using the Tier 3 method and national VKT statistics are available, the fuel consumption associated with these distance-travelled figures should be calculated and aggregated by fuel for comparison with national energy balance figures. Like the Tier 2 method, for Tier 3 it is suggested to further subdivide each vehicle type into uncontrolled and key classes of emission control technology. It should be taken into consideration that typically, emissions and distance travelled each year vary according to the age of the vehicle; the older vehicles tend to travel less but may emit more CH_4 and N_2O per unit of activity. Some vehicles, especially in developing countries, may have been converted to operate on a different type of fuel than their original design.

To implement the Tier 2 or 3 method, activity data may be derived from a number of possible sources. Vehicle inspection and maintenance (I/M) programmes, where operating, may provide insight into annual mileage accumulation rates. National vehicle licensing records may provide fleet information (counts of vehicles per model-year per region) and may even record mileage between license renewals. Other sources for developing activity data include vehicle sales, import, and export records.

Alternatively, vehicle stocks may be estimated from the number of new vehicle imports and sales by type, fuel and model year. The populations of vehicles remaining in service may be estimated by applying scrappage or attrition curves.

Higher tier methods involving an estimate of cold start emissions require knowledge of the number of starts. This can be derived from the total distance travelled and the average trip length. Typically, this can be obtained from traffic surveys. This data is often collected for local or traffic studies for transport planning.

BOX 3.2.3
VEHICLE DETERIORATION (SCRAPPAGE) CURVES

Deterioration (scrappage) curves can be used to adjust data obtained from fleet statistics based on vehicle licensing plates, where older vehicles are out of service but still registered in official records, leading to overestimation of emissions. They are approximated by Gompertz functions limiting maximum vehicle age.

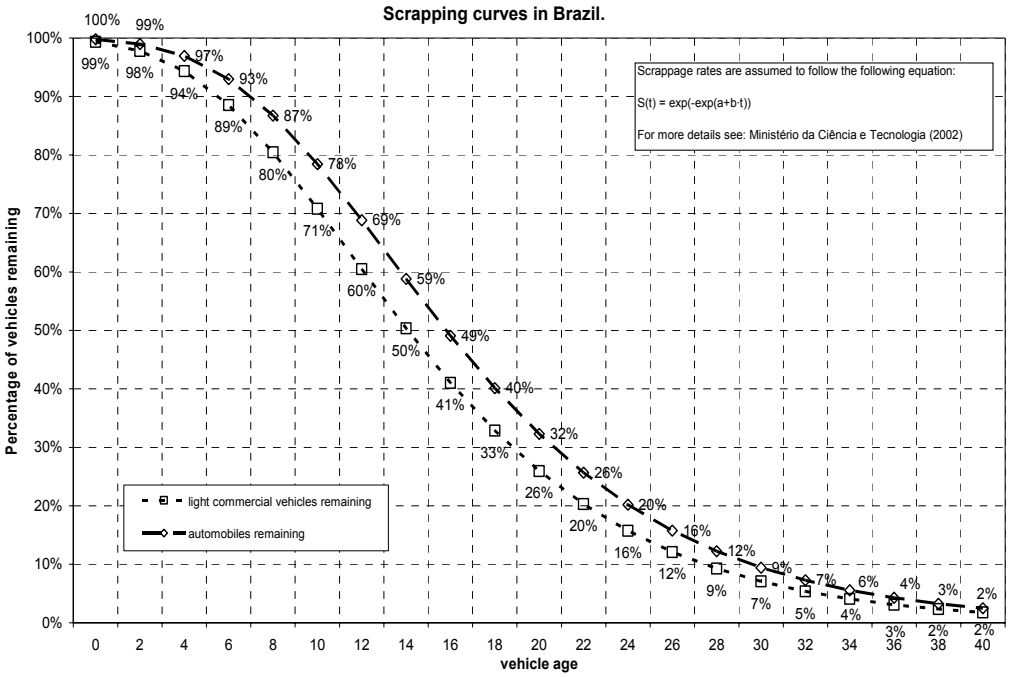
In the case of Brazil, the maximum vehicle age of 40 years was used for the National Communication of Greenhouse Gases (MCT,2002 and

http://www.mct.gov.br/clima/comunic_old/veicul03.htm)

utilizing the S-shaped Gompertz scrapping curve illustrated in this box, Vehicle Scrappage Function. This curve was provided by Petrobras, and is currently utilized by environmental agencies for emission inventories. The share of scrapped vehicles aged t is defined by the equation S(t) = exp [- exp (a + b(t))]; where (t) is the age of the vehicle (in years) and S(t) is the fraction of scrapped vehicles aged t. In the year 1994, national values were provided for automobiles (a = 1.798 and b= -0.137) and light commercial vehicles (a= 1.618 and b= -0.141).

(Ministério da Ciencia e Tecnologia (2002), Primeiro Inventário Brasileiro De Emissões

Antrópicas De Gases De Efeito Estufa Relatórios De Refencia Emissões De Gasses De Efeito Por Fontes Móveis, No Setor Eergético. Brasília, Bazil 2002)



3.2.1.4 COMPLETENESS

In establishing completeness, it is recommended that:

- Where cross-border transfers take place in vehicle tanks, emissions from road vehicles should be attributed to the country where the fuel is loaded into the vehicle.
- Carbon emitted from oxygenates and other blending agents which are derived from biomass should be estimated and reported as an information item to avoid double counting, as required by Volume 1. For more information on biofuels, see section 3.2.1.2.
- Ensure the reliability of the fuel sold data by following the recommendations listed in Section 3.2.1.3.
- Emissions from lubricants that are intentionally mixed with fuel and combusted in road vehicles should be captured as mobile source emissions. For more information on combustion of lubricants, please refer to Box 3.2.4

BOX 3.2.4
LUBRICANTS IN MOBILE COMBUSTION

Lubrication of a two-stroke petrol engine is conceptually quite different from that of a four-stroke engine, as it is not possible to have a separate lubricating oil sump. A two-stroke petrol engine should be lubricated by a mixture of lubricating oil and petrol in suitable proportion according to the manufacturer's recommendations. Depending on the engine type, mixtures of 1:25, 1:33 and 1:50 are common.

In the latest generation two-stroke engines, the lubricating oil is directly injected by an accurate metering device from a separate tank into the petrol in quantities that depend on the speed and load of the engine. Older or inexpensive two-stroke engines will receive the lubricant as part of the fuel mixture. Often these mixtures are prepared by the fuel supplier and delivered to the gas station but sometimes the vehicle owner will add oil at the service station. In some countries two stroke engines have been historically very significant as recent as the 1990's (e.g. Eastern Europe) or are still very significant (e.g. India and parts of South-East Asia).

The classification of these lubricants in energy statistics as lubricant or fuel may vary. Inventory compilers need to make sure that these lubricants are allocated to end use appropriately, accounted for properly, and that double counting or omission is avoided (compare treatment of lubricants in Volume 3 Chapter 5: Non-energy product and feedstock use of fuels). Lubricants intentionally mixed with fuel and combusted in road vehicles should be reported as energy and the associated emissions calculated using mobile source guidelines. When the chosen activity data for 2-stroke engines are based on kilometres travelled, the added lubricants should be considered in the fuel economy, as a part of the fuel blend.

3.2.1.5 DEVELOPING A CONSISTENT TIME SERIES

When data collection and accounting procedures, emission estimation methodologies, or models are revised, it is *good practice* to recalculate the complete time series. A consistent time series with regard to initial collection of fleet technology data may require extrapolation, possibly supported by the use of proxy data. This is likely to be needed for early years. Inventory compilers should refer to the discussion in Volume 1 Chapter 5: Time Series Consistency for general guidance.

Since this chapter contains many updated emission factors, for CO_2 (accounting for 100 percent fuel oxidation), CH_4, and N_2O, inventory compilers should ensure time series consistency. A consistent time series should consider the technological change in vehicles and their catalysts control systems. The time series should take into account the gradual phase-in among fleets, which is driven by legislation and market forces. Consistency can be maintained with accurate data on fleet distribution according to engine and control system technology, maintenance, control technology obsolescence, and fuel type. If VKT are not available for the whole time series but for a recent year, guidelines in Volume 1 Chapter 5: Time Series Consistency should be used to select a splicing method.

3.2.2 Uncertainty Assessment

CO_2, N_2O, and CH_4 contribute typically around 97, 2-3 and 1 percent of CO_2-equivalent emissions from the road transportation sector, respectively. Therefore, although uncertainties in N_2O and CH_4 estimates are much higher, CO_2 dominates the emissions from road transport. Use of locally estimated data will reduce uncertainties, particularly with bottom-up estimates.

Emission factor uncertainty

For CO_2, the uncertainty in the emission factor is typically less than 2 percent when national values are used (see Table 1.4 of the Introduction Chapter of this Volume). Default CO_2 emission factors given in Table 3.2.1. Road Transport Default Carbon Dioxide Emission Factors have an uncertainty of 2-5 percent), due to uncertainty in the fuel composition. Use of fuel blends, e.g. involving biofuels, or adulterated fuels may increase the uncertainty in emission factors if the composition of the blend is uncertain.

The uncertainties in emission factors for CH_4 and N_2O are typically relatively high (especially for N_2O) and are likely to be a factor of 2-3. They depend on:

- Uncertainties in fuel composition (including the possibility of fuel adulteration) and sulphur content;

- Uncertainties in fleet age distribution and other characterisation of the vehicle stock, including cross-border effects - the technical characteristics of vehicles from another country that take on fuel may be covered by technology models;
- Uncertainties in maintenance patterns of the vehicle stock;
- Uncertainties in combustion conditions (climate, altitude) and driving practices, such as speed, proportion of running distance to cold starts, or load factors (CH_4 and N_2O);
- Uncertainties in application rates of post-combustion emission control technologies (e.g. three-way catalyst);
- Uncertainties in the use of additives to minimize the aging effect of catalysts;
- Uncertainties in operating temperatures (N_2O); and
- Uncertainties of test equipment and emission measurement equipment.

It is *good practice* to estimate uncertainty based on published studies from which the emission factors were obtained. At least the following types of uncertainties may be discussed in published sources and need to be considered in the development of national emission factors from empirical data:

- A range in the emission factor of an individual vehicle, represented as a variance of measurements, due to variable emissions in different operating conditions (e.g. speed, temperature); and
- Uncertainty in the mean of emission factors of vehicles within the same vehicle class.

In addition, the vehicle sample that was measured may have been quite limited, or even a more robust sample of measurements may not be representative of the national fleet. Test driving cycles cannot fully reflect real driving behaviour, so at least some emission factor studies now test cold start emissions separately from running emissions, so that countries may be able to create country-specific adjustments, though those adjustments will themselves require more data collection with its own uncertainties.

Another source of uncertainty may be the conversion of the emission factor into units in which the activity data are given (e.g. from kg/GJ to g/km) because this requires additional assumptions about other parameters, such as fuel economy, which have an associated uncertainty as well.

The uncertainty in the emission factor can be reduced by stratifying vehicle fleets further by technology, age and driving conditions.

Activity data uncertainty

Activity data are the primary source of uncertainty in the emission estimate. Activity data are either given in energy units (e.g. TJ) or other units for different purposes such as person-/ton-kilometres, vehicle stocks, trip length distributions, fuel efficiencies, etc. Possible sources of uncertainty, which will typically be about +/-5 percent, include:

- Uncertainties in national energy surveys and data returns;
- Unrecorded cross-border transfers;
- Misclassification of fuels;
- Misclassification in vehicle stock;
- Lack of completeness (fuel not recorded in other source categories may be used for transportation purposes); and
- Uncertainty in the conversion factor from one set of activity data to another (e.g. from fuel consumption data to person-/ton-kilometres, or vice versa, see above).

Stratification of activity data may reduce uncertainty, if they can be connected to results from a top-down fuel use approach.

For estimating CH_4 and N_2O emissions, a different tier and hence different sets of activity data may be used. It is *good practice* to ensure that top-down and bottom-up approaches match, and to document and explain deviations if they do not match (see also Section 3.2.1.4 Completeness). For these gases, the emission factor uncertainty will dominate and the activity data uncertainty may be taken to be the same as for CO_2.

Further guidance on uncertainty estimates for activity data can be found in Volume 1 Chapter 3: Uncertainties.

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

It is *good practice* to conduct quality control checks as outlined in Volume 1 Chapter 6: Quality Assurance/Quality Control and Verification and expert review of the emission estimates. Additional quality control checks as outlined in Tier 2 procedures in the same chapter 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 source categories as identified in Volume 1 Chapter 4: Methodological Choice and Identification of Key Categories.

In addition to the guidance in the referenced chapters, specific procedures of relevance to this source category are outlined below.

Comparison of emissions using alternative approaches

For CO_2 emissions, the inventory compiler should compare estimates using both the fuel statistics and vehicle kilometre travelled data. Any anomalies between the emission estimates should be investigated and explained. The results of such comparisons should be recorded for internal documentation. Revising the following assumptions could narrow a detected gap between the approaches:

Off-road/non transportation fuel uses;

Annual average vehicle mileage;

Vehicle fuel efficiency;

Vehicle breakdowns by type, technology, age, etc.;

Use of oxygenates/biofuels/other additives;

Fuel use statistics; and

Fuel sold/used.

Review of emission factors

If default emission factors are used, the inventory compiler should ensure that they are applicable and relevant to the categories. If possible, the default factors should be compared to local data to provide further indication that the factors are applicable.

For CH_4 and N_2O emissions, the inventory compiler should ensure that the original data source for the local factors is applicable to the category and that accuracy checks on data acquisition and calculations have been performed. Where possible, the default factors and the local factors should be compared. If the default factors were used to estimate N_2O emissions, the inventory compiler should ensure that the revised emission factors in Table 3.2.3 were used in the calculation.

Activity data check

The inventory compiler should review the source of the activity data to ensure applicability and relevance to the category. Section 3.2.1.3 provides *good practice* for checking activity data. Where possible, the inventory compiler should compare the data to historical activity data or model outputs to detect possible anomalies. The inventory compiler should ensure the reliability of activity data regarding fuels with minor distribution; fuel used for other purposes, on- and off-road traffic, and illegal transport of fuel in or out of the country. The inventory compiler should also avoid double counting of agricultural and off-road vehicles.

External review

The inventory compiler should perform an independent, objective review of the calculations, assumptions, and documentation of the emissions inventory 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 the inventory requirements. The development of CH_4 and N_2O emission factors is particularly important due to the large uncertainties in the default factors.

3.2.4 Reporting and Documentation

It *is good practice* to document and archive all information required to produce the national emissions inventory estimates.

It is not practical to include all documentation in the national inventory report. However, the inventory 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. This applies particularly to national models used to estimate emissions from road transport, and to work done to improve knowledge of technology-specific emission factors for nitrous oxide and methane, where the uncertainties are particularly great. This type of information, provided the documentation is clear, should be submitted for inclusion in the EFDB.

Confidentiality is not likely to be a major issue with regard to road emissions, although it is noted that in some countries the military use of fuel may be kept confidential. The composition of some additives is confidential, but this is only important if it influences greenhouse gas emissions.

Where a model such as the USEPA MOVES or MOBILE models or the EEA COPERT model is used (EPA 2005a, EPA 2005b, EEA 2005, respectively), a complete record of all input data should be kept. Also any specific assumptions that were made and modifications to the model should be documented.

3.2.5 Reporting tables and worksheets

See the four pages of the worksheets (Annex 1) for the Tier I Sectoral Approach which are to be filled in for each of the source categories. The reporting tables are available in Volume 1, Chapter 8.

3.3 OFF-ROAD TRANSPORTATION

The off-road category (1 A 3 e ii) in Table 3.1.1 includes vehicles and mobile machinery used within the agriculture, forestry, industry (including construction and maintenance), residential, and sectors, such as airport ground support equipment, agricultural tractors, chain saws, forklifts, snowmobiles. For a brief description of common types of off-road vehicles and equipment, and the typical engine type and power output of each, please refer to EEA 2005. Sectoral desegregations are also available at USEPA, 2005b[12].

Engine types typically used in these off-road equipment include compression-ignition (diesel) engines, spark-ignition (motor gasoline), 2-stroke engines, and motor gasoline 4-stroke engines.

3.3.1 Methodological issues

Emissions from off-road vehicles are estimated using the same methodologies used for mobile sources, as presented in Section 3.2. These have not changed since the publication of the *1996 IPCC Guidelines and the GPG2000*, except that, as discussed in Section 3.2.1.2, the emission factors now assume full oxidation of the fuel. This is for consistency with the Stationary Combustion Chapter. Also these guidelines contain a method for estimating CO_2 emissions from catalytic converters using urea, a source of emissions that was not addressed previously.

3.3.1.1 CHOICE OF METHOD

There are three methodological options for estimating CO_2, CH_4, and N_2O emissions from combustion in off-road mobile sources: Tier 1, Tier 2, and Tier 3. Figure 3.3.1: Decision tree for estimating emissions from off-road vehicles provides the criteria for choosing the appropriate method. The preferred method of determining CO_2 emissions is to use fuel consumption for each fuel type on a country-specific basis. However, there may be difficulties with activity data because of the number and diversity of equipment types, locations, and usage

[12] Appendix B of this reference provides Source Classification Codes (SCC) and definitions for: (a) Recreational vehicles; (b) Construction equipment; (c) Industrial equipment; (d) Lawn and garden equipment; (e) Agricultural equipment; (f) Commercial equipment; (g) Logging; (h) GSE/underground mining/oil field equipment; (i) Recreational marine and; (j) Railway maintenance are provided in Appendix B.

patterns associated with off-road vehicles and machinery. Furthermore, statistical data on fuel consumption by off-road vehicles are not often collected and published. In this case higher tier methods will be needed for CO_2 and they are necessary for non-CO_2 gases because these are much more dependent on technology and operating conditions.

A single method is provided for estimating CO_2 emissions from catalytic converters using urea. Many types of off-road vehicles will not have catalytic converters installed, but emission controls will probably increasingly be used for some categories of off-road vehicles, especially those operated in urban areas (e.g., airport or harbour ground support equipment) in developed countries. If catalytic converters using urea are used in off-road vehicles, the associated CO_2 emissions should be estimated.

The general method for estimating greenhouse gas emissions from energy sources can be described as:

EQUATION 3.3.1
TIER 1 EMISSIONS ESTIMATE

$$Emissions = \sum_j \left(Fuel_j \bullet EF_j \right)$$

Where:

Emissions = Emissions (kg)

$Fuel_j$ = fuel consumed (as represented by fuel sold) (TJ)

EF_j = emission factor (kg/TJ)

j = fuel type

For Tier 1, emissions are estimated using fuel-specific default emission factors as listed in Table 3.3.1, assuming that for each fuel type, the total fuel is consumed by a single off-road source category.

For Tier 2, emissions are estimated using country-specific and fuel-specific emission factors which, if available, are specific to broad type of vehicle or machinery. There is little or no advantage in going beyond Tier 2 for CO_2 emissions estimates, provided reliable fuel consumption data are available.

EQUATION 3.3.2
TIER 2 EMISSIONS ESTIMATE

$$Emissions = \sum \left(Fuel_{ij} \bullet EF_{ij} \right)$$

Where:

Emissions =emissions (kg)

$Fuel_{i,j}$ = fuel consumed (as represented by fuel sold) (TJ)

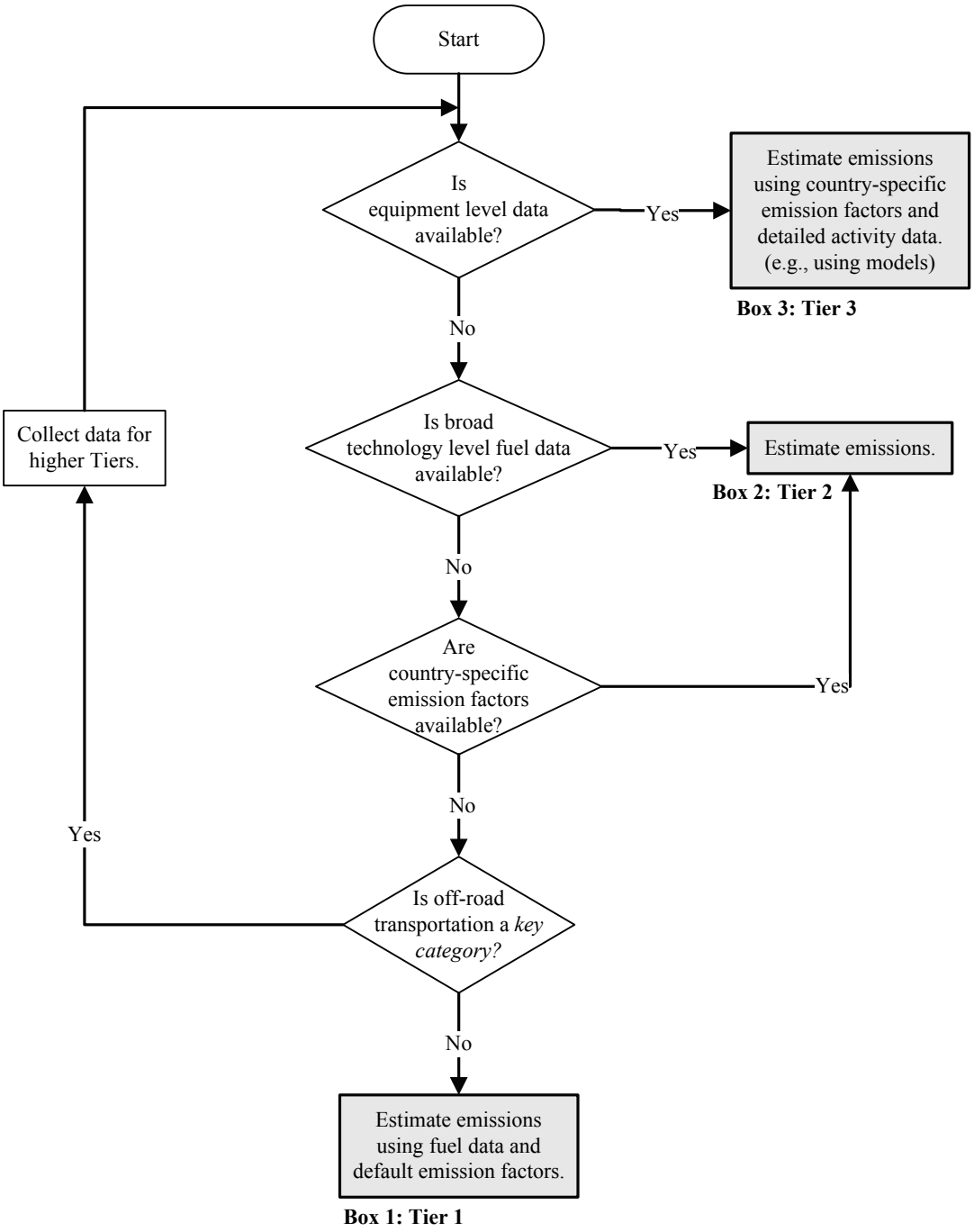
$EF_{i,j}$ = emission factor (kg/TJ)

i = vehicle/equipment type

j = fuel type

For Tier 3, if data are available, the emissions can be estimated from annual hours of use and equipment-specific parameters, such as rated power, load factor, and emission factors based on power usage. For off-road vehicles, these data may not be systematically collected, published, or available in sufficient detail, and may have to be estimated using a combination of data and assumptions.

Figure 3.3.1 Decision tree for estimating emissions from off-road vehicles



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.

Equation 3.3.3 represents the Tier 3 methodology, where the following basic equation is applied to calculate emissions (in Gg):

EQUATION 3.3.3
TIER 3 EMISSIONS ESTIMATE

$$Emission = \sum_{ij} \left(N_{ij} \bullet H_{ij} \bullet P_{ij} \bullet LF_{ij} \bullet EF_{ij} \right)$$

Where:

Emission = emission in kg.

N_{ij} = source population

H_{ij} = annual hours of use of vehicle i (h)

P_{ij} = average rated power of vehicle i (kW)

LF_{ij} = typical load factor of vehicle i (fraction between 0 and 1)

EF_{ij} = average emission factor for use of fuel j in vehicle i (kg/kWh)

i = off-road vehicle type

j = fuel type

Equation 3.3.3 may be stratified by factors such as age, technological vintage or usage pattern, and this will increase the accuracy of the estimates provided self-consistent sets of parameters H, P, LF and EF are available to support the stratification, (EEA 2005). Other detailed modelling tools are available for estimating off-road emissions using Tier 3 methodology (e.g., NONROAD (USEPA 2005a) and COPERT (Ntziachristos 2000)).

For estimating CO_2 emissions from use of urea-based additives in catalytic converters (non-combustive emissions), Equation 3.3.4 is used:

EQUATION 3.3.4
EMISSIONS FROM UREA-BASED CATALYTIC CONVERTERS

$$Emissions = Activity \bullet \left(\frac{12}{60}\right) \bullet Purity\ Factor \bullet \left(\frac{44}{12}\right)$$

Where:

Emission = Emission of CO_2 (kg)

Activity = Mass (kg) of urea-based additive consumed for use in catalytic converters

Purity factor = Fraction of urea in the urea-based additive (if percent, divide by 100)

The factor (12/60) captures the stochiometric conversion from urea ($(CO(NH_2)_2)$) to carbon, while factor (44/12) converts carbon to CO_2.

3.3.1.2 CHOICE OF EMISSION FACTORS

Default CO_2 emission factors assume that 100% of the fuel carbon is oxidised to CO_2. This is irrespective of whether the carbon is emitted initially as CO_2, CO, NMVOC or as particulate matter.

Country-specific NCV and CEF data should be used for Tiers 2 and 3. Inventory compilers may wish to consult CORINAIR 2004 or the EFDB for emission factors, noting that responsibility remains with the inventory compilers to ensure that emission factors taken from the EFDB are applicable to national circumstances.

For a Tier 3 approach example, please see Box 3.3.1 where more information on tailoring the NONROAD emissions model using country-specific data as well as the model to enhance national emission factors are given.

The default emission factors for CO_2 and their uncertainty ranges, and the default emission factors for CH_4 and N_2O for Tier 1 are provided in Table 3.3.1. To estimate CO_2 emissions, inventory compilers also have the option of using emission factors based on country-specific fuel consumption by off-road vehicles.

TABLE 3.3.1
DEFAULT EMISSION FACTORS FOR OFF-ROAD MOBILE SOURCES AND MACHINERY [a]

	CO_2			CH_4 [b]			N_2O [c]		
Off-Road Source	**Default (kg/TJ)**	**Lower**	**Upper**	**Default (kg/TJ)**	**Lower**	**Upper**	**Default (kg/TJ)**	**Lower**	**Upper**
Diesel									
Agriculture	74 100	72 600	74 800	4.15	1.67	10.4	28.6	14.3	85.8
Forestry	74 100	72 600	74 800	4.15	1.67	10.4	28.6	14.3	85.8
Industry	74 100	72 600	74 800	4.15	1.67	10.4	28.6	14.3	85.8
Household	74 100	72 600	74 800	4.15	1.67	10.4	28.6	14.3	85.8
Motor Gasoline 4-stroke									
Agriculture	69 300	67 500	73 000	80	32	200	2	1	6
Forestry	69 300	67 500	73 000						
Industry	69 300	67 500	73 000	50	20	125	2	1	6
Household	69 300	67 500	73 000	120	48	300	2	1	6
Motor Gasoline 2-Stroke									
Agriculture	69 300	67 500	73 000	140	56	350	0.4	0.2	1.2
Forestry	69 300	67 500	73 000	170	68	425	0.4	0.2	1.2
Industry	69 300	67 500	73 000	130	52	325	0.4	0.2	1.2
Household	69 300	67 500	73 000	180	72	450	0.4	0.2	1.2

Source: EEA 2005.

Note: CO_2 emission factor values represent full carbon content.

[a] Data provided in Table 3.3.1 are based on European off-road mobile sources and machinery. For gasoline, in case fuel consumption by sector is not discriminated, default values may be obtained according to national circumstances, e.g. prevalence of a given sector or weighting by activity

[b] Including diurnal, soak and running losses.

[c] In general, off-road vehicles do not have emission control catalysts installed (there may be exceptions among off-road vehicles in urban areas, such as ground support equipment used in urban airports and harbours). Properly operating catalysts convert nitrogen oxides to N_2O and CH_4 to CO_2. However, exposure of catalysts to high-sulphur or leaded fuels, even once, causes permanent deterioration (Walsh, 2003). This effect, if applicable, should be considered when adjusting emission factors.

3.3.1.3 CHOICE OF ACTIVITY DATA

Comprehensive top-down activity data on off-road vehicles are often unavailable, and where this is the case statistical surveys will be necessary to estimate the share of transport fuel used by off-road vehicles. Survey design is discussed in Chapter 2 of Vol.1 (Approaches to Data Collection). The surveys should be at the level of disaggregation indicated in Table 3.3.1 to make use of the default emission factor data, and be more detailed for the higher tiers. For the Tier 3 approach, modelling tools are available to estimate the amount of fuel consumed by each subcategory of equipment. Box 3.3.1 provides further information on using the NONROAD emissions model. This model may also be developed to incorporate country-specific modifications (see Box 3.3.2 for the Canadian experience).

BOX 3.3.1
NONROAD EMISSION MODEL (USEPA)

NONROAD 2005 is a mathematical model developed by the USEPA and may be used to estimate and forecast emissions from the non-road (off-road) transportation sectors. The model itself and all available supporting documentation are accessible on the EPA's website (http://www.epa.gov/otaq/nonrdmdl.htm). This model estimates emissions for six exhaust gases: hydrocarbons (HC), NO_X, carbon monoxide (CO), carbon dioxide (CO_2), sulphur oxides (SO_X), and particulate matter (PM). The user selects among five different types for reporting HC — as total hydrocarbons (THC), total organic gases (TOG), non-methane organic gases (NMOG), non-methane hydrocarbons (NMHC), and volatile organic compounds (VOC).

Generally, this model can perform a bottom-up estimation of emissions from the defined sources using equipment specific parameters such as: (i) engine populations; (ii) annual hours of use; (iii) power rating (horsepower); (iv) load factor (percent load or duty cycle), and (v) brake-specific fuel consumption (fuel consumed per horsepower-hour). The function will calculate the amount of fuel consumed by each subcategory of equipment. Subsequently, sub-sector (technology/fuel)-specific emission factors may then be applied to develop the emission estimate. The model is sensitive to the chosen parameters but may be used to apportion emissions estimates developed using a top-down approach.

It is not uncommon for the bottom-up approach using this model to deviate from a similar top-down result by a factor of 2 (100%) and therefore users are cautioned to review documentation for areas where this gap may be reduced through careful adjustment of their own inputs. Consequently, users must have some understanding of the population and fuel/technology make-up of the region being evaluated. However, reasonable adjustments can be established based upon: national manufacturing levels; importation/export records; estimated lifespan and scrappage functions. Scrappage functions attempt to define the attrition rate of equipment and may help illustrate present populations based upon historic equipment inventories (see Box 3.2.3 of Section 3.2 of this volume).

3.3.1.4 COMPLETENESS

Duplication of off-road and road transport activity data should be avoided. Validation of fuel consumption should follow the principles outlined in Section 3.2.1.3. Lubricants should be accounted for based on their use in off-road vehicles. Lubricants that are mixed with motor gasoline and combusted should be included with fuel consumption data. Other uses of lubricants are covered in the Volume 3: IPPU Chapter 5).

Amounts of carbon from biomass, eg. biodiesel, oxygenates and some other blending agents should be estimated separately, and reported as an information item to avoid double counting as these emissions are already treated in the AFOLU sector.

3.3.1.5 DEVELOPING A CONSISTENT TIME SERIES

It is *good practice* to determine activity data (e.g., fuel use) using the same method for all years. If this is not possible, data collection should overlap sufficiently in order to check for consistency in the methods employed. If it is not possible to collect activity data for the base year (e.g. 1990), it may be appropriate to extrapolate data backwards using trends in other activity data records.

Emissions of CH_4 and N_2O will depend on engine type and technology. Unless technology-specific emission factors have been developed, it is *good practice* to use the same fuel-specific set of emission factors for all years.

Mitigation activities resulting in changes in overall fuel consumption will be readily reflected in emission estimates if actual fuel activity data are collected. Mitigation options that affect emission factors, however, can only be captured by using engine-specific emission factors, or by developing control technology assumptions. Changes in emission factors over time should be well documented.

For more information on determining base year emissions and ensuring consistency in the time series, see Volume 1, Chapter 5 (Time Series Consistency).

BOX 3.3.2
CANADIAN EXPERIENCE WITH NONROAD MODEL

Using the model to enhance national emission factors:

NONROAD is initially populated with data native to the United States but may be customised for a given region or Party by simply adjusting the assumed input parameters to accommodate local situations. Parties may wish to designate their region as similar to one of those present in the USA to better emulate the seasonal climate. However, a designated temperature regime may also be input elsewhere. The NONROAD model is, thus, pre-loaded with local USA defaults thereby allowing their constituents to query it immediately.

Canada has begun to adjust this model by commencing national studies to better evaluate country-specific engine populations, available technologies, load factors and brake-specific fuel consumption values (BSFC) unique to the Canadian region. This new information will facilitate creation of Canada-specific input files and therefore not alter the core EPA programme algorithm but allow complete exploitation of the programmes strengths by providing more representative population and operating definitions. Through the introduction of lower uncertainty input data, the model may be used in conjunction with national fuel consumption statistics to arrive at a reasonable, disaggregated emission estimate. When operated with a similarly constructed On-Road model, for which operating parameters are better understood, a complete bottom-up, "apparent" fuel consumption estimate may be scaled to total national fuel sales. The country has used this modelling concept to help improve country-specific emission factors for the off-road consumption of fuel. The total fuel consumed is estimated by fuel type for each of the highly aggregated equipment sectors: (i) 2 cycle *versus* 4 cycle engines; (ii) Agriculture, Forestry, Industrial, Household and Recreational sub-sectors; (iii) gasoline versus diesel (spark vs. compression ignition). Once the model reports the total amount of fuels consumed according to this matrix, a composite emission factor is built based on the weighted averages of the contributing sub-sectors and their unique emission factors. The 2 cycle versus 4 cycle proportions will contribute to an average Off-Road gasoline EF while the Diesel EF is directly determined. Emission factors representing most GWP gases are not well researched and documented currently in North America and therefore, Canada has historically utilized applicable CORINAIR emission factors for these aggregated equipment sectors. The similarities between earlier technologies present in Europe and North America allow this utilization without introducing unreasonable uncertainty.

3.3.2 Uncertainty assessment

Greenhouse gas emissions from off-road sources are typically much smaller than those from road transportation, but activities in this category are diverse and are thus typically associated with higher uncertainties because of the additional uncertainty in activity data.

The types of equipment and their operating conditions are typically more diverse than that for road transportation, and this may give rise to a larger variation in emission factors and thus to larger uncertainties. However, the uncertainty estimate is likely to be dominated by the activity data, and so it is reasonable to assume as a default that the values in section 3.2.1.2 apply. Also, emission controls, if installed, are likely to be inoperable due to catalyst failure (e.g., from exposure to high-sulphur fuel). Thus, N_2O and CH_4 emissions are more closely related to combustion-related factors such as fuel and engine technology than to emission control systems.

3.3.2.1 ACTIVITY DATA UNCERTAINTY

Uncertainty in activity data is determined by the accuracy of the surveys or bottom-up models on which the estimates of fuel usage by off-road source and fuel type (see Table 3.3.1 for default classification) are based. This will be very case-specific, but factor of 2 uncertainties are certainly possible, unless if there is evidence to the contrary from the survey design.

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

It is *good practice* to conduct quality control checks as outlined in Chapter 6 of Volume 1, and expert review of the emission estimates, plus additional checks if higher tier methods are used.

In addition to the guidance above, specific procedures of relevance to this source category are outlined below.

Review of emission factors

The inventory compiler should ensure that the original data source for national factors is applicable to each category and that accuracy checks on data acquisition and calculations have been performed. For default factors, the inventory compiler should ensure that the factors are applicable and relevant to the category. If possible, the default factors should be compared to national factors to provide further indication that the factors are applicable and reasonable.

Check of activity data

The source of the activity data should be reviewed to ensure applicability and relevance to the category. Where possible, the data should be compared to historical activity data or model outputs to look for anomalies. Where surveys data have been used, the sum of on-road and off-road fuel usage should be consistent with total fuel used in the country. In addition, a completeness assessment should be conducted, as described in Section 3.3.1.4.

External review

The inventory compiler should carry out an independent, objective review of calculations, assumptions or documentation or both of the emissions inventory 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 national greenhouse gas inventory requirements.

3.3.4 Reporting and Documentation

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

It is not practical to include all documentation in the national inventory report. However, the inventory 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.

Some examples of specific documentation and reporting issues relevant to this source category are provided below.

In addition to reporting emissions, it is *good practice* to provide:

- Source of fuel and other data;
- Emission factors used and their associated references;
- Analysis of uncertainty or sensitivity of results or both to changes in input data and assumptions.
- Basis for survey design, where used to determine activity data
- References to models used in making the estimates

3.3.5 Reporting tables and worksheets

See the four pages of the worksheets (Annex 1) for the Tier I Sectoral Approach which are to be filled in for each of the source categories. The reporting tables are available in Volume 1, Chapter 8.

3.4 RAILWAYS

Railway locomotives generally are one of three types: diesel, electric, or steam. Diesel locomotives generally use diesel engines in combination with an alternator or generator to produce the electricity required to power their traction motors.

Diesel locomotives are in three broad categories – shunting or yard locomotives, railcars, and line haul locomotives. Shunting locomotives are equipped with diesel engines having a power output of about 200 to 2000 kW. Railcars are mainly used for short distance rail traction, e.g., urban/suburban traffic. They are equipped with a diesel engine having a power output of about 150 to 1000 kW. Line haul locomotives are used for long distance rail traction – both for freight and passenger. They are equipped with a diesel engine having a power output of about 400 to 4000 kW (EEA, 2005).

Electric locomotives are powered by electricity generated at stationary power plants as well as other sources. The corresponding emissions are covered under the Stationary Combustion Chapter of this Volume.

Steam locomotives are now generally used for very localized operations, primarily as tourist attractions and their contribution to greenhouse gas emissions is correspondingly small. However for a few countries, up to the 1990s, coal was used in a significant fraction of locomotives. For completeness, their emissions should be estimated using an approach similar to conventional steam boilers, which are covered in the Stationary Combustion Chapter.

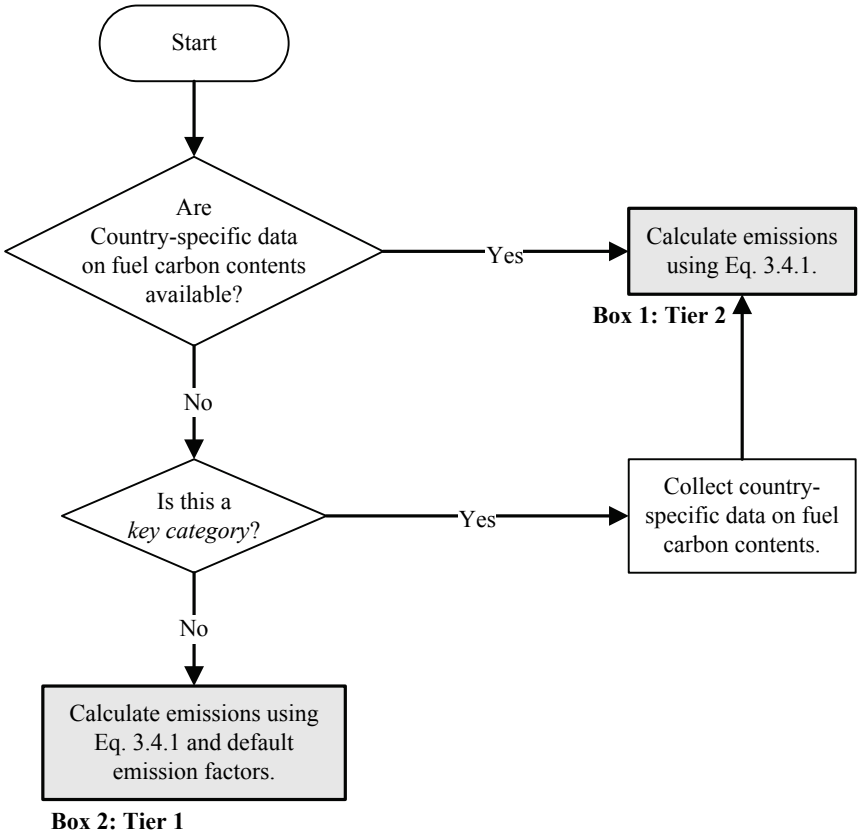
3.4.1 Methodological issues

Methodologies for estimating greenhouse gas emissions from railway vehicles (Section 3.4.1.1), have not changed fundamentally since the publication of the *1996 IPCC Guidelines* and the *GPG2000*. However, for consistency with the Stationary Combustion Chapter, CO_2 emissions are now estimated on the basis of the full carbon content of the fuel. This chapter covers *good practice* in the development of estimates for the direct greenhouse gases CO_2, CH_4 and N_2O. For the precursor gases, or indirect greenhouse gases of CO, NMVOCs, SO_2, PM, and NOx, please refer to the EMEP/Corinair Guidebook (EEA, 2005) for other mobile sources).

