CHAPTER 1

ENERGY

1. ENERGY

1.1 Overview

This chapter discusses inventory methods for emissions of SO_2 and direct and indirect greenhouse gases from energy sources, comprising CO_2, CH_4, N_2O, NO_x, CO and NMVOC. Energy systems are extremely complex and widespread components of national economies. The full range of greenhouse gases is emitted from the production, transformation, handling and consumption of energy commodities. Chapter 2, Industrial Processes, discusses emissions which arise jointly from fuel use in industrial processes and provides guidance on attributing the emissions to the energy or industrial process categories. The various emissions from energy systems are organised in two main categories: Emissions from Fuel Combustion and Fugitive Emissions.

Emissions from Fuel Combustion

CO_2 emissions from fuel combustion are discussed separately and in some depth because they can be calculated accurately at a highly aggregated level, unlike other gases. CO_2 emissions are primarily dependent on the carbon content of the fuel. The IPCC Reference Approach for CO_2 emissions is a simple, accurate and internationally transparent approach which takes advantage of this fact.

CO_2 from energy activities can be estimated from energy supply data, with a few adjustments such as for carbon non-oxidised. Supply data for all commercial fuels are available from international data bases covering individual countries of the world. These data, together with typical carbon content figures, provide a sound starting point for the estimation of CO_2 inventories, particularly for global or regional studies. However, because fuel qualities and emission factors may differ markedly between countries, sometimes by as much as ten percent for nominally similar fuels, national inventories should be prepared using local emission factors and energy data where possible.

Unlike CO_2, national inventories of CH_4, N_2O, NO_x, CO and NMVOCs require more detailed information. Accurate estimation of their emissions depends on knowledge of several interrelated factors, including combustion conditions, technology, and emission control policies, as well as fuel characteristics. The methods must, in general, be applied at a detailed activity/technology level. CO_2 emissions may also be calculated at the more detailed level required for other gases. Indeed, when calculating non-CO_2 emissions national experts are encouraged to calculate CO_2 emissions at the same time, as reconciliation of total CO_2 emissions estimated in this manner with those obtained from the Reference Approach provides a valuable verification process. Procedures for estimating CO_2 and non-CO_2 emissions at the detailed or more aggregated levels of activity are presented in this chapter. The methods for estimating the gases are divided in "Tiers" encompassing different levels of activity and technology detail. Tier 1 methods are generally very simple requiring less data and expertise than the most complicated Tier 3 methods.

Fugitive Emissions

In addition to the emission of greenhouse gases from fuel combustion, other emissions into the atmosphere occur in an unplanned or a deliberate manner. These are fugitive emissions. Fugitive emissions are intentional or unintentional releases of gases from anthropogenic activities. In particular, they may arise from the production, processing, transmission, storage and use of fuels, and include emissions from combustion only where it does not support a productive activity (e.g., flaring of natural gases at oil and gas production facilities). The most significant greenhouse gas emissions in this category are methane emissions from coal mining and from oil and gas systems. There are also emissions of other gases, such as CO_2 and NMVOCs as fugitive or by-product emissions from energy systems.

1.1.1 Recent Developments

As part of Phase II of the IPCC/OECD/IEA Programme on National Greenhouse Gas (GHG) Inventories an expert group on GHG Emissions from Fuel Combustion was set up. The group included over forty experts from various geographical and professional backgrounds. The terms of reference of this group were to continue improving the estimation methodologies on emissions from fuel combustion which had been published in the *IPCC Guidelines for National Greenhouse Inventories* in March 1995.

The issues addressed by the group can be divided into several broad areas:

- harmonisation of international emission estimation methodologies and reporting;
- improvement and review of emission factors;
- development of a new Tier 1 method for estimating non-CO_2 GHG and SO_2 emissions based on fuel consumption;
- development of a new Tier 2 method for estimating emissions from aircraft.

In addition the group identified areas for further work. These are listed at the end of this chapter.

The results of the group's work on the final three items listed above are contained in the sections which follow. The experts' conclusions following a review and discussion of the harmonisation of methodologies are summarised in the following statement.

Harmonisation of International Emission Estimation Methodologies and Reporting

Two approaches to drawing up and presenting national emission inventories in comparable form are currently in use:

- The IPCC Guidelines for National Greenhouse Gas Inventories, and
- the joint EMEP/CORINAIR Atmospheric Emission Inventory Guidebook.

Countries which are Parties to both Conventions have to apply both reporting procedures to each Convention. The IPCC approach meets FCCC 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.

To date, considerable progress has been made in the harmonisation of the IPCC and EMEP/CORINAIR approaches. The IPCC Expert Group on Fuel Combustion has made changes to the fuel list and to the source/sink categories to allow more direct comparison of the two approaches:

- Biomass fuels will be allocated to the various source categories (CO_2 from biomass will not be reported in national totals).
- In order to estimate the full emissions of the industry sector, emissions from autoproduction should be included with emissions from other fuel use within industry. At the same time the emissions from the autoproduction of electricity and heat should be excluded from the energy transformation source category to avoid double counting. This change brings the IPCC source categories for manufacturing and transformation industries into line with those used by CORINAIR.
- Treatment of evaporative emissions (NMVOC) from road transport in the IPCC Tier 2 method is consistent with CORINAIR. Combustion and evaporative emissions should be reported separately. In the IPCC Tier 1 method, all emissions from road transport are included together under fuel combustion.

The CORINAIR programme has now developed its approach further to include additional sectors and sub-divisions (e.g. the definition of civil aviation is now in line with the IPCC definition) so that a complete CORINAIR inventory, including emission estimates, can be used to produce reports in both the FCCC/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 difference between the approaches remains:

- Spatial allocation of road transport emissions: here CORINAIR, with a view to the input requirements of atmospheric dispersion models, applies the principle of territoriality (emission allocation according to fuel consumption) whereas the IPCC is bound to the principle of political responsibility (allocation according to fuel sale). For the IPCC, countries with a big disparity between emissions from fuel sales and fuel consumption have the option of estimating true consumption and reporting the emissions from consumption and trade separately. However, national totals must be on the basis of fuel sales.

1.1.2 Organisation of the Chapter

In addition to this introduction, this chapter is organised into four separate substantive sections covering fuel combustion and fugitive emissions:

- **Simple Methods (Tier 1)**: Emissions from all sources of combustion are estimated on the basis of the quantities of fuel consumed and average emission factors. The IPCC Reference Approach for CO_2 is presented together with new methods for the estimation of CO_2 and non-CO_2 emissions from the main source categories.
- **Detailed Methods (Tiers 2/3)**: Emission estimations are based on detailed fuel/technology information covering stationary and mobile sources.
- **Fugitive emissions from coal mining and handling**: Emissions are generated as a result of the mining and handling of coal, primarily methane emissions from coal mining. Other emissions of GHGs from coal mine and waste fires are briefly discussed.

- **Fugitive emissions from oil and natural gas activities**: Methane emissions from natural gas flaring and venting, and from natural gas production, transmission and distribution are the most important for this category. CO_2 emissions from venting and flaring are included as are NMVOC emissions from production, processing and distribution of oil and oil products. A new section briefly describes the estimation of emissions of ozone precursors and SO_2 from refineries.

1.2 Data

1.2.1 Data Sources

Activity Data

Subject to the requirements outlined below and intended to ensure the comparability of country inventories, 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 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 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 of the Organisation for Economic Co-operation and Development (OECD/IEA), and the United Nations (UN). The primary energy data sources cited in this report include:

- From the OECD/IEA: Energy Statistics and Balances of Non-OECD Countries (OECD/IEA, 1996b); Energy Balances of OECD Countries (OECD/IEA, 1996a); and Energy Statistics of OECD Countries (OECD/IEA, 1996c).
- From the United Nations: Energy Statistics Yearbook (UN, 1996).

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. [1]

Emission Factors

Emissions of GHGs from fuel combustion and fuel supply activities are calculated by multiplying levels of activity by emission factors usually expressed as mass of pollutant per

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[1] Approximately 130 countries (of about 170 UN Member countries) are included in the IEA data, but the countries it includes account for about 98 per cent of worldwide energy consumption and nearly all energy production.

energy unit of activity (e.g. kg N_2O/TJ). The most commonly used activity measure for energy-related emissions is the amount of fuel burned or, where fugitive emissions are concerned, the amount of fuel produced or distributed. In some cases other measures of activity are used, most notably in calculating emissions from the transport sector.

A number of international and national sources of energy activity data and industry emission factors exist largely as a result of international and national analyses of alternative control policies for SO_x, NO_x and NMVOC. A few sources have also recently emerged on various other GHGs. The more detailed factors (for gases other than CO_2) do not relate directly to national energy activity data described below, but require some additional information. The sources of emission factor data, and procedures for making these linkages are discussed in the context of specific gases and source types, in the relevant sections which follow.

1.2.2 Comparability of Reporting

In order to meet the objectives of the IPCC/OECD/IEA programme, inventories must be readily comparable. This requires a large measure of commonality of definitions of activities (source/sink categories) and fuel product groups and the use of a reporting discipline which makes evident the construction of the inventory from the activity data. Specific guidelines for reporting have been prepared. In order to reduce the uncertainty created by possibly different definitions, the IPCC *Reporting Instructions* have largely adopted definitions utilised by the IEA for the regular collection of energy data from OECD member countries. The active co-operation between the UN Statistical Division (New York), the UN ECE (Geneva), Eurostat and the IEA has ensured that there are now very few differences between the definitions employed by these organisations for the collection of their energy data. The IEA definitions may be found in the Glossary at the end of the *Reporting Instructions* (Volume 1).

Although common standards for the collection of data by international organisations exist the presentation of the data collected can be different. At least five aspects of energy data presentations need to be checked prior to using data for greenhouse gas inventories:

- Are the energy data expressed in terms of net calorific values (NCV) or gross calorific values (GCV)?[2] Since most of the world uses net calorific values, the IPCC *Guidelines* uses net calorific values.
- Are non-commercial fuels, including wood and other biomass fuels, included?[3]
- Are wood waste, agricultural wastes or waste-derived fuels included if combusted for energy production? These fuels should be accounted for in the IPCC methodology, but are included with biomass fuels.

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[2] The IEA generally reports data in net calorific values. The difference between the net and the gross calorific value of a fuel is the heat of condensation of moisture in the fuel during combustion. The net calorific value excludes this. The IEA assumes that net calorific values are 5 per cent lower than gross calorific values for oil and coal, and 10 per cent lower for natural gas.

[3] While some of these fuels (such as wood) may be included in national or international data sets, it is likely that they are underestimated due to poor record-keeping and lack of statistical information for non-commercial fuels.

- Is non-energy fuel usage (if non-oxidised) accounted for?[4]
- How are international bunker fuels for air and ship transport treated?[5]

Given responses to these questions, several adjustments may need to be made to the energy data being used in order to formulate a complete inventory of greenhouse gases. If published IEA data are being used the following corrections must be made:

1. Consumption of vegetal fuels in non-OECD countries should be added to commercial fuel consumption. Estimates of the former are available in the IEA publication cited. Consumption of vegetal fuels, as declared by OECD countries in their reports to the IEA, are included as "Combustible Renewables and Wastes" in the IEA statistics for these countries.
2. International energy statistics show fuel consumption by industrial and commercial electricity generators (autoproducers) as an identified part of fuel use by the energy industries. In order to harmonise inventory preparation with the EMEP/CORINAIR methods, countries preparing IPCC inventories should include autoproducer fuel consumption in the industry and commercial sectors and remove it from energy industries. See *Recent Developments* above.
3. Care is required when estimating the amount of fuel used without oxidation in the manufacture of non-energy products. IEA data generally cover only deliveries to the industry sector manufacturing such products. Some of the fuels delivered will be oxidised by the user. See Chapter 2, Industrial Processes, Overview.
4. IEA data do not include deliveries of oil for international air transport as part of the International Bunkers data. Where data are available they are identified as part of the national transport sector fuel consumption. UN estimates are available for many countries.

1.2.3 Uncertainty

The *Reporting Instructions*, Volume 1, make explicit provision for the reporting of estimates from all source categories identified in the Standard Data Tables. Energy activity data and emission factors are both subject to wide variations through uncertainties in basic data, identification of fuel qualities, calorific values and measurements in emissions. Furthermore, the uncertainties in estimates of fugitive emissions can be larger than those from fuel combustion as wider ranges in natural resource conditions and operations practice exist for fuel extraction and processing. This topic is discussed further in Section 1.8.7. Managing and combining uncertainty estimates from several sources is discussed in Appendix 1 to the *Reporting Instructions*.

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[4] This is normally reported in primary energy requirements but is not combusted and therefore does not contribute directly to greenhouse gas emissions.

[5] International bunker fuels are combusted in ships at sea and by airplanes (both undertaking international movements) and therefore should be included in global greenhouse gas estimations. Following guidance from the INC, the IPCC recommends that every country estimate emissions from international bunker fuels sold within national boundaries, but that these emissions would be reported separately and, as far as possible, excluded from national totals.

1.3 Fuel Combustion: Overview

In the initial stages of the IPCC/OECD/IEA programme it was recognised that work on both methods development and national inventories needed to be prioritised, as it was not possible to deal with all of the gases and sources simultaneously. Priority was given to the direct GHGs in the order: carbon dioxide, methane and nitrous oxide (IPCC/OECD, 1991). In Phase II of the *Guidelines* development, an attempt has been made to identify default methods for a simplified Tier 1 method for estimating emissions of the GHGs and SO_2.

The purpose of a Tier 1 method is to assist countries that cannot access detailed fuel use and technology data to develop emission inventories. Consequently, the Tier 1 method should enable at least rough emission estimations of CO_2, CH_4, N_2O, NO_x, CO and NMVOC using energy statistics, and of SO_2 by using additional assumptions on the sulphur content of the fuels.

The Tier 1 method should be used in cases where no detailed information is available on fuel type, technology and operating conditions. If countries have more exact national emission factors, these (and not the default factors) should be used.

Countries wanting to do more detailed emission estimations may use the Tier 2 method described in Section 1.5. A third option which may be used (Tier 3) is the CORINAIR 94 methodology which is described in the EEA TF Emission Inventory Guidebook and is available on CD-ROM[6].

1.4 Simple Methods (Tier 1) for Fuel Combustion

The Tier 1 method for CO_2 is fairly well established and is explained in Section 1.4.1. For non-CO_2 gases, a simplified methodology has been developed to estimate emissions by applying emission factors to fuel statistics which are organised by sector. In reality, emissions of these gases depend on the fuel type used, combustion technology, operating conditions, control technology, and on maintenance and age of the equipment. However, since it is unlikely that many countries will have this detailed data, the Tier 1 method ignores these refinements (see Box 1).

Section 1.4.2 provides average non-CO_2 emission factors for the agreed IPCC source categories together with additional information on the range of these factors and their use. The proposed values are based on emission factors included in Radian Corporation (1990), US EPA (1995), the EDGAR database[7], the CORINAIR 1990 database and scientific reports from different countries. SO_2 emission factors are estimated using a formula based on sulphur content in the fuel. The compilation of default factors for biomass fuels in the "Other Sectors" has been based on measurement data reported by Smith and Ramakrishna (1990), Berdowski et al. (1993a and 1993b), Delmas (1993), Smith et al. (1993), Delmas et al. (1995), Veldt and Berdowski (1995) and Brocard et al. (1996).

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[6] The CD-ROM may be obtained by contacting the European Environment Agency, Kongens Nytorv 6, 1050 Copenhagen, Denmark.

[7] EDGAR Version 2.0 was developed by TNO and RIVM and is a set of global emission inventories of greenhouse gases and ozone-depleting substances for all anthropogenic and most natural sources on a per country basis and on 1° x 1° grid (Olivier et al., 1995).

For aircraft, the emission factors for the Tier 1 method are based on the fleet average values of NO_x, CO and NMVOC of the global inventories compiled by NASA, ECAC/ANCAT, WSL and NLR [Wuebbles et al. (1993); Olivier (1995); Brok (1995)].

BOX 1
MAIN FUEL GROUPS

In the Tier 1 method for non-CO_2 gases, the fuels are aggregated into the following main groups:

- **coal**
- **natural gas**
- **oil**
  gasoline for transport;
  diesel oil for transport;
  other oil products.
- **biomass**
  wood / wood waste;
  charcoal;
  other biomass and wastes (includes dung, agricultural, municipal and industrial wastes, bagasse and agricultural residues).

Note: Refer to Section 1.2 of the Common Reporting Framework in the *Reporting Instructions* for details on which products are included in each of the main groups.

The default emission factors are internally consistent and it is essential to preserve this consistency when replacing the default by local values so that total emissions of carbon (for example) do not exceed the carbon available in the fuel.

1.4.1 Carbon Dioxide (CO_2) Emissions

In this section the methodology for estimating CO_2 emissions from energy is discussed. Carbon dioxide (CO_2) is the most common greenhouse gas produced by anthropogenic activities, accounting for about 60 per cent of the increase in radiative forcing since pre-industrial times (IPCC, 1992). By far the largest source of CO_2 emissions is from the oxidation of carbon when fossil fuels are burned, which accounts for 70-90 per cent of total anthropogenic CO_2 emissions. When fuels are burned, most carbon is emitted as CO_2 immediately during the combustion process. Some carbon is released as CO, CH_4, or non-methane hydrocarbons, which oxidise to CO_2 in the atmosphere within a period from a few days to 10-11 years. The IPCC methodology accounts for all of the carbon from these emissions in the total for CO_2 emissions. The other carbon-containing gases are also estimated and reported separately (see following sections for methodologies for estimating CH_4, CO, and NMVOCs).[8]

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[8] It is important to note that there is an intentional double counting of carbon emitted from combustion. This format treats the non-CO_2 gases as a subset of CO_2 emissions and ensures that the CO_2 emission estimates reported by each country represent the entire amount of carbon that would eventually be present in the atmosphere as CO_2. The

Fuel combustion is widely dispersed throughout most activities in national economies making assembly of a complete record of the quantities of each fuel type consumed in each "end use" activity a considerable task which some countries have not yet completed. Fortunately, it is possible to estimate national CO_2 emissions by accounting for the carbon in fuels supplied to the economy. This is the basis of the IPCC Reference Approach. The supply of fuels is simple to record and is more likely to be available in many countries than detailed end use consumption statistics.

The Reference Approach requires statistics for production of fuels and their external trade as well as changes in their stocks. It also needs a limited number of figures for the consumption of fuels used for non-energy purposes where carbon may be stored. It uses a simple assumption: once carbon is brought into a national economy in fuel, it is either saved in some way (e.g., in increases of fuel stocks, stored in products, left unoxidised in ash) or it must be released to the atmosphere. In order to calculate the carbon released it is not necessary to know exactly how the fuel was used or what intermediate transformations it underwent. In this respect the methodology may be termed a “top-down” approach compared with the “bottom-up” methods used for other gases. As stated in the *Overview*, this does not mean that a “bottom-up” approach should not be followed for estimating CO_2 emissions but the total emissions must be compared with those obtained from the Reference Approach. A “bottom-up” method for CO_2 is briefly discussed later in this section.

When estimating CO_2 emissions from fuel combustion there are a number of points of a statistical, technical or procedural nature which affect several of the estimation methods.

- **Fuel Carbon and Energy Content:** There is considerable variation in the carbon and energy content by weight of fuels. However, expressing the carbon emission factor as the carbon content per unit of energy released reduces this variation because of the close link between the carbon content and energy value of the fuel. It is natural therefore that all fuel supply and consumption data for combustion emission calculations be expressed in energy units. Energy data expressed in other units should be converted to terajoules before use.

- **Unoxidised Carbon:** When energy is consumed not all of the carbon in the fuel oxidises to CO_2. Incomplete oxidation occurs due to inefficiencies in the combustion process that leave some of the carbon unburned or partly oxidised as soot or ash.

- **Stored Carbon:** Some of the fuel supplied to an economy is used as a raw material (or feedstock) for manufacture of products such as plastics, fertiliser, or in a non-energy use (e.g. bitumen for road construction, lubricants). In some cases, the carbon from the fuels is oxidised quickly to CO_2. In other cases the carbon is stored (or sequestered) in the product, sometimes for as long as centuries. The amounts stored for long periods are called *stored carbon* and should be deducted from the carbon emissions calculation. Estimation of stored carbon requires data on fuel used as feedstock and/or quantities of non-energy fuel products produced. The calculations are discussed within each of the alternative approaches presented in this section.

- **Bunker Fuels:** The IPCC methodology subtracts the quantities delivered to and consumed by ships or aircraft *for international transport* from the fuel supply to the country. In this manner, the CO_2 emissions arising from the use of international bunkers

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reasons for this double counting are discussed in the Overview of the IPCC Guidelines, General Notes on the Guidelines.

are not included in the national total. To simplify the preparation of global estimates, these emissions should be brought together in a separate table.

- **Biomass Fuels:** Biomass fuels are included in the national energy and emissions accounts for completeness. These emissions should not be included in national CO_2 emissions from fuel combustion. If energy use, or any other factor, is causing a long term decline in the total carbon embodied in standing biomass (e.g. forests), this net release of carbon should be evident in the calculation of CO_2 emissions described in the *Land Use Change and Forestry* chapter.

All of the above issues are addressed within the methods presented in the remainder of this section.

Approaches For Estimating CO_2 Emissions

The estimation process can be divided into six steps that lead to figures for CO_2 emissions from fuel combustion.

1. Estimate consumption of fuels by fuel/product type.
2. Convert the fuel data to a common energy unit (TJ), if necessary.
3. Select carbon emission factors for each fuel/product type and estimate the total carbon content of the fuels.
4. Estimate the amount of carbon stored in products for long periods of time.
5. Account for carbon not oxidised during combustion.
6. Convert emissions of carbon to full molecular weight of CO_2 .

1.4.1.1 IPCC REFERENCE APPROACH

Estimate Fuel Consumption

The first step of the IPCC Reference Approach is to estimate apparent consumption of fuels within the country. This requires a balance of primary fuels produced, plus imports, minus exports, minus international bunkers and minus net changes in 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.

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 (production of secondary fuels and fuel products is excluded);
- the amounts of primary and secondary fuels and fuel products imported;
- the amounts of primary and secondary fuels and fuel products exported;
- the amounts of primary and secondary fuels used in international bunkers;
- the net increases or decreases in stocks of fuels.

The apparent consumption of *primary* fuels is, therefore, calculated from the above data as:

Apparent Consumption = Production + Imports - Exports
- International Bunkers - Stock Change.

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.

Apparent consumption of secondary fuels should be added to primary apparent consumption. The production (or manufacture) of secondary fuels should be ignored in the calculations because the carbon in these fuels will already have been 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 secondary fuels is calculated as follows:

Apparent Consumption = Imports - Exports - International Bunkers
- Stock Change.

Note that this calculation can result in negative numbers for apparent consumption. This is a perfectly acceptable result for the purposes of this calculation since it indicates a net export or stock increase in the country.

Since carbon content typically varies by fuel type, data should be reported for detailed categories of fuel and product types as shown in Table 1-1. The table also illustrates the inputs and calculations recommended for the IPCC Reference Approach.

TABLE 1-1
IPCC REFERENCE APPROACH
ENTRIES AND CALCULATIONS FOR STEPS (1) AND (2)

Fuel	(1) Production	(2) Imports	(3) Exports	(4) International Bunkers	(5) Stock Change	(6) Apparent Consumption(a)	(7) Conversion Factor	(8) Apparent Consumption (TJ)
A) Liquid Fossil						sum(b)		sum
Primary Fuels								
1) Crude Oil	input	input	input	NA	input	calc	input	calc
2) Orimulsion	input	input	input	NA	input	calc	input	calc
3) N. Gas Liquids	input	input	input	NA	input	calc	input	calc
Secondary Fuels / Products								
4) Gasoline	NA	input	input	input	input	calc	input	calc
5) Jet Kerosene	NA	input	input	input	input	calc	input	calc
6) Other Kerosene	NA	input	input	NA	input	calc	input	calc
7) Shale Oil	NA	input	input	NA	input	calc	input	calc
8) Gas / Diesel Oil	NA	input	input	input	input	calc	input	calc
9) Residual Fuel Oil	NA	input	input	input	input	calc	input	calc
10) LPG	NA	input	input	NA	input	calc	input	calc
11) Ethane	NA	input	input	NA	input	calc	input	calc
12) Naphtha	NA	input	input	NA	input	calc	input	calc
13) Bitumen	NA	input	input	NA	input	calc	input	calc
14) Lubricants	NA	input	input	input	input	calc	input	calc
15) Petroleum Coke	NA	input	input	NA	input	calc	input	calc
16) Refinery Feedstocks	NA	input	input	NA	input	calc	input	calc
17) Other Oil	NA	input	input	NA	input	calc	input	calc
B) Solid Fossil						sum		sum
Primary Fuels								
18) Anthracite(c)	input	input	input	NA	input	calc	input	calc
19) Coking Coal	input	input	input	NA	input	calc	input(d)	calc
20) Other Bit. Coal	input	input	input	input	input	calc	input(d)	calc
21) Sub-bit. Coal	input	input	input	input	input	calc	input(d)	calc
22) Lignite	input	input	input	NA	input	calc	input(d)	calc
23) Oil Shale	input	input	input	NA	input	calc	input	calc
24) Peat	input	input	input	NA	input	calc	input	calc
Secondary Fuels								
25) BKB & Patent Fuel	NA	input	input	NA	input	calc	input	calc
26) Coke Oven/Gas Coke	NA	input	input	NA	input	calc	input	calc
C) Gaseous Fossil						sum		sum
27) Natural Gas (Dry)	input	input	input	NA	input	calc	input	calc
Total(e)						**sum**		**sum**
Information Entries								
Biomass Total						sum		sum
28) Solid Biomass	input	input	input	NA	input	calc	input	calc
29) Liquid Biomass	input	input	input	NA	input	calc	input	calc
30) Gas Biomass	input	input	input	NA	input	calc	input	calc

TABLE 1-1 (CONTINUED)
IPCC REFERENCE APPROACH
ENTRIES AND CALCULATIONS FOR STEPS (3) TO (6)

Fuel	(8) Apparent Consumption (TJ)	(9) Carbon Emission Factor(f) (t C/TJ)	(10) Carbon Content (Gg C)	(11) Carbon Stored (Gg C)	(12) Net Carbon Emissions (Gg C)	(13) Actual Carbon Emissions (Gg C)	(14) Actual CO_2 Emissions (Gg CO_2)
A) Liquid Fossil	sum		sum	sum	sum	sum	sum
Primary Fuels							
1) Crude Oil	calc	20.0	calc		calc	calc	calc
2) Orimulsion	calc	22.0	calc		calc	calc	calc
3) N. Gas Liquids	calc	17.2	calc		calc	calc	calc
Secondary Fuels / Products							
4) Gasoline	calc	18.9	calc		calc	calc	calc
5) Jet Kerosene	calc	19.5	calc		calc	calc	calc
6) Other Kerosene	calc	19.6	calc		calc	calc	calc
7) Shale Oil	calc	20.0	calc		calc	calc	calc
8) Gas / Diesel Oil	calc	20.2	calc	Table 1-5	calc	calc	calc
9) Residual Fuel Oil	calc	21.1	calc		calc	calc	calc
10) LPG	calc	17.2	calc	Table 1-5	calc	calc	calc
11) Ethane	calc	16.8	calc	Table 1-5	calc	calc	calc
12) Naphtha	calc	(20.0)	calc	Table 1-5	calc	calc	calc
13) Bitumen	calc	22.0	calc	Table 1-5	calc	calc	calc
14) Lubricants	calc	(20.0)	calc	Table 1-5	calc	calc	calc
15) Petroleum Coke	calc	27.5	calc		calc	calc	calc
16) Refinery Feedstocks	calc	(20.0)	calc		calc	calc	calc
17) Other Oil	calc	(20.0)	calc		calc	calc	calc
B) Solid Fossil	sum		sum	sum	sum	sum	sum
Primary Fuels							
18) Anthracite(c)	calc	26.8	calc		calc	calc	calc
19) Coking Coal	calc	25.8	calc	Table 1-5	calc	calc	calc
20) Other Bit. Coal	calc	25.8	calc		calc	calc	calc
21) Sub-bit. Coal	calc	26.2	calc		calc	calc	calc
22) Lignite	calc	27.6	calc		calc	calc	calc
23) Oil Shale	calc	29.1	calc		calc	calc	calc
24) Peat	calc	28.9	calc		calc	calc	calc
Secondary Fuels							
25) BKB & Patent Fuel	calc	(25.8)	calc		calc	calc	calc
26) Coke Oven/Gas Coke	calc	29.5	calc		calc	calc	calc
C) Gaseous Fossil	sum		sum	sum	sum	sum	sum
27) Natural Gas (Dry)	calc	15.3	calc	Table 1-5	calc	calc	calc
Total(e)	**sum**		**sum**	**sum**	**sum**	**sum**	**sum**
Information Entries							
Biomass Total	sum		sum		sum	sum	sum
28) Solid Biomass	calc	29.9	calc		calc	calc	calc
29) Liquid Biomass	calc	(20.0)	calc		calc	calc	calc
30) Gas Biomass	calc	(30.6)(g)	calc		calc	calc	calc

TABLE 1-1 (CONTINUED)
IPCC REFERENCE APPROACH
EMISSIONS FROM INTERNATIONAL BUNKERS
(INTERNATIONAL MARINE AND AIR TRANSPORT)[h]

Fuel	(15) Quantities delivered[i]	(16) Conversion Factor (TJ/units)	(17) Quantities Delivered (TJ)	(18) Carbon Emission Factor (t C/TJ)	(19) Carbon Content (t C)	(20) Carbon Content (Gg C)
A) Solid Fossil						
Primary Fuels						
1) Other Bituminous Coal	input	input	calc	25.8	calc	calc
2) Sub-Bituminous Coal	input	input	calc	26.2	calc	calc
Liquid Fossil						
Secondary Fuels						
3) Gasoline	input	input	calc	18.9	calc	calc
4) Jet Kerosene	input	input	calc	19.5	calc	calc
5) Gas / Diesel Oil	input	input	calc	20.2	calc	calc
6) Residual Fuel Oil	input	input	calc	21.1	calc	calc
7) Lubricants	input	input	calc	(20.0)	calc	calc
Total			**sum**			

TABLE 1-1 (CONTINUED)
IPCC REFERENCE APPROACH
EMISSIONS FROM INTERNATIONAL BUNKERS
(INTERNATIONAL MARINE AND AIR TRANSPORT)

Fuel	(21) Fraction of Carbon Stored	(22) Carbon Stored (Gg C)	(23) Net Carbon Emissions	(24) Actual Carbon Emissions (Gg C)	(25) Actual CO_2 Emissions (Gg CO_2)
A) Solid Fossil					
Primary Fuels					
1) Other Bituminous Coal	NA	calc	calc	calc	calc
2) Sub-Bituminous Coal	NA	calc	calc	calc	calc
Liquid Fossil					
Secondary Fuels					
3) Gasoline	NA	calc	calc	calc	calc
4) Jet Kerosene	NA	calc	calc	calc	calc
5) Gas / Diesel Oil	NA	calc	calc	calc	calc
6) Residual Fuel Oil	NA	calc	calc	calc	calc
7) Lubricants	0.5	calc	calc	calc	calc
Total					**sum**

TABLE 1-1 (CONTINUED)
EXPLANATORY NOTES

calc = value to be calculated,   NA = not applicable

(a) Apparent Consumption = Production + Imports - Exports - International Bunkers - Stock Changes. A stock build is positive; a stock draw is negative.

(b) Apparent Consumption for the aggregate categories of Liquid Fossil, Solid Fossil, Gaseous Fossil, and Biomass Fuels equal the sum of Apparent Consumption over the fuel types within the appropriate categories.

(c) If anthracite is not separately identifiable, include it with Other Bituminous Coal.

(d) If data are in 10^3t, separate conversion factors are available for Production, Imports and Exports in Table 1-2. Each of these entries should be multiplied by the appropriate conversion factor. Then, the results should be summed to find Apparent Consumption in TJ (Column 8).

(e) Total should include Liquid, Solid, and Gaseous Fossil Fuel subtotals only. Biomass subtotals are for reference purposes only and should not be included in the totals.

(f) If value is in parenthesis it is a default value until a fuel-specific CEF is determined.

(g) Based on the assumption that 50 per cent of the carbon in the biomass is converted to methane.

(h) The bunker emissions are not to be added to national totals.

(i) See Column 4, "International Bunkers".

Convert Fuel Data to a Common Energy Unit (if necessary)

In the OECD/IEA *Energy Statistics*, and other energy data compilations, production and consumption of solid and liquid fuels are specified in 10^3 tonnes. To convert tonnes to terajoules, net calorific values (NCV) must be applied. The values to convert from 10^3 tonnes to terajoules are in Table 1-2. In some cases, particularly for coal, different NCVs are given for production, imports and exports in a given country and are used to convert each category separately when calculating apparent consumption. For international bunkers and stock changes national experts can use a weighted average of the different NCVs, or use the one for the coal type which meets the largest share of total apparent consumption. For refined products the NCVs from 10^3 tonnes to terajoules do not normally vary greatly by country and global default values are provided in Table 1-3.[9]

National experts may use more detailed locally available NCVs. In this case, the values used should also be reported and documented. If original data are expressed in other energy units such as British thermal units (Btu's) or million tons of oil equivalent (Mtoe), they should be converted to terajoules using standard conversion factors. If energy data are already available in terajoules on a net calorific value basis, no conversion is necessary and Column 7 of Table 1-1 can be ignored.

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[9] Throughout the *Guidelines* net calorific values are used and expressed in SI units or multiples of SI units (for example TJ/kt). The term *Conversion Factor* has two uses. First, as net calorific value, to convert quantities expressed in natural units to energy units, and second as a scaling factor to convert one form of energy unit to another (e.g., Btu's to GJ).

TABLE 1-2
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR SELECTED NON-OECD COUNTRIES

(Terajoule per kilotonne)

	Albania	Algeria	Angola Cabinda	Argentina	Armenia	Azer-baijan	Bahrain	Bangla-desh	Bela-russia	Benin	Bolivia
OIL											
Crude Oil	41.45	43.29	42.75	42.29	-	42.08	42.71	42.16	42.08	42.58	43.33
NGL	-	43.29	-	42.50	-	-	42.71	42.71	-	-	43.33
COAL											
Hard Coal											
Production	-	25.75	-	24.70	-	-	-	-	-	-	-
Imports	27.21	25.75	-	30.14	18.58	18.58	-	20.93	25.54	-	-
Exports	-	-	-	24.70	18.58	18.58	-	-	25.54	-	-
Lignite and Sub-Bituminous Coal											
Production	9.84	-	-	-	-	-	-	-	-	-	-
Imports	-	-	-	-	14.65	14.65	-	-	14.65	-	-
Exports	9.84	-	-	-	14.65	14.65	-	-	14.65	-	-
Coal Products											
Patent Fuel/BKB	-	-	-	-	29.31	29.31	-	-	29.31	-	-
Coke Oven/Gas Coke	27.21	27.21	-	28.46	25.12	25.12	-	-	25.12	-	-

	Brazil	Brunei	Bulgaria	Came-roon	Chile	China	Colombia	Congo	Cuba	Cyprus	Czech Republic
OIL											
Crude Oil	42.54	42.75	42.62	42.45	42.91	42.62	42.24	42.91	41.16	42.48	41.78
NGL	45.22	42.75	-	-	42.87	-	41.87	-	-	-	-
COAL											
Hard Coal											
Production	18.42	-	24.70	-	28.43	20.52	27.21	-	-	-	24.40
Imports	30.56	-	24.70	-	28.43	20.52	-	-	25.75	25.75	23.92
Exports	-	-	-	-	-	20.52	27.21	-	-	-	27.98
Lignite and Sub-Bituminous Coal											
Production	-	-	7.03	-	17.17	-	-	-	-	-	12.26
Imports	-	-	-	-	-	-	-	-	-	-	-
Exports	-	-	-	-	-	-	-	-	-	-	15.26
Coal Products											
Patent Fuel/BKB	-	-	20.10	-	-	-	-	-	-	-	21.28
Coke Oven/Gas Coke	28.30	-	27.21	-	28.43	28.47	20.10	-	27.21	-	27.01

Note: A few of these countries have become OECD members subsequent to the production of this table.

Crude oil conversion factors are based on weighted average production data.

The conversion factors are those used by the IEA in the construction of energy balances.

