CHAPTER 2

STATIONARY COMBUSTION

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2.1 OVERVIEW

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

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

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

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

Content:

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

Structure:

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

2.2 DESCRIPTION OF SOURCES

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

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

TABLE 2.1
DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[2]

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

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

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

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

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

TABLE 2.1 (CONTINUED) DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[4]				
Code number and name				**Definitions**
1 A 2	i	Mining (excluding fuels) and Quarrying		ISIC Divisions 13 and 14
1 A 2	j	Wood and Wood Products		ISIC Division 20
1 A 2	k	Construction		ISIC Division 45
1 A 2	l	Textile and Leather		ISIC Divisions 17, 18 and 19
1 A 2	m	Non-specified Industry		Any manufacturing industry/construction not included above or for which separate data are not available. Includes ISIC Divisions 25, 33, 36 and 37.
1 A 4	*Other Sectors*			Emissions from combustion activities as described below, including combustion for the generation of electricity and heat for own use in these sectors.
1 A 4	a	Commercial / Institutional		Emissions from fuel combustion in commercial and institutional buildings; all activities included in ISIC Divisions 41, 50, 51, 52, 55, 63-67, 70-75, 80, 85, 90-93 and 99.
1 A 4	b	Residential		All emissions from fuel combustion in households.
1 A 4	c	Agriculture / Forestry / Fishing / Fish farms		Emissions from fuel combustion in agriculture, forestry, fishing and fishing industries such as fish farms. Activities included in ISIC Divisions 01, 02 and 05. Highway agricultural transportation is excluded.
1 A 4	c	*i*	*Stationary*	Emissions from fuels combusted in pumps, grain drying, horticultural greenhouses and other agriculture, forestry or stationary combustion in the fishing industry.
1 A 4	c	*ii*	*Off-road Vehicles and Other Machinery*	Emissions from fuels combusted in traction vehicles on farm land and in forests.
1 A 4	c	*iii*	*Fishing (mobile combustion)*	Emissions from fuels combusted for inland, coastal and deep-sea fishing. Fishing should cover vessels of all flags that have refuelled in the country (include international fishing).

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

TABLE 2.1 (CONTINUED) DETAILED SECTOR SPLIT FOR STATIONARY COMBUSTION[5]				
Code number and name				**Definitions**
1 A 5	*Non-Specified*			All remaining emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries that are not engaged in multilateral operations.
1 A 5	a	Stationary		Emissions from fuel combustion in stationary sources that are not specified elsewhere.
1 A 5	b	Mobile		Emissions from vehicles and other machinery, marine and aviation (not included in 1 A 4 c ii or elsewhere).
1 A 5	b	*i*	*Mobile (aviation component)*	All remaining aviation emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the country's military as well as fuel delivered within that country but used by the militaries of other countries that are not engaged in multilateral operations.
1 A 5	b	*ii*	*Mobile (water-borne component)*	All remaining water-borne emissions from fuel combustion that are not specified elsewhere. Include emissions from fuel delivered to the country's military as well as fuel delivered within that country but used by the militaries of other countries that are not engaged in multilateral operations.
1 A 5	b	*iii*	*Mobile (other)*	All remaining emissions from mobile sources not included elsewhere.
Multilateral operations (Information item)				Emissions from fuels used in multilateral operations pursuant to the Charter of the United Nations. Include emissions from fuel delivered to the military in the country and delivered to the military of other countries.

