SNAP CODE:	**010103** **010203** **020103** **020202** **020302** **030103**
SOURCE ACTIVITY TITLE:	**COMBUSTION IN ENERGY & TRANSFORMATION INDUSTRIES** ***Particulate emissions from smaller Combustion Plants (<50MWth)***
NOSE CODE:	**101.03**
NFR CODE:	**1 A 1 a-c** **1 A 2 a-f** **1 A 4 a, bi, ci**
ISIC	**3510**

1 ACTIVITIES INCLUDED

This chapter covers emissions of particulate matter released from smaller combustion installations within the energy and transformation industries in boilers and furnaces with a thermal capacity ≤ 50 MW_{th}. Emissions of other pollutants from these sources can be found in chapter B111. Note that Chapter B216 also includes some combustion technologies relevant to the energy and transformation industries.

2 CONTRIBUTION TO TOTAL EMISSION

The contributions of PM_{10} and $PM_{2.5}$ emissions released from combustion in small combustion installations to total emissions in countries of the CORINAIR90 inventory is presented in Table 2.1.

Table 2.1 Contribution to total particulate matter emissions from 2004 EMEP database (WEBDAB)

NFR Sector	Data	PM_{10}	$PM_{2.5}$	TSP
1 A 1 a - Public Electricity and Heat Production[a]	No. of countries reporting	26	26	27
	Lowest Value	0.2%	0.2%	0.2%
	Typical Contribution	11.7%	10.1%	12.8%
	Highest Value	48.8%	47.8%	48.4%
1 A 2 - Manufacturing Industries and Construction[b]	No. of countries reporting	26	26	26
	Lowest Value	0.7%	0.6%	0.6%
	Typical Contribution	9.0%	9.5%	7.9%
	Highest Value	20.7%	22.1%	25.7%
1 A 4 a - Commercial / Institutional[c]	No. of countries reporting	23	23	23
	Lowest Value	0.1%	0.1%	0.1%
	Typical Contribution	3.9%	3.4%	4.5%
	Highest Value	19.3%	22.2%	29.5%
1 A 4 b - Residential[d]	No. of countries reporting	3	2	3
	Lowest Value	2.0%	6.5%	3.7%
	Typical Contribution	14.9%	26.2%	10.8%
	Highest Value	36.6%	45.8%	15.4%
1 A 4 b i - Residential plants[e]	No. of countries reporting	23	23	23
	Lowest Value	2.7%	5.8%	0.8%
	Typical Contribution	28.3%	33.1%	22.0%
	Highest Value	67.1%	74.6%	53.2%
1 A 5 a - Other, Stationary (including Military)[f]	No. of countries reporting	7	7	7
	Lowest Value	0.0%	0.0%	0.0%
	Typical Contribution	0.1%	0.1%	0.1%
	Highest Value	0.5%	0.4%	0.6%

[a] Includes contribution from Chapter 112

[b] Includes contributions from Chapter 112 and 316 (SNAP 030106)

[c] Includes contribution from Chapter 112 and 216 (SNAP 020205)

[d] Includes contribution from Chapter 810

[e] Includes contribution from Chapter 112

[f] Includes contribution from Chapter 112 and 216 (SNAP 020106)

3 GENERAL

3.1 Description

This chapter considers emissions of PM generated by boilers smaller than 50 MWth, this chapter covers the energy and transformation industries use of combustion plant and the devices in use are generally larger than 1 MW_{th}. Information on smaller units can be found in Chapter B216. Other emissions from this source category are considered in B111.

3.2 Definitions

See B111.

3.3 Techniques

See B111 for information on boiler types and fuels. Combustion of coal and other solid fuels present the main source for primary PM emissions.

3.4 Emissions

Particulate emissions from small combustion installations burning solid fuels are often greater than emissions from larger plants (per unit of energy input); the physical and chemical characteristics of the PM also differ. This is because different combustion and abatement techniques are applied.

Combustion of fuels will generate solid residues which may be deposited in the combustion chamber (furnace bottom ash), within the furnace, boiler surfaces or ducting (fly ash). Coal and other fuels with a significant ash content have the highest potential to emit PM. Suspended ash material in exhaust gases will be retained by particulate abatement or other emission abatement equipment (abatement residues). Material which remains in the flue gases beyond the abatement equipment and passes to the atmosphere is primary PM. Secondary PM is formed by chemical and physical processes after discharge to atmosphere and is NOT considered here.

3.5 Controls

Particulate emission reduction for smaller boilers is usually obtained applying abatement equipment. It is unlikely that solid-fuel boilers or furnaces in the size range considered in this chapter would be unabated however; some may have comparatively low technology abatement measures. Settling Chambers use gravity separation to remove particles, but the collection efficiency is low. Cyclone separators can be used or, more commonly, units with multiple cyclones are applied to improve the collection efficiency. More efficient abatement measures are electrostatic precipitators and fabric filters, although use of these on the smallest boilers may be limited due to comparatively high capital and operating costs.

Other measures to prevent or reduce particle emissions can also be implemented, such as replacing coal with other fuels, or replacing old appliances with newer, more efficient equipment.

4 SIMPLER METHODOLOGY

Emissions can be estimated at different levels of complexity; it is useful to think in terms of three tiers[1]:

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[1] The term “Tier” is used in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and adopted here for easy reference and to promote methodological harmonization.

Tier 1: a method using readily available statistical data on the intensity of processes ("activity rates") and default emission factors. These emission factors assume a linear relation between the intensity of the process and the resulting emissions. The Tier 1 default emission factors also assume an average or typical process description.

Tier 2: is similar to Tier 1 but uses more specific emission factors developed on the basis of knowledge of the types of processes and specific process conditions that apply in the country for which the inventory is being developed.

Tier 3: is any method that goes beyond the above methods. These might include the use of more detailed activity information, specific abatement strategies or other relevant technical information.

By moving from a lower to a higher Tier it is expected that the resulting emission estimate will be more precise and will have a lower uncertainty. Higher Tier methods will need more input data and therefore will require more effort to implement.

For the Tier 1 simpler methodology, where limited information is available, a default emission factor can be used together with production capacity information for the country or region of interest without further specification on the type of industrial technology or the type and efficiency of control equipment. For a Tier 2 approach an approximation to the most appropriate technology factors can be adopted with potential, if more detailed activity data are available, for use of default sector or technology factors.

Consequently the simplest methodology (Tier 1) is to combine an activity rate (AR) with a comparable, representative, value of the emissions per unit activity, the emission factors (EF). The basic equation is:

$$\text{Emission} = \text{AR x EF}$$

In the energy sector, for example, fuel consumption would be activity data and mass of material emitted per unit of fuel consumed would be a compatible emission factor.

NOTE: The basic equation may be modified, in some circumstances, to include emission reduction efficiency (abatement factors).

The Tier 2 methodology is a modified version of this basic equation :

$$\text{Emission} = \sum((\text{AR}_1 \text{ x EF}_1) + (\text{AR}_2 \text{ x EF}_2) + \ldots.(\text{AR}_n \text{ x EF}_n))$$

Default emission factors for this purpose are provided in Sections 8.1 and 8.2.

5 DETAILED METHODOLOGY

The detailed methodology (equivalent to Tier 3) to estimate emissions of pollutants from combustion plant <50 MW_{th} is based on measurements or estimations using plant specific emission factors for the types of plant and technologies used within the country - guidance on determining plant specific emission factors is given in the Measurement Protocol Annex.

The recommended detailed methodology to estimate emissions of PM from combustion activities is based on measurements and/or estimations using technology-specific emission factors.

Information on the type of the process and activity data, for example combustion and abatement technologies, is required to assign appropriate emission factors.

Reference emission factors for comparison with users' own data are provided in Section 8.2.

6 ACTIVITY STATISTICS

Activity statistics for fuel consumption in industry sectors for estimating emissions using the simpler estimation methodology (Tiers 1 and 2) are usually derived from national statistics. However, data on fuel use by smaller combustion plant within industry sectors may not be readily available. However, fuel suppliers, regulators and individual operators may be able to provide some data and other information may be available through relevant surveys, energy modelling and other studies.

The detailed methodology (Tier 3) requires more detailed information such as the amount and types of fuel consumed and the type of installation it is used in. However, the large number of plant in most countries will be a constraint on a Tier 3 approach and these data are not always easily available.

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on energy, Chapter 1.

7 POINT SOURCE CRITERIA

The largest boilers may be considered point sources if plant specific data are available however; in general, this chapter covers area sources only.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Default Emission Factors For Use With Simpler Methodology (Tier 1)

Table 8.1 Default emission factors for the simple methodology for small combustion installations

Fuel	Emission factor, g GJ^{-1}			Notes[2]
	TSP	PM_{10}	$PM_{2.5}$	
Hard coal, brown coal, other solid fuels	80	60	60	From Chapter B216
Natural gas	0.9	0.9	0.9	US EPA
Derived gases	5	5	5	CEPMEIP worst case for derived gases
Heavy fuel oil	50	40	30	From chapter B216
Other liquid fuels	50	40	30	From Chapter B216
Biomass	50	40	40	From Chapter B216

8.2 Reference Emission Factors For Use With Tier 2 Methodology

Tables 8.2a-z contain reference particulate emission factors for fuel combustion in various technologies with different types of abatement. These are suitable for use with the Tier 2 methodology.

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[2] Source: US EPA AP 42 (1996); CEPMEIP (2006)

Table 8.2a Emission factors for combustion processes burning hard coal.

Fuel	**NAPFUE**	**NFR Codes**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
Hard coal					**TSP**	**PM_{10}**	**$PM_{2.5}$**	
Bit. Coal	101	Various	Electricity, CHP, heat	FF <20 $mg.Nm^{-3}$	6	6	5	CEPMEIP 'BAT'
				ESP (or FF) <50 $mg.Nm^{-3}$	15	12	6	Scaled from CEPMEIP ESP factor. TSP scaled to a nominal 100 $mg.Nm^{-3}$ limit
				ESP <100 $mg.Nm^{-3}$	30	25	12	From CEPMEIP sub-bit coal 'high efficiency ESP', TSP scaled to a nominal 100 $mg.Nm^{-3}$ limit
				ESP Old/conventional <500 mg. Nm^{-3}	140	70	17	CEPMEIP
				Unit with multicyclone	100	60	35	CEPMEIP
				Unit, uncontrolled or cyclone	500	250	100	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
Sub-bituminous coal	103	Various	Electricity, CHP, heat plant	FF <20 $mg.Nm^{-3}$	6	6	5	CEPMEIP 'BAT'
				ESP (or FF) <50 $mg.Nm^{-3}$	15	12	6	Scaled from CEPMEIP ESP factor (TSP scaled to a nominal 100 $mg.Nm^{-3}$ limit)
				ESP <100 $mg.Nm^{-3}$	30	25	12	From CEPMEIP sub-bit coal 'high efficiency ESP', TSP scaled to a nominal 100 $mg.Nm^{-3}$ limit
				ESP Old/conventional	140	70	17	CEPMEIP

Fuel	**NAPFUE**	**NFR Codes**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
				<500 mg. Nm^{-3}				
				Unit with multicyclone	100	60	35	CEPMEIP
				Unit, uncontrolled or cyclone	500	250	100	CEPMEIP (the lower of the two TSP factors, the 800 g GJ-1 for small uncontrolled plant is such a high emission concentration that would apply to few if any plant)
Coke	107	1 A 1 b	Oil refineries	Uncontrolled	500	250	100	Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel.

Table 8.2b Emission factors for combustion processes burning brown coal.

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Brown coal	105	Various	Electricity plant, CHP plant, heat plant	Modern FF <20 mg.Nm^{-3}	9	8	6	CEPMEIP 'BAT'
				High efficiency ESP (or FF)	40	30	14	CEPMEIP
				Conventional large unit with multicyclone	100	60	35	CEPMEIP
Peat	113	Various	Electricity plant, CHP plant, heat plant	Modern abatement (FF) <30 mg.Nm3	9	8	6	CEPMEIP
				Efficient abatement, <50 mg.Nm3	20	15	10	TSP Scaled from emission limit of 50 mg.Nm^{-3}
				Efficient abatement, <100mg.Nm3	40	30	20	TSP Scaled from emission limit of 100 mg.Nm^{-3}
				Conventional technology	120	40	20	CEPMEIP
				Conventional smaller, multicyclone	300	40	20	CEPMEIP

Table 8.2c Emission factors for combustion processes burning other solid fuels

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Municipal solid waste	114	Various	Electricity plant, CHP plant, heating plant	Effective emission control (BAT)	15	13	10	CEPMEIP, (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)
				Conventional emission control	100	70	55	CEPMEIP (uncontrolled. optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)
Ind. waste	115	Various	Electricity, CHP, heating plant	Effective emission control (BAT)	15	13	10	CEPMEIP, (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)
				Conventional emission control	100	70	55	CEPMEIP (uncontrolled, optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Notes
				Older small uncontrolled	600	350	210	CEPMEIP (uncontrolled, optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)

Table 8.2d Emission factors for combustion processes burning natural gas.

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Natural gas	301	Various	Electricity, CHP and heating plant	Burner with optimised combustion	0.1	0.1	0.1	CEPMEIP
				Conventional installation	0.2	0.2	0.2	CEPMEIP
				Conventional installation	0.9	0.9	0.9	USEPA Filterable

Table 8.2e Emission factors for combustion of derived gases.

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Gas works gas	311	Various	Electricity, CHP and heating plant	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Clean fuel, Conventional installation	0.2	0.2	0.2	CEPMEIP (conventional installation)
				Conventional installation	5	5	5	CEPMEIP (High PM due to fuel quality)
Other gaseous fuel	314	Various	Electricity, CHP and heating plant	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Conventional installation	5	5	5	CEPMEIP

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
Coke oven gas	304	Various	Electricity, CHP heating plant, coke ovens	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Clean fuel, conventional installation	0.2	0.2	0.2	CEPMEIP (conventional installation)
				Conventional installation	5	5	5	CEPMEIP
Blast furnace gas	305	Various	Electricity, CHP and heating plant, coke ovens	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Clean fuel, Conventional installation	0.2	0.2	0.2	CEPMEIP (conventional installation)
				Conventional installation	5	5	5	CEPMEIP

Table 8.2f Emission factors for combustion of heavy fuel oil.

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	PM_{10}	$PM_{2.5}$	
Residual fuel oil	203	Various	Electricity, CHP and heating plant	Low S fuel with optimised burner and abatement	3	3	2.5	CEPMEIP. (About 10 mg.Nm^{-3} or BAT)
				Low S fuel, efficient combustion	14	12	10	CEPMEIP (About 50 mg. Nm^{-3})
				Low-Medium S fuel, conventional installation	20	15	9	CEPMEIP (about 70 mg. Nm^{-3})
				Low-Medium S fuel, conventional installation	60	50	40	CEPMEIP (higher of two entries used. about 200 mg.N Nm^{-3})
				High S fuel	210	190	130	CEPMEIP (lower of two entries for high S used (higher entry 240 g GJ-1 for TSP). Very high emission concentration (about 750 mg. Nm^{-3})
Petroleum coke	110	1 A 1 b	Oil refineries	Conventional, multicyclone	100	60	35	CEPMEIP, *Bit. Coal factors more appropriate.*

Table 8.2g Emission factors for combustion of other liquid fuels.

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Gas/Diesel oil	205	Various	Electricity, CHP, heating plant	Optimised burner	2	2	2	CEPMEIP
				Conventional burner	5	5	5	CEPMEIP
Naphtha	210	1 A 1 b	Oil refineries	All units	5	5	5	CEPMEIP
Liquefied Petroleum gas	303	Various	Electricity, CHP, heating plant	Optimised burner	0.1	0.1	0.1	CEPMEIP
				Conventional burner	5	5	5	CEPMEIP
Refinery gas	308	Various	Electricity, CHP, heating plant	Optimised burner	0.1	0.1	0.1	CEPMEIP
				Conventional burner	5	5	5	CEPMEIP
Other oil	224	Various	Electricity, CHP, heating plant	Low S fuel, optimised burner	3	3	2.5	CEPMEIP
				Low S fuel, efficient combustion	14	12	10	CEPMEIP for residual oil. (About 50 mg. Nm^{-3} (LCPD limit for existing plant)
				Low-Medium S fuel, conventional installation	20	15	9	CEPMEIP. (about 70 mg. Nm^{-3})
				Low-Medium S fuel, conventional installation	60	50	40	CEPMEIP, (highest of similar entries with TSP of 35, 40, 50 and 60 used. About 200 mg.N Nm^{-3})
				High S fuel	210	190	130	CEPMEIP, lower of two entries for high S used.

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
								(This is a very high emission concentration (about 750 mg.N Nm^{-3})

Table 8.2h Emission factors for combustion of biomass

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Wood	111	Various	Electricity, CHP, heating plant	Modern unit with FF, <20 mg.Nm3 TSP	7	7	6	TSP scaled from BAT benchmark, fractions applied based on Bit coal
				Older unit, <100 mg.Nm3 TSP	35	25	12	TSP scaled from emission concentration, fractions based on bit coal
				Uncontrolled conventional	100	70	55	CEPMEIP (Uncontrolled Multicyclone)
				Conventional minimal control	160	150	150	CEPMEIP for conventional installation
Charcoal	112	1 A 2 c	Chemicals	Conventional large unit with multicyclone	100	60	35	CEPMEIP, the use of charcoal is likely to be very rare.
					400	100	35	CEPMEIP, the use of charcoal is likely to be very rare. .
Black liquour	215	1 A 2 f	Textile & leather (Pulp and Paper)	Conventional installation	160	150	150	CEPMEIP (N.B. such a high emission concentration would apply to few if any

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
								plant)
Biogas	309	Various	Electricity, CHP, heating plant	Modern optimised large installation	3	3	2.5	(CEPMEIP, clean fuel)
				Conventional burner	5	5	5	CEPMEIP
				Modern, optimised	20	15	10	CEPMEIP (gasification plant),

9 SPECIES PROFILES

The US EPA (2003) undertook a review of species profiles within $PM_{2.5}$ and reports particle size distribution data for a variety of fuels and combustion and abatement technologies. Some of these data are dated and have high uncertainty ratings. Profiles of other materials are not available.

Table 9-1 US EPA $PM_{2.5}$ species profile for combustion activities

Profile ref	Profile name	Component				
		POA	PEC	GSO4	PNO3	Other
22002	Residual Oil Combustion	0.1075	0.0869	0.5504	0.0005	0.2547
22003	Distillate Oil Combustion	0.0384	0.0770	0.3217	0.0024	0.5605
22004	Natural Gas Combustion	0.6000	0.0000	0.2000	0.0055	0.1945
22007	Liquid Waste Combustion	0.0540	0.1050	0.0680	0.0000	0.7730
22009	Solid Waste Combustion	0.0068	0.0350	0.0680	0.0000	0.8902
NCOAL	Coal Combustion	0.20	0.01	0.16	0.005	0.625
NWWAS	Wood Waste Boiler	0.39	0.14	0.08	0	0.39

Notes:
POA - Primary organic aerosol derived from organic carbon
PEC Elemental Carbon
GSO4 - Sulphate
PNO3 - Nitrate
Other – Remainder of $PM_{2.5}$ material emitted.

Note that the data for the coal combustion and some other profiles are derived from dilution tunnel measurements on large combustion plant and may not be directly comparable with primary $PM_{2.5}$ from sub-50 MW_{th} boilers.

10 UNCERTAINTY ESTIMATES

The overall 'Uncertainty' in national emission inventories may be significant – as illustrated in Table 9.1.

Table 9.1 Uncertainty estimate for selected pollutants in the UK air emission inventory (NAEI, 2005).

Pollutant	Estimated Uncertainty (%)
PM_{10}	-20 to +50
$PM_{2.5}$	-20 to +30
$PM_{1.0}$	-10 to +20
$PM_{0.1}$	+/- 10
Sulphur Dioxide	+/- 3
Oxides of Nitrogen	+/- 8
NMVOCs	+/- 10
Ammonia	+/- 20

There is uncertainty in both the aggregated emission factors and activity data used to estimate emissions i.e. the imprecision and error to be expected from the application of an 'average' emission factor or activity statistic to estimate emissions from a specific sector - an artificial grouping of 'similar' sources.

The uncertainty is partly the result of how emission factors are developed and applied. In the case of primary particulate matter, the expanded statistical uncertainty is made up of: between plant variance, within plant variance, and uncertainties associated with the measurement methodology used and the aggregation of data. The measurement data in Annex 1 illustrates the variability in emission factors that occurs from between plant variance.

Process measurements, from which emission factors are developed at individual facility level, are subject to both systematic and random errors in the determination of mass concentration, mass emission, size distribution, and analytical errors etc.

In addition bias may exist in emission factors arising from:

1. Assumptions made about the abatement used on 'typical' industrial installations. For example emission factors 'age', the factors widely used in the Guidebook and hence by many countries as default emission factors in their national inventories become out of date. Recent measurement work suggests that they may overestimate emissions from the industrial processes subject to more modern industrial emissions regulation. They may, however, still be fully representative for older plant, small plant, or for poorer fuels;
2. Assumptions about the relationship between TSP and PM10/$PM_{2.5}$. The technical literature is comprehensive for TSP and the data quality can be good if measurements

have been made using the international standard methods that are available (typically the 95% confidence limit ~10%). But a variety of methods are used for particle size fractionation and as yet there are no harmonised international standards to ensure comparability. Published measurement data for PM10 is sparse, that for $PM_{2.5}$ emissions more so. An added complication is that the methodology for the determination of TSP differs from that of PM10 and $PM_{2.5}$ and so the two need not correlate directly.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Knowledge of combustion and abatement techniques, dust removal efficiencies and operating techniques is limited.

Further work should be invested to develop emission factors, which include technical or fuel dependent explanations concerning emission factor ranges. Emission factors also need to be generated, which specifically relate to different levels of abatement on different types of plant.

The stack emission factors described in the Guidebook, and all the PM_{10} emission factors, are based whenever possible on measurements. Particle measurements have often been made on the mass of total particulate matter and then converted to PM_{10} based either on the size distribution of the sample collected or, more usually, on size distributions given in the literature. There may be secondary sources of particulate matter, that are diffuse or fugitive in nature e.g. emissions from coke ovens, stockpiles, ash handling etc. These emissions are difficult to measure and in some cases it is likely that no entirely satisfactory measurements have ever been made, in many cases estimates of emissions from such sources are missing.

There is very little published data suitable for emission inventory compilation. I.e. representative data of known quality relating a) quantities of (particulate) material released to b) the activity associated with the release of that pollutant. Suitable data and associated information would record the determination of mass emissions rates using standardized measurement methods or calculation-based methods. Ideally such methods would cover the planning and execution of the data collection programme including: the selection of sampling methodology, choice of equipment, suitable working procedures, the calculation of representative emissions rates, the selection of matching activity data, the determination of sampling/measurement uncertainty, and the reporting of information in a form that is suitable for calculating emissions factors.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

Combustion plants should be considered as point sources if plant specific data are available. Otherwise national emissions should be disaggregated on the basis of plant capacity, employment, population or other relevant statistics.

13 TEMPORAL DISAGGREGATION CRITERIA

Combustion processes in most industrial sectors can be considered as a continuous process however; district and agricultural heating plants will tend to have an operational profile determined by the season. Individual combustion plant may have daily and/or seasonal temporal profiles.

14 ADDITIONAL COMMENTS

See chapters B111 and B216.

15 SUPPLEMENTARY DOCUMENTS

16 VERIFICATION PROCESSES

17 REFERENCES

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18 BIBLIOGRAPHY

For a detailed bibliography the primary literature mentioned in AP 42 can be used.

19 RELEASE VERSION, DATE AND SOURCE

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20 POINT OF ENQUIRY

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SOURCE ACTIVITY TITLE: **COMBUSTION IN ENERGY & TRANSFORMATION INDUSTRIES**
Particulate emissions from large Combustion Plants (>50MWth)

NOSE CODE:
101.01
101.02

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1 A 1 a,b,c
1 A 2 a-f
1 A 4 b,c,i

ISIC **3510**

1 ACTIVITIES INCLUDED

This Supplement, to be read in conjunction with the existing Chapter B111, covers emissions of particulate matter (PM) released from combustion processes within the energy and transformation industries in boilers and furnaces larger than 50 MWth. This Supplement includes guidance on estimating total PM (TSP), PM_{10} and $PM_{2.5}$ emissions from these sources. Emissions of other pollutants from this sector are provided in chapter B111.

2 CONTRIBUTION TO TOTAL EMISSION

The contributions of PM_{10} and $PM_{2.5}$ emissions released from combustion in large combustion plant to total emissions in countries of the CORINAIR90 inventory is presented in Table 2.1.