Source: OECD/IEA, 1993b.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR SELECTED NON-OECD COUNTRIES

(Terajoule per kilotonne)

	Ecuador	Egypt	Estonia	Ethiopia	Gabon	Georgia	Ghana	Guatemala	Hong Kong	Hungary	India
OIL											
Crude Oil	42.45	42.54	-	42.62	42.62	42.08	42.62	42.45	-	40.36	42.79
NGL	42.45	42.54	-	-	-	-	-	-	-	45.18	43.00
COAL											
Hard Coal											
Production	-	-	-	-	-	18.58	-	-	-	16.42	19.98
Imports	-	25.75	18.58	-	-	18.58	25.75	-	25.75	26.33	25.75
Exports	-	-	18.58	-	-	18.58	-	-	-	24.15	19.98
Lignite and Sub-Bituminous Coal											
Production	-	-	14.65	-	-	-	-	-	-	10.55	9.80
Imports	-	-	14.65	-	-	14.65	-	-	-	9.91	-
Exports	-	-	14.65	-	-	14.65	-	-	-	-	-
Coal Products											
Patent Fuel/BKB	-	-	20.10	-	-	29.31	-	-	-	21.44	20.10
Coke Oven/Gas Coke	-	27.21	25.12	-	-	25.12	-	-	27.21	30.11	-

	Indonesia	Iran	Iraq	Israel	Ivory Coast	Jamaica	Jordan	Kazakhstan	Kenya	Kuwait	Kyrgyzstan
OIL											
Crude Oil	42.66	42.66	42.83	42.54	42.62	42.16	42.58	42.08	42.08	42.54	42.08
NGL	42.77	42.54	42.83	-	-	-	-	-	-	42.62	-
COAL											
Hard Coal											
Production	25.75	25.75	-	-	-	-	-	18.58	-	-	18.58
Imports	25.75	25.75	-	26.63	-	25.75	-	18.58	25.75	-	18.58
Exports	25.75	-	-	-	-	-	-	18.58	-	-	18.58
Lignite and Sub-Bituminous Coal											
Production	-	-	-	-	-	-	-	14.65	-	-	14.65
Imports	-	-	-	-	-	-	-	14.65	-	-	14.65
Exports	-	-	-	-	-	-	-	14.65	-	-	14.65
Coal Products											
Patent Fuel/BKB	-	-	-	-	-	-	-	29.31	-	-	29.31
Coke Oven/Gas Coke	27.21	-	-	-	-	-	-	25.12	-	-	25.12

Note: A few of these countries have become OECD members subsequent to the production of this table.

Crude oil NCVs are based on weighted average production data.

The NCVs are those used by the IEA in the construction of energy balances.

Source: OECD/IEA, 1993b.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR SELECTED NON-OECD COUNTRIES

(Terajoule per kilotonne)

	Latvia	Lebanon	Libya	Lithuania	Malaysia	Malta	Mexico	Moldova	Morocco	Mozambique	Myanmar
OIL											
Crude Oil	-	42.16	43.00	42.08	42.71	-	42.35	-	43.00	-	42.24
NGL	-	-	-	-	43.12	-	46.81	-	-	-	42.71
COAL											
Hard Coal											
Production	-	-	-	-	25.75	-	24.72	-	23.45	25.75	25.75
Imports	18.58	-	-	18.59	25.75	25.75	30.18	18.58	27.63	25.75	25.75
Exports	18.58	-	-	18.59	25.75	-	22.41	18.58	-	-	-
Lignite and Sub-Bituminous Coal											
Production	-	-	-	-	-	-	-	-	-	-	8.37
Imports	14.65	-	-	14.65	-	-	-	14.65	-	-	-
Exports	14.65	-	-	14.65	-	-	-	14.65	-	-	-
Coal Products											
Patent Fuel/BKB	29.31	-	-	29.31	-	-	-	29.31	-	-	-
Coke Oven/Gas Coke	25.12	-	-	25.12	27.21	-	27.96	25.12	27.21	-	27.21

	Nepal	Neth. Antilles	Neutral Zone	Nigeria	North Korea	Oman	Pakistan	Panama	Paraguay	Peru	Philippines
OIL											
Crude Oil	-	42.16	42.12	42.75	42.16	42.71	42.87	42.16	42.54	42.75	42.58
NGL	-	-	-	-	-	-	-	-	-	42.75	-
COAL											
Hard Coal											
Production	-	-	-	25.75	25.75	-	18.73	-	-	29.31	20.10
Imports	25.12	-	-	-	25.75	-	27.54	25.75	-	29.31	20.52
Exports	-	-	-	25.75	25.75	-	-	-	-	-	-
Lignite and Sub-Bituminous Coal											
Production	-	-	-	-	17.58	-	-	-	-	-	8.37
Imports	-	-	-	-	-	-	-	-	-	-	-
Exports	-	-	-	-	-	-	-	-	-	-	-
Coal Products											
Patent Fuel/BKB	-	-	-	-	-	-	-	-	-	-	-
Coke Oven/Gas Coke	-	-	-	27.21	27.21	-	-	-	-	27.21	27.21

Note: A few of these countries have become OECD members subsequent to the production of this table.

Crude oil NCVs are based on weighted average production data.

The NCVs are those used by the IEA in the construction of energy balances.

Source: OECD/IEA, 1993b.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR SELECTED NON-OECD COUNTRIES

(Terajoule per kilotonne)

	Poland	Qatar	Romania	Russia	Saudi Arabia	Senegal	Singapore	South Africa	South Korea	Slovak Republic	Sri Lanka
OIL											
Crude Oil	41.27	42.87	40.65	42.08	42.54	42.62	42.71	44.13	42.71	41.78	42.16
NGL	-	43.00	-	-	42.62	-	-	-	-	-	-
COAL											
Hard Coal											
Production	22.95	-	16.33	18.58	-	-	-	25.09	19.26	-	-
Imports	29.41	-	25.12	18.58	-	-	-	-	27.21	23.92	25.75
Exports	25.09	-	-	18.58	-	-	-	25.09	-	-	-
Lignite and Sub-Bituminous Coal											
Production	8.36	-	7.24	14.65	-	-	-	-	-	12.26	-
Imports	-	-	7.24	14.65	-	-	-	-	-	-	-
Exports	9.00	-	-	14.65	-	-	-	-	-	15.26	-
Coal Products											
Patent Fuel/BKB	20.93	-	14.65	29.31	-	-	-	-	-	21.28	-
Coke Oven/Gas Coke	27.76	-	20.81	25.12	-	-	27.21	-	-	27.01	-

	Sudan	Syria	Chinese Taipei	Tajikistan	Tanzania	Thailand	Trinidad / Tobago	Tunisia	Turkmenistan	Ukraine	Utd Arab Emirates
OIL											
Crude Oil	42.62	42.04	41.41	42.08	42.62	42.62	42.24	43.12	42.08	42.08	42.62
NGL	-	-	-	-	-	46.85	-	43.12	-	-	-
COAL											
Hard Coal											
Production	-	-	25.96	18.58	25.75	-	-	-	-	21.59	-
Imports	-	-	27.42	18.58	-	26.38	-	25.75	18.58	25.54	-
Exports	-	-	-	18.58	-	-	-	-	18.58	21.59	-
Lignite and Sub-Bituminous Coal											
Production	-	-	-	-	-	12.14	-	-	-	14.65	-
Imports	-	-	-	14.65	-	-	-	-	14.65	14.65	-
Exports	-	-	-	14.65	-	-	-	-	14.65	14.65	-
Coal Products											
Patent Fuel/BKB	-	-	-	29.31	-	-	-	-	29.31	29.31	-
Coke Oven/Gas Coke	-	-	-	25.12	27.21	27.21	-	27.21	25.12	25.12	-

Note: A few of these countries have become OECD members subsequent to the production of this table.

Crude NCVs are based on weighted average production data.

The NCVs are those used by the IEA in the construction of energy balances.

Source: OECD/IEA, 1993b.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR SELECTED NON-OECD COUNTRIES

(Terajoule per kilotonne)

	Uruguay	Uzbek-istan	Venez-uela	Viet Nam	Yemen	Former Yugo-slavia	Zaire	Zambia	Zim-babwe
OIL									
Crude Oil	42.71	42.08	42.06	42.61	43.00	42.75	42.16	42.16	-
NGL	-	-	41.99	-	-	-	-	-	-
COAL									
Hard Coal									
Production	-	18.58	25.75	20.91	-	23.55	25.23	24.71	25.75
Imports	-	18.58	-	-	-	30.69	25.23	-	25.75
Exports	-	18.58	25.75	20.91	-	-	-	24.71	25.75
Lignite and Sub-Bituminous Coal									
Production	-	-	-	-	-	8.89	-	-	-
Imports	-	14.65	-	-	-	16.91	-	-	-
Exports	-	14.65	-	-	-	16.90	-	-	-
Coal Products									
Patent Fuel/BKB	-	29.31	-	-	-	20.10	29.31	-	-
Coke Oven/Gas Coke	-	25.12	27.21	27.21	-	26.90	27.21	-	27.21

Note: A few of these countries have become OECD members subsequent to the production of this table.

Crude oil NCVs are based on weighted average production data.

The NCVs are those used by the IEA in the construction of energy balances.

Source: OECD/IEA, 1993b.

TABLE 1-2 (CONTINUED)
1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR OECD COUNTRIES

(Terajoule per kilotonne)

	Australia	Austria	Belgium	Canada	Den-mark	Finland	France	Germany	Greece	Iceland	Ireland	Italy
OIL												
Crude Oil	43.21	42.75	42.75	42.79	42.71	42.66	42.75	42.75	42.75	-	42.83	42.75
NGL	45.22	45.22	-	45.22	-	-	45.22	-	45.22	-	-	45.22
Refinery Feedst.	42.50	42.50	42.50	42.50	42.50	42.50	42.50	42.50	42.50	-	42.50	42.50
COAL												
Coking Coal												
Production	28.34	-	-	28.78	-	-	28.91	28.96	-	-	-	-
Imports	-	28.00	29.31	27.55	-	34.33	30.50	28.96	-	27.44	29.10	30.97
Exports	28.21	-	-	28.78	-	-	-	28.96	-	-	-	-
Other Bituminous Coal and Anthracite(a)												
Production	24.39	-	25.00	28.78	-	-	26.71	24.96	-	-	26.13	26.16
Imports	-	28.00	25.00	27.55	26.09	26.38	25.52	26.52	27.21	25.85	29.98	26.16
Exports	25.65	-	25.00	28.78	26.09	-	26.43	31.71	-	-	26.13	-
Sub-Bituminous Coal												
Production	17.87	-	18.06	17.38	-	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-	-	-	-	-	-
Exports	-	-	18.20	-	-	-	-	-	-	-	-	-
Lignite												
Production	9.31	10.90	-	14.25	-	-	17.94	8.41	5.74	-	-	10.47
Imports	-	10.90	21.56	-	-	-	17.94	14.88	-	-	19.82	10.47
Exports	-	10.90	-	14.25	-	-	-	8.40	-	-	-	-
Coal Products												
Patent Fuel/BKB	21.00	19.30	23.81	-	18.27	-	28.80	20.64	15.28	-	20.98	-
Coke Oven/Gas Coke	25.65	28.20	29.31	27.39	31.84	28.89	28.71	28.65	29.30	26.65	32.66	29.30

(a) In IEA statistics Anthracite is combined with Other Bituminous Coal – the NCVs given above reflect this combination.

The NCVs for oil and coal are those used by the IEA in the construction of energy balances.

The NCVs for coal product groupings listed are calculated from the values of their constituents.

Source: OECD/IEA, 1993a.

TABLE 1-2 (CONTINUED)

1990 COUNTRY-SPECIFIC NET CALORIFIC VALUES FOR OECD COUNTRIES

(Terajoule per kilotonne)

	Japan	Luxem-bourg	Nether-lands	NZ	Norway	Portugal	Spain	Sweden	Switzer-land	Turkey	UK	USA
OIL												
Crude Oil	42.62	-	42.71	43.12	42.96	42.71	42.66	42.75	42.96	42.79	42.83	42.71
NGL	46.05	-	45.22	46.05	45.22	-	45.22	-	-	-	46.89	45.22
Refinery Feedst.	42.50	-	42.50	44.80	42.50	42.50	42.50	42.50	42.50	42.50	42.50	42.50
COAL												
Coking Coal												
Production	30.63	-	-	28.00	-	-	29.16	-	-	33.49	29.27	29.68
Imports	30.23	-	29.30	28.00	-	29.30	30.14	30.00	-	33.49	30.07	-
Exports	-	-	-	28.00	-	-	-	-	-	-	29.27	29.68
Other Bituminous Coal and Anthracite(a)												
Production	23.07	-	-	26.00	28.10	-	21.07	14.24	-	29.30	24.11	26.66
Imports	24.66	29.30	29.30	-	28.10	26.59	25.54	26.98	28.05	27.21	26.31	27.69
Exports	-	-	29.30	-	28.10	-	23.00	26.98	28.05	-	27.53	28.09
Sub-Bituminous Coal												
Production	-	-	-	21.30	-	17.16	11.35	-	-	-	-	19.43
Imports	-	-	-	-	-	-	11.35	-	-	-	-	-
Exports	-	-	-	-	-	-	-	-	-	-	-	-
Lignite												
Production	-	-	-	14.10	-	-	7.84	-	-	9.63	-	14.19
Imports	-	20.03	20.00	-	-	-	-	8.37	-	12.56	-	-
Exports	-	-	20.00	-	-	-	-	-	-	-	-	14.19
Coal Products												
Patent Fuel/BKB	27.05	20.10	23.53	-	-	-	20.31	20.10	21.76	20.93	26.26	-
Coke Oven/Gas Coke	28.64	28.50	28.50	-	28.50	28.05	30.14	28.05	28.05	29.28	26.54	27.47

(a) In IEA statistics Anthracite is combined with Other Bituminous Coal – the NCVs given above reflect this combination.

The NCVs for oil and coal are those used by the IEA in the construction of energy balances.

The NCVs for coal product groupings listed are calculated from the values of their constituents.

Source: OECD/IEA, 1993a.

TABLE 1-3
NET CALORIFIC VALUES FOR OTHER FUELS
(TJ/10^3 tonnes)

Refined Petroleum Products	
Gasoline (aviation and auto)	44.80
Jet Kerosene	44.59
Other Kerosene	44.75
Shale Oil	36.00
Gas/Diesel Oil	43.33
Residual Fuel Oil	40.19
LPG	47.31
Ethane	47.49
Naphtha	45.01
Bitumen	40.19
Lubricants	40.19
Petroleum Coke	31.00
Refinery Feedstocks	44.80
Refinery Gas	48.15
Other Oil Products	40.19
Other Products	
Coal Oils and Tars derived from Coking Coal	28.00
Oil Shale	9.40
Orimulsion	27.50

Source: OECD/IEA, Paris, 1996a.

Select Carbon Emission Factors and Estimate Carbon Content

Carbon emission factors may vary considerably both among and within primary fuel types:

- For natural gas, the carbon emission factor 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 be "wet", i.e., containing far larger amounts of non-methane hydrocarbons. The carbon emission factor 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.

Estimates of carbon emission factors for fuels from several studies are summarised in Table 1-4.

TABLE 1-4
CARBON EMISSION FACTORS FOR FUELS FROM DIFFERENT STUDIES
(t C/terajoule, net calorific value basis)(a)

Study		Anthracite	Bit. Coal	Sub-Bit. Coal	Lignite	Peat
Marland & Rotty (1984)			25.5(a)			
Marland & Pippin (1990)			25.4(a)			
Grubb (1989)		26.8(a)	25.8(a)		27.6(a)	28.9(a)
OECD (1991)			25.8(a,b)			
Study	**Crude Oil**	**Gasoline**	**Kerosene**	**Gas/Diesel Oil**	**Fuel Oil**	**Natural Gas**
Marland & Rotty (1984)	21.0(a)				15.2(a)	
Marland & Pippin (1990)	21.0(a)	19.4(a)	19.4(a)	19.9(a)	21.1(a,c)	15.3(a)
Grubb (1989)	20.0(a)	18.9(a)	19.5(a)	20.0(a)	21.1(a)	15.3(a)
OECD (1991)	20.0					15.3

(a) Values were originally based on gross calorific value; they were converted to net calorific value by assuming a 5% difference in calorific value for coal and oil, and 10% for natural gas. These percentage adjustments are the IEA assumptions on how to convert from gross to net calorific values.

(b) Average value for all coal: sub-bituminous through anthracite.

(c) Midpoint of range from 20.7 for light fuel oil (#4 fuel oil) to 21.6 for residual fuel oil (#6 fuel oil).

One approach for estimating the carbon emission factors was presented by Marland and Rotty (1984). For natural gas, the carbon emission factor was based on the actual composition of dry natural gas. They sampled the composition of natural gas from 19 countries and then calculated a weighted average global gas composition, breaking the gas out into methane, ethane, propane, other hydrocarbons, CO_2 and other gases. The composition of the gas then determined both the calorific values of the gas and the carbon content. The carbon emission factor of the gas (t C/terajoule, using gross calorific values) was expressed using the following relationship:

$$C_g = 13.708 + (0.0828 \times 10^{-3}) \times (H_v - 37\,234)$$

where C_g is the carbon emission factor of the gas in t C/terajoule (TJ) and H_v is the calorific value of the gas (gross calorific value, see OECD/IEA, 1996a) in kJ/cubic metre. The coefficients of the equation (13.708, 0.0828 x 10^{-3}, and 37 234) were estimated using regression analysis based on data from the 19 countries. The carbon content of oil was assumed to be a function of the API gravity: using an estimate of world average API gravity of 32.5° ± 2°, they estimated a composition of 85 ± 1 per cent carbon. Converting this to units of carbon per terajoule yielded an estimate of 21.0 t C/TJ on a net calorific value basis (assuming 42.62 terajoules per kilotonne, gross calorific value, as reported in Marland & Rotty, 1984). For coal, the literature suggested that the carbon content of coal was predominantly a function of the energy content (calorific value) and that the carbon content on a per tonne coal-equivalent basis was around 74.6 ± 2 per cent (Marland and Rotty 1984). The carbon emission factor was estimated to be 25.5 t C/TJ.

The approach used by Grubb (1989) to estimate carbon emission factors is very similar but based on more recent research. All carbon emission factors were originally reported on a gross calorific value basis, but are converted here to a net calorific value basis. He provides carbon factors for methane, ethane, propane, and butane and using data from

Marland and Rotty (1984), estimates an average emission factor for natural gas of 15.3 t C/TJ ± 1 per cent. For oil and some refined petroleum products the estimates are based on data from the literature, as summarised in Table 1-4. The carbon emission factor of coal, excluding anthracite, was defined as:

$$C_c = 32.15 - (0.234 \times H_v)$$

where C_c is the carbon emission factor in t C/TJ and H_v is the gross calorific value of the coal when the calorific value is from 31 to 37 TJ/kilotonne on a dry mineral matter free (dmf) basis. Anthracites fall outside this range and a value of 26.8 t C/TJ is used.

Since the publication of the original OECD Background Document (OECD 1991), additional information has been made available on carbon emission factors. At an IPCC-sponsored workshop in October 1992 (IPCC/OECD, 1993), experts recommended several revised emission factors based on national inventory submissions to the OECD. Additional emission factors were also made available based on the work of the expert group on GHG Emissions from Fuel Combustion during Phase II of the IPCC/OECD/IEA Programme on National GHG Inventories in 1996.

The IPCC Reference Approach relies primarily on the emission factors from Grubb (1989), with additions from other studies as discussed above, to estimate total carbon content. The suggested carbon emission factors are listed in Table 1-1. The basic formula for estimating total carbon content is:

$$\begin{gathered}\text{Total Carbon Content (Gg C)} = \\ \sum \text{Apparent Energy Consumption (by fuel type in TJ)} \\ \times \text{ Carbon emission factor (by fuel type in t C/TJ)} \\ \times 10^{-3}\end{gathered}$$

Apparent consumption of the fuels is estimated in Table 1-1 (Column 6). The carbon emission factors for the fuels are average values based on net calorific value. This approach has been recommended by the IPCC because it explicitly treats each major fuel type differently according to its carbon emission factor. When countries use local values for the carbon emission factors they should note the differences from the default values and provide documentation supporting the values used in the national inventory calculations.

Estimate Carbon Stored in Products

The next step is to estimate the amount of fossil fuel carbon that is stored in non-energy products and the portion of this carbon expected to oxidise over a long time period (e.g., greater than 20 years). All fossil fuels are used for non-energy purposes to some degree. Natural gas is used for ammonia production. LPGs are used for a number of purposes, including production of solvents and synthetic rubber. A wide variety of products is produced from oil refineries, including asphalt, naphthas and lubricants. Two by-products of the coking process, oils and tars, are used in the chemical industry.

Not all non-energy uses of fossil fuels, however, result in storage of carbon. For example, the carbon from natural gas used in ammonia production is oxidised quickly. Many products from the chemical and refining industries are burned or decompose within a few years. Several approaches for estimating the portion of carbon stored in products are reviewed in Box 2.

Box 2

APPROACHES FOR ESTIMATING CARBON STORED IN PRODUCTS

The approach used by Marland and Rotty (1984) relied on historical data for determining non-energy applications and varied depending on fossil fuel type. For natural gas they assume that close to 1/3 of the carbon used for non-energy purposes (equivalent to 1 per cent of total carbon from natural gas production) does not oxidise over long periods of time. For oil products they assume that some portion of LPG, ethane, naphthas, asphalt and lubricants does not oxidise quickly. Specifically, they assume that about 50 per cent of LPG and ethane from gas processing plants is sold for chemical and industrial uses and that 80 per cent of this amount, or 40 per cent of all LPG and ethane, goes into products that store the carbon. About 80 per cent of the carbon in naphthas is assumed to end up in products such as plastics, tires, and fabrics and oxidises slowly. All of the carbon in asphalt is assumed to remain unoxidised for long periods, while about 50 per cent of the carbon in lubricants is assumed to remained unoxidised. For coal they assume that on average 5.91 per cent of coal going to coke plants ends up as light oil and crude tar, with 75 per cent of the carbon in these products remaining unoxidised for long periods.

Grubb (1989) basically uses the Marland and Rotty (1984) approach, but suggests several changes, including higher estimates of methane losses during production and transportation of natural gas to market and a wide range of estimates concerning the fraction of carbon in refinery products that remain unoxidised. He does use Marland and Rotty's estimate of the amount of carbon in coal that does not oxidise, but also quantifies the amount of carbon emissions from SO_2 scrubbing (in which CO_2 is released during the chemical interactions in the desulphurisation process) using the formula: (% sulphur by weight) x (coal consumption) x 12/32.

Okken and Kram (1990) introduce the concept of actual and potential emissions of CO_2 where potential emissions are defined as carbon that is stored in products from non-energy uses or by-products from combustion and actual emissions as all carbon from fuels that are emitted immediately or within a short period of time. Actual emissions plus potential emissions equal total carbon in the fuels. They assume that carbon from the following non-energy uses of fossil fuels oxidises quickly: fertiliser production (ammonia), lubricants, detergents, volatile organic solvents, etc. Carbon from the following non-energy uses of fossil fuels remains stored for long periods of time (in some cases, hundreds of years): plastics, rubber, bitumen, formaldehyde, and silicon carbide.

For the IPCC Reference Approach, the suggested formula for estimating carbon stored in products for each country is:

$$\begin{gathered}\text{Total Carbon Stored (Gg C)} = \\ \text{Non-Energy Use } (10^3\text{ t}) \\ \times \text{ Conversion Factor } (\text{TJ}/10^3\text{ t}) \\ \times \text{ Emission Factor (t C/TJ)} \\ \times \text{ Fraction Carbon Stored} \\ \times\ 10^{-3}\end{gathered}$$

Most of the suggested categories conform to those used by Marland and Rotty (1984) and include naphthas, bitumen (asphalt), lubricants, LPG, and coal oils and tars. The data available from the UN reports (e.g., 1996) correspond to these categories, with the exception of coal oils and tars, which are not reported.

The assumptions of 75 per cent for naphtha as a feedstock and 50 per cent for gas/diesel oil as a feedstock, used in Table 1-5 (Column 6) should be viewed as potential overestimates, since not all of the carbon from the intermediate products will be stored. For example, carbon emissions may occur due to losses in the production of final products or incineration of final products. At this time these percentages can be used as the upper bound when determining stored carbon.

This suggested approach for estimating carbon stored in products is illustrated in Table 1-5. Whenever possible, countries should substitute assumptions that represent more accurately the practices within their own countries and provide documentation for these assumptions. The resulting estimates from Table 1-5 (Column 7) should be subtracted from carbon content of apparent consumption to determine net carbon emissions that could be oxidised. This calculation is done by entering the values from Table 1-5 (Column 7) for the relevant fuels/products into Table 1-1 (Column 11). In Table 1-1, carbon stored in products is subtracted from total carbon in the fuels ("carbon content") to get net carbon available for emission ("net carbon emissions").

Currently the fraction of carbon stored applied to the carbon content of the fuels used for product manufacture takes into account the release of carbon from the use or destruction of the products in the short term. The fraction is therefore lower than the fraction of carbon entering the products (see Box 2). The emissions resulting from the use or destruction of the products may occur in:

- industrial processes – both the production of non-fuel products from energy feedstocks, and the emissions from use of these products in industrial processes (e.g., oxidation of anodes made from petroleum coke which occurs during aluminium production);
- other end uses of products (e.g., lubricants oxidised in transportation);
- waste disposal – particularly incineration of plastics and other fossil fuel based products.

TABLE 1-5
ESTIMATION OF CARBON STORED IN PRODUCTS

	1 Estimated Fuel Quantities[a]	2 Conversion Factor	3 Estimated Fuel Quantities[b]	4 Emission Factor	5 Carbon Content[c]	6 Fraction Carbon Stored	7 Carbon Stored[d]
Product/Fuel[e]	(Original Units)	TJ/Units	(TJ)	(t C/TJ)	(Gg C)		(Gg C)
Lubricants	calc	Table 1-3	calc	Table 1-1	calc	0.50	calc
Bitumen	calc	Table 1-3	calc	Table 1-1	calc	1.0	calc
Coal Oils and Tars from Coking Coal	calc[f]	Table 1-3	calc	Table 1-1[g]	calc	0.75	calc
Naphtha as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.75	calc
Gas/Diesel Oil as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.50	calc
Natural Gas as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.33	calc
LPG as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.80	calc
Ethane as Feedstock	calc	Table 1-3	calc	Table 1-1	calc	0.80	calc

(a) Either Apparent Consumption plus domestic (manufactured) production, or Feedstock Use.

(b) Estimated Fuel Quantities in TJ (Col. 3) equals Estimated Fuel Quantities (Col. 1) times a Conversion Factor (Col. 2).

(c) Carbon Content (Col. 5) equals Estimated Fuel Quantities in TJ (Col. 3) times an Emission Factor (Col. 4).

(d) Carbon Stored (Col. 7) equals Carbon Content (Col. 5) times Fraction Carbon Stored (Col. 6) divided by 10^3.

(e) This is an incomplete list of products/fuels which account for the majority of carbon stored. Where data are available for other fuels, the estimation of stored carbon is strongly encouraged.

(f) Use 6% of apparent consumption of Coking Coal.

(g) Use the emission factor for coking coal (25.8 t C/TJ).

Estimate Carbon Unoxidised During Fuel Use

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 is stored indefinitely. Based on work by Marland and Rotty (1984), since 1991 the IPCC has been recommending that 1 per cent of the carbon in fossil fuels would remain unoxidised. This assumption was based on the following findings from Marland and Rotty for the amount unoxidised:

- For natural gas, less than 1 per cent of the carbon is unoxidised during combustion and remains as soot in the burner, stack, or in the environment.
- For oil 1.5% ±1% passes through the burners and is deposited in the environment without being oxidised. This estimate is based on 1976 US statistics of emissions of hydrocarbons and total suspended particulates.
- For coal 1% ±1% of carbon supplied to furnaces is discharged unoxidised, primarily in the ash.

However, several countries have commented that the amount of carbon remaining unoxidised is more variable than indicated by the 1 per cent assumption across all fuels. For example, it has been noted that the amount of unburnt carbon varies depending on several factors, including type of fuel consumed, type of combustion technology, age of the equipment, and operation and maintenance practices.

Information submitted by the Coal Industry Advisory Board of the OECD (Summers 1993), provided the following observations for coal combustion technologies:

- Unoxidised carbon from electric power stations in Australia averaged about 1 per cent. Test results from stoker-fired industrial boilers, however, were higher, with unoxidised carbon amounting to 1 to 12 per cent of total carbon with coals containing from 8 to 23 per cent ash. As average values, 2 per cent carbon loss was suggested for best practices, 5 per cent carbon loss for average practices, and 10 per cent carbon loss for worst practices. In those cases when coal is used in the commercial or residential sectors, carbon losses would be on the order of 5 to 10 per cent (Summers, 1993).
- In related work British Coal has provided information on the percentage of unburnt carbon for different coal combustion technologies:

Pulverised Coal	1.6%
Travelling Grate Stoker	2.7-5.4%
Underfeed Stoker	4.0-6.6%
Domestic Open Fire	0.6-1.2%
Shallow Bed AFBC[10]	Up to 4.0%
PFBC/CFBC[10]	3.0%

- Evaluations at natural gas-fired boiler installations indicate that combustion efficiency is often 99.9 per cent at units reasonably well-maintained.

It is clear from the available information that a single global default assumption of 1 per cent unoxidised carbon is not always accurate. While some additional information is available to refine the assumptions for this portion of the methodology, most of the new information requires some level of detail on the type of technology in which the fuel is combusted or information on which sector is consuming the fuel. The Reference Approach requires data only on the amount of fuels consumed in a country, not data by technology type or sector of the economy. As a result, based on the information available at this point, the default values presented in Table 1-6 are recommended for the percentage of carbon oxidised during combustion by fuel. It should be recognised that the value for coal is highly variable based on fuel quality and technology types. National experts are encouraged to vary this assumption if they have data on these factors, suggesting that different average values for their countries are appropriate. It is clear from the information available at this time that additional research should be conducted on this topic.

TABLE 1-6
FRACTION OF CARBON OXIDISED
(RECOMMENDED DEFAULT ASSUMPTIONS)

Coal(a)	0.98
Oil and Oil Products	0.99
Gas	0.995
Peat for electricity generation(b)	0.99

(a) This figure is a global average but varies for different types of coal, and can be as low as 0.91.
(b) The fraction for peat used in households may be much lower.

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[10] AFBC = Advanced Fluidised Bed Combustion
CFBC = Circulating Fluidised Bed Combustion
PFBC = Pressurised Fluidised Bed Combustion

Convert carbon emissions to full molecular weight CO_2

Net carbon emissions (Column 12 in Table 1-1) are then multiplied by the fraction of carbon oxidised to give actual carbon emissions (Column 13 of Table 1-1), and then summed across all fuel types, to determine the total amount of carbon oxidised from the combustion of fuel. To express the results as carbon dioxide (CO_2), total carbon oxidised should be multiplied by the molecular weight ratio of CO_2 to C, (44/12).

1.4.1.2 EMISSIONS BY SOURCE CATEGORIES

A sectoral breakdown of national CO_2 emissions using the defined IPCC source categories is needed for monitoring and abatement policy discussions. The IPCC Reference Approach provides a rapid method to estimate the total CO_2 emissions from fuels supplied to the country but it does not break down the emissions by sector. The development of a Tier 1 method giving non-CO_2 GHG emissions by sector (Section 1.4.2) has been extended to CO_2 so that sectoral information can be obtained simply for this gas. However, the range of the carbon emission factors for fuels and the special consideration given to CO_2 emissions from biofuels mean that the calculations for CO_2 differ in a number of respects from those used for the non-CO_2 gases.

The more detailed calculations used for this approach are essentially similar in content to those used for the Reference Approach.

The formula is:

carbon emissions

=

∑ fuel consumption expressed in energy units (TJ) for each sector

x carbon emission factor

- carbon stored

x fraction oxidised

There are seven key considerations when calculating CO_2 emissions by sector some of which have already been discussed for the Reference Approach:

- Identification of the quantities of fuels consumed (combusted) in energy industries;
- A clear understanding of how emissions from electricity generation and heat are treated;
- Identification of the fraction of carbon released during the use of fuels for non-energy purposes;
- Adjustments for carbon unoxidised;
- Identification of the quantities of fuels used for international transport;
- Separation of the emissions from the combustion of biofuels;
- Separation of the quantities of fuels used in the Agriculture/Forestry/Fisheries between mobile sources and stationary plant.

Quantities of fuels combusted in the energy industries.

For emission calculations there are three principal groups of activities involving fuels in the energy and transformation sector:

(i) The transformation of primary fuels into secondary fuels by physical or chemical processes not involving combustion of the primary fuel. For example, manufacture of petroleum products from crude oil.

(ii) The production of heat for sale or for electricity generation.

(iii) Combustion of fuels to support the main energy extraction or production business of the enterprise. For example, use of refinery gas for heating distillation columns, use of colliery methane at mines for heating purposes.

Activities within the first group are mainly those of refining and manufacture of solid fuels and derived gases. By definition, group (i) does not lead to fuel combustion emissions. Only fuels entering the activities in groups (ii) and (iii) should be considered for the calculation of emissions.

The underlying model of carbon flow which drives the reporting for the energy and transformation sector is that primary fuel carbon entering group (i) will appear either in the secondary products or be lost as fugitive emissions which are reported separately in Category 1B, Fugitive Emissions from Fuels. Carbon in secondary products will be partly or entirely stored or combusted either:

1) within the transformation industry as a group (iii) activity (e.g, refinery fuel or coke oven gas for heating coke ovens), or

2) as a group (ii) activity, or

3) by final consumers outside the energy industry.

In short therefore, because the pathways for carbon *leaving* a transformation process are covered by reporting on the worksheets in Module 1, there is no need to report quantities of primary fuels used exclusively for refining or solid fuel manufacture, notably, crude oil and coking coal. If, however, a country does use crude oil for electricity generation, for example, then the relevant quantity should be reported.

The scope of the activities to be included under group (ii) also needs further definition and this will be considered now.

Generation of electricity and heat

The Overview to this chapter (Section 1.1) describes the steps taken to harmonise reporting and inventory compilation required from those countries completing inventories according to both IPCC and EMEP/CORINAIR reporting requirements. An important step towards harmonisation has been the decision to align the IPCC reporting of emissions from electricity and heat generation by autoproducers (see Box 3) with that of CORINAIR.

In the 1995 *Guidelines* emissions from autoproducers were included with those from main power producers (referred to as "Public Electricity and Heat"). In this edition of the *Guidelines*, emissions from autoproduction are attributed to the industrial or commercial branches in which the generation activity occurs. Emissions reported under "Public Electricity and Heat" should be those from main power producers only.

BOX 3

AUTOPRODUCERS

An autoproducer of electricity or heat is an enterprise which generates electricity or sells heat as a secondary activity, i.e., not as its main business. This should be contrasted with main power producers who generate electricity or who sell heat as their main business (primary activity) and may be publicly or privately owned. Supplies from main power producers are referred to as "Public" electricity and heat supply although an increasing part of public supply is being met by autoproducers.

Wherever possible the quantities of fuel used for, and the resulting emissions from, autoproduction should be identified in the worksheets used for this calculation. The worksheets make provision for this. As a growing amount of public electricity supply comes from autoproduction, calculation of the related emissions will assist identification of total emissions from electricity generation.

Carbon release during the non-energy use of fuels

The calculation of carbon content of fuels consumed, as a step for the estimation of the CO_2 emissions from fuel combustion, must be adjusted for the quantities of carbon which are stored within products made from fuels used as raw materials or within products used for their physical properties rather than combusted (e.g., bitumen or lubricants). The approach used to do this and the types of fuels involved are fully discussed under "Stored Carbon" in Section 1.4.1.1 and the arguments will not be repeated. There are two aspects of this adjustment, however, which need to be mentioned explicitly here because the calculation of carbon release at the level of fuel deliveries permits certain simplifications not available at the level of fuel supplies used for the Reference Approach. This arises because the Reference Approach estimates emissions from the supply of primary fuels and external trade in secondary fuels whereas the sectoral approach uses the carbon content of delivered fuels from which the full quantities of fuels entering long-term storage may be identified.

1. Bitumen and coal tars are usually not combusted but used in a manner which causes most of the carbon content to enter long-term storage. As a result, these products are excluded from the calculation of fuel combustion emissions and do not feature in the list of commodities on the worksheet.
2. Other fuels that are only partly combusted are included within the worksheet and the fraction of carbon entering long-term storage estimated by means of a carbon storage factor. A similar method is used for the Reference Approach. In the present sectoral calculation, however, no special steps are required to obtain deliveries data as the approach relies on them for all of its calculations.

Adjustments For Carbon Unoxidised

As discussed above under the Reference Approach, the amount of carbon that may remain unoxidised from combustion activities can vary for many reasons, including type of fuel consumed, type of combustion technology, age of the equipment, and operation and maintenance practices. Since the present approach relies on more disaggregated fuel consumption data, it is possible to specify the assumptions for unoxidised carbon by application. Unless other data are available, countries should use as default values the assumptions recommended in the Reference Approach: 2 per cent of carbon in fuel consumed is unoxidised for coal, 1 per cent for oil-derived fuels, 0.5 per cent for natural gas and 1 per cent for peat used for electricity generation. In addition, the following assumptions (from Summers, 1993) are recommended:

- For stoker-fired industrial boilers an average value for carbon unoxidised is 5 per cent. If countries believe that their operation and maintenance procedures achieve maximum efficiency, a 2 per cent carbon loss is suggested. If these procedures are believed to lead to very poor efficiency, then a 10 per cent carbon loss is recommended.
- In those cases when coal is used in the commercial or residential sectors, the assumption for unoxidised carbon should be 5 per cent.

Clearly, much additional research needs to be done in this area. These adjustments are suggested as initial default values. As more work is done, countries are encouraged to report any additional information they may have to refine understanding of the amount of carbon unoxidised in various applications.