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

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

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

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

BOX 2.1
AUTOPRODUCERS

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

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

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

2.3 METHODOLOGICAL ISSUES

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

2.3.1 Choice of method

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

2.3.1.1 TIER 1 APPROACH

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

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

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

EQUATION 2.1
GREENHOUSE GAS EMISSIONS FROM STATIONARY COMBUSTION

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

Where:

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

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

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

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

EQUATION 2.2
TOTAL EMISSIONS BY GREENHOUSE GAS

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

2.3.1.2 TIER 2 APPROACH

Applying a Tier 2 approach requires:

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

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

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

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

2.3.1.3 TIER 3 APPROACH

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

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

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

EQUATION 2.3
GREENHOUSE GAS EMISSIONS BY TECHNOLOGY

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

Where:

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

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

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

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

EQUATION 2.4

FUEL CONSUMPTION ESTIMATES BASED ON TECHNOLOGY PENETRATION

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

Where:

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

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

EQUATION 2.5

TECHNOLOGY-BASED EMISSION ESTIMATION

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

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

Application of a Tier 3 emission estimation approach requires:

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

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

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

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

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

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

2.3.1.4 DECISION TREES

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

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

2.3.2 Choice of emission factors

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

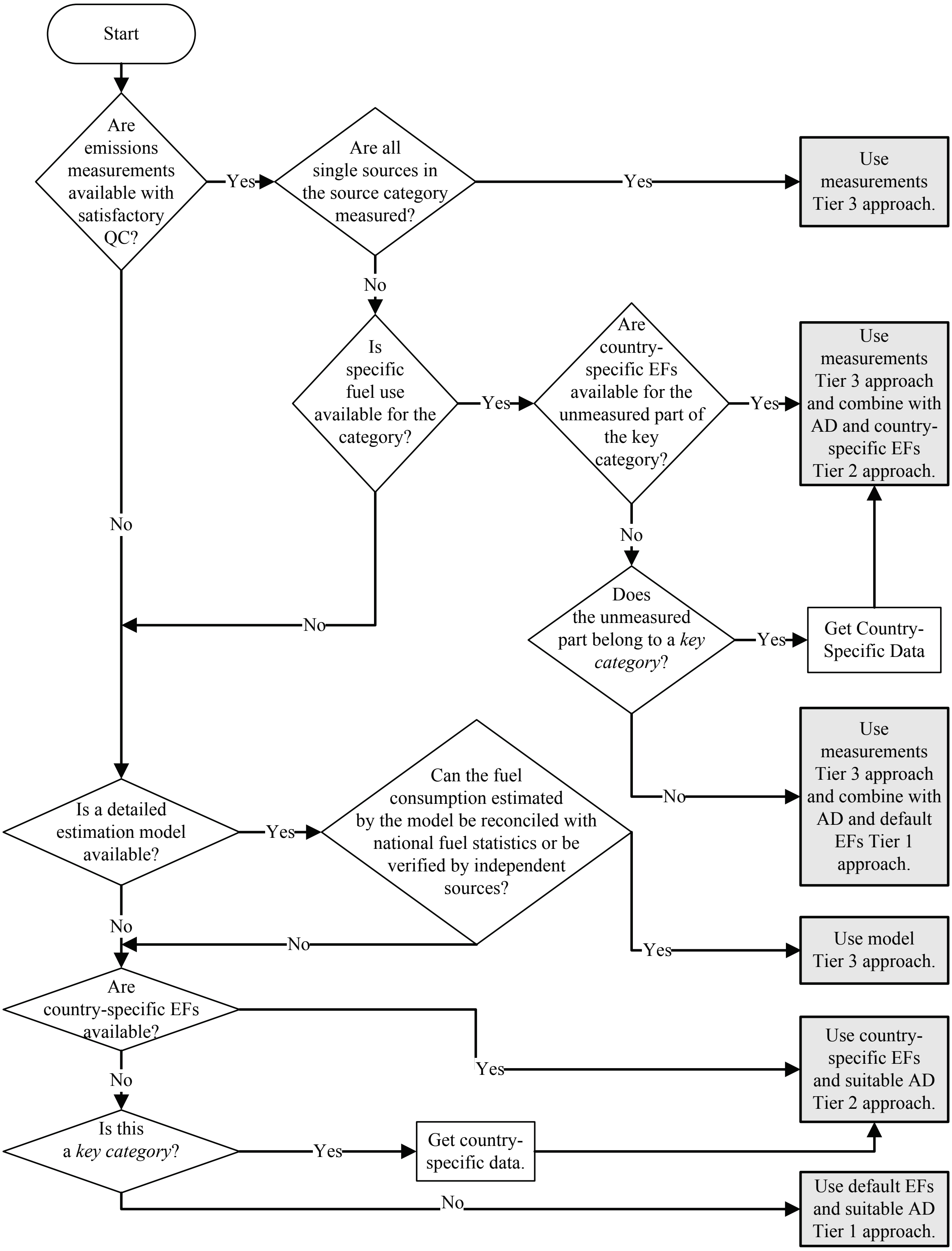
2.3.2.1 TIER 1

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