3.4.1.1 CHOICE OF METHOD

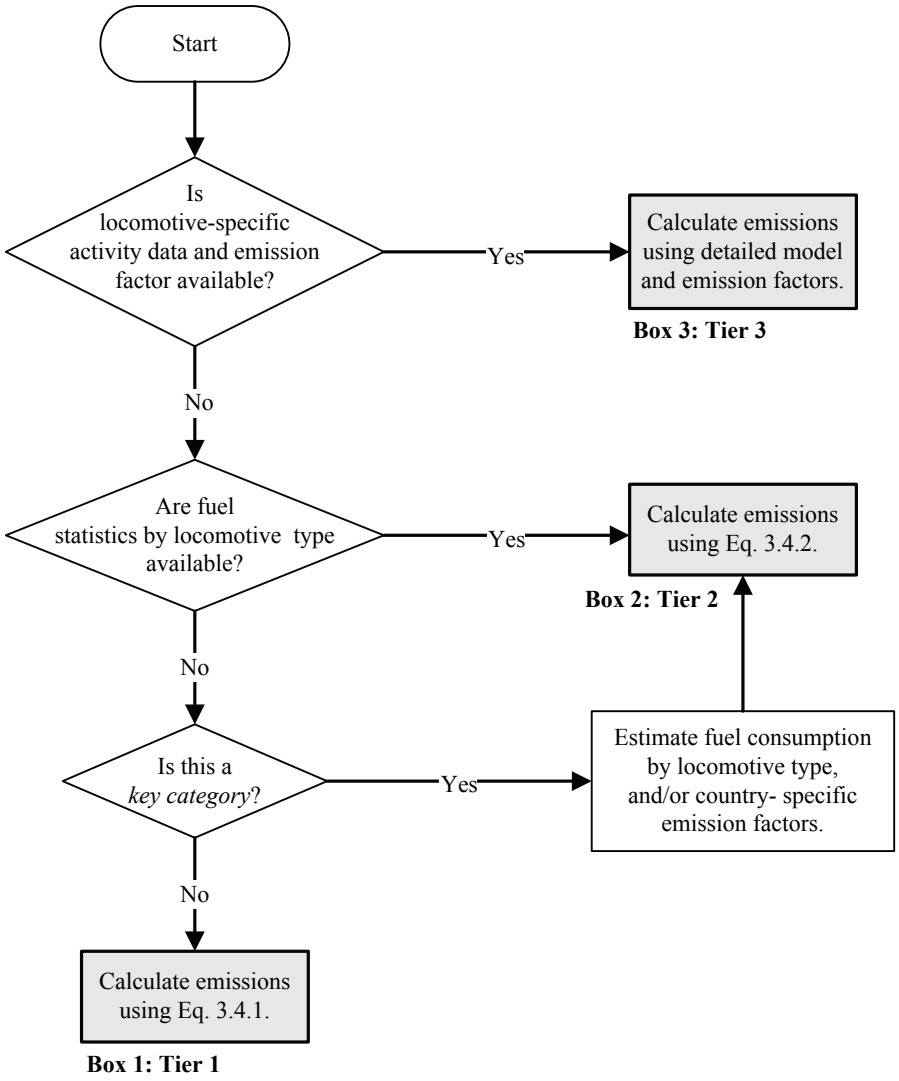
There are three methodological options for estimating CO_2, CH_4, and N_2O emissions from railways. The decision trees in Figures 3.4.1 and 3.4.2 give the criteria for choosing methodologies.

Figure 3.4.1 Decision tree for estimating CO_2 emissions from railways



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 3.4.2 Decision tree for estimating CH_4 and N_2O emissions from railways



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.

The three tiers of estimation methodologies are variations of the same fundamental equation:

EQUATION 3.4.1
GENERAL METHOD FOR EMISSIONS FROM LOCOMOTIVES

$$Emissions = \sum_j \left(Fuel_j \bullet EF_j \right)$$

Where:

Emissions = emissions (kg)

$Fuel_j$ = fuel type j consumed (as represented by fuel sold) in (TJ)

EF_j = emission factor for fuel type j, (kg/TJ)

j = fuel type

For Tier 1, emissions are estimated using fuel-specific default emission factors as listed in Table 3.4.1, assuming that for each fuel type the total fuel is consumed by a single locomotive type. For CO_2, Tier 2 uses equation 3.4.1 again with country-specific data on the carbon content of the fuel. There is little or no advantage in going beyond Tier 2 for estimating CO_2 emissions.

With respect to Tier 2 for CH_4 and N_2O, emissions are estimated using country-specific and fuel-specific emission factors in equation 3.4.2. The emission factors, if available, should be specific to broad locomotive technology type.

EQUATION 3.4.2
TIER 2 METHOD FOR CH_4 AND N_2O FROM LOCOMOTIVES

$$Emissions = \sum_i \left(Fuel_i \bullet EF_i \right)$$

Where:

Emissions = emissions (kg)

$Fuel_i$ = fuel consumed (as represented by fuel sold) by locomotive type i, (TJ)

EF_i = emission factor for locomotive type i, (kg/TJ)

i = locomotive type

Tier 3 methods , if data are available, use more detailed modelling of the usage of each type of engine and train, which will affect emissions through dependence of emission factors on load. Data needed includes the fuel consumption which can be further stratified according to typical journey (e.g. freight, intercity, regional) and kilometres travelled by type of train. This type of data may be collected for other purposes (e.g. emissions of air pollutants depending on speed and geography, or from the management of the railway).

Equation 3.4.3 is an example of a more detailed methodology (Tier 3), which is mainly based on the USEPA method for estimating off-road emissions (USEPA 2005 a & b). This uses the following basic formula to calculate emissions (in Gg):

EQUATION 3.4.3
TIER 3 EXAMPLE OF A METHOD FOR CH_4 AND N_2O FROM LOCOMOTIVES

$$Emission = \sum_i \left(N_i \bullet H_i \bullet P_i \bullet LF_i \bullet EF_i \right)$$

Where:

Emission = emissions of CH_4 or N_2O (kg)

N_i = number of locomotives of type i

H_i = annual hours of use of locomotive i [h]

P_i = average rated power of locomotive i [kW]

LF_i = typical load factor of locomotive i (fraction between 0 and 1)

EF_i = average emission factor for use in locomotive i [kg/kWh]

i = locomotive type and journey type

In this methodology, the parameters H, P, LF and EF may be subdivided, such as H into age dependent usage pattern (EEA, 2005). A number of detailed modelling tools are available for estimating locomotive emissions using Tier 3 methodologies (e.g., RAILI (VTT 2003); NONROAD (USEPA 2005a and b); COST 319 (Jorgensen & Sorenson, 1997)). Please refer to Box 3.4.1 for an example of a Tier 3 approach.

3.4.1.2 CHOICE OF EMISSION FACTORS

The default emission factors for CO_2, CH_4 and N_2O and their uncertainty ranges for Tier 1 are provided in Table 3.4.1. To estimate CH_4 and N_2O emissions, inventory compilers are encouraged to use country-specific emission factors for locomotives if available.

TABLE 3.4.1
DEFAULT EMISSION FACTORS FOR THE MOST COMMON FUELS USED FOR RAIL TRANSPORT

Gas	Diesel (kg/TJ)			Sub-bituminous Coal (kg/TJ)		
	Default	Lower	Upper	Default	Lower	Upper
CO_2	74 100	72 600	74 800	96 100	72 800	100 000
CH_4 [1]	4.15	1.67	10.4	2	0.6	6
N_2O [1]	28.6	14.3	85.8	1.5	0.5	5

Notes:

[1] For an average fuel consumption of 0.35 litres per bhp-hr (break horse power-hour) for a 4000 HP locomotive, (0.47 litres per kWh for a 2983 kW locomotive).(Dunn, 2001).

[2] The emission factors for diesel are derived from (EEA, 2005) (Table 8-1), while for coal from Table 2.2 of the Stationary Combustion chapter.

These default emission factors may, for non-CO_2 gases, be modified depending on the engine design parameters in accordance with Equation 3.4.4, using pollutant weighing factors in Table 3.4.2

EQUATION 3.4.4
WEIGHTING OF CH_4 AND N_2O EMISSION FACTORS FOR SPECIFIC TECHNOLOGIES

$$EF_{i,diesel} = PWF_i \bullet EF_{default,diesel}$$

Where:

$EF_{i,diesel}$ = engine specific emission factor for locomotive of type i (kg/TJ)

PWF_i = pollutant weighing factor for locomotive of type i [dimensionless]

$EF_{default,diesel}$ = default emission factor for diesel (applies to CH_4, N_2O) (kg/TJ)

TABLE 3.4.2
POLLUTANT WEGHTING FACTORS AS FUNCTIONS OF ENGINE DESIGN PARAMETERS FOR UNCONTROLLED ENGINES(DIMENSIONLESS)

Engine type	CH_4	N_2O
Naturally Aspirated Direct Injection	0.8	1.0
Turbo-Charged Direct Injection / Inter-cooled Turbo-Charged Direct Injection	0.8	1.0
Naturally Aspirated Pre-chamber Injection	1.0	1.0
Turbo-Charged Pre-chamber Injection	0.95	1.0
Inter-cooled Turbo-Charged Pre-chamber Injection	0.9	1.0
Source: EEA 2005 (Table 8-9);		

To take into account the increase in CH_4 and N_2O emissions with the age, the default emission factors for CH_4 may be increased by 1.5 percent per year while deterioration for N_2O is negligible (EEA, 2005).

BOX 3.4.1
EXAMPLE OF TIER 3 APPROACH

The 1998 EPA non-road diesel engine regulations are structured as a 3-tiered progression (USEPA, 1998). Each USEPA-tier involves a phase in (by horse power rating) over several years. USEPA-Tier 0 standards were in phase until 2001. The more stringent USEPA-Tier 1 standards took effect from 2002 to 2004, and yet more stringent USEPA-Tier 2 standards phase-in from 2005 and beyond. The main improvements are in the NO_x and PM emissions over the USEPA-tiers. Use of improved diesel with lower sulphur content contributes to reduced SO_2 emissions. The table below provides broad technology level emission factors for these and other locomotives above 3000 HP. Emission factors may also be provided in g/passenger-kilometer for passenger trains and g/ton-kilometer for freight trains for higher tiers if country-specific information is available (e.g., Hahn, 1989; UNECE 2002).

BROAD TECHNOLOGY LEVEL EMISSION FACTORS

Model	Engine	Power		Brake specific diesel fuel consumption (kg/kWh)	Reported emission levels (g/kWh)			
		HP	kW		NOx	CO	HC	CO_2
EMD SD-40	645E3B	3000	2237	0.246	15.82	2.01	0.36	440
EMD SD-60	710G3	3800	2834	0.219	13.81	2.68	0.35	391
EMD SD-70	710G3C	4000	2983	0.213	17.43	0.80	0.38	380
EMD SD-75	710G3EC	4300	3207	0.206	17.84	1.34	0.40	367
GE Dash 8	7FDL	3800	2834	0.219	16.63	6.44	0.64	391
GE Dash 9	7FDL	4400	3281	0.215	15.15	1.88	0.28	383
GE Dash 9	7FDL (Tier 0)	4400	3281	0.215	12.74	1.88	0.28	383
Evolution	GEVO 12	4400	3281	NA	10.86	1.21	0.40	NA
2TE116	1А-5Д49	6035	2●2250	0.214	16.05	10.70	4.07	382
2TE10M	10Д100	5900	2●2200	0.226	15.82	10.62	4.07	403
ТЕП60	11Д45	2950	2200	0.236	16.05	10.62	3.84	421
ТЕП70	2А-5Д49	3420	2550	0.211	15.83	10.55	4.01	377
2М62	14Д40	3943	2●1470	0.231	13.40	9.01	3.23	412

Sources:

[1] EMD and GE locomotive information based on Dunn, 2001. Lower tier CO and HC estimates for line-haul locomotives are 6.7 g/kWh and 1.3 g/kWh respectively.

[2] For the TE models and 2M62, estimations are based on GSTU 1994.

3.4.1.3 CHOICE OF ACTIVITY DATA

National level fuel consumption data are needed for estimating CO_2 emissions for Tier 1 and Tier 2 approaches. For estimating CH_4 and N_2O emissions using Tier 2, locomotive category level data is needed. Tier 3 approaches require activity data for operations (for example gross tonne kilometre (GTK) and duty cycles) at specific line haul locomotive level. These methods also require other locomotive-specific information, such as source population (with age and power ranges), mileage per train tonnage, annual hours of use and age-dependent usage patterns, average rated horse power (with individual power distribution within given power ranges), load factor, section information (such as terrain topography and train speeds). There are alternate modelling approaches for Tier 3 estimation (VTT 2003; EEA 2005).

The railway or locomotive companies, or the relevant transport authorities may be able to provide fuel consumption data for the line haul and yard locomotives. The contribution from yard locomotives is likely to be very small for almost all countries. If the annual fuel consumption is not provided separately for yard locomotives, it may be possible to estimate fuel use if typical data on their use and daily fuel use is available according to the following equation:

EQUATION 3.4.5
ESTIMATING YARD LOCOMOTIVE FUEL CONSUMPTION

Inventory fuel consumption = Number of yard locomotives • Average fuel consumption per locomotive and day • Average number of days of operation per locomotive in the year

The number of yard locomotives can be obtained from railway companies or transport authorities. If average fuel consumption per day is unknown, a value of 863 litres per day can be used (USEPA, 2005a). The number of days of operation is usually 365. If data for the number of yard locomotives cannot be obtained, the emissions inventory can be approximated by assuming that all fuel is consumed by line haul locomotives.

If fuel consumption data are available for the jurisdiction (State or Territory) as a whole, double counting may occur when locomotives of one company fill-in the jurisdiction of another company. This can be resolved at higher Tiers by the use of operating data.

Where higher tier approaches are used, care should be taken that the fuel consumption data used for CO_2 is consistent with the activity data used for CH_4 and N_2O.

3.4.1.4 COMPLETENESS

Diesel fuel is the most common fuel type used in railways, but inventory compilers should be careful not to omit or double count the other fuels that may be used in diesel locomotives for traction purposes. These may be mixed with diesel and may include petroleum fuels (such as residual fuel, fuel oils, or other distillates), bio-diesel (e.g. oil esters from rape seed, soy bean, sunflower, Jatropha, or Karanjia oil, or recovered vegetable and animal fats), and synthetic fuels. Bio-diesel can be used in all diesel engines with slight or no modification. Blending with conventional diesel is possible. Synthetic fuels include synthetic middle distillates (SMD) and Dimethyl Ether (DME) to be produced from various carbonaceous feedstocks, including natural gas, residual fuel oil, heavy crude oils, and coal via the production of synthesis gas. The mix varies and presently it is between 2 to 5 percent bio-diesel and the remaining petroleum diesel. The emission properties of these fuels are considered to be similar to those used for the road transport sector. CO_2 emissions from fuels derived from biomass should be reported as information items, and not included in the national total to avoid double counting.

Diesel locomotives may combust natural gas or coal for heating cars. Although these energy sources may be "mobile," the methods for estimating emissions from combustion of fuels for heat are covered under the Stationary Combustion section of this Energy Volume. Inventory compilers should be careful not to omit or double count the emissions from energy used for carriage heating in railways.

Diesel locomotives also consume significant amounts of lubricant oils. The related emissions are dealt with in Chapter 5 of the IPPU volume.

There are potential overlaps with other source sectors. A lot of statistical data will not include fuel used in other activities such as stationary railway sources; off-road machinery, vehicles and track machines in railway fuel use. Their emissions should not be included here but in the relevant non-railway categories as stationary sources, off-road etc. If this is not the case and it is impossible to separate these other uses from the locomotives, then it is *good practice* to note this in any inventory report or emission reporting tables.

3.4.1.5 DEVELOPING A CONSISTENT TIME SERIES

Emissions of CH_4 and N_2O will depend on engine type and technology. Unless technology-specific emission factors have been developed, it is *good practice* to use the same fuel-specific set of emission factors for all years.

Mitigation options that affect emission factors can only be captured by using engine-specific emission factors, or by developing control technology assumptions. These changes should be adequately documented.

For more information on determining base year emissions and ensuring consistency in the time series, see Chapter 5 of Volume 1: Time Series Consistency.

3.4.1.6 UNCERTAINTY ASSESSMENT

Greenhouse gas emissions from railways are typically much smaller than those from road transportation because the amounts of fuel consumed are less, and also because operations often occur on electrified lines, in which case the emissions associated with railway energy use will be reported under power generation and will depend on the characteristics of that sector.

To reduce uncertainty, a comprehensive approach is needed for both emission factors and activity data, especially where bottom-up activity data are used. The use of representative locally estimated data is likely to improve accuracy although uncertainties may remain large. It is *good practice* to document the uncertainties both in the emission factors as well as in the activity data. Further guidance on uncertainty estimates for emission factors can be found in Chapter 3 of Volume 1: Uncertainties.

Emission factor uncertainty

Table 3.4.1 provides ranges indicating the uncertainties associated with diesel fuel. In the absence of specific information, the percentage relationship between the upper and lower limiting values and the central estimate may be used to derive default uncertainty ranges associated with emission factors for additives.

Activity data uncertainty

The uncertainty in top-down activity data (fuel use) is likely to be of the order 5 percent. The uncertainty in disaggregated data for bottom-up estimates (usage or fuel use by type of train) is unlikely to be less than 10 percent and could be several times higher, depending on the quality of the underlying statistical surveys. Bottom-up estimates are however necessary for estimating non-CO_2 gases at higher tiers. These higher tier calculations could also yield CO_2 estimates, but these will probably be more uncertain than Tier 1 or 2. Thus the way forward where railways are a *key category* is to use the top-down estimate for CO_2 with country-specific fuel carbon contents, and higher tier estimates for the other gases. A bottom-up CO_2 estimate can then be used for QA/QC cross-checks.

Further guidance on uncertainty estimates for activity data can be found in Chapter 3 of Volume 1: Uncertainties.

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

It is *good practice* to conduct quality control checks as outlined in Chapter 6 of Volume 1: Quality Assurance/ Quality Control and Verification.

Additional quality control checks as outlined in Tier 2 procedures in Chapter 6 of Volume 1 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 Chapter 4 of Volume 1: Methodological Choice and Identification of Key Categories. In addition to the above guidance, specific procedures of relevance to this source category are outlined below.

Review of emission factors

The inventory compiler should ensure that the original data source for national factors is applicable to each category and that accuracy checks on data acquisition and calculations have been performed. For the IPCC default factors, the inventory compiler should ensure that the factors are applicable and relevant to the category. If possible, the IPCC default factors should be compared to national factors to provide further indication that the factors are applicable and reasonable.

Check of activity data

The source of the activity data should be reviewed to ensure applicability and relevance to the category. Where possible, the data should be compared to historical activity data or model outputs to look for anomalies. Data could be checked with productivity indicators such as fuel per unit of distance railway performance (freight and passenger kilometres) compared with other countries and compared across different years.

3.4.3 Reporting and Documentation

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates as outlined in Chapter 8 of Volume 1: Reporting Guidance and Tables.

In addition to reporting emissions, it is *good practice* to provide:

- the way in which detailed information needed for bottom-up estimates has been obtained, and what uncertainties are to be estimated;
- how any bottom-up method of fuel use has been reconciled with top-down fuel use statistics.
- emission factors used and their associated references, especially for additives
- the way in which any biofuel components have been identified.

The possible inclusion of fuels used for non-locomotive uses (see section 3.4.1.2 above).

3.4.4 Reporting tables and worksheets

See the four pages of the worksheets (Annex 1) for the Tier I Sectoral Approach which are to be filled in for each of the source categories. The reporting tables are available in Volume 1, Section 8.

3.5 WATER-BORNE NAVIGATION

This source category covers all water-borne transport from recreational craft to large ocean-going cargo ships that are driven primarily by large, slow and medium speed diesel engines and occasionally by steam or gas turbines. It includes hovercraft and hydrofoils. Water-borne navigation causes emissions of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), as well as carbon monoxide (CO), non-methane volatile organic compounds (NMVOCs), sulphur dioxide (SO_2), particulate matter (PM) and oxides of nitrogen (NO_x).

Section 3.5.5 contains definitions of specialist terms that may be useful to an inventory compiler.

3.5.1 Methodological issues

This section deals with the direct greenhouse gases CO_2, CH_4, and N_2O. The source category is set out in detail in Table 3.5.1. The methods discussed can be used also to estimate emissions from military water-borne navigation (see section 3.5.1.4). For the purpose of the emissions inventory, a distinction is made between domestic and international water-borne navigation. Any fugitive emissions from the transport of fossil fuels (e.g., by tanker) should be estimated and reported under the category "Fugitive emissions" as set out in Chapter 4 of this Volume.

3.5.1.1 CHOICE OF METHOD

Two methodological tiers for estimating emissions of CO_2, CH_4, and N_2O from water-borne navigation are presented. Both tiers apply emission factors to fuel consumption activity data. The decision tree shown in Figure 3.5.1 helps in making a choice between the two tiers. Emissions are estimated separately for domestic and international water-borne navigation.

Tier 1

The Tier 1 method is the simplest and can be applied with either default values or country-specific information. The fuel consumption data and emission factors in the Tier 1 method are fuel-type-specific and should be applied to the corresponding activity data (e.g. gas/diesel oil used for navigation). The calculation is based on the amount of fuel combusted and on emission factors for CO_2, CH_4, and N_2O. The calculation is shown in Equation 3.5.1 and emission factors are provided in Table 3.5.2 and Table 3.5.3

EQUATION 3.5.1
WATER-BORNE NAVIGATION EQUATION

$$Emissions = \sum (Fuel\ Consumed_{ab} \bullet Emission\ Factor_{ab})$$

Where:

a = fuel type (diesel, gasoline, LPG, bunker, etc.)

b = water-borne navigation type (i.e., ship or boat, and possibly engine type.) (Only at Tier 2 is the fuel used differentiated by type of vessel so b can be ignored at Tier 1)

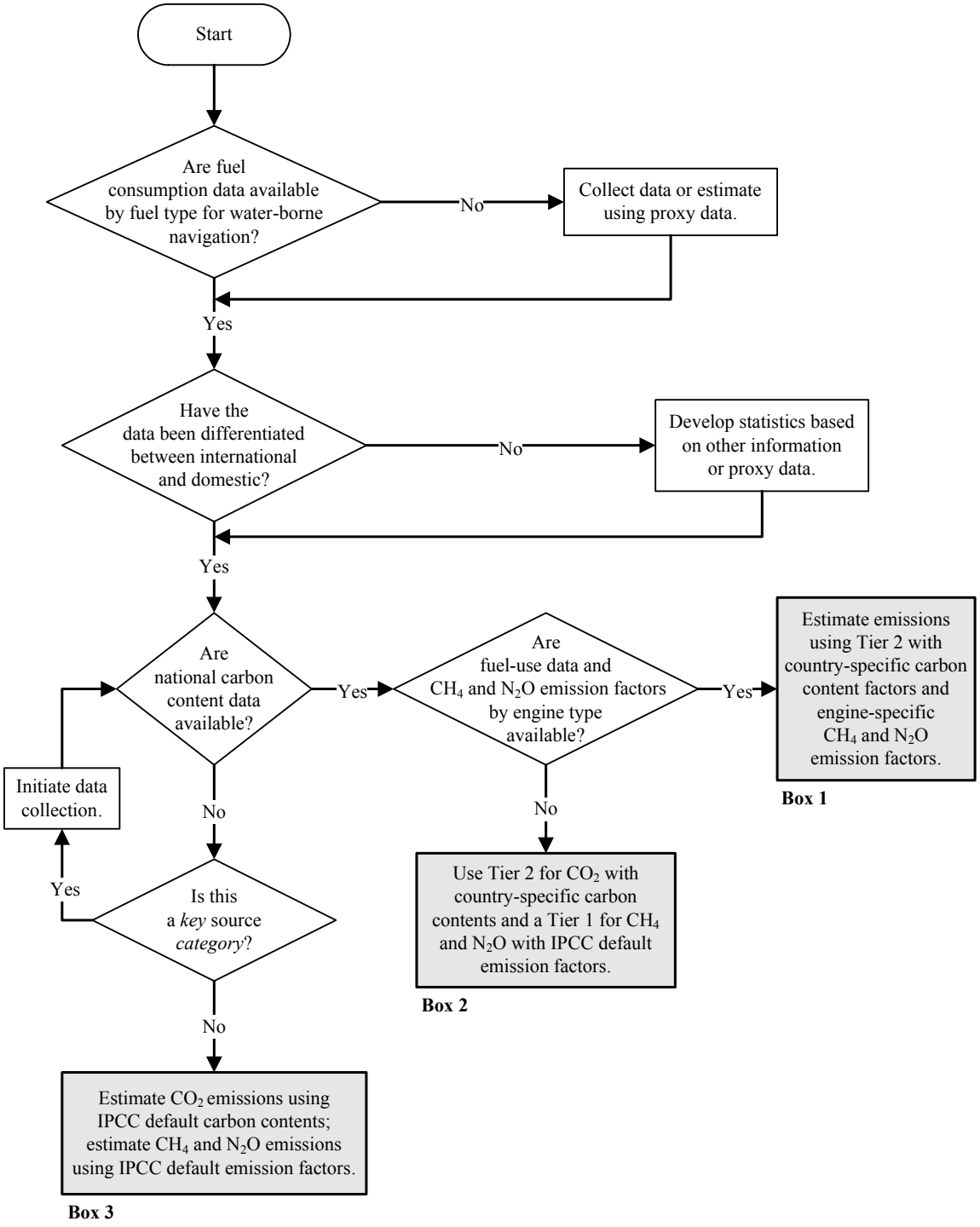
Tier 2

The Tier 2 method also uses fuel consumption by fuel type, but requires country-specific emission factors with greater specificity in the classification of modes (e.g. ocean-going ships and boats), fuel type (e.g. fuel oil), and even engine type (e.g. diesel) (Equation 3.5.1). In applying Tier 2, the inventory compilers should note that the EMEP/Corinair emission inventory guidebook (EEA, 2005) offers a detailed methodology for estimating ship emissions based on engine and ship type and ship movement data. The ship movement methodology can be used when detailed ship movement data and technical information on the ships are both available and can be used to differentiate emissions between domestic and international water-borne navigation.

TABLE 3.5.1
SOURCE CATEGORY STRUCTURE

Source category	Coverage
1 A 3 d Water-borne Navigation	Emissions from fuels used to propel water-borne vessels, including hovercraft and hydrofoils, but excluding fishing vessels. The international/domestic split should be determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship.
1 A 3 d i *International Water-borne Navigation (International bunkers)*	Emissions from fuels used by vessels of all flags that are engaged in international water-borne navigation. The international navigation may take place at sea, on inland lakes and waterways and in coastal waters. Includes emissions from journeys that depart in one country and arrive in a different country. Exclude consumption by fishing vessels (see Other Sector - Fishing). Emissions from international military water-borne navigation can be included as a separate sub-category of international water-borne navigation provided that the same definitional distinction is applied and data are available to support the definition.
1 A 3 d ii *Domestic Water-borne Navigation*	Emissions from fuels used by vessels of all flags that depart and arrive in the same country (exclude fishing, which should be reported under 1 A 4 c iii, and military, which should be reported under 1 A 5 b). Note that this may include journeys of considerable length between two ports in a country (e.g. San Francisco to Honolulu).
1 A 4 c iii *Fishing (mobile combustion)*	Emissions from fuels combusted for inland, coastal and deep-sea fishing. Fishing should cover vessels of all flags that have refuelled in the country (include international fishing).
1 A 5 b Mobile *(water-borne navigation component)*	All remaining water-borne mobile emissions from fuel combustion that are not specified elsewhere. Includes military water-borne navigation military emissions from fuel delivered to the country's military not otherwise included separately in 1 A3 d i as well as fuel delivered within that country but used by the militaries of external countries that are not engaged in multilateral operations.
Multilateral operations *(water-borne navigation component)*	Emissions from fuels used for water-borne navigation in multilateral operations pursuant to the Charter of the United Nations. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries.

Figure 3.5.1 Decision tree for emissions from water-borne navigation



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.

3.5.1.2 CHOICE OF EMISSION FACTORS

TIER 1

Default carbon dioxide emission factors (Table 3.5.2) are based on the fuel type and carbon content and take account of the fraction of carbon oxidised (100 percent), as described in Chapter 1, Introduction, of this Volume and Table 1.4).

TABLE 3.5.2
CO_2 EMISSION FACTORS

kg/TJ				
Fuel		**Default**	**Lower**	**Upper**
Gasoline		69 300	67 500	73 000
Other Kerosene		71 900	70 800	73 600
Gas/Diesel Oil		74 100	72 600	74 800
Residual Fuel Oil		77 400	75 500	78 800
Liquefied Petroleum Gases		63 100	61 600	65 600
Other Oil	Refinery Gas	57 600	48 200	69 000
	Paraffin Waxes	73 300	72 200	74 400
	White Spirit & SBP	73 300	72 200	74 400
	Other Petroleum Products	73 300	72 200	74 400
Natural Gas		56 100	54 300	58 300

For non-CO_2 gases, Tier 1 default emissions factors on a very general level are provided in Table 3.5.3.

TABLE 3.5.3
DEFAULT WATER-BORNE NAVIGATION CH_4 AND N_2O EMISSION FACTORS

	CH_4 (kg/TJ)	**N_2O (kg/TJ)**
Ocean-going Ships *	7 ± 50%	2 +140% -40%

*Default values derived for diesel engines using heavy fuel oil.
Source: Lloyd's Register (1995) and EC (2002)

TIER 2

Tier 2 emission factors should be country-specific and, if possible, derived by in-country testing of fuels and combustion engines used in water-borne navigation. Sources of emission factors should be documented in accordance with the provisions of these *Guidelines*. The EMEP/Corinair Emission inventory guidebook (EEA 2005) guidebook can be a source for NO_x, CO and NMVOC emission factors for both Tier 1 and Tier 2 calculations.

3.5.1.3 CHOICE OF ACTIVITY DATA

Data on fuel consumption by fuel type and engine type (for N_2O and CH_4) are required to estimate emissions from water-borne navigation. In addition, in the current reporting procedures, emissions from domestic water-borne navigation are reported separately from international water-borne navigation which requires disaggregating the activity data to this level. For consistency, it is *good practice* to use similar definitions of domestic and international activities for aviation and water-borne navigation. These definitions are presented in Table 3.5.4 and are independent of the nationality or flag of the carrier. In some cases, the national energy statistics may not provide data consistent with this definition. It is *good practice* that countries separate the activity data consistent with this definition. In most countries, tax and custom dues are levied on bunkers for domestic consumption, and bunkers for international consumption are free of such dues. In the absence of more direct sources of data, information about domestic taxes may be used to distinguish between domestic and international fuel consumption. In any case, a country must clearly define the methodologies and assumptions used[13].

TABLE 3.5.4
CRITERIA FOR DEFINING INTERNATIONAL OR DOMESTIC WATER-BORNE NAVIGATION (APPLIES TO EACH SEGMENT OF A VOYAGE CALLING AT MORE THAN TWO PORTS) *

Journey type between two ports	Domestic	International
Departs and arrives in same country	Yes	No
Departs from one country and arrives in another	No	Yes

* Most shipping movement data are collected on the basis of individual trip segments (from one departure to the next arrival) and do not distinguish between different types of intermediate stop (as called for in *GPG 2000*).
Basing the distinction on individual segment data is therefore simpler and is likely to reduce uncertainties. It is very unlikely that this change would make a significant change to the emission estimates. This does not change the way in which emissions from international journeys are reported as an information item and not included in national totals.

Fuel use data may be obtained using several approaches. The most feasible approach will depend on the national circumstances, but some of the options provide more accurate results than others. Several likely sources of actual fuel or proxy data are listed below, in order of typically decreasing reliability:

- National energy statistics from energy or statistical agencies;
- International Energy Agency (IEA) statistical information;
- Surveys of shipping companies (including ferry and freight);
- Surveys of fuel suppliers (e.g. quantity of fuels delivered to port facilities);
- Surveys of individual port and marine authorities;
- Surveys of fishing companies;
- Equipment counts, especially for small gasoline powered fishing and pleasure craft;
- Import/export records;
- Ship movement data and standard passenger and freight ferry schedules;
- Passenger counts and cargo tonnage data;
- International Maritime Organisation (IMO), engine manufacturers, or Jane's Military Ships Database;
- Ship movement data derived from Lloyds Register data

It may be necessary to combine and compare these data sources to get full coverage of shipping activities.

Marine diesel engines are the main power unit used within the marine industry for both propulsion and auxiliary power generation. Some vessels are powered by steam plants (EEA 2005). Water-borne navigation should also account for the fuel that may be used in auxiliary engines powering for example refrigeration plants and cargo

[13] It is *good practice* to clearly state the reasoning and justification if any country opts to use the *GPG2000* definitions.

pumps, and in boilers aboard vessels. Many steam powered oil tankers are still in operation, which consume more fuel per day when discharging their cargo in a port to operate the pumps than they do in deep sea steaming. Table 3.5.5 presents the average percentage of fuel consumed by both the main engines and auxiliary engines of the total fuel consumed by water-borne navigation vessel types. This allows the inventory compiler to apply the appropriate emissions factors, if available, as these factors may differ between main engines and auxiliary engines. Table 3.5.6 provides fuel consumption factors for various water-borne navigation vessel types, if the ship fleet by tonnage and category is collected.

TABLE 3.5.5
AVERAGE FUEL CONSUMPTION PER ENGINE TYPE (SHIPS >500 GRT)

Ship Type	Main Engine Consumption (%)	Avg. Number of Aux. Engines Per Vessel	Aux. Engine Consumption (%)
Bulk Carriers	98%	1.5	2%
Combination Carriers	99%	1.5	1%
Container Vessels	99%	2	1%
Dry Cargo Vessels	95%	1.5	5%
Offshore Vessels	98%	1	2%
Ferries/Passenger Vessels	98%	2	2%
Reefer Vessels	97%	2	3%
RoRo Vessels	99%	1.5	1%
Tankers	99%	1.5	1%
Miscellaneous Vessels	98%	1	2%
Totals	98%		2%

Source: Fairplay Database of Ships, 2004. GRT = Gross Registered Tonnage

TABLE 3.5.6
FUEL CONSUMPTION FACTORS, FULL POWER

Ship type	Average Consumption (tonne/day)	Consumption at full power(tonne/day) as a function of gross tonnage(GRT)
Bulk Carriers		
Solid Bulk	33.8	20.186 + 0.00049*GRT
Liquid Bulk	41.8	14.685 + 0.00079*GRT
General Cargo	21.3	9.8197 + 0.00143*GRT
Container	65.9	8.0552 + 0.00235*GRT
Passenger/Ro-Ro/Cargo	32.3	12.834 + 0.00156*GRT
Passenger	70.2	16.904 + 0.00198*GRT
High Speed Ferry	80.4	39.483 + 0.00972*GRT
Inland Cargo	21.3	9.8197 + 0.00143*GRT
Sail Ships	3.4	0.4268 +0.00100*GRT
Tugs	14.4	5.6511 +0.01048*GRT
Fishing	5.5	1.9387 +0.00448*GRT
Other Ships	26.4	9.7126 +0.00091*GRT
All Ships	32.8	16.263 + 0. 001*GRT

Source: Techne (1997)

In addition, although gases from cargo boil-off (primarily LNG or VOC recovery) may be used as fuels on ships, the amounts are usually not large in comparison to the total fuel consumed. Due to the small contribution, it is not required to account for this in the inventory.

3.5.1.4 MILITARY

The *2006 IPCC Guidelines* do not provide a distinct method for calculating military water-borne emissions. Emissions from military water-borne fuel use can be estimated using the equation 3.5.1 and the same calculation approach is recommended for non-military shipping. Due to the special characteristics of the operations, situations, and technologies (e.g., .aircraft carriers, very large auxiliary power plants, and unusual engine types) associated with military water-borne navigation, a more detailed method of data analysis is encouraged when data are available. Inventory compilers should therefore consult military experts to determine the most appropriate emission factors for the country's military water-borne navigation.

Due to confidentiality issues (see completeness and reporting), many inventory compilers may have difficulty obtaining data for the quantity of military fuel use. Military activity is defined here as those activities using fuel purchased by or supplied to military authorities in the country. It is *good practice* to apply the rules defining civilian domestic and international operations in water-borne navigation to military operations when the data necessary to apply those rules are comparable and available. Data on military fuel use should be obtained from government military institutions or fuel suppliers. If data on fuel split are unavailable, all the fuel sold for military activities should be treated as domestic.

Emissions resulting from multilateral operations pursuant to the Charter of the United Nations should not be included in national totals, but reported separately; other emissions related to operations shall be included in the national emissions totals of one or more Parties involved. The national calculations should take into account fuel delivered to the country's military, as well as fuel delivered within that country but used by the military of other countries. Other emissions related to operations (e.g., off-road ground support equipment) should be included in the national emissions totals in the appropriate source category.

3.5.1.5 COMPLETENESS

For water-borne navigation emissions, the methods are based on total fuel use. Since countries generally have effective accounting systems to measure total fuel consumption. The largest area of possible incomplete coverage of this source category is likely to be associated with misallocation of navigation emissions in another source category. For instance, for small watercraft powered by gasoline engines, it may be difficult to obtain complete fuel use records and some of the emissions may be reported as industrial (when industrial companies use small watercraft), other off-road mobile or stationary power production. Estimates of water-borne emissions should include not only fuel for marine shipping, but also for passenger vessels, ferries, recreational watercraft, other inland watercraft, and other gasoline-fuelled watercraft. Misallocation will not affect completeness of the total national CO_2 emissions inventory. It will affect completeness of the total non-CO_2 emissions inventory, because non-CO_2 emission factors differ between source categories.

Fugitive emissions from transport of fossil fuels should be estimated and reported under the category "Fugitive emissions". Most fugitive emissions occur during loading and unloading and are therefore accounted under that category. Emissions during travel are considered insignificant.

Completeness may also be an issue where military data are confidential, unless military fuel use is aggregated with another source category.

There are additional challenges in distinguishing between domestic and international emissions. As each country's data sources are unique for this category, it is not possible to formulate a general rule regarding how to make an assignment in the absence of clear data. It is *good practice* to specify clearly the assumptions made so that the issue of completeness can be evaluated.

3.5.1.6 DEVELOPING A CONSISTENT TIME SERIES

It is *good practice* to determine fuel use using the same method for all years. If this is not possible, data collection should overlap sufficiently in order to check for consistency in the methods employed.

Emissions of CH_4 and N_2O will depend on engine type and technology. Unless technology-specific emission factors have been developed, it is *good practice* to use the same fuel-specific set of emission factors for all years.

Mitigation activities resulting in changes in overall fuel consumption will be readily reflected in emission estimates if actual fuel activity data are collected. Mitigation options that affect emission factors, however, can

only be captured by using engine-specific emission factors, or by developing control technology assumptions. Changes in emission factors over time should be well documented.

Marine diesel oil and heavy fuel oil are the fuels used primarily for large sources within water-borne navigation. As the carbon contents of these fuels may vary over the time series, the source of CO_2 emission factors should be explicitly stated, as well as the dates the fuels were tested.

3.5.1.7 UNCERTAINTY ASSESSMENT

Emission factors

According to expert judgment, CO_2 emission factors for fuels are generally well determined as they are primarily dependent on the carbon content of the fuel (EPA, 2004). For example, the default uncertainty value for diesel fuel is about ± -1.5 percent and for residual fuel oil ± -3 percent. The uncertainty for non-CO_2 emissions, however, is much greater. The uncertainty of the CH_4 emission factor may range as high as 50 percent. The uncertainty of the N_2O emission factor may range from about 40 percent below to about 140 percent above the default value (Watterson, 2004).

Activity data

Much of the uncertainty in water-borne navigation emission estimates is related to the difficulty of distinguishing between domestic and international fuel consumption. With complete survey data, the uncertainty may be low (say ± -5 percent), while for estimations or incomplete surveys the uncertainties may be considerable (say ± -50 percent). The uncertainty will vary widely from country to country and is difficult to generalise. Global data sets may be helpful in this area, and it is expected that reporting will improve for this category in the future.

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

It is *good practice* to conduct quality control checks. Specific procedures of relevance to this source category are outlined below.

Comparison of emissions using alternative approaches

If possible, the inventory compiler should compare estimates determined for water-borne navigation using both Tier 1 and Tier 2 approaches. The inventory compiler should investigate and explain any anomaly between the emission estimates. The results of such comparisons should be recorded.

Review of emission factors

The inventory compiler should ensure that the original data source for national factors is applicable to each category and that accuracy checks on data acquisition and calculations have been performed. If national emission factors are available, they should be used, provided that they are well documented. For the default factors, the inventory compiler should ensure that the factors are applicable and relevant to the category.

If emissions from military use were developed using data other than default factors, the inventory compiler should check the accuracy of the calculations and the applicability and relevance of the data.

Check of activity data

The source of the activity data should be reviewed to ensure applicability and relevance to the category. Where possible, the data should be compared to historical activity data or model outputs to look for anomalies. Data could be checked with productivity indicators such as fuel per unit of water-borne navigation traffic performance compared with other countries. The European Environmental Agency provides a useful dataset, http://air-climate.eionet.eu.int/databases/TRENDS/TRENDS_EU15_data_Sep03.xls, which presents emissions and passenger/freight volume for each transportation mode for Europe. The information for shipping is very detailed. Examples of such indicators include: for ships with less than 3000 GT are from 0.09 to 0.16 kg CO_2/tonne-km; for larger ships between 0.04 and 0.14; and for passenger ferries, the factors range from 0.1-0.5 kg/passenger-km.

External review

The inventory compiler should perform an independent, objective review of calculations, assumptions or documentation of the emissions inventory to assess the effectiveness of the QC programme. The peer review should be performed by expert(s) (e.g. transport authorities, shipping companies, and military staff) who are familiar with the source category and who understand inventory requirements.

3.5.3 Reporting and Documentation

Emissions related to water-borne navigation are reported in different categories depending on their nature. For *good practice*, the categories to use are:

- Domestic water-borne navigation;
- International water-borne navigation (international bunkers);
- Fishing (mobile combustion);
- Mobile (Military [water-borne navigation])
- Non-specified Mobile (Vehicles and Other Machinery)

Emissions from international water-borne navigation are reported separately from domestic, and not included in the national total.

Emissions related to commercial fishing are not reported under water-borne navigation. These emissions are to be reported under the Agriculture/Forestry/Fishing category in the Energy Sector. By definition, all fuel supplied to commercial fishing activities in the reporting country is considered domestic, and there is no international bunker fuel category for commercial fishing, regardless of where the fishing occurs.

Military water-borne emissions should be clearly specified to improve the transparency of national greenhouse gas inventories. (see section 3.5.1.4).

In addition to reporting emissions, it is *good practice* to provide:

- Source of fuel and other data;
- Method used to separate domestic and international navigation;
- Emission factors used and their associated references;
- Analysis of uncertainty or sensitivity of results or both to changes in input data and assumptions.

3.5.4 Reporting tables and worksheets

The four pages of the worksheets (Annex 1) for the Tier I Sectoral Approach should be filled in for each of the source categories in Table 3.5.1. The reporting tables are available in Volume 1, Chapter 8.

3.5.5 Definitions of specialist terms

DEFINITIONS

Bulk Carriers – Ships used to transport large amounts of non-containerized cargoes such as oil, lumber, grain, ore, chemicals, etc. Identifiable by the hatches raised above deck level, which cover the large cargo holds.

Combination Carriers – Ships used to transport, in bulk, oil or, alternatively, solid cargoes.

Container Vessels – Ships used to transport large, rectangular metal boxes, usually containing manufactured goods.

Dry Cargo Vessels – Ships used to transport cargo that is not liquid and normally does not require temperature control.

Ferries/Passenger Vessels – Ships used to perform short journeys for a mix of passengers, cars and commercial vehicles. Most of these ships are Ro-Ro (roll on - roll off) ferries, where vehicles can drive straight on and off. Passenger vessels can also include vacation cruise ships.

Offshore Vessels – Term for ships engaging in a variety of support operations to larger ships. Can include offshore supply vessels, anchor handling vessels, tugboats, liftboats (i.e., deck barges), crew boats, dive support vessels, and seismic vessels.

Reefer Vessels – Ships with refrigerated cargo holds in which perishables and other temperature-controlled cargoes are bulk loaded.