Fuels used for international transport

The exclusion from national totals of emissions from (bunker) fuels used for international marine and air transport has been discussed in Section 1.4.1.1, Reference Approach. As in that approach, the emissions from international bunkers should not be omitted entirely but reported separately on the worksheet. The definitions of national and international movements for ships and aircraft are covered under the "Definition of Source Categories" (Energy) in Volume 1, *Reporting Instructions.*

Combustion of biofuels

CO_2 emissions from the combustion of biomass fuels are not to be included in the total national CO_2 emissions but should be reported separately on the worksheet.

Fuel use for mobile sources and stationary plant in the Agriculture/Forestry/Fisheries sector

The separation of fuel combustion between the two types of combustion sources in this sector has been introduced to permit the aggregation of CO_2 emissions from them with the emissions of the non-CO_2 gases. Whatever methods are used for estimating the quantities of fuels used by these two types when calculating the non-CO_2 emissions from this sector should be used for CO_2. Delivery statistics do not usually distinguish between combustion plant types in any economic activity sector.

1.4.2 Non-CO_2 Emissions

1.4.2.1 METHANE (CH_4) EMISSIONS FROM FUEL COMBUSTION

The contribution of fuel combustion to global emissions of methane is minor and the uncertainty is high. For these reasons, an aggregated fuel/sector split is sufficient for a Tier 1 approach, although exact product detail needs to be determined for CH_4 from biomass combustion. Fuel wood, charcoal, agricultural residues, agricultural waste and municipal waste combustion is by far the major contributor to CH_4 emissions within the fuel combustion group. Traditional charcoal making, which is a typical smouldering process, is a large source of methane which should be reported under Fugitive Emissions from Energy. Consequently, CH_4 emissions from developing countries with large biomass consumption could be significant.

Methane is produced in small quantities from fuel combustion due to incomplete combustion of hydrocarbons in fuel. The production of methane is dependent on the temperature in the boiler/stove. In large, efficient combustion facilities and industrial applications, the emission rate is very low, with utility emission rates being less than 1 per cent of average rates for residential coal combustion. In smaller combustion sources, emission rates are higher, particularly when smouldering occurs. The highest rates of methane emissions from fuel combustion occur in residential applications (small stoves and open burning).

The CH_4 emissions from mobile sources are a function of the methane content of the motor fuel, the amount of hydrocarbons passing unburnt through the engine, the engine type, and any post-combustion controls. In uncontrolled engines the proportion of methane emissions is highest at low speeds and when the engine is idle. Poorly tuned engines may have a particularly high output of CH_4.

The general method for estimating CH_4 can be described as:

$$\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})$$

where:

EF = Emission Factor (kg/TJ);

Activity = Energy Input (TJ);

a = Fuel type; and

b = Sector-activity.

The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, the CORINAIR 1994 default emission factors, the EDGAR Version 2.0 database, National Communications to the FCCC, Berdowski, et al. (1993a and 1993b), Radian Corporation (1990) and US EPA (1995). Additional research will need to be undertaken to further improve the quality of the emission factors.

TABLE 1-7
CH_4 DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

<table>
<tr><th colspan="3"></th><th>Coal(a)</th><th>Natural Gas</th><th colspan="2">Oil</th><th>Wood/ Wood Waste</th><th>Charcoal</th><th>Other Biomass and Wastes(c)</th></tr>
<tr><td colspan="3">Energy Industries</td><td>1</td><td>1</td><td colspan="2">3</td><td>30(b)</td><td>200(b)</td><td>30</td></tr>
<tr><td colspan="3">Manufacturing Industries and Construction</td><td>10</td><td>5</td><td colspan="2">2</td><td>30</td><td>200</td><td>30</td></tr>
<tr><td rowspan="5">Transport</td><td colspan="2">Aviation(d)</td><td></td><td></td><td colspan="2">0.5</td><td></td><td></td><td></td></tr>
<tr><td colspan="2" rowspan="2">Road</td><td rowspan="2"></td><td rowspan="2">50</td><td>Gasoline</td><td>Diesel</td><td rowspan="2"></td><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td>20(e)</td><td>5</td></tr>
<tr><td colspan="2">Railways</td><td>10</td><td></td><td colspan="2">5</td><td></td><td></td><td></td></tr>
<tr><td colspan="2">Navigation</td><td>10</td><td></td><td colspan="2">5</td><td></td><td></td><td></td></tr>
<tr><td rowspan="4">Other Sectors</td><td colspan="2">Commercial/Institutional</td><td>10</td><td>5</td><td colspan="2">10</td><td>300</td><td>200</td><td>300</td></tr>
<tr><td colspan="2">Residential</td><td>300</td><td>5</td><td colspan="2">10</td><td>300</td><td>200</td><td>300</td></tr>
<tr><td rowspan="2">Agriculture/ Forestry/ Fishing</td><td>Stationary</td><td>300</td><td>5</td><td colspan="2">10</td><td>300</td><td>200</td><td>300</td></tr>
<tr><td>Mobile</td><td></td><td>5</td><td colspan="2">5</td><td></td><td></td><td></td></tr>
</table>

Note: These factors are considered as the best available global default factors to date.

(a) The emission factors for brown coal may be several times higher than those for hard coal.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) Includes dung and agricultural, municipal and industrial wastes.

(d) 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.

(e) Emission factors for 2-stroke engines may be three times higher than those for 4-stroke engines.

1.4.2.2 NITROUS OXIDE (N_2O) EMISSIONS FROM FUEL COMBUSTION

As with methane, the contribution of fuel combustion to global emissions of N_2O is minor and the uncertainty is high. Reliable emission factors are not yet available for all sources. For these reasons, an aggregated fuel/sector split is sufficient for a Tier 1 approach.

Nitrous oxide is produced directly from the combustion of fossil fuels. It has been determined that lower combustion temperatures (particularly below 1200 K) cause higher N_2O emissions with a maximum of N_2O production occurring around 1000 K. For combustion temperatures below 800 K or over 1200 K the emissions of N_2O are negligible (de Soete, 1993). Compared to emissions from conventional stationary combustion units, emissions of nitrous oxides from fluidised bed combustion are relatively high (Rentz et al., 1992). Nitrous oxide is formed by different catalytic reduction processes. For more detailed information on N_2O chemistry see de Soete (1993). The mechanisms of N_2O chemistry seem to be relatively well understood, but experimental data are limited.

N_2O emissions from vehicles have only recently been studied in detail. Global emissions from this source are still thought to be small relative to total anthropogenic emissions, but may be substantially higher when emission controls (especially catalysts on road vehicles) are used.

Published emission rates for non-commercial fuel combustion, in particular fuelwood, charcoal, agricultural wastes and dung are few and it is uncertain whether they are representative for global application (Olivier, 1993).

The general method for estimating N_2O can be described as:

Emissions = $\sum (EF_{ab} \times Activity_{ab})$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, the CORINAIR 1994 default emission factors, Radian Corporation (1990), the EDGAR Version 2.0 database, National Communications to the FCCC and de Soete (1993). Additional research will need to be undertaken to further improve the quality of the emission factors.

TABLE 1-8
N_2O DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

			Coal(a)	Natural Gas	Oil	Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(c)
Energy Industries			1.4	0.1	0.6	4(b)	4(b)	4
Manufacturing Industries and Construction			1.4	0.1	0.6	4	4	4
Transport	Aviation				2			
	Road			0.1	Gasoline 0.6(d) Diesel 0.6			
	Railways		1.4		0.6			
	Navigation		1.4		0.6			
Other Sectors	Commercial/Institutional		1.4	0.1	0.6	4	1	4
	Residential		1.4	0.1	0.6	4	1	4
	Agriculture/ Forestry/ Fishing	Stationary	1.4	0.1	0.6	4	1	4
		Mobile		0.1	0.6			

Note: These factors are considered as the best available global default factors to date.

(a) Brown coals may produce less N_2O than bituminous coals; some measurements have shown that N_2O emissions by hard coal combustion in power plants may be negligible. N_2O emissions from FBC are generally about 10 times higher than from boilers.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) Includes dung and agricultural, municipal and industrial wastes.

(d) When there is a significant number of cars with 3-way catalysts in the country, road transport emission factors should be increased accordingly. Emission factors for 2-stroke engines may be three times higher than those for 4-stroke engines.

1.4.2.3 NITROGEN OXIDES (NO_x) EMISSIONS FROM FUEL COMBUSTION

Nitrogen oxides[11] are indirect greenhouse gases. They have been the target of environmental policies for their role in forming ozone (O_3), as well for their direct acidification effects.

Fuel combustion activities are the most significant anthropogenic source of NO_x. Within fuel combustion, the most important sources are the energy industries and mobile sources.

Generally two different formation mechanisms can be distinguished:

- formation of “fuel NO” from the conversion of chemically bound nitrogen in the fuel,
- formation of “thermal NO” from the fixation of the atmospheric nitrogen in the combustion process (Joint EMEP/CORINAIR, February 1996).

The majority of NO_x emitted from coal (80-90 per cent) is formed from fuel nitrogen. Thermal NO_x contributes less than 20 per cent and depends on combustion temperature. Excess air and high temperatures found in some firing configurations encourage the production of NO_x and these conditions are dependent on boiler type and operation of technology. For oil, the share of fuel NO_x may be less than 50 per cent. From gaseous fuels, only “thermal NO” is formed.

The NO_x emissions from mobile sources are related to the air-fuel mix and combustion temperatures, as well as pollution control equipment. For uncontrolled vehicles the proportion of NO_x emissions from a diesel-fuelled vehicle is generally lower than that for a gasoline-fuelled vehicle, and lower for a light-duty vehicle than that for a heavy-duty vehicle. Heavy-duty vehicles contribute significant emissions, which are difficult to reduce.

The general method for estimating NO_x can be described as:

$$\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})$$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

If abatement technologies for NO_x emissions reduction are used, the estimated emission factors of NO_x should be adjusted. Reduction efficiency (n) values for different types of abatement may vary; primary measures may range from 5 to 50 per cent (Joint EMEP/CORINAIR, 1996) and secondary measures from 50 to 95 per cent (Rentz, et al., 1992).

The following default values can be used for the reduction efficiency of primary measures in coal-fired installations when no information concerning the type of installation is available (Joint EMEP/CORINAIR, 1996).

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[11] The convention in this document is that NO_x ($NO+NO_2$) emissions from fossil fuel combustion are expressed on a full molecular basis assuming that all NO_x emissions are emitted as NO_2.

Default Values for Reduction Efficiency (n)		
Type of primary measure	**Hard coal**	**Lignite**
no measure (mainly relevant for old installations)	0 %	0 %
old installations / optimised operation	15 - 20 %	15 %
old installation / retrofitted	50 %	50 %
new installation	40 %	35 %

Due to large differences in emission factors for various sectors, fuel consumption should be allocated to the IPCC main source category groups.

Nitrogen oxides emission factors are available by detailed fuel/sector split for most of the fuel combustion sources. The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, Radian Corporation (1990), US EPA (1995), the EDGAR Version 2.0 database, and National Communications to the FCCC. The aggregated emission factors in this table allow a rough estimation of NO_x emissions.

TABLE 1-9
NO_X DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)(a)

			Coal	Natural Gas	Oil	Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(b)
Energy Industries			300	150	200	100(c)	100(c)	100
Manufacturing Industries and Construction			300	150	200	100	100	100
Transport	Aviation				300			
	Road			600	Gasoline 600 Diesel 800(d)			
	Railways		300		1200			
	Navigation		300		1500			
Other Sectors	Commercial/Institutional		100	50	100	100	100	100
	Residential		100	50	100	100	100	100
	Agriculture/ Forestry/ Fishing	Stationary	100	50	100	100	100	100
		Mobile(e)		1000	1200			

Note: These factors are considered as the best available global default factors to date. The emission factors may be reduced to take into account reduction efficiencies, see default values for reduction efficiencies given above.

(a) NO_X emission factors for small combustion facilities tend to be much smaller than for large facilities due to lower combustion temperatures.

(b) Includes dung and agricultural, municipal and industrial wastes.

(c) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(d) Assuming the major part is consumed by Heavy Duty Vehicles (HDV). When a country has a relatively high proportion of passenger cars running on diesel, the average emission factor may be substantially lower, as is indicated in Tables 1-31 to 1-34.

(e) The countries should, when possible, allocate the fuel consumption to road and off-road traffic. Emission factors for ships, boats, locomotives and farm equipment may be more than double those of duty vehicles.

1.4.2.4 CARBON MONOXIDE (CO) EMISSIONS FROM FUEL COMBUSTION

Carbon monoxide is an indirect greenhouse gas. The majority of CO emissions from fuel combustion come from motor vehicles. Another large contributor is the residential sector with small combustion equipment.

Carbon monoxide is an intermediate product of the combustion process and in particular under stoichiometric combustion conditions. The formation mechanism of CO is directly influenced by usage patterns, technology type and size, vintage, maintenance, and operation of the technology. Emission rates may vary by several orders of magnitude for facilities that are poorly operated or improperly maintained, such as might be the case of older units.

Size and age of unit may indicate that in smaller and older units, combustion is less controlled and hence emissions are likely to be higher than from larger and newer plants. In addition, many wood stoves (where there is a great variation in technology by geographic region) have particularly high emissions due to their largely inefficient combustion of fuel.

Carbon monoxide emissions from mobile sources are a function of the efficiency of combustion and post combustion emission controls. Emissions are highest when air-fuel mixtures are rich, with less oxygen than required for complete combustion. This occurs especially in idle, low speed, and cold start conditions in spark ignition engines.

The general method for estimating CO can be described as:

$$\boxed{\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})}$$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

Due to large differences in emission factors for various sectors, fuel consumption must be allocated to the IPCC main activity groups.

Carbon monoxide emission factors are available by detailed fuel/sector split for most of the fuel combustion sources. The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, Radian Corporation (1990), US EPA (1995), the EDGAR Version 2.0 database, and National Communications to the FCCC. The aggregated emission factors in this table allow a rough estimation of CO emissions.

TABLE 1-10
CO DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

			Coal	Natural Gas	Oil		Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(a)
Energy Industries			20	20	15		1000(b)	1000(b)	1000
Manufacturing Industries and Construction			150	30	10		2000	4000	4000
Transport	Aviation(c)				100				
	Road			400	Gasoline 8000(d)	Diesel 1000			
	Railways		150		1000				
	Navigation		150		1000				
Other Sectors	Commercial/Institutional		2000	50	20		5000	7000	5000
	Residential		2000	50	20		5000	7000	5000
	Agriculture/ Forestry/ Fishing	Stationary	2000	50	20		5000	7000	5000
		Mobile		400	1000				

Note: These factors are considered as the best available global default factors to date.

(a) Includes dung and agricultural, municipal and industrial wastes.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) The emission factor for aviation in the above table is for jet kerosene. The emission factor for aviation gasoline ranges from 10 000 to 20 000 kg/TJ (default value: 15 000 kg/TJ).

(d) Generally the emission factors for gasoline vehicles are highest for motorcycles and passenger cars without emissions control equipment.

1.4.2.5 NON-METHANE VOLATILE ORGANIC COMPOUNDS (NMVOC) EMISSIONS FROM FUEL COMBUSTION

Non-Methane Volatile Organic Compounds[12] are indirect greenhouse gases.

The most important sources of NMVOCs from fuel combustion activities are mobile sources and residential combustion (especially biomass combustion).

Emissions of NMVOC (e.g., olefins, ketones, aldehydes) are the product of incomplete combustion. They are directly influenced by fuel used, usage patterns, technology type and size, vintage, maintenance and operation of the technology. Emission rates may vary by several orders of magnitude for facilities that are poorly operated or improperly maintained, such as might be the case of older units.

The emissions are very low for large-combustion plants. NMVOC emissions tend to decrease with increases in plant size and increasing efficiency of the combustion process.

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[12] Non-methane volatile organic compounds: all hydrocarbon compounds, including those where hydrogen atoms are partly, or fully, replaced by other atoms (S,N,O, halogens) excluding those inventoried under the Montreal protocol. They are volatile under ambient air conditions and expressed as mass units as measured.

In addition, wood stoves (where there is a great variation in technology by geographic region) may have particularly high emissions rates of NMVOC due to their largely inefficient combustion of fuel.

The NMVOC emissions from mobile sources are a function of the amount of hydrocarbons passing unburnt through the engine. This depends on engine type, fuel used, use of post-combustion emission controls (e.g., catalytic converters) and driving regime. The emissions are generally highest at low speeds and when the engine is idle. Poorly tuned engines may have a particularly high output of hydrocarbon compounds.

NMVOC evaporative emissions from gasoline mobile sources should be accounted for here.

The general method for estimating NMVOC can be described as:

$$\text{Emissions} = \sum (\text{EF}_{ab} \times \text{Activity}_{ab})$$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

Due to large differences in emission factors for various sectors, fuel consumption must be allocated to the IPCC main activity groups.

Extensive NMVOC emission factor data are available for most of the fuel combustion sources. The following default emission factors have been developed by the IPCC based on the CORINAIR90 database, Radian (1990), US EPA (1995), the EDGAR Version 2.0 database, and National Communications to the FCCC. The aggregated emission factors in this table allow a rough estimation of NMVOC emissions.

TABLE 1-11
NMVOC DEFAULT (UNCONTROLLED) EMISSION FACTORS (IN KG/TJ)

			Coal	Natural Gas	Oil	Wood/ Wood Waste	Charcoal	Other Biomass and Wastes(a)
Energy Industries			5	5	5	50(b)	100(b)	50
Manufacturing Industries and Construction			20	5	5	50	100	50
Transport	Aviation(c)				50			
	Road			5	Gasoline 1500(d) Diesel 200			
	Railways		20		200			
	Navigation		20		200			
Other Sectors	Commercial/Institutional		200	5	5	600	100	600
	Residential		200	5	5	600	100	600
	Agriculture/ Forestry/ Fishing	Stationary	200	5	5	600	100	600
		Mobile		5	200			

Note: These factors are considered as the best available global default factors to date.

(a) Includes dung and agricultural, municipal and industrial wastes.

(b) These factors are for fuel combustion in the energy industries. For charcoal production, please refer to Table 1-14, Default Non-CO_2 Emission Factors for Charcoal Production.

(c) The emission factor for aviation in the above table is for jet kerosene. The emission factor for aviation gasoline is 300 kg/TJ.

(d) These factors are the sum of combustion and evaporative emissions from gasoline use. The NMVOC emission factors for mobile sources from evaporation of gasoline vary with the ambient temperature. In general, in the "warmer" countries the emission factors will be higher than in "colder" countries.

1.4.2.6 SULPHUR DIOXIDE (SO_2) EMISSIONS FROM FUEL COMBUSTION

Sulphur dioxide is not a "greenhouse gas" but its presence in the atmosphere *may* influence climate. SO_2 can react with a variety of photochemically produced oxidants to form sulphate aerosols. The concentration of these particles is increasing due to the burning of fossil fuels which contain sulphur. Over limited regions of the northern hemisphere, the effect of these particles is comparable in size, although opposite in effect, to that of human generated greenhouse gases up to the present time. Any effect of sulphur dioxide emissions on climate change can be expected to be strongly regional in character - but studies of this with climate models need to be carried out (Houghton, 1994). Although SO_2 is not a direct greenhouse gas, it is an aerosol precursor and as such, has a cooling effect on climate.

Anthropogenic SO_2 emissions world-wide amount to 70-80 million tonnes per year (Mt/y) (Vernon and Jones, 1993). This compares with natural emissions of 18-70 Mt/y (IPCC, 1992). There is, however, a paucity of information on the relative contribution of sulphur emissions arising from combustion, due to lack of detailed information on the sulphur level of the fuel consumed. More than 80 per cent of anthropogenic SO_2 arises from fuel combustion, with three-quarters of this arising from coal (Vernon, 1990). At present an estimated 10 Mt/y of coal-related SO_2 emissions are removed by flue-gas desulphurisation technology world-wide (Ando, 1992).

The general method for estimating SO_2 can be described as:

$$\text{Emissions} = \sum (EF_{ab} \times \text{Activity}_{ab})$$

where:

EF = Emission Factor (kg/TJ);
Activity = Energy Input (TJ);
a = Fuel type; and
b = Sector-activity.

The emissions of sulphur oxides (SO_x) are directly related to the sulphur content of the fuel, which for coal can vary from below 0.5 to over 10 per cent by weight. The majority of coals currently in use are in the range 0.5 to 3 per cent. Generally the “southern hemisphere” coals contain less sulphur than “northern hemisphere” coals.

For fuel oil (including heavy fuel oil) sulphur content varies from 0.3 to over 5 per cent. Lighter products may contain minimal sulphur (<0.3 per cent), whilst heavy fuel oil can contain from up to 3-5 per cent sulphur. Currently the world average sulphur content of crude oil is around 1.3 per cent, although there are considerable variations between different sources (Vernon and Jones, 1993).

The sulphur content of gas is usually negligible.

The SO_2[13] emission factors can be estimated as:

$$EF_{SO_2}\ [\text{kg/TJ}] = 2 \times \left(\frac{s}{100} \right) \times \frac{1}{Q} \times 10^6 \times \left(\frac{100 - r}{100} \right) \times \left(\frac{100 - n}{100} \right)$$

where:

EF = Emission Factor (kg/TJ);
2 = SO_2/S [kg/kg];
s = Sulphur content in fuel [%];
r = Retention of sulphur in ash [%];
Q = Net calorific value [TJ/kt];
10^6 = (Unit) conversion factor; and
n = Efficiency of abatement technology and/or reduction efficiency [%].

Sulphur appears in coal as pyritic sulphur (FeS_2), organic sulphur, sulphur salts and elemental sulphur. Pyritic and organic sulphur account for the vast majority of sulphur in coal and both types are responsible for SO_x formation. The sulphur is released when the coal is burnt, mainly oxidised to SO_2. Usually less than 1-2 per cent of the total sulphur is released as SO_3.

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[13] Sulphur dioxide (SO_2 + SO_3 expressed as SO_2 mass equivalent).

TABLE 1-12
SAMPLE AND DEFAULT VALUES OF SULPHUR CONTENT (S) IN FUEL

Fuel (IPCC grouping)		Default value[(a)] [%]	CORINAIR 90[(b)] range [%]
Coal	- low S	0.5	≥ 0.001
	- medium S	1.5	-
	- high S	3.0	≤ 16.1
Heavy fuel oil	- low S	1.0	≥ 0.001
	- medium S	3.0[(c)]	-
	- high S	4.0	≤ 4.0
Light fuel oil/diesel	- low S	0.3	≥ 0.14
	- high S	1.0	≤ 1.0
Diesel (road)		0.3	0.1-1.0
Gasoline (road)		0.1	0.012 - 0.15
Jet kerosene		0.05	0.0001-0.3[(d)]
Oil shale		1.5(1.3-1.7)[(e)]	NAV
Natural gas		negligible	NAV
Municipal waste		0.003	0.003
Industrial waste		0.2	0.200 - 1.000
Black liquor		1.5	0.004 - 8.09
Fuelwood		0.2	0.001-0.06
Other biomass		< 0.03	0.001 - 0.800

(a) To be used only if no better information is available.

(b) Fuels used in CORINAIR 90 inventories in the Czech Republic, Denmark, France, Hungary, Italy, the Netherlands, Poland and the Slovak Republic.

(c) The medium value refers to the default for marine bunkers.

(d) Values reported in literature.

(e) Values from Estonia.

During fuel combustion, part of the sulphur is retained in ash. The sulphur retention in ash for coal ranges from 5 to 60 per cent, (usually less than 10 per cent). The proportion depends upon the composition of the ash. The sulphur retention in ash for liquid fuels and biomass is minimal and can be disregarded.

Default Values for the Sulphur Retention (r) in Ash [%]	
Hard coal	5
Brown coal	30

If abatement technologies for SO_x emissions reduction are used, the estimated emission factors for SO_2 should be correspondingly reduced. Reduction efficiency values for different types of abatement technologies may vary between 45 and 95 per cent (Rentz, et al., 1992).

1.4.3 Biomass Data

The tables below provide data for use within the Reference Approach or for the calculation of all emissions by source categories using the methods described in Sections 1.4.1 and 1.4.2.

TABLE 1-13
ENERGY CONTENT OF BIOMASS FUELS: DEFAULT NET CALORIFIC VALUES

Biomass Fuel	Moisture Content (% mcwb)[(a)]	Typical Net Calorific Value[(b)] (MJ/kg)	Reference
BASIC BIOFUEL TYPES:			
Fuelwood[(c)]	20	15	Hall et al. (1994b)
Charcoal		30	Hall and Mao (1994a)
Dung		12	GOB (1987)
Bagasse	50	8	Leach and Gowen (1987)
Agricultural Waste		15	Leach and Gowen (1987)
Other Waste		11	US EPA (1995)
EXAMPLES OF SPECIFIC BIOFUELS:			
Wood			
Wet, freshly cut	40	10.9	Leach and Gowen (1987)
Air-dry, humid zone	20	15.5	Leach and Gowen (1987)
Air-dry, dry zone	15	16.6	Leach and Gowen (1987)
Oven-dry	0	20.0	Leach and Gowen (1987)
Charcoal	5	29.0	Leach and Gowen (1987)
Bagasse			
Wet	50	8.2	Leach and Gowen (1987)
Air-dry	13	16.2	Leach and Gowen (1987)
Dung cakes (dried)	12	12.0	Leach and Gowen (1987)
OTHER AGRICULTURAL RESIDUES:			
Coffee Husks	12	16.0	Leach and Gowen (1987)
Ricehulls (air-dry)	9	14.4	Leach and Gowen (1987)
Wheat straw	12	15.2	Leach and Gowen (1987)
Maize (stalk)	12	14.7	Leach and Gowen (1987)
Maize (cobs)	11	15.4	Leach and Gowen (1987)
Cotton gin trash	24	11.9	Leach and Gowen (1987)
Cotton stalk	12	16.4	Leach and Gowen (1987)
Coconut husks	40	9.8	Leach and Gowen (1987)
Coconut shells	13	17.9	Leach and Gowen (1987)

(a) mcwb : moisture content weight basis.

(b) Typical values to be considered as rough approximations.

(c) Assuming air dry wood.

Values for estimating the amount of carbon released through charcoal production and consumption, the wood-to-charcoal factor, are stated to be between 4 and 8. If no local information is available, 6 kg of wood input per kg of charcoal may be used as default

(FAO, 1990). In many developing countries, there are usually no cross checks on the quality of charcoal. Consequently, substandard charcoal will be passed on as charcoal. Typical wood to charcoal conversion factors in many developing countries would range from 2.5 to 3.5 and rarely beyond this. This also implies that the carbon fraction of charcoal is around 0.6 to 0.7. Default emission factors related to the production of charcoal are presented in the Table I-14

TABLE I-14
DEFAULT NON-CO_2 EMISSION FACTORS FOR CHARCOAL PRODUCTION (IN KG/TJ)

Compound	**Default Emission Factor (kg/TJ of Wood Input)(a)**	**Default Emission Factor (kg/TJ of Charcoal Produced)**
CH_4	300	1000
N_2O	NAV	NAV
NO_x	5	10
CO	2000	7000
NMVOC	600	1700
SO_2	NAV	NAV

(a) Assuming 1 kg charcoal is produced from 6 kg wood and the energy content for wood and charcoal is 15 and 30 MJ/kg respectively, 1 TJ charcoal produced is equivalent to 3 TJ wood input.

1.5 Detailed Methods (Tiers 2 and 3) for Fuel Combustion

1.5.1 Overview

Identification and quantification of greenhouse gas emissions by source category and economic sector, together with a sound understanding of plant combustion conditions, are essential for the study of abatement procedures and the formulation of abatement policy options. Equally, assessment of the effects of emissions on the atmosphere and climate requires detailed data on the magnitude and spatial distribution of pollutant emissions. Both sets of requirements are served by the estimation of emissions from combustion activities categorised by plant types at a level of detail for which an emission factor can be reasonably narrowly specified. Studies of the products of combustion from many types of plant under different operating conditions have resulted in a growing database of emission factors linking the emission rate to the activity. Estimation methodologies using these emission factors are described and discussed in this section.

In what follows, the emission sources are grouped into stationary and mobile sources and representative emission factors for them are assembled for use in a simple formula common to the majority of cases. The distinction between Tier 1 methods and those of Tiers 2 and 3 rests mainly on the reliance of the first on widely available fuel supply data which, by its nature, takes no account of the combustion technology to which the fuel is delivered. Distinguishing between Tiers 2 and 3 is less easily done as there is a steadily increasing degree of refinement and detail in the emissions estimation process as the methods are developed from one tier to another. However, Tier 2 methods may be regarded as those dividing fuel consumption on the basis of sample or engineering knowledge between technology types which are sufficiently homogenous to permit the use of representative emission factors. Tier 3 methods generally estimate emissions from activity figures (kilometre travelled or tonne-kilometre carried, not fuel consumption) and specific fuel efficiency or fuel rates or, alternatively, using an emission factor or factors expressed directly in terms of a unit of activity.

A new methodology, developed from that used by CORINAIR, has been introduced for the estimation of emissions from aircraft. Revised emission factors are also given for emissions from many types of stationary combustion and road transport in the United States and Europe.

Estimating CO_2

It follows from the arguments given above for the construction of detailed emission estimates that a country will also benefit from the estimation of CO_2 emissions in parallel with the calculation of non-CO_2 inventories despite the existence of Tier 1 methods for CO_2 estimation. The *Overview* to this Chapter also emphasises this point. Most of the tables of emission factors for mobile sources, but few of the tables for stationary sources, have figures for CO_2. In cases where CO_2 emission factors are not given the carbon emission factors provided for the fuel types listed for the Tier 1 methods will suffice. If different fuel qualities are used in different applications national experts may wish to vary the emission factors accordingly.

Where CO_2 emission factors are given in this Chapter they include all carbon based molecule emissions from the process. This ensures that CO_2 totals constructed by summing the results of the detailed estimation of emissions (the “bottom-up” approach) will be comparable with the IPCC Reference Approach described under Tier 1 methods above. The Reference Approach provides a simple transparent and verifiable means of accounting for all of the carbon in fuels which could be emitted to the atmosphere. Because of the complexity of covering all sources of fuel combustion and obtaining the related data it does not automatically follow that summing emissions from the many detailed sources will result in a figure close to that obtained from the Reference Approach. Consequently, verification of CO_2 totals against the Reference Approach is an obligation of the IPCC reporting system.

Use of carbon emission factors based on the fuel's carbon content also implies that adjustments may be needed (depending on the combustion process under consideration) for any carbon unoxidised. Carbon remaining unoxidised after combustion is discussed in Section 1.4.1.1. Where emission estimates are prepared by plant type the general information given in the section cited may be used when more specific carbon unoxidised factors are not available. At the level of process detail implicit in Tiers 2 and 3, quantities of fuel combusted should be known or fairly well estimated and quantities delivered for the manufacture of non-energy products identified and excluded. Where this is not the case estimates of carbon stored in manufactured products will need to be made in collaboration with national experts preparing estimates of emissions from Industrial Processes to ensure that there is no double counting of emissions.

DATA SOURCES

National experts working on detailed emission of non-CO_2 GHGs (particularly the indirect gases) and SO_2 should consult the extensive literature on emission factors and other estimation procedures which has been developed by other inventory programmes outside of the framework of the IPCC/OECD/IEA programme. These data generally contain more technology detail, and are further broken down by size of the various technologies. For mobile sources, data generally contain more vehicle and control technology detail, and are further broken down by operating conditions (e.g., catalyst vintages, driving cycles). The nature of these control assumptions should be known and carefully matched with actual conditions in the country when selecting the specific factors to be used.

Some key examples of data sources are:

- Default Emission Factors Handbook (European Environment Agency Task Force, Bouscaren, 1992)
- CORINAIR Working Group on Emission Factors for Calculating 1990 Emissions from Road Traffic, Volume 1: Methodology and Emission Factors (Eggleston, et al., 1992)
- CORINAIR Working Group on Emission Factors for Calculating 1990 Emissions from Road Traffic, Volume 2: COPERT Model, Users Manual (Andrias, et al., 1992)
- Atmospheric Emission Inventory Guidebook (Joint EMEP/CORINAIR, European Environment Agency, 1996)
- US EPA's Compilation of Air Pollutant Emissions Factors (AP-42), 4th Edition 1985, (US EPA, 1985a and 1985b), 5th Edition 1995 (US EPA, 1995) and Supplement F, (US EPA, 1993b)

- US EPA's MOBILE5a (US EPA 1994a). Contact Terry Newell, US EPA Office of Mobile Sources, 2565 Plymouth Road, Ann Arbor MI 48105, USA; tel: (313) 668-4462, Email: Newell.Terry@epamail.epa.gov or access the latest information on mobile sources on the world wide web at http://www.epa.gov/OMSWWW/omshome.htm.
- Criteria Pollutant Emission Factors for the 1985 NAPAP Emissions Inventory (Stockton and Stelling, 1987)
- Proceedings of the TNO/EURASAP Workshop (TNO, 1993)
- EMEP and CORINAIR Emission Factors and Species Profiles for Organic Compounds. (Veldt, 1991)
- Transport Statistics for Europe (UN ECE, 1989)
- World Road Statistics (International Road Federation, 1990)
- Other compilations of emission factors include

- Netherlands	Bakkum, et al., 1987, Okken, 1989
- Norway	Statens forurensningstilsyn, 1990
- Germany	Brieda and Pakleppa, 1989, Fritsche, 1989, Rentz et al., 1988, Walbeck, et al., 1988
- Japan	JAERI, 1988
- United Kingdom	Eggleston and McInnes, 1987
- UNEP Country Studies	
- US Country Studies, US CSP, 1996	
- National Communications to the FCCC	

1.5.2 Stationary Combustion

1.5.2.1 OVERVIEW

This section considers emissions of NO_x, N_2O, CO, CH_4, SO_2 and NMVOCs from stationary combustion plant. Estimation of CO_2 emissions at the level of detail of Tiers 2 and 3 is described in Section 1.5.1.

The section focuses on emissions from the combustion of commercial fuels, which include virtually all fossil fuels and biomass fuels *traded commercially* and used in large combustion plants. Non-CO_2 emissions from combustion of biomass are estimated in exactly the same manner as fossil fuel combustion emissions.[14].

Emissions of non-CO_2 greenhouse gases across activities (sectors and subsectors) will depend upon fuel, technology type and pollution control policies. Emissions will also vary with the size and vintage of the combustion technology, its maintenance, and its operation. Most of a country's NO_X emissions arise from stationary fuel combustion. As defined here (i.e., excluding "traditional" small scale use of biomass), this category generally contributes a smaller but still significant share of national emissions of CO and NMVOC, and, to a lesser extent, of N_2O and CH_4. These two gases are nonetheless discussed in some detail because of their priority status within the IPCC/OECD/IEA programme.

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[14] See Section 1.4.3 for a discussion of CO_2 emissions from biomass combustion.

A section on SO_2 has been added to the Tier 1 methodology. In the more detailed Tier 2 approach the same basic formula should be applied to more detailed fuel information.

1.5.2.2 RECOMMENDED METHODOLOGY

General Method

Estimation of emissions from stationary sources can be described using the following basic formula:

$$\text{Emissions} = \sum (EF_{abc} \times \text{Activity}_{abc})$$

where:

EF = Emission Factor (kg/TJ);

Activity = Energy Input (TJ);

a = Fuel type;

b = Sector-activity; and

c = Technology type.

Total emission for a particular country is the sum across activities, technologies and fuels of the individual estimates.

Emission estimation is based on at least three distinct sets of assumptions or data: 1) emission factors; 2) energy activities; and 3) relative share of technologies in each of the main energy activities. Sources of the emission factors and energy activity data that are relevant internationally are described briefly below and suggestions on appropriate use of such data are made.

Technology share or technology splits for each of the various energy activities are needed at least on a national level for non-CO_2 greenhouse gas estimation since emission levels are affected by the technology type. Unfortunately, there is no complete international source of data on technology splits and, as a result, each country will need to develop its own technology splits for each energy activity.

The main steps in the inventory method can be summarised as follows:

1 Determine the source and form of the best available, internationally verifiable, national (or sub-national) energy activity data.

2 Based on a survey of national energy activities, determine the main categories of emission factors.

3 Compile best available emission factor data for the country, preferably from national sources. If no national sources are available, select from the options described here. Selection among the options should be based on the similarity of the country to the source of original measurements for types of technology and operating conditions across main energy activities. The selection should also consider the extent to which control technologies may be in place and requires the ability to clearly separate and understand control policy assumptions that may be embedded in the emission factor data.

4 Based on the form of the selected emission factors, identify the technology categories to be used in the national inventory.[15]

5 Using these assumptions on technology categories, develop estimates for each of the greenhouse gases for each main activity.

6 Sum the individual activity estimates to arrive at the national inventory total for each of the greenhouse gases.

Technology Splits for Energy Data

National data or assumptions on the technology shares of each of the main source sector categories which have been identified as important in each country are necessary to create the linkage between national energy balances and the emission factors. Again, this may be based on "bottom-up" data collection at as detailed a level as individual sources, or it may be more of a “top-down” allocation based on statistical sampling, or engineering judgement. The objective is to match up fuel use, by fuel type, with specific technologies or classes of technologies, for which credible emission factors for non-CO_2 gases can be provided.