Table 2.1 Contribution to total particulate matter emissions from 2004 EMEP database (WEBDAB)

NFR Sector	Data	PM_{10}	$PM_{2.5}$	TSP
1 A 1 a - Public Electricity and Heat Production[a]	No. of countries reporting	26	26	27
	Lowest Value	0.2%	0.2%	0.2%
	Typical Contribution	11.7%	10.1%	12.8%
	Highest Value	48.8%	47.8%	48.4%
1 A 2 - Manufacturing Industries and Construction[b]	No. of countries reporting	26	26	26
	Lowest Value	0.7%	0.6%	0.6%
	Typical Contribution	9.0%	9.5%	7.9%
	Highest Value	20.7%	22.1%	25.7%
1 A 4 a - Commercial / Institutional[c]	No. of countries reporting	23	23	23
	Lowest Value	0.1%	0.1%	0.1%
	Typical Contribution	3.9%	3.4%	4.5%
	Highest Value	19.3%	22.2%	29.5%
1 A 4 b - Residential[d]	No. of countries reporting	3	2	3
	Lowest Value	2.0%	6.5%	3.7%
	Typical Contribution	14.9%	26.2%	10.8%
	Highest Value	36.6%	45.8%	15.4%
1 A 4 b i - Residential plants[e]	No. of countries reporting	23	23	23
	Lowest Value	2.7%	5.8%	0.8%
	Typical Contribution	28.3%	33.1%	22.0%
	Highest Value	67.1%	74.6%	53.2%
1 A 5 a - Other, Stationary (including Military)[f]	No. of countries reporting	7	7	7
	Lowest Value	0.0%	0.0%	0.0%
	Typical Contribution	0.1%	0.1%	0.1%
	Highest Value	0.5%	0.4%	0.6%

[a] Includes contribution from Chapter 112

[b] Includes contributions from Chapter 112 and 316 (SNAP 030106)

[c] Includes contribution from Chapter 112 and 216 (SNAP 020205)

[d] Includes contribution from Chapter 810

[e] Includes contribution from Chapter 112

[f] Includes contribution from Chapter 112 and 216 (SNAP 020106)

3 GENERAL

3.1 Description

This chapter considers emissions of PM generated by boilers larger than 50 MWth. Other emissions from this source category are considered in B111.

3.2 Definitions

See B111.

3.3 Techniques

See B111 for information on boiler types and fuels. Combustion of coal and other solid fuels present the main source for primary PM emissions.

3.4 Emissions

Particulate emissions result from activities such as storage of fuels; on site transportation of solid fuel; combustion of fuels, transport, storage and disposal of combustion residues including furnace bottom ash, fly ash and, abatement residues.

Combustion of fuels will generate solid residues which may be deposited in the combustion chamber (furnace bottom ash), within the furnace, boiler surfaces or ducting (fly ash). Coal and other fuels with a significant ash content have the highest potential to emit PM. Suspended ash material in exhaust gases will be retained by particulate abatement or other emission abatement equipment (abatement residues). Material which remains in the flue gases beyond the abatement equipment and passes to the atmosphere is primary PM. Secondary PM is formed by chemical and physical processes after discharge to atmosphere and is NOT considered here.

3.5 Controls

Particulate emission reduction is usually achieved using abatement equipment. Electrostatic precipitators (ESPs) and fabric filters (FFs) are widely used on boilers. Cyclones (particularly multicyclones) can be found on smaller grate-fired boilers. Most pulverised coal fired power station boilers use ESPs although fabric filters are becoming more common. Flue gas desulphurisation (FGD) plant can also help reduce particulate emissions from pulverised coal-fired boilers. Wet limestone FGD systems retrofitted to existing plant are generally located downstream of existing ESPs and can provide a further stage of PM reduction. Dry lime injection FGD systems incorporate a FF for sorbent capture and PM removal.

Fabric filters are capable of achieving higher emission reductions than electrostatic precipitators but both are suitable[1] for the sector and can achieve PM emission concentrations of 5 - 30 mg/m^3.

4 SIMPLER METHODOLOGY

Emissions can be estimated at different levels of complexity; it is useful to think in terms of three tiers[2]:

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[1] Either technology is considered part of Best Available Techniques (BAT) under EU Integrated Pollution Prevention and Control regulations.

[2] The term "Tier" is used in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and adopted here for easy reference and to promote methodological harmonization.

Tier 1: a method using readily available statistical data on the intensity of processes ("activity rates") and default emission factors. These emission factors assume a linear relation between the intensity of the process and the resulting emissions. The Tier 1 default emission factors also assume an average or typical process description.

Tier 2: is similar to Tier 1 but uses more specific emission factors developed on the basis of knowledge of the types of processes and specific process conditions that apply in the country for which the inventory is being developed.

Tier 3: is any method that goes beyond the above methods. These might include the use of more detailed activity information, specific abatement strategies or other relevant technical information.

By moving from a lower to a higher Tier it is expected that the resulting emission estimate will be more precise and will have a lower uncertainty. Higher Tier methods will need more input data and therefore will require more effort to implement.

The Tier 1 simpler methodology, where limited information is available, uses a restricted set of default emission factors together with production capacity information specific to the country or region of interest; there is little or no specification of the type of industrial technologies or the type and efficiency of control equipment in place. The Tier 2 approach, in addition, requires an approximation of the mix of technologies in place, and more detailed activity data, but still allows the use of default sector or technology factors.

Consequently the simplest methodology (Tier 1) is to combine an activity rate (AR) with a comparable, representative, value of the emissions per unit activity, the emission factors (EF). The basic equation is:

$$\text{Emission} = \text{AR} \times \text{EF}$$

In the energy sector, for example, fuel consumption would be the measure of activity and mass of material emitted per unit of fuel consumed would be a compatible emission factor.

NOTE: The basic equation may be modified, in some circumstances, to include emission reduction efficiency (abatement factors).

The Tier 2 methodology is a modified version of this basic equation:

$$\text{Emission} = \sum((\text{AR}_1 \times \text{EF}_1) + (\text{AR}_2 \times \text{EF}_2) + \ldots .(\text{AR}_n \times \text{EF}_n))$$

Default emission factors for this purpose are provided in Sections 8.1 and 8.2.

5 DETAILED METHODOLOGY

The detailed methodology (equivalent to Tier 3) to estimate emissions of pollutants from combustion plant >50 MW_{th} is based on measurements or estimations using plant specific emission factors - guidance on determining plant specific emission factors is given in Measurement Protocol Annex.

In many countries, operators of combustion plant >50MWth will report emissions to comply with regulatory requirements and this data can be used to help compile the national inventory.

The recommended detailed methodology to estimate emissions of PM from combustion activities is based on measurements and/or estimations using technology-specific emission factors.

Information on the type of the process and activity data, for example combustion and abatement technologies, is required to assign appropriate emission factors.

Reference emission factors for comparison with users' own data are provided in Section 8.2.

6 ACTIVITY STATISTICS

Activity statistics for energy consumption or other relevant national activity data for estimating emissions using the simpler estimation methodology (Tiers 1 and 2) are available from national statistics.

The detailed methodology (Tier 3) requires more detailed information such as the amount and types of fuel consumed within individual combustion plant or industry sectors. These data are not always easily available although in many countries operators do report fuel use for emission trading or other legislative requirements.

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on energy, Chapter 1.

7 POINT SOURCE CRITERIA

Large combustion plants are regarded as point sources if plant specific data are available.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Default Emission Factors For Use With Simpler Methodology (Tier 1)

Fuel	**Technology**	**Emission factor, g GJ^{-1}**			**Notes**[3]
		TSP	**PM_{10}**	**$PM_{2.5}$**	
Hard coal, (assumes 20% ash) Brown coal, Other solid fuels	Pulverised coal, ESP	30	20	9	Based on AP 42 - assumes 20% ash content and PM emissions from solid mineral fuels generally similar to coal
	Pulverised coal, fluid bed, other FF	7.4	7.4	3.7	
	Cyclone furnace, ESP	6.1	4.2	2.3	
	Stoker with multicyclone	330	230	27	
	Pulverised coal ESP + wet limestone FGD	6	6	5	From CEPMEIP data (US EPA default factors for wet scrubbers are very high)
Natural gas		0.9	0.9	0.9	AP-42 filterable PM factor
Derived gases		5	5	5	CEPMEIP data, worst case for derived gases.
Heavy fuel oil (1% S)	No control	25	18	13	Assumes 1% sulphur as specified in the EU Sulphur content of liquid fuels Directive
	FGD	1.5	1.5	1.5	
Heavy fuel oil (3% S)	No control	64	45	33	Assumes 3% sulphur (maximum permitted in EU countries)
	FGD	3.8	3.8	3.7	
Other liquid fuels	LPG	2.0	2.0	2.0	
Biomass	FF	51	38	33	AP 42 Wood waste
	ESP	28	21	18	

The information provided in Section 8.2 provides further information for selection of more appropriate emission factors.

8.2 Reference Emission Factors For Use With Tier 2 Methodology

Tables 8.2a-z contain reference particulate emission factors for fuel combustion in various technologies with different types of abatement.

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[3] Source: R. Stewart (2006); US EPA AP 42 (1996); CEPMEIP (2006)

Table 8.2a Emission factors for combustion processes burning hard coal.

Fuel	NAPFUE	NFR Codes	Activity description	Activity detail[4]	Emission factor $g.GJ^{-1}$			Notes[5]
Hard coal					**TSP**	**PM_{10}**	**$PM_{2.5}$**	
Bit. Coal	101	Various	Electricity plant, CHP plant	FGD, ESP or FF <20 $mg.Nm^{-3}$ (BAT)	6	6	5	CEPMEIP
				ESP (or FF) <50 $mg.Nm^{-3}$ (LCPD)	15	12	6	Scaled from CEPMEIP ESP factor
				ESP <100 $mg.Nm^{-3}$ (LCPD)	30	25	12	From CEPMEIP sub-bit coal ‘high efficiency ESP’, TSP scaled to the EU LCP Directive existing plant sub $100MW_{th}$ limit
				ESP Old/conventional <500 $mg.\ Nm^{-3}$	140	70	17	CEPMEIP
				Large unit with multicyclone	100	60	35	CEPMEIP
				Large unit, uncontrolled or cyclone	500	250	100	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
Sub-bituminous coal	103	Various	Electricity plant, CHP plant, heat plant	FGD, ESP or FF <20 $mg.Nm^{-3}$ (BAT)	6	6	5	CEPMEIP
				ESP (or FF) <50 $mg.Nm^{-3}$ (LCPD)	15	12	6	Scaled from CEPMEIP ESP factor
				ESP <100 $mg.Nm^{-3}$ (LCPD)	30	25	12	From CEPMEIP sub-bit coal ‘high efficiency ESP’, TSP scaled to LCPD existing plant sub $100MW_{th}$ limit

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[4] KEY: FGD: Flue gas desulphurisation, ESP: Electrostatic Precipitator, FF: Fabric Filter, BAT: Best Available Techniques, LCPD: Large Combustion Plant Data

[5] Sources: R. Stewart (2006); US EPA AP 42 (1996); CEPMEIP (2006)

Fuel	**NAPFUE**	**NFR Codes**	**Activity description**	**Activity detail**[4]	**Emission factor g.GJ^{-1}**			**Notes**[5]
				ESP Old/conventional <500 mg. Nm^{-3}	140	70	17	CEPMEIP
				Conventional large unit with multicyclone	100	60	35	CEPMEIP
				Conventional unit, uncontrolled or cyclone	500	250	100	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
Coke	107							Coke is unlikely to be burned as primary fuel, when co-fired use the factor for the principal fuel.

Table 8.2b Emission factors for combustion processes burning brown coal.

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference/Comments**
					TSP	**PM$_{10}$**	**PM$_{2.5}$**	
Brown coal	105	Various	Electricity plant, CHP plant, heat plant	FGD, ESP or FF <20 mg.Nm^{-3} (BAT)	9	8	6	CEPMEIP
				High efficiency ESP (or FF)	40	30	14	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
				Conventional large unit with multicyclone	100	60	35	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
				Older ESP	160	80	20	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)
				Older installation	500	250	100	CEPMEIP (N.B. such a high

Fuel	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference/Comments**
				uncontrolled or cyclone				emission concentration would apply to few if any plant)
Peat	113	Various	Electricity plant, CHP plant, heat plant	BAT/new LCPD, Modern end-of-pipe abatement FGD, ESP or FF. <30 mg.Nm3	9	8	6	CEPMEIP
				Efficient abatement LCP larger facility, <50 mg.Nm3	20	15	10	TSP Scaled from LCP emission limit of 50 $mg.Nm^{-3}$
				Efficient abatement LCP <100 MW_{th}, <100mg.Nm3	40	30	20	TSP Scaled from LCP emission limit of 50 $mg.Nm^{-3}$
				Conventional technology	120	40	20	CEPMEIP
				Conventional smaller, multicyclone	300	40	20	CEPMEIP

Table 8.2c Emission factors for combustion processes burning other solid fuels

Fuel	NAPFUE	NFR Code	Activity description	Activity detail	Emission factor			Reference
					TSP	PM_{10}	$PM_{2.5}$	
Municipal solid waste	114	Various	Electricity plant, CHP plant, heating plant	Effective emission control (BAT)	15	13	10	CEPMEIP, (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)
(Solid)				Conventional emission control	100	70	55	CEPMEIP (uncontrolled. optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)
Ind. waste	115	Various	Electricity, CHP, heating plant	Effective emission control (BAT)	15	13	10	CEPMEIP, (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)
				Conventional emission control	100	70	55	CEPMEIP (uncontrolled, optimised combustion), (N.B. care should be taken using this factor as waste burning is often controlled under national/international regulation to a more stringent specification)

Table 8.2d Emission factors for combustion processes burning natural gas.

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Natural gas	301	Various	Electricity, CHP and heating plant	Burner with optimised combustion	0.1	0.1	0.1	CEPMEIP
				Conventional installation	0.2	0.2	0.2	CEPMEIP
				Conventional installation	0.9	0.9	0.9	USEPA AP-42 filterable PM (all PM stated to be PM_1)

Table 8.2e Emission factors for combustion of derived gases.

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Gas works gas	311	Various	Electricity, CHP and heating plant	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Clean fuel, Conventional installation	0.2	0.2	0.2	CEPMEIP (conventional installation)
				Conventional installation	5	5	5	CEPMEIP. (N.B. High PM due to fuel quality)
Other gaseous	314	Various	Electricity, CHP and heating plant	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
fuel								
				Conventional installation	5	5	5	CEPMEIP
Coke oven gas	304	Various	Electricity, CHP heating plant, coke ovens	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Clean fuel, conventional installation	0.2	0.2	0.2	CEPMEIP (conventional installation)
				Conventional installation	5	5	5	CEPMEIP.
Blast furnace gas	305	Various	Electricity, CHP and heating plant, coke ovens	Clean fuel, efficient combustion	0.1	0.1	0.1	CEPMEIP
				Clean fuel, Conventional installation	0.2	0.2	0.2	CEPMEIP (conventional installation)
				Conventional installation	5	5	5	CEPMEIP.

Table 8.2f Emission factors for combustion of heavy fuel oil.

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Residual fuel oil	203	Various	Electricity, CHP and heating plant	Low S fuel with optimised burner or abatement	3	3	2.5	CEPMEIP (equivalent to about 10 mg.Nm3 or BAT)
				Low S fuel, efficient combustion	14	12	10	CEPMEIP. About 50 mg.Nm3 (EU LCPD limit for existing plant)
				Low-Medium S fuel, conventional installation	20	15	9	CEPMEIP (equivalent. to about 70 mg.Nm3.
				Low-Medium S fuel, conventional installation	60	50	40	CEPMEIP, the higher of two entries used about 200 mg.Nm3
				High S fuel	210	190	130	CEPMEIP, the lower of two entries for high S used. (N.B. such a high emission concentration 750 mg.Nm3 would apply to few if any plant)
Petroleum coke	110	1 A 1 b	Oil refineries	Conventional, multicyclone	100	60	35	CEPMEIP, N.B the factor is very high compared to the EU LCP Directive ELVs and BAT for large furnaces. Bit Coal factors more appropriate.

Table 8.2g Emission factors for combustion of other liquid fuels.

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Gas/Diesel oil	205	Various	Electricity, CHP, heating plant	Optimised burner	2	2	2	CEPMEIP
				Conventional burner	5	5	5	CEPMEIP
Naphtha	210	1 A 1 b	Oil refineries	All units	5	5	5	CEPMEIP
Liquefied Petroleum gas	303	Various	Electricity, CHP, heating plant	Optimised burner	0.1	0.1	0.1	CEPMEIP
				Conventional burner	5	5	5	CEPMEIP
Refinery gas	308	Various	Electricity, CHP, heating plant	Optimised burner	0.1	0.1	0.1	CEPMEIP
				Conventional burner	5	5	5	CEPMEIP
Other oil	224	Various	Electricity, CHP, heating plant	Low S fuel, optimised burner	3	3	2.5	CEPMEIP
				Low S fuel, efficient combustion	14	12	10	CEPMEIP for residual oil. About 50 mg.Nm3 (LCPD limit for existing plant)
				Low-Medium S fuel, conventional installation	20	15	9	CEPMEIP (equiv. to about 70 mg.Nm3.
				Low-Medium S fuel, conventional installation	60	50	40	CEPMEIP (highest of similar entries with TSP of 35, 40, 50 and 60 used. About 200 mg.Nm^{-3})

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
				High S fuel	210	190	130	CEPMEIP, lower of two entries for high S used. (N.B. this is a very high emission concentration ~750 mg.Nm3)

Table 8.2h Emission factors for combustion of biomass

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Wood	111	Various	Electricity, CHP, heating plant	Modern, BAT unit <20 mg.Nm3 TSP	7	7	6	TSP scaled from BAT benchmark, fractions applied based on Bit coal
				Older unit, <100 mg.Nm3 TSP	35	25	12	TSP scaled from emission concentration, fractions based on bit coal
				Uncontrolled conventional	100	70	55	CEPMEIP (equiv. To an uncontrolled multicyclone)
Charcoal	112	1 A 2 c	Chemicals	Conventional large unit with multicyclone	100	60	35	CEPMEIP (N.B. the use of charcoal in LCP is likely to be rare.
Black liquour	215	1 A 2 f	Textile & leather (Pulp and Paper ?)	Conventional installation	160	150	150	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor**			**Reference**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Biogas	309	Various	Electricity, CHP, heating plant	Modern optimised large installation	3	3	2.5	CEPMEIP (cleaned fuel)
				Conventional burner	5	5	5	CEPMEIP
				Modern, optimised	20	15	10	CEPMEIP (gasification plant), *seems high for gaseous fuel*
				Conventional installation	*160*	*150*	*150*	CEPMEIP (N.B. such a high emission concentration would apply to few if any plant)

8.3 Measured Emission Factors for consideration in Tier 3 Methodology

Annex 1 lists measurement derived PM emission factor data typical of that required for a tier 3 approach for large combustion plant – see also Section 15.

9 SPECIES PROFILES

The US EPA (2003) undertook a review of species profiles within $PM_{2.5}$ and reports particle size distribution data for a variety of fuels and combustion and abatement technologies. Some of these data are dated and have high uncertainty ratings. Profiles of other materials are not available.

Table 8.2j US EPA (2003) $PM_{2.5}$ species profiles

Profile ref	Profile name	Component				
		POA	PEC	GSO4	PNO3	Other
22002	Residual Oil Combustion	0.1075	0.0869	0.5504	0.0005	0.2547
22003	Distillate Oil Combustion	0.0384	0.0770	0.3217	0.0024	0.5605
22004	Natural Gas Combustion	0.6000	0.0000	0.2000	0.0055	0.1945
22007	Liquid Waste Combustion	0.0540	0.1050	0.0680	0.0000	0.7730
22009	Solid Waste Combustion	0.0068	0.0350	0.0680	0.0000	0.8902
NCOAL	Coal Combustion	0.20	0.01	0.16	0.005	0.625
NWWAS	Wood Waste Boiler	0.39	0.14	0.08	0	0.39

Notes:
POA - Primary organic aerosol derived from organic carbon
PEC - Elemental Carbon
GSO4 - Sulphate
PNO3 - Nitrate
Other – Remainder of $PM_{2.5}$ material emitted.

Note that the data for the coal combustion and other profiles are derived from dilution tunnel measurements and may not be directly comparable with primary $PM_{2.5}$.

10 UNCERTAINTY ESTIMATES

The overall ‘Uncertainty’ in national emission inventories may be significant – as illustrated in Table 9.1.

Table 9.1 Uncertainty estimate for selected pollutants in the UK air emission inventory (NAEI, 2005).

Pollutant	Estimated Uncertainty (%)
PM_{10}	-20 to +50
$PM_{2.5}$	-20 to +30
$PM_{1.0}$	-10 to +20
$PM_{0.1}$	+/- 10
Sulphur Dioxide	+/- 3
Oxides of Nitrogen	+/- 8
NMVOCs	+/- 10
Ammonia	+/- 20

There is uncertainty in both the aggregated emission factors and activity data used to estimate emissions i.e. the imprecision and error to be expected from the application of an 'average' emission factor or activity statistic to estimate emissions from a specific sector - an artificial grouping of 'similar' sources.

The uncertainty is partly the result of how emission factors are developed and applied. In the case of primary particulate matter, the expanded statistical uncertainty is made up of: between plant variance, within plant variance, and uncertainties associated with the measurement methodology used and the aggregation of data. The measurement data in Annex 1 illustrates the variability in emission factors that occurs from between plant variance.

Process measurements, from which emission factors are developed at individual facility level, are subject to both systematic and random errors in the determination of mass concentration, mass emission, size distribution, and analytical errors etc.

In addition bias may exist in emission factors arising from:

1. Assumptions made about the abatement used on 'typical' industrial installations. For example emission factors 'age', the factors widely used in the Guidebook and hence by many countries as default emission factors in their national inventories become out of date. Recent measurement work suggests that they may overestimate emissions from the industrial processes subject to more modern industrial emissions regulation. They may, however, still be fully representative for older plant, small plant, or for poorer fuels;
2. Assumptions about the relationship between TSP and PM10/$PM_{2.5}$. The technical literature is comprehensive for TSP and the data quality can be good if measurements have been made using the international standard methods that are available (typically the 95% confidence limit ~10%). But a variety of methods are used for particle size fractionation and as yet there are no harmonised international standards to ensure comparability. Published measurement data for PM10 is sparse, that for $PM_{2.5}$ emissions more so. An added complication is that the methodology for the

determination of TSP differs from that of PM10 and $PM_{2.5}$ and so the two need not correlate directly.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

The stack emission factors described in the Guidebook, and all the PM_{10} emission factors, are based whenever possible on measurements. Particle measurements have often been made on the mass of total particulate matter and then converted to PM_{10} based either on the size distribution of the sample collected or, more usually, on size distributions given in the literature. There may be secondary sources of particulate matter, that are diffuse or fugitive in nature e.g. emissions from coke ovens, stockpiles, ash handling etc. These emissions are difficult to measure and in some cases it is likely that no entirely satisfactory measurements have ever been made, in many cases estimates of emissions from such sources are missing.

There is very little published data suitable for emission inventory compilation. I.e. representative data of known quality relating a) quantities of (particulate) material released to b) the activity associated with the release of that pollutant. Suitable data and associated information would record the determination of mass emissions rates using standardized measurement methods or calculation-based methods. Ideally such methods would cover the planning and execution of the data collection programme including: the selection of sampling methodology, choice of equipment, suitable working procedures, the calculation of representative emissions rates, the selection of matching activity data, the determination of sampling/measurement uncertainty, and the reporting of information in a form that is suitable for calculating emissions factors.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

Combustion plants should be considered as point sources if plant specific data are available. Otherwise national emissions should be disaggregated on the basis of plant capacity, employment or population statistics.

13 TEMPORAL DISAGGREGATION CRITERIA

Combustion processes can be considered as a continuous process however individual combustion plant may have daily and/or seasonal temporal profiles.

14 ADDITIONAL COMMENTS

See chapter B111.

15 SUPPLEMENTARY DOCUMENTS

Digest of UK Energy Statistics

Recommendations for the Update and Improvement of Existing $PM_{2.5}$ Split Factors – Note from Pacific Environmental Services to US EPA 29 September 2003

IIASA RAINS data

16 VERIFICATION PROCESSES

The applicability of the emission factors quoted, in Section 8 above, for use with highly regulated plant may be verified using the measurement data listed in Annex 1.