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

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

Figure 2.1 Generalised decision tree for estimating emissions from stationary combustion



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

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

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

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

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

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

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

Fuel		CO_2			CH_4			N_2O		
		Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper	Default Emission Factor	Lower	Upper
Crude Oil		73 300	71 100	75 500	r 3	1	10	0.6	0.2	2
Orimulsion		r 77 000	69 300	85 400	r 3	1	10	0.6	0.2	2
Natural Gas Liquids		r 64 200	58 300	70 400	r 3	1	10	0.6	0.2	2
Gasoline	Motor Gasoline	r 69 300	67 500	73 000	r 3	1	10	0.6	0.2	2
Gasoline	Aviation Gasoline	r 70 000	67 500	73 000	r 3	1	10	0.6	0.2	2
Gasoline	Jet Gasoline	r 70 000	67 500	73 000	r 3	1	10	0.6	0.2	2
Jet Kerosene		71 500	69 700	74 400	r 3	1	10	0.6	0.2	2
Other Kerosene		71 900	70 800	73 700	r 3	1	10	0.6	0.2	2
Shale Oil		73 300	67 800	79 200	r 3	1	10	0.6	0.2	2
Gas/Diesel Oil		74 100	72 600	74 800	r 3	1	10	0.6	0.2	2
Residual Fuel Oil		77 400	75 500	78 800	r 3	1	10	0.6	0.2	2
Liquefied Petroleum Gases		63 100	61 600	65 600	r 1	0.3	3	0.1	0.03	0.3
Ethane		61 600	56 500	68 600	r 1	0.3	3	0.1	0.03	0.3
Naphtha		73 300	69 300	76 300	r 3	1	10	0.6	0.2	2
Bitumen		80 700	73 000	89 900	r 3	1	10	0.6	0.2	2
Lubricants		73 300	71 900	75 200	r 3	1	10	0.6	0.2	2
Petroleum Coke		r 97 500	82 900	115 000	r 3	1	10	0.6	0.2	2
Refinery Feedstocks		73 300	68 900	76 600	r 3	1	10	0.6	0.2	2
Other Oil	Refinery Gas	n 57 600	48 200	69 000	r 1	0.3	3	0.1	0.03	0.3
Other Oil	Paraffin Waxes	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
Other Oil	White Spirit and SBP	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
Other Oil	Other Petroleum Products	73 300	72 200	74 400	r 3	1	10	0.6	0.2	2
Anthracite		98 300	94 600	101 000	10	3	30	r 1.5	0.5	5
Coking Coal		94 600	87 300	101 000	10	3	30	r 1.5	0.5	5
Other Bituminous Coal		94 600	89 500	99 700	10	3	30	r 1.5	0.5	5
Sub-Bituminous Coal		96 100	92 800	100 000	10	3	30	r 1.5	0.5	5
Lignite		101 000	90 900	115 000	10	3	30	r 1.5	0.5	5
Oil Shale and Tar Sands		107 000	90 200	125 000	10	3	30	r 1.5	0.5	5
Brown Coal Briquettes		n 97 500	87 300	109 000	n 10	3	30	n 1.5	0.5	5
Patent Fuel		97 500	87 300	109 000	10	3	30	r 1.5	0.5	5
Coke	Coke Oven Coke and Lignite Coke	r 107 000	95 700	119 000	10	3	30	r 1.5	0.5	5
Coke	Gas Coke	r 107 000	95 700	119 000	r 1	0.3	3	0.1	0.03	0.3
Coal Tar		n 80 700	68 200	95 300	n 10	3	30	n 1.5	0.5	5
Derived Gases	Gas Works Gas	n 44 400	37 300	54 100	r 1	0.3	3	0.1	0.03	0.3
Derived Gases	Coke Oven Gas	n 44 400	37 300	54 100	r 1	0.3	3	0.1	0.03	0.3
Derived Gases	Blast Furnace Gas	n 260 000	219 000	308 000	r 1	0.3	3	0.1	0.03	0.3
Derived Gases	Oxygen Steel Furnace Gas	n 182 000	145 000	202 000	r 1	0.3	3	0.1	0.03	0.3
Natural Gas		56 100	54 300	58 300	r 1	0.3	3	0.1	0.03	0.3