Emission Factor Data

Emission factors for all non-CO_2 greenhouse gases from combustion activities vary to lesser or greater degrees with:

- fuel type
- technology
- operating conditions
- maintenance and vintage of technology

and so represent the average emission performance of similar technologies.

They are therefore technology specific, but may still represent a wide distribution of possible values because of the influence of the other three factors above. When available, the standard deviation of the emission factor should be used to show the range of possible emission factors, and hence emissions, for each particular energy activity.[16]

1.5.2.3 EMISSION FACTORS

Some tables of representative emission factors for NO_x,[17] CO, CH_4, N_2O and NMVOCs by main technology and fuel types (based on Radian, 1990) were presented in the preliminary methodology manual (OECD, 1991) distributed by the IPCC. This information is still useful in showing the range and variation of sources and emission rates, and it is

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[15] This may also require assumptions about the control technologies in place.

[16] Unfortunately, the standard deviation of emission factors is rarely reported with emission factor data. One study shows that when considered, variation of emission factors within an energy activity vary widely, from 20 to more than 50 per cent (Eggleston and McInnes, 1987).

[17] The convention in this document is that NO_x emissions from fossil fuel combustion are expressed on a full molecular basis assuming that all NO_x emissions are emitted as NO_2.

reproduced in Tables 1-15 to 1-19 for the major categories.[18] All factors are expressed on a kilograms per terajoule of energy input basis (unless stated otherwise) and are stated on a full molecular weight basis. These data are taken from Radian (1990) and 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.

It may be necessary to make adjustments to "raw" emission estimates to account for control technologies in place. Alternative control technologies, with representative percentage reductions, are shown in Tables 1-20 to 1-23 (Radian, 1990) for the main control technologies applicable to each sector. These tables reflect technologies in use for large stationary sources in OECD countries. Preliminary indications are that, in the rest of the world, control technologies are not typically used (see OECD/IEA, 1991). These data should be used in combination with the uncontrolled emission factors to develop a "net" representative emission factor for each of the technologies to be characterised in the national emission profile; alternatively, the emission estimate for each technology could be adjusted downward according to the indicated percentage reduction and the estimated penetration of the control technology.

Table 1-24 provides the fuel property assumptions upon which the Radian data are based.

The emission factor data in these tables are provided primarily for illustrative purposes. These factors could be used as a starting point or for comparison by national experts working on detailed "bottom-up" inventories. More detail on current emission factors and references is presented in the section on Data Sources.

No emission factors for SO_2 are presented in Tables 1-15 to 1-19. These emission factors should be estimated based on the sulphur content of the fuels (see Section 1.4.2.6, Sulphur Dioxide Emissions from Fuel Combustion).

In many countries, biomass is used in traditional, small-scale facilities and open stoves. Emission factors presented in Tables 1-16, 1-18 and 1-19 are for industrial combustion and large-scale facilities.

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[18] Note: several printing errors occurred in the 1995 *Guidelines*. These have been corrected here.

TABLE 1-15
UTILITY BOILER SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Pulverised Bituminous Combustion	Dry Bottom, wall fired	9	0.7	380	1.6	NAV
	Dry Bottom, tangentially fired	9	0.7	250	0.5	NAV
	Wet Bottom	9	0.9	590	1.6	NAV
Bituminous Spreader Stokers	With and without re-injection	87	1.0	240	1.6	NAV
Bituminous Fluidised Bed Combustor	Circulating Bed	310	1.0	68	96	NAV
	Bubbling Bed	310	1.0	270	96	NAV
Bituminous Cyclone Furnace		9	0.2	590	1.6	NAV
Anthracite Stokers		10	NAV	160	NAV	NAV
Anthracite Fluidised Bed Combustors		5.2	NAV	31	NAV	NAV
Anthracite Pulverised Coal Boilers		310	NAV	NAV	NAV	NAV
Pulverised Lignite Combustion	Dry Bottom, tangentially fired	NAV	NAV	130	NAV	NAV
	Dry Bottom, wall fired	45	NAV	200	NAV	NAV
Lignite Cyclone Furnace		NAV	NAV	220	NAV	NAV
Lignite Spreader Stokers		NAV	NAV	100	NAV	NAV
Lignite Atmospheric Fluidised Bed		2.8	NAV	63	42	NAV
Oil						
Residual Fuel Oil/Shale Oil	Normal Firing	15	0.9	200	0.3	NAV
	Tangential Firing	15	0.9	130	0.3	NAV
Distillate Fuel Oil	Normal Firing	16	0.9	220	0.4	NAV
	Tangential Firing	16	0.9	140	0.4	NAV
Distillate Fuel Gaseous Turbines		21	NAV	300	NAV	NAV
Large Diesel Fuel Engines >600hp (447kW)		350	4.0	1300	NAV	NAV
Natural Gas						
Boilers		18	0.1(a)	250	NAV	NAV
Large Gas-Fired Gas Turbines >3MW		46	6*	190	NAV	NAV
Large Dual-Fuel Engines		340	240	1300	NAV	NAV
Municipal Solid Waste (MSW)						
Mass Burn Waterwall Combustors		22	NAV	170	NAV	NAV
MSW - Mass Feed(a)		98	NAV	140	NAV	NAV

Source: US EPA (1995).
(a) Adapted from Radian, 1990.

TABLE 1-16
INDUSTRIAL BOILER PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Bit./Sub-bit. Overfeed Stoker Boilers		110	1.0	130	1.6	NAV
Bit./Sub-bit. Underfeed Stoker Boilers		190	14	170	1.6	NAV
Bit./Sub-bit. Hand-fed Units		4800	87	160	1.6	NAV
Bituminous/Sub-bituminous Pulverised	Dry Bottom, wall fired	9	0.7	380	1.6	NAV
	Dry Bottom, tangentially fired	9	0.7	250	0.5	NAV
	Wet Bottom	9	0.9	590	1.6	NAV
Bituminous Spreader Stokers		87	1.0	240	1.6	NAV
Bit./Sub-bit. Fluidised Bed Combustor	Circulating Bed	310	1.0	68	96	NAV
	Bubbling Bed	310	1.0	270	96	NAV
Anthracite Stokers		10	NAV	160	NAV	NAV
Anthr. Fluidised Bed Combustor Boilers		5.2	NAV	31	NAV	NAV
Anthracite Pulverised Coal Boilers		NAV	NAV	310	NAV	NAV
Oil						
Residual Fuel Oil Boilers		15	3.0	170	0.3	NAV
Distillate Fuel Oil Boilers		16	0.2	65	0.4	NAV
Small Waste Oil Boilers <0.1MW		15	NAV	58	NAV	NAV
LPG Boilers	Propane	17	NAV	96	NAV	NAV
	Butane	16	NAV	97	NAV	NAV
Small Stationary Internal Comb. Engines	Gasoline <250hp (186 kW)	27	NAV	0.7	NAV	NAV
	Diesel <600hp (447 kW)	0.4	NAV	1.9	NAV	NAV
Large Stationary Diesel Engines >600hp (447 kW)		0.3	0.0	1.3	NAV	NAV
Natural Gas						
Large Boilers >100 MBtu/h (293 MW)		18	1.4	250	NAV	NAV
Small Boilers 10-100 MBtu/h (29.3-293 MW)		16	1.4	64	NAV	NAV
Heavy Duty Nat. Gas Compressor Eng.	Turbines	2.0	0.6	4.1	NAV	NAV
	2-Cycle Lean Burn	4.7	17	33	NAV	NAV
	4-Cycle Lean Burn	5.1	13	39	NAV	NAV
	4-Cycle Rich Burn	20	2.9	28	NAV	NAV
Wood						
Fuel Cell/Dutch Oven Boilers		290	NAV	17	NAV	NAV
Stoker Boilers		590	15	65	NAV	NAV
FBC Boilers		61	NAV	87	NAV	NAV
Bagasse/Ag. Waste Boilers		NAV	NAV	68	NAV	NAV
MSW						
MSW Boilers	Mass Burn Waterwall	22	NAV	170	NAV	NAV
	Mass Burn Rotary Waterwall	36	NAV	110	NAV	NAV
	Mass Burn Rotary Refrac. Wall	64	NAV	120	NAV	NAV
	Modular, Excess Air	NAV	NAV	120	NAV	NAV
	Modular, Starved Air	14	NAV	150	NAV	NAV
Refuse Derived Combustors		90	NAV	240	NAV	NAV

Source: US EPA (1995).

TABLE 1-17
KILNS, OVENS, AND DRYERS SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)[(a)]				
Industry	**Source**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Cement, Lime	Kilns - Natural Gas	83	1.1	1,111	NAV	NAV
Cement, Lime	Kilns - Oil	79	1.0	527	NAV	NAV
Cement, Lime	Kilns - Coal	79	1.0	527	NAV	NAV
Coking, Steel	Coke Oven	211	1	35[(b)]	NAV	16[(b)]
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	11	1.1	64	NAV	NAV
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Oil	16	1.0	168	NAV	NAV
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Coal	179	1.0	226	NAV	NAV

Source: Radian, 1990.

(a) 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 assumption on how to convert from gross to net calorific values.

(b) Joint EMEP/CORINAIR (1996).

TABLE 1-18
RESIDENTIAL SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Anthracite Space Heaters		NAV	150	55	NAV	NAV
Coal Hot Water Heaters(a)		18	NAV	160	NAV	NAV
Coal Furnaces(a)		480	NAV	230	NAV	NAV
Coal Stoves(a)		3600	NAV	180	NAV	NAV
Oil						
Residual Fuel Oil		15	1.4	170	NAV	NAV
Distillate Fuel Oil		16	0.7	65	NAV	NAV
Furnaces		16	5.8	59	0.2	NAV
Propane/Butane Furnaces(a)		10	1.1	47	NAV	NAV
Natural Gas						
Furnaces		18	NAV	43	NAV	NAV
Gas Heaters(a)		10	1	47	NAV	NAV
Wood						
Wood Pits(a)		4900	200	150	NAV	NAV
Fireplaces		11000	NAV	110	NAV	NAV
Stoves	Conventional	10000	210	120	NAV	NAV
	Non-catalytic	6100	NAV	NAV	NAV	NAV
	Catalytic	4500	380	87	NAV	NAV
	Pellet, Certified	1700	NAV	600	NAV	NAV
	Pellet, Exempt	2300	NAV	NAV	NAV	NAV
Masonry Heater	Exempt	6500	NAV	NAV	NAV	NAV

Source: US EPA (1995).

(a) Adapted from Radian, 1990.

TABLE I-19
COMMERCIAL SOURCE PERFORMANCE

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Coal Boilers[(a)]		200	10	240	NAV	NAV
Oil						
Residual Fuel Oil/Shale Oil		15	1.4	170	0.3	NAV
Distillate Fuel Oil		16	0.7	65	0.4	NAV
Waste Oil Space Heaters	Vaporising Burner	5.0	NAV	33	NAV	NAV
	Atomising Burner	6.3	NAV	48	NAV	NAV
LPG Boilers	Propane	8.4	NAV	71	NAV	NAV
	Butane	12	NAV	70	NAV	NAV
Natural Gas						
Boilers		9.4	1.2	45	2.3	NAV
Wood						
Incineration - high efficiency[(a)]		440	NAV	130	NAV	NAV
Waste						
Mass Burn Waterwall		22	NAV	170	NAV	NAV
Combustors		NAV	NAV	NAV	NAV	NAV
MSW Boilers[(a)]		19	NAV	460	NAV	NAV

Source: US EPA (1995).

(a) Adapted from Radian, 1990.

TABLE 1-20
UTILITY EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss(a) (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available(b)
Low Excess Air (LEA)	-0.5	+	+	15	NAV	NAV	1970
Overfire Air (OFA) - Coal	0.5	+	+	25	NAV	NAV	1970
OFA - Gas	1.25	+	+	40	NAV	NAV	1970
OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Low NO_x Burner (LNB) - Coal	0.25	+	+	35	NAV	NAV	1980
LNB - Tangentially Fired	0.25	+	+	35	NAV	NAV	1980
LNB - Oil	0.25	+	+	35	NAV	NAV	1980
LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Cyclone Combustion Modification	0.5	NAV	NAV	40	NAV	NAV	1990
Ammonia Injection	0.5	+	+	60	NAV	NAV	1985
Selective Catalytic Reduction (SCR) - Coal	1	8	+	80	NAV	NAV	1985
SCR - Oil, AFBC	1	8	+	80	NAV	NAV	1985
SCR - Gas	1	8	+	80	60	NAV	1985
Water Injection - Gas Turbine Simple Cycle	1	+	+	70	NAV	NAV	1975
SCR - Gas Turbine	1	8	+	80	60	NAV	1985
Retrofit LEA	-0.5	+	+	15	NAV	NAV	1970
Retrofit OFA - Coal	0.5	+	+	25	NAV	NAV	1970
Retrofit OFA - Gas	1.25	+	+	40	NAV	NAV	1970
Retrofit OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Retrofit LNB - Coal	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Oil	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Burners Out of Service	0.5	+	+	30	NAV	NAV	1975

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

TABLE 1-21
INDUSTRIAL BOILER EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss(a) (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available(b)
Low Excess Air (LEA)	-0.5	+	+	15	NAV	NAV	1970
Overfire Air (OFA) - Coal	0.5	+	+	25	NAV	NAV	1970
OFA - Gas	1.25	+	+	40	NAV	NAV	1970
OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Low NO_x Burner (LNB) - Coal	0.25	+	+	35	NAV	NAV	1980
LNB - Oil	0.25	+	+	35	NAV	NAV	1980
LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Flue Gas Recirculation	0.5	+	+	40	NAV	NAV	1975
Ammonia Injection	0.5	+	+	60	NAV	NAV	1985
Selective Catalytic Reduction (SCR) - Coal	1	8	+	80	NAV	NAV	1985
SCR - Oil, AFBC	1	8	+	80	NAV	NAV	1985
SCR - Gas	1	8	+	80	60	NAV	1985
Retrofit LEA	-0.5	+	+	15	NAV	NAV	1970
Retrofit OFA - Coal	0.5	+	+	25	NAV	NAV	1970
Retrofit OFA - Gas	1.25	+	+	40	NAV	NAV	1970
Retrofit OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Retrofit LNB - Coal	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Oil	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Gas	0.25	+	+	50	NAV	NAV	1980

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

TABLE 1-22
KILN, OVENS, AND DRYERS EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss[a] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[b]
LEA - Kilns, Dryers	-6.4	+	+	14	NAV	NAV	1980
LNB - Kilns, Dryers	0	+	+	35	NAV	NAV	1985
SCR - Coke Oven	1.0	8	+	80	60	NAV	1979
Nitrogen Injection	NAV	NAV	NAV	30	NAV	NAV	1990
Fuel Staging	NAV	NAV	NAV	50	NAV	NAV	1995

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

TABLE 1-23
RESIDENTIAL AND COMMERCIAL EMISSION CONTROLS PERFORMANCE

Technology	Efficiency Loss(a) (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available(b)
Catalytic Woodstove	-44	90	90	-27	NAV	NAV	1985
Non-Catalytic Modified Combustion Stove	-30	15	50	-5	NAV	NAV	1985
Flame Retention Burner Head	-9	28	NAV	NAV	NAV	NAV	
Controlled Mixed Burner Head	-7	43	NAV	44	NAV	NAV	
Integrated Furnace System	-12	13	NAV	69	NAV	NAV	
Blueray Burner/Furnace	-12	74	NAV	84	NAV	NAV	
M.A.N. Burner	-13	NAV	NAV	71	NAV	NAV	1980
Radiant Screens	-7	62	NAV	55	NAV	NAV	
Secondary Air Baffle	NAV	16	NAV	40	NAV	NAV	
Surface Comb. Burner	NAV	55	NAV	79	NAV	NAV	
Amana HTM	-21	-55	NAV	79	NAV	NAV	
Modulating Furnace	-7	NAV	NAV	32	NAV	NAV	
Pulse Combuster	-36	NAV	NAV	47	NAV	NAV	
Catalytic Combuster	-29	NAV	NAV	86	NAV	NAV	
Replace Worn Units	NAV	65	NAV	NAV	NAV	NAV	
Tuning, Seasonal Maintenance	-2	16	NAV	NAV	NAV	NAV	
Reduced Excessive Firing	-19	14	NAV	NAV	NAV	NAV	
Reduced Excessive Firing with New Retention Burner	-40	14	NAV	NAV	NAV	NAV	
Positive Chimney Dampers	-8	11	NAV	NAV	NAV	NAV	
Increased Thermostat Anticipator	-1	43	NAV	NAV	NAV	NAV	
Night Thermostat Cutback	-15	17	NAV	NAV	NAV	NAV	
Low Excess Air	-0.8	NAV	NAV	15	NAV	NAV	1970
Flue Gas Recirculation	0.6	NAV	NAV	50	NAV	NAV	1975
Over-fire Air	1	NAV	NAV	20-30	NAV	NAV	1970
Low NO_x Burners	0.6	NAV	NAV	40-50	NAV	NAV	1980

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Source: Radian, 1990.

TABLE 1-24
NET CALORIFIC VALUES FOR PRECEDING TABLES(a)
(THESE VALUES SHOULD NOT BE USED TO CALCULATE INVENTORIES, SEE NOTE BELOW)

Fuel	Net Calorific Value (TJ/kilotonne)
GAS	
Butane	44.4
Propane	47.1
Natural Gas	52.3
LIQUID	
Crude Oil	40.9
Crude Shale Oil	42
Diesel/Distillate	42.9
Gasoline	46.5
Residual Oil	42
SOLID	
Bagasse/Agriculture	8.8
Bituminous Coal	28.7
Anthracite	27.2
Lignite	15.9
MSW	10.7
Wood	11.5

NOTE: These values are given for information only and refer to the preceding tables. They should not be used by countries to convert energy data to TJ for the inventories. The default net calorific values used in the *Guidelines* have not been changed and can be found in the *Reference Manual* Tables 1-2 and 1-3.

Source: US EPA (1995).

(a) Values in preceding tables 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 assumption on how to convert from gross to net calorific values.

1.5.3 Mobile Combustion

1.5.3.1 OVERVIEW

Emissions of greenhouse gases from mobile sources, including carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NO_x), methane (CH_4), nitrous oxide (N_2O) and non-methane volatile organic compounds (NMVOCs) are most easily estimated by major transport activity, i.e., road, air, rail, and ships. However, as road transport and aviation account for the majority of mobile-source fuel consumption (e.g., 82 per cent in 1988 for the OECD), followed by air transport (about 13 per cent), greater priority has been attached to the development of emission models and inventories for road vehicles and aircraft.

The diversity of the types of mobile source and the range of characteristics which affect emission factors are amply demonstrated by the tables included in this section for both road and air transport. Recent work has both updated and strengthened the data given and a fuller methodology for estimating aircraft emissions has been introduced based upon the EMEP/CORINAIR work in this field. 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, there is very little information on the appropriate emission factors for road transport in developing countries where age of fleet, maintenance and patterns of use are different from those in industrialised countries.

It should be recalled that transport is a significant source of CO_2 emissions and emission factors for CO_2 emissions are provided in the following tables to permit the estimation of CO_2 at this detailed level.

1.5.3.2 RECOMMENDED METHODOLOGY

Estimation of mobile source emissions is a very complex undertaking that requires consideration of many parameters, including:

- transport class
- fuel consumed
- operating characteristics
- emission controls
- maintenance procedures
- fleet age

The need for data on several parameters and the wide variety of conditions that can affect the performance of each category of mobile source makes it very difficult to generalise their emission characteristics. Also, within the transport sector, the primary measure of activity is less likely than in other sectors to be fuel consumption.

The underlying general emissions model may be expressed as:

$$\boxed{\text{Emissions} = \sum (\text{EF}_{abc} \times \text{Activity}_{abc})}$$

where: EF = emission factor

Activity = amount of energy consumed or distance travelled for a given mobile source activity

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

b = vehicle type (e.g., passenger, light-duty or heavy-duty for road vehicles)

c = emission control

which implies the following steps:

- Determine the amount of energy consumed by fuel type for the major transport modes using national data or, as an alternative, IEA or UN international data sources (all values should be reported in terajoules).
- For each fuel type, determine the amount of energy that is consumed by each vehicle type, e.g., light-duty gasoline vehicles, etc. (all units are in terajoules). If distance travelled is the activity measure, determine the total distance travelled by each vehicle type. In this case, the energy consumption associated with these distance travelled figures should be calculated and aggregated by fuel for comparison

with national energy balance figures. If necessary, further subdivide each vehicle type into uncontrolled and key classes of emission control technology.

- Multiply the amount of energy consumed, or the distance travelled by each category of vehicle or vehicle/control technology, by the appropriate emission factor for that category. Data presented in the next section (Emission Factors) can be used as a starting point. However, national experts are encouraged to consult other data sources referenced in this chapter or locally available data before determining appropriate factors for a particular country.
- Emissions of each pollutant can be summed across all categories of fuel and technology type, including for all levels of emission control, to determine total emissions from mobile source-related activities.

Emission Factors

The tables given for road transport summarise results of a detailed analysis of mobile-source emission factors covering North American and European vehicles and conditions.

Recently published work has permitted the updating of figures appearing in the 1995 edition of the *Guidelines*. The US emission factors for mobile sources, published in the 1995 edition, were developed using the MOBILE4 model. This was one of a series of emissions models developed and periodically updated by the US Environmental Protection Agency for use in its analysis of motor vehicle regulatory and policy issues. The MOBILE4 model is now out of date. Since the analysis done in 1991, several improvements have been based on new information and vehicle testing results. Emission factors developed using the latest version of the MOBILE model (MOBILE5a) are higher for most pollutants. The US tables included here contain this latest information.

CO_2 factors are derived from the carbon content of the fuels and therefore include the carbon present in other carbon molecule based emissions.

The European data are drawn from the CORINAIR COPERT model. However, for actual calculations of national emissions, users are encouraged to also consult a range of recent and more detailed information sources (see Data Sources in Section 1.5.1). Particularly for indirect GHGs, more comprehensive sources are available based on programmes outside the GHG emissions area.

Emission factor estimates are presented for CO_2, CO, NO_x, N_2O, CH_4 and NMVOCs for several classes of non-road vehicles - railway locomotives, ships and boats, farm and construction equipment.

This section on mobile sources also contains a more comprehensive explanation of a methodology for the estimation of emissions from aircraft and greater specificity of aircraft/engine emission factors for NO_x.

All emission factor data are stated on the basis of full molecular weight of the respective pollutant; NO_x factors are stated as NO_2.

Emission Factors for Mobile Sources in Developing Countries

In highly populated developing countries the estimated emissions per kilometre travelled should be altered. First, there are virtually no catalytic converters on the vehicles. Second, the number of accelerations and decelerations that the vehicle will undergo is much larger than for corresponding travel in countries that are less populated and have well arranged highway systems. The measured pollutant value of NO_x in an engine at constant rpm conditions is about 1.0 g/MJ for the United States and for Europe. However, for highly populated developing countries 1.8 g/MJ should be used.

Further information on emission factors for developing countries is available from Riveros et. al (1995), Bose (1996) and other sources listed in the bibliography.

1.5.3.3 ROAD VEHICLES

United States Emission Estimates

Technical Approach

The US emissions estimates for NO_x, CO, CH_4 and NMVOC from highway vehicles were developed directly from the US EPA's MOBILE5a model. The model calculates exhaust emission factors for gasoline and diesel fuelled US vehicles, based on the year in which they were manufactured. For gasoline vehicles, it also calculates VOC emissions due to evaporative, running and refuelling losses (VOC emissions from diesel vehicles due to these causes are negligible).

Assumptions

To develop emission estimates for different control technology types, calculations were carried out for specific model years during which US vehicles were equipped with the technology in question. Table 1-25 shows the correspondence between the technology types and the US model years used to represent them in the model. Average lifetime emissions were calculated for each vehicle type based on their assumed lifetimes. The model uses a two-step linear function to estimate deterioration rates from vehicle mileage. Linear equations are fitted to vehicle emission estimates at 0 and 50 000 miles and 50 000 and 100 000 miles and from the results lifetime average factors were calculated.

The emission factors calculated by MOBILE5a are affected by assumptions regarding average speeds, ambient temperature, diurnal temperature range, altitude and fuel volatility that are provided to the model. They are also affected by the assumed presence or absence of inspection/maintenance (I/M) programmes and anti-tampering programmes as well as the type of I/M programme used. The model calculates emission factors using three seasonal conditions: Spring/Fall, Winter and Summer. The model was also run with three different I/M scenarios; no I/M programme, basic I/M and enhanced I/M. Where I/M influences emissions, the emission factors given in the tables included here are shown as range estimates with the lower value representing the enhanced I/M and the upper value reflecting no I/M. Since there is no I/M programme for diesel vehicles in the United States the diesel vehicle emission factors generated by the model for different I/M programmes were the same. The average speed assumed by the model is 31.4 km/h - typical of uncongested urban driving (see Table 1-26).

TABLE 1-25
EMISSION CONTROL TECHNOLOGY TYPES AND US VEHICLE MODEL YEARS USED TO REPRESENT THEM

Technology	Model Year
Gasoline Passenger Cars and Light Trucks	
Uncontrolled	1964
Non-catalyst controls	1973
Oxidation catalyst	1978
Early three-way catalyst	1983
Three-way catalyst	1996
Heavy-Duty Gasoline Vehicles	
Uncontrolled	1968
Non-catalyst control	1983
Three-way catalyst	1996
Diesel Passenger Cars and Light Trucks	
Uncontrolled	1978
Moderate control	1983
Advanced control	1996
Heavy-Duty Diesel Vehicles	
Uncontrolled	1968
Moderate control	1983
Advanced control	1996
Motorcycles	
Uncontrolled	1973
Non-catalyst controls	1996

TABLE 1-26
ASSUMED AMBIENT TEMPERATURE, DIURNAL RANGE AND REID VAPOUR PRESSURE FOR DIFFERENT SEASONS

	Ambient Temperature (°C)	Diurnal Range (°C)	Reid Vapour Pressure (kPa)
Spring/Fall	16	7 to 24	62
Winter	2	-7 to 10	103
Summer	29	21 to 38	54

The estimated vehicle fuel economies were also used to calculate fuel specific and energy specific emission factors for all of the pollutants. Energy specific emission factors were based on the net calorific value of the fuel in each case. Since emission and fuel consumption tend to vary in parallel (vehicles and operating modes causing high emission rates also tend to result in high fuel consumption, and vice-versa) these energy specific emission factors are expected to be more generally applicable than the factors in grams per kilometre and their use is to be preferred.

BOX 4
LIMITATIONS OF MOBILE5A RESULTS

Emission factors for many greenhouse gases from road vehicles have been developed using the MOBILE5a Model(a) as presented in Tables 1-27 to 1-33. This model is one of a series of emissions models developed and periodically updated by the US Environmental Protection Agency for use in its analysis of motor vehicle regulatory and policy issues. The model has been used to derive average emission factors for NO_x, CO, and NMVOC by class of vehicle and for gasoline and diesel fuel. Calculations for other gases and for alternative fuels were done separately.

All "global" average emission factors like these should be considered illustrative and should not be directly used in national emissions calculations. Such values are by necessity based on "global" average assumptions in several key areas. Average emission factors by class of vehicle are sensitive to very specific assumptions including those about

- vehicle models, average age and accumulated mileage
- per cent driving in cold start, hot start and stabilised conditions
- average driving speed
- ambient temperature
- fuel comparison
- rates of tampering with control systems
- proper maintenance

Obviously, many of these assumed conditions will vary significantly from country to country and even by region within countries. For example, the light-duty gasoline vehicle class does not include two-stroke engines, which are not used in the United States, but are important in Central and Eastern Europe. Therefore, "global" illustrative factors should not be used to calculate actual emissions in a specific country.

For the above reasons, **illustrative emission factors** should not be directly used for national calculations. National inventory experts should consult the more detailed references on mobile source emission factors and use these sources to develop or adapt emission factors which are appropriate for their specific conditions. The expert group on GHG emissions from fuel combustion has identified the need for more detailed guidance and assistance to national experts on the development of locally applicable emission factors as a priority for future work.

(a) The MOBILE5a Model and its User Guide can be obtained from Terry Newell, US EPA Office of Mobile Sources, 2565 Plymouth Road, Ann Arbor MI 48105, USA; tel: (313) 668-4462, Email: Newell.Terry@epamail.epa.gov or access the latest information on mobile sources on the world wide web at http://www.epa.gov/OMSWWW/omshome.htm.

N_2O emission from internal combustion engines is not well understood and data on emissions are scarce. The 1995 edition of the *Guidelines* contained supplementary information used by the Canadian Government, based on a review of data available in 1994 (Ballantyne et al., 1994). The Canadian estimates show that N_2O emissions from vehicles with three-way catalysts increased markedly during the first 15 to 20 000 km, so that earlier estimates based on tests of low mileage vehicles are too low. These results are summarised in Box 5. The US tables, included in this section, use the Canadian data to estimate N_2O emissions from gasoline passenger cars. For light-duty gasoline trucks and motorcycles, fuel specific N_2O emissions were assumed to be the same as for the corresponding passenger car technology. N_2O emissions per kilometre were then calculated from the fuel specific emissions and the fuel consumption characteristics for each class.

In the absence of direct data, N_2O emissions from heavy-duty gasoline trucks were estimated by assuming that their fuel specific emissions were similar to those for passenger cars with similar technology. N_2O emission factors for heavy-duty diesel trucks were derived from emissions for these vehicles reported by Dietzmann, Parness and Bradow (1980). The corresponding fuel specific emission rates were used to estimate N_2O emissions from light-duty diesel vehicles in the absence of information on this class.

Box 5
RECENT INFORMATION ON N_2O MEASUREMENTS

Since the initial illustrative emission factors were estimated in 1991, a number of measurement studies have been carried out to improve understanding of vehicle N_2O emissions. A paper by Ballantyne, et al., (1994) summarised measurements in Canada, the United States and Europe.

	Canadian Measurements (Ballantyne, et al., 1994)		US Measurements (Dasch, 1992)		European Measurements (De Soete, 1989)		Values Used in Canadian National Inventory	
	mg/miles	g/km	mg/miles	g/km	mg/miles	g/km	mg/miles	g/km
New three-way catalysts	21-126	0.013-0.078	13-101	0.008-0.06	60-170	0.037-0.106	60	0.04
Aged three-way	72-211	0.045-0.131	-	-	260-356	0.162-0.221	280	0.17
Oxidation catalyst	-	-	3-66	0.002-0.04	120	0.075	120	0.075
No catalyst	-	-	2.4-4.8	0.001-0.003	8-32	0.005-0.02	32	0.02

Results of this analysis are presented by categories defined by the US EPA as listed below:

Table 1-27: Light-duty gasoline passenger cars **-** vehicles with rated gross weight less than 8 500 lb (3 855 kg) designed primarily to carry *12 or fewer passengers*. Six levels of gasoline-vehicle control technology are shown:

1 Uncontrolled (still typical of most vehicles around the world).

2 Non-catalyst emission controls - including modifications to ignition timing and air-fuel ratio to reduce emissions, exhaust gas recirculation (EGR), and air injection into the exhaust manifold.

3 Oxidation catalyst systems normally including many of the same techniques, plus a two-way catalytic converter to oxidise hydrocarbons and CO.

4 "Early" three-way catalyst results representative of vehicles sold in the United States in the early to mid-1980s, which were mostly equipped with carburettors having electronic "trim".

5 "Advanced" three-way catalyst values based on current US technology vehicles, using electronic fuel injection under computer control.

6 Low Emission Vehicles (LEV) are expected to include sequential multi-port fuel injection with adaptive learning, more sophisticated computer diagnostics and heated catalysts with secondary air injection.

Table 1-28: Light-duty gasoline trucks **-** vehicles having rated gross vehicle weight less than 8 500 lb (3 855 kg), and which are designed primarily for transportation of cargo or more than 11 passengers at a time, or which are equipped with special features for off-road operation. They include most pickup trucks, passenger and cargo vans, four-wheel drive vehicles, and derivatives of these. The technology classifications used are the same as those for gasoline passenger vehicles.

Table 1-29: Heavy-duty gasoline vehicles **-** manufacturer's gross vehicle weight rating exceeding 8 500 lb (3 855 kg). This includes large pickups, vans and specialised trucks using pickup and van chassis, as well as the larger "true" heavy-duty trucks, which have gross vehicle weights of eight short tons or more. In the United States, the large pickups and vans in this category greatly outnumber the heavier trucks, so that the emission factors calculated by MOBILE5a, and fuel economy estimates, are more representative of these vehicles. Three levels of emission control technology are shown:

1 Uncontrolled.

2 Non-catalyst emission controls, including control of ignition timing and air-fuel ratio to minimise emissions, EGR, and air injection into the exhaust manifold to reduce hydrocarbons and CO emissions.

3 Three-way catalyst technology presently used in the United States includes electronically-controlled fuel injection, EGR, air injection, and electronic control of ignition timing, as well as the catalyst itself.

Table 1-30: Light-duty diesel passenger cars **-** a diesel passenger car designed primarily to carry fewer than 12 passengers, with gross vehicle weight less than 8 500 lb (3 855 kg). Three levels of emission control technology are shown:

1 Uncontrolled.

2 Moderate emissions control (achieved by changes in injection timing and combustion system design).

3 Advanced emissions control utilising modern electronic control of the fuel injection system, and exhaust gas recirculation.

Table 1-31: Light-duty diesel trucks **-** light-duty diesel trucks defined like their gasoline counterparts, including weight, utility, and off-road operation features. The technology classifications are the same as those for diesel passenger cars.

Table 1-32: Heavy-duty diesel vehicles **-** the classification for heavy-duty diesel vehicles is the same as for gasoline vehicles, but the characteristics of US vehicle fleets are different. Heavy-duty diesel vehicles are primarily large trucks, with gross vehicle weight ratings of 10 to 40 tons. Therefore, the MOBILE5a emission factors are more representative of large trucks (and buses) than the smaller pickup and van-type vehicles, and this is reflected in the fuel economy estimates. Three levels of control are presented:

1 Uncontrolled.

2 Moderate control (typical of 1983 US engines).

3 Advanced control (for engines meeting US 1991 emissions standards).

Table 1-33: Motorcycles **-** The MOBILE5a emission factors for these vehicles are based on the US motorcycle population, which probably reflects higher average power ratings and fuel consumption than for many developing countries. The factors for uncontrolled motorcycles include a mixture of two-stroke and four-stroke engines, with the VOC emissions due primarily to the two-strokes, and the NO_x to the four-stroke engines. The factors for motorcycles with non-catalyst emission controls reflect four-stroke engines only, as US emission control regulations have essentially eliminated two-stroke engines from the market.

TABLE 1-27
ESTIMATED EMISSION FACTORS FOR US GASOLINE PASSENGER CARS

Season	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Low-Emission Vehicle Technology;(a) Assumed Fuel Economy: 8.5 km/litre (11.8 l/100 km)						
Spring/Fall	0.26-0.34	0.02-0.03	0.30-0.46	3.15-5.30	-	-
Summer	0.25-0.32	0.02-0.03	0.32-0.47	2.69-4.67	-	-
Winter	0.31-0.39	0.03-0.04	0.29-0.51	4.78-7.60	-	-
Average (g/km)	0.27-0.34	0.02-0.03	0.30-0.47	3.44-5.72	0.040	280
Average (g/kg fuel)	3.07-3.91	0.25-0.38	3.42-5.35	38.96-64.77	0.453	3172.31
Average (g/MJ)	0.070-0.089	0.006-0.009	0.078-0.122	0.885-1.472	0.010	72.098
Three-Way Catalyst Control;(a) Assumed Fuel Economy: 8.3 km/litre (12.0 l/100 km)						
Spring/Fall	0.41-0.48	0.02-0.03	0.49-0.66	3.62-5.78	-	-
Summer	0.39-0.46	0.02-0.03	0.80-0.95	2.90-4.89	-	-
Winter	0.47-0.56	0.03-0.04	0.37-0.60	6.35-9.14	-	-
Average (g/km)	0.42-0.50	0.03	0.54-0.72	4.12-6.40	0.170	285
Average (g/kg fuel)	4.67-5.53	0.28-0.39	6.00-7.99	45.92-71.22	1.892	3172.31
Average (g/MJ)	0.106-0.126	0.006-0.009	0.136-0.182	1.044-1.619	0.043	72.098
Early Three-Way Catalyst;(a) Assumed Fuel Economy: 8.0 km/litre (12.5 l/100 km)						
Spring/Fall	0.41-0.51	0.03-0.04	0.63-0.81	4.77-7.08	-	-
Summer	0.39-0.49	0.03-0.04	1.44-1.62	4.46-6.87	-	-
Winter	0.50-0.63	0.04-0.06	0.45-0.70	7.75-10.42	-	-
Average (g/km)	0.43-0.54	0.03-0.05	0.79-0.99	5.44-7.86	0.170	298
Average (g/kg fuel)	4.55-5.71	0.37-0.48	8.41-10.52	57.93-83.73	1.810	3172.31
Average (g/MJ)	0.103-0.130	0.008-0.011	0.191-0.239	1.317-1.903	0.041	72.098
Oxidation Catalyst; Assumed Fuel Economy: 6.2 km/litre (16.1 l/100 km)						
Spring/Fall	1.10-1.17	0.05-0.07	1.26-1.76	8.79-14.96	-	-
Summer	0.84-0.90	0.06-0.08	2.58-3.25	12.16-20.79	-	-
Winter	1.29-1.38	0.07-0.09	1.07-1.66	12.28-19.72	-	-
Average (g/km)	1.08-1.16	0.06-0.08	1.54-2.11	10.51-17.61	0.075	383
Average (g/kg fuel)	8.97-9.58	0.50-0.63	12.77-17.48	87.08-145.95	0.622	3172.31
Average (g/MJ)	0.204-0.218	0.011-0.014	0.290-0.397	1.979-3.317	0.014	72.098
Non-Catalyst Control; Assumed Fuel Economy: 4.5 km/litre (22.2 l/100 km)						
Spring/Fall	1.33-1.37	0.10-0.12	1.97-2.36	14.76-21.63	-	-
Summer	1.06-1.09	0.11-0.13	4.06-4.61	20.59-30.70	-	-
Winter	1.35-1.40	0.13-0.15	1.62-2.05	17.53-26.09	-	-
Average (g/km)	1.27-1.31	0.11-0.13	2.41-2.84	16.91-25.01	0.020	531
Average (g/kg fuel)	7.56-7.82	0.65-0.75	14.38-17.00	101.06-149.45	0.125	3172.31
Average (g/MJ)	0.172-0.178	0.015-0.017	0.327-0.386	2.297-3.397	0.003	72.098
Uncontrolled; Assumed Fuel Economy: 4.7 km/litre (21.3 l/100 km)						
Spring/Fall	1.54	0.12-0.14	5.72-6.06	28.23-38.04	-	-
Summer	1.31	0.11-0.12	9.76-10.07	28.22-38.04	-	-
Winter	1.83	0.16-0.17	4.24-4.66	30.89-41.63	-	-
Average (g/km)	1.56	0.13-0.14	6.36-6.71	28.89-38.94	0.020	506
Average (g/kg fuel)	9.76	0.82-0.90	39.88-42.09	181.14-244.14	0.130	3172.31
Average (g/MJ)	0.222	0.019-0.020	0.906-0.957	4.117-5.549	0.003	72.098

(a) Recent measurement results (De Soete, 1993, Ballantyne, et al., 1994) have shown that N_2O emissions from aged catalysts, e.g., tested after driving 15 000 - 25 000 km, are substantially higher than from new catalyst-equipped cars. Tests on comparable models show aged catalysts emitting from roughly 30% more to almost 5 times the rate of new equipment. As indicated in Box 5, Environment Canada has used a value almost 5 times as high for aged catalysts in its national inventory calculations.