17 REFERENCES

EMEP/CORINAIR Emission Inventory Guidebook – 2005, EEA (European Environment Agency) Chapter B111

IPPC Best Available Techniques Reference Document on the Production of Iron and Steel, December 2001, http://eippcb.jrc.es

IPPC Best Available Techniques Reference Document on Large Combustion Plants, December 2001, http://eippcb.jrc.es

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NAEI (2005) UK National Atmospheric Emissions Inventory: UK Emissions of Air Pollutants 1970 to 2003, October 2005

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Visschedijk, A.J.H., J. Pacyna, T. Pulles, P. Zandveld and H. Denier van der Gon, 2004, Cooordinated European Particulate Matter Emission Inventory Program (CEPMEIP), In: P. Dilara et. Al (eds), Proceedings of the PM emission inventories scientific workshop, Lago Maggiore, Italy, 18 October 2004, EUR 21302 EN, JRC, pp 163 - 174

18 BIBLIOGRAPHY

19 RELEASE VERSION, DATE AND SOURCE

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20 POINT OF ENQUIRY

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ANNEX 1A – SUMMARY OF RECENT MEASURED PM_{10} DATA ON COMBUSTION SOURCES

Combustion Type	Process	Size indication	Fuel	Abatement Measures	PM_{10} Emission Factor or concentration	Units	Source[6]	CEPMEIP Factor	CEPMEIP Units
Coal	Combustion Plant	180 MW	dry brown coal	ESP horizontal, scrubber	1.44	g/GJ	LAU	30.00	g/GJ
		146 MW	brown coal briquette, Limestone	ESP horizontal, drying desulphurisation	1.35	g/GJ	LAU		g/GJ
		119 MW	raw brown coal	ESP horizontal, desulph., NOx removal	6.13	g/GJ	LAU	30.00	g/GJ
		1000MW	hard coal	ESP, desulphurisation, NOx removal	0.33	g/GJ	LAU	25.00	g/GJ
		1000MW	hard coal	ESP, desulphurisation, NOx removal	0.30	g/GJ	LAU	25.00	g/GJ
		-	sub-bituminous coal	ESP	11.00	mg/MJ	NRCAN	25.00	g/GJ
		-	lignite	ESP	1.80	mg/MJ	NRCAN	30.00	g/GJ
		-	75% lignite/25% bituminous	ESP	1.10	mg/MJ	NRCAN		
		120 MW	Powdercoal	ESP	51.30	mg/Nm3	VITO	70.00	g/GJ
		-	lignite	Fabric filter, desulphurisation	0.1	mg/m3	TESO	8.00	g/GJ

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Combustion Type	**Process**	**Size indication**	**Fuel**	**Abatement Measures**	**PM_{10} Emission Factor or concentration**	**Units**	**Source[6]**	**CEPMEIP Factor**	**CEPMEIP Units**
				system					
		-	lignite	ESP, desulphurisation system	1.3	mg/m3	TESO	30.00	g/GJ
		-	hard coal	Fabric filter	7.5	mg/m3	TESO	6.00	g/GJ
		-	lignite	ESP, desulphurisation system	0.4	mg/m3	TESO	30.00	g/GJ
	Dry Bottom Ash Furnace	-	hard coal	ESP	24.4	mg/m3	TESO	25.00	
		-	lignite	ESP, desulphurisation system	1.5	mg/m3	TESO	30.00	g/GJ
		-	lignite, heavy fuel oil	ESP, desulphurisation system, fabric filter	0.2	mg/m3	TESO		
		-	lignite	ESP, desulphurisation system	14.9	mg/m3	TESO	80.00	g/GJ
		-	hard coal	ESP	0.2	mg/m3	TESO	25.00	g/GJ
		-	hard coal	Fabric filter	0.8	mg/m3	TESO	6.00	g/GJ
		-	hard coal	Fabric filter	0.2	mg/m3	TESO	6.00	g/GJ
		-	coal	ESP	1.5	mg/m3	TESO	25.00	g/GJ
	Grate and Dry Bottom Ash Furnace	-	lignite	ESP, desulphurisation system	1.2	mg/m3	TESO	80.00	g/GJ
	Grate Boiler	-	hard coal	Fabric Filter	0.7	mg/m3	TESO	6.00	g/GJ
	Grate Firing	-	lignite	ESP	6.8	mg/m3	TESO	30.00	g/GJ
	Boiler for Pulverised Solid Fuel	-	hard coal, light fuel oil	ESP	22.8	mg/m3	TESO		
		-	hard coal, lignite	ESP, desulphurisation	6.3	mg/m3	TESO	25.00	g/GJ

Combustion Type	Process	Size indication	Fuel	Abatement Measures	PM_{10} Emission Factor or concentration	Units	Source[6]	CEPMEIP Factor	CEPMEIP Units
				system					
		-	lignite	ESP, desulphurisation system	1.9	mg/m3	TESO	30.00	g/GJ
		-	lignite	ESP, desulphurisation system	4.2	mg/m3	TESO	30.00	g/GJ
		-	hard coal	Fabric filter	0.1	mg/m3	TESO	6.00	g/GJ
	Fluidised bed boiler	-	lignite	ESP, desulphurisation system, fabric filter	2.5	mg/m3	TESO	8.00	g/GJ
		-	lignite	Fabric filter, desulphurisation system	0.9	mg/m3	TESO	8.00	g/GJ
		-	hard coal, blast furnace gas	ESP	0.2	mg/m3	TESO		
		-	hard coal, blast furnace gas	ESP	0.4	mg/m3	TESO		
		-	hard coal, coke oven gas, blast furnace gas	ESP	4.3	mg/m3	TESO		
	Combustion Plant	10 MW	heavy oil	additive	12.33	g/GJ	LAU	15.00	g/GJ
		10 MW	heavy oil	additive	12.95	g/GJ	LAU	15.00	g/GJ
		10 MW	heavy oil, urea	additive, SNCR	15.29	g/GJ	LAU	15.00	g/GJ
		10 MW	heavy oil, urea	additive, SNCR	18.04	g/GJ	LAU	15.00	g/GJ
		20 t/h steam	heavy oil	SNCR	1.86	g/GJ	LAU	3.00	g/GJ
		270 MW	heavy oil	NOx removal	5.75	g/GJ	LAU	3.00	g/GJ
		270 MW	heavy oil	additive, NOx removal	4.49	g/GJ	LAU	3.00	g/GJ
		270 MW	heavy oil	NOx removal	4.79	g/GJ	LAU	3.00	g/GJ
		270 MW	heavy oil	additive, NOx removal	4.65	g/GJ	LAU	3.00	g/GJ

Combustion Type	**Process**	**Size indication**	**Fuel**	**Abatement Measures**	**PM_{10} Emission Factor or concentration**	**Units**	**Source[6]**	**CEPMEIP Factor**	**CEPMEIP Units**
		-	residual oil	-	29.00	mg/MJ	NRCAN	20.00	g/GJ
		-	heavy fuel oil, natural gas	-	6.80	mg/m3	TESO		
		-	heavy fuel oil, gas fuels	-	15.30	mg/m3	TESO		
	Combustion Plant	1.4 MW	saw chips, saw dust	cyclone	100.37	g/GJ	LAU	70.00	g/GJ
		1.4 MW	saw chips, saw dust	cyclone	75.87	g/GJ	LAU	70.00	g/GJ
		0.8 MW	saw chips, saw dust	cyclone	102.81	g/GJ	LAU	70.00	g/GJ
		3 MW	hogged wood	cyclone	96.32	g/GJ	LAU	70.00	g/GJ
		2.3 MW	rest of chipboards	multicyclone	119.09	g/GJ	LAU	70.00	g/GJ
		1.1 MW	piece of wood, saw chips	cyclone	131.93	g/GJ	LAU	70.00	g/GJ
		2 MW	hogged wood, wood waste	ESP	21.41	g/GJ	LAU	70.00	g/GJ
		7.9-9.5 MW	wood, wood chips	ESP	7.53	g/GJ	LAU	70.00	g/GJ
		7.9-9.5 MW	natural gas, wood, wood chips	ESP	7.41	g/GJ	LAU	70.00	g/GJ
		15 MW	hogged wood, rest wood, wood chips	ESP	3.22	g/GJ	LAU	70.00	g/GJ
		1.5 MW	hogged wood	chimney gas condensation, multi-cyclone	17.30	g/GJ	LAU	70.00	g/GJ
		1.5 MW	hogged wood	chimney gas condensation, multi-cyclone	21.05	g/GJ	LAU	70.00	g/GJ
		31 t/h steam	matured wood	cyclone, fabric	4.72	g/GJ	LAU	70.00	g/GJ

Combustion Type	Process	Size indication	Fuel	Abatement Measures	PM$_{10}$ Emission Factor or concentration	Units	Source[6]	CEPMEIP Factor	CEPMEIP Units
				filter, NO$_x$ removal					
	Grate Boiler		bark, natural gas	ESP	4.90	mg/m3	TESO		
Waste	hazardous waste incineration plant	-	hazardous waste	fabric filter, desulphurisation system	10.30	mg/m3	TESO		
	waste incineration plant	-	municipal solid waste	ESP, desulphurisation system	0.90	mg/m3	TESO	100.00	g/tonne
	home heating boiler	-	mixture of fuels and household waste	-	39.90	mg/m3	TESO		
	old growth , shredder	30 t/h	lumber, demolition wood, timber waste	fabric filter	2.71	g/tonne	LAU		

ANNEX 1B – SUMMARY OF RECENT MEASURED PM$_{2.5}$ DATA ON COMBUSTION SOURCES

Combustion Type	Process	Size indication	Fuel	Abatement Measures	PM$_{2.5}$ Emission Factor or concentration	Units	Source	CEPMEIP Factor	CEPMEIP Units
Coal	Combustion Plant	180 MW	dry brown coal	ESP horizontal, scrubber	1.20	g/GJ	LAU	14.00	g/GJ
		146 MW	brown coal briquette, Limestone	ESP horizontal, drying desulphurisation	1.09	g/GJ	LAU		g/GJ
		119 MW	raw brown coal	ESP horizontal, desulph., NOx removal	4.15	g/GJ	LAU	14.00	g/GJ
		1000MW	hard coal	ESP, desulphurisation,	0.26	g/GJ	LAU	12.00	g/GJ

Combustion Type	Process	Size indication	Fuel	Abatement Measures	$PM_{2.5}$ Emission Factor or concentration	Units	Source	CEPMEIP Factor	CEPMEIP Units
				NOx removal					
		1000MW	hard coal	ESP, desulphurisation, NOx removal	0.23	g/GJ	LAU	12.00	g/GJ
		-	sub-bituminous coal	ESP	8.30	mg/MJ	NRCAN	3.00	g/GJ
		-	lignite	ESP	1.20	mg/MJ	NRCAN	3.00	g/GJ
		-	75% lignite/25% bituminous	ESP	28.10	mg/MJ	NRCAN		
		120 MW	Powdercoal	ESP	30.24	mg/Nm3	VITO	17.00	g/GJ
		-	lignite	Fabric filter, desulphurisation system	0.1	mg/m3	TESO	6.00	g/GJ
		-	lignite	ESP, desulphurisation system	1.3	mg/m3	TESO	14.00	g/GJ
		-	hard coal	Fabric filter	7.4	mg/m3	TESO	5.00	
		-	lignite	ESP, desulphurisation system	0.4	mg/m3	TESO	14.00	g/GJ
	Dry Bottom Ash Furnace	-	hard coal	ESP	9.6	mg/m3	TESO	12.00	
		-	lignite	ESP, desulphurisation system	1.3	mg/m3	TESO	14.00	g/GJ
		-	lignite, heavy fuel oil	ESP, desulphurisation system, fabric filter	0.2	mg/m3	TESO		
		-	lignite	ESP, desulphurisation system	12.3	mg/m3	TESO	20.00	g/GJ
		-	hard coal	ESP	0.2	mg/m3	TESO	12.00	
		-	hard coal	Fabric filter	0.6	mg/m3	TESO	5.00	

Combustion Type	Process	Size indication	Fuel	Abatement Measures	$PM_{2.5}$ Emission Factor or concentration	Units	Source	CEPMEIP Factor	CEPMEIP Units
		-	hard coal	Fabric filter	0.2	mg/m3	TESO	5.00	
		-	coal	ESP	1.4	mg/m3	TESO	12.00	g/GJ
	Grate and Dry Bottom Ash Furnace	-	lignite	ESP, desulphurisation system	0.5	mg/m3	TESO	20.00	g/GJ
	Grate Boiler	-	hard coal	Fabric Filter	0.6	mg/m3	TESO	5.00	g/GJ
	Grate Firing	-	lignite	ESP	6	mg/m3	TESO	14.00	g/GJ
	Boiler for Pulverised Solid Fuel	-	hard coal, light fuel oil	ESP	20.8	mg/m3	TESO		
		-	hard coal, lignite	ESP, desulphurisation system	5.9	mg/m3	TESO		
		-	lignite	ESP, desulphurisation system	1.9	mg/m3	TESO	14.00	g/GJ
		-	lignite	ESP, desulphurisation system	4.1	mg/m3	TESO	14.00	g/GJ
		-	hard coal	Fabric filter	0.1	mg/m3	TESO	5.00	g/GJ
	Fluidised bed boiler	-	lignite	ESP, desulphurisation system, fabric filter	1.2	mg/m3	TESO	6.00	g/GJ
		-	lignite	Fabric filter, desulphurisation system	0.8	mg/m3	TESO	6.00	g/GJ
		-	hard coal, blast furnace gas	ESP	0.4	mg/m3	TESO		
		-	hard coal, blast furnace gas	ESP	0.1	mg/m3	TESO		
		-	hard coal, coke oven gas, blast furnace gas	ESP	4.1	mg/m3	TESO		

Combustion Type	Process	Size indication	Fuel	Abatement Measures	$PM_{2.5}$ Emission Factor or concentration	Units	Source	CEPMEIP Factor	CEPMEIP Units
Oil	Combustion Plant	10 MW	heavy oil	additive	10.30	g/GJ	LAU	10.00	g/GJ
		10 MW	heavy oil	additive	9.18	g/GJ	LAU	10.00	g/GJ
		10 MW	heavy oil, urea	additive, SNCR	12.21	g/GJ	LAU	10.00	g/GJ
		10 MW	heavy oil, urea	additive, SNCR	13.12	g/GJ	LAU	10.00	g/GJ
		20 t/h steam	heavy oil	SNCR	1.38	g/GJ	LAU	11.00	g/GJ
		270 MW	heavy oil	NOx removal	4.69	g/GJ	LAU	2.50	g/GJ
		270 MW	heavy oil	additive, NOx removal	4.15	g/GJ	LAU	2.50	g/GJ
		270 MW	heavy oil	NOx removal	4.41	g/GJ	LAU	2.50	g/GJ
		270 MW	heavy oil	additive, NOx removal	4.23	g/GJ	LAU	2.50	g/GJ
		-	residual oil	-	28.10	mg/MJ	NRCAN	10.00	g/GJ
		-	heavy fuel oil, natural gas	-	6.70	mg/m3	TESO		
		-	heavy fuel oil, gas fuels	-	15.20	mg/m3	TESO		
Waste	Combustion Plant	1.4 MW	saw chips, saw dust	cyclone	71.66	g/GJ	LAU	55.00	g/GJ
		1.4 MW	saw chips, saw dust	cyclone	52.25	g/GJ	LAU	55.00	g/GJ
		0.8 MW	saw chips, saw dust	cyclone	65.47	g/GJ	LAU	55.00	g/GJ
		3 MW	hogged wood	cyclone	90.13	g/GJ	LAU	55.00	g/GJ
		2.3 MW	rest of chipboards	multi-cyclone	91.92	g/GJ	LAU	55.00	g/GJ
		1.1 MW	piece of wood, saw chips	cyclone	80.80	g/GJ	LAU	55.00	g/GJ
		2 MW	hogged wood, wood waste	ESP	16.10	g/GJ	LAU	55.00	g/GJ
		7.9-9.5 MW	wood, wood chips	ESP	5.49	g/GJ	LAU	55.00	g/GJ

Combustion Type	**Process**	**Size indication**	**Fuel**	**Abatement Measures**	**$PM_{2.5}$ Emission Factor or concentration**	**Units**	**Source**	**CEPMEIP Factor**	**CEPMEIP Units**
		7.9-9.5 MW	natural gas, wood, wood chips	ESP	5.21	g/GJ	LAU	55.00	g/GJ
		15 MW	hogged wood, rest wood, wood chips	ESP	1.95	g/GJ	LAU	55.00	g/GJ
		1.5 MW	hogged wood	chimney gas condensation, multi-cyclone	17.25	g/GJ	LAU	55.00	g/GJ
		1.5 MW	hogged wood	chimney gas condensation, multi-cyclone	20.46	g/GJ	LAU	55.00	g/GJ
		31 t/h steam	matured wood	cyclone, fabric filter, NO_x removal	1.85	g/GJ	LAU	55.00	g/GJ
		-	wooden briquettes	-	12.10	mg/m3	TESO	135.00	g/GJ
	Grate Boiler		bark, natural gas	ESP	4.80	mg/m3	TESO		
Waste	hazardous waste incineration plant	-	hazardous waste	fabric filter, desulphurisation system	8.80	mg/m3	TESO		
	waste incineration plant	-	municipal solid waste	ESP, desulphurisation system	0.80	mg/m3	TESO	100.00	g/tonne
			municipal solid waste	ESP	1.80	ng/Nm3	VITO	101.00	g/tonne
	home heating boiler	-	mixture of fuels and household waste	-	34.60	mg/m3	TESO		
	old growth , shredder	30 t/h	lumber, demolition wood, timber waste	fabric filter	0.49	g/tonne	LAU		

SNAP CODE:	**010104 & 010105** **010204 & 010205** **010404 & 010405** **020104 & 020105** **020203 & 020204** **020303 & 020304** **030104 & 030105**

SOURCE ACTIVITY TITLE: **COMBUSTION IN ENERGY & TRANSFORMATION INDUSTRIES**
Particulate emissions from gas turbines and internal combustion engines

NOSE CODE:	**101.01** **101.02**
NFR CODE:	**1 A 1 a,b,c** **1 A 2 a-f** **1 A 4 b,c,i**
ISIC	**3510**

1 ACTIVITIES INCLUDED

This supplement covers emissions of particulate matter (PM) released from combustion processes within the energy and transformation industries by internal combustion engines - gas turbines and reciprocating engines . This supplement includes guidance on estimating total PM (TSP), PM_{10} and $PM_{2.5}$ emissions from these sources. Information related to the estimation of emissions of other pollutants from this sector is given in chapter B111.

2 CONTRIBUTION TO TOTAL EMISSION

The contributions of PM_{10} and $PM_{2.5}$ emissions from combustion plant to total emissions in countries according to the CORINAIR90 inventory are indicated in Table 2.1.

Table 2.1 Contribution to total particulate matter emissions from 2004 EMEP database (WEBDAB)

NFR Sector	Data	PM_{10}	$PM_{2.5}$	TSP
1 A 1 a - Public Electricity and Heat Production[a]	No. of countries reporting	26	26	27
	Lowest Value	0.2%	0.2%	0.2%
	Typical Contribution	11.7%	10.1%	12.8%
	Highest Value	48.8%	47.8%	48.4%
1 A 2 - Manufacturing Industries and Construction[b]	No. of countries reporting	26	26	26
	Lowest Value	0.7%	0.6%	0.6%
	Typical Contribution	9.0%	9.5%	7.9%
	Highest Value	20.7%	22.1%	25.7%
1 A 4 a - Commercial / Institutional[c]	No. of countries reporting	23	23	23
	Lowest Value	0.1%	0.1%	0.1%
	Typical Contribution	3.9%	3.4%	4.5%
	Highest Value	19.3%	22.2%	29.5%
1 A 4 b - Residential[d]	No. of countries reporting	3	2	3
	Lowest Value	2.0%	6.5%	3.7%
	Typical Contribution	14.9%	26.2%	10.8%
	Highest Value	36.6%	45.8%	15.4%
1 A 4 b i - Residential plants[e]	No. of countries reporting	23	23	23
	Lowest Value	2.7%	5.8%	0.8%
	Typical Contribution	28.3%	33.1%	22.0%
	Highest Value	67.1%	74.6%	53.2%
1 A 5 a - Other, Stationary (including Military)[f]	No. of countries reporting	7	7	7
	Lowest Value	0.0%	0.0%	0.0%
	Typical Contribution	0.1%	0.1%	0.1%
	Highest Value	0.5%	0.4%	0.6%

[a] Includes contribution from Chapter 112

[b] Includes contributions from Chapter 112 and 316 (SNAP 030106)

[c] Includes contribution from Chapter 112 and 216 (SNAP 020205)

[d] Includes contribution from Chapter 810

[e] Includes contribution from Chapter 112

[f] Includes contribution from Chapter 112 and 216 (SNAP 020106)

3 GENERAL

3.1 Description

This supplement considers emissions of PM generated by internal combustion engines including gas turbines and reciprocating engines. Reciprocating engines include compression ignition (CI) and spark ignition (SI) technologies. Other emissions from this source category are considered in B111.

3.2 Definitions

See B111.

3.3 Techniques

See B111 for more information on combustion plant types and fuels.

Gas turbines range in size from <100kW electrical generation (microturbines) to over 250 MW electrical generation. The most common primary fuel is natural gas but gas oil and a range of derived fuels are also used.

Diesel compression engines also range from a few kW to about 50 MW electrical generation. The most typical fuel is gas oil but, various derived fuels can be used and heavy fuel oil is used on some large units. Dual fuel engines burn natural gas or derived gases with a small quantity of gas oil.

3.4 Emissions

Internal combustion engines use liquid or gaseous fuels and particulate emissions result mainly from combustion of the fuels.

Combustion of liquid fuels can generate solid residues which may be deposited within exhaust ducts oron heat exchanger surfaces (soot and fly ash). Suspended ash material in exhaust gases may be retained by particulate abatement or other emission abatement equipment (abatement residues). Material which remains in the flue gases beyond the abatement equipment and passes to the atmosphere is primary PM. Secondary PM is formed by chemical and physical processes after discharge to atmosphere and is NOT considered here.

3.5 Controls

Particulate emission reduction is not usually associated with combustion of gaseous fuels except where derived fuels are used (in which case filtering or other treatment of the fuel gas is the preferred approach). Particulate abatement equipment may be used with oil fuels and can include, fuel pre-treatment to reduce mineral content (particularly for heavy fuel oil), diesel particle filters (on smaller units) or more traditional emission abatement equipment. . N.B. Emission concentrations of TSP from compression ignition engines associated with Best Available Techniques (BAT) as defined by EU Integrated Pollution Prevention and Control regulations are 30 mg m^{-3} for gas oil and 50 mg m^{-3} for heavy fuel oil.

4 SIMPLER METHODOLOGY

Emissions can be estimated at different levels of complexity; it is useful to think in terms of three tiers[1]:

Tier 1: a method using readily available statistical data on the intensity of processes ("activity rates") and default emission factors. These emission factors assume a linear relation between the intensity of the process and the resulting emissions. The Tier 1 default emission factors also assume an average or typical process description.

Tier 2: is similar to Tier 1 but uses more specific emission factors developed on the basis of knowledge of the types of processes and specific process conditions that apply in the country for which the inventory is being developed.

Tier 3: is any method that goes beyond the above methods. These might include the use of more detailed activity information, specific abatement strategies or other relevant technical information.

By moving from a lower to a higher Tier it is expected that the resulting emission estimate will be more precise and will have a lower uncertainty. Higher Tier methods will need more input data and therefore will require more effort to implement.

For the Tier 1 simpler methodology, where limited information is available, a default emission factor can be used together with activity information for the country or region of interest with limited or no specification on the type of technology or the type and efficiency of control equipment. For a Tier 2 approach an approximation may be made of the most representative technologies, thereby allowing the use of more appropriate default factors if more detailed activity data are available.

Consequently the simplest methodology (Tier 1) is to combine an activity rate (AR) with a comparable, representative, value of the emissions per unit activity, the emission factors (EF). The basic equation is:

$$\text{Emission} = \text{AR} \times \text{EF}$$

In the energy sector, for example, fuel consumption would be activity data and mass of material emitted per unit of fuel consumed would be a compatible emission factor.

NOTE: The basic equation may be modified, in some circumstances, to include emission reduction efficiency (abatement factors).

The Tier 2 methodology is a modified version of this basic equation:

$$\text{Emission} = \sum((\text{AR}_1 \times \text{EF}_1) + (\text{AR}_2 \times \text{EF}_2) + \ldots(\text{AR}_n \times \text{EF}_n))$$

Default emission factors for this purpose are provided in Sections 8.1 and 8.2.

---

[1] The term "Tier" is used in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and adopted here for easy reference and to promote methodological harmonization.

5 DETAILED METHODOLOGY

The detailed methodology (equivalent to Tier 3) to estimate emissions of pollutants from combustion plant >50 MW_{th} is based on measurements or estimations using plant specific emission factors - guidance on determining plant specific emission factors is given in Measurement Protocol Annex.

In many countries, operators of combustion plant >50MWth will report emissions to comply with regulatory requirements and this data can be used to help compile the national inventory.

The recommended detailed methodology to estimate emissions of PM from combustion activities is based on measurements and/or estimations using technology-specific emission factors.

Information on the type of the process and activity data, for example combustion and abatement technologies, is required to assign appropriate emission factors.

6 ACTIVITY STATISTICS

Activity statistics for energy consumption or other relevant national activity data for estimating emissions using the simpler estimation methodology (Tiers 1 and 2) are available from national statistics.

The detailed methodology (Tier 3) requires more detailed information such as the amount and types of fuel consumed within individual combustion plant or industry sectors. These data are not always easily available although in many countries operators do report fuel use for emission trading or other legislative requirements.

Further guidance is provided in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, volume 2 on energy, Chapter 1.

7 POINT SOURCE CRITERIA

Large combustion plants are regarded as point sources if plant specific data are available.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Default Emission Factors For Use With Simpler Methodology (Tier 1)

Fuel	Technology	**Emission factor, $g.GJ^{-1}$**			Notes
		TSP	**PM_{10}**	**$PM_{2.5}$**	
Hard Coal		-	-	-	Not applicable
Brown Coal		-	-	-	Not applicable
Other solid fuels		-	-	-	Not applicable

Natural gas	Gas turbines	0.9	0.9	0.9	US EPA
	Spark ignition	18	18	18	US EPA 2 stroke lean burn, 4 stroke lean burn is 0.04 gGJ^{-1}.
Derived gases	Gas turbine	11	11	11	Based on US EPA Landfill gas
Heavy fuel oil	Diesel	28	23	22	US EPA factor for diesel engines
Other liquid fuels	Gas turbine	2.0	2.0	2.0	US EPA factor for PM applied to other fractions
	Diesel	28	23	22	US EPA
Biomass	Gas turbine	11	11	11	Landfill gas
	Gas turbine	5.7	5.7	5.7	Anaerobic digester gas

8.2 Reference Emission Factors For Use With Tier 2 Methodology

Tables 8.2a-z contain reference particulate emission factors for fuel combustion in various technologies with different types of abatement.

Table 8.2a Emission factors for gas turbines combustion processes

Fuel	**NAPFUE**	**NFR Codes**	**Activity description**	**Activity detail**	**Emission factor, g.GJ^{-1}**			**Notes**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Natural gas					0.9	0.9	0.9	Sierra (234 tests), assumes all PM2.5
Gas oil					3	3	3	Sierra (15 tests), assume all PM2.5

Table 8.2b Emission factors for compression ignition combustion processes

Fuel (IPCC Cat)	**NAPFUE**	**NFR Code**	**Activity description**	**Activity detail**	**Emission factor g GJ^{-1}**			**Reference/Comments**
					TSP	**PM_{10}**	**$PM_{2.5}$**	
Natural gas			Dual fuel engine, gas with HFO		11	11	11	LCP BREF, assumed all PM2.5
Heavy fuel oil			Diesel engine		50	41	39	LCP BREF, ‘BAT’ US EPA profile applied
			Diesel engine		<64	53	50	LCP BREF, US EPA profile applied, applicable to older equipment
Gas oil			Diesel engine	<0.02% S	<26	21	20	LCP BREF, US EPA profile
			Diesel engine		<17	14	14	Smaller unit with diesel particulate filter, US EPA profile

9 SPECIES PROFILES

The US EPA (2003) undertook a review of species profiles within $PM_{2.5}$ and reports particle size distribution data for a variety of fuels and combustion and abatement technologies. Some of these data are dated and have high uncertainty ratings. Profiles of other materials are not available.