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

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

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

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

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

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

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

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

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

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

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

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

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

2.3.2.2 TIER 2 COUNTRY-SPECIFIC EMISSION FACTORS

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

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

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

2.3.2.3 TIER 3 TECHNOLOGY-SPECIFIC EMISSION FACTORS

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

2.3.3 Choice of activity data

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

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

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

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

TABLE 2.6
UTILITY SOURCE EMISSION FACTORS

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

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

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

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

NA, data not available.

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

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

TABLE 2.7
INDUSTRIAL SOURCE EMISSION FACTORS

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

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

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

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

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

NA, data not available

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

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

TABLE 2.8 KILNS, OVENS, AND DRYERS SOURCE EMISSION FACTORS			
Industry	**Source**	**Emission factors[1] (kg/TJ energy input**	
		CH_4	**N_2O**
Cement, Lime	Kilns - Natural Gas	1.1	NA
Cement, Lime	Kilns - Oil	1.0	NA
Cement, Lime	Kilns - Coal	1.0	NA
Coking, Steel	Coke Oven	1.0	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	1.1	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Oil	1.0	NA
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer – Coal	1.0	NA

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

NA, data not available.

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

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

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

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

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

TABLE 2.9
RESIDENTIAL SOURCE EMISSION FACTORS

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

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

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

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

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

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

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

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

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

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

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

NA, data not available.

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

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

TABLE 2.10 COMMERCIAL/INSTITUTIONAL SOURCE EMISSION FACTORS			
Basic technology	Configuration	Emission factors[1] (kg/TJ energy input)	
		CH_4	N_2O
Liquid Fuels			
Residual Fuel Oil Boilers		1.4	0.3
Gas/Diesel Oil Boilers		0.7	0.4
Liquefied Petroleum Gases Boilers		**n** 0.9	**n** 4
Solid Fuels			
Other Bituminous/Sub-bit. Overfeed Stoker Boilers		**n** 1	**n** 0.7
Other Bituminous/Sub-bit. Underfeed Stoker Boilers		**n** 14	**n** 0.7
Other Bituminous/Sub-bit. Hand-fed Units		**n** 87	**n** 0.7
Other Bituminous/Sub-bituminous Pulverised Boilers	Dry Bottom, wall fired	**n** 0.7	**n** 0.5
	Dry Bottom, tangentially fired	**n** 0.7	**n** 1.4
	Wet Bottom	**n** 0.9	**n** 1.4
Other Bituminous Spreader Stokers		**n** 1	**n** 0.7
Other Bituminous/Sub-bit. Fluidised Bed Combustor	Circulating Bed	**n** 1	**n** 61
	Bubbling Bed	**n** 1	**n** 61
Natural Gas			
Boilers		**r** 1	**r** 1
Gas-Fired Gas Turbines >3MWa		**n** 4	**n** 1.4
Biomass			
Wood/Wood Waste Boilers[2]		**n** 11	**n** 7