TABLE 1-28
ESTIMATED EMISSION FACTORS FOR US LIGHT-DUTY GASOLINE TRUCKS.

Season	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Low-Emission Vehicle Technology;(a) Assumed Fuel Economy: 6.0 km/litre (16.7 l/100 km)						
Spring/Fall	0.31-0.40	0.02-0.04	0.30-0.50	3.57-6.03	-	-
Summer	0.29-0.38	0.02-0.03	0.31-0.50	2.87-5.11	-	-
Winter	0.37-0.47	0.03-0.05	0.34-0.62	6.02-9.33	-	-
Average (g/km)	0.32-0.41	0.02-0.04	0.31-0.53	4.01-6.62	0.058	396
Average (g/kg fuel)	2.50-3.23	0.18-0.29	2.43-4.13	31.30-51.71	0.450	3172.31
Average (g/MJ)	0.057-0.073	0.004-0.007	0.055-0.094	0.711-1.175	0.010	72.098
Three-Way Catalyst Control;(a) Assumed Fuel Economy: 6.0 km/litre (16.7 l/100 km)						
Spring/Fall	0.49-0.59	0.02-0.04	0.47-0.69	4.45-7.08	-	-
Summer	0.47-0.56	0.02-0.03	0.66-0.87	3.64-6.05	-	-
Winter	0.57-0.69	0.04-0.05	0.47-0.77	7.68-11.22	-	-
Average (g/km)	0.50-0.61	0.03-0.04	0.52-0.76	5.06-7.86	0.236	396
Average (g/kg fuel)	4.04-4.86	0.21-0.30	4.14-6.06	40.46-62.87	1.890	3172.31
Average (g/MJ)	0.092-0.111	0.005-0.007	0.094-0.138	0.920-1.429	0.043	72.098
Early Three-Way Catalyst;(a) Assumed Fuel Economy: 4.8 km/litre (20.8 l/100 km)						
Spring/Fall	0.63-0.76	0.05-0.07	0.74-1.04	6.49-9.97	-	-
Summer	0.60-0.73	0.05-0.07	1.34-1.65	5.97-9.52	-	-
Winter	0.76-0.93	0.08-0.10	0.76-1.19	9.58-13.54	-	-
Average (g/km)	0.65-0.80	0.06-0.08	0.90-1.23	7.13-10.75	0.227	396
Average (g/kg fuel)	5.23-6.36	0.47-0.63	7.16-9.82	56.96-85.86	1.810	3172.31
Average (g/MJ)	0.119-0.144	0.011-0.014	0.163-0.223	1.294-1.951	0.041	72.098
Oxidation Catalyst; Assumed Fuel Economy: 4.8 km/litre (20.8 l/100 km)						
Spring/Fall	1.15-1.28	0.07-0.09	1.48-2.31	9.56-18.76	-	-
Summer	0.77-0.86	0.09-0.11	2.70-3.85	13.72-27.86	-	-
Winter	1.34-1.50	0.10-0.12	1.30-2.30	13.47-26.33	-	-
Average (g/km)	1.10-1.23	0.08-0.10	1.74-2.69	11.58-22.93	0.097	498
Average (g/kg fuel)	7.03-7.84	0.52-0.66	11.08-17.16	73.77-146.07	0.620	3172.31
Average (g/MJ)	0.160-0.178	0.012-0.015	0.252-0.390	1.677-3.320	0.014	72.098
Non-Catalyst; Assumed Fuel Economy: 4.0 km/litre (25.0 l/100 km)						
Spring/Fall	1.62-1.68	0.12-0.14	3.09-3.55	18.41-27.08	-	-
Summer	1.28-1.32	0.13-0.15	5.80-6.39	23.76-35.80	-	-
Winter	1.67-1.72	0.15-0.17	2.29-2.83	23.08-34.24	-	-
Average (g/km)	1.55-1.60	0.13-0.15	3.57-4.08	20.92-31.05	0.023	601
Average (g/kg fuel)	8.17-8.45	0.69-0.80	18.85-21.55	110.41-163.90	0.120	3172.31
Average (g/MJ)	0.186-0.192	0.016-0.018	0.428-0.490	2.509-3.725	0.003	72.098
Uncontrolled; Assumed Fuel Economy: 4.1 km/litre (24.4 l/100 km)						
Spring/Fall	1.84	0.12-0.14	6.87-7.24	29.92-40.29	-	-
Summer	1.56	0.11-0.12	11.07-11.41	29.91-40.29	-	-
Winter	2.18	0.16-0.17	5.31-5.77	33.17-44.09	-	-
Average (g/km)	1.85	0.13-0.14	7.53-7.92	30.73-41.24	0.024	579
Average (g/kg fuel)	10.16	0.71-0.79	41.26-43.37	168.36-225.95	0.130	3172.31
Average (g/MJ)	0.231	0.016-0.018	0.938-0.986	3.826-5.135	0.003	72.098

(a) Recent measurement results (De Soete, 1993, Ballantyne, et al., 1994) have shown that N_2O emissions from aged catalysts, e.g., tested after driving 15 000 - 25 000 km, are substantially higher than from new catalyst-equipped cars. Tests on comparable models show aged catalysts emitting from roughly 30% more to almost 5 times the rate of new equipment. As indicated in Box 5, Environment Canada has used a value almost 5 times as high for aged catalysts in its national inventory calculations.

TABLE 1-29 ESTIMATED EMISSION FACTORS FOR US HEAVY-DUTY GASOLINE VEHICLES						
	EMISSIONS					
Season	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Three-Way Catalyst Control;(a) Assumed Fuel Economy: 2.3 km/litre (43.5 l/100 km)						
Spring/Fall	1.69-1.74	0.07-0.08	0.88-1.03	6.06-7.49	-	-
Summer	1.76-1.81	0.07	1.64-1.80	6.22-7.67	-	-
Winter	1.81-1.86	0.07-0.08	0.65-0.79	6.75-8.35	-	-
Average (g/km)	1.74-1.78	0.07-0.08	1.01-1.16	6.27-7.75	0.606	1017
Average (g/kg fuel)	5.42-5.56	0.21-0.24	3.17-3.62	19.57-24.19	1.890	3172.31
Average (g/MJ)	0.123-0.126	0.005	0.072-0.082	0.445-0.550	0.043	72.098
Non-Catalyst Control; Assumed Fuel Economy: 2.3 km/litre (43.5 l/100 km)						
Spring/Fall	2.37-2.39	0.12-0.13	3.97-4.20	27.04-32.15	-	-
Summer	1.85-1.88	0.12-0.13	9.92-10.20	40.28-47.89	-	-
Winter	2.54-2.56	0.12-0.13	1.71-1.97	30.12-35.81	-	-
Average (g/km)	2.28-2.31	0.12-0.13	4.89-5.14	31.12-37.00	0.591	1036
Average (g/kg fuel)	6.98-7.06	0.36-0.41	14.98-15.75	95.28-113.28	1.810	3172.31
Average (g/MJ)	0.159-0.161	0.008-0.009	0.341-0.358	2.166-2.575	0.041	72.098
Uncontrolled; Assumed Fuel Economy: 1.8 km/litre (55.6 l/100 km)						
Spring/Fall	3.48-4.13	0.26-0.29	13.38-14.55	97.66-115.91	-	-
Summer	2.83-3.38	0.25-0.29	19.97-21.11	111.10-131.87	-	-
Winter	4.11-4.88	0.26-0.29	12.01-13.38	103.06-122.33	-	-
Average (g/km)	3.47-4.13	0.25-0.29	14.68-15.90	102.37-121.51	0.054	1320
Average (g/kg fuel)	8.35-9.92	0.61-0.70	35.30-38.21	246.08-292.08	0.130	3172.31
Average (g/MJ)	0.190-0.226	0.014-0.016	0.802-0.868	5.593-6.638	0.003	72.098

(a) Recent measurement results (De Soete, 1993, Ballantyne, et al., 1994) have shown that N_2O emissions from aged catalysts, e.g., tested after driving 15 000 - 25 000 km, are substantially higher than from new catalyst-equipped cars. Tests on comparable models show aged catalysts emitting from roughly 30% more to almost 5 times the rate of new equipment. As indicated in Box 5, Environment Canada has used a value almost 5 times as high for aged catalysts in its national inventory calculations.

TABLE 1-30
ESTIMATED EMISSION FACTORS FOR US DIESEL PASSENGER CARS

Season	**EMISSIONS**					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Advanced Control; Assumed Fuel Economy: 10.0 km/litre (10 l/100 km)						
Spring/Fall	0.42	0.01	0.17	0.56	-	-
Summer	0.42	0.01	0.17	0.56	-	-
Winter	0.44	0.01	0.19	0.58	-	-
Average (g/km)	0.43	0.01	0.17	0.56	0.007	237
Average (g/kg fuel)	5.68	0.06	2.32	7.54	0.09	3172.31
Average (g/MJ)	0.129	0.001	0.053	0.171	0.002	72.098
Moderate Control; Assumed Fuel Economy: 9.6 km/litre (10.4 l/100 km)						
Spring/Fall	0.54	0.01	0.17	0.56	-	-
Summer	0.54	0.01	0.17	0.62	-	-
Winter	0.54	0.01	0.17	0.56	-	-
Average (g/km)	0.54	0.01	0.17	0.58	0.01	248
Average (g/kg fuel)	6.88	0.08	2.17	7.35	0.13	3172.31
Average (g/MJ)	0.156	0.002	0.049	0.167	0.003	72.098
Uncontrolled; Assumed Fuel Economy: 7.5 km/litre (13.3 l/100 km)						
Spring/Fall	0.67	0.01	0.24	0.61	-	-
Summer	0.67	0.01	0.24	0,.61	-	-
Winter	0.67	0.01	0.24	0.61	-	-
Average (g/km)	0.67	0.01	0.24	0,.61	0.014	319
Average (g/kg fuel)	6.62	0.12	2.39	6.04	0.14	3172.31
Average (g/MJ)	0.150	0.003	0.054	0.137	0.003	72.098

TABLE 1-31 ESTIMATED EMISSION FACTORS FOR US LIGHT-DUTY DIESEL TRUCKS						
	EMISSIONS					
Season	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Advanced Control; Assumed Fuel Economy: 7.2 km/litre (13.9 l/100 km)						
Spring/Fall	0.49	0.01	0.24	0.64	-	-
Summer	0.49	0.01	0.24	0.64	-	-
Winter	0.49	0.01	0.24	0.64	-	-
Average (g/km)	0.49	0.01	0.24	0.64	0.024	330
Average (g/kg fuel)	4.70	0.08	2.35	6.11	0.23	3172.31
Average (g/MJ)	0.107	0.002	0.053	0.139	0.005	72.098
Moderate Control; Assumed Fuel Economy: 7.2 km/litre (13.9 l/100 km)						
Spring/Fall	0.68	0.01	0.24	0.64	-	-
Summer	0.68	0.01	0.24	0.64	-	-
Winter	0.68	0.01	0.24	0.64	-	-
Average (g/km)	0.68	0.01	0.24	0.64	0.063	331
Average (g/kg fuel)	6.52	0.08	2.34	6.10	0.60	3172.31
Average (g/MJ)	0.148	0.002	0.053	0.139	0.014	72.098
Uncontrolled; Assumed Fuel Economy: 5.7 km/litre (17.5 l/100 km)						
Spring/Fall	0.92	0.01	0.49	1.01	-	-
Summer	0.92	0.01	0.49	1.01	-	-
Winter	0.92	0.01	0.49	1.01	-	-
Average (g/km)	0.92	0.01	0.49	1.01	0.031	415
Average (g/kg fuel)	7.02	0.10	3.76	7.73	0.24	3172.31
Average (g/MJ)	0.159	0.002	0.086	0.176	0.005	72.098

TABLE 1-32
ESTIMATED EMISSION FACTORS FOR US HEAVY DUTY DIESEL VEHICLES

Season	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Advanced Control; Assumed Fuel Economy: 2.4 km/litre (41.7 l/100 km)						
Spring/Fall	3.52	0.04	0.86	4.36	-	-
Summer	3.52	0.04	0.86	4.36	-	-
Winter	3.52	0.04	0.86	4.36	-	-
Average (g/km)	3.52	0.04	0.86	4.36	0.025	987
Average (g/kg fuel)	11.32	0.14	2.78	14.01	0.08	3172.31
Average (g/MJ)	0.257	0.003	0.063	0.318	0.002	72.098
Moderate Control; Assumed Fuel Economy: 2.4 km/litre (41.7 l/100 km)						
Spring/Fall	7.96	0.05	1.13	5.01	-	-
Summer	7.96	0.05	1.13	5.01	-	-
Winter	7.96	0.05	1.13	5.01	-	-
Average (g/km)	7.96	0.05	1.13	5.01	0.025	1011
Average (g/kg fuel)	24.96	0.16	3.55	15.71	0.08	3172.31
Average (g/MJ)	0.567	0.004	0.081	0.357	0.002	72.098
Uncontrolled; Assumed Fuel Economy: 2.2 km/litre (45.5 l/100 km)						
Spring/Fall	10.30	0.06	1.63	4.85	-	-
Summer	10.30	0.06	1.63	4.85	-	-
Winter	10.30	0.06	1.63	4.85	-	-
Average (g/km)	10.30	0.06	1.63	4.85	0.031	1097
Average (g/kg fuel)	29.79	0.18	4.70	14.03	0.09	3172.31
Average (g/MJ)	0.677	0.004	0.107	0.319	0.002	72.098

TABLE 1-33
ESTIMATED EMISSION FACTORS FOR US MOTORCYCLES

Season	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Non-catalytic Control; Assumed Fuel Economy: 10.8 km/litre (9.3 l/100 km)						
Spring/Fall	0.37	0.12	2.26	13.77	-	-
Summer	0.31	0.12	2.59	16.74	-	-
Winter	0.43	0.14	2.47	18.01	-	-
Average (g/km)	0.37	0.13	2.39	15.57	0.002	219
Average (g/kg fuel)	5.40	1.83	36.60	225.14	0.03	3172.31
Average (g/MJ)	0.123	0.042	0.786	5.117	0.001	72.098
Uncontrolled; Assumed Fuel Economy: 8.9 km/litre (11.2 l/100 km)						
Spring/Fall	0.19	0.25	5.87	21.78	-	-
Summer	0.16	0.24	5.96	21.55	-	-
Winter	0.22	0.31	6.93	24.09	-	-
Average (g/km)	0.19	0.26	6.16	22.30	0.002	266
Average (g/kg fuel)	2.29	3.13	73.33	265.51	0.02	3172.31
Average (g/MJ)	0.052	0.071	1.667	6.034	0.001	72.098

European Emission Estimates

The European emission estimates for NO_x, CH_4, NMVOC (total VOC minus CH_4), CO, N_2O and CO_2 are based on the COPERT90 model, developed for the Commission of the European Communities.[19] The calculation is based on five main types of input parameters:

- total fuel consumption
- vehicle park
- driving condition
- emission factors
- other parameters

For these main types of input parameters, additional information (e.g., on vehicle classes, production years etc.) is needed in order to carry out the calculations.

The methodology is defined in such a way that it uses the firm technical data and that national variations among European countries can be incorporated. The variations may include such things as composition of vehicle park, vehicle age, driving patterns, some fuel parameters and a few climatic parameters. Other variations which may exist, for example, variations in vehicle maintenance, mountain driving etc., are not accounted for because there is not enough data available to do so.

Vehicle categories

The vehicle categories chosen by CORINAIR 1990 do not meet all the requirements for modelling vehicle emissions considered important by the working group. In particular the age of vehicle (year of production) and the engine technology are not sufficiently reflected. Thus, for the purpose of the COPERT work only, a more detailed vehicle category split has been developed.

Hot Emissions

These emissions depend on a variety of factors including the distance that each vehicle travels, its speed (or road type), its age and engine size.

The basic formula for estimating hot emissions using an experimentally obtained emission factor is:

$$\boxed{\text{Emissions [g]} = \text{emission factor [g/km]} \cdot \text{vehicle kilometres per year [km]}}$$

The emission factors and vehicle kilometres are in most cases split into certain classes of road types and vehicle categories.

However, for many countries the only data known with any certainty are the total fuel consumption of gasoline, diesel and LPG, not vehicle kilometres. It is therefore suggested that fuel consumption data are used to check vehicle mileage where they are known and to make a final fuel balance.

Cold Start Emissions

Cold starts result in additional emissions. They take place under all three (urban, rural and highway) driving conditions, but seem to be most significant for urban driving. In

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[19] As is the convention throughout these *Guidelines*, CO_2 emissions are calculated to include the carbon emitted as CO and as VOC.

principle they occur for all vehicle categories. However, emission factors are available or can be reasonably estimated only for gasoline, diesel and LPG passenger cars and - assuming that these vehicles behave like passenger cars - light-duty vehicles. Consequently, only these categories are covered by the methodology. Moreover, cold start emissions are considered not to be a function of vehicle age.

Cold start emissions are calculated as emissions additional to emissions that would be expected if all vehicles had only hot engines. A factor, the ratio of cold to hot emissions, is used and applied to the fraction of kilometres driven with cold engines. These factors may vary from country to country. Different driving behaviour, road conditions and climate as well as trip length affect the warm up time and the fraction of distance travelled with cold engines. These factors can be taken into account, but again information may not be available to do this thoroughly in all countries, so that estimates have to close identified gaps.

Evaporative VOC Emissions

There are three primary sources of evaporative emissions from vehicles:

i) diurnal (daily) emissions;
ii) hot soak emissions; and
iii) running losses.

These are estimated separately. Again they are affected by factors that vary from country to country.

All three types of evaporative emissions are significantly affected by the volatility of the gasoline being used, the absolute ambient temperature and temperature changes, and vehicle design characteristics. For hot soak emissions and running losses the driving pattern is also of importance.

In general, the estimation of evaporative emissions from gasoline vehicles involves a large number of uncertainties which can not be resolved without carrying out further measurements.

Application of the baseline methodology to the different vehicle categories and pollutants

Due to gaps in knowledge, the baseline methodology can not be applied in full and in the same way to all vehicle categories. Moreover, there are variations depending on the pollutant considered. In general, one can distinguish between four methods:

Method A

Hot emissions are calculated based on:

- the total annual kilometres driven per vehicle;
- the share of kilometres driven under the driving modes “urban”, “rural” and “highway”;
- the average speed of the vehicles under the driving modes “urban”, “rural” and “highway”;
- speed-dependent hot emission factors.

Cold start emissions are calculated based on:

- the average trip length per vehicle trip;
- the average monthly temperature;
- temperature and trip length dependent cold start correction factor.

Evaporative emissions are calculated based on:

- the fuel volatility (RVP);
- the average monthly temperature and the average monthly temperature variation;
- fuel volatility and temperature dependent emission factors.

Method B

The total annual emissions per vehicle are calculated based on:

- the total annual kilometres driven per vehicle;
- the share of kilometres driven under the driving modes “urban”, “rural” and “highway”;
- the average speed of the vehicles under the driving modes “urban”, “rural” and “highway”;
- speed-dependent emission factors.

Note: for diesel passenger cars, cold start extra emissions for CO, NO_x and NMVOC, as well as extra fuel consumption, are added using the method described under A. For LPG passenger cars a simplified method is used.

Method C

The total annual emissions per vehicle are calculated based on:

- the total annual kilometres driven per vehicle;
- the share of kilometres driven under the driving modes “urban”, “rural” and “highway”;
- driving mode dependent emissions factors.

Note: for gasoline and diesel light-duty vehicle, cold start extra emissions for CO, NO_X and NMVOC, as well as fuel consumption, are added using the method described under A. For gasoline light-duty vehicles, NMVOC evaporative emissions are added using the method described under A.

Method D	The total annual emissions per vehicle category are calculated based on: - the total annual fuel consumption of the vehicle category and/or the total annual kilometres driven by the vehicle category; - fuel consumption and/or kilometre related emission factors. Note: For two wheelers NMVOC evaporative emissions are added using the method described under A.

TABLE 1-34

SUMMARY OF PRECISION INDICATORS OF THE EMISSION ESTIMATES AND OF CALCULATION METHODS APPLIED FOR THE DIFFERENT VEHICLE CATEGORIES AND POLLUTANTS
(A, B, C, D: Method Indicators - 1, 2, 3, 4: Precision Indicators)

Vehicle Category	NO$_x$	CO	NMVOC	CH$_4$	N$_2$O	CO$_2$	Fuel
Passenger Cars							
Gasoline	A/1	A/1	A/1	C/1	C/3	D/1	A/1
Diesel	B/1	B/1	B/1	C/2	C/3	D/1	B/1
LPG	B/1	B/1	B/1	-	-	D/1	B/1
Two stroke	C/2	C/2	C/2	C/4	C/4	D/2	C/2
Light-Duty Vehicles	C/1	C/1	C/1	C/3	C/4	D/1	C/1
Heavy-Duty Vehicles	C/2	C/2	C/2	C/4	D/4	D/2	C/2
Two Wheelers	D/2	D/2	D/2	D/4	-	D/2	D/2
Evaporation							
Passenger Cars	-	-	A/3(a)	-	-	-	-
Light-Duty Vehicles	-	-	C/4(a)	-	-	-	-
Two Wheelers	-	-	D/4	-	-	-	-
Cold Start							
Passenger Cars							
Conventional Gas.	A/2	A/2	A/2	-	-	A/2	A/2
Catalyst Gasoline	A/3	A/3	A/3	-	-	A/2	A/3
Diesel	A/3	A/3	A/3	-	-	A/3	A/3
LPG	B/3	B/3	B/3	-	-	B/3	B/3
Light Duty Vehicles	C/4	C/4	C/4	-	-	C/4	C/4

1: Statistically significant emission factors based on a sufficiently large set of measured and re-evaluated data.
2: Emission factors non-statistically significant based on a small set of measured and re-evaluated data.
3: Emission factors estimated on the basis of available literature.
4: Emission factors estimated applying similarity considerations and/or extrapolation.
(a) Only for gasoline engine vehicles.

For the IPCC *Guidelines*, the emission factors from the COPERT model are presented using the American vehicle and control type categories, for ease of comparison. The emission factors have been calculated using data from 15 western and eastern European countries. Therefore the vehicle usage pattern, such as average speed and frequency of cold starts, climatic conditions like the monthly average temperature, and the fuel characteristics of these countries are incorporated in the figures. The emission factors provided are therefore valid for an average European situation.

In developing the following tables, a net calorific value of 43.5 TJ/kt was assumed for gasoline, 42.4 TJ/kt for diesel and 46.1 TJ/kt for LPG.

TABLE 1-35
EUROPEAN EMISSION CONTROL TECHNOLOGY TYPES AND CORRESPONDING EU LEGISLATION AND MODEL YEARS

TECHNOLOGY	LEGISLATION (MODEL YEAR)
Uncontrolled	Pre ECE (up to 1970)
Early non-catalyst controls	ECE 15 00 to 02 (1971-1979)
Non-catalyst controls	ECE 15 03 to 04 (1980-early 1990s)
Oxidation catalyst	88/76/EEC (1988-1991)
Three-way catalyst	91/441/EEC (1989-1995)

TABLE 1-36
ESTIMATED EMISSION FACTORS FOR EUROPEAN GASOLINE PASSENGER CARS

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Uncontrolled: Assumed Fuel Economy 8.9 km/l (11.2 l/100 km)						
Total **g/km**	2.2	0.07	5.3	46	0.005	270
Exhaust	2.2	0.07	3.9	46	0.005	270
Evaporative(a)			1.4			
g/kg fuel	27	0.8	63	550	0.06	3180
g/MJ	0.6	0.02	1.5	13	0.001	73
Early non-catalyst controls: Assumed Fuel Economy 10.6 km/l (9.4 l/100 km)						
Total g/km	2.0	0.08	5.2	29	0.005	225
Exhaust	2.0	0.08	3.8	29	0.005	225
Evaporative(a)			1.4			
g/kg fuel	29	1.1	74	405	0.07	3180
g/MJ	0.7	0.03	1.7	9.3	0.002	73
Non-catalyst controls: Assumed Fuel Economy 12.0 km/l (8.3 l/100 km)						
Total **g/km**	2.3	0.07	4.5	19	0.005	200
Exhaust	2.3	0.07	3.2	19	0.005	200
Evaporative(a)			1.3			
g/kg fuel	37	1.1	72	300	0.08	3180
g/MJ	0.8	0.03	1.7	6.9	0.002	73
Oxidation catalyst: Assumed Fuel Economy 12.3 km/l (8.1 l/100 km)						
Total **g/km**	1.4	0.07	1.4	7.5	0.005	190
Exhaust	1.4	0.07	1.0	7.5	0.005	190
Evaporative(a)			0.4			
g/kg fuel	22	1.2	24	125	0.08	3180
g/MJ	0.5	0.03	0.6	2.9	0.002	73
Three-way catalyst: Assumed Fuel Economy 11.8 km/l (8.5 l/100 km)						
Total **g/km**	0.5	0.02	0.5	2.9	0.05	205
Exhaust	0.5	0.02	0.4	2.9	0.05	205
Evaporative(a)			0.06			
g/kg fuel	8.2	0.3	7.1	45.9	0.8	3180
g/MJ	0.12	0.007	0.2	1	0.02	73
2-stroke: Assumed Fuel Economy 9.2 km/l (10.9 l/100 km)						
Total **g/km**	0.8	0.08	12	12	0.005	260
Exhaust	0.8	0.08	10.7	12	0.005	260
Evaporative(a)			1.5			
g/kg fuel	9.3	1.0	164	150	0.06	3180
g/MJ	0.2	0.02	3.8	3.4	0.001	73

(a) Including diurnal, soak and running losses

TABLE 1-37
ESTIMATED EMISSION FACTORS FOR EUROPEAN DIESEL PASSENGER CARS

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Moderate control: Assumed Fuel Economy 13.7 km/l (7.3 l/100 km)						
Total **g/km**	0.7	0.005	0.2	0.7	0.01	190
g/kg fuel	11	0.08	3.0	12	0.2	3140
g/MJ	0.3	0.002	0.07	0.3	0.004	74

TABLE 1-38
ESTIMATED EMISSION FACTORS FOR EUROPEAN DIESEL LIGHT-DUTY VEHICLES

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Moderate control: Assumed Fuel Economy 9.2 km/l (10.9 l/100 km)						
Total **g/km**	1.4	0.005	0.4	1.6	0.02	280
g/kg fuel	16	0.06	4.6	18	0.2	3140
g/MJ	0.4	0.001	0.1	0.4	0.004	74

TABLE 1-39
ESTIMATED EMISSION FACTORS FOR EUROPEAN DIESEL HEAVY-DUTY VEHICLES

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Moderate control: Assumed Fuel Economy 3.3 km/l (29.9 l/100 km)						
Total **g/km**	10	0.06	1.9	9.0	0.03	770
g/kg fuel	42	0.2	8.0	36	0.1	3140
g/MJ	1.0	0.006	0.2	0.9	0.003	74

TABLE 1-40
ESTIMATED EMISSION FACTORS FOR EUROPEAN GASOLINE LIGHT-DUTY VEHICLES

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Moderate control: Assumed Fuel Economy 7.4 km/l (13.6 l/100 km)						
Total **g/km**	2.9	0.08	6.1	37	0.006	325
Exhaust	2.9	0.08	4.8	37	0.006	325
Evaporative(a)			1.3			
g/kg fuel	29	0.8	59	360	0.06	3180
g/MJ	0.7	0.02	1.4	8.3	0.001	73

TABLE 1-41
ESTIMATED EMISSION FACTORS FOR EUROPEAN GASOLINE HEAVY-DUTY VEHICLES

	EMISSIONS					
	NO_x	CH_4	VOC	CO	N_2O	CO_2
Uncontrolled: Assumed Fuel Economy 4.4 km/l (22.5 l/100 km)						
Total **g/km**	6.9	0.1	5.4	58	0.006	535
Exhaust	6.9	0.1	5.4	58	0.006	535
Evaporative(a)						
g/kg fuel	40	0.7	32	346	0.04	3180
g/MJ	0.9	0.02	0.8	7.9	0.001	73

TABLE 1-42
ESTIMATED EMISSION FACTORS FOR EUROPEAN MOTORCYCLES

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
MOTORCYCLES < 50 CC						
Uncontrolled: Assumed Fuel Economy 41.7 km/l (2.4 l/100 km)						
Total **g/km**	0.05	0.1	6.5	10	0.001	57
Exhaust	0.05	0.1	6.2	10	0.001	57
Evaporative(a)			0.3			
g/kg fuel	2.8	5.6	359	550	0.06	3180
g/MJ	0.06	0.1	8.3	13	0.001	73
MOTORCYCLES > 50 CC 2 STROKE						
Uncontrolled: Assumed Fuel Economy 25.0 km/l (4.0 l/100 km)						
Total **g/km**	0.08	0.15	16	22	0.002	95
Exhaust	0.08	0.15	15	22	0.002	95
Evaporative(a)			1.0			
g/kg fuel	2.7	5.0	530	730	0.07	3180
g/MJ	0.06	0.1	12	17	0.002	73
MOTORCYCLES > 50 CC 4 STROKE						
Uncontrolled: Assumed Fuel Economy 19.6 km/l (5.1 l/100 km)						
Total **g/km**	0.30	0.20	3.9	20	0.002	120
Exhaust	0.30	0.20	3.4	20	0.002	120
Evaporative(a)			0.5			
g/kg fuel	7.9	5	105	530	0.05	3180
g/MJ	0.2	0.1	2.4	12	0.001	73

(a) Including diurnal, soak and running losses

Road Vehicles - Alternative Fuels

Alternative motor vehicle fuels such as natural gas, liquefied petroleum gas (LPG), methanol and ethanol are presently being used in a limited way, and are the subjects of a great deal of research and development effort aimed at increasing their usage in the future. This section presents some preliminary estimates of the emissions to be expected from vehicles using these fuels, based on fuel properties and the limited emissions data available.[20]

Natural gas

Because natural gas is mostly methane, natural gas vehicles (NGVs) have lower exhaust NMVOC emissions than gasoline vehicles, but higher emissions of methane. There are no evaporative or running-loss emissions, while refuelling emissions and cold-start emissions are lower. These conditions reduce both NMVOC and CO emissions relative to gasoline vehicles. CO_2 emissions from NGVs will be lower than for gasoline vehicles, since natural gas has a lower carbon content per unit of energy. It is possible to attain increased efficiency by increasing the compression ratio. Optimised heavy-duty NGV engines can approach diesel efficiency levels. NO_x emissions from uncontrolled NGVs may be higher or lower than comparable gasoline vehicles, depending on the engine technology. NO_x emissions from NGVs are more difficult to control using three-way catalysts. N_2O emissions from NGVs were not included.

Table 1-43 shows three types of NGVs: passenger cars, gasoline-type heavy-duty vehicles, and diesel-type heavy-duty vehicles.[21] Two sets of emission factors are shown for each: uncontrolled (typical of a simple natural gas conversion, without catalytic converter or optimisation for emissions) and advanced control (reflecting an engine and catalytic converter factory-produced and optimised for natural gas). The estimates for the passenger car and gasoline-type heavy-duty vehicle are based on a gasoline-type engine, converted to use natural gas. For the uncontrolled vehicles, no changes in the engine are assumed beyond the fitting of a natural gas mixer and modified spark timing such that the efficiency would be the same. For the vehicles with advanced control, a higher compression ratio is assumed to give 15 per cent better fuel efficiency.

For the diesel-type heavy-duty vehicles, the engine assumed is a diesel-type engine, converted to lean, Otto-cycle operation using natural gas. The uncontrolled case reflects no further optimisation beyond the conversion, while the controlled case includes extensive combustion optimisation for NO_x control and an oxidation catalytic converter.

Liquefied petroleum gas

LPG is primarily propane (or a propane/butane mixture) rather than methane which affects the composition of exhaust VOC emissions, but otherwise is similar to natural gas. Evaporative and refuelling emissions are virtually zero, and CO and exhaust NMVOC emissions are usually lower than gasoline vehicles. The CO_2 emissions should be somewhat lower than gasoline, due to the lower carbon-energy ratio, and the higher

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[20] Actual emission levels from these vehicles may be very different, and further testing is needed to confirm these estimates.

[21] The emissions considered are only those of the vehicle itself – additional emissions due to, e.g., compression or liquefaction of gas for storage on the vehicle, leakage from pipelines, etc. are not included, nor are the potential emissions credits due to, e.g., production of methane from biomass. This is consistent with the treatment of emissions from vehicles using oil-based fuels.

octane level allows some increase in efficiency, although less than for natural gas. NO_x emissions from LPG vehicles tend to be higher than for gasoline, but can also be controlled using three-way catalysts. N_2O emissions were not included.

Table 1-44 shows two types of LPG vehicles. The engines and technologies considered are the same as those for natural gas, except that the lean, diesel-derived natural gas engine with propane is not considered.

Methanol and Ethanol

The two alcohols have similar properties, and are discussed together. Development efforts have focused primarily on mixtures of alcohols with gasoline, in flexible fuel vehicles, capable of running on any combination of gasoline and up to 85 per cent methanol or ethanol. Engines and emission control systems are similar to those for advanced-technology gasoline vehicles, and the overall energy efficiency and emissions properties are similar. Table 1-46 shows estimated emissions for a vehicle of this type using M85 (85% methanol / 15% gasoline) fuel. Also shown are some rough emissions estimates for heavy-duty vehicles equipped with methanol or ethanol engines.

TABLE 1-43
ESTIMATED EMISSION FACTORS FOR US LIGHT- AND HEAVY-DUTY NATURAL GAS VEHICLES

	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Passenger Cars						
Advanced Control; Assumed Fuel Economy: 14.9 km/m^3						
g/km	0.5	0.7	0.05	0.3	NAV	133
g/kg fuel	10.3	14.5	1.0	6.2	NAV	2750
g/MJ	0.21	0.29	0.02	0.12	NAV	56.1
Uncontrolled; Assumed Fuel Economy: 6.5 km/m^3						
g/km	2.1	3.5	0.5	4.0	NAV	305
g/kg fuel	19.0	31.6	4.5	36.1	NAV	2750
g/MJ	0.38	0.63	0.09	0.72	NAV	56.1
Heavy-Duty Vehicles: Stoichiometric Engine (compare with gasoline)						
Advanced Control; Assumed Fuel Economy: 3.6 km/m^3						
g/km	2.6	3.0	0.20	1.0	NAV	550
g/kg fuel	13.0	15.0	1.0	5.0	NAV	2750
g/MJ	0.26	0.30	0.02	0.10	NAV	56.1
Uncontrolled; Assumed Fuel Economy: 2.2 km/m^3						
g/km	5.7	10.0	1.4	12.0	NAV	900
g/kg fuel	17.4	30.6	4.3	36.7	NAV	2750
g/MJ	0.35	0.61	0.09	0.73	NAV	56.1
Heavy-Duty Vehicles: Lean Burn Engine (compare with diesel)						
Advanced Control; Assumed Fuel Economy: 2.4 km/m^3						
g/km	4.0	4.0	0.40	1.5	NAV	825
g/kg fuel	13.3	13.3	1.3	5.0	NAV	2750
g/MJ	0.27	0.27	0.03	0.10	NAV	56.1
Uncontrolled; Assumed Fuel Economy: 2.0 km/m^3						
g/km	23.0	10.0	2.0	8.0	NAV	990
g/kg fuel	63.9	27.8	5.6	22.2	NAV	2750
g/MJ	1.28	0.56	0.11	0.44	NAV	56.1

Table 1-44
Estimated Emission Factors For US Light- And Heavy-Duty LPG Vehicles.