Table

Profile ref	**Profile name**	**Component**				
		POA	**PEC**	**GSO4**	**PNO3**	**Other**
22002	Residual Oil Combustion	0.1075	0.0869	0.5504	0.0005	0.2547
22003	Distillate Oil Combustion	0.0384	0.0770	0.3217	0.0024	0.5605
22004	Natural Gas Combustion	0.6000	0.0000	0.2000	0.0055	0.1945

Notes:
POA - Primary organic aerosol derived from organic carbon
PEC Elemental Carbon
GSO4 - Sulphate
PNO3 - Nitrate
Other – Remainder of PM2.5 material emitted.

Note that the data are derived from a variety of sources including dilution tunnel measurements and may not be directly comparable with filterable $PM_{2.5}$.

10 UNCERTAINTY ESTIMATES

The overall 'Uncertainty' in national emission inventories may be significant – as illustrated in Table 9.1.

Table 9.1 Uncertainty estimate for selected pollutants in the UK air emission inventory (NAEI, 2005).

Pollutant	Estimated Uncertainty (%)
PM_{10}	-20 to +50
$PM_{2.5}$	-20 to +30
$PM_{1.0}$	-10 to +20
$PM_{0.1}$	+/- 10
Sulphur Dioxide	+/- 3
Oxides of Nitrogen	+/- 8
NMVOCs	+/- 10
Ammonia	+/- 20

There is uncertainty in both the aggregated emission factors and activity data used to estimate emissions i.e. the imprecision and error to be expected from the application of an 'average' emission factor or activity statistic to estimate emissions from a specific sector - an artificial grouping of 'similar' sources.

The uncertainty is partly the result of how emission factors are developed and applied. In the case of primary particulate matter, the expanded statistical uncertainty is made up of: between plant variance, within plant variance, and uncertainties associated with the measurement methodology used and the aggregation of data. The measurement data in Annex 1 illustrates the variability in emission factors that occurs from between plant variance.

Process measurements, from which emission factors are developed at individual facility level, are subject to both systematic and random errors in the determination of mass concentration, mass emission, size distribution, and analytical errors etc.

In addition bias may exist in emission factors arising from:

1. Assumptions made about the abatement used on 'typical' industrial installations. For example emission factors 'age', the factors widely used in the Guidebook and hence by many countries as default emission factors in their national inventories become out of date. Recent measurement work suggests that they may overestimate emissions from the industrial processes subject to more modern industrial emissions regulation. They may, however, still be fully representative for older plant, small plant, or for poorer fuels;

Assumptions about the relationship between TSP and $PM_{10}/PM_{2.5}$. The technical literature is comprehensive for TSP and the data quality can be good if measurements have been made using the international standard methods that are available (typically the 95% confidence limit ~10%). But a variety of methods are used for particle size fractionation and as yet there are no harmonised international standards to ensure comparability. Published measurement data for PM10 is sparse, that for $PM_{2.5}$ emissions more so. An added complication is that the methodology for the determination of TSP differs from that of PM10 and $PM_{2.5}$ and so the two need not correlate directly.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Published $PM_{2.5}$ emission factor information for stationary engines is sparse. It is difficult to form a representative estimate the emissions likely to arise from the range of engine/fuel combinations commonly encountered. Further work is required to develop a more complete range of emission factors.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

Combustion plants should be considered as point sources if plant specific data are available. Otherwise national emissions should be disaggregated on the basis of plant capacity, employment or population statistics.

13 TEMPORAL DISAGGREGATION CRITERIA

Combustion processes can be considered as a continuous process however individual combustion plant may have daily and/or seasonal temporal profiles.

14 ADDITIONAL COMMENTS

See chapter B111 and B111 (S2) for measurement data in Annex 1.

15 SUPPLEMENTARY DOCUMENTS

None

16 VERIFICATION PROCESSES

Published $PM_{2.5}$ emission data for stationary engines is sparse.

17 REFERENCES

AEAT CCGT Measurement data

Digest of UK Energy Statistics

England, G.C., "Development of Fine Particulate Emission Factors and Speciation Profiles for Oil and Gas-fired Combustion Systems, Final Report, 2004."

EMEP/CORINAIR Emission Inventory Guidebook – 2005, EEA (European Environment Agency) Chapter B111

IIASA RAINS data

IPPC Best Available Techniques Reference Document on Large Combustion Plants, December 2001, http://eippcb.jrc.es

IPCC Guidance document

NAEI (2005) UK National Atmospheric Emissions Inventory: UK Emissions of Air Pollutants 1970 to 2003, October 2005

US EPA (1996) Compilation of Air Pollutant Emission Factors Vol.1 Report AP-42 (5th ed.)

US EPA (2003) $PM_{2.5}$ Source Profiles
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Rentz, O.; Karl, U.; Peter, H. Determination and evaluation of emission factors for combustion installations in Germany for the years 1995, 2000 and 2010. French-German Institute for Environmental Research University of Karlsruhe (TH), Dec 2002.

Rubenstein, G. Gas Turbine PM Emissions – Update. Sierra Research, June 2003 Paper to ASME/IGTI Turbo-Expo, Atlanta 2003

18 BIBLIOGRAPHY

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SNAP CODES: (See below)

SOURCE ACTIVITY TITLE: COMBUSTION IN ENERGY & TRANSFORMATION INDUSTRIES
Combustion Plants as Point Sources

The following activities are taken into account, when treating combustion plants individually as point sources.

Combustion plants with a thermal capacity < 300 MW, gas turbines and stationary engines, which may also be considered collectively as area sources, are covered by chapter B112 "Combustion Plants as Area Sources" as well.

SNAP97 Codes	NOSE CODE	NFR CODE	**Combustion plants as point sources** Boilers/Furnaces								
			Thermal capacity [MW]	Public power and cogeneration plants	District heating	Industrial combustion and specific sector	Commercial and institutional combustion	Residential combustion	Agriculture forestry and fishing	Gas turbines	Stationary engines
01 01 01	101.01	1 A 1 a	≥ 300	x							
01 02 01	101.01	1 A 1 a			x						
01 03 01	101.01	1 A 1 b				x					
01 04 01	101.01	1 A 1 c				x					
01 05 01	101.01	1 A 1 c				x					
02 01 01	101.01	1 A 4 a					x				
03 01 01	101.01	1 A 2 a-f				x					
01 01 02	101.02	1 A 1 a	≥ 50 and < 300	x							
01 02 02	101.02	1 A 1 a			x						
01 03 02	101.02	1 A 1 b				x					
01 04 02	101.02	1 A 1 c				x					
01 05 02	101.02	1 A 1 c				x					
02 01 02	101.02	1 A 4 a					x				
02 02 01	101.02	1 A 4 b i						x			
02 03 01	101.02	1 A 4 c i							x		
03 01 02	101.02	1 A 2 a-f				x					
01 01 03	101.03	1 A 1 a	< 50	x							
01 02 03	101.03	1 A 1 a			x						
01 03 03	101.03	1 A 1 b				x					
01 04 03	101.03	1 A 1 c				x					
01 05 03	101.03	1 A 1 c				x					
02 01 03	101.03	1 A 4 a					x				
02 02 02	101.03	1 A 4 b i						x			
02 03 02	101.03	1 A 4 c i							x		
03 01 03	101.03	1 A 2 a-f				x					
01 01 04	101.04	1 A 1 a	not relevant							x	
01 02 04	101.04	1 A 1 a								x	
01 03 04	101.04	1 A 1 b								x	
01 04 04	101.04	1 A 1 c								x	
01 05 04	101.04	1 A 1 c								x	
02 01 04	101.04	1 A 4 a								x	
02 02 03	101.04	1 A 4 b i								x	
02 03 03	101.04	1 A 4 c i								x	
03 01 04	101.04	1 A 2 a-f								x	
01 01 05	101.05	1 A 1 a	not relevant								x
01 02 05	101.05	1 A 1 a									x
01 03 05	101.05	1 A 1 b									x
01 04 05	101.05	1 A 1 c									x
01 05 05	101.05	1 A 1 c									x

SNAP97 Codes	NOSE CODE	NFR CODE	**Combustion plants as point sources** Boilers/Furnaces								
			Thermal capacity [MW]	Public power and cogeneration plants	District heating	Industrial combustion and specific sector	Commercial and institutional combustion	Residential combustion	Agriculture forestry and fishing	Gas turbines	Stationary engines
02 01 05	101.05	1 A 4 a									x
02 02 04	101.05	1 A 4 b i									x
02 03 04	101.05	1 A 4 c i									x
03 01 05	101.05	1 A 2 a-f									x

x = indicates relevant combination

1 ACTIVITIES INCLUDED

This chapter covers emissions from boilers, gas turbines and stationary engines as point sources. According to CORINAIR90, combustion plants with

– a thermal capacity $\geq$ 300 MW
or
– emissions of SO_2 or NO_x or NMVOC > 1,000 Mg/a[1]

should be considered as point sources /41/. Within CORINAIR other combustion plants may also be considered as point sources on a voluntary basis. Different criteria are applied for the classification of combustion plants according to the Large Combustion Plant Directive (88/609/EEC)[2] /9, 42/.

Boilers, gas turbines and stationary engines need to be treated separately (see table at start of this chapter). With regard to boilers, a combustion plant may consist of one single boiler or may comprise a series of boilers of different sizes (joint plant). Therefore, whenever there is more than one boiler on a site, a decision on the aggregation of these facilities to plants has to be taken. Through this decision, an allocation to the respective SNAP categories is achieved. For aggregation criteria see Section 3.2 and Annex 1.

The subdivision of SNAP activities according to CORINAIR90 concerning combustion plants takes into account two criteria:

a) the economic sector concerning the use of energy
  - public power and co-generation,
  - district heating,
  - commercial and institutional combustion,
  - industrial combustion in boilers,
    (Note: Process furnaces are allocated separately.)

---

[1] For CO_2 a further optional criterion for point sources is the emission of > 300 Gg/a.

[2] The Large Combustion Plant Directive covers combustion plants with a thermal capacity $\geq$ 50 MW in the EU. Gas turbines and stationary engines are excluded. Existing plants with a thermal capacity > 300 MW have to be reported as point sources on an individual basis.

b) the technical characteristics
  - with respect to boilers, the installed thermal capacity,
    - ≥ 300 MW,
    - ≥ 50 to < 300 MW,
    - ≤ 50 MW,
  - other combustion technologies,
    - gas turbines,
    - stationary engines.

Emissions considered in this section are released by a controlled combustion process (boiler emissions, emissions from the combustion chamber of gas turbines or stationary engines), taking into account primary reduction measures, such as furnace optimisation inside the boiler or the combustion chamber, and secondary reduction measures downstream of the boiler or the combustion chamber. Solid, liquid or gaseous fuels are used, where solid fuels comprise coal, coke, biomass and waste (as far as waste is used to generate heat or power). In addition, a non-combustion process can be a source of ammonia emissions, namely ammonia slip in connection with several NO_x abatement techniques.

2 CONTRIBUTION TO TOTAL EMISSIONS

This section covers emissions of SO_x, NO_x, CO, CO_2, NMVOC, CH_4, N_2O, NH_3 and heavy metals (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V). The contributions of point source emissions released by combustion plants to the total emissions in countries of the CORINAIR90 inventory are given as follows in Table 1:

Table 1: Contributions of emissions from combustion plants as point sources to total emissions of the CORINAIR90 inventory reported as point sources

		Contribution to total emissions [%]							
Source category	SNAP90 code	SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
≥ 300 MW	01 01 01 01 02 01 03 01 01	85.6	81.4	10.2	5.5	16.8	79.0	35.7	2.4
50-300 MW	01 01 02 01 02 02 02 00 01 03 01 02	6.4	5.4	1.1	0.6	3.1	6.5	1.9	0.2
< 50 MW	01 01 03 01 02 03 02 00 02 03 01 03	0.2	0.3	0.1	0.05	0.1	0.2	0.1	0
Gas turbines(1)	01 01 04 01 02 04 02 00 03	0	0.39	0.07	0.06	0.05	0.35	0.02	-

	03 01 04								
Stationary engines[1]	01 01 05 01 02 05 02 00 04 03 01 05	0.04	0.10	0.04	0	0.01	0.02	0	-

- : no emissions are reported

0 : emissions are reported, but the precise number is under the rounding limit

[1] Gas turbines and stationary engines may be reported either as point or as area sources.

In the literature concerning heavy metal emissions across Europe, point source emissions are not reported separately. Giving an order of magnitude of heavy metal emissions released from combustion plants emission data of coal-fired public power plants in Germany and Austria is presented here as an example, due to the availability of data:

Table 2: Contributions of heavy metal emissions from coal-fired public power plants to national total emissions of Germany[1] /36/

	Contribution in [wt.-%]	
Pollutant	1982	1990
As	38	27
Cd[2]	7	7
Cr	12	4
Cu	22	8
Hg[3]	11	14
Ni	5	4
Pb	8	1
Se	1	1
Zn	7	6

[1] Western part of Germany

[2] E.g. emissions of Cd in Austria in 1992 were 0,2 % /37/.

[3] E.g. emissions of Hg in Austria in 1992 were 6 % /37/.

By comparing the heavy metal emissions in 1982 (without flue gas desulphurisation (FGD) installed) to the emissions in 1990 (where most plants are equipped with FGD), it can be seen that the application of FGD technologies has lead to a significant decrease in heavy metal emissions within the last years.

For Particulate Matter:
Combustion Plants < 50 MW (boilers) are now covered in the new supplementary chapter Particulate emissions from smaller Combustion Plants (<50MWth) B111(S1).

Combustion Plants >= 50 and < 300 MW (boilers) are now covered in the new supplementary chapter Particulate emissions from large Combustion Plants (>50MWth) B111(S2).

Gas Turbines are now covered in the new supplementary chapter Particulate emissions from gas turbines and internal combustion engines B111(S3).

3 GENERAL

3.1 Description

The emissions considered in this chapter are generated either by boilers or by gas turbines and stationary engines regardless of the allocation of plants to SNAP activities. Emissions from process furnaces (combustion with contact) and from waste incineration are not included here (therefore see SNAP code 090200).

3.2 Definitions

ar	as received, a reference state of coal which determines the conditions, when coal arrives at the plant /73/.
Availability (of an abatement technology)	ratio of full load operating hours with operating emission control technology to total full load operating hours of the power plant; the availability β normally amounts to 99 %; but extreme low values of β can occur down to 95 %. By taking into account the start-up behaviour of emission reduction technologies, the availability β can decrease further down to 92 %. Default values are proposed in Tables 7 and 11.
Boiler	any technical apparatus, in which fuels are oxidised in order to generate heat for locally separate use.
Coking coal (NAPFUE 101)	subcategory of hard coal with a quality that allows the production of a coke suitable for supporting a blast furnace charge /114/.
Co-generation plant	steam production in boilers (one or more boilers) for both, power generation (in a steam turbine) and heat supply.
Combined Cycle Gas Turbine (CCGT)	gas turbine combined with a steam turbine. The boiler can also be fuelled separately.
daf	dry and ash free, a reference state of coal which is calculated with reference to a theoretical base of no moisture or ash associated with the sample (equivalent to maf - moisture and ash free) /73/.
Hard coal	refers to coal of a gross caloric value greater than 23,865 kJ/kg on an ash-free but moist basis and with a mean random

reflectance[3] of vitrinite of at least 0.6. Hard coal comprises the subcategories coking coal and steam coal[4] /114/.

---

[3] Mean random reflectance: characteristic value, which stands for a defined coal composition (modular component is e.g. vitrinite).

[4] The following coal classification codes cover those coals, which would fall into these subcategories /114/:

International classification codes (UN, Geneva, 19956)	323, 333, 334, 423, 433, 435, 523, 533, 534, 535, 623, 633, 634, 635, 723, 733, 823
USA classification	Class II Group 2 „Medium Volatile Bituminous“
British classification	Class 202, 203, 204, 301, 302, 400, 500, 600
Polish classification	Class 33, 34, 35.1, 35.2, 36, 37
Australian classification	Class 4A, 4B, 5.

Integrated Coal Gasification Combined Cycle Gas Turbine (IGCC)	gas turbine fuelled by gas, which is a product of a coal gasification process.
Lignite (NAPFUE 105)	non-agglomerating coals with a gross caloric value less than 17,435 kJ/kg and containing more than 31 % volatile matter on a dry mineral matter free basis /114/.
maf	moisture and ash free, a reference state of coal (equivalent to daf - dry and ash free) /73/.
Plant/Joint Plant	classification with respect to boilers (one or more boilers) according to the respective boiler configuration on a given site and the applied concept of aggregation. The stack-by-stack principle considers all boilers linked to the same stack as a common plant. On the other hand, according to the virtual stack principle, all boilers which, for technical and economic reasons, could be connected to a common stack, are treated as one unit. It is also possible to carry out a still broader combination following e.g. administrative aspects. Gas turbines and stationary engines are allocated separately. A typical example of different allocation possibilities of boilers to the SNAP codes is given in Annex 1.
Power plant	steam generation in boilers (one or more boilers) for power generation.
Reduction efficiency (of an abatement technology)	difference between the pollutant concentration in the raw gas (c_{raw}) and the pollutant concentration in the clean gas (c_{clean}) divided by the pollutant concentration in the raw gas (referred to full load operating hours); default values for the reduction efficiency $\eta = (c_{raw} - c_{clean})/c_{raw}$ of different emission control technologies are recommended in Tables 7 and 11 (extreme low values of η can be up to ten percent below the values given).
Start-up emission	here start-up emissions have been considered for boilers equipped with secondary measures: For SO_2 and NO_2 from the time when burners switch on up to the time when the secondary abatement facility operates under optimum conditions; for CO up to the time when the boiler operates at minimum load.
Stationary engines	spark-ignition or compression-ignition engines (2- and 4-stroke).
Steam coal (NAPFUE 102)	subcategory of hard coal used for steam raising and space heating purposes. Steam coal includes all anthracite and bituminous coals not included under coking coal /114/.

Sub-bituminous coal (NAPFUE 103)	non-agglomerating coals with a gross caloric value between 17,435 and 23,865 kJ/kg containing more than 31 % volatile matter on a dry mineral free matter basis /114/
Sulphur retention in ash	difference between the sulphur dioxide concentration calculated from the total sulphur content of fuel (c_{max}) and the sulphur dioxide concentration of the flue gas (c_{eff}) divided by the sulphur dioxide concentration calculated from the total sulphur content of the fuel. Default values for the sulphur retention in ash $\alpha_s = (c_{max} - c_{eff})/c_{max}$ are proposed in Table 8.

3.3 Techniques

3.3.1 Combustion of coal

3.3.1.1 Dry bottom boiler (DBB)

The DBB is characterised by the dry ash discharge from the combustion chamber due to combustion temperatures from 900 up to 1,200 °C. This type of boiler is mainly used for the combustion of hard coal and lignite and is applied all over Europe.

3.3.1.2 Wet bottom boiler (WBB)

Typical combustion temperatures exceeding 1,400 °C lead to a liquid slag discharge from the combustion chamber. This type of boiler is used for hard coal with a low content of volatiles and is mainly applied in Germany.

3.3.1.3 Fluidised bed combustion (FBC)

The combustion of coal takes place by injection of combustion air through the bottom of the boiler into a turbulent bed. The typical relatively low emissions are achieved by air staging, limestone addition and low combustion temperatures of about 750 - 950 °C. FBC is in particular adapted to coals rich in ash. Only few large combustion plants are equipped with the FBC technique; in the category of thermal capacities $\geq$ 300 MW mostly Circulating Fluidised Bed Combustion (CFBC) is installed.

3.3.1.4 Grate Firing (GF)

The lump fuel (coal, waste) is charged on a stationary or slowly moving grate. The combustion temperatures are mainly between 1,000 and 1,300 °C.

3.3.2 Combustion of biomass

The combustion of biomass (peat, straw, wood) is only relevant for some countries (e.g. Finland, Denmark). FBC (mostly CFBC) and DBB facilities are installed.

3.3.3 Combustion of waste

For the combustion of waste, mostly grate firing installations are in use.

3.3.4 Combustion of gas/oil

3.3.4.1 Combustion in boilers (general aspects of the combustion techniques)

For both, gas and oil combustion, the fuel and oxidising agents are gaseous under combustion conditions. The main distinctions between gas/oil combustion and pulverised coal combustion are the operation designs of the individual burners of the boiler. With respect to emissions, a principal distinction can be made between burners with and without a pre-mix of fuel and combustion air: pre-mixing burners are characterised by a homogeneous short flame and a high conversion rate of fuel bound nitrogen; non-pre-mixing burners are characterised by inhomogeneous flames with understoichiometric reaction zones and a lower conversion rate of fuel bound nitrogen.

The importance of oil and gas combustion considered as point sources (see Section 1) is low compared to coal combustion, due to the smaller total capacity of these installations. The main parameters determining emissions from oil and gas fired plants are given in Table 3.

Table 3: Main parameters determining emissions from oil and gas fired boilers /40/

	Fuel dependent	Process dependent
Pollutant	Oil-fired boiler	
SO_2	x	-
NO_x	x	x
CO	-	x
	Gas-fired boiler	
SO_2	x(1)	-
NO_x	-	x
CO	-	x

(1) trace amounts x : relevant - : not relevant

3.3.4.2 Gas turbines

Gas turbines are installed with a thermal capacity ranging from several hundred kW up to 500 MW. Gaseous fuels are mainly used, such as natural gas or the product of coal gasification (e.g. CCGT or IGCC installations) or other process gases. Also liquid fuels are used, such as light distillates (e.g. naphtha, kerosene or fuel oil) and in some cases other fuels (e.g. heavy fuel oil). Combustion temperatures of up to 1,300 °C in the combustion chambers may lead to considerable NO_X emissions.

Gas turbines are installed as a part of different types of combustion plants such as Combined Cycle Gas Turbine (CCGT) or Integrated Coal Gasification Combined Cycle Gas Turbine (IGCC) Plants (see also Section 3.2). For IGCC plants, the only emission relevant unit considered here is the gas turbine (combustion chamber). For CCGT, in addition to the gas turbine any installed fossil fuelled boiler should also be taken into account.

3.3.4.3 Stationary engines

Stationary engines are installed as spark-ignition engines and compression-ignition engines (2- and 4-stroke) with electrical outputs ranging from less than 100 kW to over 10 MW (e.g. in co-generation plants) /cf. 46/. Both types represent relevant emission sources.

3.4 Emissions

Relevant pollutants are sulphur oxides (SO_x), nitrogen oxides (NO_x), carbon dioxide (CO_2) and heavy metals (arsenic (As), cadmium (Cd), chromium (Cr), copper (Cu), mercury (Hg), nickel (Ni), lead (Pb), selenium (Se), zinc (Zn) and in the case of heavy oil also vanadium (V)). Emissions of volatile organic compounds (non-methane VOC and methane (CH_4)), nitrous oxide (N_2O), carbon monoxide (CO) and ammonia (NH_3) are of less importance. For species profiles of selected pollutants see section 9.

The emissions are released through the stack. Fugitive emissions (from seals etc.) can be neglected for combustion plants.

The emissions of sulphur oxides (SO_x) are directly related to the sulphur content of the fuel, which for coal normally varies between 0.3 and 1.2 wt.-% (maf) (up to an extreme value of 4.5 wt.-%) and for fuel oil (including heavy fuel oil) from 0.3 up to 3.0 wt.-% /15, 16/; usually, the sulphur content of gas is negligible. Sulphur appears in coal as pyritic sulphur (FeS_2), organic sulphur, sulphur salts and elemental sulphur. A major part of the sulphur in coal comes from pyritic and organic sulphur; both types are responsible for SO_x formation. The total sulphur content of coal is usually determined by wet chemical methods; by comparison with results from the X-ray method, it has been found that standard analytical procedures may overestimate the organic sulphur content of coal /30/. The uncertainty introduced by the analytical procedures should be determined by further research.

For nitric oxide (NO, together with NO_2 normally expressed as nitrogen oxides NO_x) three different formation mechanisms have to be distinguished (see also Section 9):

-formation of "fuel-NO" from the conversion of chemically bound nitrogen in the fuel (NO_{fuel}),

-formation of "thermal-NO" from the fixation of atmospheric nitrogen coming from the combustion air ($NO_{thermal}$),

-formation of "prompt-NO".

In the temperature range considered (up to 1,700 °C) the formation of "prompt6-NO" can be neglected. The majority of NO_x emissions from coal combustion (80 to more than 90 %) is formed from fuel nitrogen. Depending on combustion temperatures, the portion of thermal-NO_x formed is lower than 20 %. The content of nitrogen in solid fuels varies: for hard coal between 0.2 and 3.5 wt.-% (maf), for lignite between 0.4 and 2.5 wt.-% (maf), for coke between 0.6 and 1.55 wt.-% (maf), for peat between 0.7 and 3.4 wt.-% (maf), for wood between 0.1 and 0.3 wt.-% (maf), and for waste between 0.3 and 1.4 wt.-% (maf) /17/. The content of nitrogen in liquid fuels varies for heavy fuel oil between 0.1 and 0.8 wt.-%, and for fuel oil between 0.005 and 0.07 wt.-% /17/. Natural gas contains no organically bound nitrogen. The content of molecular nitrogen in natural gas has no influence on the formation of fuel-NO; only thermal-NO is formed.