Ro-Ro Vessels – Ships with roll-on/roll-off cargo spaces or special category spaces, which allows wheeled vehicles to be loaded and discharged without cranes.

Tankers – Ships used to transport crude oil, chemicals and petroleum products. Tankers can appear similar to bulk carriers, but the deck is flush and covered by oil pipelines and vents.

3.6 CIVIL AVIATION

Emissions from aviation come from the combustion of jet fuel (jet kerosene and jet gasoline) and aviation gasoline[14]. Aircraft engine emissions are roughly composed of about 70 percent CO_2, a little less than 30 percent H_2O, and less than 1 percent each of NO_x, CO, SO_x, NMVOC, particulates, and other trace components including hazardous air pollutants. Little or no N_2O emissions occur from modern gas turbines (IPCC, 1999). Methane (CH_4) may be emitted by gas turbines during idle and by older technology engines, but recent data suggest that little or no CH_4 is emitted by modern engines.

Emissions depend on the number and type of aircraft operations; the types and efficiency of the aircraft engines; the fuel used; the length of flight; the power setting; the time spent at each stage of flight; and, to a lesser degree, the altitude at which exhaust gases are emitted.

For the purpose of these guidelines, operations of aircraft are divided into (1) *Landing/Take-Off (LTO) cycle* and (2) *Cruise*. Generally, about 10 percent of aircraft emissions of all types, except hydrocarbons and CO, are produced during airport ground level operations and during the LTO cycle[15]. The bulk of aircraft emissions (90 percent) occur at higher altitudes. For hydrocarbons and CO, the split is closer to 30 percent local emissions and 70 percent at higher altitudes, (FAA, 2004a).

Section 3.6.5 contains definitions of specialist terms that may be useful to an inventory compiler.

[14] A fuel used only in small piston engine aircraft, and which generally represents less than 1 percent of fuel used in aviation.

[15] LTO cycle is defined in ICAO, 1993. If countries have more specific data on times in mode these can be used to refine computations in higher tier methods.

3.6.1 Methodological issues

This source category includes emissions from all civil commercial use of airplanes, including civil and general aviation (e.g. agricultural airplanes, private jets or helicopters). Methods discussed in this section can also be used to estimate emissions from military aviation, but emissions should be reported under category 1A 5 'Other' or the Memo Item "Multilateral Operations."

For the purpose of the emissions inventory, a distinction is made between domestic and international aviation, and it is *good practice* to report under the source categories listed in Table 3.6.1.

All emissions from fuels used for international aviation (bunkers) and multilateral operations pursuant to the Charter of UN are to be excluded from national totals, and reported separately as memo items.

3.6.1.1 CHOICE OF METHOD

Three methodological tiers for estimating emissions of CO_2, CH_4 and N_2O from aviation are presented. Tier 1 and Tier 2 methods use fuel consumption data. Tier 1 is purely fuel based, while Tier 2 method is based on the number of landing/take-off cycles (LTOs) and fuel use. Tier 3 uses movement[16] data for individual flights.

All tiers distinguish between domestic and international flights. However, energy statistics used in Tier 1 often do not accurately distinguish between domestic and international fuel use or between individual source categories, as defined in Table 3.6.1. Tiers 2 and 3 provide more accurate methodologies to make these distinctions.

The choice of methodology depends on the type of fuel, the data available, and the relative importance of aircraft emissions. For aviation gasoline, though country-specific emission factors may be available, the numbers of LTOs are generally not available. Therefore, Tier 1 and its default emission factors would probably be used for aviation gasoline. All tiers can be used for operations using jet fuel, as relevant emission factors are available for jet fuel. Table 3.6.2 summarizes the data requirements for the different tiers:

The decision tree shown in Figure 3.6.1 should help to select the appropriate method. The resource demand for the various tiers depends in part on the number of air traffic movements. Tier 1 should not be resource intensive. Tier 2, based on individual aircraft, and Tier 3A, based on Origin and Destination (OD) pairs, would use incrementally more resources. Tier 3B, which requires sophisticated modelling, requires the most resources.

Given the current limited knowledge of CH_4 and N_2O emission factors, more detailed methods will not significantly reduce uncertainties for CH_4 and N_2O emissions. However, if aviation is a *key category*, then it is recommended that Tier 2 or Tier 3 approaches are used, because higher tiers give better differentiation between domestic and international aviation, and will facilitate estimating the effects of changes in technologies (and therefore emission factors) in the future.

The estimates for the cruise phase become more accurate when using Tier 3A methodology or Tier 3B models. Moreover because Tier 3 methods use flight movement data instead of fuel use, they provide a more accurate separation between domestic and international flights. Data may be available from the operators of Tier 3 models (such as SAGE, (Kim, 2005a and b; Malwitz, 2005) and AERO2K (Eyers, 2004). Other methods for differentiating national and international fuel use such as considering LTOs, passenger-kilometer data, a percentage split based on flight timetables (e.g., OAG data, ICAO statistics for tonne-kilometres performed by countries) are shortcuts. The methods may be used if no other methods or data are available.

[16] Movement data refers to, at a minimum, information on the origin and destination, aircraft type, and date of individual flights.

TABLE 3.6.1
SOURCE CATEGORIES

Source category	Coverage
1 A 3 a Civil Aviation	Emissions from international and domestic civil aviation, including take-offs and landings. Comprises civil commercial use of airplanes, including: scheduled and charter traffic for passengers and freight, air taxiing, and general aviation. The international/domestic split should be determined on the basis of departure and landing locations for each flight stage and not by the nationality of the airline. Exclude use of fuel at airports for ground transport which is reported under 1 A 3 e Other Transportation. Also exclude fuel for stationary combustion at airports; report this information under the appropriate stationary combustion category.
1 A 3 a i International aviation (International Bunkers)	Emissions from flights that depart in one country and arrive in a different country. Include take-offs and landings for these flight stages. Emissions from international military aviation can be included as a separate sub-category of international aviation provided that the same definitional distinction is applied and data are available to support the definition.
1 A 3 a ii Domestic Aviation	Emissions from civil domestic passenger and freight traffic that departs and arrives in the same country (commercial, private, agriculture, etc.), including take-offs and landings for these flight stages. Note that this may include journeys of considerable length between two airports in a country (e.g. San Francisco to Honolulu). Exclude military, which should be reported under 1 A 5 b.
1 A 5 b Mobile *(aviation component)*	All remaining aviation mobile emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the country's military not otherwise included separately in 1 A3 a i as well as fuel delivered within that country but used by the militaries of other countries that are not engaged in multilateral operations.
1.A.5 c Multilateral Operations *(aviation component)*	Emissions from fuels used for aviation in multilateral operations pursuant to the Charter of the United Nations. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries.

TABLE 3.6.2
DATA REQUIREMENTS FOR DIFFERENT TIERS

Data, both Domestic and International	Tier 1	Tier 2	Tier 3A	Tier 3B
Aviation gasoline consumption	X			
Jet Fuel consumption	X	X		
Total LTO				
LTO by aircraft type		X		
Origin and Destination (OD) by aircraft type			X	
Full flight movements with aircraft and engine data				X

Other reasons for choosing to use a higher tier include estimation of emissions jointly with other pollutants (e.g. NO_x) and harmonisation of methods with other inventories. In Tier 2 (and higher) the emissions for the LTO and cruise phases are estimated separately, in order to harmonise with methods that were developed for air pollution programmes that cover only emissions below 914 meters (3000 feet). There may be significant discrepancies between the results of a bottom-up approach and a top-down fuel-based approach for aircraft. An example is presented in Daggett *et al*. (1999).

TIER 1 METHOD

The Tier 1 method is based on an aggregate quantity of fuel consumption data for aviation (LTO and cruise) multiplied by average emission factors. The methane emission factors have been averaged over all flying phases based on the assumption that 10 percent of the fuel is used in the LTO phase of the flight. Emissions are calculated according to Equation 3.6.1:

EQUATION 3.6.1
(AVIATION EQUATION 1)

$$Emissions = Fuel\ Consumption \bullet Emission\ Factor$$

Tier 1 method should be used to estimate emissions from aircraft that use aviation gasoline which is only used in small aircraft and generally represents less than 1 percent of fuel consumption from aviation. Tier 1 method is also used for jet-fuelled aviation activities when aircraft operational use data are not available.

Domestic and international emissions are to be estimated separately using the above equation, using one of the methods discussed in section 3.6.1.3 to allocate fuel between the two.

TIER 2 METHOD

Tier 2 method is only applicable for jet fuel use in jet aircraft engines. Operations of aircraft are divided into LTO and cruise phases. To use Tier 2 method, the number of LTO operations must be known for both domestic and international aviation, preferably by aircraft type. In Tier 2 method a distinction is made between emissions below and above 914 m (3000 feet); that is emissions generated during the LTO and cruise phases of flight.

Tier 2 method breaks the calculation of emissions from aviation into the following steps:

1. Estimate the domestic and international fuel consumption totals for aviation.
2. Estimate LTO fuel consumption for domestic and international operations.
3. Estimate the cruise fuel consumption for domestic and international aviation.
4. Estimate emissions from LTO and cruise phases for domestic and international aviation.

Tier 2 approach uses Equations 3.6.2 to 3.6.5 to estimate emissions:

EQUATION 3.6.2
(AVIATION EQUATION 2)

$$Total\ Emissions = LTO\ Emissions + Cruise\ Emissions$$

Where:

EQUATION 3.6.3
(AVIATION EQUATION 3)

$$LTO\ Emissions = Number\ of\ LTOs \bullet Emission\ Factor\ LTO$$

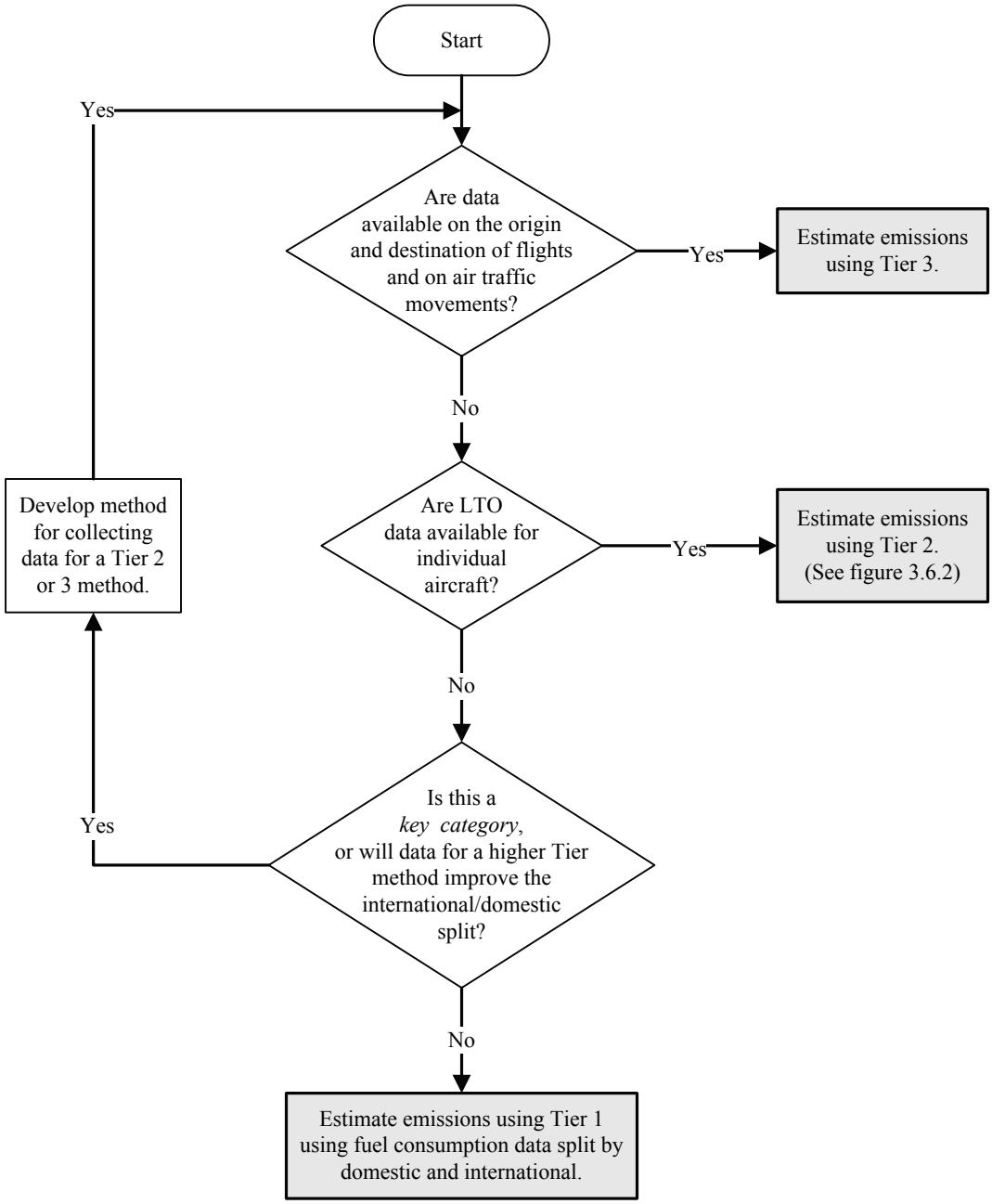
EQUATION 3.6.4
(AVIATION EQUATION 4)

$$LTO\ Fuel\ Consumption = Number\ of\ LTOs \bullet Fuel\ Consumption\ per\ LTO$$

EQUATION 3.6.5
(AVIATION EQUATION 5)

$$Cruise\ Emissions = (Total\ Fuel\ Consumption - LTO\ Fuel\ Consumption) \bullet Emission\ Factor\ Cruise$$

Figure 3.6.1 Decision tree for estimating aircraft emissions (applied to each greenhouse gas)



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.

The basis of the recommended Tier 2 methodology is presented schematically in Figure 3.6.2.

In Tier 2 method, the fuel used in the cruise phase is estimated as a residual: total fuel use minus fuel used in the LTO phase of the flight (Equation 3.6.5). Fuel use is estimated for domestic and international aviation separately. The estimated fuel use for cruise is multiplied by aggregate emission factors (average or per aircraft type) in order to estimate the CO_2 and NO_x cruise emissions.[17] Emissions and fuel used in the LTO phase are estimated from statistics on the number of LTOs (aggregate or per aircraft type) and default emission factors or fuel use factors per LTO cycle (average or per aircraft type).

[17] Current scientific understanding does not allow other gases (e.g., N_2O and CH_4) to be included in calculation of cruise emissions. (IPCC,1999).

Tier 2 method considers activity data at the level of individual aircraft types and therefore needs data on the number of domestic LTOs by aircraft type and international LTOs by aircraft type. The estimate should include all aircraft types frequently used for domestic and international aviation. Table 3.6.3 provides a way of mapping actual aircraft to representative aircraft types in the database. Cruise emission factors for emissions other than NO_x are not provided in Tier 2 method; either national emission factors or the tier default emission factors must be used to estimate these cruise emissions.

TIER 3 METHODS

Tier 3 methods are based on actual flight movement data, either: for Tier 3A origin and destination (OD) data or for Tier 3B full flight trajectory information. National Tier 3 approaches can be used if they are well documented and have been reviewed following the guidance provided in Volume 1, Chapter 6 (QA/QC). To facilitate data review, countries that use Tier 3 methodology could separately report emissions for Commercial Scheduled Aviation and Other Jet Fuelled Activities.

Tier 3A takes into account cruise emissions for different flight distances. Details on the origin (departure) and destination (arrival) airports and aircraft type are needed to use Tier 3A, for both domestic and international flights. In Tier 3A, inventories are modelled using average fuel consumption and emissions data for the LTO phase and various cruise phase lengths, for an array of representative aircraft categories.

The data used in Tier 3A methodology takes into account that the amount of emissions generated varies between phases of flight. The methodology also takes into account that fuel burn is related to flight distance, while recognizing that fuel burn can be comparably higher on relatively short distances than on longer routes. This is because aircraft use a higher amount of fuel per distance for the LTO cycle compared to the cruise phase.

The EMEP/CORINAIR Emission inventory guidebook (EEA 2002) provides an example of Tier 3A method for calculating emissions from aircraft. The EMEP/CORINAIR Emission inventory guidebook is continually being refined and is published electronically via the European Environment Agency Internet web site. EMEP/CORINAIR provides tables with emissions per flight distance.

(Note that there are three EMEP/CORINAIR methods for calculating aircraft emissions; but, only the Detailed CORINAIR Methodology equates to Tier 3A.)

Tier 3B methodology is distinguished from Tier 3A by the calculation of fuel burnt and emissions throughout the full trajectory of each flight segment using aircraft and engine-specific aerodynamic performance information. To use Tier 3B, sophisticated computer models are required to address all the equipment, performance and trajectory variables and calculations for all flights in a given year. Models used for Tier 3B level can generally specify output in terms of aircraft, engine, airport, region, and global totals, as well as by latitude, longitude, altitude and time, for fuel burn and emissions of CO, hydrocarbons (HC), CO_2, H_2O, NO_x, and SOx. To be used in preparing annual inventory submissions, Tier 3B model must calculate aircraft emissions from input data that take into account air-traffic changes, aircraft equipment changes, or any input-variable scenario. The components of Tier 3B models ideally are incorporated so that they can be readily updated, so that the models are dynamic and can remain current with evolving data and methodologies. Examples of models include the System for assessing Aviation's Global Emissions (SAGE), by the United States Federal Aviation Administration (Kim, 2005 a and b; Malwitz, 2005), and AERO2k, (Eyers, 2004), by the European Commission.

Figure 3.6.2 Estimating aircraft emissions with Tier 2 method

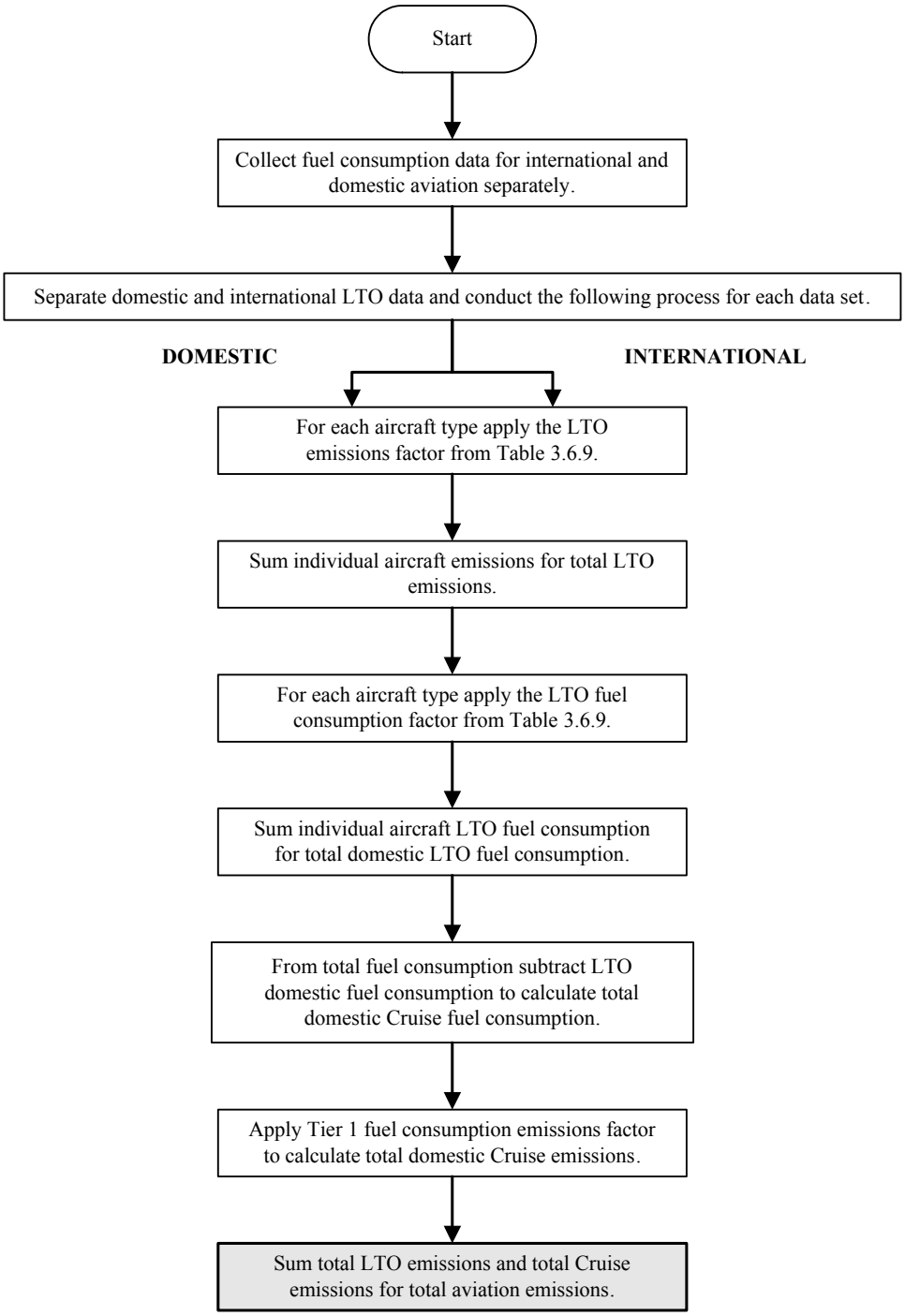


TABLE 3.6.3
CORRESPONDENCE BETWEEN REPRESENTATIVE AIRCRAFT AND OTHER AIRCRAFT TYPES

Generic aircraft type	ICAO	IATA aircraft in group
Airbus A300	A30B	AB3
	A306	AB4
		AB6
		ABF
		ABX
		ABY
Airbus A310	A310	310
		312
		313
		31F
		31X
		31Y
Airbus A319	A319	319
	A318	318
Airbus A320	A320	320
		32S
Airbus A321	A321	321
Airbus A330-200	A330	330
	A332	332
Airbus A330-300	A330	330
	A333	333
Airbus A340-200	A342	342
Airbus A340-300	A340	340
	A343	343
Airbus A340-500	A345	345
Airbus A340-600	A346	346
Boeing 707	B703	703
		707
		70F
		70M
Boeing 717	B712	717
Boeing 727-100	B721	721
		72M
Boeing 727-200	B722	722
		727
		72C
		72B
		72F
		72S
Boeing 737-100	B731	731
Boeing 737-200	B732	732
		73M
		73X
Boeing 737-300	B733	737
		73F
		733
		73Y
Boeing 737-400	B734	737
		734
Boeing 737-500	B735	737
		735
Boeing 737-600	B736	736
Boeing 737-700	B737	73G
		73W
Boeing 737-800	B738	738
		73H
Boeing 737-900	B739	739
Boeing 747-100	B741	74T
	N74S	74L
	B74R	74R
	B74R	74V
Boeing 747-200	B742	742
		74C
		74X
Boeing 747-300	B743	743
		74D
Boeing 747-400	B744	747
		744
		74E
		74F
		74J
		74M
		74Y
Boeing 757-200	B752	757
		75F
		75M
Boeing 757-300	B753	753
Boeing 767-200	B762	762
		76X
Boeing 767-300	B763	767
		76F
		763
		76Y
Boeing 767-400	B764	764
Boeing 777-200	B772	777
		772
Boeing 777-300	B773	773
Douglas DC-10	DC10	D10
		D11
		D1C
		D1F
		D1M
		D1X
		D1Y
Douglas DC-8	DC85	D8F
	DC86	D8L
	DC87	D8M
		D8Q
		D8T
		D8X
		D8Y
Douglas DC-9	DC9	DC9
	DC91	D91
	DC92	D92
	DC93	D93
	DC94	D94
	DC95	D95
		D9C
		D9F
		D9X
Lockheed L-1011	L101	L10
		L11
		L15
		L1F
McDonnell Douglas MD11	MD11	M11
		M1F
		M1M
McDonnell Douglas MD80	MD80	M80
	MD81	M81
	MD82	M82
	MD83	M83
	MD87	M87
	MD88	MD88
McDonnell Douglas MD90	MD90	M90
Tupolev Tu134	T134	TU3
Tupolev Tu154	T154	TU5
Avro RJ85	RJ85	AR8
		ARJ
BAe 146	B461	141
	B462	142
	B463	143
		146
		14F
		14X
		14Y
		14Z
Embraer ERJ145	E145	ER4
		ERJ
Fokker 100/70/28	F100	100
	F70	F70
	F28	F21
		F22
		F23
		F24
		F28
BAC 111	BA11	B11
		B12
		B13
		B14
		B15
Donier Do 328	D328	D38
Gulfstream IV/V		GRJ
Yakovlev Yak 42	YK42	YK2

3.6.1.2 CHOICE OF EMISSION FACTORS

TIER 1

Carbon dioxide emission factors are based on the fuel type and carbon content. National emission factors for CO_2 should not deviate much from the default values because the quality of jet fuel is well defined. It is *good practice* to use the default CO_2 emission factors in Table 3.6.4 for Tier 1 (see Chapter 1, Introduction, of this Volume and Table 1.4). National carbon content could be used if available. CO_2 should be estimated on the basis of the full carbon content of the fuel.

TABLE 3.6.4
CO_2 EMISSION FACTORS

Fuel	Default (kg/TJ)	Lower	Upper
Aviation Gasoline	70 000	67 500	73 000
Jet Kerosene	71 500	69 800	74 400

Default values for CH_4 and N_2O from aircraft are given in Table 3.6.5. Different types of aircraft/engine combinations have specific emission factors and these factors may also vary according to distance flown. Tier 1 assumes that all aircraft have the same emission factors for CH_4 and N_2O based on the rate of fuel consumption. This assumption has been made because more disaggregated emission factors are not available at this level of aggregation.

TABLE 3.6.5
NON-CO_2 EMISSION FACTORS

Fuel	CH_4 Default (Uncontrolled) Factors (in kg/TJ)	N_2O Default (Uncontrolled) Factors (in kg/TJ)	NO_X Default (Uncontrolled) Factors (in kg/TJ)
All fuels	0.5[a] (-57%/+100%)[b]	2 (-70%/+150%)[b]	250 ±25%[c]

[a] In the cruise mode CH_4 emissions are assumed to be negligible (Wiesen *et al.*, 1994). For LTO cycles only (i.e., below an altitude of 914 metres (3000 ft.)) the emission factor is 5 kg/TJ (10% of total VOC factor) (Olivier, 1991). Since globally about 10% of the total fuel is consumed in LTO cycles (Olivier, 1995), the resulting fleet averaged factor is 0.5 kg/TJ.

[b] IPCC, 1999.

[c] Expert Judgement.

Emission factors for other gases (CO and NMVOC) and sulphur content which were included in the 1996 IPCC Guidelines can be found in the EFDB.

TIER 2

For Tier 2 method, it is *good practice* to use emission factors from Table 3.6.9 (or updates reflected in the EFDB) for the LTO emissions. For cruise calculations only NO_x emissions can be computed directly based on specific emission factors (Table 3.6.10) and N_2O can be computed indirectly from NO_x emissions[18]. CO_2 cruise emissions are calculated using Tier 1 CO_2 emission factors (Table 3.6.4). The CH_4 emissions are negligible and are assumed to be zero unless new information becomes available. Note that there is limited information on the emission factors for CH_4 and N_2O from aircraft, and the default values provided in Table 3.6.5 are similar to values found in the literature.

TIER 3

Tier 3A emission factors may be found in the EMEP/CORINAIR emission inventory guidebook, while Tier 3B uses emissions factors contained within the models necessary to employ this methodology. Inventory compilers should check that these emission factors are in fact appropriate.

[18] Countries vary on the method to be used to convert NO_x emissions to N_2O

3.6.1.3 CHOICE OF ACTIVITY DATA

Since emissions from domestic aviation are reported separately from international aviation, it is necessary to disaggregate activity data between domestic and international components. For this purpose, the following definitions should be applied irrespective of the nationality of the carrier (Table 3.6.6). For consistency, it is *good practice* to use similar definitions of domestic and international activities for aviation and water-borne navigation. In some cases, the national energy statistics may not provide data consistent with this definition. It is *good practice* that countries separate the activity data consistent with this definition. In any case, a country must clearly define the methodologies and assumptions used.

TABLE 3.6.6
CRITERIA FOR DEFINING INTERNATIONAL OR DOMESTIC AVIATION (APPLIES TO INDIVIDUAL LEGS OF JOURNEYS WITH MORE THAN ONE TAKE-OFF AND LANDING)

Journey type between two airports	Domestic	International
Departs and arrives in same country	Yes	No
Departs from one country and arrives in another	No	Yes

Based on past experience compiling aviation emissions inventories, difficulties have been identified regarding the international/domestic split, in particular obtaining the information on passenger and freight drop-off and pick up at stops in the same country that was required by the *1996 IPCC Guidelines*/*GPG2000* (Summary report of ICAO/UNFCCC Expert Meeting April 2004). Most flight data are collected on the basis of individual flight segments (from one take-off to the next landing) and do not distinguish between different types of intermediate stops (as called for in *GPG2000*). Basing the distinction on flight segment data (origin/destination) is therefore simpler and is likely to reduce uncertainties. It is very unlikely that this change would make a significant change to the emission estimates.[19] This does not change the way in which emissions from international flights are reported as a memo item and not included in national totals.

Improvements in technology and optimization of airline operating practices have significantly reduced the need for intermediate technical stops. An intermediate technical stop would also not change the definition of a flight as being domestic or international. For example if explicit data is available, countries may define as international flight segments that depart one country with a destination in another country and make an intermediate technical stop. A technical stop is solely for the purpose of refuelling or solving a technical difficulty and not for the purpose of passenger or cargo exchange.

If national energy statistics do not already provide data consistent with this definition, countries should then estimate the split between domestic and international fuel consumption according to the definition, using the approaches set out below.

Top-down data can be obtained from taxation authorities in cases where fuel sold for domestic use is subject to taxation, but that for international use is not taxed. Airports or fuel suppliers may have data on delivery of aviation kerosene and aviation gasoline to domestic and to international flights. In most countries tax and custom dues are levied on fuels for domestic consumption, and fuels for international consumption (bunkers) are free of such dues. In the absence of more direct sources of data, information about domestic taxes may be used to distinguish between domestic and international fuel consumption.

Bottom-up data can be obtained from surveys of airline companies for fuel used on domestic and international flights, or estimates from aircraft movement data and standard tables of fuel consumed or both. Fuel consumption factors for aircraft (fuel used per LTO and per nautical mile cruised) can be used for estimates and may be obtained from the airline companies.

Examples of sources for bottom-up data, including aircraft movement, are:

- Statistical offices or transport ministries as a part of national statistics;
- Airport records;
- ATC (Air Traffic Control) records, for example EUROCONTROL statistics;

[19] It is *good practice* to clearly state the reasoning and justification if any country opts to use the *GPG2000* definitions.

- Air carrier schedules published monthly by OAG which contains worldwide timetable passenger and freight aircraft movements as well as regular scheduled departures of charter operators. It does not contain ad-hoc charter aircraft movements;

Some of these sources do not cover all flights (e.g. charter flights may be excluded). On the other hand, airline timetable data may include duplicate flights due to codeshares between airlines or duplicate flight numbers. Methods have been developed to detect and remove these duplicates. (Baughcum *et al*., 1996; Sutkus *et al*., 2001).

The aircraft types listed in Table 3.6.9, LTO Emission Factors were defined based on the assumptions listed below. Aircraft were divided into four major groups to reflect and note the distinct data source for each group:

Large Commercial Aircraft: This includes aircraft that reflect the 2004 operating fleet and some aircraft types for back compatibility, identified by minor model. It was felt that this method would most accurately reflect operational fleet emissions. To minimize table size, some aircraft minor models were grouped when LTO emissions factors were similar. The Large Commercial Aircraft group LTO emissions factors data source is the ICAO Engine Exhaust Emissions Data Bank (ICAO, 2004a).

Regional Jets: This group includes aircraft that are representative of the 2004 operating Regional Jet (RJ) fleet. Representative RJ aircraft were selected based on providing an appropriate range of RJ aircraft with LTO emissions factors available. The RJ group LTO emissions factors data source is the ICAO Engine Exhaust Emissions Data Bank (ICAO, 2004a).

Low Thrust Jets: In some countries, aircraft in the low thrust category (engines with thrust below 26.7 kN) make up a non-trivial number of movements and therefore should be included in inventories. However, aircraft engines in this group are not required to satisfy ICAO engine emissions standards, thus LTO emissions factors data are not included in the ICAO Engine Exhaust Emissions Data Bank and difficult to provide. Therefore, there is one representative aircraft with typical emissions for aircraft in this group. The Low Thrust Jets group LTO emissions factors data source is the FAA's Emissions and Dispersion Modelling System (EDMS) (FAA 2004b).

Turboprops: This group includes aircraft that are representative of the 2004 Turboprop fleet, which can be represented by three typical aircraft size based on engine shaft horsepower. The Turboprop group LTO emissions factors data source is the Swedish Aeronautical Institute (FOI) LTO Emissions Database.

Similar data could be obtained from other sources (e.g. EEA, 2002). The equivalent data for turboprop and piston engine aircraft need to be obtained from other sources. The relationship between actual aircraft and representative aircraft are provided in the Table 3.6.3.

Aircraft Fleet data may be obtained from various sources. ICAO collects fleet data through two of its statistics sub-programmes: the fleet of commercial air carriers, reported by States for their commercial air carriers, and civil aircraft on register, reported by States for the civil aircraft on their register at 31 December (ICAO 2004b).

Some ICAO States do not participate in this data collection, in part because of the difficulty to split the fleet into commercial and non-commercial entities. Because of this, ICAO also makes use of other external sources. One of these sources is the International Register of Civil Aircraft, 2004, published by the Bureau Veritas (France), the CAA (UK) and ENAC (Italy) in cooperation with ICAO. This database contains the information from the civil aircraft registers of some 45 States (including the United States) covering over 450 000 aircraft.

In addition to the above, there are commercial databases of which ICAO also makes use. None of them cover the whole fleet as they have limitations in scope and aircraft size. Among these one can find the BACK Aviation Solutions Fleet Data (fixed wing aircraft over 30 seats), AirClaims CASE database (fixed wing jet and turboprop commercial aircraft), BUCHAir, publishers of the JP Airline Fleet (covers both fixed and rotary wing aircraft). Other companies such as AvSoft may also have relevant information. Further information may be obtained from these companies' websites.

3.6.1.4 MILITARY AVIATION

Military activity is defined here as those activities using fuel purchased by or supplied to the military authorities of the country. Emissions from aviation fuel use can be estimated using equation 3.6.1 and the same calculations approach recommended for civilian aviation. Some types of military transport aircraft and helicopters have fuel and emissions characteristics similar to civil types. Therefore default emission factors for civil aircraft should be used for military aviation unless better data are available. Alternatively, fuel use may be estimated from the hours in operation. Default fuel consumption factors for military aircraft are given in Tables 3.6.7 and 3.6.8. For fuel use factors see Section 3.6.1.3 'Choice of activity data'.

TABLE 3.6.7
FUEL CONSUMPTION FACTORS FOR MILITARY AIRCRAFT

Group	Sub- group	Representative type	Fuel flow(kg/hour)
Combat	Fast Jet – High Thrust	F16	3 283
	Fast Jet – Low Thrust	Tiger F-5E	2 100
Trainer	Jet trainers	Hawk	720
	Turboprop trainers	PC-7	120
Tanker/transport	Large tanker/ transport	C-130	2 225
	Small Transport	ATP	499
Other	MPAs Maritime Patrol	C-130	2 225

Sources: Tables 3.1 and 3.2 of Gardner *et. al* 1998 USEPA, 2005)

TABLE 3.6.8
FUEL CONSUMPTION PER FLIGHT HOUR FOR MILITARY AIRCRAFT

AIRCRAFT TYPE	Aircraft Description	FUEL USE (LITRES PER HOUR)
A-10A	Twin engine light bomber	2 331
B-1B	Four engine long-range strategic bomber. Used by USA only	13 959
B-52H	Eight engine long-range strategic bomber. Used by USA only.	12 833
C-12J	Twin turboprop light transport. Beech King Air variant.	398
C-130E	Four turboprop transport. Used by many countries.	2 956
C-141B	Four engine long-range transport. Used by USA only	7 849
C-5B	Four engine long-range heavy transport. Used by USA only	13 473
C-9C	Twin engine transport. Military variant of DC-9.	3 745
E-4B	Four engine transport. Military variant of Boeing 747.	17 339
F-15D	Twin engine fighter.	5 825
F-15E	Twin engine fighter-bomber	6 951
F-16C	Single engine fighter. Used by many countries.	3 252
KC-10A	Three engine tanker. Military variant of DC-10	10 002
KC-135E	Four engine tanker. Military variant of Boeing 707.	7 134
KC-135R	Four engine tanker with newer engines. Boeing 707 variant.	6 064
T-37B	Twin engine jet trainer.	694
T-38A	Twin engine jet trainer. Similar to F-5.	262

Military aircraft (transport planes, helicopters and fighters) may not have a civilian analogue, so a more detailed method of data analysis is encouraged where data are available. Inventory compilers should consult military experts to determine the most appropriate emission factors for the country's military aviation.

Due to confidentiality issues (see completeness and reporting), many inventory compilers may have difficulty obtaining data for the quantity of fuel used by the military. Military activity is defined here as those activities using fuel purchased by or supplied to the military authorities in the country. Countries can apply the rules defining civilian, national and international aviation operations to military operations when the data necessary to apply those rules are comparable and available. In this case, the international military emissions may be reported under International Aviation (International Bunkers), but must then be shown separately. Data on military fuel

use should be obtained from government military institutions or fuel suppliers. If data on fuel split are unavailable, all the fuel sold for military activities should be treated as domestic.

Emissions resulting from multilateral operations pursuant to the Charter of the United Nations should not be included in national totals; other emissions related to operations shall be included in the national emissions totals of one or more Parties involved. The national calculations should take into account fuel delivered to the country's military, as well as fuel delivered within that country but used by the military of other countries. Other emissions related to operations (e.g., off-road ground support equipment) shall be included in the national emissions totals in the appropriate source category.

These data should be used with care as national circumstances may vary from those assumed in this table. In particular, distances travelled and fuel consumption may be affected by national route structures, airport congestion and air traffic control practices.

3.6.1.5 COMPLETENESS

Regardless of method, it is important to account for all fuel used for aviation in the country. The methods are based on total fuel use, and should completely cover CO_2 emissions. However, the allocation between LTO and cruise will not be complete for Tier 2 method if the LTO statistics are not complete. Also, Tier 2 method focuses on passenger and freight carrying scheduled and charter flights, and thus not all aviation. In addition, Tier 2 method does not automatically include non-scheduled flights and general aviation such as agricultural airplanes, private jets or helicopters, which should be added if the quantity of fuel is significant. Completeness may also be an issue where military data are confidential; in this situation it is *good practice* to aggregate military fuel use with another source category.

Other aviation-related activities that generate emissions include: fuelling and fuel handling in general, maintenance of aircraft engines and fuel jettisoning to avoid accidents. Also, in the wintertime, anti-ice and de-ice treatment of wings and aircraft is a source of emissions at airport complexes. Many of the materials used in these treatments flow off the wings when planes are idling, taxiing, and taking off, and then evaporate. These emissions are, however, very minor and specific methods to estimate them are not included.

There are additional challenges in distinguishing between domestic and international emissions. As each country's data sources are unique for this category, it is not possible to formulate a general rule regarding how to make an assignment in the absence of clear data. It is *good practice* to specify clearly the assumptions made so that the issue of completeness can be evaluated.

3.6.1.6 DEVELOPING A CONSISTENT TIME SERIES

Volume 1 Chapter 5: Time Series Consistency and Recalculation of the *2006 IPCC Guidelines* provides more information on how to develop emission estimates in cases where the same data sets or methods cannot be used during every year of the time series. If activity data are unavailable for the base year (e.g. 1990) an option may be to extrapolate data to this year by using changes in freight and passenger kilometres, total fuel used or supplied, or the number of LTOs (aircraft movements).

Emissions trends of CH_4 and NO_x (and by inference N_2O) will depend on aircraft engine technology and the change in composition of a country's fleet. This change in fleet composition may have to be accounted for in the future, and this is best accomplished using Tier 2 and Tier 3B methods based on individual aircraft types for 1990 and subsequent years. If fleet composition is not changing, the same set of emission factors should be used for all years.

Every method should be able to reflect accurately the results of mitigation options that lead to changes in fuel use. However, only Tier 2 and 3B methods, based on individual aircraft, can capture the effect of mitigation options that result in lower emission factors.

Tier 2 has been revised to account for NO_x emissions in the climb phase, which are substantially different from those in cruise, and the differences in the amount of NO_x calculated during that phase could be in the range of approximately 15 to 20 percent, due to the thrust/power required in that phase, and its relation with the higher production of NO_x. Special care should be taken to develop a consistent time series if Tier 2 is used.

3.6.1.7 UNCERTAINTY ASSESSMENT

EMISSION FACTORS

The CO_2 emission factors should be within a range of ±5 percent, as they are dependent only on the carbon content of the fuel and fraction oxidised. However, considerable uncertainty is inherent in the computation of CO_2 based on the uncertainties in activity data discussed below. For Tier 1, the uncertainty of the CH_4 emission factor may range between -57 and +100 percent. The uncertainty of the N_2O emission factor may range between -70 and +150 percent Moreover, CH_4 and N_2O emission factors vary with technology and using a single emission factor for aviation in general is a considerable simplification.

Information to assist in computing uncertainties associated with LTO emission factors found in Table 3.6.9 can be found in Lister and Norman, 2003; and ICAO, 1993. Information to assist in computing the uncertainties associated with cruise emission factors found in Table 3.6.10 data can be found in: Baughcum *et al,* 1996. Sutkus, *et al,* 2001; Eyers *et al,* 2004; Kim, 2005 a and b; Malwitz, 2005. If resources are not available to compute uncertainties, uncertainty bands can be used as defined as default factors in Section 3.6.1.2.

Special attention should be taken with the cruise NO_x emission factors for Tier 2 found in Table 3.6.10. These emission factors, have been updated from the 1996 Guidelines to reflect the fact that climb phase emissions are substantially different from those in cruise. The calculation of the NO_x emission factors is based on two sets of data, one from 1 km to 9 km, and the second from 9 km to 13 km., and the differences in the amount of NO_x calculated during that phase could be in the range of approximately 15 to 20 percent, due to the thrust/power required in that phase, and its relation with the higher production of NO_x. If Tier 2 is used, care should be taken to report a consistent time series (see Section 3.6.1.6 and Volume 1, Chapter 5).

ACTIVITY DATA

The uncertainty in the reporting will be strongly influenced by the accuracy of the data collected on domestic aviation separately from international aviation. With complete survey data, the uncertainty may be very low (less than 5 percent) while for estimates or incomplete surveys the uncertainties may become large, perhaps a factor of two for the domestic share. The uncertainty ranges cited represent an informal polling of experts aiming to approximate the 95 percent confidence interval around the central estimate. The uncertainty will vary widely from country to country and is difficult to generalise. The use of global data sets, supported by radar, may be helpful in this area, and it is expected that reporting will improve for this category in the future.