	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Passenger Cars						
Advanced Control						
g/km	0.5	0.03	0.25	0.3	NAV	170
g/kg fuel	8.8	0.6	4.4	5.3	NAV	3000
g/MJ$^{(a)}$	0.19	0.01	0.10	0.11	NAV	63.1
Uncontrolled						
g/km	2.1	0.18	3.5	8.0	NAV	356
g/kg fuel	17.7	1.5	29.5	67.5	NAV	3000
g/MJ	0.38	0.03	0.64	1.45	NAV	63.1
Heavy-Duty Vehicles: Stoichiometric Engine (compare with gasoline)						
Advanced Control						
g/km	2.6	0.15	0.70	1.0	NAV	695
g/kg fuel	11.2	0.6	3.0	4.3	NAV	3000
g/MJ	0.24	0.01	0.07	0.09	NAV	63.1
Uncontrolled						
g/km	5.7	0.4	8.0	24.0	NAV	1020
g/kg fuel	16.8	1.2	23.5	70.6	NAV	3000
g/MJ	0.36	0.03	0.51	1.52	NAV	63.1

(a) Berdowski, et al. (1993a) suggest a CH_4 emission factor of 0.013 g/MJ for this vehicle/technology class.

Table 1-45
Estimated Emission Factors for
European LPG Passenger Cars

	Emissions					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Moderate control: Assumed Fuel Economy 8.9 km/l$^{(a)}$ (11.2 l/100 km)						
Total **g/km**	2.2	0.06	1.5	7.1	-	180
g/kg fuel	37	1.0	25	120	-	3030
g/MJ	0.9	0.02	0.6	2.6	-	65

(a) Under 5 bar pressure

TABLE 1-46
ESTIMATED EMISSION FACTORS FOR US LIGHT- AND HEAVY-DUTY METHANOL VEHICLES

	EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Passenger Cars (M85 Fuel)						
Advanced Control						
g/km	0.5	0.02	0.66	3.14	NAV	183
g/kg fuel	4.5	0.2	5.9	28.0	NAV	1632
g/MJ	0.19	0.01	0.25	1.19	NAV	69.7
Heavy-Duty Vehicles - Methanol-Diesel Engine - M100 Fuel						
Advanced Control						
g/km	4.0	0.1	1.50	4.0	NAV	908
g/kg fuel	6.1	0.2	2.3	6.1	NAV	1375
g/MJ	0.30	0.01	0.11	0.30	NAV	68.8

1.5.3.4 SURFACE NON-ROAD SOURCES

Emission factors are provided for major non-road vehicle source categories including farm and construction equipment, railway locomotives, boats, and ships (all primarily equipped with diesel engines), jet aircraft, and gasoline-fuelled piston aircraft.

Table 1-47 presents emission factors specific to the United States, but may be applicable to other regions as well. The emission factors for diesel engines used in railway locomotives, farm equipment such as tractors and harvesters, construction equipment such as bulldozers and cranes, and diesel boats, are from Weaver (1988). N_2O emission factors for off-road diesels are assumed to be the same as those for heavy-duty on-highway diesel engines.

Large ocean-going cargo ships are driven primarily by large, slow-speed and medium-speed diesel engines, and occasionally by steam turbines and gas turbines (the latter in high power-weight ratio vessels such as fast ferries and warships). The number of vessels equipped with steam or gas-turbine propulsion is small, however, since these vessels are unable to compete with the more efficient diesels in most applications. The results shown for NO_x and CO are from Hadler (1990)[22]. N_2O emissions for these engines were assumed to be the same, on a fuel-specific basis, as those for other heavy-duty diesels, and VOC emissions from these large diesels are probably negligible.

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[22] Other sources consulted for comparison are Melhus (1990), Bremnes (1990), Alexandersson (1990).

TABLE 1-47
ESTIMATED EMISSION FACTORS FOR US NON-ROAD MOBILE SOURCES

	UNCONTROLLED EMISSIONS					
	NO_x	CH_4	NMVOC	CO	N_2O	CO_2
Ocean-Going Ships						
g/kg fuel	87	NAV	NAV	1.9	0.08	3212
g/MJ	2.1	NAV	NAV	0.046	0.002	77.6
Boats						
g/kg fuel	67.5	0.23	4.9	21.3	0.08	3188
g/MJ	1.6	0.005	0.11	0.50	0.002	75.0
Locomotives						
g/kg fuel	74.3	0.25	5.5	26.1	0.08	3188
g/MJ	1.8	0.006	0.13	0.61	0.002	75.0
Farm Equipment						
g/kg fuel	63.5	0.45	9.6	25.4	0.08	3188
g/MJ	1.5	0.011	0.23	0.60	0.002	75.0
Construction and Industrial Equipment						
g/kg fuel	50.2	0.18	3.9	16.3	0.08	3188
g/MJ	1.2	0.004	0.09	0.38	0.002	75.0
Jet and Turboprop Aircraft						
g/kg fuel	12.5	0.087	0.78	5.2	NAV	3149
g/MJ	0.29	0.002	0.018	0.12	NAV	72.8
Gasoline (Piston) Aircraft						
g/kg fuel	3.52	2.64	24	1034	0.04	3172
g/MJ	0.08	0.06	0.54	24	0.0009	72.1

A detailed experimental assessment of exhaust emissions from a broad cross section of ship categories including bulk carriers, container ships, dredgers, ferries, tankers and tugs has recently been completed by Lloyd's Register (1995). The vessels evaluated by Lloyd's Register were powered by in-service diesel engines of various vintages and sizes, and tested without modification.

A total of sixty engines on fifty vessels were tested under steady-state conditions, and a further eight vessels were tested under transient engine loads by Lloyd's Register (1995). Emission factors reported by Lloyd's Register for medium and slow speed diesel engines are considered to be the best available to date and have been adopted in this study (see Table 1-48).

In the absence of data on the relative time spent under steady state versus transient engine loads, steady state engine emission rates are adopted in this study for ocean-going ships. For detailed regional studies, it is recommended that surveys of engine type and mode of operation be undertaken to establish fleet emission rates for non-CO_2 gases.

For slow to medium speed diesel engines, considered to be representative of large ocean-going cargo ships, Lloyd's Register (1995) reported NO_x emission rates of 57 and 87 kg/tonne of fuel, respectively. In the absence of data on the fleet composition of slow versus medium speed diesel engines for ocean going fleets, a NO_x emission factor of 72 kg/tonne of fuel is recommended. The corresponding emission rate documented by IPCC (1995) was 87 kg/tonne of fuel. Emission rates for CH_4 and NMVOC for ocean-going ships were not reported by IPCC (1995). In this study, CH_4 and NMVOC emission rates are estimated from hydrocarbon (HC) data reported by Lloyd's Register according to $CH_4 = 0.12 \times HC$ and $NMVOC = HC - CH_4$.

Lloyd's Register reported a CO emission rate of 7.4 kg/tonne of fuel for slow to medium speed diesel engines. In this study, the value of 7.4 kg CO/tonne of fuel is adopted for slow to medium speed diesel engines on ocean-going ships.

Emission factors for small engines mainly used in pleasure crafts and small fishing boats can be found in Table 1-49 under the heading "Inland waterways" for diesel engines as well as for 2-stroke and 4-stroke gasoline engines.

The difference in emission rates noted above, illustrates the importance of characterising fleet engine types and fuel use for regional scale emissions from marine and other non-road sources.

TABLE 1-48
DEFAULT MARINE EMISSION FACTORS

	CH_4	N_2O	NO_x	CO	NMVOC
Ocean-going Ships (diesel engines*)					
g/MJ	0.007	0.002	1.8	0.18	0.052

* Mostly using heavy fuel oil.

Table 1-49 presents emission factors for non-road vehicles in Europe. These estimates were produced for CORINAIR using national data and information compiled by Andrias et al., 1994.

TABLE 1-49
ESTIMATED EMISSION FACTORS FOR
EUROPEAN NON-ROAD MOBILE SOURCES AND MACHINERY

PART 1: DIESEL ENGINES												
	EMISSIONS											
	NO$_x$		CH$_4$(a)		NMVOC(a)		CO		N$_2$O		CO$_2$	
Diesel Engines												
	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ
Agriculture	50	1.2	0.17	0.004	7.3	0.17	16	0.37	1.3	0.03	3140	73
Forestry	50	1.2	0.17	0.004	6.5	0.15	15	0.35	1.3	0.03	3140	73
Industry	49	1.1	0.17	0.004	7.1	0.16	16	0.37	1.3	0.03	3140	73
Household	48	1.1	0.17	0.004	10	0.23	23	0.53	1.2	0.03	3140	73
Railways	40	0.9	0.18	0.004	4.7	0.11	11	0.25	1.2	0.03	3140	73
Inland waterways	42	1.0	0.18	0.004	4.7	0.11	11	0.25	1.3	0.03	3140	73
PART 2: GASOLINE ENGINES												
	EMISSIONS											
	NO$_x$		CH$_4$(a)		NMVOC(a)		CO		N$_2$O		CO$_2$	
Gasoline 4-stroke												
	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ
Agriculture	7.6	0.17	3.7	0.08	74	1.7	1500	33	0.07	0.002	3200	71
Forestry	-	-	-	-	-	-	-	-	-	-	3200	71
Industry	9.6	0.21	2.2	0.05	43	1.0	1200	27	0.08	0.002	3200	71
Household	8.0	0.18	5.5	0.12	110	2.5	2200	79	0.07	0.002	3200	71
Railways	-	-	-	-	-	-	-	-	-	-	-	-
Inland waterways	9.7	0.22	1.7	0.04	34	0.76	1000	22	0.08	0.002	3200	71
Gasoline 2-stroke												
	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ	g/kg	g/MJ
Agriculture	1.7	0.04	6.2	0.14	620	14	1100	25	0.02	0.0004	3200	71
Forestry	1.6	0.04	7.7	0.17	760	17	1400	31	0.02	0.0004	3200	71
Industry	2.1	0.05	6.0	0.13	600	13	1100	31	0.02	0.0004	3200	71
Household	1.8	0.04	8.1	0.18	810	18	1600	36	0.02	0.0004	3200	71
Railways	-	-	-	-	-	-	-	-	-	-	-	71
Inland waterways	2.7	0.06	5.1	0.11	500	11	890	20	0.02	0.0004	3200	71

(a) Including diurnal, soak and running losses.

1.5.3.5 AIRCRAFT

Background information

While the emission factors for aircraft in the Tier 1 approach are fleet average factors for NO$_x$, CO and NMVOC as derived from global inventories compiled by NASA, ECAC/ANCAT and others, this section presents a more refined Tier 2 method. The methodology includes four sub-activities:

Box 6

OVERVIEW OF THE ACTIVITIES INCLUDED IN THE PRESENT METHODOLOGY	**CORINAIR94 CLASSIFICATION(A)**
Domestic airport traffic (LTO(b) -cycles < 914m (3000 ft) altitude)	SNAP(c) code 080501
International airport traffic (LTO-cycles < 914m (3000 ft) altitude)	SNAP code 080502
Domestic cruise traffic (> 914m (3000 ft) altitude(d))	SNAP code 080503
International cruise traffic (> 914m (3000 ft) altitude(d))	SNAP code 080504

(a) CORINAIR uses a round figure of 1000 metres (for 3000 feet) as the cut-off.

(b) LTO is short for the Landing and Take-Off cycle.

(c) SNAP codes refer to the joint EMEP/CORINAIR Methodology, used in Europe.

(d) Including further climbout from and descent to 914 metres (3000 feet) altitude.

Activities include all civil commercial use of airplanes consisting of scheduled and charter traffic of passengers and freight. This also includes taxiing. Military and private aviation activities are not included because respectively, it is unlikely that detailed information is available and fuel usage is proportionately very small. However, theoretically this method could also be used for the estimation of the emissions of military aircraft. In that case, these emissions should be reported under 1A5 "Other" and not with domestic or international aviation.

Operations of aircraft are divided into two parts:

- *The Landing/Take-Off (LTO) cycle* [23] which includes all activities near the airport that take place under the altitude of 914 metres (3000 feet). This includes engines running idle, taxi-in and out, and climbing and descending under this altitude. In aircraft industry-related literature (e.g., the ICAO), the cut-off altitude is often 3000 feet which corresponds to 914 metres.
- *Cruise* is defined as all activities that take place at altitudes above 914 metres (3000 feet). No upper limit is given. This also includes further climb-out from and descent to an altitude of 914 metres.

Activities

For the purposes of the emissions inventory a distinction is made between domestic and international flights[24].

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[23] Some statistics count either a landing or a take-off as one operation. **However it is *both* one take-off and one landing, that together define one LTO-operation.**

[24] If an aircraft goes from one airport in one country to another in the same country and then leaves to a third airport in another country, the first flight stage is considered a domestic trip while the second is considered an international trip. It is not important whether the airport is a domestic or an international airport. In addition, the type of

- *Domestic aviation* (1 A 3 a ii) includes all civil domestic passenger and freight traffic inside a country. All flight stages between two airports in one country are considered domestic no matter the nationality of the carrier or the subsequent destination of the aircraft.
- *International aviation* (1 A 3 a i) includes all civil air traffic coming to or leaving a country. It is assumed that the number of out-bound flights equals the number of in-bound flights.

- LTOs take the classification (domestic or international) of the flight stage to which they belong. As most flights are regarded as return flights, fuel used during landing and take-off will be regarded as equal to a take-off and landing.

Techniques

In general, there exist two types of engines (Olivier, 1991):

- *reciprocating piston engines*, where energy is extracted from a combustion chamber by means of a piston and crank mechanism which drives the propellers to give the aircraft momentum; and
- *gas turbines*, where compressed air is heated by combustion in a combustion chamber and the major part of the released energy is used for propulsion of the aircraft. Part of the energy contained in the hot air flow is used to drive the turbine which in turn drives the compressor. Turbojet engines use energy only from the expanding exhaust stream for propulsion, whereas turbofan and turboprop engines use energy to drive an extra turbine which drives a fan or propeller respectively, for propulsion.

Emissions

Air traffic as a source of combustion emissions varies with respect to the type of fuel which is being used, the location (altitude) of the exhaust gases, the types and the efficiency of the engines, and the length of the flight. Emissions come from jet kerosene and aviation gasoline which are used as fuel on the aircraft.

This Tier 2 methodology is only applicable for jet fuel used in jet engines. Aviation gasoline is only used in small aircraft (often referred to as "general aviation") and generally represents less than 1 per cent of fuel consumption for aviation. As a result, no attempt has been made to estimate emission factors for private aviation as this represents such a small proportion of global consumption.

Use of energy, and therefore emissions, is dependent on the aircraft operations and the time spent at each stage[25]. A substantial part of the fuel consumption takes place outside

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activity (LTO, cruise, domestic, international) is independent of the nationality of the carrier. This treatment of domestic and international differs from that recommended to states by the International Civil Aviation Organization (ICAO,1994). ICAO defines as domestic all flight stages flown between domestic points by an airline registered in that state and therefore excludes flights between domestic points by foreign airlines.

[25] Note: The reference LTO cycle that was used to estimate the emission factors has a cycle time of 32.9 minutes made up of the four individual Times in Mode (TIM) according to ICAO recommendations. Depending on whether there is more or less congestion at the airport this time may be shorter or longer. In particular, taxi times may differ substantially between large metropolitan airports and small airports. This can be

the LTO-cycle. Studies indicate that in national airspace 60-80 per cent of NO_x and 80-90 per cent of SO_2 and CO_2 is emitted at altitudes above 914 metres (3000 feet). For CO it is about 50 per cent and for VOC it is about 20-40 per cent (Olivier, 1991). Globally, however, 80 to 90 per cent of these emissions are emitted above an altitude of 914 metres (3000 feet) (Olivier, 1995).

Besides the combustion of fuel in the LTO and cruise activities, fuelling and fuel handling in general, maintenance of aircraft engines and fuel jettisoning to avoid accidents are emission sources. In the wintertime, anti-ice and de-ice treatment of wings and aircraft is a source of emissions at airport complexes. Many of the substances used flow off the wings when planes are idling, taxiing, and taking off, and then evaporate. These emissions are, however, not included in the methodology.

Emission factors

For LTO cycles, Table 1-50 gives relevant examples from the ICAO Engine Exhaust Emissions Databank (ICAO, 1995). This provides emission factors for LTO cycles for a large number of engines treated under standard conditions. Another useful source of aircraft emission factors is the FAA Aircraft Emission database, US Office of Environment and Energy (1991), derived from an early draft version of the ICAO database.

For cruise activities, average NO_x emission factors related to fuel consumption have been estimated and are displayed in Table 1-51. The cruise emission factors take into account the number of engines fitted to each specific aircraft.

Where aircraft types used in a country are not displayed in Tables 1-50 or 1-51, data for the nearest equivalent type in either of those tables can be used or alternatively the average emission factors displayed in Table 1-52 can be used.

Please note that when using the emission factors, the assumptions on sulphur content in the fuel should be taken into account. The factors have been calculated assuming a weight percentage of 0.05 per cent[26]. Actual values of sulphur content in jet kerosene vary between 0.0001 and 0.3 per cent.

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calculated for individual airports and individual aircraft as a Tier 3 methodology (see last paragraph of Section 1.3).

[26] For example, if the sulphur content of fuel used is 0.01 per cent, the emission factor for SO_2 should be divided by 5 to show the corresponding factor.

Recommended Methodology

The fundamental basis of the recommended Tier 2 methodology is presented schematically in Figure 1.

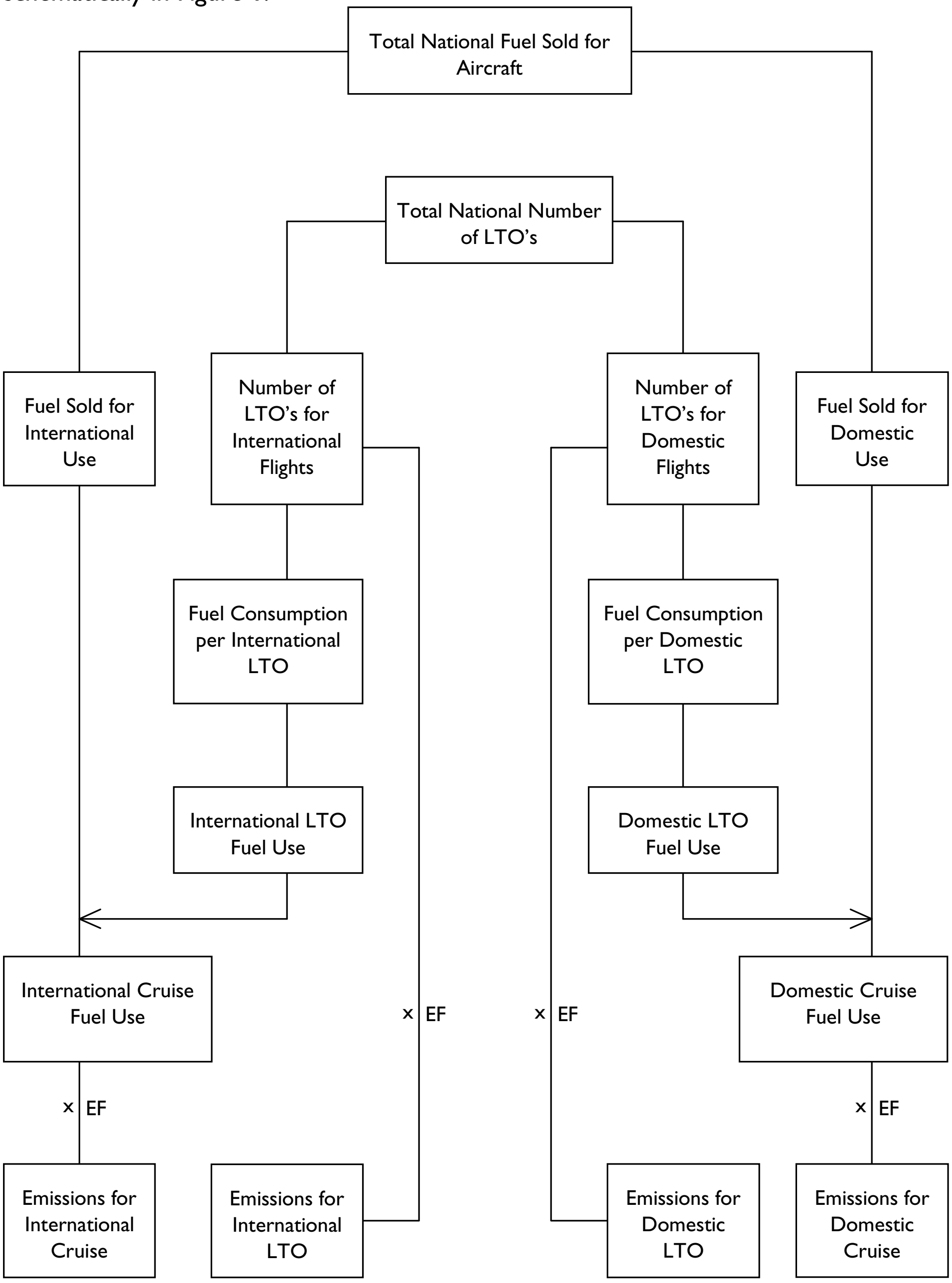

Figure 1: *Estimation of Aircraft Emissions with the Tier 2 Method*

To use the Tier 2 method, the aircraft types used for both domestic and international aviation, as well as the number of LTO's carried out with the various aircraft types, must be known. If such information is available, it is recommended that the emission factors in Table 1-52 be used. If information on LTO's is not available, it is recommended that the Tier 1 method be used.

The emissions calculated using Tier 2 should be reported following the IPCC *Reporting Instructions*:

- **1 A 3 a i International aviation (international bunkers) -** note: as far as possible, these emissions are to be excluded from national totals and reported separately.
- **1 A 3 a ii Domestic aviation**

TABLE 1-50
EXAMPLES OF AIRCRAFT TYPES AND EMISSION FACTORS FOR LTO CYCLES AS WELL AS FUEL CONSUMPTION PER AIRCRAFT TYPE

	Emission factors (kg/LTO)							**Fuel consumption (kg/LTO)**
Aircraft type(a)	**CO_2**	**CH_4 (b)**	**N_2O(c)**	**NO_X**	**CO**	**NMVOC(b)**	**SO_2(d)**	
A300	5470	1.0	0.2	27.21	34.4	9.3	1.7	1730
A310	4900	0.4	0.2	22.7	19.6	3.4	1.5	1550
A320	2560	0.04	0.1	11.0	5.3	0.4	0.8	810
BAC1-11	2150	6.8	0.1	4.9	67.8	61.6	0.7	680
BAe 146	1800	0.16	0.1	4.2	11.2	1.2	0.6	570
B707*	5880	9.8	0.2	10.8	92.4	87.8	1.9	1860
B727	4455	0.3	0.1	12.6	9.1	3.0	1.4	1410
B727*	3980	0.7	0.1	9.2	24.5	6.3	1.3	1260
B737-200	2905	0.2	0.1	8.0	6.2	2.0	0.9	920
B737*	2750	0.5	0.1	6.7	16.0	4.0	0.9	870
B737-400	2625	0.08	0.1	8.2	12.2	0.6	0.8	830
B747-200	10680	3.6	0.3	53.2	91.0	32.0	3.4	3380
B747*	10145	4.8	0.3	49.2	115	43.6	3.2	3210
B747-400	10710	1.2	0.3	56.5	45.0	10.8	3.4	3390
B757	4110	0.1	0.1	21.6	10.6	0.8	1.3	1300
B767	5405	0.4	0.2	26.7	20.3	3.2	1.7	1710
Caravelle*	2655	0.5	0.1	3.2	16.3	4.1	0.8	840
DC8	5890	5.8	0.2	14.8	65.2	52.2	1.9	1860
DC9	2780	0.8	0.1	7.2	7.3	7.4	0.9	880
DC10	7460	2.1	0.2	41.0	59.3	19.2	2.4	2360
F28	2115	5.5	0.1	5.3	54.8	49.3	0.7	670
F100	2340	0.2	0.1	5.7	13.0	1.2	0.7	740
L1011*	8025	7.3	0.3	29.7	112	65.4	2.5	2540
SAAB 340	945	1.4(E)	0.03(E)	0.3(E)	22.1(E)	12.7(E)	0.3(E)	300(E)
Tupolev 154	6920	8.3	0.2	14.0	116.81	75.9	2.2	2190
Concorde	20290	10.7	0.6	35.2	385	96	6.4	6420
GAjet	2150	0.1	0.1	5.6	8.5	1.2	0.7	680

Source: ICAO (1995).

(a) Except where indicated, values are for world fleet weighted LTO fuel and emissions performance. The average age of aircraft in service is 10-20 years old. Values for aircraft types marked with a * are specific to older types with poorer emissions performance. Aircraft can be equipped with different engines.

(b) Assuming 10% of total VOC emissions in LTO cycles are methane emission (Olivier, 1991).

(c) Estimates based on Tier 1 default values.

(d) The sulphur content of the fuel is assumed to be 0.05%.

(E) indicates that the figure is based on estimations.

TABLE 1-51
EMISSION FACTORS OF NO_x FOR VARIOUS AIRCRAFT AT CRUISE LEVELS

Aircraft	**Emission Factor for NO_x (g/kg)**		
	ANCAT	NASA	Average
A300	NAV	14.4	NAV
A310	11.5	13.6	12.5
A320	11.7	12.1	11.9
BAC 1-11	7.1	9.3	8.2
BAe 146	6.7	7.7	7.2
B727	8.0	8.7	8.4
B737-200	6.8	7.7	7.3
B737-400	8.3	9.6	9.0
B747-200	16.7	14.2	15.5
B747-400	15.8	13.9	14.9
B757	13.1	12.6	12.9
B767	10.0	12.2	11.1
DC8	12.4	5.6	9.0
DC9	7.6	8.1	7.9
DC10	17.5	13.2	15.4
F28	8.5	8.5	8.5
F100	8.4	6.4	7.4
MD80	8.3	10.6	9.5
TU154	NAV	8.7	NAV
Concorde	19.9	NAV	NAV
GAjet	6.7	NAV	NAV

Source: Gardner et al. (1997) and Baughcum et al. (1996).

TABLE 1-52
DEFAULT EMISSION FACTORS AND FUEL CONSUMPTION FOR AIRCRAFT
(LTO EMISSION FACTORS ARE GIVEN ON A PER AIRCRAFT BASIS)

Domestic

	Fuel Consumption	Emission Factors						
		CO_2	CH_4 (a)	N_2O(b)	NO_x	CO	NMVOC(a)	SO_2(c)
LTO average fleet (kg/LTO)	850	2680	0.3	0.1	10.2	8.1	2.6	0.8
LTO old fleet (kg/LTO)	1000	3150	0.4	0.1	9.0	17	3.7	1.0
Cruise (kg/t of fuel)		3150	0	0.1	11	7	0.7	1.0

International

	Fuel Consumption	Emission Factors						
		CO_2	CH_4 (a)	N_2O(b)	NO_x	CO	NMVOC(a)	SO_2(c)
LTO average fleet (kg/LTO)	2500	7900	1.5	0.2	41	50	15	2.5
LTO old fleet (kg/LTO)	2400	7560	7	0.2	23.6	101	66	2.4
Cruise (kg/t of fuel)		3150	0	0.1	17	5	2.7	1.0

Note: The emission factors were calculated as weighted averages for a number of typical aircraft. For domestic traffic, the average fleet is represented by Airbus A320, Boeing 727, Boeing 737--400 and Mc Donald Douglas DC9 and MD80 aircraft. The old fleet is represented by Boeing B737 and McDonald Douglas DC9. For international traffic, the average fleet is represented by Airbus A300, Boeing B767, B747 and McDonald Douglas DC10, whilst the old fleet is represented by the Boeing B707, Boeing B747 and McDonald Douglas DC8. The data for LTO are shown in Table 1-50. Cruise data were taken from Wuebbles et al. (1993). The emission factors for cruise are considered as the best available default factors to date.

(a) For CH_4 and NMVOC it is assumed that the emission factors for LTO cycles be 10% and 90% of total VOC, respectively (Olivier, 1991). Studies indicate that during cruise no methane is emitted (Wiesen et al., 1994).

(b) Estimates based on Tier 1 default values.

(c) Sulphur content of the fuel is assumed to be 0.05% for both LTO and cruise activities.

1.6 Fugitive Emissions: Overview

During all of the stages from the extraction of fossil fuels through to their final use the escape or release of gaseous fuels or volatile components or absorbed gases may occur. The methodologies for the estimation of these emissions (mostly methane) are presented in the sections which follow and are limited to activities conducted within the confines of the energy industries. Emissions from the use of road vehicle fuels are covered under fuel combustion. Emissions from solvents use are estimated within Chapter 3 but emissions arising from the manufacture of solvents within refineries are subsumed within the estimation of emissions from refineries in Section 1.8 Fugitive Emissions from Oil and Natural Gas Activities.

1.7 Fugitive Emissions from Coal Mining and Handling

1.7.1 Overview

This section covers fugitive emissions of greenhouse gases (GHGs) from production, processing, handling and utilisation of coal. Intentional or unintentional releases of gases such as methane in mining are included here, as are emissions from inadvertent combustion of coal in coal mine fires. By far the most important component of this subcategory is methane (CH_4) emissions from the mining and handling of coal. The bulk of this section, therefore, deals with these emissions. Two other fugitive emission sources are discussed briefly at the end of the section. These are burning coal mines and waste piles, which emit CO_2, and SO_2 scrubbing, which is also a source of CO_2. There are very likely other fugitive emissions associated with the coal fuel cycle. If important sources are identified, these will be considered for inclusion in future editions of the *Guidelines*.

1.7.2 CH_4 from Coal Mining and Handling

1.7.2.1 GENERAL METHODOLOGY

The process of coal formation, commonly called coalification, inherently generates methane and other by-products. The formation of coal is a complex physio-chemical process occurring over millions of years. The degree of coalification (defined by the rank of the coal) determines the quantity of methane generated and, once generated, the amount of methane stored in the coal is controlled by the pressure and temperature of the coal seam and by other, less well-defined characteristics of the coal. The methane will remain stored in the coal until the pressure on the coal is reduced, which can occur through the erosion of overlying strata or the process of coal mining. Once the methane has been released, it flows through the coal toward a region of lower pressure (such as a coal mine) and into the atmosphere (Boyer, 1990). Methane emissions from coal mining in 1990 contributed an estimated 23 to 39 Tg of global methane emissions (US EPA, 1993*a*; CIAB, 1992; Airuni and Zeidenvarg, 1992).

The amount of CH_4 generated during coal mining is primarily a function of coal rank and depth, gas content, and mining methods, as well as other factors such as moisture. Coal rank represents the differences in the stages of coal formation and depends on the pressure and temperature history of the coal seam; high coal ranks, such as bituminous coal, contain more CH_4 than low coal ranks, such as lignite. Depth is important because it affects the pressure and temperature of the coal seam, which in turn determines how much CH_4 is generated during coal formation. If two coal seams have the same rank, the deeper seam will hold larger amounts of CH_4 because the pressure is greater at lower depths, all other things being equal. As a result, the methane emission factors for surface-mined coal are assumed to be lower than for underground mining.

In most underground mines, methane is removed by ventilating large quantities of air through the mine and exhausting this air (typically containing a concentration of 1 per cent methane or less) into the atmosphere. In some mines, however, more advanced methane recovery systems may be used to supplement the ventilation systems and ensure mine safety. These recovery systems typically produce a higher concentration product, ranging from 35 to 95 per cent methane. In some countries, some of this recovered methane is used as an energy source, while other countries vent it to the atmosphere. Recent technological innovations are increasing the amount of medium- or high-quality methane that can be recovered during coal mining and the options available to use it. Thus, methane emissions could be reduced from this source in the future.

In surface mines, exposed coal faces and surfaces, as well as areas of coal rubble created by blasting operations, are believed to be the major sources of methane. As in underground mines, however, emissions may come from the overburden (in limited cases where these strata contain gas), which is broken up during the mining process, and underlying strata, which may be fractured and destressed due to removal of the overburden. Because surface-mined coals are generally lower rank and less deeply buried, they do not tend to contain as much methane as underground-mined coals. Thus, emissions per tonne of coal mined are generally much lower for surface mines. Research is underway in the United States and elsewhere to increase the understanding of CH_4 emissions from surface mines (Kirchgessner et al., 1993; USGS, 1993).

A portion of the CH_4 emitted from coal mining comes from post-mining activities such as coal processing, transportation, and use. Coal processing involves the breaking, crushing, and thermal drying of coal, making it acceptable for sale. Methane is released mainly because the increased surface area allows more CH_4 to desorb from the coal. Transportation of the coal contributes to CH_4 emissions, because CH_4 desorbs directly from the coal to the atmosphere while in transit (e.g., in railroad cars). Use of metallurgical coal also emits methane. For instance, in metallurgical coke production, coal is crushed to a particle size of less than 5 mm, vastly increasing the surface area of the coal and allowing more CH_4 to desorb. During the coking process, methane, carbon monoxide, and other volatile gases are released. In modern coke ovens, this gas is typically collected and used as a fuel source, but in older coke ovens, particularly those used in less developed regions, coke gas is vented to the atmosphere (Boyer et al., 1990; coke production is covered in Chapter 3).

Some methane is also released from coal waste piles and abandoned mines. Coal waste piles are comprised of rock and small amounts of coal that are produced during mining along with marketable coal. There are currently no emission measurements for this source. Emissions are believed to be low, however, because much of the methane would likely be emitted in the mine and the waste rock would have a low gas content compared to the coal being mined. Emissions from abandoned mines may come from unsealed shafts and from vents installed to prevent the build-up of methane in mines. There is very little information on the number of abandoned mines, and no data are currently available on emissions from these mines. Most available evidence indicates that methane flow rates decay rapidly once deep mine coal production ceases (Williams and Mitchell, 1992;

Creedy, 1991). In some abandoned mines, however, methane can continue to be released from the surrounding strata for many years. In Belgium, France, and Germany, for example, several abandoned mines are currently being used as a source of methane which is being added to the gas system (Smith and Sloss, 1992; KfA, 1993). Due to the absence of measurement data for both coal waste piles and abandoned mines, no emissions estimates have been developed for these sources.

Review of Previous Methane Emission Estimation Studies

Over the years, a variety of methane emissions estimates have been developed for coal mining, as shown in Table 1-53. As the table shows, the variation in estimates has been quite large, although more recent studies are showing more similar results. Many of the emission studies conducted to date have confronted difficulties in developing estimation methodologies and these have resulted in the widely varying estimates and large uncertainties. These difficulties include:

- **Absence of data on which to base estimates:** Many studies were developed without access to detailed data on methane emissions associated with various components of the coal cycle. For certain sources such as surface mines and post-mining activities, moreover, reliable emissions measurements are still lacking.
- **Use of national data to develop global estimates:** Some studies have relied on data from a single country to estimate global methane emissions from coal mining. This approach can introduce large errors into the estimates, due to the difficulty of generalising from one country's coal characteristics and mining conditions to those of other countries. Mining experience has shown that there are frequently significant differences in methane emission factors within countries, coal basins, and even coal mines for a variety of geological and other reasons.
- **Failure to include all possible emission sources:** Some studies prepared to date have only estimated underground coal mining emissions from ventilation systems and have not included emissions from degasification systems, or post-mining emissions. In addition, many estimates have assumed emissions from surface mines to be negligible and have not included this source. At this point, moreover, there are still potential emission sources, such as abandoned mines, for which emissions cannot be estimated due to the absence of necessary data.
- **Over-reliance on statistical estimation methodologies:** Several studies have estimated global emission factors using statistical models that relate methane emissions to various coal properties. For the most part, these models have proven unreliable when estimates are compared to those developed using more detailed country-specific information. The principal problem with using statistical methodologies is the number of variables that can affect methane emissions. Mining experience has shown that a complete understanding of methane emissions requires detailed examination of coal and geological characteristics and that methane emissions can be highly variable within mines, basins and countries. Collecting comprehensive data and developing statistical models that can reliably predict emissions on a global basis is thus very difficult.

In general, the results of the more recent country-specific and global methane emission studies are likely to be more reliable than previous efforts. For several of the major coal producing countries, for example, detailed data on methane emissions from underground mine ventilation and degasification systems are reported to central institutes and are publicly available. More recent studies have been able to use these data in preparing and validating their estimates of methane emissions from underground mines. Data are still lacking on emissions from surface mines and post-mining activities, thus even the emission estimates from more recent studies should be considered uncertain.