Emissions of non-methane volatile organic compounds (NMVOC), e.g. olefins, ketones, aldehydes, result from incomplete combustion. Furthermore, unreacted fuel compounds such as methane (CH_4) can be emitted. The relevance of NMVOC/CH_4 emissions from boilers, which are often reported together as VOC, is very low for large-sized combustion plants. VOC emissions tend to decrease as the plant size increases (cf. /24/).

Carbon monoxide (CO) appears always as an intermediate product of the combustion process and in particular under understoichiometric combustion conditions. However, the relevance of CO released from combustion plants is not very high compared to CO_2. The formation mechanisms of CO, thermal-NO and VOC are similarly influenced by combustion conditions.

Carbon dioxide (CO_2) is a main product from the combustion of all fossil fuels. The CO_2 emission is directly related to the carbon content of fuels. The content of carbon varies for hard and brown coal between 61 and 87 wt.-% (maf), for wood it is about 50 wt.-% and for gas oil and heavy fuel oil about 85 wt.-% .

The formation mechanism of nitrous oxide (N_2O) has not yet been completely clarified. There is a possible formation mechanism based on intermediate products (HCN, NH_3), which is comparable to the formation of NO /55/. It has been found, that lower combustion temperatures, particularly below 1,000 °C, cause higher N_2O emissions /13/. At lower temperatures the N_2O molecule is relatively stable; at higher temperatures the N_2O formed is reduced to N_2 /55/. Compared to emissions from conventional stationary combustion units, nitrous oxides from either bubbling, circulating or pressurised fluidised bed combustion are relatively high /13, 14/. In laboratory experiments, it has been found that nitrous oxide is formed by Selective Catalytic Reduction (SCR) processes, passing a maximum at, or close to, the optimum temperature "window" of the SCR process /13/.

Emissions of ammonia (NH_3) are not caused by a combustion process; the emissions result from incomplete reaction of NH_3 additive in the denitrification process (slip of ammonia in SCR and SNCR units).

Most of the heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V) are normally released as compounds (e.g. oxides, chlorides) in association with particulates. Only Hg and Se are at least partly present in the vapour phase. Less volatile elements tend to condense onto the surface of smaller particles in the flue gas stream. Therefore, an enrichment in the finest particle fractions is observed. The content of heavy metals in coal is normally several orders of magnitude higher than in oil (except occasionally for Ni and V in heavy fuel oil) and in natural gas. For natural gas only emissions of mercury are relevant. The concentrations are reported to be in the range of 2 - 5 $\mu g/m^3$ for natural gas /35, 63/. During the combustion of coal, particles undergo complex changes which lead to vaporisation of volatile elements. The rate of volatilisation of heavy metal compounds depends on fuel characteristics (e.g.

concentrations in coal, fraction of inorganic components, such as calcium) and on technology characteristics (e.g. type of boiler, operation mode).

From DBB, all heavy metals of concern are emitted as particulate matter, except Hg and Se. Emissions from lignite fired DBB are potentially lower than from hard coal, as the trace element content in lignite and the combustion temperatures are lower. In WBB, the recirculation of fly ash is a common operation mode, which creates an important increase in heavy metal concentrations in the raw gas. Heavy metal emissions from FBC units are expected to be lower due to the lower operating temperatures and a smaller fraction of fine particles. The addition of limestone in FBC facilities might reduce the emission of some heavy metals, corresponding to an increased retention of heavy metals in the bottom ash. This effect can be partially compensated by the increase in the fraction of fine particulates in the flue gas leading to increased emissions from particulates highly enriched by heavy metals.

High concentrations of As poison denitrification catalysts. Therefore, Selected Catalytic Reduction plants (SCR) in a high-dust configuration may require special measures (e.g. reduction of fly ash recirculation). /10, 11, 12/

3.5 Controls

Relevant abatement technologies for SO_x, NO_x and heavy metals are outlined below. Abatement techniques for gas turbines and stationary engines are treated separately. Average reduction efficiencies and availabilities of abatement technologies for SO_x and NO_x are summarised in Tables 7, 10, and 11. Due to the fact, that most published studies do not clearly distinguish between SO_x and SO_2, for the following chapters, it can be assumed that SO_2 includes SO_3, if not stated otherwise.

3.5.1 Sulphur oxides: Flue Gas Desulphurisation Processes (FGD) (Secondary measures) /cf. 18/

FGD processes are designed to remove SO_2 from the flue gas of combustion installations. Most processes, like the wet scrubbing process (WS), the spray dryer absorption (SDA), the dry sorbent injection (DSI) and the Walther process (WAP) are based on the reaction of the SO_2 with an alkaline agent added as solid or as suspension/solution of the agent in water to form the respective salts. In secondary reactions also SO_3, fluorides and chlorides are removed. In the case of the DESONOX process (see Section 3.5.4.2), the SO_2 is catalytically oxidised to SO_3 and reacts with water to form sulphuric acid. The Activated Carbon process (see Section 3.5.4.1) and the Wellman-Lord process remove the SO_2 to produce a SO_2 rich gas, which may be further processed to sulphur or sulphuric acid.

3.5.1.1 Lime/Limestone Wet Scrubbing (WS)

The pollutants are removed from the flue gas by chemical reactions with an alkaline liquid (suspension of calcium compounds in water). The main product is gypsum. The WS process represents about 90 % of the total FGD-equipped electrical capacity installed in European OECD countries. Facilities are in operation at combustion units using hard coal, lignite and oil with sulphur contents from about 0.8 to more than 3.0 wt.-%. Other fossil fuels (such as peat) are presently rarely used at combustion plants with a thermal capacity ≥ 300 MW. The SO_2 reduction efficiency is > 90 %.

3.5.1.2 Spray Dryer Absorption (SDA)

The SDA process removes the pollutant components from flue gas of fossil fired combustion units by injection of $Ca(OH)_2$. The process forms a dry by-product ($CaSO_3 \cdot 1/2\ H_2O$). This technology covers about 8 % of the total FGD-equipped electrical capacity installed in the European OECD countries. The SDA process is mostly in use at hard coal fired combustion units (sulphur content of fuel up to 3 wt.-%). Recent pilot studies have shown that this technique is also operational with other fossil fuels (oil, lignite, peat). The SO_2 reduction efficiency is > 90 %.

3.5.1.3 Dry Sorbent Injection (DSI, LIFAC Process)

The DSI process is based on a gas/solid reaction of the flue gas and a dry sorbent (e.g. lime/limestone, sodium hydrogen carbonate $NaHCO_3$) inside the boiler. There are three different process types according to the injection point of the additive into the boiler (e.g. primary or secondary air, flame front). The by-products are a dry mixture of the respective salts (mostly $CaSO_4$). Only few power plants (some 5 % of the total FGD-equipped electrical capacity installed in European OECD countries) are equipped with this technology due to its low SO_2 reduction efficiency of 40 - 50 %, which is not sufficient to meet the emission standards of some countries. DSI processes are presently in use for hard coal, lignite, oil and coal/oil fired boilers. The optimum reduction efficiency is obtained for the sulphur contents of fuel between 0.5 and 1.7 wt.-% (max. 2 wt.-%).

The LIFAC process is an advanced dry sorbent injection process using additional water injection in a separate reactor downstream of the boiler, in order to raise the reduction efficiency. Generally, the SO_2 reduction efficiency is > 50 %. At present, the LIFAC process is used in one plant in Finland with a SO_2 reduction efficiency of already 70 %.

3.5.1.4 Wellman-Lord (WL)

The WL process is a regenerable FGD process, which uses the sodium sulphite (Na_2SO_3)/ sodium bisulphite ($NaHSO_3$) equilibrium in order to remove SO_2 from the flue gas. An SO_2-rich gas is obtained, which is used for the production of sulphuric acid. At present only three installations with a total thermal capacity of 3,300 MW are in use (in Germany), due to the complexity of the process and the resulting high investments and operating costs (this technology represents about 3 % of the total thermal capacity installed in the European OECD countries). The WL process is operational with various types of fuel (e.g. hard coal, oil), especially with high sulphur contents (of about 3.5 wt.-%). The SO_2 reduction efficiency is > 97 %.

3.5.1.5 Walther Process (WAP)

The WAP process uses ammonia water in order to remove SO_2 from the flue gas. The by-product is a dry salt mixture of the respective ammonia salts (mainly ammonium sulphate ($(NH_4)_2SO_4$). One reference installation is currently operating in Germany. This process is operational with all types of fuel. However, the maximum sulphur content should be limited to 2 wt.-% (due to the increasing formation of ammonia sulphate aerosols). The SO_2 reduction efficiency is > 88 %.

3.5.2 Nitrogen oxides: Primary measures - Denitrification techniques /cf. 17, 18, 19/

3.5.2.1 Low NO_x burner (LNB)

A characteristic of LNB is the staged air to fuel ratio at the burner. Three different technical modifications are in use:

- Air-staged LNB: An understoichiometric zone is created by a fuel-air mixture and primary air. An internal recirculation zone occurs due to the swirl of primary air. A burn-out zone is created due to secondary air fed by air nozzles arranged around the primary air nozzles.
- Air-staged LNB with flue gas recirculation (FGR): The basic function is similar to air-staged LNB. The distances between the primary and secondary nozzles are greater, therefore, a flue gas layer is formed. As a result, the residence time in the reducing atmosphere increases and the oxygen concentration decreases.
- Air/Fuel staged LNB: An additional reduction zone around the primary zone is achieved by the extremely overstoichiometric addition of secondary fuel around the secondary flame.

LNB is operational with all fuels and all types of burners. The NO_x reduction efficiency for coal fired boilers varies between 10 and 30 % (see Table 10).

3.5.2.2 Staged Air Supply (SAS)

Staged air means the creation of two divided combustion zones - a primary zone with a lack of oxygen and a burn-out zone with excess air. SAS covers the low excess air (LEA), burners out of service (BOOS) and biased burner firing (BBF) techniques:

- Low excess air (LEA) means reduction of the oxygen content in the primary combustion zone of the burners. When firing hard coal, experience has shown that the general limitations are fouling and corrosion, caused by the reducing atmosphere and incomplete burn-out. When firing gas, the reduction efficiency is limited by the CO formed. LEA is more suitable for lignite and often used for retrofitting combustion plants. For oil fired boilers a reduction efficiency of 20 % has been achieved.
- Burners out of service (BOOS) means that the lower burner row(s) in the boiler operate under a lack of oxygen (fuel rich), the upper burners are not in use. This technology is in particular suitable for older installations, but the thermal capacity of the boiler decreases by about 15 - 20 %.
- Biased burner firing (BBF) means that the lower burner rows in the boiler operate under a lack of oxygen (fuel rich) and the upper burners with an excess of oxygen. The boiler efficiency is less compared to BOOS and the NO_x reduction is also lower.

The NO_x reduction efficiency for coal fired boilers varies between 10 and 40 % (see Table 10).

3.5.2.3 Overfire Air (OFA)

All burner rows in the boiler operate with a lack of oxygen. The combustion air is partly (5 - 20 %) injected through separate ports located above the top burner row in the boiler. OFA is operational with most fuels and most types of boilers. For gas fired boilers a reduction efficiency of 10 - 30 % and for oil fired boilers 10 - 40 % has been achieved. The NO_x reduction efficiency for coal fired boilers varies between 10 and 40 % (see Table 10).

3.5.2.4 Flue Gas Recirculation (FGR)

The recirculation of flue gas into the combustion air is an efficient NO_x abatement method for firing modes with high combustion temperatures, such as wet bottom boilers and especially for gas and oil fired boilers.

The recirculated flue gas can be added to the secondary or primary air. In the first case, the flame core is not affected and the only effect is a reduction of the flame temperature, which is favourable for thermal-NO_x abatement. The influence on dry bottom boilers is thus very limited, considering the fact that about 80 % of the NO_x formed originates from fuel bound nitrogen; FGR can be used as an additional measure. A more efficient method is the introduction of flue gas into the primary air of an unstaged burner. High reduction efficiencies of FGR in the primary flow (15 - 20 %) have been achieved in gas and oil fired boilers. The NO_x reduction efficiency for coal fired boilers varies between 5 and 25 % (see Table 10).

3.5.2.5 Split Primary Flow (SPF)

Split primary flow means fuel staging in the furnace. This technique involves injecting fuel into the furnace above the main combustion zone, thereby producing a second understoichiometric combustion zone. In the primary zone of the boiler the main fuel is burnt under fuel-lean conditions. This zone is followed by a secondary zone with a reducing atmosphere, into which the secondary fuel is injected. Finally, secondary air is injected into the burn-out zone of the boiler. This reburning technique can, in principle, be used for all types of fossil fuel fired boilers and in combination with low NO_x combustion techniques for the primary fuels. When nitrogen is present in the reburning fuel, a part of it will be converted into NO_x in the burn-out zone. Therefore, natural gas is the most appropriate reburning fuel. NO_x reduction efficiencies have not been yet reported.

3.5.3 Nitrogen oxides: Secondary measures - Denitrification Processes /cf. 18, 19/

3.5.3.1 Selective Non-Catalytic Reduction (SNCR)

The reduction of nitrogen oxides in the flue gas is based on the selective reaction of NO_x with injected ammonia, urea or caustic ammonia to form nitrogen and water. The SNCR process has been implemented at several installations (e.g. in Germany, in Austria and in Sweden) and has in principle proved to be operational with various types of fuels. The NO_x reduction efficiency is about 50 %, in some installations up to 80 %.

3.5.3.2 Selective Catalytic Reduction (SCR)

The reduction of nitrogen oxides is based on selective reactions with injected additives in the presence of a catalyst. The additives used are mostly gaseous ammonia, but also liquid caustic ammonia or urea. The SCR technology accounts for about 95 % of all denitrification processes. SCR is mostly used for hard coal. For brown coal, lower combustion temperatures lead to lower NO_x formation, so that primary measures fulfil the emission reduction requirements. Several heavy metals in the flue gas can cause rapid deactivation of the catalyst. The NO_x reduction efficiency varies between 70 and 90 %.

3.5.4 Nitrogen oxides and sulphur oxides: Simultaneous Processes /18, 19/

3.5.4.1 Activated Carbon Process (AC)

The AC process is a dry process for simultaneous SO_2 and NO_x removal based on the adsorption of the pollutants in a moving bed filter of activated carbon. The sulphur oxides undergo catalytic oxidation with the moisture in the flue gas to form sulphuric acid. NO_2 is completely reduced to N_2; NO reacts catalytically with the ammonia injected and forms N_2 and H_2O. The AC process has been installed at four power plants in Germany (in two cases downstream of an SDA process). The sulphur content in the fuel used should not exceed 2.3 wt.-%. The SO_2 reduction efficiency is > 95 %, the NO_x reduction efficiency is > 70 %.

3.5.4.2 DESONOX Process/SNOX Process (DESONOX)

The purification of the flue gas by the DESONOX process is based on the simultaneous catalytic reduction of nitrogen oxides (NO_x) to nitrogen (N_2) and water (H_2O) and on the catalytic oxidation of sulphur dioxide (SO_2) to sulphur trioxide (SO_3). The by-product is sulphuric acid. The process has been installed at one power plant in Germany, where hard coal is used with a sulphur content of about 1 wt.-%. The concentration of catalyst toxics (mainly arsenic, but also chromium, selenium etc.) has to be taken into account. The SO_2 reduction efficiency is up to 95 %, the NO_x reduction efficiency is also up to 95 %.

The SNOX process works on the same basic principle as the DESONOX process, with the main difference that reduction and oxidation take place in two separate reaction towers. The SNOX process has been applied at one Danish power plant. No reduction efficiency has been reported yet. The SNOX process is also known as a combination of the Topsøe WSA-2 process and the SCR process.

3.5.5 Heavy metals: Secondary measures /12, 20, 21, 22, 23/

Heavy metal emissions are mainly reduced by dust control equipment. Particulate control systems, which are used in coal-fired power plants, are cyclones, wet scrubbers, electrostatic precipitators (ESP), and fabric filters. In most power plants 99 % of the particulates are removed from the flue gases by using ESP or fabric filters. The latter are more efficient in controlling fine particulate matter; wet scrubbers and cyclones are less efficient.

The reduction efficiency of ESP for most elements in the solid state is > 99 %. Only for some higher volatile elements, such as Cd, Pb, Zn and Se, is the reduction efficiency less, but it remains above 90 %. The reduction efficiency of an ESP for Hg depends on the operating temperature of the ESP. A cold-side ESP operating at about 140 °C is estimated to have an average Hg reduction efficiency of about 35 %.

The influence of FGD- and $DeNO_x$-units on heavy metal emissions has been investigated mainly in the frame of mass balance studies. WS-FGD-units remove a further fraction of particulate matter in flue gas in addition to dust control. Particle bound elements are removed by FGD-units with an efficiency of about 90 %. In FGD-units, in particular WS-units, the gaseous compounds can additionally condense on particulate matter, which are mainly removed in the prescrubber. With regard to gaseous elements, various studies have shown reduction efficiencies of 30 - 50 % for Hg and 60 - 75 % for Se. Lime contributes over 90 % of the input of As, Cd, Pb and Zn to the FGD.

The abatement of Hg emissions is influenced indirectly by DeNO$_x$-units. A high dust SCR-unit improves Hg removal in a subsequent FGD-unit using a lime scrubbing system. The SCR-unit increases the share of ionic mercury ($HgCl_2$) to up to 95 %, which can be washed out in the prescrubber of the FGD-unit. A study in the Netherlands found no influence of LNB on heavy metal emissions.

3.5.6 Gas turbines /cf. 68, 69/

For gas turbines mainly NO_X emissions are of most relevance. Primary measures for NO_X reduction are the following: dry controls (e.g. overstoichiometric combustion in a dry low NO_X burner with $\eta = 0.6 - 0.8$, which is a relatively new development as a primary measure) and wet controls (injection of water and/or steam with $\eta \geq 0.6$ /114/) in order to regulate the combustion temperature. For large gas turbines secondary measures are also installed such as Selective Catalytic Reduction (SCR).

3.5.7 Stationary engines /cf. 70/

For spark-ignition engines the main pollutants emitted are NO_x, CO and unburned hydrocarbons (VOC). For diesel engines sulphur dioxide (SO_2) emissions have also to be considered. Emissions of soot also contribute to emissions of heavy metals and persistent organic pollutants, but at this stage insufficient information is available /35/.

Primary measures are installed to optimise combustion conditions (air ratio, reduced load, water injection, exhaust-gas recirculation, optimised combustion chamber etc.). Reduction efficiencies can be given e.g. for exhaust gas recirculation from 6.5 to 12 % and for internal exhaust gas recirculation from 4 to 37 %. External exhaust gas recirculation (turbo charged models) can have reductions of NO_x varying from 25 to 34 %. /cf. 114/

Secondary measures are installed, if the emission thresholds cannot be met by adjustments to the engine itself. The following methods are used depending on the air ratio λ:

$\lambda = 1$	Reduction of NO_X, CO and VOC by using a three-way catalytic converter (NSCR),
$\lambda > 1$	Reduction of NO_X by Selective Catalytic Reduction with NH_3 (SCR), Reduction of other emissions (CO, VOC) using oxidation catalytic converter (NSCR).

Typical conversion rates of NO_x range from 80 to 95 % with corresponding decreases in CO and VOC. Depending on the system design, NO_x removal of 80 up to 90 % is achievable. /114/

4 SIMPLER METHODOLOGY

4.1 General

4.1.1 General / specified emission factors

Here "simpler methodology" refers to the calculation of emissions, based on emission factors and activities. The simpler methodology should only be used in cases where no measured data is available. The simpler methodology covers all relevant pollutants (SO_2, NO_x, NMVOC, CH_4, CO, CO_2, N_2O, NH_3, heavy metals). Special emphasis is put on the pollutants SO_x, NO_x and heavy metals, due to the significant contribution of combustion plants as point sources to the total emissions of these pollutants.

A combustion plant can be treated either as a whole (irrespective of kind/size of individual boilers) or on a boiler-by-boiler level. Differences in design and operation of boilers, in fuels used and/or controls installed require different emission factors. The same applies to gas turbines and stationary engines.

The annual emission E is derived from an activity A and a factor which determines their linear relation (see Equation (1)):

$$E_i = EF_i \cdot A \qquad (1)$$

E_i annual emission of pollutant i
EF_i emission factor of pollutant i
A activity rate

The activity rate A and the emission factor EF_i have to be determined on the same level of aggregation by using available data (e.g. fuel consumption) (see Section 6). For the activity rate A, the energy input in [GJ] should be used, but in principle other relations are also applicable.

Two different approaches in order to obtain the emission factor EF_i are proposed:

- General emission factor EF_{G_i}

The general emission factor is a mean value for defined categories of boilers taking into account abatement measures (primary and secondary). A general emission factor is only related to the type of fuel used and is applicable for all pollutants considered, except of SO_2[5]. It should only be used where no technique specific data are available (only as a makeshift).

- Specified emission factor EF_{R_i}

The specified emission factor is an individually determined value for boilers taking into account abatement measures (primary and secondary). A specified emission factor is related to individual fuel characteristics (e.g. sulphur content of fuel) and to technology specific

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[5] For the appropriate determination of SO_2 emissions the sulphur content of fuel is required. Therefore, the specified emission factor approach has to be applied.

parameters. The following sections provide determination procedures for suitable specified emission factors for the pollutants NO_x, SO_x and heavy metals.

In principle, plant specific data should be used, if available, for the determination of emission factors. The following Sections 4.1 to 4.8 give recommendations for the estimation and the use of general and specified emission factors as given in Table 4.

Table 4: Applicability of general emission factors EF_{G_i} and specified emission factors EF_{R_i}

Pollutant	General emission factor EF_{G_i}	Specified emission factor EF_{R_i}
SO_x	-	+
NO_x	+	++[1)]
Heavy metals	+	++[2)]
NMVOC, CH_4, CO, CO_2, N_2O, NH_3	+	*

+ : possible, but not recommended methodology; ++ : possible and recommended methodology;

- : not appropriate; * : not available

[1)] detailed calculation schemes are given for pulverised coal combustion

[2)] detailed calculation schemes are given for coal combustion

An accurate determination of full load emissions can only be obtained by using specified emission factors. For the calculation of specified SO_x and NO_x emission factors for pulverised coal combustion, a computer programme has been developed (see Annexes 2 - 6 and Annex 14).

If not stated otherwise, the general and specified emission factors presented refer to full load conditions. Start-up emissions have to be considered separately (see Section 4.1.2).

4.1.2 Start-up dependence

Start-up emissions depend on the load design of the plant and on the type of start-up (see Tables 5 and 6). A plant can be designed for:

- peak load:	to meet the short-term energy demand,
- middle load:	to meet the energy demand on working days,
- base load:	continuous operation.

Table 5: Load design and start-ups per year

Load design	Start-ups per year		Full load hours per year		Emission
	range	value	range	value	relevance[2)]
Peak load[1)]	150 - 500	200	1,000 - 2,500	2,000	x[1)]
Middle load	50 - 250	150	3,000 - 5,000	4,000	xxx
Base load	10 - 20	15	6,000 - 8,000	7,000	x

[1)] For peak load often high-quality fuels (e.g. gas, oil) and often gas turbines are used.

[2] x: low; xxx: high.

Table 6: Status of the boiler at starting time for a conventional power plant

Type of start-up	Time of stand-still [h] /65/	Status of the boiler	Frequency[2]	Emission relevance[2]
Hot-start	< 8	hot	xxx	x
Warm-start	8 - ca. 50	warm	xx	xx
Cold-start	> 50	cold	x[1]	xxx

[1] normally once a year, only for maintenance.

[2] x: low; xx: medium; xxx: high.

In order to take into consideration the relevance of start-up emissions, a detailed investigation has been carried out. There, start-up emissions and start-up emission factors have been determined for different types of boilers (DBB, WBB, gas-fired boiler, see Annex 15). Start-up emissions are only relevant if secondary measures are installed.

By taking into account boiler characteristics as given in Annex 15, the following general trends of start-up emissions of SO_x, NO_x and CO on the type of fuel and type of boiler are obtained (based on /116/).

- For the boilers considered in the detailed investigation it has been found that start-up emissions for the combustion of coal are significantly higher than for the combustion of gas.
- Start-up emissions are higher for dry bottom boilers than for wet bottom boilers and gas boilers.

In the following sections, start-up emissions and start-up emission factors derived from measured data are presented as ratios:

$$F^{EF} = EF^{A} / EF^{V} \tag{2}$$

F^{EF}	ratio of start-up and full load emission factors [ ]
EF^{A}	emission factor at start-up period [g/GJ]
EF^{v}	emission factor at full load conditions [g/GJ]

$$F^{E} = E^{A} / E^{V} \tag{3}$$

F^{E}	ratio of start-up and full load emissions [ ]
E^{A}	emission during start-up period (see Section 3.2) [Mg]
E^{v}	emission for full load conditions during start-up period [Mg]

Start-up emissions and full load emissions are related to comparable periods; the energy input (fuel consumption) during the start-up period is lower than during full load operation. The emission factor ratio F^{EF} is often higher than the emission ratio F^{E}. Increased specific emissions during the start-up period were found to be compensated to a high degree by the lower fuel consumption. Further pollutant specific results are given in the Sections 4.2 - 4.9.

If start-up emissions are taken into account the corresponding activity rates have to be determined as follows:

$$A = A_{\text{full load}} + A_{\text{cold}} + A_{\text{warm}} + A_{\text{hot}} \qquad (4a)$$

A	activity rate within the period considered [GJ]
$A_{\text{full load}}$	activity rate for full load operation periods [GJ]
A_{cold}	activity rate for cold start periods [GJ]
A_{warm}	activity rate for warm start periods [GJ]
A_{hot}	activity rate for hot start periods [GJ]

Each sub-activity (e.g. A_{cold}) has to be determined separately by totalling the thermal energy input for the respective periods e.g. cold start periods.