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

It is *good practice* to conduct quality control checks as outlined in Chapter 6 of Volume 1 (Quality Assurance/ Quality Control and Verification), Tier 1 General Inventory Level QC Procedures. It is *good practice* to conduct expert review of the emission estimates when using Tier 2 or 3 methods. Additional quality control checks as outlined in Tier 2 procedures in the same chapter 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 Chapter 4 of Volume I.

Specific procedures relevant to this source category are outlined below.

Comparison of emissions using alternative approaches

If higher tier approaches are used, the inventory compiler should compare inventories to estimates with lower tiers. Any anomaly between the emission estimates should be investigated and explained. The results of such comparisons should be recorded for internal documentation.

Review of Emission factors

If national factors are used rather than the default values, directly reference the QC review associated with the publication of the emission factors, and include this review in the QA/QC documentation to ensure that the procedures are consistent with *good practice*. If possible, the inventory compiler should compare the IPCC default values to national factors to provide further indication that the factors are applicable. If emissions from military use were developed using data other than the default factors, the accuracy of the calculations and the applicability and relevance of the data should be checked.

TABLE 3.6.9
LTO EMISSION FACTORS FOR TYPICAL AIRCRAFT

	AIRCRAFT	LTO emissions factors (kg/LTO/) ([12])							LTO FUEL CONSUMPTION (Kg/LTO)
		CO_2[11]	CH_4[8]	N_2O[9]	NO_x	CO	NMVOC[8]	SO_2[10]	
Large Commercial Aircraft [1] [2]	A300	5450	0.12	0.2	25.86	14.80	1.12	1.72	1720
	A310	4760	0.63	0.2	19.46	28.30	5.67	1.51	1510
	A319	2310	0.06	0.1	8.73	6.35	0.54	0.73	730
	A320	2440	0.06	0.1	9.01	6.19	0.51	0.77	770
	A321	3020	0.14	0.1	16.72	7.55	1.27	0.96	960
	A330-200/300	7050	0.13	0.2	35.57	16.20	1.15	2.23	2230
	A340-200	5890	0.42	0.2	28.31	26.19	3.78	1.86	1860
	A340-300	6380	0.39	0.2	34.81	25.23	3.51	2.02	2020
	A340-500/600	10660	0.01	0.3	64.45	15.31	0.13	3.37	3370
	707	5890	9.75	0.2	10.96	92.37	87.71	1.86	1860
	717	2140	0.01	0.1	6.68	6.78	0.05	0.68	680
	727-100	3970	0.69	0.1	9.23	24.44	6.25	1.26	1260
	727-200	4610	0.81	0.1	11.97	27.16	7.32	1.46	1460
	737-100/200	2740	0.45	0.1	6.74	16.04	4.06	0.87	870
	737-300/400/500	2480	0.08	0.1	7.19	13.03	0.75	0.78	780
	737-600	2280	0.10	0.1	7.66	8.65	0.91	0.72	720
	737-700	2460	0.09	0.1	9.12	8.00	0.78	0.78	780
	737-800/900	2780	0.07	0.1	12.30	7.07	0.65	0.88	880
	747-100	10140	4.84	0.3	49.17	114.59	43.59	3.21	3210
	747-200	11370	1.82	0.4	49.52	79.78	16.41	3.60	3600
	747-300	11080	0.27	0.4	65.00	17.84	2.46	3.51	3510
	747-400	10240	0.22	0.3	42.88	26.72	2.02	3.24	3240
	757-200	4320	0.02	0.1	23.43	8.08	0.20	1.37	1370
	757-300	4630	0.01	0.1	17.85	11.62	0.10	1.46	1460
	767-200	4620	0.33	0.1	23.76	14.80	2.99	1.46	1460
	767-300	5610	0.12	0.2	28.19	14.47	1.07	1.77	1780
	767-400	5520	0.10	0.2	24.80	12.37	0.88	1.75	1750
	777-200/300	8100	0.07	0.3	52.81	12.76	0.59	2.56	2560
	DC-10	7290	0.24	0.2	35.65	20.59	2.13	2.31	2310
	DC-8-50/60/70	5360	0.15	0.2	15.62	26.31	1.36	1.70	1700
	DC-9	2650	0.46	0.1	6.16	16.29	4.17	0.84	840
	L-1011	7300	7.40	0.2	31.64	103.33	66.56	2.31	2310

TABLE 3.6.9 (CONTINUED)
LTO EMISSION FACTORS FOR TYPICAL AIRCRAFT

	AIRCRAFT	LTO emissions factors (kg/LTO/) (12)							LTO FUEL CONSUMPTION (KG/LTO)
		CO_2(11)	CH_4(8)	N_2O(9)	NO_x	CO	NMVOC(8)	SO_2(10)	
	MD-11	7290	0.24	0.2	35.65	20.59	2.13	2.31	2310
	MD-80	3180	0.19	0.1	11.97	6.46	1.69	1.01	1010
	MD-90	2760	0.01	0.1	10.76	5.53	0.06	0.87	870
	TU-134	2930	1.80	0.1	8.68	27.98	16.19	0.93	930
	TU-154-M	5960	1.32	0.2	12.00	82.88	11.85	1.89	1890
	TU-154-B	7030	11.90	0.2	14.33	143.05	107.13	2.22	2230
Regional Jets	RJ-RJ85	1910	0.13	0.1	4.34	11.21	1.21	0.60	600
	BAE 146	1800	0.14	0.1	4.07	11.18	1.27	0.57	570
	CRJ-100ER	1060	0.06	0.03	2.27	6.70	0.56	0.33	330
	ERJ-145	990	0.06	0.03	2.69	6.18	0.50	0.31	310
	Fokker 100/70/28	2390	0.14	0.1	5.75	13.84	1.29	0.76	760
	BAC111	2520	0.15	0.1	7.40	13.07	1.36	0.80	800
	Dornier 328 Jet	870	0.06	0.03	2.99	5.35	0.52	0.27	280
	Gulfstream IV	2160	0.14	0.1	5.63	8.88	1.23	0.68	680
	Gulfstream V	1890	0.03	0.1	5.58	8.42	0.28	0.60	600
	Yak-42M	2880	0.25	0.1	10.66	10.22	2.27	0.91	910
Low Thrust Jets (3) (Fn < 26.7 kN)	Cessna 525/560	1070	0.33	0.03	0.74	34.07	3.01	0.34	340
Turboprops4)	Beech King Air (5)	230	0.06	0.01	0.30	2.97	0.58	0.07	70
	DHC8-100 (6)	640	0.00	0.02	1.51	2.24	0.00	0.20	200
	ATR72-500 (7)	620	0.03	0.02	1.82	2.33	0.26	0.20	200

Notes:

(1) ICAO Engine Exhaust Emissions Data Bank (ICAO, 2004) based on average measured data. Emissions factors apply to LTO (Landing and Take off) only.

(2) Engine types for each aircraft were selected on a consistent basis of the engine with the most LTOs. This approach, for some engine types, may underestimate (or overestimate) fleet emissions which are not directly related to fuel consumption (eg NO_x, CO, HC).

(3) Emissions and Dispersion Modelling System (EDMS) (FAA 2004b)

(4) FOI (The Swedish Defence Research Agency) Turboprop LTO Emissions database

(5) Representative of Turboprop aircraft with shaft horsepower of up to 1000 shp/engine

(6) Representative of Turboprop aircraft with shaft horsepower of 1000 to 2000 shp/engine

(7) Representative of Turboprop aircraft with shaft horsepower of more than 2000 shp/engine

(8) Assuming 10% of total VOC emissions in LTO cycles are methane emissions (Olivier, 1991) (as in the *1996 IPCC Guidelines*).

(9) Estimates based on Tier I default values (EF ID 11053) (as in the *1996 IPCC Guidelines*).

(10) The sulphur content of the fuel is assumed to be 0.05% (as in the *1996 IPCC Guidelines*).

(11) CO_2 for each aircraft based on 3.16 kg CO_2 produced for each kg fuel used, then rounded to the nearest 10 kg.

(12) Information regarding the uncertainties associated with this data can be found in: Lister and Norman, 2003; ICAO, 1993.

Table prepared in 2005 updates will be available in the Emission Factor Data Base.

TABLE 3.6.10
NO_X EMISSION FACTORS FOR VARIOUS AIRCRAFT AT CRUISE LEVELS

	Aircraft	NO_x Emission Factor (g/kg) [(1) (5)]
Large Commercial Aircraft	A300	14.8
	A310	12.2
	A319	11.6
	A320	12.9
	A321	16.1
	A330-200/300	13.8
	A340-200	14.5
	A340-300	14.6
	A340-500/600	13.0 [(2)]
	707	5.9
	717	11.5 [(3)]
	727-100	8.7
	727-200	9.5
	737-100/200	8.7
	737-300/400/500	11.0
	737-600	12.8
	737-700	12.4
	737-800/900	14.0
	747-100	15.5
	747-200	12.8
	747-300	15.2
	747-400	12.4
	757-200	11.8
	757-300	9.8 [(3)]
	767-200	13.3
	767-300	14.3
	767-400	13.7 [(3)]
	777-200/300	14.1
	DC-10	13.9
	DC-8-50/60/70	10.8
	DC-9	9.1
	L-1011	15.7
	MD-11	13.2
	MD-80	12.4
	MD-90	14.2
	TU-134	8.5
	TU-154-M	9.1
	TU-154-B	9.1
Regional Jets	RJ-RJ85	15.6
	BAE 146	8.4
	CRJ-100ER	8.0
	ERJ-145	7.9
	Fokker 100/70/28	8.4
	BAC111	12.0
	Dornier 328 Jet	14.8 [(2)]
	Gulfstream IV	8.0 [(2)]
	Gulfstream V	9.5 [(2)]
	Yak-42M	15.6 [(4)]
Low Thrust Jets (Fn < 26.7 kN)	Cessna 525/560	7.2 [(4)]
Turboprops	Beech King Air	8.5
	DHC8-100	12.8
	ATR72-500	14.2

Notes:

(1) Sutkus *et al* 2001, Unless otherwise noted.

(2) Data from SAGE model Kim, 2005 a and b; Malwitz, 2005

(3) Sutkus, Baughcum, DuBois, 2003

(4) Average of the data from SAGE (Kim, 2005 a and b; Malwitz, 2005) and AERO2k (Eyers *et al*, 2004)

(5) Information to assist in computing uncertainties can be found in: Baughcum *et al*, 1996; Sutkus, *et al*, 2001; Eyers *et al*, 2004; Kim, 2005 a and b; Malwitz, 2005.

Activity data check

The source of the activity data should be reviewed to ensure applicability and relevance to the source category. Where possible, the inventory compiler should compare current data to historical activity data or model outputs to look for anomalies. In preparing the inventory estimates, the inventory compiler should ensure the reliability of the activity data used to differentiate emissions between domestic and international aviation.

Data can be checked with productivity indicators such as fuel per unit of traffic performance (per passenger km or ton km). Where data from different countries are being compared, the band of data should be small. The European Environmental Agency provides a useful dataset[20] which presents emissions and passenger/freight volume for each transportation mode for Europe. For example, Norway estimates that for domestic aviation, emissions are 0.22 kg CO_2/passenger-km. However, note that the global fleet includes many small aircraft with relatively low energy efficiency. The U.S. Department of Transportation estimates an average energy intensity for the U.S. fleet of 3666 Btu/passenger mile (2403 kJ/passenger km). The International Air Transport Association estimates that the average aircraft consumes 3.5 litres of jet fuel per 100 passenger-km (67 passenger miles per U.S. gallon).

Reliance on scheduled operations for activity data may introduce higher uncertainties than simple reliance on fuel use for CO_2. However, fuel loss and use of jet fuel for other activities will result in over estimates of aviation's contributions.

External review

The inventory compiler should perform an independent, objective review of calculations, assumptions or documentation of the emissions inventory to assess the effectiveness of the QC programme. The review should be performed by expert(s) (e.g. aviation authorities, airline companies, and military staff) who are familiar with the source category and who understand inventory requirements.

3.6.3 Reporting and Documentation

It is *good practice* to document and archive all information required to produce the national emissions inventory estimates as outlined in Chapter 8 of Volume 1 of the *2006 IPCC Guidelines*. Some examples of specific documentation and reporting relevant to this source category are provided below.

Inventory compilers are required to report emissions from international aviation separately from domestic aviation, and exclude international aviation from national totals. It is expected that all countries have aviation activity and should therefore report emissions from this category. Though countries covering small areas might not have domestic aviation, emissions from international aviation should be reported. Inventory compilers should explain how the definition for international and domestic in the guidelines has been applied.

Transparency would be improved if inventory compilers provide data on emissions from LTO separately from cruise operations. Emissions from military aviation should be clearly specified, so as to improve the transparency on national greenhouse gas inventories. In addition to the numerical information reported in the standard tables, provision of the following data would increase transparency:

- Sources of fuel data and other essential data (e.g. fuel consumption factors) depending on the method used;
- The number of flight movements split between domestic and international;
- Emission factors used, if different from default values. Data sources should be referenced.
- If Tier 3 method is used, emissions data could be provided separately for Commercial Scheduled Aviation and Other Jet Fuelled Activities.

Confidentiality may be a problem if only one or two airline companies operate domestic transport in a given country. Confidentiality may also be a problem for reporting military aviation in a transparent manner.

3.6.4 Reporting tables and worksheets

The four pages of the worksheets (Annex 1) for the Tier 1 Sectoral Approach are to be filled in for each of the source categories in Table 3.6.1. The reporting tables are available in Volume 1, Chapter 8.

[20] See http://air-climate.eionet.eu.int/databases/TRENDS/TRENDS_EU15_data_Sep03.xls

3.6.5 Definitions of specialist terms

Aviation Gasoline - A fuel used only in small piston engine aircraft, and which generally represents less than 1% of fuel used in aviation

Climb – The part of a flight of an aircraft, after take off and above 914 meters (3000 feet) above ground level, consisting of getting an aircraft to the desired cruising altitude.

Commercial scheduled – All commercial aircraft operations that have publicly available schedules (e.g., the Official Airline Guide, OAG 2006), which would primarily include passenger services. Activities that do not operate with publicly available schedules are not included in this definition, such as non-scheduled cargo, charter, air-taxi and emergency response operations. Note: *Commercial Scheduled Aviation* is used as a subset of jet fuel powered aviation operations.

Cruise – All aircraft activities that take place at altitudes above 914 meters (3000 feet), including any additional climb or descent operations above this altitude. No upper limit is given.

Gas Turbine Engines – Rotary engines that extract energy from a flow of combustion gas. Energy is added to the gas stream in the combustor, where air is mixed with fuel and ignited. Combustion increases the temperature and volume of the gas flow. This is directed through a nozzle over a turbine's blades, spinning the turbine and powering a compressor. For an aircraft, energy is extracted either in the form of thrust or through a turbine driving a fan or propeller.

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CHAPTER 4

FUGITIVE EMISSIONS

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4 FUGITIVE EMISSIONS

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

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

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.

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:

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

- Post-mining emissions
- Low temperature oxidation

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

- 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.

4.1.1.2 SUMMARY OF SOURCES

The major sources are summarised in Table 4.1.1 below.

TABLE 4.1.1
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 1a	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 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. CO_2 emissions 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.

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 global 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

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

$$\textit{Greenhouse gas emissions} = \textit{Raw coal production} \bullet \textit{Emission Factor} \bullet \textit{Units conversion factor}$$

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 the *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
ESTIMATING EMISSIONS FROM UNDERGROUND COAL MINES FOR TIER 1 AND TIER 2 WITH ADJUSTMENT FOR METHANE UTILISATION OR FLARING

$$CH_4 \text{ emissions from underground mining activities} = \text{Emissions from underground mining } CH_4 + \text{Post-mining emission of } CH_4 - CH_4 \text{ recovered and utilized for energy production or flared}$$

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

Figure 4.1.1 shows the decision tree 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 Figure 4.1.1).

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.

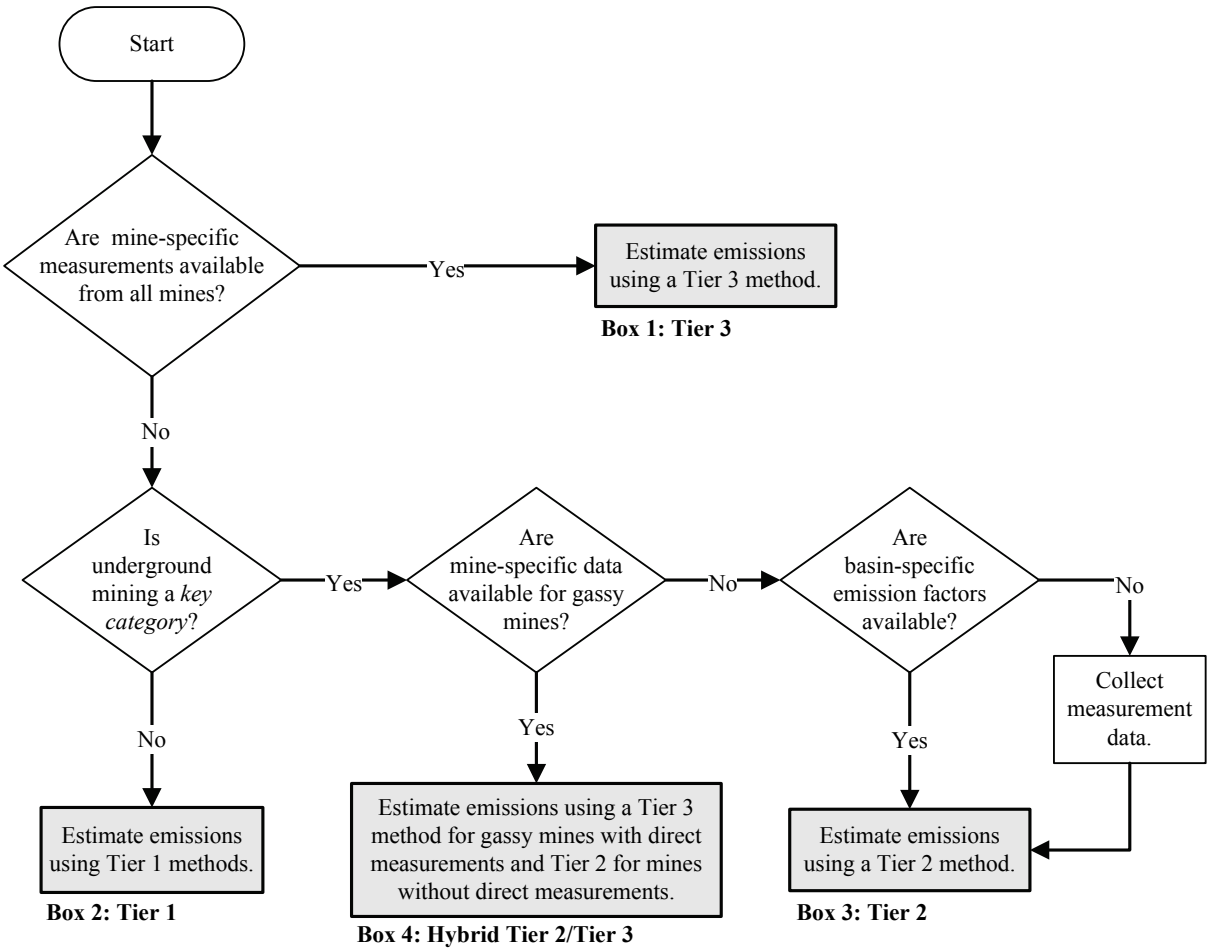
LOW TEMPERATURE OXIDATION

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. Where there are significant emissions of CO_2 in addition to methane in the seam gas, these should be reported on a mine-specific basis.

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 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

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 – 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).

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 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 gas distribution system and used as natural gas, the *fugitive* emissions 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

$$\text{(a)Emissions of } CO_2 \text{ from } CH_4 \text{ combustion} = 0.98 \bullet \text{Volume of methane flared} \bullet \text{Conversion Factor} \bullet \text{Stoichiometric Mass Factor}$$

$$\text{(a)Emissions of unburnt methane} = 0.02 \bullet \text{Volume of methane flared} \bullet \text{Conversion Factor}$$

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 $0.67 \bullet 10^{-6}$ 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

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
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)

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

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

EQUATION 4.1.6
GENERAL EQUATION FOR ESTIMATING FUGITIVE EMISSIONS FROM SURFACE COAL MINING

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

4.1.4.1 CHOICE OF METHOD

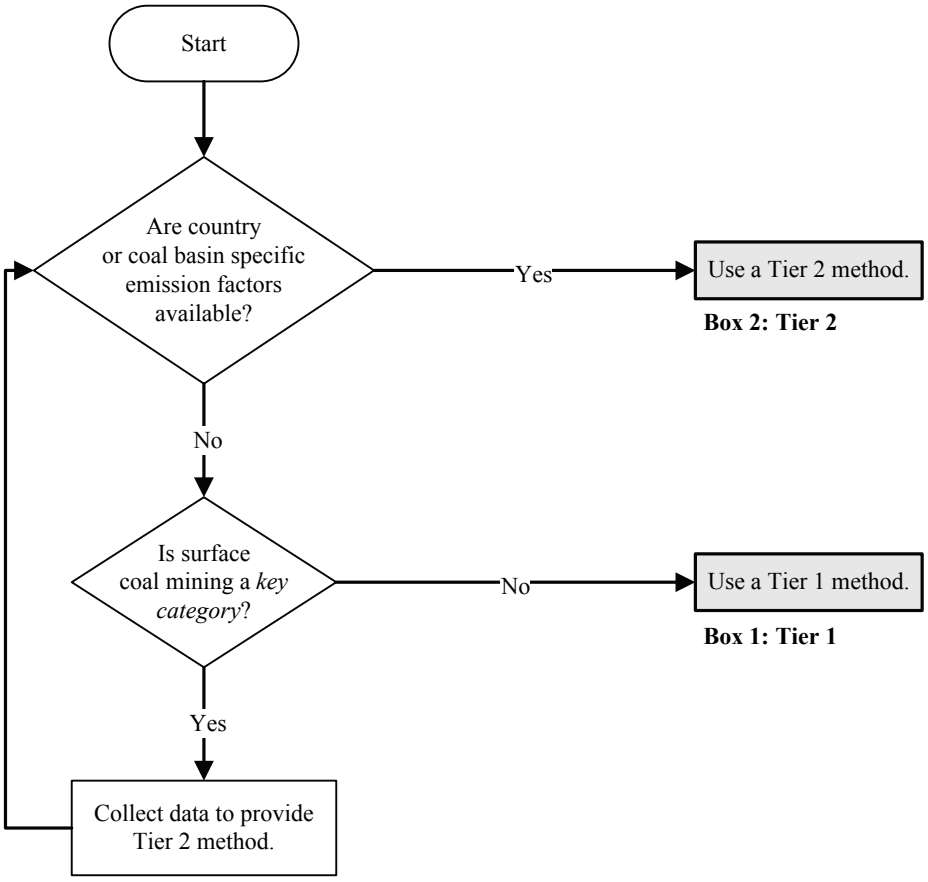
It is not yet feasible to collect mine-specific Tier 3 measurement data for surface mines. The alternative is to collect data on surface mine coal production and use emission factors. For countries with significant coal production and multiple coal basins, disaggregation of data and emission factors 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 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 emission factors are shown together with the estimation method in Equation 4.1.7.

EQUATION 4.1.7
TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES

$$\textit{Methane emissions} = \textit{CH}_4\ \textit{Emission Factor} \bullet \textit{Surface Coal Production} \bullet \textit{Conversion Factor}$$

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_4Emission 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 the coal basin level.

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

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
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)		

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

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

Where units are:

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

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

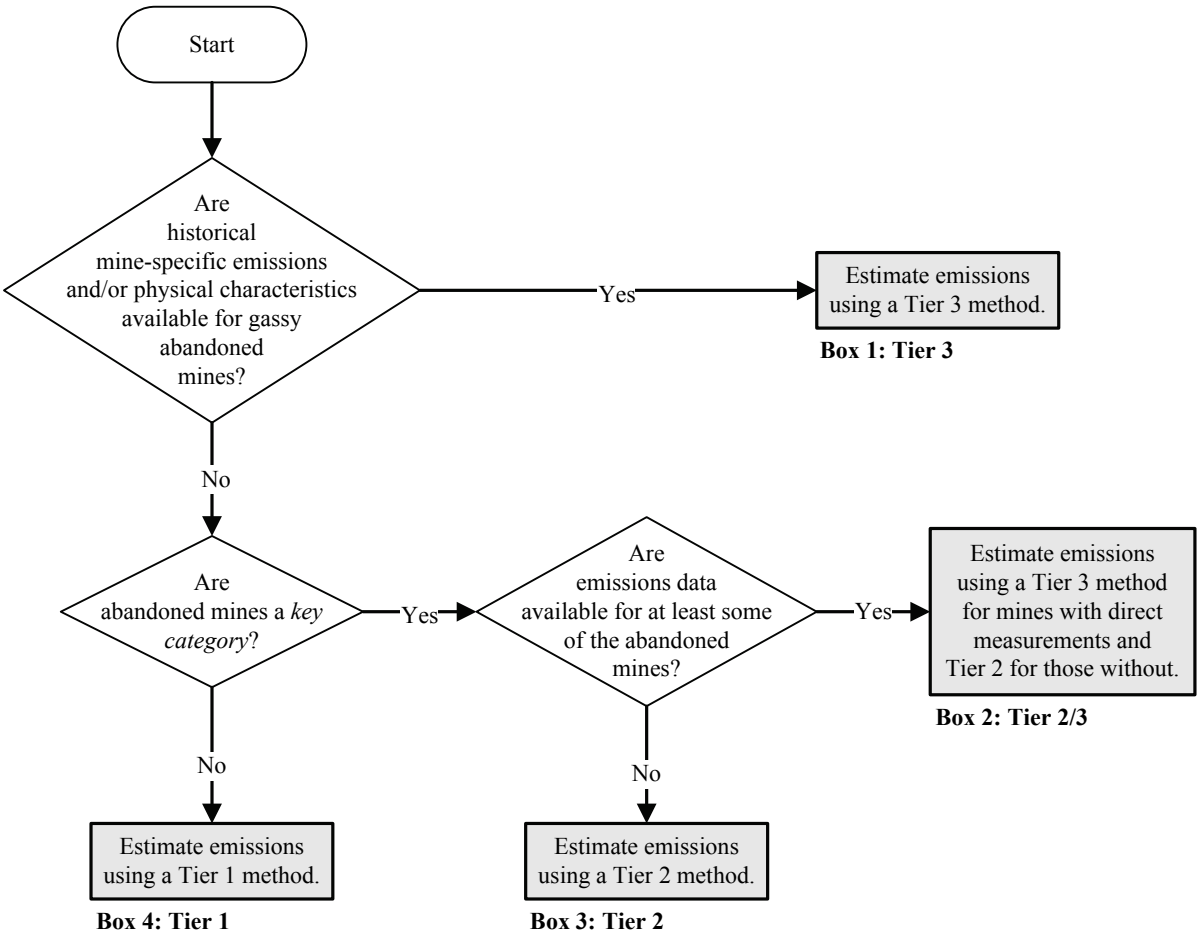
Note: the Emission Factor has different units here compared with the definitions for underground, surface and post-mining emissions. This is because of the different method for estimating emissions from abandoned mines compared with underground or surface mining.

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%
1951-1975	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 $0.67 \bullet 10^{-6}$ 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 ● Emission Factor ● 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 ● 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 Completeness for coal mining

There are three remaining gaps in developing a complete inventory for fugitive emissions from coal mining. These are abandoned surface mines, uncontrolled combustion and CO_2 in coal seam gas.

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.

CO_2 IN COAL MINE GAS

Countries with data available on CO_2 in their coal mine gas should include it with the sub-category used for the corresponding methane emissions.

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

4.1.7.1 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.

4.1.7.2 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

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 Table 4.2.1. The main distinction is made between oil and natural gas systems, with each being subdivided according to the primary type of emissions source, namely: venting, flaring and all other types of fugitive emissions. The latter category is further subdivided into the different parts (or segments) of the oil or gas system according to the type of activity.

The term fugitive emissions is broadly applied here to mean all greenhouse gas emissions from oil and gas systems except contributions from fuel combustion. 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 well head, or oil and gas source, and ends at the final sales point to the consumer. 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).
- Fugitive emissions that occur at industrial facilities other than oil and gas facilities, or that are associated with the end use of oil and gas products at anything 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).

Fugitive emissions from the oil and gas production portions of EOR, EGR and ECBM projects are part of Category 1.B.2.

When determining fugitive emissions from oil and natural gas systems it may, primarily in the areas of production and processing, be necessary to apply greater disaggregation than is shown in Table 4.2.1 to account better 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 Table 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. Typically, production and processing activities tend to have greater amounts of fugitive emissions as a percentage of throughput than downstream activities. Some examples of the potential distribution of fugitive emissions by subcategory are provided in the API (2004) Compendium.

4.2.1 Overview, description of sources

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). While some of these emission sources are engineered or intentional (e.g., tank, seal and process vents and flare systems), and therefore relatively well characterised, the quantity and composition of the emissions is generally subject to significant uncertainty. This is due, in part, to the limited use of measurement systems in these cases, and where measurement systems are used, the typical inability of these to cover the wide range of flows and variations in composition that may occur. Even where some of these losses or flows are tracked as part of routine production accounting procedures, there are often inconsistencies in the activities which get accounted for and whether the amounts are based on engineering estimates or measurements. 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 should 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).

TABLE 4.2.1
DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS

IPCC code	Sector name	Explanation
1 B 2	*Oil and Natural Gas*	Comprises fugitive emissions from all oil and natural gas activities. The primary sources of these emissions may include fugitive equipment leaks, evaporation losses, venting, flaring and accidental releases.
1 B 2 a	Oil	Comprises emissions from venting , flaring and all other fugitive sources associated with the exploration, production, transmission, upgrading, and refining of crude oil and distribution of crude oil products.
1 B 2 a i	Venting	Emissions from venting of associated gas and waste gas/vapour streams at oil facilities
1 B 2 a ii	Flaring	Emissions from flaring of natural gas and waste gas/vapour streams at oil facilities
1 B 2 a iii	All Other	Fugitive emissions at oil facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, land farms, gas migration to the surface around the outside of wellhead casing, surface casing vent bows, biogenic gas formation from tailings ponds and any other gas or vapour releases not specifically accounted for as venting or flaring
1 B 2 a iii 1	*Exploration*	Fugitive emissions (excluding venting and flaring) from oil well drilling, drill stem testing, and well completions

TABLE 4.2.1(CONTINUED)
DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS

IPCC code	Sector name	Explanation
1 B 2 a iii 2	*Production and Upgrading*	Fugitive emissions from oil production (excluding venting and flaring) occur at the oil wellhead or at the oil sands or shale oil mine through to the start of the oil transmission system. This includes fugitive emissions related to well servicing, oil sands or shale oil mining, transport of untreated production (i.e , well effluent, emulsion, oil shale and oilsands) 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 upgraders are often integrated with extraction facilities and their relative emission contributions are difficult to establish. However, upgraders may also be integrated with refineries, co-generation plants or other industrial facilities and their relative emission contributions can be difficult to establish in these cases
1 B 2 a iii 3	*Transport*	Fugitive emissions (excluding 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
1 B 2 a.iii 4	*Refining*	Fugitive emissions (excluding 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). Where refineries are integrated with other facilities (for example, upgraders or co-generation plants) their relative emission contributions can be difficult to establish.
1 B 2 a iii 5	*Distribution of Oil Products*	This comprises fugitive emissions (excluding 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 fugitive equipment leaks are the primary sources of these emissions
1 B 2 a iii 6	*Other*	Fugitive emissions from oil systems (excluding venting and flaring) 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
1 B 2 b	Natural Gas	Comprises emissions from venting, flaring and all other fugitive sources associated with the exploration, production, processing, transmission, storage and distribution of natural gas (including both associated and non-associated gas).
1 B 2 b i	Venting	Emissions from venting of natural gas and waste gas/vapour streams at gas facilities

TABLE 4.2.1(CONTINUED)
DETAILED SECTOR SPLIT FOR EMISSIONS FROM PRODUCTION AND TRANSPORT OF OIL AND NATURAL GAS

IPCC code	Sector name	Explanation
1 B 2 b ii	Flaring	Emissions from flaring of natural gas and waste gas/vapour streams at gas facilities.
1 B 2 b iii	All Other	Fugitive emissions at natural gas facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, gas migration to the surface around the outside of wellhead casing, surface casing vent bows and any other gas or vapour releases not specifically accounted for as venting or flaring.
1B 2 b iii 1	Exploration	Fugitive emissions (excluding venting and flaring) from gas well drilling, drill stem testing and well completions
1B 2 b iii 2	Production	Fugitive emissions (excluding 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. This includes fugitive emissions related to well servicing, gas gathering, processing and associated waste water and acid gas disposal activities
1 B 2 b iii 3	Processing	Fugitive emissions (excluding venting and flaring) from gas processing facilities
1 B 2 b iii 4	Transmission and Storage	Fugitive emissions from systems used to transport processed natural gas to market (i.e., to industrial consumers and natural gas distribution systems). Fugitive emissions from natural gas storage systems should also be included in this category. 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 Category 1.B.2.a.iii.3
1 B 2 b iii 5	Distribution	Fugitive emissions (excluding venting and flaring) from the distribution of natural gas to end users
1 B 2 b iii 6	Other	Fugitive emissions from natural gas systems (excluding venting and flaring) not otherwise accounted for in the above categories. This may include emissions from well blowouts and pipeline ruptures or dig-ins
1 B 3	*Other emissions from Energy Production*	Emissions from geo thermal energy production and other energy production not included in 1.B.1 or 1.B.2

4.2.2 Methodological issues

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). As is done for fuel combustion (see Chapter 1 of this Volume), CO_2 emissions are calculated in Tier 1 assuming that all hydrocarbons are fully oxidized. If information is available on partial oxidation, this can be taken into account in higher Tiers.

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 or re-injection.
- 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. 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.i. 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.i. Care should be taken to ensure that the feedstock for the hydrogen plant is not also reported as fuel in these cases.

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.

If a rigorous bottom-up approach is chosen, then it is *good practice* to involve technical representatives from the industry in the development of the inventory.

4.2.2.1 CHOICE OF METHOD, DECISION TREES, TIERS

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 Major Categories and Subcategories in the Oil and Gas Industry (see Table 4.2.2 in Section 4.2.2.2), 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 categories and subcategories, 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 4.2.1 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 subcategory within the

natural gas system (e.g., gas production, then gas processing, then gas transmission, then gas distribution). The basic decision process is as follows:

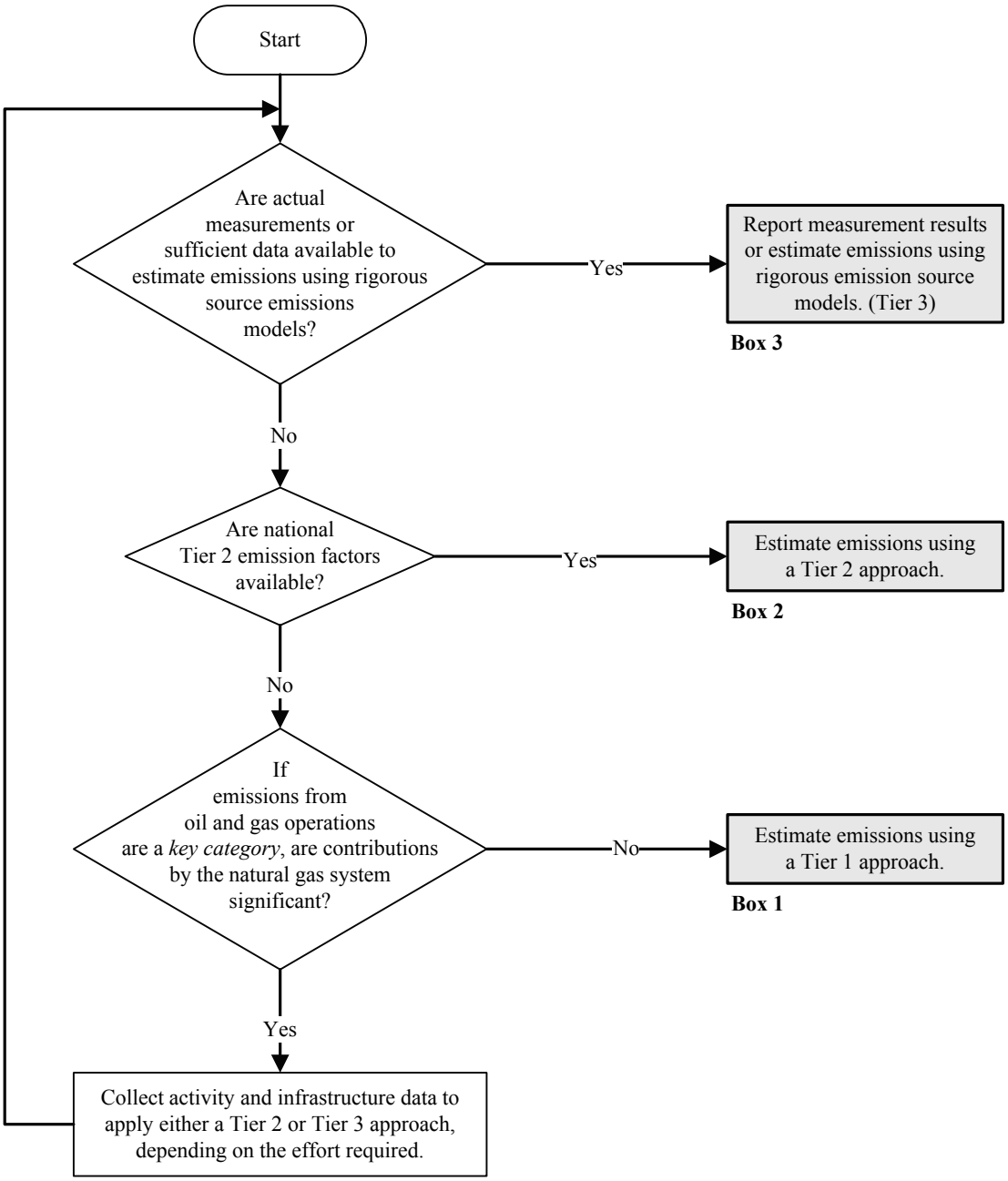
- check if the detailed data needed to apply a Tier 3 approach are readily available, and if so, then apply a Tier 3 approach (i.e., regardless of whether the category is key and the subcategory is significant), otherwise, if these data are not readily available:
- check if the detailed data needed to 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 subcategory 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 subcategory 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 to apply it under all circumstances. 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 methodology should be reported as Tier 2 in those other years.

Similarly, Figures 4.2.2 and 4.2.3 apply to crude oil production and transport systems, and to oil upgraders and refineries, respectively.