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

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

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

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

2.3.3.1 TIER 1 AND TIER 2

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

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

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

ENERGY INDUSTRIES

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

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

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

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

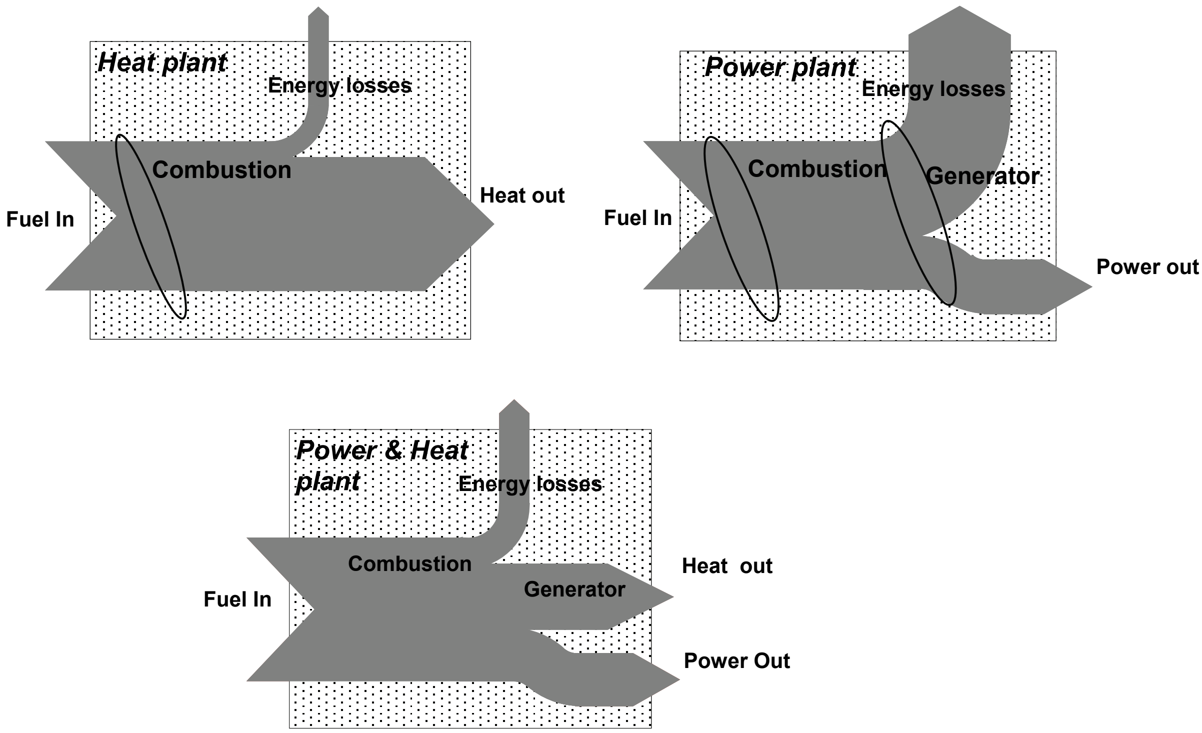
Emissions from combustion during production and conversion processes are counted under energy industries. Emissions from the secondary fuels produced by the energy industries are counted in the sector where they are used. When collecting activity data, it is essential to distinguish between the fuel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

MAIN ACTIVITY ELECTRICITY AND HEAT PRODUCTION

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

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

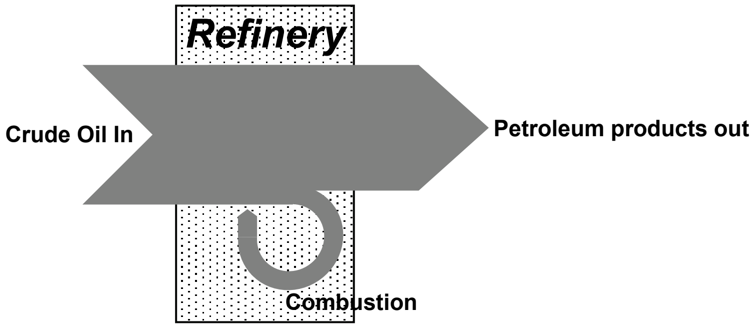
Figure 2.2 Power and heat plants use fuels to produce electric power and/or useful heat.