Accordingly, Equation (1) becomes:

$$E = EF^{V} \cdot (A_{\text{full load}} + F^{EF}_{\text{cold}} \cdot A_{\text{cold}} + F^{EF}_{\text{warm}} \cdot A_{\text{warm}} + F^{EF}_{\text{hot}} \cdot A_{\text{hot}}) \cdot 10^{-6} \qquad (4b)$$

E	emission within the period considered [Mg]
EF^{V}	emission factor at full load operation conditions [g/GJ]
$F^{EF}_{\text{cold/warm/hot}}$	ratio of start-up (cold/warm/hot start) to full load emission factor [ ]
$A_{\text{full load/cold/...}}$	activity rates at full load operation/cold start/... [GJ]

The emission factor at full load conditions EF^{V} can be approximated by using the emission factors given in Tables 24 and 25 (for NO_x) and Table 28 (for CO); SO_2 emission factors can be determined as given in Equation (5). A correction factor for the annual emission can be obtained by calculating the ratio of the annual emissions resulting from Equation (4b) to those determined without consideration of start-up emissions.

4.1.3 Load dependence

A load dependence of emissions has only been found for NO_x emissions released from older types of boiler (see Section 4.3).

4.2 SO_2 emission factors

For SO_2, only specified emission factors $EF_{R_{SO2}}$ are recommended here. For the determination of specified SO_2 emission factors the following general equation should be used (for emissions of SO_3 see Section 9):

$$EF_{R_{SO2}} = 2 \cdot C_{S_{\text{fuel}}} \cdot (1 - \alpha_S) \cdot \frac{1}{H_u} \cdot 10^{6} \cdot (1 - \eta_{\text{sec}} \cdot \beta) \qquad (5)$$

$EF_{R_{SO2}}$	specified emission factor [g/GJ]
$C_{S_{\text{fuel}}}$	sulphur content in fuel [kg/kg]
α_s	sulphur retention in ash [ ]

H_u lower heating value of fuel [MJ/kg]
η_{sec} reduction efficiency of secondary measure [ ]
β availability of secondary measure [ ]

Equation (5) can be used for all fuels, but not all parameters may be of relevance for certain fuels (e.g. α_S for gas). Default values for reduction efficiencies and availabilities of secondary measures installed are presented in Table 7. The technologies listed in Table 7 are mainly installed in the case of coal-fired boilers, but they can also be applied when burning other fuels.

Table 7: Default values for secondary measures for SO_2 reduction (all fuels) /18, 19/

No.	Type of secondary measure	Reduction efficiency η_{sec} [ ]	Availability β [ ]
1	WS	0.90	0.99
2	SDA	0.90	0.99
3	DSI	0.45	0.98
4	LIFAC	0.70	0.98
5	WL	0.97	0.99
6	WAP	0.88	0.99
7	AC	0.95	0.99
8	DESONOX	0.95	0.99

4.2.1 Combustion of coal

SO_2 emission factors for coal fired boilers can be calculated by using Equation (5). If some input data are not available, provided default values based on literature data can be used:

- $C_{S,fuel}$ see Annexes 7 and 8, Table 23,
- α_S see Table 8,
- η_{sec} and β see Table 7,
- H_u see Annexes 7 and 8.

For further details concerning the calculation of SO_2 emission factors, see Annexes 2 (flowsheet of the computer programme) and 3 (description of the computer programme). Default values for sulphur retention in ash for coal fired boilers are presented in Table 8.

Table 8: Default values for the sulphur retention in ash (α_S) for pulverised coal fired boilers

Type of boiler	α_S [ ]	
	Hard coal	Brown coal
DBB	0.05	0.3[1)]
WBB	0.01	-

[1)] average value; in practice, a range of 0.05 - 0.60 can occur (e.g. in the Czech Republic 0.05 is used)

Emission factors obtained by using Equation (5) are related to full load conditions; start-up emissions are not taken into account. If a flue gas desulphurisation unit is installed, start-up emissions should be considered as given in Section 4.1.2. The relevance of start-up emissions of SO_2 depends strongly on the following parameters:

- the type of fuel (e.g. SO_x emissions are directly related to the fuel sulphur content),
- the status of the boiler at starting time (hot, warm or cold start, see also Table 6),
- start-up of the flue gas desulphurisation unit (FGD direct or in by-pass configuration),
- limit for SO_x emissions, which has to be met (boiler specific limits can be set up below the demands of the LCP Directive).

For the combustion of coal in dry bottom boilers, the following ranges and values of F^{EF}, F^E have been obtained within the investigation outlined in Annex 15:

Table 9: Ratios of start-up to full load emission factors F^{EF} and ratios of start-up to full load emissions F^E for SO_2 for dry bottom boilers

	Ratio of start-up to full load emission factors F^{EF} [ ]	Ratio of start-up to full load emissions F^E [ ]
Range	3 - max. 16	1 - max. 4
Values for direct start-up of the FGD	F^{EF}_{cold}: 5 F^{EF}_{warm}: 5 F^{EF}_{hot}: 4	F^{E}_{cold}: 1 F^{E}_{warm}: 1 F^{E}_{hot}: 1
Values for by-pass start-up of the FGD	F^{EF}_{cold}: 8.5 - 16 F^{EF}_{warm}: 5 - 14.5 F^{EF}_{hot}: 5 - 5.5	F^{E}_{cold}: 2 - 4.5 F^{E}_{warm}: 1 - 3.5 F^{E}_{hot}: 1.5

$F^{EF}_{cold,warm,hot}$	Ratio of start-up to full load emission factors for cold, warm or hot start-ups (see also Table 6)
$F^{E}_{cold,warm,hot}$	Ratio of start-up to full load emissions for cold, warm or hot start-ups (see also Table 6)

The values from the direct start-up of the FGD show, that start-up emissions of SO_2 are not relevant (ratio F^E of ca. 1). In the case of a by-pass start-up of the FGD, start-up emissions of SO_2 are significant for hot, warm and cold starts; start-up emissions can be up to 4 times higher than emissions in a comparable full load time span (based on /116/).

4.2.2 Combustion of other fuels (biomass, waste, liquid fuels, gaseous fuels)

SO_2 emissions are directly related to the sulphur content of biomass, waste, liquid and gaseous fuels (see Equation (5)). The sulphur retention in ash α_s is not relevant. The reduction efficiency η_{sec} and the availability β of installed secondary measures have to be taken into account (in particular for the combustion of waste). Default values for η and β are given in Table 7. Sulphur contents of different fuels are given in Table 23 and in Annexes 7 and 8.

4.3 NO_x emission factors

For the determination of NO_x emissions, general as well as specified NO_x emission factors can be used. Emission factors are listed in Tables 24 and 25 depending on installed capacity, type of boiler, primary measures and type of fuel used.

4.3.1 Combustion of pulverised coal

Specified NO_x emission factors can be calculated individually for pulverised coal fired boilers. Due to the complex reaction mechanism of NO_x formation (see also Section 3.4) an estimate of specified NO_x emission factors can only be made on the basis of empirical relations as given in Equation (6). The decisive step in Equation (6) is the undisturbed NO_x formation (without primary measures) inside the boiler ($C_{NO_{2.boiler}}$). $C_{NO_{2.boiler}}$ is determined by an empirical equation depending on fuel parameters only, as described in Annex 5.

$$EF_{R_{NO_2}} = C_{NO_2,boiler} \cdot (1 - \eta_{prim}) \cdot \frac{1}{H_u} \cdot 10^6 \cdot (1 - \eta_{sec}\,\beta) \qquad (6)$$

$EF_{R_{NO2}}$	specified emission factor [g/GJ]
$C_{NO_{2.boiler}}$	total content of nitrogen dioxide formed in the boiler without taking into account primary reduction measures (in mass NO_2/mass fuel [kg/kg])[6]
η_{prim}	reduction efficiency of primary measures [ ]
H_u	lower heating value of fuel [MJ/kg]
η_{sec}	reduction efficiency of secondary measure [ ]
β	availability of secondary measure

For further details concerning the calculation of specified NO_2 emission factors see Annexes 4 (flowsheet of the computer programme) and 5 (description of the computer programme).

If some input data are not available, default values based on literature data are provided for:

- $C_{N,\ fuel}$, content of fuel-nitrogen, see Annexes 7 and 8,
- $C_{volatiles}$, content of volatiles in the fuel, see Annexes 7 and 8,

---

[6] Note: The computer programme, which is described in Annex 5, provides $C_{NO2\ boiler}$ as (mass pollutant/mass flue gas [kg/kg]).

- η_{prim} see Table 10,
- η_{sec} and β see Table 11,
- H_u see Annexes 7 and 8.

Default values for the reduction efficiency of primary measures are presented in the following Tables 10 and 11.

Table 10: Reduction efficiencies for selected primary measures for NO_X emissions in coal fired boilers /17, 18, 19, 28, 31, 32, 33, 34, 53/ (value means recommended value)

	Reduction efficiency DBB η [ ]				Reduction efficiency WBB η [ ]	
Type of primary measure[1]	Hard coal		Lignite		Hard coal	
	range	value[3]	range	value[3]	range	value[3]
no measure[4]	0	0	0	0	0	0
LNB	0.10 - 0.30	0.20	0.10 - 0.30	0.20	0.10 - 0.30	0.20
SAS	0.10 - 0.40	0.30	0.10 - 0.40	0.30	0.10 - 0.40	0.30
OFA	0.10 - 0.40	0.30	0.10 - 0.35	0.25	0.10 - 0.35	0.25
FGR	0.05 - 0.15	0.10	0.05 - 0.20	0.15	0.10 - 0.25	0.20
LNB/SAS	0.20 - 0.60	0.45	0.20 - 0.60	0.45	0.20 - 0.60	0.45
LNB/OFA	0.20 - 0.60	0.45	0.20 - 0.55	0.40	0.20 - 0.55	0.40
LNB/FGR	0.15 - 0.40	0.30	0.15 - 0.45	0.30	0.20 - 0.50	0.35
SAS/OFA	0.20 - 0.65	0.50	0.20 - 0.60	0.40	0.20 - 0.60	0.40
SAS/FGR	0.15 - 0.50	0.40	0.15 - 0.50	0.40	0.20 - 0.55	0.45
OFA/FGR	0.15 - 0.50	0.40	0.15 - 0.50	0.35	0.20 - 0.50	0.40
LNB/SAS/OFA	0.30 - 0.75	0.60	0.30 - 0.75	0.60	0.30 - 0.75	0.60
LNB/SAS/FGR	0.25 - 0.65	0.50	0.25 - 0.70	0.50	0.30 - 0.70	0.55
LNB/OFA/FGR	0.25 - 0.65	0.50	0.25 - 0.65	0.50	0.30 - 0.65	0.50
old installation/ optimised		0.15		0.15		0.15
old installation/ retrofitted[2]		0.50		0.50		0.50
new installation[2]		0.40		0.40		0.40

[1] Selection from the DECOF database developed by and available at the Institute for Industrial Production (IIP).

[2] Recommended values, when no information concerning the type of primary measure is available.

[3] Default values used in the computer programme.

[4] No primary measures are installed. This case is mainly relevant for old installations.

Table 11: Default values for reduction efficiency and availability of secondary measures for NO_X reduction /18, 19/ (all fuels)

No.	Type of secondary measure	Reduction efficiency η_{sec} [ ]	Availability β [ ]
1	SNCR	0.50	0.99
2	SCR	0.80	0.99
3	AC	0.70	0.99
4	DESONOX	0.95	0.99

Emission factors of NO_2 for different coal compositions have been calculated by using default values as given above and are listed in Table 25.

The load dependence of NO_X emissions can be split into two different phenomena (see Sections 4.1.2 and 4.1.3):

a) Load variations during normal operation:
Load variations are discussed very controversially in the literature. Often a strong correlation of NO_X emissions and load is reported. Load corrections, e.g. as given in /66/, may be appropriate for older types of boilers.

For boilers of modern design, with optimised combustion conditions e.g. by primary measures, only a negligible load dependence has been reported /64/. This is explained by the fact that for modern boilers (with primary measures) under reduced load conditions an overstoichiometric air ratio is applied in order to achieve an acceptable burning out of the fuel, which leads to NO_x emission factors similar to those obtained under full load conditions. Therefore, for boilers of modern design no load correction is proposed.

For older boilers (without primary measures) a load dependent emission factor can be calculated according to Equation (7), which has been derived for German dry bottom boilers (combustion of hard coal) /71/:

$$EF = 1{,}147 + 0.47 \cdot L \tag{7}$$

EF emission factor [g/MWh][7]
L actual load [MW]

At this stage, no general approach is available for estimating the load dependence of NO_x emissions. However, a load correction factor can be obtained by using a ratio between reduced load and full load emission factors:

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[7] 1 MWh = 3.6 GJ

$$k^{load} = \frac{EF^{Reduced\ load}}{EF^{V}} = \frac{1,147 + 0.47 \cdot L}{1,147 + 0.47 \cdot L_{nominal}} \tag{8}$$

k^{load}	ratio of reduced load to full load emission factor [ ]
$EF^{Reduced\ load}$	emission factor for reduced load conditions [g/MWh][6]
EF^{V}	emission factor for full load conditions [g/MWh][6]
L	actual load [MW]
$L_{nominal}$	nominal load [MW]

Figure 1.1 gives a graphic presentation of the results of Equation (8):

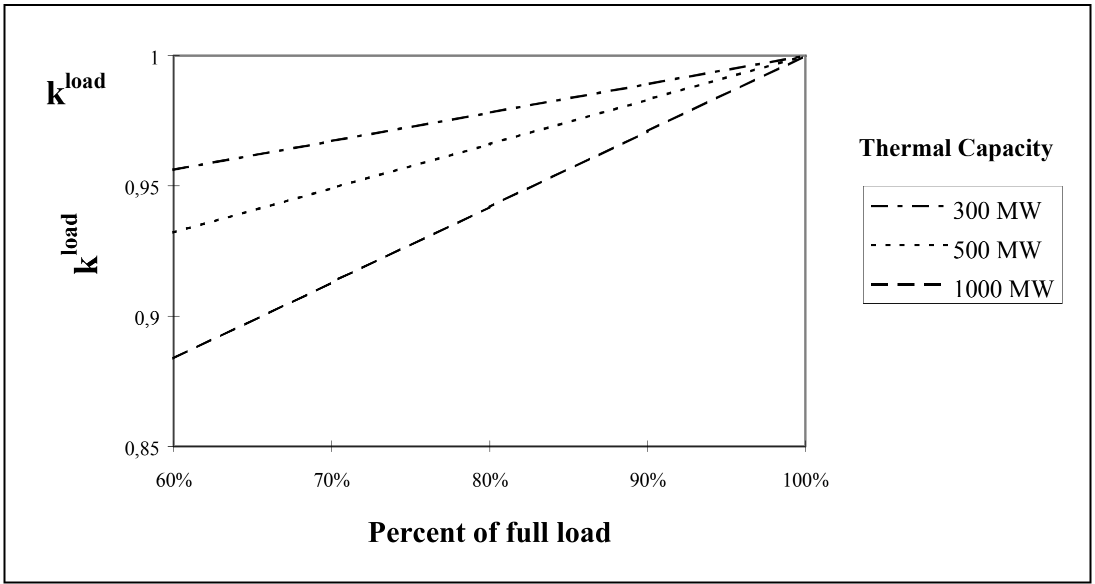


Figure 1.1: Variation of k^{load} with load

If reduced load operation is taken into account the corresponding activity rates have to be determined as follows:

$$A = A_{full\ load} + A_{load\ 1} + A_{load\ 2} + \ldots \tag{9a}$$

A	activity rate within the period considered [GJ]
$A_{full\ load}$	activity rate for full load operation periods [GJ]
$A_{load\ i}$	activity rate for reduced load operation periods at level i [GJ]

Each sub-activity (e.g. $A_{load\ 1}$) has to be determined separately by totalling the thermal energy input for the respective periods of operation e.g. at load level 1.

Emissions are calculated according to Equation (9b):

$$E = EF^{V} \cdot (A_{\text{full load}} + k^{\text{load 1}} \cdot A_{\text{load 1}} + k^{\text{load 2}} \cdot A_{\text{load 2}} + ...) \cdot 10^{-6} \tag{9b}$$

E	emission within the period considered [Mg]
EF^{V}	emission factor at full load conditions [g/GJ]
$A_{\text{load i}}$	activity rates at load level i [GJ]
$k^{\text{load i}}$	ratio of reduced load to full load emission factor at load level i [ ]

If secondary measures are installed, no load correction for NO_X emissions has to be taken into account.

b) Load variations with respect to start-up behaviour:

Emission factors for NO_x, as given in Tables 24 and 25, are related to full load conditions; start-up emissions are not taken into account. If an SCR is installed, start-up emissions should be considered as given in Section 4.1.2. The relevance of start-up emissions of NO_x depends strongly on the following parameters:

- the type of boiler (e.g. NO_x emissions released by wet bottom boilers are always higher than those by dry bottom boilers, due to higher combustion temperatures),
- the type of fuel used (e.g. fuel nitrogen also contributes to the formation of NO_x),
- the status of the boiler at starting time (hot, warm or cold start),
- the specifications of any individual start-up, such as
  - -- the duration and the velocity of start-up,
  - -- the load level (reduced load or full load),
  - -- the configuration of secondary measures (e.g. the start-up time of the high-dust-configurations (SCR-precipitator-FGD) depends on the boiler load, due to the fact that the SCR catalyst is directly heated by the flue gas; tail-end-configurations (precipitator-FGD-SCR) can have shorter start-up times, due to the fact that the SCR catalyst can be preheated by an additional furnace),
  - -- emission standards, which have to be met (boiler-specific emission standards can be set up below the demands of the LCP Directive).

In the investigation mentioned in Annex 15 the measured data from different boilers have been analysed. For the combustion of coal the following ratios have been obtained (based on /116/):

- For the combustion of coal in dry bottom boilers the following ranges and values can be given:

Table 12: Ratios of start-up to full load emission factors F^{EF} and ratios of start-up to full load emissions F^{E} for NO_2 for dry bottom boilers

	Ratio of start-up to full load emissions factors F^{EF} [ ]	Ratio of start-up to full load emissions F^{E} [ ]
Range	2 - max. 6	1 - 2
Values for DBB	F^{EF}_{cold} : 3.5 – 6 F^{EF}_{warm} : 3 – 6.5 F^{EF}_{hot} : 2.5 – 3	F^{E}_{cold} : 1.5 – 2 F^{E}_{warm} : 1 – 2 F^{E}_{hot} : 1 – 1.5

$F^{EF}_{cold,warm,hot}$	Ratio of start-up to full load emission factors for cold, warm or hot start-ups (see also Table 6)
$F^{E}_{cold,warm,hot}$	Ratio of start-up to full load emissions for cold, warm or hot start-ups (see also Table 6)

The investigation revealed that start-up emissions of NO_2 were mostly higher than emissions under full load conditions. There is a dependence between start-up emissions (see Section 3.2) and the time of standstill of the boiler: cold starts showed emissions about 2 times higher, warm starts about 1 up to 2 times higher and hot starts about 1 up to 1.5 higher than at full load conditions. Start-up emission factors can be up to 6 times higher than full load emission factors. At the investigated boilers the SCR was installed in a high-dust configuration.

- For the combustion of coal in wet bottom boilers (SCR in tail-end configuration) it was found that start-up emissions were not higher than full load emissions (ratio of ≤ 1). However, this consideration is based on data of only two boilers. Measured data for hot starts was not available.

NO_x emissions, in particular for the combustion of coal in DBB, might be underestimated, if these effects are not taken into account.

4.3.2 Combustion of other fuels (biomass, waste, liquid fuels, gaseous fuels)

The emission calculation is based on Equation (1). During the combustion of solid and liquid fuels, fuel-NO and thermal-NO are formed. For gaseous fuels only thermal-NO_x is relevant, as gaseous fuels do not contain any fuel-nitrogen. For gaseous fuels the emission reduction is mainly achieved by primary measures. There are several biomass-fuelled plants with SNCR in Sweden.

The analysis of emission data from a gas fired boiler, equipped with an SCR, revealed that start-up emissions are not of relevance (ratios F^{E} were below 1) (based on /116/).

4.4 NMVOC/CH_4 emission factors

The emission calculation is based on Equation (1). Fuel and technique specific emission factors are given in Tables 26 and 27.

4.5 CO emission factors

The emission calculation is based on Equation (1). Fuel and technique specific emission factors are given in Table 28 (full load conditions); start-up emissions are not taken into account. CO emissions at starting time and under full load conditions are mainly influenced by the combustion conditions (oxygen availability, oil spraying etc.). In the detailed investigation start-up emissions for CO have only been found to be relevant for the combustion of coal. Start-up emissions for CO are determined for the time when burners switch-on up to the time when the boiler operates on minimum load.

For the combustion of coal and gas the following results have been obtained (based on /116/ see also Section 4.1.2):

- For the combustion of coal in dry bottom boilers the following ranges can be given:

Table 13: Ratios of start-up to full load emission factors F^{EF} and ratios of start-up to full load emissions F^{E} for CO for dry bottom boilers

	Ratios for start-up to full load emission factors F^{EF} [ ]	Ratios for start-up to full load emissions F^{E} [ ]
Range	0.5 - 3.5	0.1 - 0.7
Values for DBB	F^{EF}_{cold} : 1.5 – 3.5 F^{EF}_{warm} : 1 F^{EF}_{hot} : 0.5	F^{E}_{cold} : 0.4 – 0.7 F^{E}_{warm} : 0.2 – 0.7 F^{E}_{hot} : 0.1

$F^{EF}_{cold,warm,hot}$ Ratio of start-up to full load emission factors for cold, warm or hot start-ups (see also Table 6)

$F^{E}_{cold,warm,hot}$ Ratio of start-up to full load emissions for cold, warm or hot start-ups (see also Table 6)

The values in Table 13 show that start-up emissions for CO for DBB are lower than full load emissions for the boilers considered.

- Start-up emissions from wet bottom boilers can be up to 1.2 times higher than full load emissions for cold starts ($F^{EF} = 4$); they are lower for warm starts ($F^{E} = 0.3$; $F^{EF} = 0.8$).

- Start-up emissions of CO from gas boilers are also negligible.

4.6 CO_2 emission factors

The emission calculation is based on Equation (1). Fuel specific emission factors are given in Table 29. For the determination of specified CO_2 emission factors, the following general Equation (10) can be used:

$$EF_{R_{CO2}} = \frac{44}{12} \cdot C_{C_{fuel}} \cdot \varepsilon \cdot \frac{1}{H_u} \cdot 10^6 \qquad (10)$$

$EF_{R_{CO2}}$	specified emission factor [g/GJ]
$C_{C_{fuel}}$	carbon content of fuel (in mass C/mass fuel [kg/kg])
ε	fraction of carbon oxidised [ ]
H_u	lower heating value of fuel [MJ/kg]

Default values for carbon content and lower heating value of different coals, available on the world market, are given in Annexes 7 and 8. The fraction of carbon oxidised (ε) is defined as the main part of carbon which is oxidised to CO_2; small amounts of carbon may remain unoxidised. Default values for ε according to IPCC /61/ are for liquid fuels 0.99, for solid fuels 0.98 and for gaseous fuels 0.995. In this approach it is assumed that the only product of the oxidation is CO_2. Nevertheless, double counting of CO_2 has to be avoided: products of incomplete oxidation, like CO, must not be converted into CO_2.

The IPCC/OECD presented an overall model (the so-called reference approach) specially designed for the calculation of CO_2 emissions on a national level (not on a plant level) /61/. This methodology is based on national energy balances.

4.7 N_2O emission factors

The emission calculation is based on Equation (1). The fuel and technique specific emission factors are given in Table 30. At this stage, several pilot studies using measured data are described in the literature /13, 14, 25, 26, 27/. A complete list of influencing parameters has not yet been identified.

4.8 NH_3 emission factors

Emission factors referring to the energy input are not yet available. The available data for ammonia slip at SCR/SNCR installations are based on measurements and are related to the flue gas volume: SCR/SNCR installations are often designed for an ammonia slip of about 5 ppm (3.8 mg NH_3/m^3 flue gas) /45, 62/. The ammonia slip at SCR and SNCR installations increases with an increasing NH_3/NO_x ratio, but also with a decreasing catalyst activity.

4.9 Heavy metal emission factors

For heavy metals, general and specified emission factors can be used. Emission factors, depending on the fuel used and the technique installed, are given in Table 31.

The IPCC/OECD presented an overall model (the so-called reference approach) specially designed for the calculation of CO_2 emissions on a national level (not on a plant level) /61/. This methodology is based on national energy balances.

4.9.1 Combustion of coal

For an individual determination of specific heavy metal emission factors, three different methodologies can be applied, taking into account:

- fuel composition	(particle-bound and gaseous emissions),
- fly ash composition	(particle-bound emissions),
- fly ash concentration in clean gas	(particle-bound emissions).

The choice of the methodology depends on data availability.