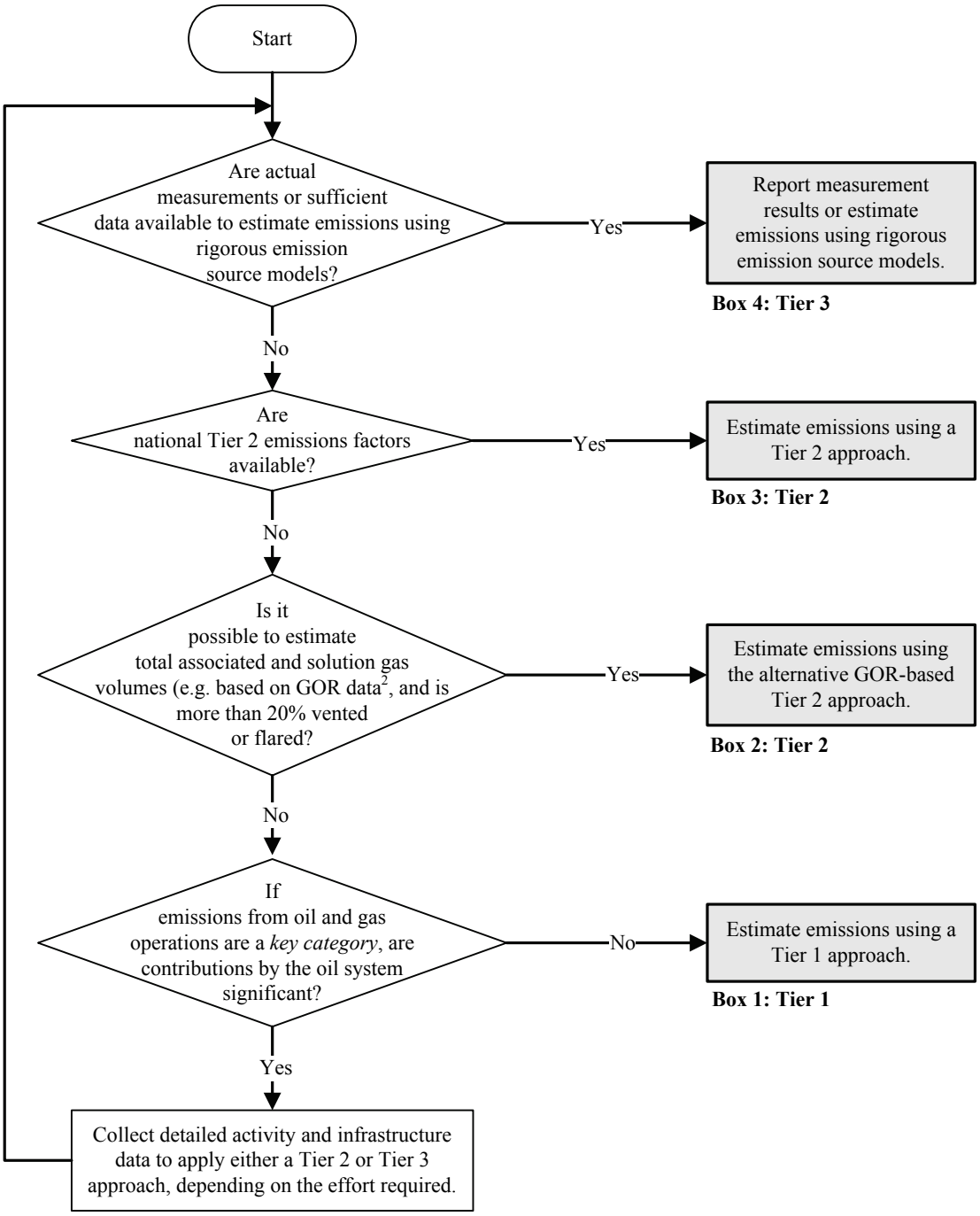
Where a country has estimated fugitive emissions from oil and gas systems based on a compilation of estimates reported by individual oil and gas companies, this may either be a Tier 2 or Tier 3 approach, depending on the actual approaches applied by individual companies and facilities. In both cases,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

Figure 4.2.1 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

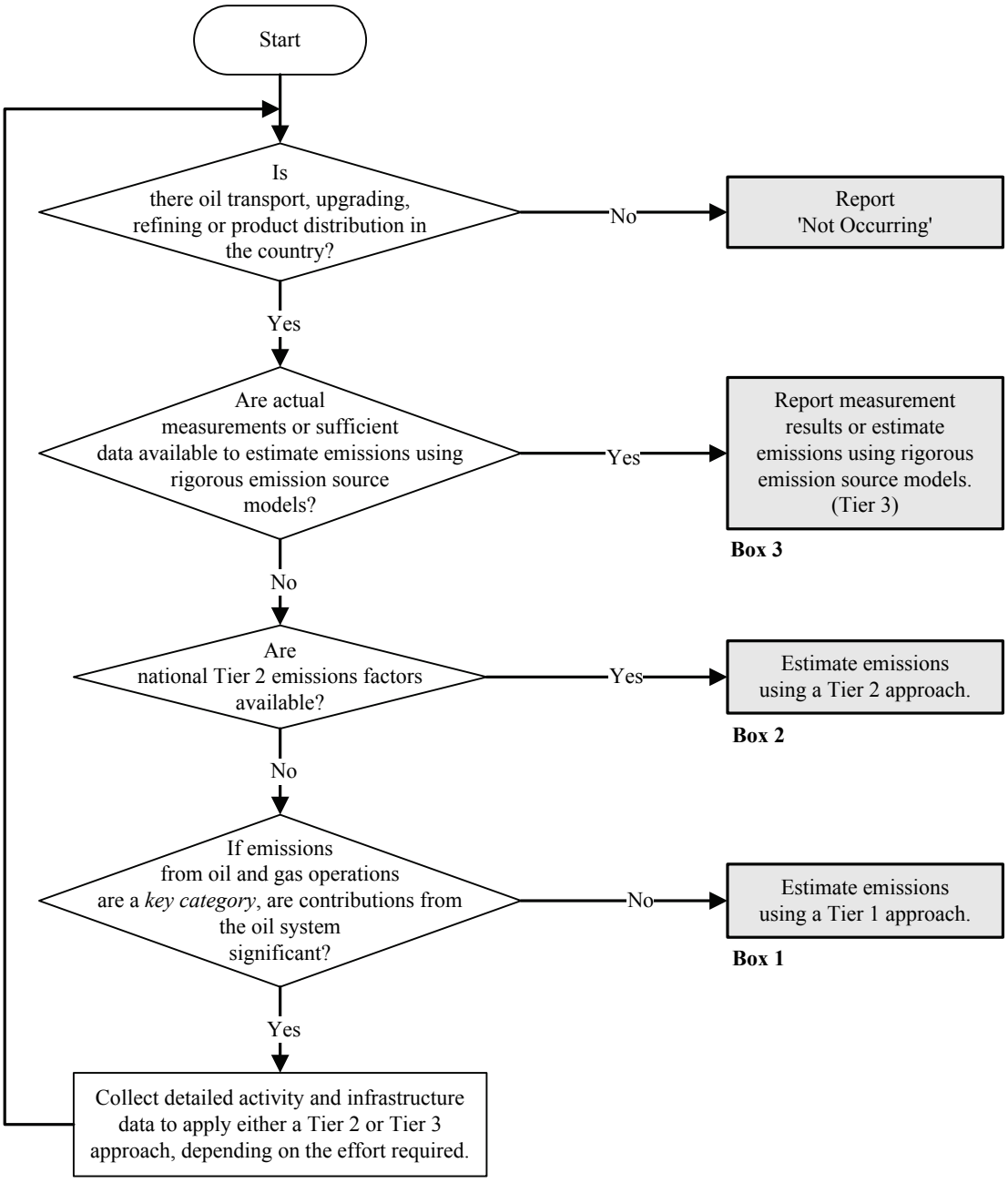
Figure 4.2.2 Decision tree for crude oil production



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

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

Figure 4.2.3 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

4.2.2.2 CHOICE OF METHOD

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 (Gg)

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

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

The industry segments to be considered are listed in Table 4.2.2. 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. The available Tier 1 default emission factors are presented in Tables 4.2.4 and 4.2.5 in Section 4.2.2.3. These factors have been related to throughput, because production, imports and exports are the only national oil and gas statistics that are consistently available. On a small scale, fugitive emissions are completely independent of throughput. The best relation for estimating emissions from fugitive equipment leaks is based on the number and type of equipment components and the type of service, which is a Tier-3 approach. On a larger scale, there is a reasonable relationship between the amount of production and the amount of infrastructure that exists. Consequently, the reliability of the presented Tier 1 factors for oil and gas systems will depend on the size of a country's oil and gas industry. The larger the industry, the more important its fugitive emissions contribution will be and the more reliable the presented Tier 1 emission factors will be.

Besides having a high degree of uncertainty, the Tier 1 approach for oil and natural gas systems does not allow countries to show any real changes in emission intensities over time (e.g., due to the implementation of control measures or changing source characteristics). Rather, emissions become fixed in proportion to the activity levels, and the changes in reported emissions over time simply reflect the changes in activity levels. Tier 2 and 3 approaches are needed to capture real changes in emission intensities. However, going to these higher tier approaches requires considerably more effort and, for Tier 3 approaches, more detailed activity data. The completeness and accuracy of the input information used for higher tier approaches will generally need to be comparable to, or better than, the values of the input information used for the lower methodological tiers in order to achieve more accurate results.

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 upon 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 4.2.2
MAJOR CATEGORIES AND SUBCATEGORIES IN THE OIL AND GAS INDUSTRY

Industry Segment	Sub-Categories
Well Drilling	All
Well Testing	All
Well Servicing	All
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 Plants
	Deep-cut Extraction Plants[d]
Gas Transmission & Storage	Pipeline Systems
	Storage Facilities
Gas Distribution	Rural Distribution
	Urban Distribution
Liquefied Gases Transport	Condensate
	Liquefied Petroleum Gas (LPG)
	Liquefied Natural Gas (LNG) (including associated liquefaction and gasification facilities)
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)
	Synthetic Crude Oil (From Oil Sands)
	Synthetic Crude Oil (From Oil Shales)
Oil Upgrading	Crude Bitumen
	Heavy Oil
Waste Oil Reclaiming	All
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)

[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

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 should 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. Since 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).

Table 4.2.3 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 m^3/m^3, depending on the location.

TABLE 4.2.3
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)

$$E_{gas,oil\ prod,\ venting} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet (1 - X_{Flared}) \bullet M_{gas} \bullet y_{gas} \bullet 42.3 \times 10^{-6}$$

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

$$E_{CH4,oil\ prod,flaring} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet X_{Flared} \bullet (1 - FE) \bullet M_{CH4} \bullet y_{CH4} \bullet 42.3 \times 10^{-6}$$

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

$$E_{CO2,\,oilprod,flaring} = GOR \bullet Q_{OIL} \bullet (1 - CE) \bullet X_{Flared} \bullet M_{CO2} \bullet \left[y_{CO2} + (Nc_{CH4} \bullet y_{CH4} + Nc_{NMVOC} \bullet y_{NMVOC})(1 - X_{Soot}) \right] \bullet 42.3x10^{-6}$$

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 ● 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, fugitive 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

TIER 1

The available Tier 1 default emission factors are presented in Tables 4.2.4 and 4.2.5. All of the presented emission factors are expressed in units of mass emissions per unit volume of oil or gas throughput. While some types of fugitive emissions correlate poorly with, or are unrelated to, throughput on an individual source basis (e.g., fugitive equipment leaks), the correlations with throughput become more reasonable when large populations of sources are considered. Furthermore, throughput statistics are the most consistently available activity data for use in Tier 1 calculations.

Table 4.2.4 should only be applied to systems designed, operated and maintained to North American and Western European standards. Table 4.2.5 generally applies to systems in developing countries and countries with economies in transition where there are much greater amounts of fugitive emissions per unit of activity (often by an order of magnitude or more). The reasons for the greater emissions in these cases may include less stringent design standards, use of lower quality components, restricted access to natural gas markets, and, in some cases,

artificially low energy pricing resulting in reduced energy conservation. Reference should also be made to the IPCC emission factor database (EFDB) since it would contain the values for higher tier emission factors.

TABLE 4.2.4
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[1]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Well Drilling	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	3.3E-05	±100%	1.0E-04	±50%	8.7E-07	±100%	ND	ND	Gg per 10^3 m^3 total oil production
Well Testing	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	5.1E-05	±50%	9.0E-03	±50%	1.2E-05	±50%	6.8E-08	-10 to +1000%	Gg per 10^3 m^3 total oil production
Well Servicing	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	1.1E-04	±50%	1.9E-06	±50%	1.7E-05	±50%	ND	ND	Gg per 10^3 m^3 total oil production
Gas Production	All	Fugitives[d]	1.B.2.b.iii.2	3.8E-04 to 2.3E-03	±100%	1.4E-05 to 8.2E-05	±100%	9.1E-05 to 5.5E-04	±100%	NA	NA	Gg per 10^6 m^3 gas production
		Flaring[e]	1.B.2.b.ii	7.6E-07	±25%	1.2E-03	±25%	6.2E-07	±25%	2.1E-08	-10 to +1000%	Gg per 10^6 m^3 gas production
Gas Processing	Sweet Gas Plants	Fugitives	1.B.2.b.iii.3	4.8E-04 to 10.3E-04	±100%	1.5E-04 to 3.2E-04	±100%	2.2E-04 to 4.7E-04	±100%	NA	NA	Gg per 10^6 m^3 raw gas feed
		Flaring	1.B.2.b.ii	1.2E-06	±25%	1.8E-03	±25%	9.6E-07	±25%	2.5E-08	-10 to +1000%	Gg per 10^6 m^3 raw gas feed
	Sour Gas Plants	Fugitives	1.B.2.b.iii.3	9.7E-05	±100%	7.9E-06	±100%	6.8E-05	±100%	NA	NA	Gg per 10^6 m^3 raw gas feed
		Flaring	1.B.2.b.ii	2.4E-06	±25%	3.6E-03	±25%	1.9E-06	±25%	5.4E-08	-10 to +1000%	Gg per 10^6 m^3 raw gas feed
		Raw CO_2 Venting	1.B.2.b.i	NA	NA	6.3E-02	-10 to +1000%	NA	NA	NA	NA	Gg per 10^6 m^3 raw gas feed

TABLE 4.2.4(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[l]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Deep-cut Extraction Plants (Straddle Plants)	Fugitives	1.B.2.b.iii.3	1.1E-05	±100%	1.6E-06	±100%	2.7E-05	±100%	NA	NA	Gg per 10^6 m^3 raw gas feed
		Flaring	1.B.2.b.ii	7.2E-08	±25%	1.1E-04	±50%	5.9E-08	±25%	1.2E-08	-10 to +1000%	Gg per 10^6 m^3 raw gas feed
	Default Weighted Total	Fugitives	1.B.2.b.iii.3	1.5E-04 to 10.3E-04	±100%	1.2E-05 to 3.2E-04	±100%	1.4E-04 to 4.7E-04	±100%	NA	NA	Gg per 10^6 m^3 gas production
		Flaring	1.B.2.b.ii	2.0E-06	±25%	3.0E-03	±50%	1.6E-06	±25%	3.3E-08	-10 to +1000%	Gg per 10^6 m^3 gas production
		Raw CO_2 Venting	1.B.2.b.i	NA	N/A	4.0E-02	-10 to +1000%	NA	N/A	NA	N/A	Gg per 10^6 m^3 gas production
Gas Transmission & Storage	Transmission	Fugitives[f,k]	1.B.2.b.iii.4	6.6E-05 to 4.8E-04	±100%	8.8E-07	±100%	7.0E-06	±100%	NA	NA	Gg per 10^6 m^3 of marketable gas
		Venting[g,k]	1.B.2.b.i	4.4E-05 to 3.2E-04	±75%	3.1E-06	±75%	4.6E-06	±75%	NA	NA	Gg per 10^6 m^3 of marketable gas
	Storage	All[k]	1.B.2.b.iii.4	2.5E-05	-20 to +500%	1.1E-07	-20 to +500%	3.6E-07	-20 to +500%	ND	ND	Gg per 10^6 m^3 of marketable gas

TABLE 4.2.4(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[l]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
Gas Distribution	All	All[k]	1.B.2.b.iii.5	1.1E-03	-20 to +500%	5.1E-05	-20 to +500%	1.6E-05	-20 to +500%	ND	ND	Gg per 10^6 m^3 of utility sales
Natural Gas Liquids Transport	Condensate	All[k]	1.B.2.a.iii.3	1.1E-04	±100%	7.2E-06	±100%	1.1E-03	±100%	ND	ND	Gg per 10^3 m^3 Condensate and Pentanes Plus
	Liquefied Petroleum Gas	All	1.B.2.a.iii.3	NA	NA	4.3E-04	±50%	ND	ND	2.2E-09	-10 to +1000%	Gg per 10^3 m^3 LPG
	Liquefied Natural Gas	All	1.B.2.a.iii.3	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^6 m^3 of marketable gas
Oil Production	Conventional Oil	Fugitives (Onshore)	1.B.2.a.iii.2	1.5E-06 to 3.6E-03	±100%	1.1E-07 to 2.6E-04	±100%	1.8E-06 to 4.5E-03	±100%	NA	NA	Gg per 10^3 m^3 conventional oil production
		Fugitives (Offshore)	1.B.2.a.iii.2	5.9E-07	±100%	4.3E-08	±100%	7.4E-07	±100%	NA	NA	Gg per 10^3 m^3 conventional oil production
		Venting	1.B.2.a.i	7.2E-04	±50%	9.5E-05	±50%	4.3E-04	±50%	NA	NA	Gg per 10^3 m^3 conventional oil production
		Flaring	1.B.2.a.ii	2.5E-05	±50%	4.1E-02	±50%	2.1E-05	±50%	6.4E-07	-10 to +1000%	Gg per 10^3 m^3 conventional oil production

TABLE 4.2.4(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[1]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Heavy Oil/Cold Bitumen	Fugitives	1.B.2.a.iii.2	7.9E-03	±100%	5.4E-04	±100%	2.9E-03	±100%	NA	NA	Gg per 10^3 m^3 heavy oil production
		Venting	1.B.2.a.i	1.7E-02	±75%	5.3E-03	±75%	2.7E-03	±75%	NA	NA	Gg per 10^3 m^3 heavy oil production
		Flaring	1.B.2.a.ii	1.4E-04	±75%	2.2E-02	±75%	1.1E-05	±75	4.6E-07	-10 to +1000%	Gg per 10^3 m^3 heavy oil production
	Thermal Oil Production	Fugitives	1.B.2.a.iii.2	1.8E-04	±100%	2.9E-05	±100%	2.3E-04	±100%	NA	NA	Gg per 10^3 m^3 thermal bitumen production
		Venting	1.B.2.a.i	3.5E-03	±50%	2.2E-04	±50%	8.7E-04	±50%	NA	NA	Gg per 10^3 m^3 thermal bitumen production
		Flaring	1.B.2.a.ii	1.6E-05	±75%	2.7E-02	±75%	1.3E-05	±75%	2.4E-07	-10 to +1000%	Gg per 10^3 m^3 thermal bitumen production
	Synthetic Crude (from Oilsands)	All	1.B.2.a.iii.2	2.3E-03	±75%	ND	ND	9.0E-04	±75%	ND	ND	Gg per 10^3 m^3 synthetic crude production from oilsands

TABLE 4.2.4(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[l]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Synthetic Crude (from Oil Shale)	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^3 m^3 synthetic crude production from oil shale
	Default Weighted Total	Fugitives	1.B.2.a.iii.2	2.2E-03	±100%	2.8E-04	±100%	3.1E-03	±100%	NA	NA	Gg per 10^3 m^3 total oil production
		Venting	1.B.2.a.i	8.7E-03	±75%	1.8E-03	±75%	1.6E-03	±75%	NA	NA	Gg per 10^3 m^3 total oil production
		Flaring	1.B.2.a.ii	2.1E-05	±75%	3.4E-02	±75%	1.7E-05	±75	5.4E-07	-10 to +1000%	Gg per 10^3 m^3 total oil production
Oil Upgrading	All	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^3 m^3 oil upgraded
Oil Transport	Pipelines	All[k]	1.B.2.a.iii.3	5.4E-06	±100%	4.9E-07	±100%	5.4E-05	ND	NA	NA	Gg per 10^3 m^3 oil transported by pipeline

TABLE 4.2.4(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[l]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	
	Tanker Trucks and Rail Cars	Venting[k]	1.B.2.a.i	2.5E-05	±50%	2.3E-06	±50%	2.5E-04	ND	NA	NA	Gg per 10^3 m^3 oil transported by Tanker Truck
	Loading of Off-shore Production on Tanker Ships	Venting[k]	1.B.2.a.i	ND[h]	ND	ND[h]	ND	ND[h]	ND	NA	NA	Gg per 10^3 m^3 oil transported by Tanker Ships
Oil Refining	All	All	1.B.2.a.iii.4	$2.6x10^{-6}$ to $41.0x10^{-6}$	±100%	ND	ND	0.0013[i]	±100%	ND	ND	Gg per 10^3 m^3 oil refined.
Refined Product Distribution	Gasoline	All	1.B.2.a.iii.5	NA	NA	NA	NA	0.0022[j]	±100%	NA	NA	Gg per 10^3 m^3 product distributed.
	Diesel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.
	Aviation Fuel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.
	Jet Kerosene	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.

TABLE 4.2.4(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPED COUNTRIES[a,b]

NA - Not Applicable ND - Not Determined

[a] While the presented emission factors may all vary appreciably between countries, the greatest differences are expected to occur with respect to venting and flaring, particularly for oil production due to the potential for significant differences in the amount of gas conservation and utilisation practised.

[b] The range in values for fugitive emissions is attributed primarily to differences in the amount of process infrastructure (e.g. average number and sizes of facilities) per unit of gas throughput.

[c] 'All' denotes all fugitive emissions as well as venting and flaring emissions.

[d] 'Fugitives' denotes all fugitive emissions including those from fugitive equipment leaks, storage losses, use of natural gas as the supply medium for gas-operated devices (e.g. instrument control loops, chemical injection pumps, compressor starters, etc.), and venting of still-column off-gas from glycol dehydrators. The presented range in values reflects the difference between fugitive emissions at offshore (the smaller value) and onshore (the larger value) emissions.

[e] 'Flaring' denotes emissions from all continuous and emergency flare systems. The specific flaring rates may vary significantly between countries. Where actual flared volumes are known, these should be used to determine flaring emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH_4, CO_2 and N_2O emissions from reported flared volumes are 0.012, 2.0 and 0.000023 Gg, respectively, per 10^6 m^3 of gas flared based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (i.e. 91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-methane hydrocarbons by volume).

[f] The larger factor reflects the use of mostly reciprocating compressors on the system while the smaller factor reflects mostly centrifugal compressors.

[g] 'Venting' denotes reported venting of waste associated and solution gas at oil production facilities and waste gas volumes from blowdown, purging and emergency relief events at gas facilities. Where actual vented volumes are known, these should be used to determine venting emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH_4 and CO_2 emissions from reported vented volumes are 0.66 and 0.0049 Gg, respectively, per 10^6 m^3 of gas vented based on a typical gas analysis for gas transmission and distribution systems (i.e. 97.3% CH_4, 0.26% CO_2, 1.7% N_2 and 0.74% non-methane hydrocarbons by volume).

[h] While no factors are available for marine loading of offshore production for North America, Norwegian data indicate a CH_4 emission factor of 1.0 to 3.6 Gg/10^3 m^3 of oil transferred (derived from data provided by Norwegian Pollution Control Authority, 2000).

[I] 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).

[j] 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 warm climates.

[k] NMVOC values are derived from methane values based on the ratio of the mass fractions of NMVOC to CH_4. 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.

[l] The presented CO_2 emissions factors account for direct CO_2 emissions only, except for flaring, in which case the presented values account for the sum of direct CO_2 emissions and indirect contributions due to the atmospheric oxidation of gaseous non-CO_2 carbon emissions.

Sources: Canadian Association of Petroleum Producers (1999, 2004); API (2004); GRI/US EPA (1996); US EPA (1999).

TABLE 4.2.5
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
Well Drilling	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	3.3E-05 to 5.6E-04	-12.5 to +800%	1.0E-04 to 1.7E-03	-12.5 to +800%	8.7E-07 to 1.5E-05	-12.5 to +800%	ND	ND	Gg per 10^3 m^3 total oil production
Well Testing	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	5.1E-05 8.5E-04	-12.5 to +800%	9.0E-03 to 1.5E-01	-12.5 to +800%	1.2E-05 to 2.0E-04	-12.5 to +800%	6.8E-08 to 1.1E-06	-10 to +1000%	Gg per 10^3 m^3 total oil production
Well Servicing	All	Flaring and Venting	1.B.2.a.ii or 1.B.2.b.ii	1.1E-04 to 1.8E-03	-12.5 to + 800%	1.9E-06 to 3.2E-05	-12.5 to +800%	1.7E-05 to 2.8E-04	-12.5 to +800%	ND	ND	Gg per 10^3 m^3 total oil production
Gas Production	All	Fugitives[d]	1.B.2.b.iii.2	3.8E-04 to 2.4E-02	-40 to +250%	1.4E-05 to 1.8E-04	-40 to +250%	9.1E-05 to 1.2E-03	-40 to +250%	NA	NA	Gg per 10^6 m^3 gas production
		Flaring[e]	1.B.2.b.ii	7.6E-07 to 1.0E-06	±75%	1.2E-03 to 1.6E-03	±75%	6.2E-07 to 8.5E-07	±75%	2.1E-08 to 2.9E-08	-10 to +1000%	Gg per 10^6 m^3 gas production
Gas Processing	Sweet Gas Plants	Fugitives	1.B.2.b.iii.3	4.8E-04 to 1.1E-03	-40 to +250%	1.5E-04 to 3.5E-04	-40 to +250%	2.2E-04 to 5.1E-04	-40 to +250%	NA	NA	Gg per 10^6 m^3 raw gas feed
		Flaring	1.B.2.b.ii	1.2E-06 to 1.6E-06	±75%	1.8E-03 to 2.5E-03	±75%	9.6E-07 to 1.3E-06	±75%	2.5E-08 to 3.4E-08	-10 to +1000%	Gg per 10^6 m^3 raw gas feed
	Sour Gas Plants	Fugitives	1.B.2.b.iii.3	9.7E-05 to 2.2E-04	-40 to +250%	7.9E-06 to 1.8E-05	-40 to +250%	6.8E-05 to 1.6E-04	-40 to +250%	NA	NA	Gg per 10^6 m^3 raw gas feed

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
		Flaring	1.B.2.b.ii	2.4E-06 to 3.3E-06	±75%	3.6E-03 to 4.9E-03	±75%	1.9E-06 to 2.6E-06	±75%	5.4E-08 to 7.4E-08	-10 to +1000%	Gg per 10^6 m^3 raw gas feed
		Raw CO_2 Venting	1.B.2.b.i	NA	NA	6.3E-02 to 1.5E-01	-10 to +1000%	NA	NA	NA	NA	Gg per 10^6 m^3 raw gas feed
	Deep-cut Extraction Plants (Straddle Plants)	Fugitives	1.B.2.b.iii.3	1.1E-05 to 2.5E-05	-40 to +250%	1.6E-06 to 3.7E-06	-40 to +250%	2.7E-05 to 6.2E-05	-40 to +250%	NA	NA	Gg per 10^6 m^3 raw gas feed
		Flaring	1.B.2.b.ii	7.2E-08 to 9.9E-08	±75%	1.1E-04 to 1.5E-04	±75%	5.9E-08 to 8.1E-08	±75%	1.2E-08 to 8.1E-08	-10 to +1000%	Gg per 10^6 m^3 raw gas feed
	Default Weighted Total	Fugitives	1.B.2.b.iii.3	1.5E-04 to 3.5E-04	-40 to +250%	1.2E-05 to 2.8E-05	-40 to +250%	1.4E-04 to 3.2E-04	-40 to +250%	NA	NA	Gg per 10^6 m^3 gas production
		Flaring	1.B.2.b.ii	2.0E-06 to 2.8E-06	±75%	3.0E-03 to 4.1E-03	±75%	1.6E-06 to 2.2E-06	±75%	3.3E-08 to 4.5E-08	-10 to +1000%	Gg per 10^6 m^3 gas production
		Raw CO_2 Venting	1.B.2.b.i	NA	N/A	4.0E-02 to 9.5E-02	-10 to +1000%	NA	N/A	NA	N/A	Gg per 10^6 m^3 gas production

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
Gas Transmission & Storage	Transmission	Fugitives[f]	1.B.2.b.iii.4	16.6E-05 to 1.1E-03	-40 to +250%	8.8E-07 to 2.0E-06	-40 to +250%	7.0E-06 to 1.6E-05	-40 to +250%	NA	NA	Gg per 10^6 m^3 of marketable gas
		Venting[g]	1.B.2.b.i	4.4E-05 to 7.4E-04	-40 to +250%	3.1E-06 to 7.3E-06	-40 to +250%	4.6E-06 to 1.1E-05	-40 to +250%	NA	NA	Gg per 10^6 m^3 of marketable gas
	Storage	All	1.B.2.b.iii.4	2.5E-05 to 5.8E-05	-20 to +500%	1.1E-07 to 2.6E-07	-20 to +500%	3.6E-07 to 8.3E-07	-20 to +500%	ND	ND	Gg per 10^6 m^3 of marketable gas
Gas Distribution	All	All	1.B.2.b.iii.5	1.1E-03 to 2.5E-03	-20 to +500%	5.1E-05 to 1.4E-04	-20 to +500%	1.6E-05 to 3.6E-5	-20 to +500%	ND	ND	Gg per 10^6 m^3 of utility sales
Natural Gas Liquids Transport	Condensate	All	1.B.2.a.iii.3	1.1E-04	-50 to +200%	7.2E-06	-50 to +200%	1.1E-03	-50 to +200%	ND	ND	Gg per 10^3 m^3 Condensate and Pentanes Plus
	Liquefied Petroleum Gas	All	1.B.2.a.iii.3	NA	NA	4.3E-04	±100%	ND	ND	2.2E-09	-10 to +1000%	Gg per 10^3 m^3 LPG
	Liquefied Natural Gas	All	1.B.2.a.iii.3	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^6 m^3 of marketable gas

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
Oil Production	Conventional Oil	Fugitives (Onshore)	1.B.2.a.iii.2	1.5E-06 to 6.0E-02	-12.5 to +800%	1.1E-07 to 4.3E-03	-12.5 to +800%	1.8E-06 to 7.5E-02	-12.5 to +800%	NA	NA	Gg per 10^3 m^3 conventional oil production
		Fugitives (Offshore)	1.B.2.a.iii.2	5.9E-07	-12.5 to +800%	4.3E-08	-12.5 to +800%	7.4E-07	-12.5 to +800%	NA	NA	Gg per 10^3 m^3 conventional oil production
		Venting	1.B.2.a.i	7.2E-04 to 9.9E-04	±75%	9.5E-05 to 1.3E-04	±75%	4.3E-04 to 5.9E-04	±75%	NA	NA	Gg per 10^3 m^3 conventional oil production
		Flaring	1.B.2.a.ii	2.5E-05 to 3.4E-05	±75%	4.1E-02 to 5.6E-02	±75%	2.1E-05 to 2.9E-05	±75%	6.4E-07 to 8.8E-07	-10 to +1000%	Gg per 10^3 m^3 conventional oil production

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
	Heavy Oil/Cold Bitumen	Fugitives	1.B.2.a.iii.2	7.9E-03 to 1.3E-01	-12.5 to +800%	5.4E-04 to 9.0E-03	-12.5 to +800%	2.9E-03 to 4.8E-02	-12.5 to +800%	NA	NA	Gg per 10^3 m^3 heavy oil production
		Venting	1.B.2.a.i	1.7E-02 to 2.3E-02	-67 to +150%	5.3E-03 to 7.3E-03	-67 to +150%	2.7E-03 to 3.7E-03	-67 to +150%	NA	NA	Gg per 10^3 m^3 heavy oil production
		Flaring	1.B.2.a.ii	1.4E-04 to 1.9E-04	-67 to +150%	2.2E-02 to 3.0E-02	-67 to +150%	1.1E-05 to 1.5E-05	-67 to +150%	4.6E-07 to 6.3E-07	-10 to +1000%	Gg per 10^3 m^3 heavy oil production
	Thermal Oil Production	Fugitives	1.B.2.a.iii.2	1.8E-04 to 3.0E-03	-12.5 to +800%	2.9E-05 to 4.8E-04	-12.5 to +800%	2.3E-04 to 3.8E-03	-12.5 to +800%	NA	NA	Gg per 10^3 m^3 thermal bitumen production
		Venting	1.B.2.a.i	3.5E-03 to 4.8E-03	-67 to +150%	2.2E-04 to 3.0E-04	-67 to +150%	8.7E-04 to 1.2E-03	-67 to +150%	NA	NA	Gg per 10^3 m^3 thermal bitumen production
		Flaring	1.B.2.a.ii	1.6E-05 to 2.2E-05	-67 to +150%	2.7E-02 to 3.7E-02	-67 to +150%	1.3E-05 to 1.8E-05	-67 to +150%	2.4E-07 to 3.3E-07	-10 to +1000%	Gg per 10^3 m^3 thermal bitumen production

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
	Synthetic Crude (from Oilsands)	All	1.B.2.a.iii.2	2.3E-03 to 3.8E-02	-67 to +150%	ND	ND	9.0E-04 to 1.5E-02	-67 to +150%	ND	ND	Gg per 10^3 m^3 synthetic crude production from oilsands
	Synthetic Crude (from Oil Shale)	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^3 m^3 synthetic crude production from oil shale
	Default Weighted Total	Fugitives	1.B.2.a.iii.2	2.2E-03 to 3.7E-02	-12.5 to +800%	2.8E-04 to 4.7E-03	-12.5 to +800%	3.1E-03 to 5.2E-02	-12.5 to +800%	NA	NA	Gg per 10^3 m^3 total oil production
		Venting	1.B.2.a.i	8.7E-03 to 1.2E-02	±75%	1.8E-03 to 2.5E-03	±75%	1.6E-03 to 2.2E-03	±75%	NA	NA	Gg per 10^3 m^3 total oil production
		Flaring	1.B.2.a.ii	2.1E-05 to 2.9E-05	±75%	3.4E-02 to 4.7E-02	±75%	1.7E-05 to 2.3	±75	5.4E-07 to 7.4E-07	-10 to +1000%	Gg per 10^3 m^3 total oil production

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		NMVOC		N_2O		Units of measure
				Value	Uncertainty (% of value)	Value	Uncertainty (% of value)	Value	Uncertainty (% of Value)	Value	Uncertainty (% of value)	
Oil Upgrading	All	All	1.B.2.a.iii.2	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^3 m^3 oil upgraded
Oil Transport	Pipelines	All	1.B.2.a.iii.3	5.4E-06	-50 to +200%	4.9E-07	-50 to +200%	5.4E-05	-50 to +200%	NA	NA	Gg per 10^3 m^3 oil transported by pipeline
	Tanker Trucks and Rail Cars	Venting	1.B.2.a.i	2.5E-05	-50 to +200%	2.3E-06	-50 to +200%	2.5E-04	-50 to +200%	NA	NA	Gg per 10^3 m^3 oil transported by Tanker Truck
	Loading of Off-shore Production on Tanker Ships	Venting	1.B.2.a.i	ND[h]	ND	ND[h]	ND	ND	ND	NA	NA	Gg per 10^3 m^3 oil transported by Tanker Truck
Oil Refining	All	All	1.B.2.a.iii.4	ND	ND	ND	ND	ND	ND	ND	ND	Gg per 10^3 m^3 oil refined.

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

Category	Sub-category[c]	Emission source	IPCC Code	CH_4		CO_2[i]		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	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.
	Diesel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.
	Aviation Fuel	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.
	Jet Kerosene	All	1.B.2.a.iii.5	NA	NA	NA	NA	ND	ND	NA	NA	Gg per 10^3 m^3 product transported.

TABLE 4.2.5(CONTINUED)
TIER 1 EMISSION FACTORS FOR FUGITIVE EMISSIONS (INCLUDING VENTING AND FLARING) FROM OIL AND GAS OPERATIONS
IN DEVELOPING COUNTRIES AND COUNTRIES WITH ECONOMIES IN TRANSITION[a,b]

NA - Not Applicable ND – Not Determined

[a] While the presented emission factors may all vary appreciably between countries, the greatest differences are expected to occur with respect to venting and flaring, particularly for oil production due to the potential for significant differences in the amount of gas conservation and utilisation practised.

[b] The range in values for fugitive emissions is attributed primarily to differences in the amount of process infrastructure (e.g. average number and sizes of facilities) per unit of gas throughput.

[c] 'All' denotes all fugitive emissions as well as venting and flaring emissions.

[d] 'fugitives' denotes all fugitive emissions including those from fugitive equipment leaks, storage losses, use of natural gas as the supply medium for gas-operated devices (e.g. instrument control loops, chemical injection pumps, compressor starters, etc.), and venting of still-column off-gas from glycol dehydrators.

[e] 'Flaring' denotes emissions from all continuous and emergency flare systems. The specific flaring rates may vary significantly between countries. Where actual flared volumes are known, these should be used to determine flaring emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH_4, CO_2 and N_2O emissions from reported flared volumes are 0.012, 2.0 and 0.000023 Gg, respectively, per 106 m3 of gas flared based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (i.e. 91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-methane hydrocarbons by volume).

[f] The larger factor reflects the use of mostly reciprocating compressors on the system while the smaller factor reflects mostly centrifugal compressors.

[g] 'Venting' denotes reported venting of waste associated and solution gas at oil production facilities and waste gas volumes from blowdown, purging and emergency relief events at gas facilities. Where actual vented volumes are known, these should be used to determine venting emissions rather than applying the presented emission factors to production rates. The emission factors for direct estimation of CH_4 and CO_2 emissions from reported vented volumes are 0.66 and 0.0049 Gg, respectively, per 106 m3 of gas vented based on a typical gas analysis for gas transmission and distribution systems (i.e. 97.3% CH_4, 0.26% CO_2, 1.7% N_2 and 0.74% non-methane hydrocarbons by volume).

[h] While no factors are available for marine loading of offshore production for North America, Norwegian data indicate a CH_4 emission factor of 1.0 to 3.6 Gg/103 m3 of oil transferred (derived from data provided by Norwegian Pollution Control Authority, 2000).

[I] The presented CO_2 emissions factors account for direct CO_2 emissions only, except for flaring, in which case the presented values account for the sum of direct CO_2 emissions and indirect contributions due to the atmospheric oxidation of gaseous non-CO_2 carbon emissions.

Sources: The factors presented in this table have been determined by setting the lower limit of the range for each category equal to at least the values published in Table 4.2.4 for North America. Otherwise, all presented values have been adapted from applicable data provided in the 1996 IPCC Guidelines and from limited measurement data available from more recent unpublished studies of natural gas systems in China, Romania and Uzbekistan.

The factors in Table 4.2.4 for North America are derived from detailed emission inventory results for Canada and the United States and, where possible, have been updated from the values previously presented in the IPCC Good Practice Guidance (2000) document to reflect the results of more current and refined emissions inventories. Where applicable, factors from the API Compendium of Emissions Estimating Methodologies for the Petroleum Industry have been indicated.

The factors in Table 4.2.4 are presented as examples and reflect the following practices and state of the oil and gas industry:

- Most associated gas is conserved;
- Sweet waste gas is flared or vented;
- Sour waste gas is flared;
- Many gas transmission companies are voluntarily implementing programmes to reduce methane losses due to fugitive equipment leaks;
- The oil and gas industry is mature and actually in decline in many areas;
- System reliability is high;
- Equipment is generally well maintained and high-quality components are used;
- Line breaks and well blowouts are rare;
- The industry is highly regulated and these regulations are generally well enforced.

The emission factors presented in Table 4.2.5 have been set so that the lower limit of each range is at least equal to the corresponding value from Table 4.2.4. Otherwise, all values have been adapted from the factors presented in the 1996 Revised IPCC Guidelines and from limited measurement data available for several recent unpublished studies of natural gas systems in developing countries or countries with economies in transition. Where ranges in values are presented, these are either based on the relative ranges given in the 1996 Revised IPCC Guidelines or are estimated based on expert judgement and data from unpublished reports.

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 through the Internet at www.ipcc-nggip.iges.or.jp/EFDB/main.php. In addition regular reviews of the literature 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 and industry associations. 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 2004. The API Compendium is available at:

http://api-ec.api.org/policy/index.cfm.

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, 2003):

www.ipieca.org/downloads/climate_change/GHG_Reporting_Guidelines.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.

4.2.2.4 CHOICE OF ACTIVITY DATA

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.

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 4.2.7 below lists the activity data required by each of the Tier 1 emission factors presented in Tables 4.2.4 and 4.2.5, 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 4.2.6
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
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	Oil and Gas Throughputs
1	All	Oil and Gas Throughputs

TABLE 4.2.7
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	Required Activity Data Value	Guidance
Well Drilling	All	10^3 m^3 total oil production	Reference directly from national statistics.
Well Testing	All	10^3 m^3 total oil production	Reference directly from national statistics.
Well Servicing	All	10^3 m^3 total oil production	Reference directly from national statistics.
Gas Production	All	10^6 m^3 gas production	Reference directly from national statistics.
		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	
	Deep-cut Extraction Plants (Straddle Plants)	10^6 m^3 raw gas feed	Reference directly from national statistics if total gas receipts by straddle plants located on gas transmission systems is reported, otherwise, assume this value is equal to an appropriate portion of total marketable natural gas. In the absence of any information to make this apportionment, assume there are no straddle plants.
	Default Weighted Total	10^6 m^3 gas production	Reference directly from national statistics.
Gas Transmission & Storage	Transmission	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	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 4.2.7(CONTNUED)
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 Production	Conventional Oil	10^3 m^3 conventional oil production	Reference directly from national statistics.
	Heavy Oil/Cold Bitumen	10^3 m^3 heavy oil production	Reference directly from national statistics.
	Thermal Oil Production	10^3 m^3 thermal bitumen production	Reference directly from national statistics.
	Synthetic Crude (from Oilsands)	10^3 m^3 synthetic crude production from oilsands	Reference directly from national statistics.
	Synthetic Crude (from Oil Shale)	10^3 m^3 synthetic crude production from oil shale	Reference directly from national statistics.
	Default Weighted Total	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.

TABLE 4.2.7(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

	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.

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, regardless of the reason, and the gas is not produced into a gathering system, 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

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 indicative factors presented in Table 4.2.8 may be used to qualify specific methane losses as being low, medium or high and help assess their reasonableness. If specific methane losses are appreciably less than the low benchmark or greater than the high benchmark, 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.

TABLE 4.2.8
CLASSIFICATION OF GAS LOSSES AS LOW, MEDIUM OR HIGH AT SELECTED TYPES OF NATURAL GAS FACILITIES

Facilities	Activity data	Yearly emission factors			
		Low	Medium	High	Units of Measure
Production and Processing	Net gas production (i.e. marketed production)	0.05	0.2	0.7	% of net production
Transmission Pipeline Systems	Length of transmission pipelines	200	2 000	20 000	m^3/km/yr
Compressor Stations	Installed compressor capacity	6 000	20 000	100 000	m^3/MW/yr
Underground Storage	Working capacity of underground storage stations	0.05	0.1	0.7	% of working gas capacity
LNG Plant (liquefaction or regasification)	Gas throughput	0.005	0.05	0.1	% of throughput
Meter and Regulator Stations	Number of stations	1 000	5 000	50 000	m^3/station/yr
Distribution	Length of distribution network	100	1 000	10 000	m^3/km/yr
Gas Use	Number of gas appliances	2	5	20	m^3/appliance/yr

Source: Adapted by the authors from currently unpublished work by the International Gas Union, and based on data for a dozen countries including Russia and Algeria.

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.

4.2.2.6 DEVELOPING CONSISTENT TIME SERIES

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 should be updated to reflect the use of the improved factor and be reported in a transparent manner.

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

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;
- 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 4.2.4 and 4.2.5. 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[2] may not agree between different

2 A disposition analysis provides a reconciled accounting of produced hydrocarbons from the wellhead, or point of receipt, through to the final sales point or point of export. Typical disposition categories include flared/vented volumes, fuel usage, system losses, volumes added to/removed from inventory/storage, imports, exports, etc.

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.

Counts of major facilities (e.g., gas plants, refineries and transmission compressor stations) will usually be known with little if any 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 industry involvement in the preparation and refinement of these inventories.

REVIEW OF DIRECT EMISSION MEASUREMENTS

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.

EMISSION FACTORS CHECK

The inventory compiler should compare measurement-based factors to IPCC default factors and factors developed by other countries with similar industry characteristics. If IPCC default factors are used, the inventory compiler should ensure that they are applicable and relevant to the category. If possible, the IPCC default factors should be compared to national or local data to provide further indication that the factors are applicable.

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 will be susceptible to significant 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 industry involvement in the preparation and refinement of these inventories.

4.2.4 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 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. 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 4.2.9 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.

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. This is critical for proper interpretation of the results and any claims of net reductions.

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 4.2.9
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	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.b	Natural Gas										
1.B.2.b.i	Venting										

TABLE 4.2.9 (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	Throughput	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.3	Other emissions from Energy Production										

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

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CHAPTER 5

CARBON DIOXIDE TRANSPORT, INJECTION AND GEOLOGICAL STORAGE

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5 CARBON DIOXIDE TRANSPORT, INJECTION AND GEOLOGICAL STORAGE

5.1 INTRODUCTION

Carbon dioxide (CO_2) capture and storage (CCS) is an option in the portfolio of actions that could be used to reduce greenhouse gas emissions from the continued use of fossil fuels.

At its simplest, the CCS process is a chain consisting of three major steps: the capture and compression of CO_2 (usually at a large industrial installation[1]), its transport to a storage location and its long-term isolation from the atmosphere. IPCC (2005) has produced a Special Report on Carbon Dioxide Capture and Storage (SRCCS), from which additional information on CCS can be obtained. The material in these Guidelines has been produced in consultation with the authors of the SRCCS.

Geological storage can take place in natural underground reservoirs such as oil and gas fields, coal seams and saline water-bearing formations utilizing natural geological barriers to isolate the CO_2 from the atmosphere. A description of the storage processes involved is given in Chapter 5 of the SRCCS. Geological CO_2 storage may take place either at sites where the sole purpose is CO_2 storage, or in tandem with enhanced oil recovery, enhanced gas recovery or enhanced coalbed methane recovery operations (EOR, EGR and ECBM respectively).