PETROLEUM REFINING

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

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



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

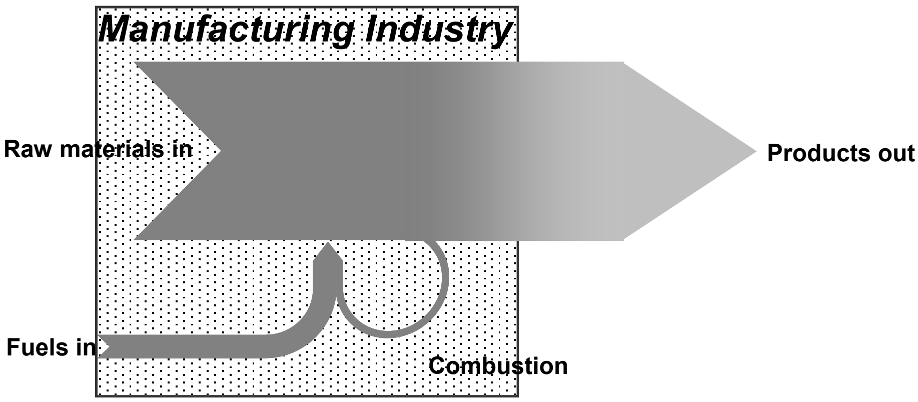
In many cases, the exact products and fuels used in refineries to produce the heat and steam needed to run the refinery processes are not easily derived from the energy statistics. The fuel combusted within petroleum refineries typically amounts to 6 to 10 percent of the total fuel input to the refinery,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

MANUFACTURING INDUSTRIES AND CONSTRUCTION

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

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

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



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

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

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

2.3.3.2 TIER 3

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

2.3.3.3 AVOIDING DOUBLE COUNTING ACTIVITY DATA WITH OTHER SECTORS

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

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

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

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

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

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

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

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

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

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

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

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

- WASTE – Incineration of waste

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

- ENERGY – Mobile combustion

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

2.3.3.4 TREATMENT OF BIOMASS

Biomass is a special case:

- Emissions of CO_2 from biomass fuels are estimated and reported in the AFOLU sector as part of the AFOLU methodology. In the reporting tables, emissions from combustion of biofuels are reported as information items but not included in the sectoral or national totals to avoid double counting. In the emission factor tables presented in this chapter, default CO_2 emission factors are presented to enable the user to estimate these information items.

- For biomass, only that part of the biomass that is combusted for energy purposes should be estimated for inclusion as an information item in the Energy sector.

- The emissions of CH_4 and N_2O, however, are estimated and included in the sector and national totals because their effect is in addition to the stock changes estimated in the AFOLU sector.

- For fuel wood, activity data are available from the IEA or the FAO (Food and Agriculture Organisation of the United Nations). These data originate from national sources and inventory compilers can obtain a better understanding of national circumstances by contacting national statistical agencies to find the organisations involved.

- For agricultural crop residues (part of other primary solid biomass) and also for fuel wood, estimation methods for activity data are available in Chapter 5 of the AFOLU volume.