Suggested Emission Estimation Methods

Methane emission estimates should be developed for the three principal sources of methane emissions: underground mines, surface mines, and post-mining activities. To assist in developing these estimates, the IPCC recommends use of a "tiered" approach for estimating emissions. For each source, two or more approaches (or "tiers") are presented for estimating emissions, with the first tier requiring basic and readily available data and higher tiers requiring additional data. Selection among the tiers will depend upon the quality of the data available in the country.

TABLE 1-53
SUMMARY OF EMISSIONS ESTIMATES FROM SELECTED STUDIES

Study Author	Emissions Estimate (Tg)	Year of Estimate	Methodological Issues
Koyama (1963)	20	1960	Hard coal only; no emissions estimates for surface mining or post-mining activities. 1960 coal production data.
Hitchcock & Wechsler (1972)	8 - 28	1967	Post-mining not included; source of emission factors, particularly low end, unspecified. 1967 coal production data.
Seiler (1984)	30	1975	Based on Koyama, with 1975 coal production data.
Crutzen (1987)	34	NA	Source of emission factors unclear. Hard coal only; no emissions estimates for surface mining or post-mining activities.
Okken & Kram (1989)	15 - 45	NA	Source of emission factors unclear. Hard coal only; no emissions estimates for surface mines or post-mining activities.
Zimmermeyer (1989)	24	NA	Only underground mining considered; no emissions estimates for surface mines or post-mining activities.
Seltzer & Zittel (1990)	23	NA	Adjusted Zimmermeyer by: (1) including surface mines; (2) assuming that 15 per cent of underground mining emissions (3.6 Tg) not emitted to the atmosphere due to methane utilisation.
Barns & Edmonds (1990)	25	1986	Assumed mathematical relationship between coal rank and depth and that in-situ methane content was equal to the mining emission factor.
Boyer et al. (1990)	33 - 64	1988	Statistical approach related methane emissions to in situ methane content. Correlation based on US data only. Large uncertainty in application of results for global estimates.
Hargraves (1990)	29	NA	Method based on current methane production rates due to continued coalification.
Airuni and Zeidenvarg (1992)	28	1990	Methodology unspecified.
CIAB (1992)	24	1990	Country specific data used where available for underground mines. Surface and post-mining emissions developed using low emission assumptions. No uncertainty analysis.
US EPA (1993c)	23 - 39	1990	Country specific data used where available for underground mines. Global average emission factors for rest of countries for underground mines and for all surface mining and post-mining emissions.

1.7.2.2 UNDERGROUND MINING

Methane emissions from underground mines should include estimated emissions from ventilation systems and from degasification systems, if any of a country's mines use degasification systems to supplement ventilation. In the approaches outlined below, methods of estimating emissions from both of these sources are presented.

Three possible approaches are suggested by the IPCC, with the choice among them depending upon the availability of data and the degree to which coal mining is considered a significant source of emissions by particular countries. Two of the methods, the "Global" and the "Country or Basin Average" methods are essentially identical in form; only the degree of detail and specificity in choice of emission factor(s) differs. The third, "Mine Specific" method relies on the assembly of methane emission measurements taken at coal mines. In the first two methods, Tiers 1 and 2, ranges of emission factors are given in terms of m^3 CH_4/tonne of coal produced. The structure of the estimation is simply

$$\text{Emissions (Gg } CH_4) = \text{Emission Factor } (m^3\ CH_4 / \text{tonne})$$
$$\times \text{ tonnes of coal produced}$$
$$\times \text{ Conversion Factor } (Gg/10^6 m^3)$$

A single value from the range of emission factors should be used to prepare the emissions estimate. The relevant coal production figure will be that for the country or the coal basin depending upon the method selected. Factors are given in the table below which permit the conversion of the volume emitted to mass.

For those countries with comparatively large methane emissions from coal mining, the use of more detailed estimation methodologies may be warranted. In countries producing smaller quantities of coal, however, the most simple approach may provide a reasonably accurate first approximation of CH_4 emissions from underground mines.

Tier 1: Global Average Method

The simplest method for estimating methane emissions is to multiply underground coal production by a factor drawn from a range of factors representing global average emissions from underground mining, including both ventilation and degasification system emissions. This method may be selected in cases where total coal production from underground mines is available but more detailed data are not. The Tier 1 Equation is shown below.

EQUATION 1
TIER 1: GLOBAL AVERAGE METHOD – UNDERGROUND MINES

CH_4 Emissions (Gg) = CH_4 Emission Factor (m^3 CH_4/tonne of coal mined)
x Underground Coal Production (Mt)
x Conversion Factor (Gg/10^6 m^3)

Where:

- the Emission Factor should be chosen from the following range

Low CH_4 Emission Factor = 10 m^3/tonne
High CH_4 Emission Factor = 25 m^3/tonne

- Conversion Factor converts the volume of CH_4 to a weight measure and is the density of methane at 20°C and 1 atmosphere, namely:

0.67 Gg / 10^6 m^3

The IPCC recommends revised global average emission factors of 10 to 25 m^3/tonne of coal mined (not including emissions from post-mining activities which should be calculated separately). This range reflects the findings of various country studies, as shown in Table 1-54. As more detailed emissions data are published by various countries, the factors can be further revised, if necessary.

TABLE 1-54
ESTIMATED UNDERGROUND EMISSION FACTORS FOR SELECTED COUNTRIES

Country	Emission Factors (m^3/tonne)	Source
Former Soviet Union	17.8 - 22.2	US EPA, 1993c
United States	11.0 - 15.3	US EPA, 1993a
Germany (East & West)	22.4	Zimmermeyer, 1989
United Kingdom	15.3	BCTSRE, 1992
Poland	6.8 - 12.0	Pilcher et al., 1991
Czechoslovakia	23.9	Bibler et al., 1992
Australia	15.6	Lama, 1992

Tier 2: Country or Basin Specific Method

The suggested Tier 2 approach – called the "Country or Basin Specific Method" – can be used to refine the range of emission factors used for underground mining by incorporating some additional country or basin-specific information. Basically, this method enables a country with limited available data to determine a more appropriate and probably narrower range of emission factors for their underground mines. For many countries, it is expected that this range will fall within the global average emission factor range of 10 to 25 m^3/tonne. The range of possible emission factors is not constrained under the Tier 2 approach, however, and some countries may find that their underground mining emission factors lie outside the global average emission factor range. The calculation procedure is identical to that described in Tier 1.

To implement the Tier 2 approach, national experts must examine measurement data from at least a limited number of underground coal mines in their country or region. Using this data, either statistical analysis or expert judgement should be applied to develop a reasonable range of emission factors for the country or region.[27] Making this estimate will require judgement on the part of the estimator as to the adequacy of the available data and its uncertainty. If sufficient expertise is not available to make such judgements, it is recommended that the Tier 1 approach (the Global Average Method) be used instead.

In some cases, measurement data on emissions from mines may be unavailable but a country will still seek to develop a narrower estimate based on other types of available data. In such cases, a country may seek to develop a simple emissions model based on physical principles or make judgements based on an evaluation of available data. Among the key types of data that should be considered in such a model or evaluation are:

- the gas content of the coal, which contributes to the total amount of methane available for emission during mining;
- the amount of coal within the strata above and below the mined coal seam, which also contributes to the total amount of methane available for emission during mining; and,
- the method of mining, which determines the amount of ground that is disturbed by mining the coal and the extent to which the mining process liberates methane contained in the mined coal seam and in the strata surrounding it.

It should be noted that while the Tier 2 approach can provide some additional information about methane emissions in a particular country or coal basin, the estimates will still be quite uncertain because of the absence of comprehensive and reliable emissions data. This approach should thus be used only in cases where there is a strong need to make an estimate drawn from a narrower range than the Tier 1 (Global Average Method) and not enough data are available to prepare an estimate using the Tier 3 (Mine Specific Method) described in the next section. It should further be noted that an estimate from the narrower range will not necessarily be more accurate than that developed under Tier 1.

In all cases where the Tier 2 approach is used, a detailed discussion of the types of data available and the manner used to determine the refined range of emission factors should be presented, so as to allow for the independent verification of the estimate and ensure comparability with estimates being prepared by other countries.

Tier 3: Mine Specific Method

Because methane is a serious safety hazard in underground mines, many countries have collected data on methane emissions from mine ventilation systems, and some also collect data on methane emissions from mine degasification systems. Where such data are available, the more detailed Tier 3 approach – called the "Mine Specific Method" – should provide the most accurate estimate of methane emissions from underground mines. Since these data have been collected for safety, not environmental reasons, however, it is necessary to ensure that they account for total emissions from coal mines. The key issues that should be considered when using mine safety data, as well as the recommendations of the IPCC for resolving them, are shown in Table 1-55.

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[27] If measurement data is available for most or all or a country's underground coal mines, the Tier 3 approach – called the "Mine Specific Method" – should be used to estimate emissions.

Treatment of Methane Utilisation

All of the methods described above, with the possible exception of the Mine Specific Method, assume that all of the methane liberated by mining will be emitted to the atmosphere. In many countries, however, some of the methane recovered by mine degasification systems is used as fuel instead of being emitted. Wherever possible, the emission estimates should be corrected for the amount of methane that is used as fuel, by subtracting this amount from total estimated emissions.

In several countries, data on the disposition of methane recovered by degasification systems (i.e., whether it is used or emitted to the atmosphere) can be obtained from the coal industry or energy ministries. Poland, for example, reports that its mine degasification systems recovered 286 million m^3 of methane in 1989, of which 201 million m^3 was used and the remaining 85 million m^3 was emitted to the atmosphere (Polish Central Mining Institute, 1990). Regardless of the method used to develop the emissions estimates, the Polish emission estimate should be adjusted to reflect the use of methane by subtracting 201 million m^3 from total emissions.

In some countries figures for the quantity of gas recovered from mines may not be available from the mining industry. Nevertheless estimates may be constructed if the users of the gas are known and they are able to give data for their consumption. Consumption may also be inferred if it is known that the gas is used to fuel a particular plant of a known capacity (e.g. if the methane is used to fuel a gas turbine of a known size).

TABLE 1-55
KEY ISSUES FOR CONSIDERATION WHEN USING TIER 3 – MINE SPECIFIC METHOD

ISSUE	DESCRIPTION	RECOMMENDATION
Where and how are ventilation system emissions monitored?	When used to develop overall methane emission estimates, the optimal location for ventilation air monitors is at the point where ventilation air exhausts to the atmosphere.	If ventilation emissions are not monitored at the point of exhaust, emission data should be corrected based on estimated additional methane emissions between the point of measurement and the point of exhaust to the atmosphere.
Are ventilation system emissions monitored and/or reported for all mines?	In some countries, emissions are only reported for "gassy mines".	Estimates should be developed for non-gassy mines as well. Estimates can be prepared using information about the definitions of gassy and non-gassy mines and data on the total number of mines and the coal production at these mines.
Are methane emissions from degasification systems reported?	Some countries collect and report methane emissions from ventilation and degasification systems, while others only report ventilation system emissions. Both emission sources must be included in emissions estimates.	If degasification system emissions are not included, those mines with degasification systems should be identified and estimates prepared on emissions from their degasification systems. Emissions estimates can be based on knowledge about the efficiency of the degasification system in use at the mine or the average efficiency of degasification in the country.

The sources of any adjustments to emissions that are made to reflect the utilisation of methane should be clearly specified, to permit the independent verification of the emissions estimates. In the absence of data, estimated adjustments for the use of methane should not be undertaken.

1.7.2.3 SURFACE MINING

Two possible approaches for estimating methane emissions from surface mining are suggested by the IPCC. For the most part, these approaches resemble those developed for underground mining, but the results will be much more uncertain due to the absence of emissions data. Methane emissions from surface mining are assumed to arise from two sources: the coal mined and the surrounding strata exposed during the mining process. In the Tier 1 approach, (Global Average Method) the separation of these sources is ignored and a single emission factor is used. In the Tier 2 approach (Country or Basin Specific Method), emission factors for each source are required. If emissions measurements are developed in the future, it should be possible to refine these methodologies.

Tier 1: Global Average Method

As for underground mining, the simplest Tier 1 approach for surface mines – called the "Global Average Method" – is to multiply surface coal production by an emission factor selected from a global range, within which most emission factors are believed to lie.

EQUATION 2

TIER 1: GLOBAL AVERAGE METHOD – SURFACE MINES

$$\text{CH}_4 \text{ Emissions (Gg)} = \text{CH}_4 \text{ Emission Factor (m}^3 \text{ CH}_4\text{/tonne of coal mined)} \times \text{Surface Coal Production (Mt)} \times \text{Conversion Factor (Gg/10}^6 \text{ m}^3)$$

Where:

- the Emission Factor should be chosen from the following range:

  Low CH_4 Emission Factor = 0.3 m^3/tonne

  High CH_4 Emission Factor = 2.0 m^3/tonne

- Conversion Factor converts the volume of CH_4 to a weight measure, and is the density of methane at 20°C and 1 atmosphere, namely:

  0.67 Gg/ 10^6 m^3

In the original IPCC methodology, an average emission factor of 2.5 m^3/tonne was recommended (OECD, 1991), based on the results of Boyer et al. (1990) and including emissions from post-mining operations. Based on more recent analyses and additional studies, a revised emission factor range of 0.3 to 2.0 m^3/tonne is recommended by the IPCC, not including post-mining emissions (US EPA, 1993c; CIAB, 1992; BCTSRE, 1992; CMRC, 1990; Kirchgessner et al., 1993).

Given the lack of information and measurements on methane emissions from surface mines, this range must be considered extremely uncertain, and it should be refined in the future as more data become available.

Tier 2: Country or Basin Specific Method

A second tier estimation of methane emissions – called the "Country or Basin Specific Method" – can be used if additional information is available on *in-situ* methane content and other characteristics of a country's surface-mined coals. This approach enables a country to develop emission factors that better reflect specific conditions in their countries.

Depending on the degree of detail desired, emissions can be estimated for specific coal basins or countries, using the equation below.

EQUATION 3

TIER 2: COUNTRY OR BASIN SPECIFIC METHOD – SURFACE MINES

CH_4 Emissions (Gg) = [*In-Situ* Gas Content (m^3 CH_4/tonne)

x Surface Coal Production (Mt)

x Conversion Factor (Gg/10^6 m^3)]

\+ [Assumed Emission Factor for Surrounding Strata (m^3 CH_4/tonne)

x Surface Coal Production (Mt)

x Conversion Factor (Gg/10^6 m^3)]

Where:

- *In-Situ* Gas Content and Assumed Emission Factor for Surrounding Strata are described in the text.
- Conversion Factor converts the volume of CH_4 to a weight measure and is the density of methane at 20°C and 1 atmosphere, namely:

$$0.67 \text{ Gg} / 10^6 \text{ m}^3$$

In Equation 3, *In-Situ* Gas Content represents the methane actually contained in the coal being mined, as determined by measuring the gas content of coal samples. Average values for a coal mine, coal basin or country could be developed, depending on the level of detail in the estimate. For surface mines, unlike underground mines, it is frequently assumed that all of the methane contained in the coal is released during mining and that post-mining emissions from surface-mined coals are effectively zero (BTSCRE, 1992; CIAB, 1992; CMRC, 1990). Some countries may choose to modify this assumption based on their specific conditions. Care should be taken, however, to ensure that any emissions assumed to occur during post-mining activities are subsequently estimated.

Assumed Emission Factor for Surrounding Strata represents the possibility that more methane will be emitted during surface mining than is contained in the coal itself because of emissions from the strata below (or in limited cases, above) the coal seam. Some countries have assumed that there are no emissions from surrounding strata associated with surface-mined coals (BTSCRE, 1992; CMRC, 1990). However, if available information indicates that there are gas-bearing strata surrounding the mined coal seam and that these strata are emitting their gas in conjunction with the mining, countries should include these emissions in their estimates.

Emission factors for the surrounding strata can be developed using one of two approaches. Ideally, the assumed emission factor should be based on an evaluation of the gas content of the surrounding strata and verified by measurements. If such data are unavailable, an alternative method of developing an emission factor is to assume that some multiple of the gas content of the mined coal is emitted by the surrounding strata. It should be noted, however, that the alternative approach is highly speculative given the lack of data upon which to base such an assumption.

1.7.2.4 POST-MINING

Like surface mining emissions, there are currently few measurements of methane emissions from post-mining activities. In fact, many past studies have overlooked this emission source, while others have developed only rudimentary estimation methodologies. Two possible approaches for estimating emissions from post-mining activities are recommended by the IPCC.

Tier 1: Global Average Method

For the most simple estimates, a global average emission factor can be multiplied by coal production for underground and surface mining, as shown in the equation below. It is important to distinguish between underground- and surface-mined coals because the gas contents are likely to be very different and hence emissions could vary significantly.

EQUATION 4

TIER 1: GLOBAL AVERAGE METHOD – POST-MINING ACTIVITIES

Underground CH_4 Emissions (Gg) = CH_4 Emission Factor (m^3 CH_4/tonne of coal mined)
x Underground Coal Production (Mt)
x Conversion Factor (Gg/10^6 m^3)

Surface CH_4 Emissions (Gg) = CH_4 Emission Factor (m^3 CH_4/tonne of coal mined)
x Surface Coal Production (Mt)
x Conversion Factor (Gg/10^6 m^3)

Where:

- Underground CH_4 Emission Factors are in the range of:

  0.9 to 4.0 m^3/tonne

- Surface CH_4 Emission Factors are in the range of:

  0 to 0.2 m^3/tonne

- Conversion Factor converts the volume of CH_4 to a weight measure and is the density of methane at 20°C and 1 atmosphere, namely:

  0.67 Gg/10^6 m^3

Underground-Mined Coals: The IPCC recommends emission factors of 0.9 to 4.0 m^3/tonne for underground-mined coal, based on recent studies (CIAB, 1992; BCTSRE, 1992; US EPA, 1993c).

Surface-Mined Coals: Emission factors of 0 to 0.2 m^3/tonne are recommended by the IPCC for post-mining activities involving surface-mined coal (CIAB, 1992; CMRC, 1990; US EPA, 1993c).

Tier 2: Country or Basin Specific Method

Emissions estimates can be refined if additional data are available on coal characteristics. This method may be preferable if higher tier methods have been used to estimate emissions from underground and surface mines. The equation below summarises the approach for preparing refined emission estimates.

EQUATION 5
TIER 2: COUNTRY OR BASIN SPECIFIC METHOD – POST-MINING ACTIVITIES

a) Underground CH_4 Emissions (Gg) = *In-Situ* Gas Content (m^3 CH_4/tonne)
x Underground Coal Production (Mt)
x Fraction of Gas Released During Post-Mining Activities (%)
x Conversion Factor (Gg/10^6 m^3)

When Necessary:
b) Surface CH_4 Emissions (Gg) = *In-Situ* Gas Content (m^3 CH_4/tonne)
x Surface Coal Production (Mt)
x Fraction of Gas Released During Post-Mining Activities (%)
x Conversion Factor (Gg/10^6 m^3)

Where:

- *In-Situ* Gas Content and Fraction of Gas Released During Mining are described in the text
- Conversion Factor converts the volume of CH_4 to a weight measure and is the density of methane at 20°C and 1 atmosphere, namely: 0.67 Gg/10^6 m^3

In-Situ Gas Content represents the methane actually contained in the coal being mined, as determined by measuring gas contents in coal samples. Average values for a coal mine, coal basin or country could be developed, depending on the level of detail in the estimate.

Fraction of Gas Released During Post-Mining Activities represents the percentage of the in-situ gas content that is assumed to be emitted during post-mining activities. There are three key issues related to the estimation of this fraction:

- For Surface-Mined Coal: In most cases, if the Tier 2 approach is used to estimate methane emissions from surface mines, post-mining emissions from surface-mined coals are assumed to be zero. In these cases, the use of Equation 5(b) is unnecessary and countries should be careful to avoid double counting. **However**, if a country has not assumed that all of the methane contained in surface-mined coal is released during mining, Equation 5(b) should be used to estimate post-mining emissions and the value selected for "Fraction of Gas Released During Post-Mining Activities" should be consistent with the emission factor selected to estimate emissions during surface mining.
- For Underground-Mined Coal: The assumed fractions for underground mining will be based on information about coal permeability, desorption rates, mining methods and other factors. Recent studies have assumed that 25 to 40 per cent of the *in-situ* CH_4 content of underground mined coal is emitted during post-mining activities (US EPA, 1993a; BCTSRE, 1992).
- Fraction of Methane Not Emitted: It is currently assumed that all of the CH_4 contained in mined coal will be emitted to the atmosphere, although it is possible that a fraction could remain in the coal until the point of combustion and be burned instead of emitted. At this time, estimates of the extent to which this may be the

case have not been developed. If countries have such information, however, they could further incorporate this factor into Equation 5.

Total Emissions from Coal Mining Activities

Total methane released as a result of coal mining activities will be the summation of emissions from underground mining (ventilation and degasification systems), surface mining, and post-mining activities. The IPCC recommends that emissions be estimated for each of these categories, in tonnes of CH_4, then aggregated to determine total national methane releases. To the extent that methane that would otherwise have been released to the atmosphere is recovered and used as fuel, the recovered quantity and its use should be reported and the quantity subtracted from the emission total.

Availability and Quality of Activity Data

Data are readily available to develop general emissions estimates using the Tier 1 approach – the Global Average Methods – for underground, surface mining as well as post-mining activities. For these estimates, the only data required are country statistics on underground and surface coal production, which are available from domestic sources, such as energy ministries, or from the OECD/IEA, which publishes Coal Information (OECD/IEA, 1996).

The IPCC recommends that countries involve their coal mining personnel in the development of emissions estimates as much as possible, because of the improved accuracy of emissions estimates prepared with more detailed coal and mining data. The availability and quality of data collected by mining personnel for mine safety purposes should be assessed on a case-by-case basis, however, to ensure that it can be used appropriately for preparing emissions estimates.

The IPCC further recommends that future efforts attempt to better characterise the factors affecting methane emissions from coal mining for those countries and emission sources with limited data, so as to develop more refined emission factors. Specific activities should include:

- Obtaining more data on coal and geological characteristics in selected coal-producing countries;
- Monitoring emissions from surface mines and post-mining activities; and,
- Monitoring emissions from closed or inactive mining operations, and some other potential methane sources, such as mine water.

1.7.3 CO_2 Emissions From Coal Mining and Handling

1.7.3.1 BURNING COAL DEPOSITS AND WASTE PILES

Marland and Rotty (1984) estimated that burning of coal in coal deposits is less than 0.3 per cent of total coal produced and that burning of all coal in waste banks in the United States over a ten year period would represent less than 1 per cent of US coal consumption. Subsequently, they chose to ignore these emissions.

If these sources are estimated, the amount of coal burned in waste piles and coal deposits must be specified along with an emission factor that represents the percentage of coal that is carbon times the percentage of carbon oxidised. We suggest an arbitrary value of 50 per cent of the carbon present in the coal to represent this emission factor; this value would be highly variable from one country to another and one site to another. This assumption of 50 per cent for an emission factor should be evaluated to determine its validity. The formula for calculating these emissions would be:

EQUATION 6

Emissions from Coal Burning (Gg C) = Quantity of Coal Burned (10^3 t)
x Emission Factor

Where:

- The Emission Factor is: Percentage of Carbon in Coal
x Percentage of Carbon Oxidised;
(and the default value is 50%)

Note that other GHGs such as N_2O, CO, NO_x, etc. are also emitted from combustion of coal wastes.

1.7.3.2 SO_2 SCRUBBING

When SO_2 scrubbing (or flue gas desulphurisation) technology is used in conjunction with combustion of coal, the process, which removes sulphur dioxide from the flue gas, also releases CO_2 from the chemical reactions during the process. This can be considered a fugitive emission resulting from coal use. Typically, calcium carbonate reacts with sulphur oxides in flue gas to produce calcium sulphate and carbon dioxide. Marland and Rotty (1984) suggest that CO_2 emissions from SO_2 scrubbing are small enough to be ignored in global calculations. However, for completeness, some national experts may wish to include this subcategory.

To estimate carbon emissions from SO_2 scrubbing, the approach is derived from Grubb (1989) with slight modifications. In Grubb's approach, carbon emissions would equal the total amount of coal combusted in plants equipped with scrubbers times the fraction of sulphur by weight in the coal, adjusted for the differences in molecular weight between carbon and sulphur (12/32). Since this procedure assumes that all of the sulphur is removed, it should be adjusted by the sulphur removal efficiency of the desulphurisation process (an average removal efficiency of 90 per cent is suggested). The formula for calculating these emissions would be:

EQUATION 7

Emissions from SO_2 Scrubbing (Gg C) = Total Coal Consumption (10^3 t)
x Fraction burned in plants equipped with scrubbers(%)
x Average Sulphur Content of Coal in these plants (%)
x Sulphur Removal Efficiency (default value is 90%)
x 12/32 (i.e., the Carbon/Sulphur Ratio)

Finally, to convert from carbon emissions (in Gg) into CO_2 emissions (in Gg), it is necessary to multiply by 44/12, the molecular weight ratio of CO_2 to C.

1.8 Fugitive Emissions from Oil And Natural Gas Activities

1.8.1 Overview

This section covers fugitive emissions of greenhouse gases (GHGs) from oil and natural gas activities. The category includes all emissions from the production, processing, transport and use of oil and natural gas, and from non-productive combustion. It excludes use of oil and gas or derived fuel products to provide energy for internal use, in energy production processing and transport. The latter are considered fuel combustion and treated in an earlier section of this chapter. Fugitive emissions do include, however, emissions which result from the combustion of natural gas during flaring operations.

By far the most important components of this subcategory are methane emissions from oil and gas production, and from all aspects of natural gas activities. The majority of this section identifies and describes different methane emission sources from oil and natural gas, and presents a default methodology to estimate these emissions on a national level. The basis for estimating methane emissions from oil and gas is, however, weak for most regions at this time. Only a few detailed studies of emissions rates have been performed. Better emissions data that take into account region- and country-specific factors are needed. Information currently available indicates that gas production and transmission in the former USSR and Eastern Europe are by far the most important sources, accounting for perhaps 50 per cent of global CH_4 emissions from oil and natural gas. Because the data are so limited at present, global and regional estimates of CH_4 emissions from this source category should be considered highly uncertain.

The IPCC/OECD/IEA programme has not yet addressed the indirect GHGs (including NMVOCs) in detail. However, the Joint EMEP/CORINAIR method offers both a simplified and a more detailed approach to the estimation of ozone precursors and SO_2. Considerable information has been obtained in other national and international emissions inventory programmes for NMVOCs because of the importance of these gases for local and regional (as well as global) pollution. References to some of the available sources of emission factor data and other information for calculating emissions from this category are provided in the last subsection of this section.

Background

Fugitive emissions of methane from oil and gas activities probably account for about 30 to 60 Tg per year of global methane emissions. Sources of fugitive emissions within oil and gas systems include: releases during normal operation, such as emissions associated with venting and flaring, chronic leaks or discharges from process vents, emissions during maintenance, and emissions during system upsets and accidents.

1.8.2 Oil and Natural Gas Activities

Oil and gas activities are divided into three main parts, for this discussion:

1 **Oil and Gas Production**: Oil and gas are withdrawn from underground formations using on-shore and off-shore wells and are often taken simultaneously from the same geological formation, and then separated. Gathering lines are generally used to bring the crude oil and raw gas streams to one or more collection

point(s) within a production field. Because methane is the major component of natural gas, leaks or venting from these systems result in methane emissions. Oil and/or gas are produced in approximately 186 countries world-wide.

2 **Crude Oil Transportation and Refining**: Crude oil is transported by pipelines and tankers to refineries where it is stored in tanks for a period of time. Methane is present, in varying degrees, in crude oil, and leaks or venting of vapours during transport and storage result in methane emissions, particularly from crude oil tankering.

Refineries process crude oil into a variety of hydrocarbon products such as gasoline and kerosene. During the refining process, dissolved gases are separated some of which may be leaked or vented during processing. Refinery outputs, referred to as "refined products," generally contain negligible amounts of methane. Consequently, methane emissions are not estimated for transporting and distributing refined products. Refineries are operated in 102 countries.

3 **Natural Gas Processing, Transportation, and Distribution**: Natural gas is processed to recover heavier hydrocarbons, such as ethane, propane and butane, and to prepare the “dried” gas for transport to consumers. Most gas is transported through transmission and distribution pipelines. A small amount of gas is shipped by tanker as liquefied natural gas (LNG). Because for the time being only a small portion of gas is transported as LNG, emissions from LNG facilities are not included in default emission methods.

The following are the main processing, transportation, and distribution activities:

- Gas processing plant: Natural gas is usually processed in gas plants to produce products with specific characteristics. Depending on the composition of the unprocessed gas, a variety of processes may be used to remove most of the heavier hydrocarbons, or condensate, from the gas. The processed, marketable, gas is then injected into the natural gas transmission system and the heavier hydrocarbons are marketed separately. Unintentional leaks of methane occur during natural gas processing.

- Transmission pipelines: Transmission facilities are high pressure lines that transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to distribution centres, or large volume customers. Although transmission lines are usually buried, a variety of above-ground facilities support the overall system including metering stations, maintenance facilities, and compressor stations located along the pipeline routes. These activities use gas from the pipeline as fuel and may emit methane.

- Distribution systems: Distribution pipelines are extensive networks of generally small diameter, low pressure pipelines. Gas enters distribution networks from transmission systems at "gate stations" where the pressure is reduced for distribution within cities or towns. As with transmission pipelines emissions from leaks or supporting facilities may take place.

1.8.3 Sources of Methane Emissions from Oil and Natural Gas Activities

Emissions from oil and gas activities can be categorised into: (1) emissions during normal operations; (2) maintenance; and (3) system upsets and accidents. Typically the majority of emissions are from normal operations.

The values of the emission factors are determined using the equations presented below.

$$K_{Oil-P_{min}} = 1 - \frac{Q_{Gas-fuel} + Q_{Gas-Inj} + Q_{Gas-flared} + Q_{Gas-other}}{Q_{Oil-P} \times GOR}$$

where,

$K_{Oil-P_{min}}$ = minimum emission factor for oil production (dimensionless)

Q_{Oil-P} = oil produced (m^3/year)

GOR = gas to oil ratio (dimensionless)

$Q_{Gas-fuel}$ = quantity of gas used as fuel (m^3/year)

$Q_{Gas-flared}$ = quantity of gas flared (m^3/year)

$Q_{Gas-inj}$ = quantity of gas injected back into ground (m^3/year)

$Q_{Gas-other}$ = quantity of gas accounted for in some other manner and that is not emitted (m^3/year)

The minimum emission is the amount of gas not otherwise accounted for. If no gas is used as fuel, flared, injected, or otherwise handled, then the minimum emission factor is 1; (i.e., all the gas withdrawn from the ground in conjunction with the oil is emitted). If some amount of gas is accounted for, then the minimum emission factor is 1 minus the portion accounted for.

Emissions also occur due to leaks. The leak emissions are the amount of gas leaked during various types of handling. If no gas is used as fuel, flared, injected, or otherwise handled, then the leaks are zero. If some amount of gas is managed in these ways, then the leak emission is the amount of gas handled times the leak rate, which is expressed as a fraction. The following is the equation for the leak emission factor:

$$K_{Oil-P_{leak}} = \frac{\left(Q_{Gas-fuel} \times L_{fuel}\right) + \left(Q_{Gas-inj} \times L_{Inj}\right) + \left(Q_{Gas-flared} \times L_{flared}\right) + \left(Q_{gas-other} \times L_{other}\right)}{Q_{Oil-P} \times GOR}$$

$K_{Oil-P_{leak}}$ = emission factor for leaks in the systems used to handle gas during oil production

Q_{Oil-P} = oil produced (m^3/year)

GOR = gas to oil ratio; defines the amount of gas produced (in volume) per unit of oil produced (in volume) (dimensionless)

$Q_{Gas-fuel}$ = quantity of gas used as fuel (m^3/year)

$Q_{Gas-flared}$ = quantity of gas flared (m^3/year)

$Q_{gas-inj}$ = quantity of gas injected back into ground (m^3/year)

$Q_{Gas-other}$ = quantity of gas accounted for in some other manner (m^3/year)

L_x = leak rates for the handling of the gas in the various ways, expressed as a fraction (e.g., 0.01) (dimensionless)

The total emission factor for oil production is then estimated as:

$$K_{Oil-P} = K_{Oil-P_{min}} + K_{Oil-P_{leak}}$$

If none of the gas is controlled or utilised (i.e., $L_x = 1$ for all x), then the emission factor (K_{Oil-P}) is equal to one. This situation occurs when it is not economical to conserve or reinject the gas (e.g., there is no local market for the gas and the volumes are relatively small) and when venting of the gas is preferable to disposal by flaring. It is not then necessary to evaluate the different paths by which CH_4 emissions may occur (e.g., fugitive equipment leaks, process venting, system upsets, etc.) in these cases since the end effect is the same: essentially all the CH_4 produced is emitted to the atmosphere.

Crude Oil Transportation and Refining: The crude oil from production facilities will initially contain a certain amount of gas in solution. This gas, particularly the CH_4 fraction, evaporates quickly as this oil progresses through the storage and transportation systems en route to the refinery. When the oil reaches the refinery, it is usually fully weathered and essentially free of any CH_4.

Accordingly, the basic mass balance relation for oil transportation and refining activities may be expressed as follows:

$$E_{Oil-T} = Q_{Oil-T} \times F \times Y_{F-CH_4} \times K_{Oil-T} \times D_F \times 10^{-12}$$

where,

E_{Oil-T} = methane emissions from crude oil transportation and refining (Tg/year)

Q_{Oil-T} = oil transported and refined (m^3/year)

F = factor defining the amount of gas in solution with the crude oil (per unit of oil by volume) (Dimensionless)

Y_{F-CH_4} = methane fraction; the fraction of the gas in solution in the oil that is methane, on a volume basis, for example, 0.1m^3 of methane per 1.0 m^3 of gas. (Dimensionless)

K_{Oil-T} = emission factor for oil transportation and refining, see below. (Dimensionless).

D_F = density of methane at the temperature and pressure at which F is estimated (g/m^3). The relevant temperature and pressure may vary, depending on the values used to calculate F. For example, at 0°C and at a pressure of 1 atmosphere, the density of methane is 715.4 g/m^3, and at 20°C and 1 atmosphere, the density of methane is 666.6 g/m^3.

The first two terms (Q_{Oil-T} and F) estimate the total amount of gas that is in solution with the crude oil. The term Y_{F-CH_4} converts the total gas quantity into the quantity of methane (still on a volume basis).[4] The emission factor (K_{Oil-T}) is the fraction of the total gas in solution that is emitted (at most, $K_{Oil-T} = 1$). To put the emissions estimate on a mass basis, D_F is used to estimate grams, and the conversion to teragrams follows.

The value of the solution gas factor and the corresponding mole fraction of methane is determined by the type of crude oil (light, medium, heavy, or crude bitumen), the composition of the associated gas, and the initial vapour pressure of the crude oil when it is placed in the storage tanks or compartments at the production site. Typically, the initial vapour pressure will be equal to the operating pressure of the first vessel upstream of the storage facilities.

Table 1-59 presents some estimated values for these two parameters at onshore and offshore facilities. Better estimates may be determined by performing site specific process simulations.

TABLE 1-59
SOLUTION GAS FACTORS AND CORRESPONDING CH_4 MOLE FRACTIONS FOR DIFFERENT TYPES OF CRUDE OIL PRODUCTION AT ONSHORE AND OFFSHORE FACILITIES

Type of Crude Oil	Onshore and Offshore Facilities	
	F SOLUTION GAS FACTOR	$Y_{F\text{-}CH_4}$ MOLE FRACTION
Light	3.3 to 5.0	0.5642
Medium	3.2 to 5.0	0.1001
Heavy (Primary)	1.0	0.8723
Heavy (Thermal)	8.3	0.6666

The value of the system adjustment factor is determined using the equation below:

$$K_{Oil-T} = 1 - \frac{Q_{\text{Collected } CH_4}}{Q_{Oil-T} \times F \times Y_{F-CH_4}}$$

$Q_{\text{Collected } CH_4}$ = the amount of methane collected, and not emitted, during transportation and refining.

Often this amount is zero

Other terms defined above.

In the absence of any data regarding the volume of CH_4 collected, the value of system adjustment factor should be set to a default value of one.

Exploration and Drilling Losses

Total CH_4 emissions from the exploration and drilling sector will usually be small compared to the amount emitted by other sectors of the oil and gas industry. Consequently, a simple Tier 1 approach is perhaps most appropriate for use here.

The basic relation is shown below:

$$E_D = N_{wells} \cdot F_D$$

where,

E_D = total CH_4 emissions (Tg) from drilling and testing of oil and gas wells,

N_{wells} = number of wells drilled and tested, and

F_D = average amount of CH_4 emitted per well (Tg/well).

Tier 3 - Rigorous Source-Specific Evaluations Approach

Rigorous source-specific evaluations will generally involve compiling the following types of information and may require significant interaction with industry and associated regulatory agencies:

- detailed inventories of the amount and types of process infrastructure (e.g., wells, minor field installations, and major production and processing facilities),

- production disposition analyses (e.g., oil and gas production; vented, flared and reinjected volumes of gas; and fuel gas consumption),
- accidental releases (i.e., well blow-outs and pipeline ruptures),
- typical design and operating practices and their impact on the overall level of emission control.