These Guidelines provide emission estimation guidance for carbon dioxide transport, injection and geological storage (CCGS) only. No emissions estimation methods are provided for any other type of storage option such as ocean storage or conversion of CO_2 into inert inorganic carbonates. With the exception of the mineral carbonation of certain waste materials, these technologies are at the research stage rather than the demonstration or later stages of technological development IPCC (2005). If and when they reach later stages of development, guidance for compiling inventories of emissions from these technologies may be given in future revisions of the Guidelines.

Emissions resulting from fossil fuels used for capture, compression, transport, and injection of CO_2, are not addressed in this chapter. Those emissions are included and reported in the national inventory as energy use in the appropriate stationary or mobile energy use categories. Fuel use by ships engaged in international transport will be excluded where necessary by the bunker rules, whatever the cargo, and it is undesirable to extend the bunker provisions to emissions from any energy used in operating pipelines.

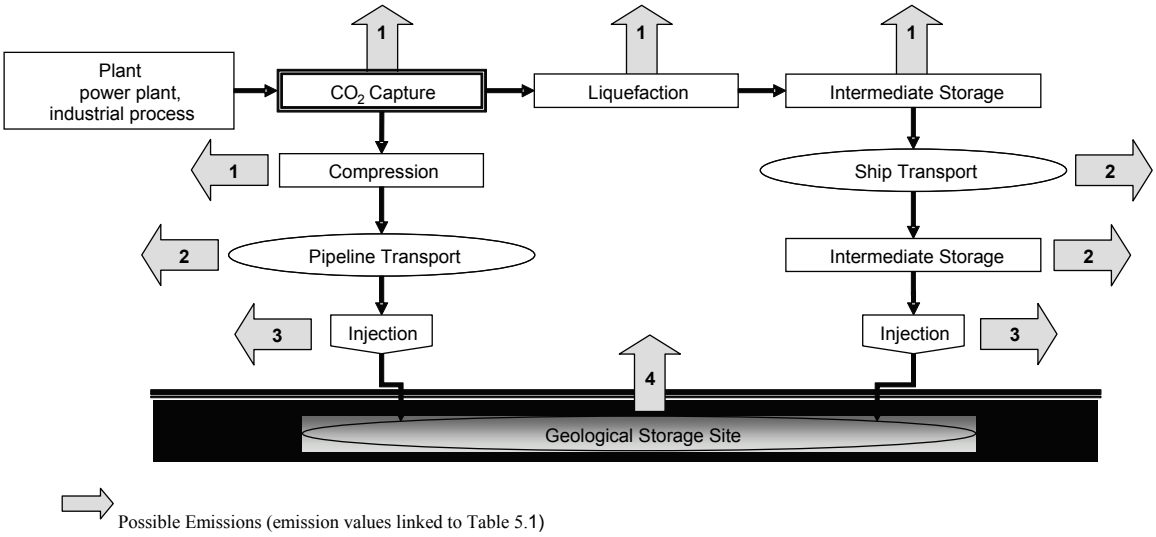
5.2 OVERVIEW

In these Guidelines, the CO_2 capture and geological storage chain is subdivided into four systems (Figure 5.1)

1. Capture and compression system. The systems boundary includes capture, compression and, where necessary, conditioning, for transport.
2. Transport system. Pipelines and ships are considered the most likely means of large-scale CO_2 transport. The upstream systems boundary is the outlet of the compression / conditioning plant in the capture and compression system. The downstream systems boundary is the downstream end of a transport pipeline, or a ship offloading facility. It should be noted that there may be compressor stations located along the pipeline system, which would be additional to any compression in System 1 or System 3.
3. Injection system. The injection system comprises surface facilities at the injection site, e.g. storage facilities, distribution manifold at end of transport pipeline, distribution pipelines to wells, additional compression facilities, measurement and control systems, wellhead(s) and the injection wells. The upstream systems boundary is the downstream end of transport pipeline, or ship offloading facility. The downstream systems boundary is the geological storage reservoir.
4. Storage system. The storage system comprises the geological storage reservoir.

[1] Examples of large point sources of CO_2 where capture is possible include power generation, iron and steel manufacturing, natural gas processing, cement manufacture, ammonia production, hydrogen production and ethanol manufacturing plants.

Figure 5.1 Schematic representation of the carbon capture and storage process with numbering linked to systems discussion above.



This chapter does not include guidance for CO_2 capture and compression. A brief summary and information on where to find emissions estimation guidelines for CO_2 capture and compression can be found in Section 5.3. Guidelines for compiling inventories of emissions from the CO_2 transport, injection and storage systems of the CCGS chain are given in Sections 5.4, 5.5 and 5.6 of this Chapter, respectively. Fugitive emissions from surface facilities at EOR, EGR and ECBM site (with or without CO_2 storage*)* are classified as oil and gas operations and Volume 2, Chapter 4 provides guidance on estimating these emissions. Emissions from underground storage reservoirs at EOR, EGR and ECBM sites are classified as emissions from geological storage sites and Section 5.7 of this Chapter provides guidance on estimating these emissions.

Table 5.1 shows the categories in which the emissions from the CO_2 transport, injection and storage systems are reported.

5.3 CO_2 CAPTURE

Anthropogenic carbon dioxide emissions arise mainly from combustion of fossil fuels (and biomass) in the power generation, industrial, buildings and transport sectors. CO_2 is also emitted from non-combustion sources in certain industrial processes such as cement manufacture, natural gas processing and hydrogen production.

CO_2 capture produces a concentrated stream of CO_2 at high pressure that can be transported to a storage site and stored. In these Guidelines, the systems boundary for capture includes compression and any dehydration or other conditioning of the CO_2 that takes place before transportation.

Electric power plants and other large industrial facilities are the primary candidates for CO_2 capture, although it is the high purity streams of CO_2 separated from natural gas in the gas processing industry that have been captured and stored to date. Available technology is generally deployed in a way that captures around 85-95 percent of the CO_2 processed in a capture plant IPCC (2005). Figure 5.2, taken from the SRCCS provides an overview of the relevant processes. The main techniques are briefly described below. Further detail is available in Chapter 3 of the SRCCS:

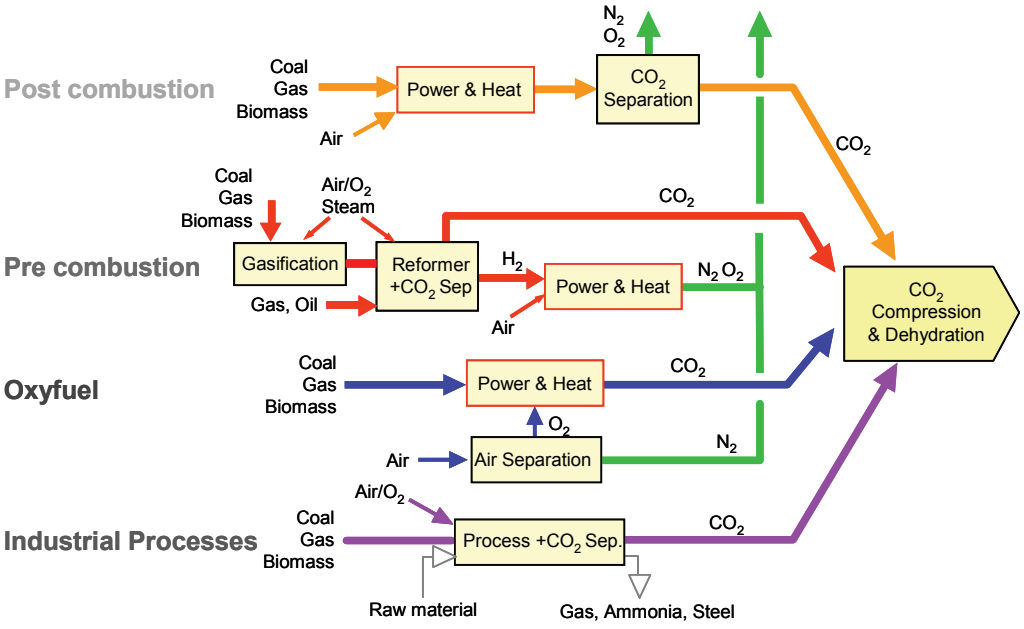
- Post-combustion capture: CO_2 can be separated from the flue gases of the combustion plant or from natural gas streams and fed into a compression and dehydration unit to deliver a relatively clean and dry CO_2 stream to a transportation system. These systems normally use a liquid solvent to capture the CO_2.
- Pre-combustion capture: This involves reacting a fuel with oxygen or air, and/or steam to produce a 'synthesis gas' or 'fuel gas' composed mainly of carbon monoxide and hydrogen. The carbon monoxide is reacted with steam in a catalytic reactor, called a shift converter, to give CO_2 and more hydrogen. CO_2 is then separated from the gas mixture, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as boilers, furnaces, gas turbines and fuel cells. This technology is widely used in hydrogen production, which is used mainly for ammonia and fertilizer manufacture, and in petroleum refining operations. Guidance on how to estimate and report emissions from this process is provided in Chapter 2, section 2.3.4 of this Volume.

- Oxy-fuel capture: In oxy-fuel combustion, nearly pure oxygen is used for combustion instead of air, resulting in a flue gas that is mainly CO_2 and H_2O. This flue gas stream can directly be fed into a CO_2 compression and dehydration unit. This technology is at the demonstration stage. Guidance on how to estimate and report emissions from this process is provided in Chapter 2, section 2.3.4 of this volume.

TABLE 5.1
SOURCE CATEGORIES FOR CCS

1	C			Carbon dioxide Transport and Storage	Carbon dioxide (CO_2) capture and storage (CCS) involves the capture of CO_2, its transport to a storage location and its long-term isolation from the atmosphere. Emissions associated with CO_2 transport, injection and storage are covered under category 1C. Emissions (and reductions) associated with CO_2 capture should be reported under the IPCC sector in which capture takes place (e.g. Stationary Combustion or Industrial Activities).
1	C	1		*Transport of CO_2*	Fugitive emissions from the systems used to transport captured CO_2 from the source to the injection site. These emissions may comprise fugitive losses due to equipment leaks, venting and releases due to pipeline ruptures or other accidental releases (e.g. temporary storage).
1	C	1	a	Pipelines	Fugitive emissions from the pipeline system used to transport CO_2 to the injection site.
1	C	1	b	Ships	Fugitive emissions from the ships used to transport CO_2 to the injection site.
1	C	1	c	Other (please specify)	Fugitive emissions from other systems used to transport CO_2 to the injection site and temporary storage.
1	C	2		*Injection and Storage*	Fugitive emissions from activities and equipment at the injection site and those from the end containment once the CO_2 is placed in storage.
1	C	2	a	Injection	Fugitive emissions from activities and equipment at the injection site.
1	C	2	b	Storage	Fugitive emissions from the end containment once the CO_2 is placed in storage.
1	C	3		*Other*	Any other emissions from CCS not reported elsewhere.

Figure 5.2 CO_2 capture systems (After the SRCCS):



As already mentioned in a number of industrial processes, chemical reactions lead to the formation of CO_2 in quantities and concentrations that allow for direct capture or separation of the CO_2 from their off gases, for example: ammonia production, cement manufacture, ethanol manufacture, hydrogen manufacture, iron and steel manufacture, and natural gas processing plant.

The location of guidelines for compiling inventories of emissions from the CO_2 capture and compression system depends on the nature of the CO_2 source:

- Stationary combustion systems (mainly electric power and heat production plants): Volume 2, Chapter 2, Section 2.3.4.
- Natural gas processing plants: Volume 2, Section 4.2.1.
- Hydrogen production plants: Volume 2, Section 4.2.1.
- Capture from other industrial processes: Volume 3 (IPPU) Chapter 1, Section 1.2.2, and specifically for
  - (i) Cement manufacture: IPPU Volume, Section 2.2
  - (ii) Methanol manufacture: IPPU Volume, Section 3.9
  - (iii) Ammonia production: IPPU Volume, Section 3.2
  - (iv) Iron and steel manufacture: IPPU Volume section 4.2

Negative emissions may arise from the capture and compression system if CO_2 generated by biomass combustion is captured. This is a correct procedure and negative emissions should be reported as such.

Although many of the potential emissions pathways are common to all types of geological storage, some of the emission pathways in enhanced hydrocarbon recovery operations differ from those for geological CO_2 storage without enhanced hydrocarbon recovery. In EOR operations, CO_2 is injected into the oil reservoir, but a proportion of the amount injected is commonly produced along with oil, hydrocarbon gas and water at the production wells. The CO_2-hydrocarbon gas mixture is separated from the crude oil and may be reinjected into the oil reservoir, used as fuel gas on site or sent to a gas processing plant for separation into CO_2 and hydrocarbon gas, depending upon its hydrocarbon content. EGR and ECBM processes attempt to avoid CO_2 production because it is costly to separate the CO_2 from a produced gas mixture. CO_2 separated from the hydrocarbon gas may be recycled and re-injected in the EOR operation, or vented; depending on the economics of recycling versus injecting imported CO_2. CO_2-rich gas is also released from the crude oil storage tanks at the EOR operation. This vapour may be vented, flared or used as fuel gas depending upon its hydrocarbon content. Thus there are possibilities for additional sources of fugitive emissions from the venting of CO_2 and the flaring or combustion of CO_2-rich hydrocarbon gas, and also from any injected CO_2 exported with the incremental hydrocarbons. These emissions along with fugitive emissions from surface operations at EOR, and EGR and ECBM sites (from the injection of CO_2, and/or the production, recycling, venting, flaring or combustion of CO_2-rich hydrocarbon gas), and including any injected CO_2 exported with the incremental hydrocarbons, can be estimated and reported using the higher methods described guidance given in Volume 2 Chapter 4.

5.4 CO_2 TRANSPORT

Fugitive emissions may arise e.g. from pipeline breaks, seals and valves, intermediate compressor stations on pipelines, intermediate storage facilities, ships transporting low temperature liquefied CO_2, and ship loading and offloading facilities. Emissions from transport of captured CO_2 are reported under category 1C (see Table 5.1). CO_2 pipelines are the most prevalent means of bulk CO_2 transport and are a mature market technology in operation today. Bulk transport of CO_2 by ship also already takes place, though on a relatively minor scale. This occurs in insulated containers at temperatures well below ambient, and much lower pressures than pipeline transport. Transport by truck and rail is possible for small quantities of CO_2, but unlikely to be significant in CCS because of the very large masses likely to be captured. Therefore no methods of calculating emissions from truck and rail transport are given here. Further information on CO_2 transport is available in Chapter 4 of the SRCCS (IPCC 2005).

5.4.1 CO_2 transport by pipeline

To estimate emissions from pipeline transport of CO_2, default emission factors can be derived from the emission factors for transmission (pipeline transport) of natural gas as provided in section 4.2 of this volume. The Tier 1 emission factors for natural gas pipeline transport, presented in, Tables 4.2.4 and 4.2.5 are provided on the basis of gas throughput primarily because pipeline length is not a national statistic that is commonly available. However, fugitive emissions from pipeline transport are largely independent of the throughput, but depend on the size of and the equipment installed in the pipeline systems. Since it is assumed that there exists a relationship between the size of the systems and natural gas used, such an approach is acceptable as Tier 1 method for natural gas transport.

The above might not be true for the transport of CO_2 in CCS applications. Since it is *good practice* to treat both capture and storage in a per plant or facility basis, the length of the transporting CO_2 pipeline system will be known and should be used to estimate emissions from transport.

BOX 5.1

DERIVATION OF DEFAULT EMISSION FACTORS FOR CO_2 PIPELINE TRANSPORT

The pressure drop of a gas over any geometry is described by:

$$\Delta P = \frac{f}{2} \rho * v^2 \frac{l}{D}$$

in which

- v is the linear velocity of the gas through the leak and, with the same size of the leak, is proportional to the leaking volume;
- ρ is the density of the gas;
- f is the dimensionless friction number
- l/D (length divided by diameter) is characterizing the physical size of the system.

For leaks, f = 1 and independent on the nature of the gas. So assuming the internal pressure of the pipe-line and the physical dimensions being the same for CO_2 and CH_4 transport, the leak-velocity is inversely proportional to the root of the density of the gas and hence proportional to the root of the molecular mass.

So when ΔP is the same for methane and carbon dioxide

$$v \sim \frac{1}{\sqrt{\rho}}$$

The molecule mass of CO_2 is 44 and of CH_4 is 16. So on a mass-basis the CO_2-emission rate is $\sqrt{\frac{44}{16}} = 1.66$ times the CH_4-emission rate.

From this the default emission factors for CO_2 pipeline transport are obtained by multiplying the relevant default emission factors[a] in Table 4.2.8 for natural gas (is mainly CH_4) by a factor of 1.66.

Notes:

[a] to convert the factors expressed in m^3 to mass units, a specific mass of 0.7 kg/m^3 for methane is applied.

See chapter 5 in: R.H. Perry, D. Green, *Perry's chemical engineers handbook*, 6th edition, McGraw Hill Book Company - New York, 1984.

Table 4.2.8 in section 4.2 of this volume provides indicative leakage factors for natural gas pipeline transport. To obtain Tier 1 default emission factors for CO_2 transport by pipeline these values should be converted from cubic metres to mass units and multiplied by 1.66 (see Box 1). The resulting default emission factors are given in Table 5.2.

TABLE 5.2
DEFAULT TIER 1 EMISSION FACTORS FOR PIPELINE TRANSPORT OF CO_2 FROM A CO_2 CAPTURE SITE TO THE FINAL STORAGE SITE

Emission Source	Value			Uncertainty	Units of Measure
	Low	Medium	High		
Fugitive emissions from CO_2 transportation by pipeline	0.00014	0.0014	0.014	± a factor of 2	Gg per year and per km of transmission pipeline

Although the leakage emissions from pipeline transport are independent of throughput, the number of leaks is not necessarily correlated to the length of the pipeline. The best correlation will be between the number and type of equipment components and the type of service. Most of the equipment tends to occur at the facilities connected to the pipeline rather than with the pipeline itself. In fact, unless the CO_2 is being transported over very large distances and intermediate compressor stations are required, virtually all of the fugitive emissions from a CCS system will be associated with the initial CO_2 capture and compression facilities at the start of the pipeline and the injection facilities at the end of the pipeline, with essentially no emissions from the pipeline itself. In Tier 3 approach, the leakage emissions from the transport pipeline could be obtained from data on number and type of equipment and equipment-specific emission factors.

5.4.2 CO_2 transport by ship

Default emission factors for fugitive emissions from CO_2 transport by ship are not available. The amounts of gas should be metered during loading and discharge using flow metering and losses reported as fugitive emissions of CO_2 resulting from transport by ship under category 1C1 b.

5.4.3 Intermediate storage facilities on CO_2 transport routes

If there is a temporal mismatch between supply and transport or storage capacity, a CO_2 buffer (above ground or underground) might be needed to temporarily store the CO_2. If the buffer is a tank, fugitive emissions should be measured and treated as part of the transport system and reported under category 1C1 c (other). If the intermediate storage facility (or buffer) is a geological storage reservoir, fugitive emissions from it can be treated in the same way as for any other geological storage reservoir (see Section 5.6 of this Chapter) and reported under category 1C3.

5.5 CO_2 INJECTION

The injection system comprises surface facilities at the injection site, e.g. storage facilities, any distribution manifold at the end of the transport pipeline, distribution pipelines to wells, additional compression facilities, measurement and control systems, wellhead(s) and the injection wells. Additional information on the design of injection wells can be found in the SRCCS, Chapter 5, Section 5.5.

Meters at the wellhead measure the flow rate, temperature and pressure of the injected fluid. The wellhead also contains safety features to prevent the blowout of the injected fluids. Safety features, such as a downhole safety valve or check valve in the tubing, may also be inserted below ground level, to prevent backflow in the event of the failure of the surface equipment. Valve and other seals may be affected by supercritical CO_2, so appropriate materials will need to be selected. Carbon steel and conventional cements may be liable to be attacked by highly saline brines and CO_2-rich fluids (Scherer et al. 2005). Moreover the integrity of CO_2 injection wells needs to be maintained for very long terms, so appropriate well construction materials and regulations will be needed. Cements used for sealing between the well and the rock formation and, after abandonment, plugging the well, must also be CO_2/salt brine resistant over long terms. Such cements have been developed but need further testing. Due to the potential for wells to act as conduits for CO_2 leakage back to the atmosphere, they should be monitored as part of a comprehensive monitoring plan as laid out in Section 5.7 of this Chapter.

The amount of CO_2 injected into a geological formation through a well can be monitored by equipment at the wellhead, just before it enters the injection well. A typical technique is described by Wright and Majek (1998). Meters at the wellhead continuously measure the pressure, temperature and flow rate of the injected gas. The

composition of the imported CO_2 commonly shows little variation and is analyzed periodically using a gas chromatograph. The mass of CO_2 passing through the wellhead can then be calculated from the measured quantities. No default method is suggested and the reporting of the mass of CO_2 injected as calculated from direct measurements is *good practice*.

If the pressure of the CO_2 arriving at the storage site is not as high as the required injection pressure, compression will be necessary. Any emissions from compression of the stored gas at the storage site should be measured and reported.

5.6 GEOLOGICAL STORAGE OF CO_2

Chapter 5 of the SRCCS (IPCC 2005) indicates that geological storage of carbon dioxide may take place onshore or offshore, in:

- **Deep saline formations**. These are porous and permeable reservoir rocks containing saline water in their pore spaces.
- **Depleted or partially depleted oil fields** - either as part of, or without, enhanced oil recovery (EOR) operations.
- **Depleted or partially depleted natural gas fields** – either with or without enhanced gas recovery (EGR) operations.
- **Coal seams** (= coal beds) – either with or without enhanced coalbed methane recovery (ECBM) operations.

Additionally, niche opportunities for storage may arise from other concepts such as storage in salt caverns, basalt formations and organic-rich shales.

Further information on these type of storage sites and the trapping mechanisms that retain CO_2 within them can be found in Chapter 5 of the SRCCS (IPCC 2005).

5.6.1 Description of emissions pathways/sources

The Introduction to the SRCCS states that >99% of the CO_2 stored in geological reservoirs is likely to remain there for over one thousand years. Therefore potential emissions pathways created or activated by slow or long-term processes need to be considered as well as those that may act in the short to medium term (decades to centuries).

In these Guidelines the term migration is defined as the movement of CO_2 within and out of a geological storage reservoir whilst remaining below the ground surface or the sea bed, and the term leakage is defined as a transfer of CO_2 from beneath the ground surface or sea bed to the atmosphere or ocean.

The only emissions pathways that need to be considered in the accounting are CO_2 leakage to the ground surface or seabed from the geological storage reservoir[2]. Potential emission pathways from the storage reservoir are shown in Table 5.3.

There is a possibility that methane emissions, as well as CO_2 emissions, could arise from geological storage reservoirs that contain hydrocarbons. Although there is insufficient information to provide guidance for estimating methane emissions, it would be *good practice* to undertake appropriate assessment of the potential for methane emissions from such reservoirs and, if necessary, include any such emissions attributable to the CO_2 storage process in the inventory.

[2] Emissions of CO_2 may occur as free gas or gas dissolved in groundwater that reaches the surface e.g. at springs.

TABLE 5.3
POTENTIAL EMISSION PATHWAYS FROM GEOLOGICAL RESERVOIRS

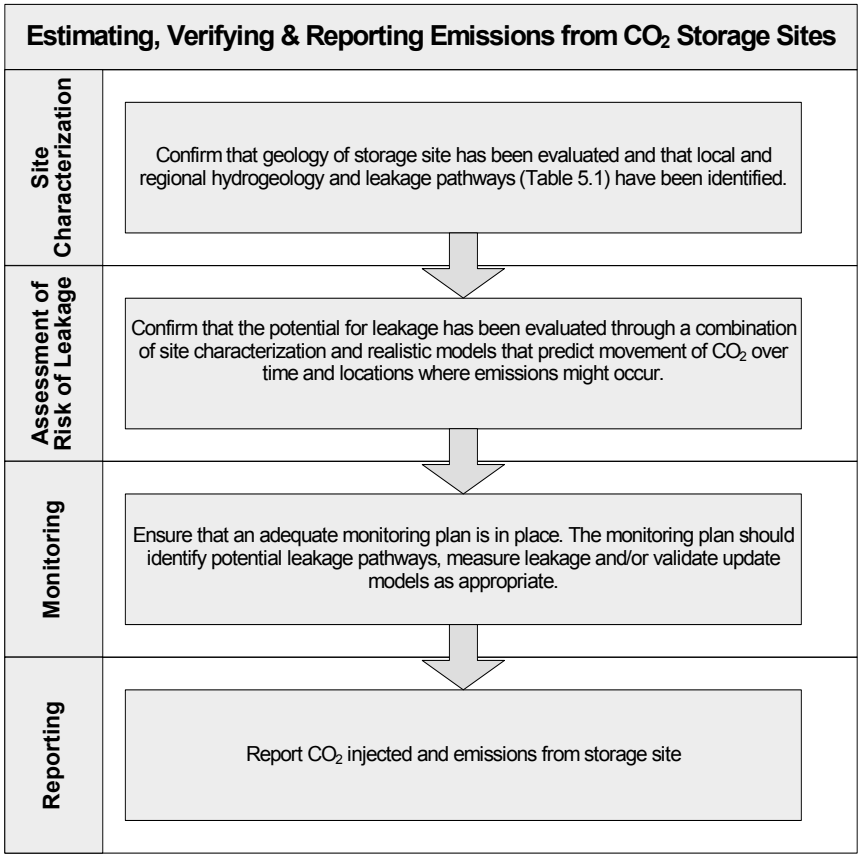
Type of emission	Potential emissions pathways/ sources	Additional comments
Direct leakage pathways created by wells and mining	• Operational or abandoned wells	• It is anticipated that every effort will be made to identify abandoned wells in and around the storage site. Inadequately constructed, sealed, and/or plugged wells may present the biggest potential risk for leakage. Techniques for remediating leaking wells have been developed and should be applied if necessary.
	• Well blow-outs (uncontrolled emissions from injection wells)	• Possible source of high-flux leakage, usually over a short period of time. Blowouts are subject to remediation and likely to be rare as established drilling practice reduces risk.
	• Future mining of CO_2 reservoir	• An issue for coal bed reservoirs
Natural leakage and migration pathways (that may lead to emissions over time)	• Through the pore system in low permeability cap rocks if the capillary entry pressure is exceeded or the CO_2 is in solution	• Proper site characterization and selection and controlled injection pressure can reduce risk of leakage.
	• If the cap rock is locally absent	• Proper site characterization and selection can reduce risk of leakage.
	• Via a spill point if reservoir is overfilled	• Proper site characterization and selection, including an evaluation of the hydrogeology, can reduce risk of leakage.
	• Through a degraded cap rock as a result of CO_2/water/rock reactions	• Proper site characterization and selection can reduce risk of leakage. Detailed assessment of cap rock and relevant geochemical factors will be useful.
	• Via dissolution of CO_2 into pore fluid and subsequent transport out of the storage site by natural fluid flow	• Proper site characterization and selection, including an evaluation of the hydrogeology, can determine/reduce risk of leakage.
	• Via natural or induced faults and/or fractures	• Possible source of high-flux leakage. Proper site characterization and selection and controlled injection pressure can reduce risk of leakage.
Other Fugitive Emissions at the Geological Storage Site	• Fugitive methane emissions could result from the displacement of CH_4 by CO_2 at geological storage sites. This is particularly the case for ECBM, EOR, and depleted oil and gas reservoirs.	Needs appropriate assessment.

5.7 METHODOLOGICAL ISSUES

Geological conditions vary widely and only a few published studies of monitoring programmes that identify and quantify fugitive anthropogenic carbon dioxide emissions from geological storage operations currently exist (Arts et al. 2003, Wilson and Monea 2005; Klusman 2003a, b, c). Although the Summary for Policymakers of the SRCCS suggests that properly selected geological storage sites are likely to retain greater than 99 percent of the stored CO_2 over 1000 years and may retain it for up to millions of years, at the time of writing, the small number of monitored storage sites means that there is insufficient empirical evidence to produce emission factors that could be applied to leakage from geological storage reservoirs. Consequently, this guidance does not include Tier 1 or Tier 2 methodology. However, there is the possibility of developing such methodologies in the future, when more monitored storage sites are in operation and existing sites have been operating for a long time (Yoshigahara et al. 2005). However a site-specific Tier 3 approach can be developed. Monitoring technologies have been developed and refined over the past 30 years in the oil and gas, groundwater and environmental monitoring industries (also see Annex 1). The suitability and efficacy of these technologies can be strongly influenced by the geology and potential emissions pathways at individual storage sites, so the choice of monitoring technologies will need to be made on a site-by-site basis. Monitoring technologies are advancing rapidly and it would be *good practice* to keep up to date on new technologies.

Tier 3 procedures for estimating and reporting emissions from CO_2 storage sites are summarised in Figure 5.3 and discussed below.

Figure 5.3 Procedures for estimating emissions from CO_2 storage sites



In order to understand the fate of CO_2 injected into geological reservoirs over long timescales, assess its potential to be emitted back to the atmosphere or seabed via the leakage pathways identified in Table 5.3, and measure any fugitive emissions, it is necessary to:

(a) Properly and thoroughly characterise the geology of the storage site and surrounding strata;

(b) Model the injection of CO_2 into the storage reservoir and the future behaviour of the storage system;

(c) Monitor the storage system;

(d) Use the results of the monitoring to validate and/or update the models of the storage system.

Proper site selection and characterization can help build confidence that there will be minimal leakage, improve modelling capabilities and results, and ultimately reduce the level of monitoring needed. Further information on site characterisation is available in the SRCCS and from the International Energy Agency Greenhouse Gas R & D Programme (IEAGHG 2005).

Monitoring technologies have been developed and refined over the past 30 years in the oil and gas, groundwater and environmental monitoring industries. The most commonly used technologies are described in Tables 5.1-5.6 in Annex I of this chapter. The suitability and efficacy of these technologies can be strongly influenced by the geology and potential emissions pathways at individual storage sites, so the choice of monitoring technologies will need to be made on a site-by-site basis. Monitoring technologies are advancing rapidly and it would be *good practice* to keep up to date on new technologies.

A range of modelling tools is available, some of which have undergone a process of code inter-comparison (Pruess et al. 2004). All models approximate and/or neglect some processes, and make simplifications. Moreover, their results are dependent on their intrinsic qualities and, especially, on the quality of the data put into them. Many of the physico-chemical factors involved (changes in temperature and pressure, mixing of the injected gas with the fluids initially present in the reservoir, the type and rate of carbon dioxide immobilization mechanisms and fluid flow through the geological environment) can be modelled successfully with numerical modelling tools known as reservoir simulators. These are widely used in the oil and gas industry and have proved effective in predicting movement of gases and liquids, including CO_2, through geological formations.

Reservoir simulation can be used to predict the likely location, timing and flux of any emissions, which, in turn, could be checked using direct monitoring techniques. Thus it can be an extremely useful technique for assessing the risk of leakage from a storage site. However, currently there is no single model that can account for all the processes involved at the scales and resolution required. Thus, sometimes, additional numerical modelling techniques may need to be used to analyze aspects of the geology. Multi-phase reaction transport models, which are normally used for the evaluation of contaminant transport can be used to model transport of CO_2 within the reservoir and CO_2/water/rock reactions, and potential geomechanical effects may need to be considered using geomechanical models. Such models may be coupled to reservoir simulators or independent of them.

Numerical simulations should be validated by direct measurements from the storage site, where possible. These measurements should be derived from a monitoring programme, and comparison between monitoring results and expectations used to improve the geological and numerical models. Expert opinion is needed to assess whether the geological and numerical modelling are valid representations of the storage site and surrounding strata and whether subsequent simulations give an adequate prediction of site performance.

Monitoring should be conducted according to a suitable plan, as described below. This should take into account the expectations from the modelling on where leakage might occur, as well as measurements made over the entire zone in which CO_2 is likely to be present. Site managers will typically be responsible for installing and operating carbon dioxide storage monitoring technologies (see Annex 1). The inventory compiler will need to ensure that it has sufficient information from each storage site to assess annual emissions in accordance with the guidance provided in this Chapter. To make this assessment, the inventory compiler should establish a formal arrangement with each site operator that will allow for annual reporting, review and verification of site-specific data.

5.7.1 Choice of method

At the time of writing, the few CO_2 storage sites that exist are part of petroleum production operations and are regulated as such. For example, acid gas storage operations in western Canada need to conform to requirements that deal with applications to operate conventional oil and gas reservoirs (Bachu and Gunter, 2005). Regulatory development for CCS is in its early stages. There are no national or international standards for performance of geological CO_2 storage sites and many countries are currently developing relevant regulations to address the risks of leakage. Demonstration of monitoring technologies is a necessary part of this development (see Annex 1). As these standards and regulatory approaches are developed and implemented, they may be able to provide emissions information with relative certainty. Therefore, as part of the annual inventory process, if one or more appropriate governing bodies that regulate carbon dioxide capture and storage exist, then the inventory compiler may obtain emissions information from those bodies. If the inventory compiler relies on this information, he/she should submit supporting documentation that explains how emissions were estimated or measured and how these methods are consistent with IPCC practice. If no such agency exists, then it would be *good practice* for the inventory compiler to follow the methodology presented below. In the methodology presented below, site characterization, modelling, assessment of the risk of leakage and monitoring activities are the responsibility of the storage project manager and/or an appropriate governing body that regulates carbon dioxide capture and

storage. In addition, the storage project manager or regulatory authority will likely develop the emission estimates that will be reported to the national inventory compiler as part of the annual inventory process. The responsibility of the national inventory compiler is to request the emissions data and seek assurance of its validity. In the case of CCS associated with ECBM recovery, the methodology should be applied both to CO_2 and CH_4 detection.

1. Identify and document all geological storage operations in the jurisdiction. The inventory compiler should keep an updated record of all geological storage operations, including all the information needed to cross-reference from this section to other elements of the CO_2 capture and storage chain for QA/QC purposes, that is for each operation:

- The location of the site;
- The type of operation (whether or not associated with EOR, EGR, ECBM);
- The year in which CO_2 storage began;
- Source(s), annual mass of CO_2 injected attributable to each source and the imputed cumulative amount in storage; and
- Associated CO_2 transport, injection and recycling infrastructure, if appropriate (i.e. on-site generation and capture facilities, pipeline connections, injection technology etc.) and emissions therefrom.

Although the inventory compiler is only responsible for reporting on the effect of operations in its jurisdiction, he/she must record cross-border transfers of CO_2 for cross-checking and QA/QC purposes (see Section 5.9).

2. Determine whether an adequate geological site characterization report has been produced for each storage site. The site characterization report should identify and characterize potential leakage pathways such as faults and pre-existing wells, and quantify the hydrogeological properties of the storage system, particularly with respect to CO_2 migration. The site characterisation report should include sufficient data to represent such features in a geological model of the site and surrounding area. It should also include all the data necessary to create a corresponding numerical model of the site and surrounding area for input into an appropriate numerical reservoir simulator.

3. **Determine whether the operator has assessed the potential for leakage at the storage site.** The operator should determine the likely timing, location and flux of any fugitive emissions from the storage reservoir, or demonstrate that leakage is not expected to occur. Short-term simulations of CO_2 injection should be made, to predict the performance of the site from the start of injection until significantly after injection ceases (likely to be decades). Long-term simulations should be performed to predict the fate of the CO_2 over centuries to millenia. Sensitivity analysis should be conducted to assess the range of possible emissions. The models should be used in the design of a monitoring programme that will verify whether or not the site is performing as expected. The geological model and reservoir model should be updated in future years in the light of any new data and to account for any new facilities or operational changes.

4. Determine whether each site has a suitable monitoring plan. Each site's monitoring plan should describe monitoring activities that are consistent with the leakage assessment and modelling results. Existing technologies presented in Annex 1 can measure leaks to the ground surface or seabed. The SRCCS includes detailed information on monitoring technologies and approaches (see Annex 1). In summary the monitoring programme should include provisions for:

(i) Measurement of background fluxes of CO_2 (and if appropriate CH_4) at both the storage site and any likely emission points outside the storage site. Geological storage sites may have a natural, seasonally variable (ecological and/or industrial) background flux of emissions prior to injection. This background flux should not be included in the estimate of annual emissions. See Annex 1 for a discussion of potential methods. Isotopic analysis of any background fluxes of CO_2 is recommended, as this is likely to help distinguish between natural and injected CO_2.

(ii) Continuous measurement of the mass of CO_2 injected at each well throughout the injection period, see Section 5.5 above.

(iii) Monitoring to determine any CO_2 emissions from the injection system.

(iv) Monitoring to determine any CO_2 (and if appropriate CH_4) fluxes through the seabed or ground surface, including where appropriate through wells and water sources such as springs. Periodic investigations of the entire site, and any additional area below which monitoring and modelling suggests CO_2 is distributed, should be made to detect any unpredicted leaks.

(v) Post-injection Monitoring: The plan should provide for monitoring of the site after the injection phase. The post-injection phase of monitoring should take account of the results of

the forward modelling of CO_2 distribution to ensure that monitoring equipment is deployed at appropriate places and appropriate times. Once the CO_2 approaches its predicted long-term distribution within the reservoir and there is agreement between the models of CO_2 distribution and measurements made in accordance with the monitoring plan, it may be appropriate to decrease the frequency of (or discontinue) monitoring. Monitoring may need to be resumed if the storage site is affected by unexpected events, for example seismic events.

(vi) Incorporating improvements in monitoring techniques/technologies over time.

(vii) Periodic verification of emissions estimates. The necessary periodicity is a function of project design, implementation and early determination of risk potential. During the injection period, verification at least every five years or after significant change in site operation is suggested.

Continuous monitoring of the injection pressure and periodic monitoring of the distribution of CO_2 in the subsurface would be useful as part of the monitoring plan. Monitoring the injection pressure is necessary to control the injection process, e.g. to prevent excess pore fluid pressure building up in the reservoir. It can provide valuable information on the reservoir characteristics and early warning of leakage. This is already common practice and can be a regulatory requirement for current underground injection operations. Periodically monitoring the distribution of CO_2 in the subsurface, either directly or remotely would also be useful because it can provide evidence of any migration of CO_2 out of the storage reservoir and early warning of potential leaks to the atmosphere or seabed.

5. Collect and verify annual emissions from each site: The operators of each storage site should, on an annual basis, provide the inventory compiler with annual emissions estimates, which will be made publicly available. The emissions recorded from the site and any leaks that may occur inside or outside the site in any year will be the emissions as estimated from the modelling (which may be zero), adjusted to take account of the annual monitoring results. If a sudden release occurs, e.g. from a well blowout, the amount of CO_2 emitted should be estimated in the inventory. To simplify accounting for offshore geological storage, leakage to the seabed should be considered as emissions to the atmosphere for the purposes of compiling the inventory. In addition to total annual emissions, background data should include the total amount of CO_2 injected, the source of the injected CO_2, the cumulative total amount of CO_2 stored to date, the technologies used to estimate emissions, and any verification procedures undertaken by the site operators in accordance with the monitoring plan as indicated under 4(iii) and 4(iv) above. To verify emissions, the inventory compiler should request and review documentation of the monitoring data, including the frequency of monitoring, technology detection limits, and the share of emissions coming from the various pathways identified in the emission monitoring plan and any changes introduced as a result of verification. If a model was used to estimate emissions during years in which direct monitoring did not take place, the inventory compiler should compare modelled results against the most recent monitoring data. Steps 2, 3, and 4 above should indicate the potential for, and likely timing of future leaks and the need for direct monitoring.

Total national emissions for geological carbon dioxide storage will be the sum of the site-specific emission estimates:

EQUATION 5.1
TOTAL NATIONAL EMISSIONS

$$National\ Emissions\ from\ geological\ carbon\ dioxide\ storage = \sum carbon\ dioxide\ storage\ site\ emissions$$

Further guidance on reporting emissions where more than one country is involved in CO_2 capture, storage, and/or emissions is provided in Section 5.10: Reporting and Documentation.

5.7.2 Choice of emission factors and activity data

Tier 1 or 2 emission factors are not currently available for carbon dioxide storage sites, but may be developed in the future (see Section 5.7). However, as part of a Tier 3 emissions estimation process, the inventory compiler should collect activity data from the operator on annual and cumulative CO_2 stored. These data can be easily monitored at the injection wellhead or in adjacent pipework.

Monitoring in early projects may help obtain useful data that could be used to develop Tier 1 or 2 methodologies in the future. Examples of the application of monitoring technologies are provided by the monitoring programmes at the enhanced oil recovery projects at Rangely in Colorado, USA (Klusman, 2003a, b, c) Weyburn in Saskatchewan, Canada (Wilson and Monea, 2005), and the Sleipner CO_2 storage project, North Sea (Arts et al., 2003; also see Annex 5.1). None of the other CO_2-injection projects around the world have yet published the results of systematic monitoring for leaking CO_2.

The Rangely enhanced oil recovery project started injecting CO_2 into the Weber Sand Unit oil reservoir in the Rangely field in 1986. Cumulative CO_2 injection to 2003 was approximately 23 million tonnes. A monitoring programme was undertaken (Klusman 2003a, b, c), based on 41 measurement locations scattered across a 78 km^2 site. No pre-injection background measurements were available (which, at a new site, would be determined at step 4 (i) in the monitoring plan outlined above). In lieu of a pre-injection baseline, 16 measurement locations in a control area outside the field were sampled. The results of the monitoring programme indicate an annual deep-sourced CO_2 emission of less than 3 800 tonnes/yr from the ground surface above the oil field. It is likely that at least part, if not all, of this flux is due to the oxidation of deep-sourced methane derived from the oil reservoir or overlying strata, but it is possible that part of it could be fugitive emissions of CO_2 injected into the oil reservoir. The absence of pre-injection baseline measurements prevents definitive identification of its source.

CO_2 has been injected at the Weyburn oil field (Saskatchewan, Canada) for EOR since September 2000. Soil gas sampling, with the primary aims of determining background concentrations and whether there have been any leaks of CO_2 or associated tracer gases from the reservoir, took place in three periods from July 2001 and October 2003. There is no evidence to date for escape of injected CO_2. However, further monitoring of soil gases is necessary to verify that this remains the case in the future and more detailed work is necessary to understand the causes of variation in soil gas contents, and to investigate further possible conduits for gas escape (Wilson and Monea 2005).

The Sleipner CO_2 storage site in the North Sea, offshore Norway (Chadwick et al. 2003) has been injecting approximately 1 million tonnes of CO_2 per year into the Utsira Sand, a saline formation, since 1996. Cumulative CO_2 injection to 2004 was >7 million tonnes. The distribution of CO_2 in the subsurface is being monitored by means of repeated 3-D seismic surveys (pre-injection and two repeat surveys are available publicly to date) and, latterly, by gravity surveys (only one survey has been acquired to date). The results of the 3D seismic surveys indicate no evidence of leakage (Arts et al. 2003).

Taken together, these studies show that a Tier 3 methodology can be implemented so as to support not only zero emissions estimates but also to detect leakage, even at low levels, if it occurs.