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

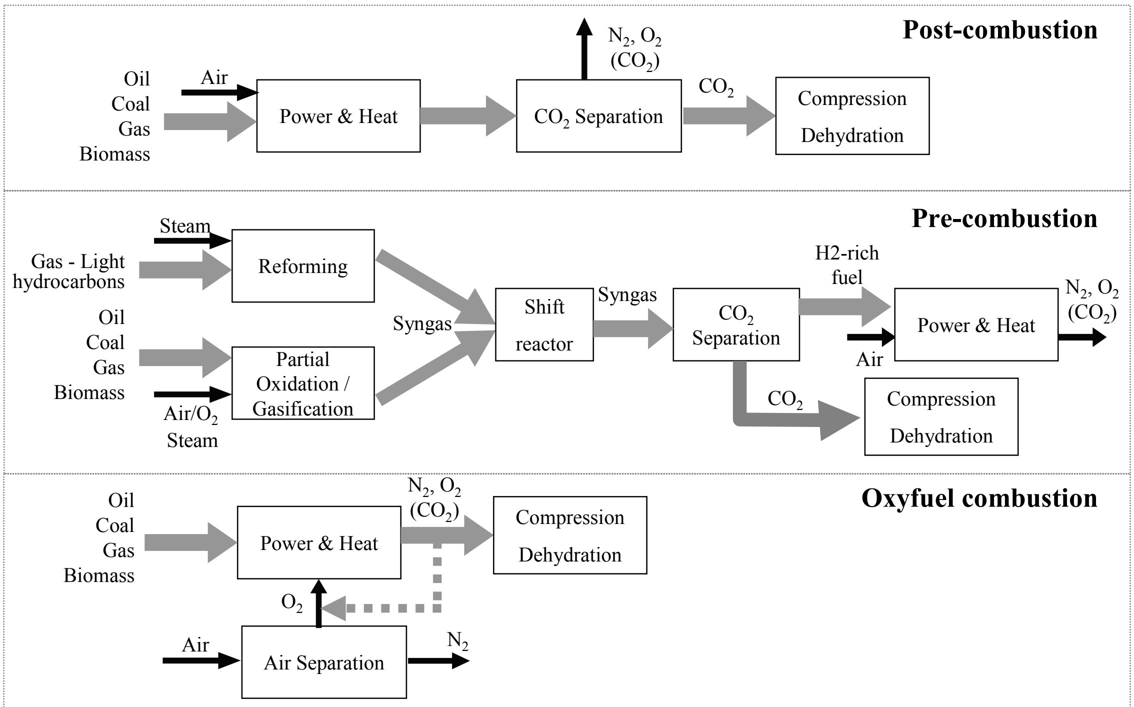
2.3.4 Carbon dioxide capture

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

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

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

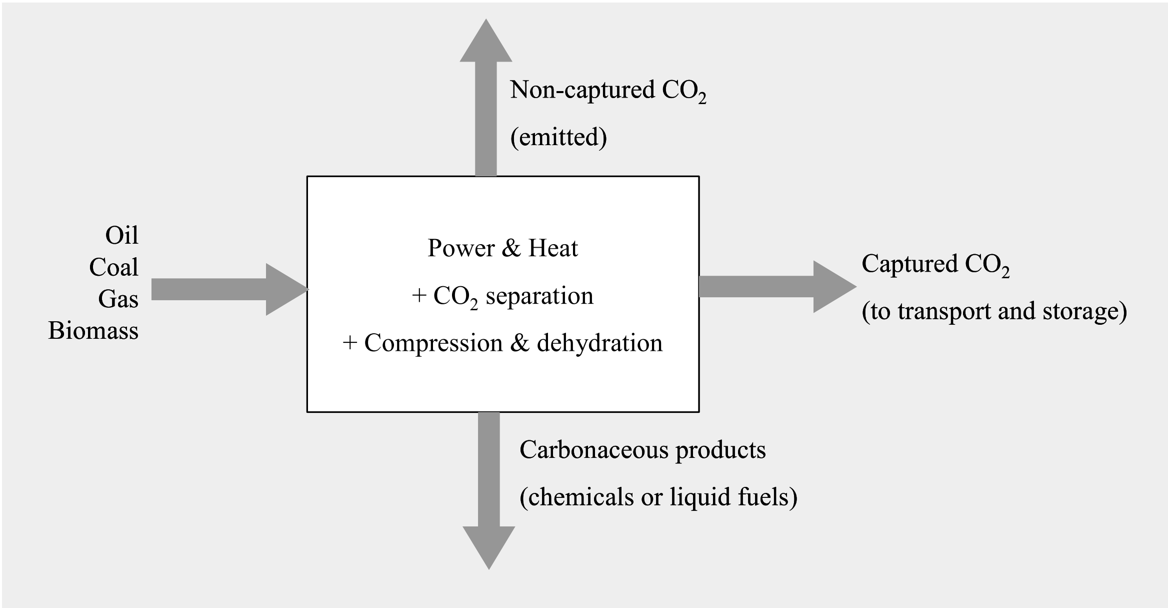
Figure 2.5 CO_2 capture systems from stationary combustion sources