The amount of emissions is then assessed by applying appropriate emission factors, empirical correlations, process simulation results, and field measurements to these data.

Some examples of detailed emission inventories that have been developed in this manner are listed below:

- US Environmental Protection Agency (US EPA). Anthropogenic Methane Emissions in the United States. Estimates for 1990: Report to the Congress. October 1992 (US EPA, 1993).
- Picard, D.J., B.D. Ross, and D.W.H. Koon. A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta. Clearstone Engineering Ltd., for the Canadian Petroleum Association, March 1992 (Picard et al., 1992).
- UK Offshore Operators Association Ltd. (1992). Methane Emissions From Offshore Oil & Gas Exploration & Production Activities. Submitted to The Watt Committee on Energy, 1993.
- Norwegian Oil Industry Association - OLF. Report from OLF Environmental Programme - Phase 2. 1993.

1.8.7 Uncertainty

Some of these studies do analyse uncertainties, but emissions estimates in general are very uncertain. The overall magnitude of the emissions estimates that will be obtained for some countries using the methods and assumptions outlined in this chapter is driven by two key studies:

- **Rabchuk et al. (1991)** report that emissions from gas production and transportation in the former USSR is very high, about 3 to 7 per cent of total gas production. Recent visits to this region indicate that system construction, maintenance, and operations may be consistent with high emissions rates (Craig, 1992). However, a better quantitative evaluation is needed to validate the current emissions estimates.
- **Barns and Edmonds (1990)** report emissions from venting and flaring by region. The emissions estimates for the OPEC countries are relatively high, and account for most of the emissions from this category. The safety concerns associated with venting, and the value of re-injecting gas into oil reservoirs to maintain reservoir pressures, would tend to render the high emissions estimates questionable. Improved data are needed to resolve this question.

The adoption of emission factor estimates from US EPA (1992) for various regions also adds uncertainty to the overall estimates. US oil and gas production facilities and refineries are subject to emission control requirements. The US emission factors, particularly for refining, may under-estimate emissions in other regions. Nevertheless, this may not be a significant global uncertainty since, if the emission factors for oil production and oil refining were increased by a factor of 10 for the entire world, the estimate of total global emissions would only increase by about 1 to 6 Tg for 1988.

TABLE 1-60
USA AND CANADA - EMISSION FACTORS

Emissions Type	Emission factor kg/petajoule	Source
Oil and Gas Production		
Oil	290 - 4 670 of Oil Production	US EPA (1992)
Gas	39 590 - 104 220 of Gas Production	US EPA (1992)
Oil & Gas	2 870 - 13 920 of Oil & Gas Production	US EPA (1992)
Crude Oil Transportation and Refining		
Transportation	745 of Oil Tankered	API (1987)
Refining	90 - 1 400 of Oil Refined	US EPA (1992)
Storage Tanks	20 - 260 of Oil Refined	US EPA (1992)
Natural Gas Processing, Transport, and Distribution	59 660 - 116 610 of Gas Consumption	US EPA (1992)
Gas Processing	..	..
Gas Pipelines	..	..
Gas Distribution	..	..

TABLE 1-61
EASTERN EUROPE AND FORMER USSR - EMISSION FACTORS

Emissions Type	Emission factor kg/petajoule	Source
Oil and Gas Production		
Oil	290 - 4 670 of Oil Produced	US EPA (1992)
Gas	218 000 - 567 600 of Gas Produced	Rabchuk et al. (1991)
Oil & Gas	6 300 - 29 700 of Gas Produced	Barns and Edmonds (1990)
Crude Oil Transportation and Refining		
Transportation	745 of Oil Tankered	API (1987)
Refining	90 - 1 400 of Oil Refined	US EPA (1992)
Storage Tanks	20 - 260 of Oil Refined	US EPA (1992)
Natural Gas Processing, Transport, and Distribution	340 000 - 715 800 of Gas Consumption	Rabchuk et al. (1991)
Gas Processing	..	..
Gas Pipelines	..	..
Gas Distribution	..	..

TABLE 1-62
WESTERN EUROPE - EMISSION FACTORS

Emissions Type	Emission factor kg/petajoule	Source
Oil and Gas Production		
Oil	290 - 4 670 of Oil Produced	US EPA (1992)
Gas	14 800 - 27 000 of Gas Produced	Schneider-Fresenius et al. (1989)
Oil & Gas	13 000-16 000 of Gas Produced	Norwegian SPCA (1992)
	3 000-8 000 of Gas Produced	Norwegian O.I.A. OLF (1993)
Crude Oil Transportation and Refining		
Transportation	745 of Oil Tankered	API (1987)
	2 500 of Oil Tankered	Norwegian SPCA (1992)
Refining	90 - 1 400 of Oil Refined	US EPA (1992)
Storage Tanks	20 - 260 of Oil Refined	US EPA (1992)
Natural Gas Processing, Transport, and Distribution	58 000 - 111 000 of Gas Consumption	Schneider-Fresenius et al. (1989)
Gas Processing	1 800 of Gas Processed	Norwegian SPCA (1992)
Gas Pipelines	..	..
Gas Distribution	..	..

TABLE 1-63
OTHER OIL EXPORTING COUNTRIES - EMISSION FACTORS

Emissions Type	Emission factor kg/petajoule	Source
Oil and Gas Production		
Oil	290 - 4 670 of Oil Produced	US EPA (1992)
Gas	39 590 - 96 000 of Gas Produced	US EPA (1992) and Barns and Edmonds (1990)
Oil & Gas	739 470 - 1 019 220 of Gas Produced	Barns and Edmonds (1990)
Crude Oil Transportation and Refining		
Transportation	745 of Oil Tankered	API (1987)
Refining	90 - 1 400 of Oil Refined	US EPA (1992)
Storage Tanks	20 - 260 of Oil Refined	US EPA (1992)
Natural Gas Processing, Transport, and Distribution	116 610 - 340 000 of Gas Consumption	US EPA (1992 and Rabchuk et al. (1991)
Gas Processing	..	..
Gas Pipelines	..	..
Gas Distribution	..	..

TABLE 1-64
REST OF THE WORLD - METHANE EMISSION FACTORS

Emissions Type	Emission factor kg/petajoule	Source
Oil and Gas Production		
Oil	290 - 4 670 of Oil Produced	US EPA (1992)
Gas	39 590 - 96 000 of Gas Produced	US EPA (1992) and Barns and Edmonds. (1990)
Oil & Gas	170 000 - 209 000 of Gas Produced	Barns and Edmonds (1990)
Crude Oil Transportation and Refining		
Transportation	745 of Oil Tankered	API (1987)
Refining	90 - 1 400 of Oil Refined	US EPA (1992)
Storage Tanks	20 - 260 of Oil Refined	US EPA (1992)
Natural Gas Processing, Transport, and Distribution	116 610 - 340 000 of Gas Consumption	US EPA (1992 and Rabchuk et al. (1991)
Gas Processing	..	..
Gas Pipelines	..	..
Gas Distribution	..	..

1.8.8 Fugitive Emissions of Other GHGs

Methane is by far the most important greenhouse gas emitted on a fugitive basis from oil and gas activities. However, other GHGs are clearly emitted and should be included in a comprehensive national inventory.

After methane, the most significant fugitive emissions from oil and gas activities are of non-methane volatile organic compounds (NMVOCs). Oil and gas are largely composed of organic compounds, and releases through evaporation or leakages are likely at all stages wherever the fuels or their products come into contact with the atmosphere. Fugitive emissions from refining, transport and distribution of oil products are a major component of national NMVOC emissions in many countries.

The IPCC/OECD/IEA programme has not yet addressed the indirect GHGs (including NMVOCs) in detail. However, the Joint EMEP/CORINAIR Guidebook offers both a simplified and a more detailed approach to the estimation of ozone precursors and SO_2. The relevant tables and accompanying text are summarised below.

National experts interested in including the other fugitive emissions of GHGs from oil and natural gas systems should consult the existing literature which provides detailed emission factors and procedures for calculating emissions. Some key examples are:

- Default Emission Factors Handbook (EEATF, 1992);
- Proceedings of the TNO/EURASAP Workshop (TNO Inst. of Environmental Sciences, 1993);
- Atmospheric Emission Inventory Guidebook (Joint EMEP/CORINAIR, 1996);
- EMEP and CORINAIR Emission Factors and Species Profiles for Organic Compounds. (Veldt, 1991);
- US EPA's Compilation of Air Pollutant Emissions Factors (AP-42), 5th Edition 1995 (US EPA, 1995);

- Criteria Pollutant Emission Factors for the 1985 NAPAP Emissions Inventory (Stockton and Stelling, 1987).

1.8.9 Refineries

OVERVIEW

A basic refinery converts crude petroleum into a variety of sub-products. Principal products of a refinery may include liquid fuels, coke, feedstocks and primary petrochemicals (like ethylene). This section covers basic refineries, not the synthesis of petrochemicals. Chemical production is included in Chapter 2, Industrial Processes, whether or not the actual production takes place at a refinery or in a separate plant.

Storage and handling of intermediates and products may account for between 1 to 8 per cent of a country's NMVOC emissions. There are also significant non-combustion emissions of SO_2, NO_x, and CO.

Refinery Operations

Refinery operations include separation processes (distillation and gas processing), petroleum conversion processes (cracking, coking, catalytic reforming, alkylation, polymerisation), petroleum treating processes (desulphurisation, chemical sweetening, acid gas removal, deasphalting) and blending.

Vacuum distillation, catalytic cracking, thermal cracking, sweetening, blowdown systems, sulphur recovery and asphalt blowing have been identified as being potentially significant sources of SO_2 and NMVOCs from these sources. Storage and handling of petroleum products will lead to NMVOC emissions.

SIMPLE METHODOLOGY FOR OZONE PRECURSORS AND SO_2

A simple estimation can be made on the basis of throughput and single emission factors. However in most cases more detailed information may be available and the more detailed approach outlined in the Joint EMEP/CORINAIR Guidebook (1996) under SNAP code 40100 or in the following section here should be adopted. This considers the actual processes taking place in the refinery and the throughput of crude and products. While emission rates will depend on the specific process and equipment in a refinery, its state of maintenance and the sulphur content of the crude oil, a very simple estimate can be made on the basis of the throughput of crude oil and simple emission factors alone. The default emission factors are shown in Table 1-65.

TABLE I-65 NON-COMBUSTION EMISSION FACTORS FOR PETROLEUM REFINING. SIMPLE METHODOLOGY (KG/M^3 REFINERY FEEDSTOCK E.G., CRUDE OIL)		
POLLUTANT	**EMISSION FACTOR**	**SOURCES**
SO_2(a)	0.8	Vacuum tower, catalytic cracker, fluid coking, sulphur plant, SWS, incinerator, caustic regeneration, vents, off gases, others
NO_x(a)	0.05	Catalytic cracking
CO(a)	0.08	Fluid catalytic cracker only
NMVOC(b)	0.53	Fugitive and process emissions
Source : (a) EMEP/CORINAIR (1996). (b) based on CPPI and Environment CANADA (1991).		

NMVOC Emissions estimates vary widely. The proposed default value is 0.53 kg/m^3 input. Estimates range from 0.085 kg/m^3 from the best West European refinery to 10 kg/m^3 for a Russian refinery.

In practice it may be possible to use a more detailed approach where some of the makeup of the refinery is known or where only some of the emission activities are known. Some of these constituent parts are outlined below as an alternative to the above approach.

DETAILED METHODOLOGY FOR OZONE PRECURSORS AND SO_2

In the detailed methodology, emissions are calculated separately from sub processes in the refinery. The total emissions are the sum of the emissions from each individual sub process. The calculations should be based on plant specific data.

Fluid Catalytic Cracking (SNAP 40102)

Emission factors for a petroleum refinery which uses a fluid catalytic cracking system are shown in Table I-66.

TABLE I-66 NON-COMBUSTION EMISSION FACTORS FOR REFINERIES (FLUID CATALYTIC CRACKING KG/M^3 OIL TREATED IN THE FLUID CATALYTIC CRACKER)		
POLLUTANT	**EMISSION FACTOR** **(VALUE)**	**EMISSION FACTOR** **(RANGE)**
SO_2	1.4	0.286-1.505
NO_x	0.2	0.107-0.416
CO	39.2	NA
NMVOC	0.6	NA
Source: US EPA (1985a, 1995).		

No emission factors are currently available for cracking of coal to fluid products.

Sulphur recovery plants (SNAP 40103)

Sulphur recovery is the conversion of hydrogen sulphide to elemental sulphur. Emission factors are based on the amount of elemental sulphur produced and are shown in Table I-67.

TABLE I-67
NON-COMBUSTION EMISSION FACTORS FOR REFINERIES AND SULPHUR RECOVERY PLANTS.
(KG/TONNE SULPHUR)

POLLUTANT	EMISSION FACTOR
SO_2	139

Source : US EPA (1993b).

Storage and handling (SNAP 40104)

Emissions of NMVOC result from evaporation from tanks during storage, displacement of vapour during volume changes, loading and unloading and spillages. Storage may occur at a refinery or at separate locations. Emissions depend on the type and state of the tanks. Emission factors are suggested in Table I-68. Where nothing is known the highest factor should be used. The activity statistic is the crude oil throughput of the refineries.

TABLE I-68
NON-COMBUSTION EMISSION FACTORS FOR REFINERIES
(STORAGE AND HANDLING. G/KG OIL THROUGHPUT)

CONDITION	EMISSION FACTOR
• Majority of volatile products are stored in *floating roof tanks with secondary seals*	0.2
• Majority of volatile products are stored in *floating roof tanks with only primary seals*	0.7
• Majority of volatile products are stored in *fixed roof tanks*	4.9

Source : EMEP/CORINAIR (1996).

These emissions are intended to account for evaporative losses during storage and the displacement losses resulting from the loading and unloading of storage tanks.

Emissions from this source may be higher in countries with a warm climate.

1.9 Further Work

At the end of the Experts' Meeting on GHG Emissions from Fuel Combustion (Abingdon, 29-30 March 1996), experts were asked to identify areas for future work on emissions from energy. The subsequent list was then prioritised into short/medium-term activities and longer-term activities.

Short to Medium term (1-3 years):

1. Perform sensitivity analysis to assess importance of emission factors for various sectors.
2. Critically assess key emission factors found during sensitivity analysis, and key calorific values and activity data.
3. Enhance the EDGAR emission factors that feed into the Tier 1 methodology with information from US country studies and from other sources.
4. Critically compare IPCC emission factors and methodology with US EPA (1995) and CORINAIR.
5. Perform a literature search on emission factors:
   - Mobile sources in developing countries
   - N_2O (all sources)
   - Biomass (especially fuelwood)
6. Perform more research on emission factors for developing countries, including emission factors for biomass.
7. Enhance the section on fugitive emissions: coal mines (CH_4), oil & gas industry (CH_4 and NMVOC).
8. Analyse double counting with Industrial Processes section of *IPCC Guidelines*. Re-evaluate the default carbon stored values provided in the *Guidelines*, including the fate of carbon stored in petroleum products.
9. Add a category for non-fuel energy related emissions, such as from geothermal energy, CH_4 from flooding to create reservoirs, etc.
10. Evaluate the adequacy of guidelines.
11. Compare the results obtained by using Tier 1 and Tier 2 calculations for the non-CO_2 gases.
12. Investigate the possibility of reporting inventories and background information on the Internet.

Long term:

1. Develop/update software to support computation and reporting of both the Tier 1 and Tier 2 approaches.
2. Enhance reliability of biomass consumption figures.
3. Perform statistical analysis of data reported, and validate results with globally measured concentrations of all direct greenhouse gases.

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1 **Normal Operations:** . Emissions from normal operations can be divided into two main source categories: (1) venting and flaring and (2) discharges from process vents, chronic leaks, etc.

Venting and Flaring - Venting and flaring refers to the disposal of gas that cannot be contained or otherwise handled. Such venting and flaring activities are associated with combined oil and gas production and take place in production areas where gas pipeline infrastructure is incomplete and the natural gas is not injected into reservoirs (emissions from process vents are not included here - see below).

Venting activities release methane because the vented gas typically has a high methane content. If the excess gas is burned in flares the emissions of methane will depend on how efficient the burning processes are. Generally the combustion efficiency for flare sources are assumed to be between 95 and 100 per cent. However a new study based upon measurements carried out by Norwegian Oil Industry Association - OLF (1993) indicates very small amounts of unburned methane from flares, less than 0.1 per cent of the gas flared. To estimate the methane emissions from venting and flaring activities satisfactorily it is required to know the flare efficiency rates and the division between the quantity of gas vented and gas flared.

The *combined* quantity of gas vented and flared is reported by countries that produce oil and gas (Barns and Edmonds, 1990). A few countries also are able to report separately gas vented and gas flared. The reliability of the data is questionable in many cases because vented and flared amounts are not normally metered but inferred from the difference between total production and disposals.

Discharges from Process Vents, Chronic Leaks etc. - These include:

- Emissions from pneumatic devices (gas-operated controls such as valves and actuators) depend on the size, type, age of the devices, the frequency of their operation and the quality of their maintenance.
- Leaks from system components are unintentional and usually continuous releases resulting from the failure of a seal or the development of a flaw, crack or hole in a component designed to contain or convey oil or gas. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from flawed or worn seals, while pipelines and storage tanks can develop leaks from cracks or from corrosion.
- Emissions from process vents, such as vents on glycol dehydrators and vents on crude oil tankers and storage tanks resulting from normal operation of the facilities. However such process vents are minor methane sources in most gas production facilities.
- Emissions from starting and stopping reciprocating engines and turbines.
- Emissions during drilling activities, e.g., gas migration from reservoirs through wells.

2 **Maintenance:** Includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (“pigs”) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.

3 **System Upsets and Accidents:** System upsets are unplanned events in the system, the most common of which is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is

considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure. Relief systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and re-injected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or may send gases to flare systems where complete combustion may not be achieved.

The frequency of system upsets varies with the facility design and operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and resulting emissions. Emissions associated with accidents are also included under the category of upsets. Occasionally, gas transmission and distribution pipelines are accidentally ruptured by construction equipment or other activities.

Table 1-56 lists the most important sources of emissions within each segment of the oil and gas industry. Based on available information, the sources listed as "major" account for the majority of emissions from each segment. Because data are limited and, because there is considerable diversity among oil and gas systems throughout the world, other possible sources are listed which may, in some cases, be important contributors to emissions.

TABLE 1-56
METHANE EMISSIONS FROM OIL AND NATURAL GAS ACTIVITIES

Segment	Major Emission Sources	Other Possible Emission Sources
Oil and Gas Production Oil and Gas Wells Gathering lines Treatment facilities	Venting Normal operations: fugitive emissions; deliberate releases from pneumatic devices and process vents	Flaring, maintenance, system upsets and accidents
Crude oil transportation and Refining Pipelines Tankers Storage tanks Refineries	Normal operations: fugitive emissions; deliberate releases from process vents at refineries, during loading and unloading of tankers and storage tanks	Flaring, maintenance, system upsets and accidents
Natural Gas Processing, Transportation, and Distribution Gas Plants Underground storage reservoirs Transmission Pipelines Distribution Pipelines	Normal operations: fugitive emissions; deliberate releases from pneumatic devices and process vents	Flaring, maintenance, system upsets and accidents

1.8.4 Available Emissions Data

Only very limited data are available that describe methane emissions from natural gas and oil activities. Estimating the types of emissions defined above is complicated by the fact that emissions rates from similar activities in various regions and countries are influenced by differences in the industry's supporting infrastructure, operating and maintenance practices, and level of technology used. Because natural gas and oil activities are complex, it is not easy to define simple relationships between emissions and gross descriptors of the activities undertaken.

The available published data were reviewed to identify emissions estimates that include: a detailed consideration of the physical attributes of oil and gas systems; the operation and maintenance characteristics of key facilities; and country- or region-specific factors that may influence emission rates. The following data were identified:

- **Surveys:** Several studies have surveyed system operators to estimate emissions as a fraction of production or throughput. These studies include Alphatania (1989), AGA (1989), and INGAA (1989). While these studies provide a basis for identifying the activities that operators believe are likely to be major sources of emissions, they are not based on detailed assessments of emission rates and therefore do not provide a quantitative basis for making estimates of methane emissions from oil and natural gas activities.
- **Estimates Based on "Reported Unaccounted For Gas":** Several studies, such as Hitchcock and Wechsler (1972), Abrahamson (1989) and Cicerone and Oremland (1988), have assumed that emissions can be approximated by reported amounts of "unaccounted for" gas. Unaccounted for gas is defined as the difference between gas production and gas consumption on an annual basis. Like estimates of venting and flaring, unaccounted for gas often is used as an accounting convenience to balance company or national production and consumption estimates.

  The use of unaccounted for gas estimates as estimates of emissions is questionable because factors other than emissions account for the majority of the gas listed as unaccounted for. These include: meter inaccuracies, use of gas within the system itself, theft of gas (PG&E, 1990), variations in temperature and pressure and differences in billing cycles and accounting procedures between companies receiving and delivering the gas (INGAA, 1989). Furthermore, because known releases of gas are not reflected in unaccounted for gas estimates, such as emissions from compressor exhaust, the unaccounted for gas estimates cannot unambiguously be considered an upper or lower bound on emissions.
- **Engineering Studies and Measurements:** A small number of studies are based on detailed engineering and/or field measurement analyses. Several engineering analyses have considered the manner in which actual or model facilities are built and operated, and extrapolate facility emissions to a system-wide basis. Several measurement studies have measured emissions from operating facilities or identified actual leaks and extrapolated these measurements to estimate system-wide emissions. In general, data from engineering studies and measurements are the preferred basis for emission estimates. However, only a few of these types of studies have been performed, thereby limiting the ability to estimate emissions nationally, regionally and globally from oil and gas systems. Table 1-57 lists the studies identified and the information they contain. The methane emissions estimates from the studies in the table have been converted to common units of kilograms of emissions per petajoule of energy (kg/PJ). A total of five studies are listed, with emissions estimates for parts of North America (US EPA, 1992), Eastern Europe (Rabchuk et al., 1991), and Western Europe (Schneider-Fresenius et al., 1989, Norwegian SPCA, 1992b and Norwegian Oil Industry Association OLF, 1993). Additionally, Barns and Edmonds (1990) present estimates based on a global assessment. Further studies are needed to improve the basis for making emissions estimates.

TABLE 1-57
SUMMARY OF METHANE EMISSION FACTORS

Data source	Study methodology	Emission factors	Applicability
US EPA (1992) All emissions have been scaled down to 1988 energy consumption or production levels	Compilation of estimates from: • detailed engineering analyses • field measurement studies	**Oil and Gas Production:**	
		290 - 4 670 kg/PJ of oil produced	Emissions from non-gas producing oil wells including fugitive emissions and maintenance emissions in the USA
		39 590 - 104 220 kg/PJ of gas produced	Emissions from gas production, including fugitive emissions, dehydrator venting, bleeding from pneumatic devices, maintenance, and systems upsets in the USA
		2 870 - 13 920 kg/PJ of total oil and gas produced	Venting and flaring emissions from oil and gas production and fugitive emissions from gas-producing oil wells in the USA
		Crude Oil Transportation and Refining:	
		110 - 1 666 kg/PJ of oil refined	Emissions from oil refining and related oil storage tanks in the USA
		Natural Gas Processing, Transmission and Distribution:	
		59 660 - 116 610 kg/PJ of gas consumed	Emissions from gas processing, transmission and distribution including fugitive emissions, dehydrator venting, bleeding from pneumatic devices, maintenance, and system upsets in the USA
Rabchuk et al. (1991)	Compilation of estimates from: • previous measurement studies • official data for 1989	**Oil and Gas Production:**	
		218 000 - 567 600 kg/PJ of gas produced	Emissions from leakages at gas wells including routine equipment venting in the former USSR
		Natural Gas Processing, Transmission and Distribution:	
		340 000 - 715 800 kg/PJ of gas consumed	Emissions from leakages at underground storage facilities, compressor stations, linear part of main pipelines and distribution networks in the former USSR
Schneider-Fresenius et al. (1989)	Compilation of results from: • Batelle study's 1988 literature survey	**Oil and Gas Production:**	
		14 800 - 270 00 kg/PJ of gas produced	Emissions from gas production and treatment facilities in Germany
		Natural Gas Processing, Transmission and Distribution:	
		58 000 - 111 000 kg/PJ of gas consumed	Emissions from transportation, distribution and storage of gas in Germany

TABLE 1-57 (CONTINUED)
SUMMARY OF METHANE EMISSION FACTORS

Data source	Study Methodology	Emission Factors	Applicability
Barns and Edmonds (1990)	Compilation of:	**Oil and Gas Production:**	
	official reports and projections on international emissions	96 000 kg/PJ of natural gas production	Emissions from gas production and separation facilities in the world
		6 300 - 1 019 000 kg/PJ of gas production	Emissions from venting and flaring activity by region of the world
Norwegian SPCA (1992b)	Summary of:	**Oil and Gas Production:**	
	emissions estimates for 1989 based on:	12 800 kg/PJ of gas produced	Emissions from cold vents and fugitive emissions
	information and measurements collected from oil companies	3 200 kg/PJ of gas produced	Flare and gas turbines
	and industry associations	200 kg/PJ of gas produced	Pre-production emissions (well testing)
		Crude oil transportation:	
		2 500 kg/PJ oil tankered	Emissions from offshore loading of crude oil
		Natural gas processing:	
		1 800 kg/PJ of gas processed	Emissions from one Norwegian gas processing terminal
Norwegian Oil Industry Association (OLF), 1993	Summary of emission estimates based on:	**Oil and Gas Production:**	
	information and measurements collected from oil associations	3 000 - 7 500 kg/PJ of gas produced	Emissions from cold vents and fugitive emissions
		100 - 400 kg/PJ of gas produced	Pre-production emissions

1.8.5 Recent Revisions to Emission Factors

The above methodology and emission factors are based on the report of an expert group convened to advise the IPCC/OECD/IEA programme on methods and data in this specific area (Ebert, et al., 1993). Since that group delivered its report in mid-1993, a more recent analysis (US EPA, 1994b) has provided a somewhat different interpretation of some emission factors. While this very detailed analysis endorses the basic tiered methodology included in this *Manual*, the emission factors it derives differ from those presented here. This evaluation was based on essentially the same set of measurement data as cited in this *Manual*, but draws different results from the limited available data. The results of the recent US EPA analysis are summarised in Table 1-58. The most significant differences are in natural gas processing, transportation and distribution, where a more detailed set of emission factor ranges are recommended for non-OECD countries, some which are based on production of natural gas and some which are based on consumption of natural gas (which is the case for all of the factors provided above). Where emission factors are provided for more than one subcategory, they are intended to be additive, and would result in a higher total emissions estimates. Other differences in this US EPA analysis are that venting and flaring emissions for Western Europe are based on oil rather than gas production, and there are minor revisions to some factors for fugitive and other emissions from gas production.

These differences are significant, even given the overall uncertainty in this category, and should be considered carefully by national experts in regions where emissions from this source category are significant. It is hoped that the differences can be resolved or explained in more detail in a subsequent version of these *Guidelines*.

TABLE 1-58
REVISED REGIONAL EMISSION FACTORS FOR METHANE FROM OIL AND GAS ACTIVITIES (kg/PJ)

Source Type	Basis	Western Europe	US & Canada	Former USSR, Central & Eastern Europe	Other Oil Exporting Countries	Rest of the World
OIL & GAS PRODUCTION						
Fugitive and Other Maintenance Emissions from Oil Production	Oil Produced	300 - 5 000	300 - 5 000	300 - 5 000	300 - 5 000	300 - 5 000
Fugitive and Other Maintenance Emissions from Gas Production	Gas Produced	15 000 - 27 000	46 000 - 84 000	140 000 - 314 000	46 000 - 96 000	46 000 - 96 000
Venting & Flaring from Oil and Gas Production	Oil & Gas Produced(a)	-	3 000 - 14 000	-	-	-
	Oil Produced	1 000 - 3 000	-	-	-	-
	Gas Produced	-	-	6 000 - 30 000	758 000 - 1 046 000	175 000 - 209 000
CRUDE OIL TRANSPORTATION, STORAGE AND REFINING						
Transportation	Oil Tankered	745	745	745	745	745
Refining	Oil Refined	90 - 1 400	90 - 1 400	90 - 1 400	90 - 1 400	90 - 1 400
Storage Tanks	Oil Refined	20 - 250	20 - 250	20 - 250	20 - 250	20 - 250
NATURAL GAS PROCESSING, TRANSPORT AND DISTRIBUTION						
Emissions from Processing, Distribution and Transmission	Gas Produced	-	-	288 000 - 628 000	288 000 (high)(b)	288 000 (high)(b)
	Gas Consumed	72 000 - 133 000	57 000 - 118 000	-	118 000 (low)(c)	118 000 (low)(c)
Leakage at industrial plants and power stations	Non-residential Gas Consumed(d)	-	-	175 000 - 384 000	0 - 175 000	0 - 175 000
Leakage in the residential and commercial sectors	Residential Gas Consumed(e)	-	-	87 000 - 192 000	0 - 87 000	0 - 87 000

(a) In the US and Canada, the emissions are based on total production of both oil and gas produced.

(b) The emission factor of 288 000 kg/PJ of gas produced is used only for the high emissions estimate.

(c) The emission factor of 118 000 kg/PJ of gas consumed is used only for the low emissions estimate.

(d) Gas consumption by utilities and industries.

(e) Gas consumption by the residential and commercial sectors.

Source: US EPA (1994b).

1.8.6 Methodologies For Estimating Methane Emissions

A three-tiered approach is presented for estimating methane emissions from oil and gas activities. The specific tiers are listed below in the order of increasing sophistication, data requirements, and accuracy:

- Tier 1 - Production-Based Average Emission Factors Approach,
- Tier 2 - Mass Balance Approach, and
- Tier 3 - Rigorous Source-Specific Approach.

Countries should select the approach or combination of approaches that is most suited to their circumstances. Some important considerations may include the relative contribution of oil and natural gas to total methane emissions for the country, the available information and resources, and the complexity of the local oil and gas industry.

Regardless of the method that is used, the results must be aggregated back to a Tier 1 format to provide a consistent basis for comparison.

Note that methane emissions from combustion plant and incomplete combustion in flaring processes in the non-oil and gas industry are excluded. They are accounted for separately in the section on methane emissions from combustion and industry.

Tier 1 - Production-Based Average Emission Factors Approach

This is the simplest approach for estimating CH_4 emission from oil and gas activities, and is the only one that does not require any direct interaction with the oil and gas industry and associated regulatory agencies. Accordingly, it is the least reliable of the methods.

The required activity data may be easily referenced from published documents of the IEA or the United Nations Statistical Division, and the necessary emission factors are provided in this document. The Tier 1 Approach can be used as a starting point for any country, and may be all that is needed where the emissions from a country's oil and gas industry are comparatively small and/or where data or resources are not available to pursue a more rigorous approach.

Production Base: To estimate emissions, the following steps are recommended as a default estimation procedure:

1 Global oil and gas systems have been divided into regions with relatively homogeneous oil and gas system characteristics. Each country should decide which system characterisation best fits its own oil and gas system(s).

2 For each region, representative emission factors for each activity within each segment have been selected with the objective of taking into account the various system designs and operating practices found in each region.

3 For each country, country-specific activity levels must be obtained and multiplied by the appropriate emission factor. Emission factors for countries should be selected from those corresponding to the appropriate region.

As more data become available for oil and gas producing activities within different countries, the default methodology described above (including activity data and emission factors) should be refined. Each step is discussed below in more detail.

Regional Definitions: Regions have been defined considering the limitations in data on emission factors and activity levels, but also recognising the key differences in oil and gas systems that are found globally. The following five regions are recommended at this time:

- **USA and Canada:** The United States is a large producer and importer of oil and is a large producer of gas. Detailed emissions estimates are available for the United States.
- **Former USSR and Eastern Europe:** Indications are that emission rates from this region are much higher than emission rates from other regions, in particular for the gas system. This region includes the former USSR (which is by far the largest oil and gas producer in the region), Albania, Bulgaria, Czech & Slovak Republics, Hungary, Poland, Romania, and the former Yugoslavia.
- **Western Europe:** This region is a net importer of oil and gas, and mainly produces oil and gas off shore. This region includes: Austria, Belgium, Denmark, Faroe Islands, Finland, France, Germany, Gibraltar, Greece, Iceland, Ireland, Italy, Luxembourg, Malta, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, and the United Kingdom.
- **Other Oil Exporting Countries:** This region includes the world's other major oil producing countries: the 11 OPEC members (Algeria, Libya, Nigeria, Venezuela, Indonesia, Iran, Iraq, Kuwait, Qatar, Saudi Arabia and the United Arab Emirates), Gabon, Ecuador and Mexico. Generally, these countries produce large quantities of oil and have limited markets for gas.
- **Rest of the World:** This region includes the remaining countries of Asia, Africa, Middle East, Oceania and Latin America.

In defining these regions, countries with relatively similar oil and gas systems were aggregated. Additional investigation would likely improve the definition of the regions.

Emission Factors: As discussed above, the basis for selecting emission factors is weak because very few detailed studies of emissions have been performed. Using the information summarised in Table 1-57, emission factors should be selected by industry segment and emission type for each of the regions. In some cases data from the United States were used when region-specific information was not available.

Tables 1-60 to 1-64 offer emission factors for each region. Emission factors from US EPA (1992) were used for the United States. Key emission factors for Eastern Europe and the Former USSR were taken from Rabchuk et al. (1990) and Barns and Edmonds (1990). Estimates were used for emission factors for venting and flaring for the several regions, including Eastern Europe.

Studies by Schneider-Fresenius et al. (1989) and Norwegian SPCA (1992b) were adopted as representative of emission factors for Western European gas production, venting and flaring. No region-specific data were available for the Other Oil Exporting countries and the Rest of the World. Emission factors in these regions are expected to fall between the relatively low rates found in North America and Western Europe and the relatively high rates found in Eastern Europe. Consequently, a range of emission factors is suggested for these regions unless more information can be obtained.

Activity Levels: Data on the quantity of oil and gas produced, refined, and consumed can be obtained from the IEA or the UN Statistical Division. Sources are described in Section 1.2.1 Data Sources. Data on oil refining capacity can be used to approximate oil refined. Data on oil tankered were not available by region. It is important for national experts to ensure that production figures used in calculation of apparent consumption for CO_2 emissions estimates (described in the Tier 1 method for CO_2) are consistent with those used in this section.

Tier 2 - Mass Balance Approach

The Mass Balance Approach is only recommended for oil system releases of CH_4, and should not be used for releases from natural gas activities. No Tier 2 method exists for natural gas activities. This is a priority for future work. The Mass Balance Approach employs standard, generally easy-to-obtain, oil and gas data (i.e., production volumes, gas-to-oil ratios (GORs), and gas compositions) to estimate the maximum amount of methane that could be emitted to the atmosphere by different sectors of the oil and gas industry. These amounts are then scaled to reflect actual emissions by applying appropriate emission factors. The minimum emission factors account for the amount of gas that is disposed of by control devices, consumed by combustion equipment, conserved, or reinjected. Leak emission factors account for the amounts lost through leaks from these control/utilisation systems.

The basic procedures for performing the mass balance calculations for each oil and gas activity are set out below. Total CH_4 emissions is the sum of emissions for each of these activities. Default data and factors are provided where possible.

Oil Production: Emissions from oil production may be estimated using the relation,

$$E_{\text{Oil-P}} = Q_{\text{Oil-P}} \times GOR \times Y_{CH_4} \times K_{\text{Oil-P}} \times D_{GOR} \times 10^{-12}$$

where

$E_{\text{Oil-P}}$ = methane emissions from oil production (Tg/year)

$Q_{\text{Oil-P}}$ = oil produced (m^3/year)

GOR = gas to oil ratio; defines the amount of gas produced (in volume) per unit of oil produced (in volume). (m^3/m^3, or dimensionless).

Y_{CH_4} = methane Fraction; the volume of gas dissolved in the oil that is methane, on a volume basis, for example, 0.1 m^3 of methane per 1.0 m^3 of gas. (may be considered dimensionless)

$K_{\text{Oil-P}}$ = emission factor for oil production, see below (dimensionless)

D_{GOR} = density of methane at the temperature and pressure at which the GOR is estimated, (g/m^3). The relevant temperature and pressure may vary, depending on the values used to calculate the GOR. For example, at 0°C and a pressure of 1 atmosphere, the density of methane is 715.4 g/m^3, and at 20°C, and a pressure of 1 atmosphere, the density of methane is 666.6 g/m^3.

The first two terms ($Q_{\text{Oil-P}}$ and GOR) estimate the total amount of gas that is withdrawn from the ground while the oil is produced. The term Y_{CH_4} converts the total gas quantity into the quantity of methane (still on a volume basis). The emission factor ($K_{\text{Oil-P}}$) is the fraction of the total gas withdrawn that is emitted. At most, $K_{\text{Oil-P}} = 1$. To put the emissions estimate on a mass basis, D_{GOR} is used to estimate grams, and the conversion to teragrams follows.