There has been only one large-scale trial of enhanced coalbed methane (ECBM) production using CO_2 as an injectant; the Allison project in the San Juan Basin, USA (Reeves, 2005). There was sufficient information derived from the Allison project to indicate that CO_2 was sequestered securely in the coal seams. Pressure and compositional data from 4 injection wells and 15 production wells indicated no leakage. Some CO_2 was recovered from the production wells after approximately five years. However, this was expected and, for inventory purposes, it would be accounted as an emission (if it was not separated from the produced coalbed methane and recycled). No monitoring of the ground surface for CO_2 or methane leakage was undertaken.

5.7.3 Completeness

All emissions (CO_2 and if relevant, CH_4) from all CO_2 storage sites should be included in the inventory. In cases where CO_2 capture occurs in a different country from CO_2 storage, arrangements to ensure that there is no double accounting of storage should be made between the relevant national inventory compilers.

The site characterization and monitoring plans should identify possible sources of emissions outside the site (e.g., lateral migration, groundwater, etc.). Alternatively, a reactive strategy to locations outside the site could be deployed, based on information from inside it. If the emissions are predicted and/or occur outside the country where the storage operation (CO_2 injection) takes place, arrangements should be made between the relevant national inventory compilers to monitor and account these emissions.(see Section 5.10 below).

Estimates of CO_2 dissolved in oil and emitted to the atmosphere as a result of surface processing are covered under the methodologies for oil and gas production. The inventory compiler should ensure that information on these emissions collected from CO_2 storage sites is consistent with estimates under those source categories.

5.7.4 Developing a consistent time series

If the detection capabilities of monitoring equipment improve over time, or if previously unrecorded emissions are identified, or if updating of models suggests that unidentified emissions have occurred, and an updated monitoring programme corroborates this, appropriate recalculation of emissions will be necessary. This is particularly important given the generally low precision associated with current monitoring suites, even using the most advanced current technologies. Establishment of the background flux and variability is also critical. For dedicated CO_2 storage sites, anthropogenic emissions prior to injection and storage will be zero. For some enhanced oil recovery operations, there may be anthropogenic emissions prior to conversion to a CO_2 storage site.

5.8 UNCERTAINTY ASSESSMENT

It is a part of *good practice* that an uncertainty assessment is included when using Tier 3 methods. Uncertainty in the emissions estimates will depend on the precision of the monitoring techniques used to verify and measure any emissions and the modelling used to predict leakage from the storage site. The concept of percentage uncertainties may not be applicable for this sector and therefore confidence intervals and/or probability curves could be given.

The uncertainty in field measurements is most important and will depend on the sampling density and frequency of measurement and can be determined using standard statistical methods.

An effective reservoir simulation should address the issues of variability and uncertainty in the physical characteristics, especially reservoir rock and reservoir fluid properties, because reservoir models are designed to predict fluid movements over a long timescale and because geological reservoirs are inherently heterogeneous and variable. The uncertainty in estimates derived from modelling will therefore depend on:

- The completeness of the primary data used during the site assessment;
- The correspondence between the geological model and critical aspects of the geology of the site and surrounding area, in particular the treatment of possible migration pathways;

The accuracy of critical data that support the model:

- Its subsequent numerical representation by grid blocks
- Adequate representation of the processes in the physico-chemical numerical and analytical models

Uncertainty estimates are typically made by varying the model input parameters and undertaking multiple simulations to determine the impact on short-term model results and long-term predictions. The uncertainty in field measurements will depend on the sampling density and frequency of measurement and can be determined using standard statistical methods. Where model estimates and measurements are both available, the best estimate of emissions will be made by validating the model, and then estimating emissions with the updated model. Multiple realizations using the history-matched model can address uncertainty in these estimates. These data may be used to modify original monitoring requirements (e.g. add new locations or technology, increase or reduce frequency) and ultimately comprise the basis of an informed decision to decommission the facility.

5.9 INVENTORY QUALITY ASSURANCE/QUALITY CONTROL (QA/QC)

QA/QC for the whole CCS system

CO_2 capture should not be reported without linking it to long-term storage.

A check should be made that the mass of CO_2 captured does not exceed the mass of CO_2 stored plus the reported fugitive emissions in the inventory year (Table 5.4).

There has been limited experience with CCS to date, but it is expected that experience will increase over the next few years. Therefore, it would be *good practice* to compare monitoring methods and possible leakage scenarios between comparable sites internationally. International cooperation will also be advantageous in developing monitoring methodologies and technologies.

TABLE 5.4
OVERVIEW TABLE: OVERVIEW OF CO_2 CAPTURE, TRANSPORT, INJECTION AND CO_2 FOR LONG-TERM STORAGE

Category	Activity		CO_2 (Gg) [1]
	Data Source	Unit	
Total amount captured for storage (A)	Summed from all relevant categories	Gg	
Total amount of import for storage (B)	Data from pipeline companies, or statistical agencies	Gg	
Total amount of export for storage (C)	Data from pipeline companies, or statistical agencies	Gg	
Total amount of CO_2 injected at storage sites (D)	Data from storage sites provided by operators, as described in Chapter 5	Gg	
Total amount of leakage during transport (E1)	Summed from IPCC reporting category 1 C 1	Gg	
Total amount of leakage during injection (E2)	Summed from IPCC reporting category 1 C 2 a	Gg	
Total amount of leakage from storage sites (E3)	Summed from IPCC reporting category 1 C 2 b	Gg	
Total leakage (E4)	E1 + E2 + E3	Gg	
Capture + Imports (F)	A + B	Gg	
Injection + Leakage + Exports (G)	D + E4 + C	Gg	
Discrepancy	F - G	Gg	

[1] Once captured, there is no differentiated treatment between biogenic carbon and fossil carbon: emissions and storage of both will be estimated and reported.

Ideally, (Capture + Imports) = (Injection + Exports + Leakage)

If (Capture + Imports) < (Injection + Exports + Leakage) then there is need to check that

Exports are not overestimated

Imports are not underestimated

Data for CO_2 injection does not include EOR operations not associated with storage

If (Capture + Imports) > (Injection + Exports + Leakage) then need to check that

Exports are not under-estimated

Imports are not overestimated

CO_2 capture designated as 'for long-term storage' is actually going to other short-term emissive uses (e.g., products, EOR without storage)

Site QA/QC

On-site QA/QC will be achieved by regular inspection of monitoring equipment and site infrastructure by the operator. Monitoring equipment and programmes will be subject to independent scrutiny by the inventory compiler and/or regulatory agency.

All data including the site characterization reports, geological models, simulations of CO_2 injection, predictive modelling of the site, risk assessments, injection plans, licence applications, monitoring strategies and results and verification should be retained by the operator and forwarded to the inventory compiler for QA/QC.

The inventory compiler should compare (benchmark) the leak rates of a given storage facility against analogous storage sites and explain the reasons for differences in performance.

Where applicable, the relevant regulatory body can provide verification of emissions estimates and/or the monitoring plan described above. If no such body exists, the site operator should at the outset provide the inventory compiler with the results of peer review by a competent third party confirming that the geological and numerical models are representative, the reservoir simulator is suitable, the modelling realistic and the monitoring plan suitable. As they become available, the site operator should compare the results of the monitoring programme with the predictive models and adjust models, monitoring programme and/or injection strategy appropriately. The site operator should inform the inventory compiler of changes made.

5.10 REPORTING AND DOCUMENTATION

Guidelines for reporting emissions from geological storage:

Prior to the start of the geological storage operation, the national inventory compiler where storage takes place should obtain and archive the following:

- Report on the methods and results of the site characterization
- Report on the methods and results of modelling
- A description of the proposed monitoring programme including appropriate background measurements
- The year in which CO_2 storage began or will begin
- The proposed sources of the CO_2 and the infrastructure involved in the whole CCGS chain between source and storage reservoir

The same national inventory compiler should receive annually from each site:

- The mass of CO_2 injected during the reporting year
- The mass of CO_2 stored during the reporting year
- The cumulative mass of CO_2 stored at the site
- The source (s) of the CO_2 and the infrastructure involved in the whole CCGS chain between source and storage reservoir
- A report detailing the rationale, methodology, monitoring frequency and results of the monitoring programme - to include the mass of any fugitive emissions of CO_2 and any other greenhouse gases to the atmosphere or sea bed from the storage site during the reporting year
- A report on any adjustment of the modelling and forward modelling of the site that was necessary in the light of the monitoring results
- The mass of any fugitive emissions of CO_2 and any other greenhouse gases to the atmosphere or sea bed from the storage site during the reporting year
- Descriptions of the monitoring programmes and monitoring methods used, the monitoring frequency and their results
- Results of third party verification of the monitoring programme and methods

There may be additional reporting requirements at the project level where the site is part of an emissions trading scheme.

Reporting of cross-border CCS operations

CO_2 may be captured in one country, Country A, and exported for storage in a different country, Country B. Under this scenario, Country A should report the amount of CO_2 captured, any emissions from transport and/or temporary storage that takes place in Country A, and the amount of CO_2 exported to Country B. Country B should report the amount of CO_2 imported, any emissions from transport and/or temporary storage (that takes place in Country B), and any emissions from injection and geological storage sites.

If CO_2 is injected in one country, Country A, and travels from the storage site and leaks in a different country, Country B, Country A is responsible for reporting the emissions from the geological storage site. If such leakage is anticipated based on site characterization and modelling, Country A should make an arrangement with Country B to ensure that appropriate standards for long-term storage and monitoring and/or estimation of

emissions are applied (relevant regulatory bodies may have existing arrangements to address cross-border issues with regard to groundwater protection and/or oil and gas recovery).

If more than one country utilizes a common storage site, the country where the geological storage takes place is responsible for reporting emissions from that site. If the emissions occur outside of that country, they are still responsible for reporting those emissions as described above. In the case where a storage site occurs in more than one country, the countries concerned should make an arrangement whereby each reports an agreed fraction of the total emissions.

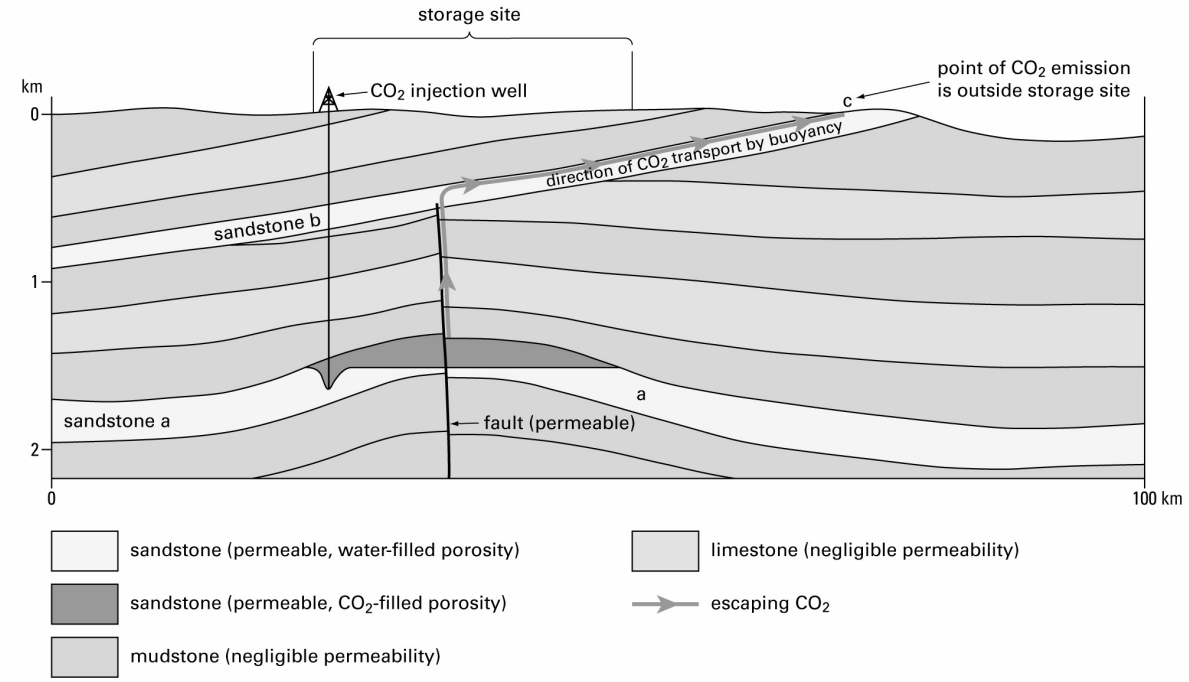
Annex 5.1 Summary description of potential monitoring technologies for geological CO_2 storage sites

Introduction

Monitoring of the geological storage of CO_2 requires the use of a range of techniques that can define the distribution, phase and mass of the injected CO_2 anywhere along any path from the injection point in the geological storage reservoir to the ground surface or seabed. This will commonly require the application of several different techniques concurrently.

The geology of the storage site and its surrounding area should be characterized to identify features, events and processes that could lead to an escape of CO_2 from the storage reservoir, and also to model potential CO_2 transport routes and fluxes in case there should be an escape of CO_2 from a storage reservoir, as this will not necessarily be on the injection site (Figure A1).

Figure A1 An illustration of the potential for leakage of CO_2 from a geological storage reservoir to occur outside the storage site.



If CO_2 migrates from a storage reservoir (a) via an undetected fault into porous and permeable reservoir rock (b), it may be transported by buoyancy towards the ground surface at point (c). This may result in the emission of CO_2 at the ground surface several kilometres from the site itself at an unknown time in the future. Characterization of the geology of the storage site and surrounding area and numerical modelling of potential leakage scenarios and processes can provide the information needed to correctly site surface and subsurface monitoring equipment during and after the injection process.

Tables A5.1 - A5.6 list the more common monitoring techniques and measurement tools that can be used for monitoring CO_2 in the deep subsurface (here considered to be the zone approximately 200 metres to 5 000 metres below the ground surface or sea bed), the shallow subsurface (approximately the top 200 metres below the ground surface or sea bed) and the near surface (regions less than 10 metres above and below the ground surface or sea bed).

The techniques that will produce the most accurate results given the circumstances should be used. The appropriate techniques will usually be apparent to specialists, but different techniques can also be assessed for relative suitability. There are no sharply defined detection limits for most techniques. In the field, their ability to measure the distribution, phase and mass of CO_2 in a subsurface reservoir will be site-specific. It will be determined as much by the geology of the site and surrounding area, and ambient conditions of temperature, pressure and water saturation underground as by the theoretical sensitivity of the techniques or measurement instruments themselves.

Similarly, the detection limits of surface monitoring techniques are determined by environmental parameters as well as the sensitivity of the monitoring instruments themselves. In near-surface systems on land, CO_2 fluxes and concentrations are determined by uptake of CO_2 by plants during photosynthesis, root respiration, microbial respiration in soil, deep outgassing of CO_2 and exchange of CO_2 between the soil and atmosphere [Oldenburg and Unger 2003]. Any outgassing of CO_2 from a man-made CO_2 storage reservoir needs to be distinguished from the variable natural background (Oldenburg and Unger 2003, Klusman 2003a, c). Analysis of stable and radiogenic carbon isotope ratios in detected CO_2 can help this process.

Most techniques require calibration or comparison with baseline surveys made before injection starts, e.g. to determine background fluxes of CO_2. Strategies for monitoring in the deep subsurface have been applied at the Weyburn oil field and Sleipner CO_2 storage site (Wilson and and Monea 2005, Arts et al. 2003). Interpretation of 4D seismic surveys has been highly successful in both cases. In the Weyburn field, geochemical information obtained from some of the many wells has also proved extremely useful.

Strategies for monitoring the surface and near-surface onshore have been proposed (Oldenburg and Unger 2003) and applied (Klusman 2003a, c; Wilson and Monea 2005). Soil gas surveys and surface gas flux measurements have been used. To date there has been no application of shallow subsurface or seabed monitoring specifically for CO_2 offshore. However, monitoring of natural gas seepage and its effects on the shallow subsurface and seabed has been undertaken and considered as an analogue for CO_2 seepage [e.g., Schroot and Schüttenhelm 2003a, b].

TABLE A 5.1
POTENTIAL DEEP SUBSURFACE MONITORING TECHNOLOGIES AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
2D, 3D and 4D (time-lapse) and multi-component seismic reflection surveys	Images geological structure of site and surrounding area; structure, distribution and thickness of the reservoir rock and cap rock; distribution (and with time-lapse surveys movement) of CO_2 in reservoir. May verify (within limits) mass of CO_2 in reservoir. Permanent seismic arrays can be installed (but are not necessary) for time-lapse (4D) acquisition.	Site-specific. Optimum depth of target commonly 500-3000 m. At Sleipner, which is close to optimum for the technique, detection limit in Utsira Sand is c. 2800 tonnes CO_2. At Weyburn, detection limit is c. 2500 - 7500 tonnes CO_2 (White et al. 2004). Likely that dispersed CO_2 in overlying strata could be detected - shallow natural gas pockets imaged as bright spots and dispersed methane in gas chimneys can be well imaged.	Onshore and offshore. Imaging poorer through karst, beneath salt, beneath gas, in general resolution decreases with depth	Cannot image dissolved CO_2 (insufficient impedance contrast between CO_2-saturated pore fluid and native pore fluid). Cannot image well in cases in which there is little impedance contrast between fluid and CO_2-saturated rock. These will be fairly common (Wang, 1997)	Highly developed with full commercial deployment in oil and gas industry
Crosshole seismic	Images velocity distribution between wells. Provides 2D information about rocks and their contained fluids.	Site specific. Resolution could be higher than surface seismic reflection surveys but coverage more restricted	Onshore and offshore	As above, and limited to area between wells	Highly developed with full commercial deployment in oil and gas industry
Vertical seismic profile	Image velocity distribution around a single well. Map fluid pressure distribution around well. Potential early warning of leakage around well.	Site specific	Onshore and offshore	As above and limited to small area around a single well	Highly developed with full commercial deployment in oil and gas industry

TABLE A 5.1(CONTINUED)
POTENTIAL DEEP SUBSURFACE MONITORING TECHNOLOGIES AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Microseismic monitoring	Detects and triangulates location of microfractures in the reservoir rock and surrounding strata. Provides an indication of location of injected fluid fronts. Assesses induced seismic hazard.	Site specific. Depends on background noise amongst other factors. More receivers in more wells provides greater accuracy in location of events	Onshore and offshore	Requires wells for deployment	Well developed with some commercial deployment
Monitoring wells	Many potential functions including measurement of CO_2 saturation, fluid pressure, temperature. Cement and or casing degradation or failure. Well logging. Tracer detection - fast-moving tracers might provide an opportunity to intervene in the leakage prevention by modifying operating parameters. Detection of geochemical changes in formation fluids. Physical sampling of rocks and fluids. In-well tilt meters for detecting ground movement caused by CO_2 injection. Monitoring formations overlying the storage reservoir for signs of leakage from the reservoir.	Downhole geochemical samples can be analyzed by Inductively Coupled Plasma Mass Spectrometer (has resolution of parts per billion). Perflourocarbon tracers can be detected in parts per 10^{12}. Well logs provide accurate measurement of many parameters (porosity, resistivity, density, etc).	Onshore and offshore. More expensive to access offshore.	Certain functions can only be performed before the well is cased. Others require the perforation of certain intervals of the casing. Cost is a limitation, especially offshore	Monitoring wells deployed e.g. in natural gas storage industry. Many tools highly developed and routinely deployed in oil and gas industry, others under development
Wellhead pressure monitoring during injection, formation pressure testing	Injection pressure can be continuously monitored at the wellhead by meters (Wright & Majek 1998). Downhole pressure can be monitored with gauges. Injection pressure tests and production tests applied in well to determine permeability, presence of barriers in reservoir, ability of cap rocks to retain fluids.	Proven technology for oil and gas field reservoir engineering and reserves estimation. ICP-MS used to detect subtle changes in elemental composition due to CO_2 injection.	Onshore and offshore. More expensive offshore		Highly developed with full commercial deployment in oil and gas industry
Gravity surveys	Determine mass and approximate distribution of CO_2 injected from minute change in gravity caused by injected CO_2 displacing the original pore fluid from the reservoir. Can detect vertical CO_2 migration from repeat surveys, especially where phase change from supercritical fluid to gas is involved because of change in density. Detection limit is poor and site-specific.	Minimum amounts detectable in the order of hundreds of thousands to low millions of tonnes (Benson et al. 2004; Chadwick et al 2003). Actual amounts detectable are site - specific. The greater the porosity and the density contrast between the native pore fluid and the injected CO_2, the better the resolution	Onshore and offshore. Cheap onshore.	Cannot image dissolved CO_2 (insufficient density contrast with native pore fluid).	Highly developed with full commercial deployment in oil and gas industry. Widely used in geophysical research

TABLE A 5.2
POTENTIAL SHALLOW SUBSURFACE MONITORING TECHNOLOGIES AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Sparker: Seismic source with central frequency around 0.1 to 1.2 kHz is towed generally at shallow depth.	Image (changes in) gas distribution in the shallow subsurface (typically represented by acoustic blanking, bright spots, reflector enhancement).	Generally free gas concentrations >2% identified by acoustic blanking. Vertical resolution >1m	Offshore	Greater penetration but less resolution than deep towed boomer Gas quantification can be difficult when concentrations above 5%	Highly developed, widely deployed commercially, in sea bed and shallow seismic survey industry, also in marine research
Deep towed boomer: Seismic source generating a broad band sound pulse with a central frequency around 2.5 kHz is towed at depth.	Image (changes in) shallow gas distribution in sediments (typically represented by acoustic blanking, bright spots, etc.). Image the morphology of the sea bed. Image bubble streams in sea water	Generally free gas concentrations >2% identified by acoustic blanking. Resolution of sea bed morphology typically less than 1 metre. Penetration can be up to about 200 m below sea bed but generally less.	Offshore	Bubble streams more soluble than methane bubbles therefore may dissolve in relatively shallow water columns (approximately 50 m). Bubble streams may be intermittent and missed by a single survey. Accurate positioning of boomer is critical	Highly developed, widely deployed commercially, in sea bed and shallow seismic survey industry, also in marine research
Sidescan sonar	Image the morphology of the sea bed. Image bubble streams in sea water Characterisation of sea bed lithology eg carbonate cementation	Optimum method for detecting gas bubbles.	Offshore	As above. Accurate positioning of side scan sonar fish is critical.	Highly developed, widely deployed commercially in sea bed survey industry, also in marine research
Multi-beam echo-sounding (Swath bathymetry)	Image the morphology of the sea bed. Repeat surveys allow quantification of morphological change. Sea bed lithology identified from backscatter.	Can identify changes in sea bed morphology of as little as 10 cm.	Offshore	As above. Greater coverage in shorter time	Widely deployed in marine research
Electrical methods	May detect change in resistivity due to replacement of native pore fluid with CO_2, especially when the CO_2 is supercritical. EM and electrical methods potentially could map the spread of CO_2 in a storage reservoir. Surface EM may have potential to map CO_2 saturation changes within the reservoir.	Relatively low cost and low resolution	Onshore and offshore surface EM capability demonstrated. Needs development for application in CO_2 storage	Resolution - Needs development and further demonstration	At research stage

TABLE A 5.3
TECHNOLOGIES FOR DETERMINING FLUXES FROM GROUND OR WATER TO ATMOSPHERE, AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Eddy covariance technique (Miles, Davis and Wyngaard 2005).	Measures CO_2 fluxes in air from a mathematically-defined footprint upwind of the detection equipment. Equipment is mounted on a platform or tower. Gas analysis data, usually from fixed open- or closed-path infra-red CO_2 detectors, is integrated with wind speed and direction to define footprint and calculate flux.	Realistic flux detectable in a biologically active area with hourly measurements = 4.4×10^{-7} kg m^{-2} s^{-1} = 13870 t km^{-2}/year (Miles, Davis and Wyngaard 2005)	Can only be used onshore. Proven technology. Relatively cheap. Potential to survey relatively large areas to determine fluxes and detect leaks. Once a leak is detected likely to require detailed (portable IR CO_2 detector or soil gas) survey of footprint to pinpoint it.	Several instrument towers may be needed to cover a whole site. With a detector mounted on a 10 m tower a footprint in the order of 10^4-10^6 m^2 is likely. Development may be desirable to automate measurement. Quantitative determination of fluxes may be limited to regions of flat terrain.	Deployed by research community
Accumulation chambers technique, using field IR or lab analysis of sampled gas to measure flux (Klusman 2003).	Accumulation chambers of known volume are placed on the ground and loosely connected to the ground surface, e.g. by building up soil around them, or placed on collars inserted into the ground. Gas in chambers is sampled periodically and analysed e.g. by portable IR gas detectors, and then returned to chamber to monitor build-up over time,. Detects any fluxes through the soil.	Easily capable of detecting fluxes of 0.04g CO_2 m^{-2} day^{-1} = 14.6 t/km^2/year (Klusman 2003a). Main issue is detection of genuine underground leak against varying biogenic background levels (potentially, tracers could help with this). Works better in winter because the seasonal variation in biological activity is suppressed during winter.	Technology proven at Rangely (Klusman 2003a, b, c). Powerful tool when used in combination with analysis of other gases and stable and radiogenic carbon isotope analysis -these help in identify the source of the collected CO_2. Tracer gases added to the injected CO_2 could also help with this – detection of fast-moving tracers might provide an opportunity to intervene in the leakage prevention by modifying operating parameters (i.e., avoid remediation).	Gaps between sample points allow theoretical possibility of undetected leaks. In oil and gas fields the possibility exists that CO_2 may be microbially oxidised CH_4 rather than leaking CO_2 from a repository.	Deployed by research community
Groundwater and surface water gas analysis.	Samples and measures gas content of groundwater and surface water such as springs. Could: a) Place a partial vacuum over the liquid and extract dissolved gases. Analyse for gases by gas chromatography, mass spectrometry etc. b) For a fresh sample, analyse for bicarbonate content. This is essentially what was done at Weyburn in the field and at the well-head (Shevalier et al. 2004). As dissolved CO_2 and bicarbonate contents are linked, then analysis of bicarbonate can be directly related to dissolved CO_2 content (assuming equilibrium conditions).	Background levels likely to be in low ppm range. Detection limit for bicarbonate in <2 ppm range	Onshore. Should be used in combination with ground to atmosphere flux measurements as provides an alternative pathway for CO_2 emissions. Measurement techniques well developed and relatively straightforward (e.g. Evans et al., 2002) but care should be taken to account for rapid degassing of CO_2 from the water (Gambardella et al., 2004).	Should take account of varying water flux.	Commercially deployed

TABLE A 5.4
TECHNOLOGIES FOR DETECTION OF RAISED CO_2 LEVELS IN AIR AND SOIL (LEAKAGE DETECTION)

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Long open path infra-red laser gas analysis	Measures absorption by CO_2 in air of a specific part of the infra-red spectrum along the path of a laser beam, and thus CO_2 levels in air near ground level. It is possible to construct a tomographic map from the measurements but little track record of converting this to a flux through the ground.	Needs development but estimate potential at ±3% of ambient (c.11 ppm) or better	Onshore. Probably has the best near-term potential to cover several km^2 with one device, therefore whole fields with a few devices. Costs estimated at $1000's per unit, therefore potential to survey whole fields relatively cheaply. Once a leak is detected may require more detailed (portable IR CO_2 detector or soil gas) survey to pinpoint it.	Technology still under development. Measures CO_2 concentration over long path, so interpretation of tomography or more detailed survey necessary to locate leaks precisely. Difficult to calculate fluxes or detect low level leaks against relatively high and varying natural background.	At demonstration and development stage
Soil gas analysis	Establishment of the background flux from the ground surface and its variation is critical. Technique measures CO_2 levels and fluxes in soil using probes, commonly hammered into soil to a depth of 50-100 cm but can also sample from wells. Sampling usually on a grid. Lower part of probe or tube inserted in well is perforated and soil gas is drawn up for on-site analysis using a portable IR laser detector or into gas canisters for lab analysis.	Portable infra-red detectors used in soil gas surveys can resolve changes in CO_2 concentration down to at least ± 1-2 ppm. Absolute values of CO_2 in soil gas (0.2-4%) are higher than in air, but background flux variations are less below ground than above so low fluxes from underground are easier to detect. A range of gases may be measured - ratios of other gases and isotopes can provide clues to origin of CO_2.	Onshore. Technology proven at Weyburn and Rangely fields and volcanic/geothermal areas. Useful for detailed measurements, especially around detected low flux leakage points.	Each measurement may take several minutes. Surveying large areas accurately is relatively costly and time consuming. In oil and gas fields the possibility exists that CO_2 may be microbially oxidised CH_4 rather than leaking CO_2 from repository	Deployed by research community
Portable personal safety-oriented hand-held infra-red gas analyzers	Measures CO_2 levels in air	Resolution of small hand-held devices for personal protection is typically c. 100 ppm.	Can be used onshore and on offshore infrastructure such as platforms. Proven technology. Small hand-held devices for personal protection typically <$1000 per unit. Could also be useful for pinpointing high-concentration leaks detected by wider search methods.	Not sufficiently accurate for monitoring CO_2 leakage	Widely deployed commercially
Airborne infra-red laser gas analysis	Helicopter or aeroplane-mounted open or closed-path infra-red laser gas detectors have potential to take measurements of CO_2 in air every ~10m.	Brantley and Koepenick (1995) quote a ±1 ppm above ambient detection limit for the equipment used in airborne closed path technique. Less information is available on the open path technique, though it is likely to be ±1% or less.	Onshore. Proven technology for detecting methane leaks from pipelines and CO_2 from very large point sources. Possible application for detecting CO_2 leaks from pipelines and infrastructure or concentrated leaks from underground.	Measurements are made a minimum of hundred(s) metres above ground, and concentrations at ground level likely to be much higher than minimum detectable at these levels. CO_2 is heavier then air, so will hug the ground and not be so easily detectable as methane by airborne methods	Commercially deployed in natural gas pipeline applications, not in CO_2 detection applications

Notes: Data partly from Schuler & Tang (2005) included by permission of the CO_2 Capture Project.

TABLE A 5.5
PROXY MEASUREMENTS TO DETECT LEAKAGE FROM GEOLOGICAL CO_2 STORAGE SITES

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Satellite or airborne hyperspectral imaging	Detects anomalous changes in the health of vegetation that could be due to leakage of CO_2 to ground surface. Can also detect subtle or hidden faults that may be pathways for gases emerging at the ground surface. Uses parts of visible and infra-red spectrum.	Spatial resolution of satellite and airborne images 1-3m. Not calibrated in terms of flux or volume fraction of CO_2 in air or soil gas, but may give indications of areas that should be sampled in detail.	Onshore	Research required to determine levels of CO_2 in soil that will produce detectable changes in vegetation health and distribution. Many repeat surveys needed to establish (seasonal) responses to variations in weather. Not useful in arid areas	At research stage
Satellite interferometry	Repeated satellite radar surveys detect changes in ground surface elevation potentially caused by CO_2 injection, if absidence (ground uplift) occurs	InSAR (Interferometric Synthetic Aperture Radar) can detect millimetre-scale changes in elevation	Onshore	Changes in elevation may not occur, or may occur seasonally, e.g. due to freezing/thawing. Local atmospheric and topographic conditions may interfere.	At research stage, not yet deployed for CO_2 storage

TABLE A 5.6
TECHNOLOGIES FOR MONITORING CO_2 LEVELS IN SEA WATER AND THEIR LIKELY APPLICATION

Technique	Capabilities	Detection limits	Where applicable, costs	Limitations	Current technology status
Sediment gas analysis	Samples and, in laboratory, measure gas content of sea bed sediments.	Uncertain how measured gas contents relate to in situ gas contents.	Offshore. Ship time costly.	Pressure correction of data will be necessary unless pressurised sample is collected. ROV's and divers could be used for sampling if necessary. Ship time costly.	Deployed by research community for methane gas analysis offshore
Sea water gas analysis	Sample and, in laboratory, measure gas content of sea water. Protocols exist for analysis of sea water samples.	Detection limits of analytical equipment likely to be in low ppm range or better. Detection limit for bicarbonate in <2 ppm range. Ability to detect leaks in field unproven. Minimum size of leak that could be detected in practice unproven.	Offshore. Ship time costly.	As above	Deployed in near surface waters in research community, not widely used at depth.

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CHAPTER 6

REFERENCE APPROACH

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6 REFERENCE APPROACH

6.1 OVERVIEW

The Reference Approach is a top-down approach, using a country's energy supply data to calculate the emissions of CO_2 from combustion of mainly fossil fuels. The Reference Approach is a straightforward method that can be applied on the basis of relatively easily available energy supply statistics. Excluded carbon has increased the requirements for data to some extent. However, improved comparability between the sectoral and reference approaches continues to allow a country to produce a second independent estimate of CO_2 emissions from fuel combustion with limited additional effort and data requirements.

It is *good practice* to apply both a sectoral approach and the reference approach to estimate a country's CO_2 emissions from fuel combustion and to compare the results of these two independent estimates. Significant differences may indicate possible problems with the activity data, net calorific values, carbon content, excluded carbon calculation, etc. (see Section 6.8 for a more detailed explanation of this comparison).

6.2 SOURCE CATEGORIES COVERED

The Reference Approach is designed to calculate the emissions of CO_2 from fuel combustion, starting from high level energy supply data. The assumption is that carbon is conserved so that, for example, carbon in crude oil is equal to the total carbon content of all the derived products. The Reference Approach does not distinguish between different source categories within the energy sector and only estimates total CO_2 emissions from Source category 1A, Fuel Combustion. Emissions derive both from combustion in the energy sector, where the fuel is used as a heat source in refining or producing power, and from combustion in final consumption of the fuel or its secondary products. The Reference Approach will also include small contributions that are not part of 1A and this is discussed in Section 6.8.

6.3 ALGORITHM

The Reference Approach methodology breaks the calculation of carbon dioxide emissions from fuel combustion into 5 steps:

Step 1: Estimate Apparent Fuel Consumption in Original Units

Step 2: Convert to a Common Energy Unit

Step 3: Multiply by Carbon Content to Compute the Total Carbon

Step 4: Compute the Excluded Carbon

Step 5: Correct for Carbon Unoxidised and Convert to CO_2 Emissions

These steps are expressed in the following equation:

EQUATION 6.1
CO_2 EMISSIONS FROM FUEL COMBUSTION USING THE REFERENCE APPROACH

$$CO_2\ Emissions = \sum_{all\ fuels} \left[\begin{array}{l} ((Apparent\ Consumption_{fuel} \bullet Conv\ Factor_{fuel} \bullet CC_{fuel}) \bullet 10^{-3} \\ - Excluded\ Carbon_{fuel}) \bullet COF_{fuel} \bullet 44/12 \end{array} \right]$$

Where:

CO_2 Emissions	= CO_2 emissions (Gg CO_2)
Apparent Consumption	= production + imports – exports – international bunkers - stock change
Conv Factor (conversion factor)	= conversion factor for the fuel to energy units (TJ) on a net calorific value basis
CC	= carbon content (tonne C/TJ) Note that tonne C/TJ is identical to kg C/GJ
Excluded Carbon	=carbon in feedstocks and non-energy use excluded from fuel combustion emissions (Gg C)

COF (carbon oxidation factor)	= fraction of carbon oxidised. Usually the value is 1, reflecting complete oxidation. Lower values are used only to account for carbon retained indefinitely in ash or soot
44/12	= molecular weight ratio of CO_2 to C.

6.4 ACTIVITY DATA

The Reference Approach starts from statistics for production of fuels and their external (international) trade as well as changes in their stocks. From this information the "Apparent Consumption" is estimated. It also needs a limited number of values for the consumption of fuels used for non-energy purposes where carbon may be emitted through activities not covered or only partly covered under fuel combustion.

6.4.1 Apparent consumption

The first step of the Reference Approach is to estimate apparent consumption of fuels within the country. This requires a supply balance of primary and secondary fuels (fuels produced, imported, exported, used in international transport (bunker fuels) and stored or removed from stocks). In this way carbon is brought into the country from energy production and imports (adjusted for stock changes) and moved out of the country through exports and international bunkers. In order to avoid double counting it is important to distinguish between primary fuels, which are fuels found in nature such as coal, crude oil and natural gas, and secondary fuels or fuel products, such as gasoline and lubricants, which are derived from primary fuels. A complete list of fuels is provided in Section 1.4.1.1 of the Energy Volume Introduction chapter.

To calculate the supply of fuels to the country, the following data are required for each fuel and inventory year:

- the amounts of primary fuels produced[1] (production of secondary fuels and fuel products is not included);
- the amounts of primary and secondary fuels imported;
- the amounts of primary and secondary fuels exported;
- the amounts of primary and secondary fuels used in international bunkers;
- the net increases or decreases in stocks of primary and secondary fuels.

The apparent consumption of a primary fuel is, therefore, calculated from the above data as:

EQUATION 6.2
APPARENT CONSUMPTION OF PRIMARY FUEL

$$Apparent\,Consumption_{fuel} = Production_{fuel} + Imports_{fuel} - Exports_{fuel} - International\,Bunkers_{fuel} - Stock\,Change_{fuel}$$

An increase in stocks is a positive stock change which withdraws supply from consumption. A stock reduction is a negative stock change which, when subtracted in the equation, causes an increase in apparent consumption.

The total apparent consumption of primary fuels will be the sum of the apparent consumptions for each primary fuel.

Apparent consumption of secondary fuels should be added to apparent consumption of primary fuels. The production (or manufacture) of secondary fuels should be ignored in the calculations because the carbon in these fuels is already included in the supply of primary fuels from which they were derived; for instance, the estimate for apparent consumption of crude oil already contains the carbon from which gasoline would be refined. Apparent consumption of a secondary fuel is calculated as follows:

[1] Production of natural gas is measured after purification and extraction of NGLs and sulphur. Extraction losses and quantities re-injected, vented or flared are not included. Production of coal includes the quantities extracted or produced calculated after any operation for removal of inert matter. Production of oil includes marketable production and excludes volumes returned to formation.

EQUATION 6.3
APPARENT CONSUMPTION OF SECONDARY FUEL

$$Apparent\,Consumption_{fuel} = Imports_{fuel} - Exports_{fuel} - International\,Bunkers_{fuel} - Stock\,Change_{fuel}$$

Note that this calculation can result in negative numbers for apparent consumption of a given fuel. This is possible and it indicates a net export or stock increase of that fuel in the country.

The total apparent consumption of secondary fuels will be the sum of the apparent consumptions for each secondary fuel.

6.4.2 Conversion to energy units

Often oil and coal data are expressed in metric tonnes. Natural gas may be expressed in cubic meters or in a heat value such as BTU on a gross or net calorific value basis[2]. For the purposes of the Reference Approach, the apparent consumption should be converted to terajoules on a net calorific value basis. However, since the intention of the Reference Approach is to verify the estimates made using a more detailed approach, if the country has used gross calorific values in their detailed calculations, then it is preferable to do so also in the calculations for the Reference Approach. When selecting a country-specific calorific value for the Reference Approach based on detailed consumption values, *good practice* suggests that a weighted average be used. See the Introduction chapter of this Volume for a detailed description of the conversion to energy units (Section 1.4.1.2).

6.5 CARBON CONTENT

The carbon content of the fuel may vary considerably both among and within primary fuel types:

- For natural gas, the carbon content depends on the composition of the gas which, in its delivered state, is primarily methane, but can include small quantities of ethane, propane, butane, CO_2 and heavier hydrocarbons. Natural gas flared at the production site will usually be "wet", i.e., containing far larger amounts of non-methane hydrocarbons. The carbon content will be correspondingly different.
- For crude oil, the carbon content may vary depending on the crude oil's composition (e.g. depending on API gravity and sulphur content). For secondary oil products, the carbon content for light refined products such as gasoline is usually less than for heavier products such as residual fuel oil.
- For coal, the carbon content per tonne varies considerably depending on the coal's composition of carbon, hydrogen, sulphur, ash, oxygen, and nitrogen.

Since the carbon content is closely related to the energy content of the fuel, the variability of the carbon content is small when the activity data are expressed in energy units.

Since carbon content varies by fuel type, data should be used for detailed categories of fuel and product types. The default values for carbon content given in the Introduction chapter of the Energy Volume are suggested only if country-specific values are not available. When selecting a country-specific carbon content for the Reference Approach based on detailed consumption values, *good practice* suggests that a weighted average be used.

For a given fuel, the country-specific carbon content may vary over time. In this instance, different values may be used in different years.

6.6 EXCLUDED CARBON

The next step is to exclude from the total carbon the amount of carbon which does not lead to fuel combustion emissions, because the aim is to provide an estimate of fuel combustion emissions (Source category 1A).

[2] The difference between the "net" and the "gross" calorific value for each fuel is the latent heat of vaporisation of the water produced during combustion of the fuel. For the purposes of the IPCC Guidelines, the default carbon emission factors have been given on a net calorific value basis. Some countries may have their energy data on a gross calorific value basis. If these countries wish to use the default emission factors, they may assume that the net calorific value for coal and oil is about 5% less than the gross value and for natural gas is 9 to 10% less.

Carbon excluded from fuel combustion is either emitted in another sector of the inventory (for example as an industrial process emission) or is stored in a product manufactured from the fuel. In the 1996 Guidelines, carbon in the apparent consumption that does not lead to fuel combustion emissions has been referred to as "stored carbon" but, as the above definition makes clear, stored carbon is only part of the carbon to be excluded from "total carbon" in the *2006 IPCC Guidelines.*

The main flows of carbon concerned in the calculation of excluded carbon are those used as feedstock, reductant or as non-energy products. Table 6.1 sets out the main products in each group.[3] If countries have other fossil fuel carbon products which should be excluded they should be taken into consideration and documented.

TABLE 6.1
PRODUCTS USED AS FEEDSTOCKS, REDUCTANTS AND FOR NON-ENERGY PURPOSES

Feedstock	Naphtha
	LPG (butane/propane)
	Refinery gas
	Gas/diesel oil and Kerosene
	Natural gas
	Ethane
Reductant	Coke oven coke (metallurgical coke) and petroleum coke
	Coal and coal tar/pitch
	Natural gas
Non-energy products	Bitumen
	Lubricants
	Paraffin waxes
	White spirit

6.6.1 Feedstock

Carbon emissions from the use of fuels listed above as feedstock are reported within the source categories of the Industrial Processes and Product Use (IPPU) chapter. Consequently, all carbon in fuel delivered as feedstock is excluded from the total carbon of apparent energy consumption. Most of the fuels used as feedstock are also used for heat raising in refineries or elsewhere. For example, gas oil or natural gas may be delivered for heat raising purposes in addition to any feedstock uses. It is therefore essential that only the quantities of fuel delivered for feedstock use are subtracted from the total carbon of apparent energy consumption. The distinction between the feedstock use of fuels and use for fuel combustion needs careful consideration.