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

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

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



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

EQUATION 2.6
CO_2 CAPTURE EFFICIENCY

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

Where:

$\mathrm{Efficiency}_{\mathrm{CO_2\ capture\ \ technology}}$ = CO_2 capture system efficiency (percent)

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

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

$\mathrm{C}_{\mathrm{products}}$ = amount of carbon in carbonaceous chemical or fuel products of the plant (kg).

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

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

[1] Reference plant without CO_2 capture system

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

TIER 3 CO_2 EMISSION ESTIMATES

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

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

EQUATION 2.7
TREATMENT OF CO_2 CAPTURE

$$Emissions_s = Production_s - Capture_s$$

Where:

s = source category or subcategory where capture takes place

Captures	= Amount captured.
Productions	= Estimated emissions, using these guidelines assuming no capture
$Emissions_s$	= Reported emission for the source category or sub-category

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

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

2.3.5 Completeness

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

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

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

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

2.3.6 Developing a consistent time series and recalculation

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

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

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

2.4 UNCERTAINTY ASSESSMENT

2.4.1 Emission factor uncertainties

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

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

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

TABLE 2.12
DEFAULT UNCERTAINTY ESTIMATES FOR STATIONARY COMBUSTION EMISSION FACTORS

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

* i.e. having an uncertainty range from one-tenth of the mean value to ten times the mean value.

Source: IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (2000)

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

There is currently relatively little experience in assessing and compiling inventory uncertainties and more experience is needed to assess whether the few available results are typical and comparable, and what the main weaknesses in such analyses are. Some articles addressing uncertainty assessment of greenhouse inventories have recently appeared in the peer-reviewed literature. Rypdal and Winiwater (2001) evaluated the uncertainties in greenhouse gas inventories and compared the results reported by five countries namely Austria (Winiwarter and Rypdal, 2001), the Netherlands (van Amstel *et al*., 2000), Norway (Rypdal, 1999), UK (Baggott *et al*., 2005) and USA (EIA, 1999). More recently, Monni *et al*. (2004) evaluated the uncertainties in the Finnish greenhouse gas emission inventory.

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

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

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

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

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

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

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

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

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

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

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

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

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

2.4.2 Activity data uncertainties

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

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

Overall uncertainty in activity data is a combination of both systematic and random errors. Most developed countries prepare balances of fuel supply and deliveries and this provides a check on systematic errors. In these circumstances, overall systematic errors are likely to be small. Experts believe that the uncertainty resulting from the two errors combined is probably in the range of ±5 percent for most developed countries. For countries with less well-developed energy data systems, this could be considerably larger, probably about ±10 percent. Informal activities may increase the uncertainty up to as much as 50 percent in some sectors for some countries.

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

TABLE 2.15
LEVEL OF UNCERTAINTY ASSOCIATED WITH STATIONARY COMBUSTION ACTIVITY DATA

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

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

2.5 INVENTORY QUALITY ASSURANCE/QUALITY CONTROL QA/QC

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

2.5.1 Reporting and Documentation

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

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

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

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

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

2.6 WORKSHEETS

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

TABLE 2.16
LIST OF SOURCE CATEGORIES FOR STATIONARY COMBUSTION

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

TABLE 2.17
QA/QC PROCEDURES FOR STATIONARY SOURCES

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

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

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

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