4.9.1.1 Calculation of specified emission factors based on fuel composition /cf. 35/

Emissions of heavy metals associated with particulate matter and gaseous emissions are assessed subsequently as given in Equation (11). The enrichment behaviour of heavy metals with regard to fine particles is taken into account as an enrichment factor (see also Section 3.4). Gaseous emissions have to be taken into account additionally in the case of arsenic, mercury and selenium.

$$EF_{R_{HM}} = C_{HM_{coal}} \cdot f_a \cdot f_e \cdot 10^{-2} \cdot (1-\eta_p) + C_{HM_{coal}} \cdot f_g \cdot 10^{-2} \cdot (1-\eta_g) \qquad (11)$$

$EF_{R_{HM}}$	specified emission factor of heavy metal (in mass pollutant/mass coal [g/Mg])
$C_{HM_{coal}}$	concentration of heavy metal in coal [mg/kg]
f_a	fraction of ash leaving the combustion chamber as particulate matter [wt.-%]
f_e	enrichment factor [ ]
f_g	fraction of heavy metal emitted in gaseous form [wt.-%]
η_p	efficiency of the dust control equipment [ ]
η_g	efficiency of the emission control equipment with regard to gaseous heavy metals [ ]

The characteristics of fuel and technology are taken into account by f_a and f_e and the following default values are proposed:

Table 14: Default values for f_a for different combustion technologies (based on /35/)

Type of boiler	f_a [wt.-%]
DBB (Pulverised coal)	80
Grate firing	50
Fluidised bed	15

Table 15: Default values for f_e for different heavy metals released by the combustion of coal (based on /35/)

Heavy metal	f_e [ ]	
	range	value[1)]
Arsenic	4.5 - 7.5	5.5
Cadmium	6 - 9	7
Copper	1.5 - 3	2.3
Chromium	0.8 - 1.3	1.0
Nickel	1.5 - 5	3.3
Lead	4 - 10	6
Selenium	4 - 12	7.5
Zinc	5 - 9	7

[1)] Recommended value, if no other information is available.

Gaseous emissions (arsenic, mercury and selenium) are calculated from the heavy metal content in coal; the fraction emitted in gaseous form is given in Table 16. The efficiency of emission control devices with regard to these elements is outlined in Section 3.5.5.

Table 16: Fractions of heavy metals emitted in gaseous form (f_g) released by the combustion of coal /35/

Heavy metal	f_g [wt.-%]
Arsenic	0.5
Mercury	90
Selenium	15

4.9.1.2 Calculation of specified emission factors based on fly ash composition /cf. 39/

If the concentration of heavy metals in raw gas fly ash is known, emission factors of heavy metals can be assessed by Equation (12). Gaseous emissions have to be taken into account separately as outlined in Section 4.9.1.1.

$$EF_{R_{HM,P}} = EF_f \cdot C_{HM_{FA,raw}} \cdot 10^{-3} \cdot (1 - \eta_p) \qquad (12)$$

$EF_{R_{HM,P}}$	specified emission factor of heavy metal in particulate matter (in mass pollutant/mass coal [g/Mg])
EF_f	fly ash emission factor of raw gas (in mass particulate matter/mass coal [kg/Mg])
$C_{HM_{FA,raw}}$	heavy metal concentration in raw gas fly ash (in mass pollutant/mass particulate matter [g/Mg])
η_p	efficiency of dust control equipment [ ]

Values of EF_f can be calculated in a technology specific way using default parameters, as given in Table 17 depending on the content of ash in coal (a) in [wt.-%].

Table 17: Fly ash emission factor for raw gas (EF_f) as function of the ash content in coal (a) [wt.-%] /cf. 39/

Technology	EF_f (in mass particulate matter / mass coal) [kg/Mg]
Cyclone	$1.4 \cdot a$
Stoker	$5.9 \cdot a$
Pulverised coal combustion	$7.3 \cdot a$

The emission factors calculated by taking into account the fuel or the fly ash composition mainly depend on the estimation of the efficiency of dust control equipment.

4.9.1.3 Calculation of specified emission factors based on fly ash concentration in clean flue gas /cf. 36/

If the concentration of heavy metals in fly ash in clean flue gas is known, emission factors of heavy metals can be assessed by Equation (13). Gaseous emissions have to be taken into account separately, as outlined in Section 4.9.1.1.

$$EF_{R_{HM,P}} = C_{HM_{FA,clean}} \cdot C_{FG} \cdot V_{FG} \cdot 10^{-9} \tag{13}$$

$EF_{R_{HM,P}}$	specified emission factor of heavy metal in particulate matter (in mass pollutant/mass coal [g/Mg])
$C_{HM_{FA,clean}}$	concentration of heavy metal in fly ash in clean flue gas (in mass pollutant/mass fly ash [g/Mg])
C_{FG}	concentration of fly ash in clean flue gas (in mass fly ash/volume flue gas [mg/m^3])
V_{FG}	specific flue gas volume (in volume flue gas/ mass coal [m^3/Mg])

Fuel and technology specific heavy metal concentrations in fly ash in clean flue gas ($C_{HM_{FA.clean}}$) are given in Table 18 /36/:

Table 18: Concentration of heavy metals in fly ash in clean flue gas /36/

$C_{HM_{FA.clean}}$	DBB/hc [g/Mg]		WBB/hc [g/Mg]		DBB/hc [g/Mg]	
Heavy metal	range	value	range	value	range	value
As	61 - 528	300	171 - 1,378	690	70 - 120	100
Cd	0.5 - 18	10	18 - 117	80	7 - 12	10
Cr	73 - 291	210	84 - 651	310	10 - 250	70
Cu	25 - 791	290	223 - 971	480	13 - 76	50
Ni	58 - 691	410	438 - 866	650	n. a.	90
Pb	31 - 2,063	560	474 - 5,249	2,210	10 - 202	90
Se1)	18 - 58	45	7 - 8	7	n. a.	n. a.
Zn	61 - 2,405	970	855 - 7,071	3,350	50 - 765	240

1) does not include gaseous Se

n. a.: not available

Default values of particulate matter concentrations downstream of FGD (C_{FG}) are given in Table 19.

Table 19: Particulate matter concentrations downstream of FGD (C_{FG}) released by the combustion of coal based on /18/

Type of FGD	C_{FG} [mg/m^3]	
	range	value1)
WS	20 - 30	25
SDA	20 - 30	25
WL	5 - 10	8
WAP	5 - 10	8
AC	< 40	20
DESONOX	< 40	20

1) Recommended value, if no other information is available.

The concentration of fly ash in flue gas is often monitored continuously. In this case the total annual fly ash emissions can be derived from measured data (see Section 5.2).

4.9.2 Combustion of other fuels

General emission factors for oil and gas combustion can be found in Table 31. Among the other fuels, only waste is relevant for heavy metal emissions. Emission factors for the combustion of waste are currently not available (reported emission factors within the literature mainly refer to the incineration of waste).

5 DETAILED METHODOLOGY

The detailed methodology refers to the handling of measured data in order to determine annual emissions or in order to verify emission factors (for comparison purposes). Annual emissions from major contributors should only be obtained by using continuously measured data which are normally available if secondary abatement technologies are installed. Furthermore, the detailed methodology should be used whenever measured data are available; e.g. for medium and small sized combustion installations periodically measured data are often available.

Measurements are carried out downstream of the boiler or at the stack; measured values obtained by both variants are usable.

National monitoring programmes should include guidelines for quality assurance of measurements (measuring places, methods, reporting procedures, etc.).

The pollutants normally measured at power plants are SO_2, NO_x, CO, and particulate matter. Gaseous emissions of SO_2, NO_x, and CO are treated in Section 5.1. Continuously measured particulate matter emission data can be used to estimate heavy metal emissions (see Section 5.2).

5.1 Gaseous emissions

It is desirable to obtain annual emissions in [Mg]. The annual emission as a function of time is normally given by the following Equation (14):

$$E = \int_T e(t) \qquad dt \tag{14}$$

E	emission within the period T [Mg]
e (t)	emission per unit of time in the periods of operation [Mg/h]
t	time [h]
T	annual time period (see also Figure 1)

Usually, the emission e(t) cannot be or is not directly measured. Therefore, for practical reasons, the concentration of pollutants and the flue gas volume are used for the determination of e(t), as described by Equation (15):

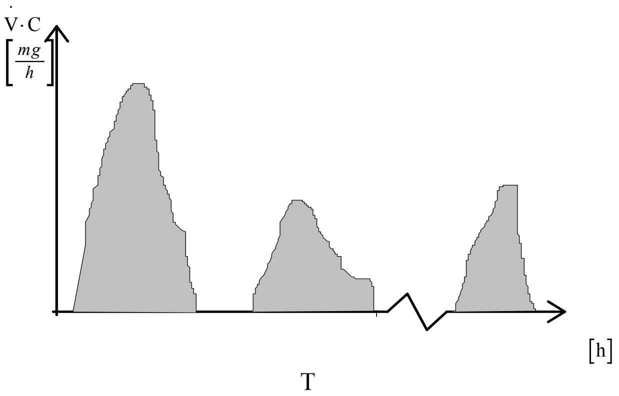
$$\mathrm{e(t)} = \dot{\mathrm{V}}(\mathrm{t}) \cdot \mathrm{C(t)} \tag{15}$$

e (t)	emission in the periods of operation [Mg/h]
$\dot{V}(t)$	flue gas volume flow rate [m^3/h]

C (t)	flue gas concentration of a pollutant [mg/m^3]

Usually, emission fluctuations occur within a year (see Figure 1) as:

- periodical fluctuations (e.g. daily, weekly, seasonally), due to load management depending on the demand of e.g. district heat or electricity,
- operational fluctuations (e.g. start-ups/shut downs, raw material properties, working conditions/reaction conditions).



$\dot{V}$	flue gas volume flow rate [m^3/h]
C	flue gas concentration of a pollutant (abatement techniques installed are included) [mg/m^3]
t	time [h]
t_{bn}	beginning of operation (e.g. start-up of boiler) [h]
t_{en}	ending of operation (e.g. shut down of boiler) [h]
T	annual time period

Figure 1: Periods of operation of a combustion installation

The following approaches can be used to determine annual emissions depending on the level of detail of measured data available.

– First approach:

The flue gas volume and the concentration of a pollutant are measured continuously (e.g. in Finland). Then, the annual emission is given exactly by the following Equation (16):

$$E = 10^{-9}\int_T V(t)\cdot C(t)dt \qquad (16)$$

E	emission within the period T [Mg]
$\dot{V}(t)$	flue gas volume flow rate [m^3/h]
C (t)	flue gas concentration of a pollutant (abatement techniques installed are included) [mg/m^3]
t	time [h]
T	annual time period (see also Figure 1)

The precision of measurements of $\dot{V}(t)$ and C(t) depends on the performance of the analytical methods (e.g. state-of-the-art) used. In particular, the regular calibration of measuring instruments is very important. Analytical methods commonly used for NO$_x$ detect only NO and those used for SO_x detect only SO_2. It is implicitly assumed that NO_2 in the flue gas is normally below 5 %, and that SO_3 in the flue gas is negligible. Nevertheless, for some combustion plants the amounts of NO_2 and/or SO_3 formed can be significant and have to be detected by appropriate analytical methods. The measured values have to be specified with regard to dry/wet flue gas conditions and standard oxygen concentrations[8].

For the annual time period T considered, a case distinction has to be made:

- calendar year T_1 (e.g. including time out of operation),
- real operating time T_2 of boiler/plant (e.g. start-ups are reported when „burner on/off“),
- official reporting time T_3 determined by legislation (e.g. start-ups are reported, as soon as the oxygen content in the flue gas goes below 16 %),

where $T_3 \subset T_2 \subset T_1$. If C(t) is only available for T_3, adequate corrections have to be provided.

– Second approach:

Due to the difficulty in measuring V(t) continuously in large diameter stacks, in most cases the flue gas volume flow rate V(t) is not measured. Then the annual emission can be determined by Equation (17):

$$E = 10^{-9}\overline{\dot{V}}\int_T C(t)dt \tag{17}$$

E emission within the period T [Mg]
$\overline{\dot{V}}$ average flue gas volume flow rate [m^3/h]
C(t) flue gas concentration of a pollutant (abatement techniques installed are included) [mg/m^3]
t time [h]
T annual time period (see also Figure 1)

The average flue gas volume flow rate $\overline{\dot{V}}$ (dry conditions) can be determined according to the following Equations (18) and (19):

$$\overline{\dot{V}} = V_{FG} \cdot \dot{m}_{fuel} \tag{18}$$

$\overline{\dot{V}}$ average flue gas volume flow rate [m^3/h]
V_{FG} dry flue gas volume per mass fuel [m^3/kg]
$\dot{m}_{fuel}$ fuel consumption rate [kg/h]

$$V_{FG} \approx 1.852\left[\tfrac{m^3}{kg}\right]\cdot C_c + 0.682\left[\tfrac{m^3}{kg}\right]\cdot C_s + 0.800\left[\tfrac{m^3}{kg}\right]\cdot C_N + V_{N_{air}} \tag{19}$$

V_{FG} dry flue gas volume per mass fuel [m^3/kg]
C_c concentration of carbon in fuel [kg/kg]
C_s concentration of sulphur in fuel [kg/kg]

---

[8] In some countries the measured values obtained are automatically converted into values under standard oxygen concentrations (e.g. in Germany).

C_N	concentration of nitrogen in fuel [kg/kg]
$V_{N_{air}}$	specific volume of air nitrogen (in volume/mass fuel [m^3/kg])

This calculation of V according to Equation (19) can be performed by the computer programme (see Annex 6) by using default values for C_C, C_S, C_N and $V_{N_{air}}$.

- Third approach:
  In some countries the term $\int_T C(t)dt$ is available as an annual density function P(C) (histogram). In this case Equation (17) can be simplified to:

$$E = \overline{\dot{V}} \cdot \overline{C} \cdot t_{op} \cdot 10^{-9} \tag{20}$$

$$\text{where} \quad \overline{C} = \int_0^\infty P(C) \cdot C \cdot dC \tag{21}$$

E	emission within the period T [Mg]
$\overline{\dot{V}}$	average flue gas volume flow rate [m^3/h]
$\overline{C}$	expected value (mean value) of the flue gas concentration for each pollutant (abatement techniques installed are included) [mg/m^3]
t_{op}	annual operating time [h]
P(C)	density function [ ]
C	flue gas concentration per pollutant as given in the histogram [mg/m^3]

The variable t_{op} has to be introduced consistently with $\overline{\dot{V}}$ and $\overline{C}$ according to periods T_1, T_2 or T_3 mentioned above. If e.g. start-ups are not included, they should be taken into account as given in Sections 4.1, 4.2 and 4.4.

- Fourth approach:
  If neither T_2 nor T_3 are available, the annual full load operating hours can also be used. Then Equation (20) becomes:

$$E = \overline{\dot{V}}_{normed} \cdot \overline{C} \cdot t_{op}^{full\,load} \cdot 10^{-9} \tag{22}$$

E	emission within the period considered [Mg]
$\overline{\dot{V}}_{normed}$	average flue gas volume flow rate related to full load operation [m^3/h]
$\overline{C}$	mean value of the flue gas concentration for each pollutant (abatement techniques installed are included) [mg/m^3]
$t_{op}^{full\,load}$	annual operating time expressed as full load operating hours [h]

From here, emission factors, based on measured values, can be derived e.g. for verification purposes:

$$EF = \frac{E}{A} \cdot 10^6 \tag{23}$$

EF	emission factor [g/GJ]

E	emission within the period considered [Mg]
A	activity rate within the time period considered [GJ]

5.2 Heavy metal emissions

Continuously measured values for the total heavy metal emissions (particle-bound and gaseous) are not available for the combustion of fossil fuels. National legislation can require periodical measurements, e.g. weekly measurements of heavy metal emissions [mg/m^3] in the case of waste incineration/combustion.

The emissions of particle-bound heavy metals depend on the emission of particulate matter which is normally periodically or continuously monitored. Therefore, the particle-bound heavy metal emissions can be derived from the element content in particulate matter. The heavy metal emission factor can be back-calculated as follows:

$$EF = \frac{\overline{\dot{m}}_{FA} \cdot \overline{C}_{HM_{FA.clean}}}{A} \tag{24}$$

EF	emission factor [g/GJ]
$\overline{\dot{m}}_{FA}$	mass of fly ash within the period considered [Mg]
$\overline{C}_{HM_{FA.clean}}$	average concentration of heavy metal in fly ash (in mass pollutant/mass fly ash [g/Mg])
A	activity rate within the period considered [GJ]

Measured data should also be used to replace the default values of Equation (13) for $C_{HM_{FA.clean}}$ and C_{FG}.

6 RELEVANT ACTIVITY STATISTICS

In general, the published statistics do not include point sources individually. Information on this level should be obtained directly from each plant operator.

On a national level, statistics can be used for the determination of fuel consumption, installed capacity and/or types of boilers mainly used. The following statistical publications can be recommended:

- Office for Official Publication of the European Communities (ed.): Annual Statistics 1990; Luxembourg 1992
- Commission of the European Communities (ed.): Energy in Europe - Annual Energy Review; Brussels 1991
- Statistical Office of the European Communities (EUROSTAT) (ed.): CRONOS Databank, 1993
- OECD (ed.): Environmental Data, Données OCDE sur l'environnement; compendium 1993
- Commission of the European Communities (ed.): Energy in Europe; 1993 - Annual Energy Review; Special Issue; Brussels 1994

- EUROSTAT (ed.): Panorama of EU Industry'94; Office for official publications of the European Communities; Luxembourg 1994

7 POINT SOURCE CRITERIA

Point source criteria for a combustion plant according to CORINAIR are given in chapter AINT and in /41/.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

Tables 23 - 31 list emission factors for all pollutants considered, except for SO_2. For SO_2 emission factors have to be calculated individually (see Equation (5)). Sulphur contents of different fuels are given. The emission factors have been derived from the literature, from the calculations presented here (see also Section 4) and from recommendations from expert panel members. All emission factor tables have been designed in a homogenous structure: Table 20 contains the allocation of SNAP activities used related to combustion installations, where three classes are distinguished according to the thermal capacity installed. Table 21 includes the main types of fuel used within the CORINAIR90 inventory. Table 22 provides a split of combustion techniques (types of boilers, etc.); this standard table has been used for all pollutants. The sequence of the emission factor tables is:

Table 20: SNAP code and SNAP activity related to the thermal capacities installed in combustion plants

Table 21: Selection of relevant fuels from NAPFUE and lower heating values for boilers, gas turbines and stationary engines

Table 22: Standard table for emission factors for the relevant pollutants

Table 23: S-contents of selected fuels

Table 24: NO_X emission factors [g/GJ] for combustion plants

Table 25: NO_X emission factors [g/GJ] for coal combustion according to the model description (see Annexes 4 and 5)

Table 26: NMVOC emission factors [g/GJ] for combustion plants (coal combustion)

Table 27: CH_4 emission factors [g/GJ] for combustion plants

Table 28: CO emission factors [g/GJ] for combustion plants

Table 29: CO_2 emission factors [kg/GJ] for combustion plants

Table 30: N_2O emission factors [g/GJ] for combustion plants

Table 31: Heavy metal emission factors [g/Mg] for combustion plants

References of the emission factors listed are given in footnotes of the following tables. Quality codes are not available in the literature.

Table 20: SNAP code and SNAP activity related to the thermal capacities installed in combustion plants

Thermal capacity [MW]	SNAP code	SNAP activity
>= 300	010101	Public power and co-generation combustion plants
	010201	District heating combustion plants
	010301	Petroleum and/or gas refining plants
	010401	Solid fuel transformation plants
	010501	Coal mining, oil, gas extraction/distribution plants
	020101	Commercial and institutional plants
	030101	Industrial combustion plants
>=50 up to < 300	010102	Public power and co-generation combustion plants
	010202	District heating combustion plants
	020102	Commercial and institutional plants
	020201	Residential combustion plants
	020301	Plants in agriculture, forestry and fishing
	030102	Industrial combustion plants
< 50	010103	Public power and co-generation combustion plants
	010203	District heating combustion plants
	020103	Commercial and institutional plants
	020202	Residential combustion plants
	020302	Plants in agriculture, forestry and fishing
	030103	Industrial combustion plants

Table 21: Selection of relevant fuels from NAPFUE and lower heating values for boilers, gas turbines and stationary engines

Type of fuel according to NAPFUE					NAPFUE code	H_u [MJ/kg][2]
s	coal	hc	coking [1]	GHV[11] > 23,865 kJ/kg	101	29.3[4]
s	coal	hc	steam [1]	GHV[11] > 23,865 kJ/kg	102	29.3[4]
s	coal	hc	sub-bituminous	17,435 kJ/kg < GHV[11] < 23,865 kJ/kg	103	20.6
s	coal	hc/bc	patent fuels	from hard/sub-bituminous coal	104	
s	coal	bc	brown coal/lignite	GHV[11] < 17,435 kJ/kg	105	12.1
s	coal	bc	briquettes		106	19.5[4]; 18.6[5]
s	coke	hc	coke oven		107	26.3[10]
s	coke	bc	coke oven		108	29.9[7]
s	coke		petroleum		110	30[10]
s	biomass		wood		111	12.4[4], 16[10]
s	biomass		charcoal		112	
s	biomass		peat		113	9.5[10]
s	waste		municipal		114	7.5[4]
s	waste		industrial		115	8.4[8]
s	waste		wood	except wastes similar to wood	116	
s	waste		agricultural	corncobs, straw etc.	117	
l	oil		residual		203	41.0[4]
l	oil		gas		204	42.7[4], 42.5[10]
l	oil		diesel	for road transport	205	
l	kerosene				206	
l	gasoline		motor		208	43.5[4]
l	naphtha				210	
l	black liquor				215	
g	gas		natural	except liquified natural gas	301	heavy 39.7 MJ/m^3 [3], light 32.5 MJ/m^3 [3]
g	gas		liquified petroleum gas		303	45.4[10]
g	gas		coke oven		304	19.8[10]
g	gas		blast furnace		305	3.0[10]
g	gas		coke oven and blast furnace gas		306	
g	gas		waste		307	
g	gas		refinery	not condensable	308	48.4[6], 87 MJ/m^3 [10]
g	gas		biogas		309	34.7[9]
g	gas		from gas works		311	

(1) A principal differentiation between coking coal and steam coal is given in section 3.2. Further differentiation between coking coal and steam coal can be made by using the content of volatiles: coking coal contains 20 - 30 wt.-% volatiles (maf), steam coal contains 9.5 - 20 wt.-% volatiles (maf) (based on official UK subdivision). This is necessary if no information concerning the mean random reflectance of vitrinite (see Section 3.2) is available.

(2) H_u = lower heating value; lower heating values for coals from different countries are given in Annexes 7 and 8 and for solid, liquid and gaseous fuels in (/88/, Table 1-2).