Processing feedstock may produce by-product gases or oils. Equally, part of a feedstock supply to a process may be used to fuel the process. The reporting of emissions from the combustion of by-product (or 'off') gases from petrochemical processing or iron and steel manufacture or from the direct use of the feedstock as a fuel is guided by the principle formulated in Section 1.2 of the Introduction chapter of this Volume for allocating fuel combustion emissions between the IPPU and the fuel combustion sectors. Application of the principle will mean that some countries will report some of the feedstock carbon as fuel combustion emissions in their inventories. However, as simplicity is an objective of the Reference Approach, complete exclusion of the feedstock carbon should be maintained there. It is *good practice* that any discrepancies that this generates between the Reference Approach and Sectoral Approach be quantified and explained at the reporting stage.

[3] Detailed bottom-up methods for estimating emissions from use of fuels for feedstock, reductant or other non-energy use are provided in Volume 3, Chapter 5.

6.6.2 Reductant

COKE OVEN COKE AND PETROLEUM COKE

Cokes manufactured from coals and oil products may be used for fuel combustion or industrial processes, most notably in the iron and steel and non-ferrous metals industries. When used as a reductant in industrial processes the coke is heated with inorganic oxides and reduces them carrying away the oxygen in the carbon monoxide and dioxide. The 'off gases' so produced may be combusted on site to help heat the process or combusted elsewhere in another source category. In the latter case, the emissions are reported as fuel combustion. Section 1.2 of the Introduction chapter of this Volume provides guidance on the principles of the reporting. However, as data for this activity are not always readily available and, in order to preserve the simplicity of the Reference Approach, quantities of coke delivered for the iron and steel and non-ferrous metals industries should be excluded from total carbon. The effect of this will be reflected as a difference between the Reference Approach and Sectoral Approach when the comparison is made. See Section 6.8.

COAL AND COAL TAR/PITCH

Pulverised coal may be injected into blast furnaces as a reductant and coal is similarly used as a reductant in some titanium dioxide manufacturing processes. The carbon will largely enter the by-product gases associated with the processes and the emissions covered under the activity where the gases are burned. For the pulverised coal this will be mainly within the iron and steel industry and reported under IPPU. Only where some blast furnace gas is transferred to another industry as fuel will the emissions be classified as Energy sector and the portion of the emissions attributable to the pulverised coal and other injected hydrocarbons will be very small.

The distillation of coal in coke ovens to produce coke leads to the production of tars and light oils recovered from coke oven gas. The light oils include benzene, toluene, xylene and non-aromatics as well as lesser amounts of other chemicals. Tars include naphthalene, anthracene, and pitch. The light oils are valuable as solvents and as basic chemicals. The related emissions are assumed covered under IPPU.

Pitches are often used as binders for anode production. Heavier oils associated with pitches may be used for dyestuffs, wood preservatives or in road oils for asphalt laying. All of these activities are covered under IPPU and their related emissions are excluded from fuel combustion.

If there are coke manufacturing plants where the oils or tars are burned for heat raising, it is suggested that any instances of this activity in a country be taken into account to explain differences between the Reference Approach and a Sectoral Approach when the reconciliation is made.

NATURAL GAS

In some iron and steel plants natural gas may be injected into blast furnaces as a reductant in the iron making process. The classification of the emissions related to the injection of gas is identical to that made for pulverised coal discussed above and these amounts should be excluded.

6.6.3 Non-energy products use

BITUMEN

Bitumen/asphalt is used for road paving and roof covering where the carbon it contains remains stored for long periods of time. Consequently, there are no fuel combustion emissions arising from the deliveries of bitumen within the year of the inventory.

LUBRICANTS

Lubricating oil statistics usually cover not only use of lubricants in engines but also oils and greases for industrial purposes and heat transfer and cutting oils. All deliveries of lubricating oil should be excluded from the Reference Approach. This avoids a potential double count of emissions from combustion of waste lubricants covered in the Reference Approach under "other fossil fuels" but ignores the inclusion of emissions from lubricants in two-stroke engines. See the discussion under 'Simplifications in the Reference Approach' in Section 6.8.

PARAFFIN (PETROLEUM) WAXES

All quantities of paraffin waxes are excluded from the Reference Approach. Within the many uses for paraffin waxes there are two main uses which lead to fuel combustion as defined in Section 1.2. These are the burning of candles in heating or warming devices (for example, chafing dishes) and the incineration of wax-coated materials amongst other waste in municipal waste plants with heat recovery. Use of candles for lighting is

considered mainly a decorative purpose and not fuel combustion. Emissions from combustion of waxes in municipal waste plants with heat recovery are already included in the Reference Approach (under "Other fossil fuels") so the relevant wax quantities should be excluded. Data on the contribution from the remaining small source of energy are very difficult to obtain so, within the Reference Approach, these sources are excluded from fuel combustion.

WHITE SPIRIT

White spirit leads to solvent emissions which are not fuel combustion emissions and therefore should be excluded.

6.6.4 Method

The quantity of carbon to be excluded from the estimation of fuel combustion emissions is calculated according to following equation.

EQUATION 6.4
CARBON EXCLUDED FROM FUEL COMBUSTION EMISSIONS

$$Excluded\ Carbon_{fuel} = Activity\ \ Data_{fuel} \bullet CC_{fuel} \bullet 10^{-3}$$

Where:

Excluded Carbon	= carbon excluded from fuel combustion emissions (Gg C)
Activity Data	= activity data (TJ)
CC	= carbon content (tonne C/TJ)

The activity data for each relevant product are given in Table 6.2.

TABLE 6.2
ACTIVITY DATA FOR EXCLUDED CARBON FLOWS

Fuel	Activity data[1]
LPG, ethane, naphtha, refinery gas[2], gas/diesel oil, kerosene	Deliveries to petrochemical feedstocks[3]
Bitumen	Total deliveries
Lubricants	Total deliveries
Paraffin waxes[2]	Total deliveries
White spirit[2]	Total deliveries
Cokes	
Calcined petroleum coke	Total deliveries
Coke oven coke	Deliveries to the iron and steel and non-ferrous metals industries
Coal Tar	
Light oils from coal	Deliveries to chemical industry
Coal tar/pitch	Deliveries to chemical industry and construction
Natural gas	Deliveries to petrochemical feedstocks and for the direct reduction of iron ore in the iron and steel industry

Notes:

[1] Deliveries refers to the total amount of fuel delivered and is not the same thing as apparent consumption (where the production of secondary fuels is excluded).

[2] Refinery gas, paraffin waxes and white spirit are included in "other oil".

[3] For the purposes of the Reference Approach, the deliveries used as activity data should be net of any oils returned to refineries from petrochemical processing.

6.7 CARBON UNOXIDISED DURING FUEL COMBUSTION

A small part of the fuel carbon entering combustion escapes oxidation but the majority of this carbon is later oxidised in the atmosphere. It is assumed that the carbon that remains unoxidised (e.g. as soot or ash) is stored indefinitely. For the purposes of the Reference Approach, unless country-specific information is available, a default value of 1 (full oxidation) should be used.

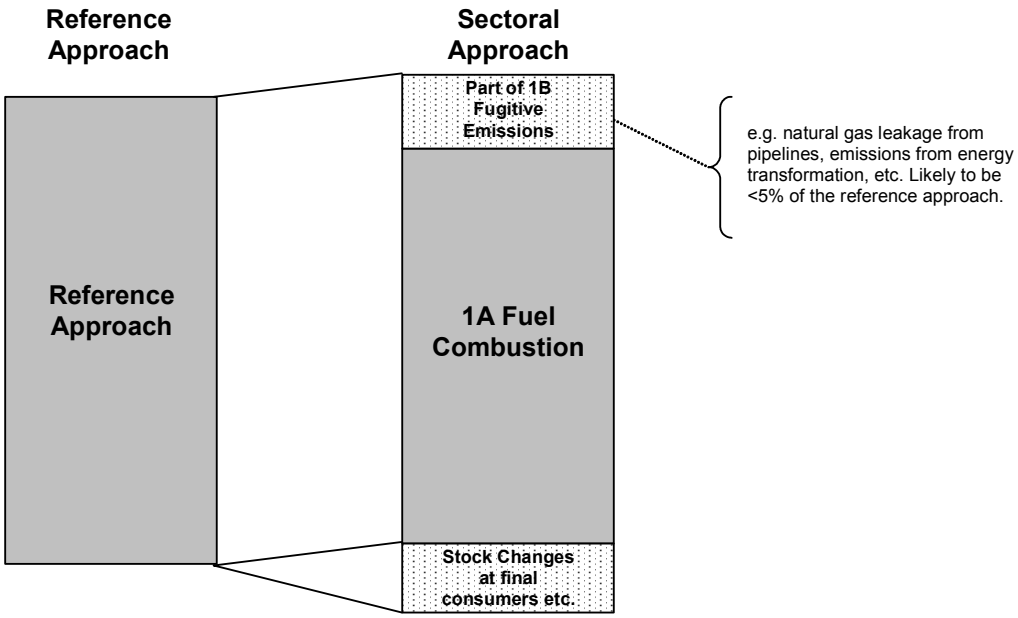
6.8 COMPARISON BETWEEN THE REFERENCE APPROACH AND A SECTORAL APPROACH

The Reference Approach and the Sectoral Approach often have different results because the Reference Approach is a top-down approach using a country's energy supply data and has no detailed information on how the individual fuels are used in each sector.

The Reference Approach provides estimates of CO_2 to compare with estimates derived using a Sectoral Approach. Since the Reference Approach does not consider carbon captured, the results should be compared to the CO_2 emissions before those amounts are subtracted out. Theoretically, it indicates an upper bound to the Sectoral Approach '1A Fuel Combustion', because some of the carbon in the fuel is not combusted but will be emitted as fugitive emissions (as leakage or evaporation in the production and/or transformation stage).

Calculating CO_2 emissions with the two approaches can lead to different results for some countries. Typically, the gap between the two approaches is relatively small (5 per cent or less) when compared to the total carbon flows involved. In cases where 1) fugitive emissions are proportional to the mass flows entering production and/or transformation processes, 2) stock changes in final consumer level are not significant and 3) statistical differences in the energy data are limited, the Reference Approach and the Sectoral Approach should lead to similar evaluations of the CO_2 emissions trends.

Figure 6.1 Reference approach versus sectoral approach



When significant discrepancies and/or large time-series deviation do occur, the main reasons are listed below.

- Large **statistical differences** between the energy supply and the energy consumption in the basic energy data. Statistical differences arise from the collection of data from different parts of the fuel flow from its supply origins to the various stages of downstream conversion and use. They are a normal and proper part of a fuel balance. Large random statistical differences must always be examined to determine the reason for the difference but equally important smaller statistical differences which systematically show an excess of supply over demand (or vice versa) should be pursued.
- Significant **mass imbalances** between crude oil and other feedstock entering refineries and the (gross) petroleum products manufactured.
- The use of **approximate net calorific and carbon content values** for primary fuels which are converted rather than combusted. For example, it may appear that there is no conservation of energy or carbon depending on the calorific value and/or the carbon content chosen for the crude oil entering refineries and for the mix of products produced from the refinery for a particular year. This may cause an overestimation or underestimation of the emissions associated with the Reference Approach.
- The **misallocation of the quantities of fuels used for conversion into derived products** (other than power or heat) **or quantities combusted in the energy sector**. When reconciling differences between the Reference Approach and a Tier 1 Sectoral Approach it is important to ensure that the quantities reported in the transformation and energy sectors (e.g. for coke ovens) reflect correctly the quantities used for conversion and for fuel use, respectively, and that no misallocation has occurred. Note that the quantities of fuels converted to derived products should have been reported in the transformation sector of the energy balance. If any derived products are used to fuel the conversion process, the amounts involved should have been reported in the energy sector of the energy balance. In Tier 1 Sectoral Approach the inputs to the transformation sector should not be included in the activity data used to estimate emissions.
- **Missing information on combustion of certain transformation outputs**. Emissions from combustion of secondary fuels produced in integrated processes (for example, coke oven gas) may be overlooked in Tier 1 Sectoral Approach if data are poor or unavailable. The use of secondary fuels (the output from the transformation process) should be included in the Sectoral Approach for all secondary products. Failure to do so will result in an underestimation of the Sectoral Approach.
- **Simplifications in the Reference Approach.** There are small quantities of carbon which should be included in the Reference Approach because their emissions fall under fuel combustion. These quantities have been excluded where the flows are small or not represented by a major statistic available within energy data. Examples of quantities not accounted for in the Reference Approach include lubricants used in two-stroke

engines, blast furnace and other by-product gases which are used for fuel combustion outside their source category of production and combustion of waxed products in waste plants with heat recovery. On the other hand, there are flows of carbon which should be excluded from the Reference Approach but for reasons similar to the above no practical means can be found to exclude them without over complicating the calculations. These include coals and other hydrocarbons injected into blast furnaces as well as cokes used as reductants in the manufacture of inorganic chemicals. The effects of these simplifications will be seen in the discrepancy between the Reference Approach and a Sectoral Approach and if data are available, their magnitudes can be estimated.

- Missing **information on stock changes** that may occur at the final consumer level. The relevance of consumer stocks depends on the method used for the Sectoral Approach. If delivery figures are being used (this is often the case) then changes in consumers' stocks are irrelevant. If, however, the Sectoral Approach is using actual consumption of the fuel, then this could cause either an overestimation or an underestimation of the Reference Approach.
- High **distribution losses** for gas will cause the Reference Approach to be higher than the Sectoral Approach,
- **Unrecorded consumption** of gas or other fuels may lead to an underestimation of the Sectoral Approach.
- The treatment of **transfers** and **reclassifications of energy products** may cause a difference in the Sectoral Approach estimation since different net calorific values and emission factors may be used depending on how the fuel is classified.
- It should be noted that for **countries that produce and export large amounts of fuel**, the uncertainty on the residual supply may be significant and could affect the Reference Approach.

6.9 DATA SOURCES

The IPCC approach to the calculation of emission inventories encourages the use of fuel statistics collected by an officially recognised national body, as this is usually the most comprehensive and accessible source of activity data. In some countries, however, those charged with the task of compiling inventory information may not have ready access to the entire range of data available within their country and may wish to use data specially provided by their country to the international organisations whose policy functions require knowledge of energy supply and use in the world. There are, currently, two main sources of international energy statistics: the International Energy Agency (IEA), and the United Nations (UN). Information on international data sources is given in the Introduction chapter of the Energy Volume (Section 1.4.1.3).

6.10 UNCERTAINTIES

If the Reference Approach is the primary accounting method for the CO_2 from fuel combustion, then it is *good practice t*o carry out an uncertainty analysis.

6.10.1 Activity data

Overall uncertainty in activity data is a combination of both systematic and random errors. Most developed countries prepare balances of fuel supply and this provides a check on systematic errors. In these circumstances, overall systematic errors are likely to be small. However, incomplete accounting may occur in places where individuals and small producers are extracting fossil fuel (generally coal) for their own use and it does not enter into the formal accounting system. However, experts believe that uncertainty resulting from errors in the activity data of countries with well-developed statistical systems is probably in the range of ±5% for a given fuel. For countries with less well-developed energy data systems, this could be considerably larger, probably about ±10% for a given fuel.

6.10.2 Carbon content and net calorific values

The uncertainty associated with the carbon content and the net calorific values results from two main elements, the accuracy with which the values are measured, and the variability in the source of supply of the fuel and quality of the sampling of available supplies. Consequently, the errors can be considered mainly random. The uncertainty will result mostly from variability in the fuel composition. For traded fuels, the uncertainty is likely to be less than for non-traded fuels (see Tables 1.2 and 1.3).

6.10.3 Oxidation factors

Default uncertainty ranges are not available for oxidation factors. Uncertainties for oxidation factors may be developed based on information provided by large consumers on the completeness of combustion in the types of equipment they are using.

References

IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)

Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories

ANNEX 1

WORKSHEETS

Contents

Annex 1 Worksheets

1A Fuel Combustion Activities A1.6

1B.1 Solid Fuels A1.11

1B.2 Oil and Natural Gas A1.14

Reference Approach A1.16

Auxiliary Worksheet (Reference Approach) A1.19

1.1 INTRODUCTION

This Annex presents worksheets to enable inventory compilers to readily implement the Tier 1 methods. Volume 1, Chapter 8 gives guidance on how to report the resulting emission estimates.

Table 1 explains the main considerations concerning fuel consumption to be taken into account with respect to column A of the fuel combustion activities worksheets.

Worksheets for fuel combustion activities also cater for CO_2 capture from the subcategories 1A 1 and 1A 2.

Emissions of CO_2 from biomass fuels are estimated and reported in the AFOLU sector as part of the AFOLU methodology. In the reporting tables, emissions from combustion of biofuels are reported as information items but not included in the sectoral or national totals to avoid double counting.

Worksheets for fugitive emissions are of two types:

(1) Emissions arising from mining, processing, storage and transportation of coal. This includes the new method of determining CH_4 emissions from abandoned coal mines.

(2) Emissions from oil and natural gas systems.

Reference Approach worksheets are also included though its main purpose in the *2006 IPCC Guidelines* is to serve as an independent verification cross-check of the bottom-up approach methods described in Tiers 1, 2 and 3.

TABLE 1
MAIN CONSIDERATIONS CONCERNING THE FUEL CONSUMPTION TO BE INCLUDED IN COLUMN A OF THE FOUR WORKSHEETS

Fuel[1]	Activity data
Liquid Fuels	
Crude Oil	Only the amount used as a fuel should be included.
Orimulsion	Only the amount used as a fuel should be included.
Natural Gas Liquids	Only the amount used as a fuel should be included.
Motor Gasoline	Generally, all consumption is used as a fuel.
Aviation Gasoline	In unusual circumstances small quantities may be burned as a fuel in stationary sources.
Jet Gasoline	In unusual circumstances small quantities may be burned as a fuel in stationary sources.
Jet Kerosene	In unusual circumstances small quantities may be burned as a fuel in stationary sources.
Other Kerosene	Only the amount used as a fuel should be included. Do not include the fraction used as petrochemical feedstock.
Shale Oil	Only the amount used as a fuel should be included.
Gas/Diesel Oil	Only the amount used as a fuel should be included. Do not include the amount used as petrochemical feedstock.
Residual Fuel Oil	Generally, all consumption is used as a fuel.
Liquefied Petroleum Gases	Only the amount used as a fuel should be included. Do not include the amount used as petrochemical feedstock.
Ethane	Only the amount used as a fuel should be included. Do not include the amount used as petrochemical feedstock.
Naphtha	Only the amount used as a fuel should be included. Do not include the amount used as petrochemical feedstock.
Lubricants	Only include the amount of fuel that is mixed with gasoline for 2-stroke engines.
Petroleum Coke	Only the amount used as a fuel should be included. The amount used as a feedstock (e.g. in coke ovens for the steel industry, for electrode manufacture and for production of chemicals) should not be included.
Refinery Feedstocks	Generally used as a feedstock. The amount used as petrochemical feedstock should not be included.
Refinery Gas	Only the amount used as fuel should be included. Do not include the amount used as petrochemical feedstock.
Paraffin Waxes	Only the amount used as a fuel should be included. Do not include the amount that is burned as waste.
Other Petroleum Products	Only the amount used as a fuel should be included. Do not include the amount used as petrochemical feedstock.
Solid Fuels	
Anthracite	Only the amount used as a fuel should be included.
Coking Coal	Only the amount used as a fuel should be included.
Other Bituminous Coal	Only the amount used as a fuel should be included.
Sub-Bituminous Coal	Only the amount used as a fuel should be included.
Lignite	Only the amount used as a fuel should be included.
Oil Shale / Tar Sands	Only the amount used as a fuel should be included.
Brown Coal Briquettes	Generally, all consumption is used as a fuel.
Patent Fuel	Generally, all consumption is used as a fuel.
Coke Oven Coke / Lignite Coke	Do not include amount delivered to industrial processes (e.g. metal production).
Gas Coke	Generally, all consumption is used as a fuel.
Coal Tar	Do not include amount delivered to the chemical and petrochemical industries or for construction.
Gas Works Gas	Only the amount used as a fuel should be included.

[1] Fuels not burned for energy purposes are not included in this table (e.g. bitumen and white spirits).

TABLE 1 (CONTINUED)
MAIN CONSIDERATIONS CONCERNING THE FUEL CONSUMPTION TO BE INCLUDED IN COLUMN A OF THE WORKSHEETS

Fuel[2]	Activity data
Coke Oven Gas	Include the amount that is used as a fuel except the gas used in the iron and steel industry since these emissions are accounted for in the IPPU sector.
Blast Furnace Gas	Include the amount that is used as a fuel except the gas used in the iron and steel industry since these emissions are accounted for in the IPPU sector.
Oxygen Steel Furnace Gas	Include the amount that is used as a fuel except the gas used in the iron and steel industry since these emissions are accounted for in the IPPU sector.
Natural Gas	
Natural Gas (Dry)	Only the amount used as a fuel should be included. Do not include the amount used as petrochemical feedstock or used for reducing purposes in blast furnaces or direct reduction processes.
Other Fossil Fuels	
Municipal Wastes (non-biomass fraction)	Only the non-biomass fraction that is used as a fuel should be included.
Industrial Wastes	Only the amount used as a fuel should be included. Do not include the amount that is burned without energy recovery. For waste gas from the petrochemical industry, do not include the amount combusted since these emissions are accounted for in the IPPU sector.
Waste Oils	Only the amount used as a fuel should be included.
Peat	
Peat	Only the amount used as a fuel should be included
Biomass	
Wood/Wood Waste	Only the amount used as fuel should be included.
Sulphite lyes (Black Liquor)	Only the amount used as fuel should be included.
Other Primary Solid Biomass	Only the amount used as fuel should be included.
Charcoal	Only the amount used as fuel should be included.
Biogasoline	In unusual circumstances small quantities may be burned as a fuel in stationary sources.
Biodiesels	In unusual circumstances small quantities may be burned as a fuel in stationary sources.
Other Liquid Biofuels	Only the amount used as fuel should be included.
Landfill Gas	Only the amount used as fuel should be included.
Sludge Gas	Only the amount used as fuel should be included.
Other Biogas	Only the amount used as fuel should be included.
Municipal Wastes (biomass fraction)	Only the amount used as a fuel should be included. Do not include the amount that is burned without energy recovery.

[2] Fuels not burned for energy purposes are not included in this table (e.g. bitumen and white spirits).

Sector	Energy								
Category	Fuel combustion activities								
Category Code	1A [(a)]								
Sheet	1 of 4 (CO_2, CH_4 and N_2O from fuel combustion by source categories – Tier 1)								
	Energy consumption			CO_2		CH_4		N_2O	
	A Consumption (Mass, Volume or Energy unit)	B Conversion Factor[(b)] (TJ/unit)	C Consumption (TJ)	D CO_2 Emission Factor (kg CO_2/TJ)	E CO_2 Emissions (Gg CO_2)	F CH_4 Emission Factor (kg CH_4/TJ)	G CH_4 Emissions (Gg CH_4)	H N_2O Emission Factor (kg N_2O /TJ)	I N_2OEmissions (Gg N_2O)
			C=A*B		**$E=C*D/10^6$**		**$G=C*F/10^6$**		**$I=C*H/10^6$**
Liquid fuels									
Crude Oil									
Orimulsion									
Natural Gas Liquids									
Motor Gasoline									
Aviation Gasoline									
Jet Gasoline									
Jet Kerosene									
Other Kerosene									
Shale Oil									
Gas / Diesel Oil									
Residual Fuel Oil									
LPG									
Ethane									
Naphtha									

[a] Fill out a copy of this worksheet for each source category listed in Table 2.16 of the Stationary Combustion Chapter and insert the source category name next to the worksheet number.

[b] When the consumption is expressed in mass or volume units, the conversion factor is the net calorific value of the fuel.

Sector	**Energy**								
Category	**Fuel Combustion Activities**								
Category Code	**1A [(a)]**								
Sheet	**2 of 4 (CO_2, CH_4 and N_2O from fuel combustion by source categories – Tier 1)**								
	Energy consumption			**CO_2**		**CH_4**		**N_2O**	
	A Consumption (Mass, Volume or Energy unit)	B Conversion Factor (TJ/unit)	C Consumption (TJ)	D CO_2 Emission Factor (kg CO_2/TJ)	E CO_2 Emissions (Gg CO_2)	F CH_4 Emission Factor (kg CH_4/TJ)	G CH_4 Emissions (Gg CH_4)	H N_2O Emission Factor (kg N_2O /TJ)	I N_2O Emissions (Gg N_2O)
			C=A*B		**E=C*D/10^6**		**G=C*F/10^6**		**I=C*H/10^6**
Lubricants									
Petroleum Coke									
Refinery Feedstocks									
Refinery Gas									
Paraffin Waxes									
Other Petroleum Products									
Solid fuels									
Anthracite									
Coking Coal									
Other Bituminous Coal									
Sub-bituminous coal									
Lignite									
Oil Shale and Tar Sands									
Brown Coal Briquettes									

[a] Fill out a copy of this worksheet for each source category listed in Table 2.16 of the Stationary Combustion chapter and insert the source category name next to the worksheet number.

Sector	**Energy**								
Category	**Fuel combustion activities**								
Category Code	**1A** [(a)]								
Sheet	**3 of 4 (CO_2, CH_4 and N_2O from fuel combustion by source categories – Tier 1)**								
	Energy consumption			**CO_2**		**CH_4**		**N_2O**	
	A Consumption (Mass, Volume or Energy unit)	B Conversion Factor (TJ/unit)	C Consumption (TJ)	D CO_2 Emission Factor (kg CO_2/TJ)	E CO_2 Emissions (Gg CO_2)	F CH_4 Emission Factor (kg CH_4/TJ)	G CH_4 Emissions (Gg CH_4)	H N_2O Emission Factor (kg N_2O /TJ)	I N_2O Emissions (Gg N_2O)
			C=A*B		**E=C*D/10^6**		**G=C*F/106**		**I=C*H/106**
Patent Fuel									
Coke Oven Coke / Lignite Coke									
Gas Coke									
Coal Tar									
Gas Work Gas									
Coke Oven Gas									
Blast Furnace Gas									
Oxygen Steel Furnace Gas									
Natural gas									
Natural Gas (Dry)									
Other fossil fuels									
Municipal wastes (non-biomass fraction)									
Industrial Wastes									
Waste Oils									
Peat									
Peat									
				Total					

[a] Fill out a copy of this worksheet for each source category listed in Table 2.16 of the Stationary combustion chapter and insert the source category name next to the worksheet number.

Sector	**Energy**								
Category	**Fuel combustion activities**								
Category Code	**1A** [(a)]								
Sheet	**4 of 4 (CO_2, CH_4 and N_2O from fuel combustion by source categories – Tier 1)**								
	Energy consumption			**CO_2**		**CH_4**		**N_2O**	
	A Consumption (Mass, Volume or Energy unit)	B Conversion Factor (TJ/unit)	C Consumption (TJ)	D CO_2 Emission Factor (kg CO_2/TJ)	E CO_2 Emissions (Gg CO_2)	F CH_4 Emission Factor (kg CH_4/TJ)	G CH_4 Emissions (Gg CH_4)	H N_2O Emission Factor (kg N_2O /TJ)	I N_2OEmissions (Gg N_2O)
			C=A*B		**$E=C*D/10^6$**		**$G=C*F/10^6$**		**$I=C*H/10^6$**
Biomass				**Information Items**[b]					
Wood / Wood Waste									
Sulphite Lyes									
Other Primary Solid Biomass									
Charcoal									
Biogasoline									
Biodiesels									
Other Liquid Biofuels									
Landfill Gas									
Sludge Gas									
Other Biogas									
Municipal wastes (biomass fraction)									
				Total		**Total**		**Total**	

[a] Fill out a copy of this worksheet for each source category listed in Table 2.16 of the Stationary combustion chapter and insert the source category name next to the worksheet number.

[b] Information item: Emissions from biomass fuels are only reported as an information item because they are not added to the national totals. They are dealt with in the AFOLU sector.

Sector	Energy																				
Category	Fuel combustion activities																				
Category Code	1A 1 and 1A 2																				
Sheet	1 of 1 (CO_2 emissions from capture for sub-categories 1A 1 and 1A 2 by type of fuel (Gg CO_2))																				
	Liquid fuels			Solid fuels			Natural gas			Other fossil fuels			Peat			Biomass			Total		
	A[a] CO_2 produced	B CO_2 captured	C CO_2 emitted	D[a] CO_2 produced	E CO_2 captured	F CO_2 emitted	G[a] CO_2 produced	H CO_2 captured	I CO_2 emitted	J[a] CO_2 produced	K CO_2 captured	L CO_2 emitted	M[a] CO_2 produced	N CO_2 captured	O CO_2 emitted	P[a] CO_2 produced	Q CO_2 captured	R CO_2 emitted	S[a] CO_2 produced	T CO_2 captured	U CO_2 emitted
			C=A-B			F=D-E			I=G-H			L=J-K			O=M-N			R=-Q	S=A+D +G+J	T=B+E +H+K+ N+Q	U=C+F +I+L+O
1A Fuel Combustion Activities																					
1A1 Energy Industries																					
1A1a Main Activity Electricity and Heat Production																					
1A1ai Electricity Generation																					
1A1aii Combined Heat and Power Generation (CHP)																					
1A1aiii Heat Plants																					
1A1b Petroleum Refining																					
1A1c Manufacture of Solid Fuels and Other Energy Industries																					
1A1ci Manufacture of Solid Fuels																					
1A1cii Other Energy Industries																					
1A2 Manufacturing Industries and Construction																					
1A2a Iron and Steel																					
1A2b Non-Ferrous Metals																					
1A2c Chemicals																					
1A2d Pulp, Paper and Print																					
1A2e Food Processing, Beverages and Tobacco																					
1A2f Non-Metallic Minerals																					
1A2g Transport Equipment																					
1A2h Machinery																					
1A2i Mining and Quarrying																					
1A2j Wood and wood products																					
1A2k Construction																					
1A2l Textile and Leather																					
1A2m Non-specified Industry																					
Note: CO_2 produced is the sum of the amounts of CO_2 captured and emitted.																					

Sector	**Energy**
Category	**Solid Fuels - Coal Mining and Handling - Underground Mines**
Category Code	**1B 1 a i**
Sheet	**1of 3 (CH_4 and CO_2 emissions from underground mining activities)**

CH_4 Emissions

	A **Amount of Coal Produced** **(tonne)**	**B** **Emission Factor** **(m^3 $tonne^{-1}$)**	**C** **Methane Emissions** **(m^3)** **C = A*B**	**D** **Conversion Factor** **(Gg CH_4 m^{-3})**	**E** **Methane Emissions** **(Gg CH_4)** **E=C*D**	**F** **Methane Recovered** **(Gg CH_4)**	**G** **Methane Emissions to be Reported** **(Gg CH_4)** **G=E-F**
Mining (1.B.1.a.i.1)				$0.67x10^{-6}$			
Post-Mining (1.B.1.a.i.2)				$0.67x10^{-6}$			

CO_2 Emissions

	A **Amount of Coal Produced** **(tonne)**	**B** **Emission Factor** **(m^3 $tonne^{-1}$)**	**C** **CO_2 Emissions** **(m^3)** **C=A*B**	**D** **Conversion Factor** **(Gg CO_2 m^{-3})**	**E** **CO_2 Emissions** **(Gg CO_2)** E=C*D
Mining (1.B.1.a.i.1)				$1.83x10^{-6}$	
Post-Mining (1.B.1.a.i.2)				$1.83x10^{-6}$	

Sector	**Energy**
Category	**Solid Fuels - Coal Mining and Handling - Underground Mines**
Category Code	**1B 1 a i**
Sheet	**2 of 3 (Methane emissions from abandoned coal mines)**

CH_4 Emissions

Closure Interval (e.g., 1901-1925)	**A** Number of Abandoned Mines	**B** Fraction of Gassy Coal Mines	**C** Emission Factor (m^3 $year^{-1}$)	**D** Conversion Factor (Gg CH_4 m^{-3})	**E** Methane Emissions (Gg CH_4) E=A*B*C*D	**F** Methane Recovered (Gg CH_4)	**G** Methane Emissions to be Reported (Gg CH_4) G=E-F
				$0.67x10^{-6}$			
				$0.67x10^{-6}$			
				$0.67x10^{-6}$			
				Total			

Sector	**Energy**
Category	**Solid Fuels - Coal Mining and Handling - Underground Mines**
Category Code	**1B 1 a i**
Sheet	**3 of 3 (CO_2 emissions and unburnt CH_4 emissions from drained methane flared or catalytically oxidised)**

CO_2 emissions from CH_4 flaring

	A Volume of Methane Combusted (m^3)	**B** Conversion Factors (Gg CH_4 m^{-3})	**C** Factor to Take Account of Combustion Efficiency	**D** Stoichio-metric Mass Factor	**E** Emissions (Gg) E=A*B*C*D
CO_2		$0.67x10^{-6}$	0.98	2.75	
CH_4			0.02	1	

Sector	**Energy**				
Category	**Solid Fuels - Coal Mining and Handling - Surface Mines**				
Category Code	**1B 1 a ii**				
Sheet	**1of 1 (CH_4 and CO_2 emissions from surface mining activities)**				
CH_4 Emissions					
	A **Amount of Coal Produced** **(tonne)**	**B** **Emission Factor** **(m^3 $tonne^{-1}$)**	**C** **Methane Emissions** **(m^3)** **C = A*B**	**D** **Conversion Factor** **(Gg CH_4 m^{-3})**	**E** **Methane Emissions** **(Gg CH_4)** **E=C*D**
Mining (1.B.1.a.ii.1)				$0.67x10^{-6}$	
Post-Mining (1.B.1.a.ii.2)				$0.67x10^{-6}$	
CO_2 Emissions					
	A **Amount of Coal Produced** **(tonne)**	**B** **Emission Factor** **(m^3 $tonne^{-1}$)**	**C** **CO_2 Emissions** **(m^3)** **C=A*B**	**D** **Conversion Factor** **(Gg CO_2 m^{-3})**	**E** **CO_2 Emissions** **(Gg CO_2)** **E=C*D**
Mining (1.B.1.a.ii.1)				$1.83x10^{-6}$	
Post-Mining (1.B.1.a.ii.2)				$1.83x10^{-6}$	

The following worksheet for the Tier 1 approach should be filled in for each source category and subcategory. The potential subcategories are indicated in Tables 4.2.2 and 4.2.4 to 4.2.5 of the Chapter 4: Fugitive Emissions.

Sector		**Energy**							
Category		**Oil and natural gas**							
Category Code		**1B 2**							
Sheet		**1 of 2**							
				CO_2		**CH_4**		**N_2O**	
IPCC Code	**Sector Name**	**Subcategory**	**A Activity**	**B Emission Factor**	**C Emissions (Gg)**	**D Emission Factor**	**E Emissions (Gg)**	**F Emission Factor**	**G Emissions (Gg)**
					C=A*B		**E=A*D**		**G=A*F**
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								
				TOTAL		**TOTAL**		**TOTAL**	
1.B.2.b	Natural Gas								
1.B.2.b.i	Venting								
1.B.2.b.ii	Flaring								

Sector	Energy								
Category	Oil and natural gas								
Category Code	1B 2								
Sheet	2 of 2								
				CO_2		CH_4		N_2O	
IPCC Code	Sector Name	Subcategory	A Activity	B Emission Factor	C Emissions (Gg)	D Emission Factor	E Emissions (Gg)	F Emission Factor	G Emissions (Gg)
					C=A*B		E=A*D		G=A*F
1.B.2.b.iii	All Other								
1.B.2.b.iii.1	Exploration								
1.B.2.b.iii.2	Production								
1.B.2.b.iii.3	Processing								
1.B.2.b.iii.4	Transmission and Storage								
1.B.2.b.iii.5	Distribution								
1.B.2.b.iii.6	Other								
				TOTAL		TOTAL		TOTAL	
1.B.3	Other emissions from Energy Production								

Sector			Energy					
Category			Fuel combustion activities					
Category Code			1A					
Sheet			1 of 3 (CO_2 from energy sources - Reference Approach)					
			STEP 1					
			A Production	B Imports	C Exports	D International Bunkers	E Stock Change	F Apparent Consumption
Fuel Types								F=A+B-C-D-E
Liquid Fossil	Primary Fuels	Crude Oil						
		Orimulsion						
		Natural Gas Liquids						
	Secondary Fuels	Gasoline						
		Jet Kerosene						
		Other Kerosene						
		Shale Oil						
		Gas / Diesel Oil						
		Residual Fuel Oil						
		LPG						
		Ethane						
		Naphtha						
		Bitumen						
		Lubricants						
		Petroleum Coke						
		Refinery Feedstocks						
		Other Oil						
Liquid Fossil Total								
Solid Fossil	Primary Fuels	Anthracite[a]						
		Coking Coal						
		Other Bit. Coal						
		Sub-bit. Coal						
		Lignite						
		Oil Shale						
	Secondary Fuels	BKB & Patent Fuel						
		Coke Oven/Gas Coke						
		Coal Tar						
Solid Fossil Total								
Gaseous Fossil		Natural Gas (Dry)						
Other	Municipal Wastes (non-bio. fraction)							
	Industrial Wastes							
	Waste Oils							
Other Fossil Fuels Total								
Peat								
Total								

[a] If anthracite is not separately available, include with Other Bituminous Coal.

Sector			**Energy**			
Category			**Fuel combustion activities**			
Category Code			**1A**			
Sheet			**2 of 3 (CO_2 from energy sources - Reference Approach)**			
			STEP 2		**STEP 3**	
			G[a] Conversion Factor (TJ/Unit)	**H** Apparent Consumption (TJ)	**I** Carbon Content (t C/TJ)	**J** Total Carbon (Gg C)
Fuel Types				**H=F*G**		**J=H*I/1000**
Liquid Fossil	Primary Fuels	Crude Oil				
		Orimulsion				
		Natural Gas Liquids				
	Secondary Fuels	Gasoline				
		Jet Kerosene				
		Other Kerosene				
		Shale Oil				
		Gas / Diesel Oil				
		Residual Fuel Oil				
		LPG				
		Ethane				
		Naphtha				
		Bitumen				
		Lubricants				
		Petroleum Coke				
		Refinery Feedstocks				
		Other Oil				
Liquid Fossil Total						
Solid Fossil	Primary Fuels	Anthracite				
		Coking Coal				
		Other Bit. Coal[b]				
		Sub-bit. Coal				
		Lignite				
		Oil Shale				
	Secondary Fuels	BKB & Patent Fuel				
		Coke Oven/Gas Coke				
		Coal Tar				
Solid Fossil Total						
Gaseous Fossil		Natural Gas (Dry)				
Other	Municipal Wastes (non-bio. fraction)					
	Industrial Wastes					
	Waste Oils					
Other Fossil Fuels Total						
Peat						
Total						

[a] Please specify units.

[b] If anthracite is not separately available, include with Other Bituminous Coal.

Sector	Energy			
Category	Fuel combustion activities			
Category Code	1A			
Sheet	3 of 3 (CO_2 from energy sources - Reference Approach)			
	STEP 4		STEP 5	
	K Excluded Carbon (Gg C)	L Net Carbon Emissions (Gg C)	M Fraction of Carbon Oxidised	N Actual CO_2 Emissions (Gg CO_2)
Fuel Types		L=J-K		N=L*M*44/12
Liquid Fossil – Primary Fuels – Crude Oil				
Liquid Fossil – Primary Fuels – Orimulsion				
Liquid Fossil – Primary Fuels – Natural Gas Liquids				
Liquid Fossil – Secondary Fuels – Gasoline				
Liquid Fossil – Secondary Fuels – Jet Kerosene				
Liquid Fossil – Secondary Fuels – Other Kerosene				
Liquid Fossil – Secondary Fuels – Shale Oil				
Liquid Fossil – Secondary Fuels – Gas / Diesel Oil				
Liquid Fossil – Secondary Fuels – Residual Fuel Oil				
Liquid Fossil – Secondary Fuels – LPG				
Liquid Fossil – Secondary Fuels – Ethane				
Liquid Fossil – Secondary Fuels – Naphtha				
Liquid Fossil – Secondary Fuels – Bitumen				
Liquid Fossil – Secondary Fuels – Lubricants				
Liquid Fossil – Secondary Fuels – Petroleum Coke				
Liquid Fossil – Secondary Fuels – Refinery Feedstocks				
Liquid Fossil – Secondary Fuels – Other Oil				
Liquid Fossil Total				
Solid Fossil – Primary Fuels – Anthracite				
Solid Fossil – Primary Fuels – Coking Coal				
Solid Fossil – Primary Fuels – Other Bit. Coal[(a)]				
Solid Fossil – Primary Fuels – Sub-bit. Coal				
Solid Fossil – Primary Fuels – Lignite				
Solid Fossil – Primary Fuels – Oil Shale				
Solid Fossil – Secondary Fuels – BKB & Patent Fuel				
Solid Fossil – Secondary Fuels – Coke Oven/Gas Coke				
Solid Fossil – Secondary Fuels – Coal Tar				
Solid Fossil Total				
Gaseous Fossil – Natural Gas (Dry)				
Other – Municipal Wastes (non-bio-fraction)				
Other – Industrial Wastes				
Other – Waste Oils				
Other Fossil Fuels Total				
Peat				
Total				

[a] If anthracite is not separately available, include with Other Bituminous Coal.

Sector	Energy				
Category	Reference Approach (Auxiliary Worksheet 1-1: Estimating Excluded Carbon)				
Category Code	1A				
Sheet	1 of 1 Auxiliary Worksheet 1-1: Estimating Excluded Carbon				
	A Estimated Fuel Quantities	B Conversion Factor (TJ/Unit)	C Estimated Fuel Quantities (TJ)	D Carbon Content (t C/TJ)	E Excluded Carbon (Gg C)
Fuel Types			**C=A*B**		**E=C*D/1000**
LPG[a]					
Ethane[a]					
Naphtha[a]					
Refinery Gas[a] [b]					
Gas/Diesel Oil[a]					
Other Kerosene[a]					
Bitumen[c]					
Lubricants[c]					
Paraffin Waxes[b] [c]					
White Spirit[b] [c]					
Petroleum Coke[c]					
Coke Oven Coke[d]					
Coal Tar (light oils from coal)[e]					
Coal Tar (coal tar/pitch)[f]					
Natural Gas[g]					
Other fuels[h]					
Other fuels[h]					
Other fuels[h]					

Note: Deliveries refers to the total amount of fuel delivered and is not the same thing as apparent consumption (where the production of secondary fuels is excluded).

[a] Enter the amount of fuel delivered to petrochemical feedstocks.

[b] Refinery gas, paraffin waxes and white spirit are included in “other oil”.

[c] Total deliveries.

[d] Deliveries to the iron and steel and non-ferrous metals industries.

[e] Deliveries to chemical industry.

[f] Deliveries to chemical industry and construction.

[g] Deliveries to petrochemical feedstocks and blast furnaces.

[h] Use the Other fuels rows to enter any other products in which carbon may be stored. These should correspond to the products shown in Table 1-1.