(3) given under standard conditions

(4) Kolar 1990 /17/

(5) /98/

(6) MWV 1992 /97/

(7) Boelitz 1993 /78/

(8) Schenkel 1990 /105/

(9) Steinmüller 1984 /107/

(10) NL-handbook 1988 /99/

(11) GHV = Gross heating value

Table 22: Standard table of emission factors for the relevant pollutants

						Thermal boiler capacity [MW]4)																				no specification
						>= 300			>= 50 and < 300						< 50											
						Type of boiler			Type of boiler						Type of boiler							GT10)		Stat. E.11)		CORINAIR90 12)
						DBB5)	WBB6)	FBC7)	DBB	WBB	FBC7)		GF8)		DBB	WBB	FBC7)			GF						
Type of fuel1)			NAPFUE code1)	H_u 2) [MJ/kg]	P1 3)	Primary measures9)	Primary measures9)	CFBC			CFBC	PFBC	ST1	ST2			AFBC	CFBC	PFBC	ST1	ST2	SC	CC	CI	SI	
s	coal	hc																								
s	coal	hc																								
s	coal	hc																								
s	coal	bc	...	...	...																					
s	coke																									
s	biomass																									
s	waste																									
l	oil																									
g	gas																									

1) the type of fuel is based on the NAPFUE code, see table 21

2) H_u = lower heating value, when different from table 21

3) relevant parameter of fuel composition for SO_2: P1 = sulphur content of fuel;

4) the corresponding SNAP-codes are listed in table 20

5) DBB - Dry bottom boiler

6) WBB - Wet bottom boiler

7) FBC - Fluidised bed combustion; CFBC = Circulating FBC; PFBC = Pressurised FBC (Dense FBC); AFBC = Atmospheric FBC

8) GF - Grate firing; ST1 and ST2 are different types of stoker (e.g. travelling stoker, spreader stoker)

9) Primary measures are described by reduction efficiency

10) GT = Gas turbine; SC = Simple cycle; CC = Combined cycle

11) Stat. E. = Stationary engine; CI = Compression ignition; SI = Spark ignition

12) CORINAIR90 data on combustion plants as point sources

Table 23: S-contents of selected fuels [1]

Type of fuel				NAPFUE code	Sulphur content of fuel		
					value [2]	range	unit
s	coal [3]	hc	coking	101		0.4 - 6.2	wt.-% (maf)
s	coal [3]	hc	steam	102		0.4 - 6.2	wt.-% (maf)
s	coal [3]	hc	sub-bituminous	103		0.4 - 6.2	wt.-% (maf)
s	coal [3]	bc	brown coal/lignite	105		0.4 - 6.2	wt.-% (maf)
s	coal	bc	briquettes	106		0.25 - 0.45 [13]	wt.-% (maf)
s	coke	hc	coke oven	107		< 1 [5]	wt.-% (maf)
s	coke	bc	coke oven	108		0.5 - 1 [5] [6]	wt.-% (maf)
s	coke		petroleum	110			
s	biomass		wood	111		< 0.03 [5]	wt.-% (maf)
s	biomass		charcoal	112		< 0.03 [5]	wt.-% (maf)
s	biomass		peat	113			
s	waste		municipal	114			
s	waste		industrial	115			
s	waste		wood	116			
s	waste		agricultural	117			
l	oil		residual	203		0.3 [8] - 3.5 [9]	wt.-%
l	oil		gas	204	0.3 [11]	0.08 - 1.0	wt.-%
l	oil		diesel	205	0.3 [11]		wt.-%
l	kerosene			206			
l	gasoline		motor	208		< 0.05 [12]	wt.-%
l	naphtha			210			
l	black liquor			215			
g	gas [4]		natural	301	(0.0075) [10]		$g \cdot m^{-3}$
g	gas		liquified petroleum gas	303	-		
g	gas		coke oven	304	8		$g \cdot m^{-3}$
g	gas		blast furnace	305	$45 \cdot 10^{-3}$ [10]		$g \cdot m^{-3}$
g	gas		coke oven and blast furnace gas	306			
g	gas		waste	307			
g	gas		refinery	308		<= 8 [10]	$g \cdot m^{-3}$
g	gas		biogas	309			
g	gas		from gas works	311			

[1] for emission factor calculation see Section 4.1, and Annexes 2 and 3

[2] recommended value

[3] for complete coal composition see Annexes 7 and 8

[4] only trace amounts

[5] Marutzky 1989 /94/

[6] Boelitz 1993 /78/

[8] Mr. Hietamäki (Finland): Personal communication

[9] Referring to NL-handbook 1988 /99/ the range is 2.0 - 3.5

[10] NL-handbook 1988 /99/

[11] 87/219 CEE 1987 /113/

[12] $\alpha_s \sim 0$

[13] Davids 1986 /46/

Table 24: NO_x emission factors [g/GJ] for combustion plants

Type of fuel				NAPFUE code	Thermal boiler capacity [MW]				
					>= 300[32)]			>= 50 and < 300[32)]	
					Type of boiler[43)]			Type of boiler	
					DBB/boiler[27)]	WBB	FBC CFBC	DBB/boiler[27)]	WBB
s	coal	hc	coking	101	see table 25	see table 25	70[1)]	see table 25	see table 25
s	coal	hc	steam	102	see table 25	see table 25	70[1)]	see table 25	see table 25
s	coal	hc	sub-bitumious	103	see table 25	see table 25	70[1)]	see table 25	see table 25
s	coal	bc	brown coal/lignite	105	see table 25		70[1)]	see table 25	
s	coal	bc	briquettes	106					
s	coke	hc	coke oven	107					
s	coke	bc	coke oven	108					
s	coke		petroleum	110				300[1)]	
s	biomass		wood	111				200[1),15)]	
s	biomass		charcoal	112					
s	biomass		peat	113	300[1),28)]			300[1)]	
s	waste		municipal	114					
s	waste		industrial	115					
s	waste		wood	116					
s	waste		agricultural	117					
l	oil		residual	203	210[1),29)], 260[1),28)], 155 - 296[19),20)]			150[1),29)], 170[1),29)], 190[1),30)], 210[1),30)]	
l	oil		gas	204	64 - 68[21)]			100[1)]	
l	oil		diesel	205					
l	kerosene			206					
l	gasoline		motor	208					
l	naphtha			210					
l	black liquor			215					
g	gas		natural	301	170[1)], 48 - 333[22) 23)]			125[1),25)], 150[1),26)], 48 - 333[22),23),24)]	
g	gas		liquified petroleum gas	303	88 - 333[23),24)]			88 - 333[23),24)]	
g	gas		coke oven	304	150[1)], 88 - 333[23) 24)]			110[1),25)], 130[1),26)], 88 - 333[23),24)]	
g	gas		blast furnace	305	95[1)], 88 - 333[23) 24)]			65[1)25)], 80[1),26)], 88 - 333[23),24)]	
g	gas		coke oven and blast furnace gas	306	88 - 333[23),24)]			88 - 333[23),24)]	
g	gas		waste	307	88 - 333[23),24)]			88 - 333[23),24)]	
g	gas		refinery	308	88 - 333[23),24)]			140[1)], 88 - 333[23),24)]	
g	gas		biogas	309	88 - 333[23),24)]			88 - 333[23),24)]	
g	gas		from gas works	311					

to be continued

Table 24: continued

Thermal boiler capacity [MW]													no specification
> 50 and < 300 $^{32)}$			< 50$^{32)}$										
Type of boiler			Type of boiler						Gas turbine		Stationary engine		CORINAIR 90$^{44)}$
FBC		GF	DBB/boiler$^{27)}$	WBB	FBC			GF					
PFBC	CFBC				PFBC	CFBC	AFBC		SC	CC	CI	SI	
150$^{1)}$	70$^{1)}$	150$^{1)}$	180$^{1),31)}$, 230$^{1),29)}$			70$^{1)}$		150$^{1)}$					545$^{44)}$
150$^{1)}$	70$^{1)}$	150$^{1)}$	180$^{1),31)}$, 230$^{1),29)}$			70$^{1)}$		150$^{1)}$					36.5 - 761$^{44)}$
150$^{1)}$	70$^{1)}$	150$^{1)}$	180$^{1),31)}$, 230$^{1),29)}$			70$^{1)}$		150$^{1)}$					20.5 - 1,683$^{44)}$
150$^{1)}$	70$^{1)}$	150$^{1)}$	180$^{1),31)}$, 230$^{1),29)}$			70$^{1)}$		150$^{1)}$					180 - 380$^{44)}$
													33.3 - 175$^{44)}$
			300$^{1)}$		300$^{1)}$	300$^{1)}$							
		200$^{1)}$, 33 - 115$^{15)}$	200$^{1)}$, 33 - 115$^{15)}$					200$^{1),15)}$					50 - 200$^{44)}$
160$^{1)}$	100$^{1)}$	230$^{1)}$	280$^{1)}$		160$^{1)}$	100$^{1)}$							150 - 240$^{44)}$
		90 - 463$^{16),17)}$						90 - 463$^{16),17)}$					220$^{44)}$
		139 - 140$^{18)}$						139 - 140$^{18)}$					
													80 - 200$^{44)}$
		88$^{6)}$											160$^{44)}$
			140$^{1),29)}$, 180$^{1),30)}$						250$^{45)}$		1,090-1,200$^{45)}$		24 - 370$^{44)}$
			80$^{1)}$, 100$^{1)}$						120 $^{1),35)}$, 350$^{1),33)}$, 380$^{1),34)}$, 780$^{1),36)}$		100 - 1,200$^{45)}$		50 - 269$^{44)}$
									100 - 700$^{45)}$, 300$^{46)}$		600$^{1),37),42)}$, 1,200$^{1),38)}$	1,000$^{1),40),42)}$, 1,800$^{1),39),42)}$	
													180$^{44)}$
													20 - 440$^{44)}$
			100$^{1)}$, 48 - 333$^{22),23),24)}$						150 - 360$^{45)}$		600$^{1),37),42)}$, 1,200$^{1),38),42)}$	1,000$^{1),40),42)}$, 1,800$^{1),39),42)}$	22 - 350$^{44)}$
									188$^{4),41)}$	187$^{4),41)}$			
			88 - 333$^{23),24)}$										35 - 100$^{44)}$
			90$^{1),23),24)}$										70 - 571$^{44)}$
			88 - 333$^{23),24)}$										6.7 - 330$^{44)}$
			88 - 333$^{23),24)}$										
			88 - 333$^{23),24)}$										35 - 327$^{44)}$
			140$^{1),23),24)}$						150-151$^{45)}$				35 - 140$^{44)}$
			88 - 333$^{23),24)}$										60$^{44)}$

[1] CORINAIR 1992 /80/, without primary measures
[2] Ratajczak 1987 /103/, Kolar 1990 /17/
[3] Lim 1982 /91/, Kolar 1990 /17/
[4] Mobley 1985 /96/, Kolar 1990 /17/
[5] LIS 1977 /92/
[6] Radian 1990 /102/, IPCC 1994 /88/, without primary measues
[7] UBA 1985 /111/, Kolar 1990 /17/
[8] Kolar 1990 /17/
[9] Bartok 1970 /75/, Kolar 1990 /17/
[10] Kremer 1979 /90/, Kolar 1990 /17/
[11] UBA 1981 /110/, Kolar 1990 /17/
[12] LIS 1987 /93/
[13] Davids 1984 /81/, Kolar 1990 /17/
[14] Ministry 1980 /95/, Kolar 1990 /17/
[15] utility boiler: 112[6], commercial boiler: 33[6], industrial boiler: 115[6]
[16] utility boiler (GF): 140[6], commercial boiler: 463[6], commercial open burning: 3[6] kg/Mg waste
[17] GF: 90 - 180[8]
[18] industrial combustion (mass burn.): 140[6], industrial combustion (small burner): 139[6]
[19] DBB (power plants): 240[11], 245[10], 296[9], 270[10]
[20] utility boiler: 201[6], commercial boiler: 155[6], industrial boiler: 161[6]
[21] utility boiler: 68[6], commercial boiler: 64[6]
[22] utility boiler: 267[6], commercial boiler: 48[6], industrial boiler: 67[6]
[23] power plant: 160[9], 170[10], 185[10], 190[11], 215[10], 333[13]
[24] industry: 88[9], 100[11]
[25] 50 - 100 MW thermal
[26] 100 - 300 MW thermal
[27] DBB for coal combustion; boiler for other fuel combustion
[28] wall firing
[29] tangential firing
[30] wall/bottom firing
[31] wall/tangential firing
[32] The emission factors [g/GJ] are given at full load operating modus.
[33] no specification
[34] with diffusion burner
[35] modern with pre-mixer
[36] derived from aero engines
[37] prechamber injection
[38] direct injection
[39] 4 stroke engines
[40] 2 stroke engines
[41] 80[1,35], 250[1,33], 160 - 480[1,34], 650[1,36]
[42] 1000[1,33]
[43] The formation of thermal-NO is much more influenced by the combustion temperature than by the burner arrangement within the boiler /64/. Therefore, no emission factors are given for different burner arrangements (e.g. tangential firing).
[44] CORINAIR90 data of combustion plants as point sources with thermal capacity of > 300, 50 - 300, <50 MW
[45] CORINAIR90 data of combustion plants as point sources
[46] AP42 /115/

Table 25: NO_x emission factors [g/GJ] for coal combustion according to the model (see Annexes 4 and 5)

Type of fuel			coal mining country	NAPFUE code	H_u [MJ/kg] (maf)	Thermal boiler capacity [MW] >= 50 [1]									
						Type of boiler									
						DBB					WBB				
						PM0[2]	PM1	PM2	PM3	PM4	PM0	PM1	PM2	PM3	PM4
						η= 0	η= 0.20	η=0.45	η=0.45	η=0.60	η= 0	η= 0.20	η=0.45	η=0.40	η=0.60
s	coal	hc	Australia	(101)	34	568	454	312	312	227	703	562	387	422	281
			Canada	(101)	33	500	405	278	278	202	627	501	345	376	251
			China	(101)	32	413	331	227	227	165	512	409	281	307	205
			Columbia	(101)	32	535	428	394	394	214	662	529	364	397	265
			Czech Republic	(101)	34	483	387	266	266	193	598	479	329	359	239
			France	101	35	374	299	205	205	149	463	370	254	278	185
			Germany RAG	102	35	384	307	211	211	154	476	381	262	285	190
			Germany others	101	30	495	396	272	272	198	613	490	337	368	245
			CIS	(101)	32	308	247	169	169	123	382	305	210	229	153
			Hungary	101	34	401	320	220	220	160	496	397	273	298	198
			India	103	30	551	441	303	303	220	682	545	375	409	273
			South Africa	(101)	32	569	456	313	313	228	705	504	388	423	282
			USA	(101)	34	563	450	310	310	225	697	558	383	418	279
			Venezuela	(101)	34	588	471	324	324	235	728	583	401	437	291
						η= 0	η= 0.20	η=0.45	η=0.40	η=0.60					
s	coal	bc	Czech Republic	105	28	506	405	278	304	202					
			Germany												
			- Rheinisch Coal	105	27	325	260	179	195	130					
			- Middle Germany	105	25	504	403	277	302	202					
			- East Germany	105	26	539	431	296	323	215					
			Hungary-1	105	36	379	303	208	227	151					
			Hungary-2	103	28	379	304	209	228	152					
			Poland	105	25	531	425	292	319	213					
			Portugal	105	25	461	369	254	277	185					
			Turkey-2	103	27	725	580	399	435	290					

[1] The emission factors [g/GJ] are given at full load operating modus.

[2] PM0 ... PM4 = most used combinations of primary measures; η = reduction efficiencies [ ]

PM0 - no primary measures
PM1 - one primary measure: LNB
PM2 - two primary measures: LNB/SAS
PM3 - two primary measures: LNB/OFA
PM4 - three primary measures: LNB/SAS/OFA

Table 26: NMVOC emission factors [g/GJ] for combustion plants

Type of fuel				NAPFUE code	Thermal boiler capacity [MW] >= 50 boiler	GF	< 50 boiler	Gas turbine	Stationary engine	no specification CORINAIR90[6]
s	coal	hc	coking	101	3[5], 30[2]	50[2]	600[1]			3[6]
s	coal	hc	steam	102	3[5], 30[2]	50[2]	600[1]			1 - 15[6]
s	coal	hc	sub-bituminous	103	3[5], 30[2]	50[2]	600[1]			1.5 - 15[6]
s	coal	bc	brown coal/lignite	105	30[2,3]	50[2]				1.5 - 15[6]
s	coal	bc	briquettes	106			150[1]			
s	coke	hc	coke oven	107			12[1]			5 - 15[6]
s	coke	bc	coke oven	108						
s	coke		petroleum	110						1.5[6]
s	biomass		wood	111	80[2]		100[5], 150[1], 400[4]			10 - 48[6]
s	biomass		charcoal	112						
s	biomass		peat	113	30[2,3]	30[2]				3 - 48[6]
s	waste		municipal	114						10[6]
s	waste		industrial	115						
s	waste		wood	116						40 - 48[6]
s	waste		agricultural	117						50[6]
l	oil		residual	203	10[2,3]			3[7]	50[7]	1.5 - 47.6[6]
l	oil		gas	204	5[2]		15[1]	5[2], 1.5 - 2[7]	1.5 - 100[7], 100[2]	1.5 - 9.3[6]
l	oil		diesel	205						
l	kerosene			206						3[6]
l	gasoline		motor	208						
l	naphtha			210						3[6]
l	black liquor			215						3[6]
g	gas		natural	301	5[2]			5[2], 2.5 - 4[7]	200[2]	2 - 4[6]
g	gas		liquified petroleum gas	303						2 - 2.6[6]
g	gas		coke oven	304						2.5 - 167[6]
g	gas		blast furnace	305						1 - 2.5[6]
g	gas		coke oven and blast furnace gas	306						
g	gas		waste	307						2.5[6]
g	gas		refinery	308	25[2]			2.5[7]		2.1 - 10[6]
g	gas		biogas	309						2.5[6]
g	gas		from gas works	311						

[1] LIS 1977 /92/ [2] CORINAIR 1992 /80/ [3] DBB only [4] small consumers cf. /24/ [5] power plants cf. /24/

[6] CORINAIR90 data of combustion plants as point sources with a thermal capacity of > 300, 50 - 300, < 50 MW

[7] CORINAIR90 data, point sources

Table 27: CH$_4$ emission factors [g/GJ] for combustion plants

Tpe of fuel				NAPFUE code	Type of combustion										stat. E.	no specification
					Utility combustion			Commercial comb.		Industrial combustion						
					DBB/WBB FBC/ boiler$^{3)}$	GF stoker		boiler	GF	boiler	GF stoker		GT			CORINAIR90$^{5)}$
						spreader	travell.				spreader	travell.	SC	CC		
s	coal	hc	coking	101	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						0.3 - 15$^{5)}$
s	coal	hc	steam	102	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						1.5 - 15$^{5)}$
s	coal	hc	sub-bituminous	103	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						0.3 - 15$^{5)}$
s	coal	bc	brown coal/lignite	105	0.6$^{1)}$	0.7$^{1)}$		10$^{1)}$		2.4$^{1)}$						
s	coal	bc	briquettes	106												
s	coke	hc	coke oven	107												0.2 - 15$^{5)}$
s	coke	bc	coke oven	108												
s	coke		petroleum	110												1.5$^{5)}$
s	biomass		wood	111	18$^{1)}$			15$^{1)}$		15$^{1)}$						1 - 40$^{5)}$
s	biomass		charcoal	112												
s	biomass		peat	113												1 - 39$^{5)}$
s	waste		municipal	114				6.5$^{1),4)}$								1$^{5)}$
s	waste		industrial	115												10$^{5)}$
s	waste		wood	116												4 - 40$^{5)}$
s	waste		agricultural	117				9$^{1),4)}$								32$^{5)}$
l	oil		residual	203	0.7$^{1)}$			1.6$^{1)}$		2.9$^{1)}$			3$^{5)}$		3$^{6)}$	0.1 - 10$^{5)}$
l	oil		gas	204	0.03$^{1)}$			0.6$^{1)}$					1 - 8$^{5)}$		1.5$^{6)}$	0.1 - 8$^{5)}$
l	oil		diesel	205												
l	kerosene			206												7$^{5)}$
l	gasoline		motor	208												
l	naphtha			210												3$^{5)}$
l	black liquor			215												1 - 17.7$^{5)}$
g	gas		natural	301	0.1$^{1)}$			1.2$^{1)}$ $^{2)}$		1.4$^{1)}$			2.5 - 4$^{6)}$ 5.9$^{1)}$	6.1$^{1)}$		0.3 - 4$^{5)}$
g	gas		liquified petroleum gas	303												1 - 2.5$^{5)}$
g	gas		coke oven	304												0.3 - 4$^{5)}$
g	gas		blast furnace	305												0.3 - 2.5$^{5)}$
g	gas		coke oven and blast furnace gas	306												
g	gas		waste	307												2.5$^{5)}$
g	gas		refinery	308												0.1 - 2.5$^{5)}$
g	gas		biogas	309									2.5$^{6)}$			0.5 - 2.5$^{5)}$
g	gas		from gas works	311												

[1] Radian 1990 /102/, IPCC 1994 /88/ [2] for all types of gas [3] DBB/WBB/FBC for coal combustion; boiler for fuel combustion [4] open burning

[5] CORINAIR90 data of combustion plants as point sources with thermal capacity of >300, 50 - 300 and <50 MW

[6] CORINAIR90 data, point sources

Table 28: CO emission factors [g/GJ] for combustion plants

					Type of combustion										no specification
					Utility combustion			Commercial comb.		Industrial combustion					
Type of fuel				NAPFUE code	DBB/WBB/ boilers[1]	GF stoker		boiler	GF	DBB/WBB/ boiler[1]	GF stoker		GT	stat. E.	CORINAIR90[9]
						spreader	travell.				spreader	travelling			
s	coal	hc	coking	101	14[3]	121[3]		195[3]		9.7[2], 13[4]	81[2], 115[4]	97.2[2]			15[9]
s	coal	hc	steam	102	14[3]	121[3]		195[3]		9.7[2], 13[4]	115[4]	9.7[2]			10 - 175.2[9]
s	coal	hc	sub-bituminous	103	14[3]	121[3]		195[3]		9.7[2], 13[4]	81[2], 115[4]	97.2[2]			12 - 246.9[9]
s	coal	bc	brown coal/lignite	105	14[3]	121[3]		195[3]		16[2], 13[4]	133[2], 115[4]	160[2]			9.6 - 64.4[9]
s	coal	bc	briquettes	106											
s	coke	hc	coke oven	107											102 - 121[9]
s	coke	bc	coke oven	108											
s	coke		petroleum	110											15[9]
s	biomass		wood	111	1,473[3]			199[3]		1,504[3]					30 - 300[9]
s	biomass		charcoal	112											
s	biomass		peat	113											30 - 160[9]
s	waste		municipal	114		98[3,6]		19[3]			19[3,7], 96[3,7], 42 kg/Mg[3,8]				30[9]
s	waste		industrial	115											
s	waste		wood	116											12 - 300[9]
s	waste		agricultural	117				58 kg/Mg[3,8]							20[9]
l	oil		residual	203	15[3]			17[3]		15[3]			10 - 15[10]	100[10]	3 - 32.6[9]
l	oil		gas	204	15[3]			16[3]		12[3]			10 - 20[10] 20.6[11]	12 - 1,130[10]	10 - 46.4[9]
l	oil		diesel	205											
l	kerosene			206											12[9]
l	gasoline		motor	208											
l	naphtha			210											15[9]
l	black liquor			215											11.1 - 314[9]
g	gas		natural	301	19[3]			9.6[3]		17[3], 13[5]				10 - 20[10], 32[3]	0.05 - 60[9]
g	gas		liquified petroleum gas	303											10 - 13[9]
g	gas		coke oven	304											0.03 - 130[9]
g	gas		blast furnace	305											0.3 - 64.4[9]
g	gas		coke oven and blast furnace gas	306											
g	gas		waste	307											0.1 - 25.5[9]
g	gas		refinery	308										10[10]	2 - 15[9]
g	gas		biogas	309											13[9]
g	gas		from gas works	311											

[1] DBB/WBB for coal combustion; boiler for other fuel combustion
[2] EPA 1987 /85/, CORINAIR 1992 /80/
[3] Radian 1990 /102/, IPCC 1994 /88/, without primary measure
[4] OECD 1989 /100/, CORINAIR 1992 /80/
[5] CORINAIR 1992 /80/, part 8
[6] grate firing without specification
[7] small combustion 19 g/GJ, mass burning 96 g/GJ
[8] open burning
[9] CORINAIR90 data of combustion plants as point sources with a thermal capacity of > 300, 50 - 300, < 50 MW
[10] CORINAIR90 data, point sources
[11] AP42 /115/

Table 29: CO_2 emission factors [kg/GJ] for combustion plants

Type of fuel				NAPFUE code	Emission factors		
					value	range	remarks
s	coal	hc	coking	101		92 - 93 5), 89.6 - 94 2)	
s	coal	hc	steam	102	93.7 3), 92 5)	92 - 93 5), 10 - 98 2)	
s	coal	hc	sub-bituminous	103	94.7 3)	91 - 115.2 2)	
s	coal	bc	brown coal/lignite	105	100.2 3)	94 - 107.9 2), 110 - 113 5)	
s	coal	bc	briquettes	106	98	97 - 99 5)	
s	coke	hc	coke oven	107	95.9 4), 108 1)	100 - 105 5), 105 - 108 2)	
s	coke	bc	coke oven	108		96 - 111 5)	
s	coke		petroleum	110	101 5), 121.2 4), 100.8 2)		
s	biomass		wood	111	100 1), 124.9 4)	92 - 100 2)	
s	biomass		charcoal	112			
s	biomass		peat	113	98 5)	102 - 115 2)	
s	waste		municipal	114	15 5), 28 2)	109 - 141 1)	
s	waste		industrial	115		13.5 - 20 5)	
s	waste		wood	116		83 - 100 2)	
s	waste		agricultural	117			
l	oil		residual	203	75.8 4), 76.6 3), 78 5)	15 - 93 2)	petroleum oil 72.6 3)
l	oil		gas	204	72.7 4), 74 5), 75 1)	73 - 74 5), 57 - 75 2)	
l	oil		diesel	205	72.7 4), 73 5)		
l	kerosene			206	73.3 2)	72 - 74 5)	
l	gasoline		motor	208	70.8 3), 71.7 4), 72.2 1)	72 - 74 5)	
l	naphtha			210	72.6 3), 74 2)		
l	black liquor			215		100 - 110 2)	
g	gas		natural	301	55.5 3), 60.8 4)	55 - 56 5), 44 - 57 2)	
g	gas		liquified petroleum gas	303		64 - 65 5), 57 - 65 2)	
g	gas		coke oven	304	44 5)	44 - 49 5), 41.6 - 90 2)	
g	gas		blast furnace	305	105 5)	100 - 105 5), 92 - 280 2)	
g	gas		coke oven and blast furnace gas	306			
g	gas		waste	307		44.4 - 57 2)	
g	gas		refinery	308	60 5)		
g	gas		biogas	309	75 2)	10.5 - 73.3 2)	
g	gas		from gas works	311	52 2)		

(1) Schenkel 1990 /105/

(2) CORINAIR90 data on combustion plants as point sources with thermal capacity of > 300, 50 - 300, < 50 MW

(3) IPCC 1993 /87/

(4) Kamm 1993 /89/

(5) BMU 1994 /77/

Table 30: N_2O emission factors [g/GJ] for combustion plants

Type of fuel				NAPFUE	Type of boiler								GT	stat. E.	no speci-fication
					DBB		WBB		FBC		GF				
				code	value	remarks	value	remarks	value	remarks	value	remarks			CORINAIR90[4]
s	coal	hc	coking	101	0.8 [1]	utility, no PM[3]	0.8 [1]	utility, no PM [3]			0.8 [1]	utility, no PM [3]			14[4]
s	coal	hc	steam	102	0.8 [1]	utility, no PM[3]	0.8 [1]	utility, no PM [3]			0.8 [1]	utility, no PM [3]			2.5 - 100[4]
s	coal	hc	sub-bituminous	103	0.8 [1]	utility, no PM[3]	0.8 [1]	utility, no PM [3]			0.8 [1]	utility, no PM [3]			2.5 - 30[4]
s	coal	bc	brown coal/lignite	105	0.8 [1]	utility, no PM[3]					0.8 [1]	utility, no PM [3]			1.4 - 30[4]
s	coal	bc	briquettes	106											
s	coke	hc	coke oven	107											1.4 - 25[4]
s	coke	bc	coke oven	108											
s	coke		petroleum	110											14[4]
s	biomass		wood	111	4.3 [1]	commercial, no PM[3]			4.3 [1]	commercial, no PM[3]	4.3 [1]	commercial, no PM[3]			1.4 - 75[4]
s	biomass		charcoal	112											
s	biomass		peat	113											2 - 75[4]
s	waste		municipal	114					14 - 165 [2]	g/t waste	11 - 270 [2]	g/t waste			4[4]
s	waste		industrial	115											1.4[4]
s	waste		wood	116											2 - 6[4]
s	waste		agricultural	117											5[4]
l	oil		residual	203	46.5 [1]	commercial, no PM[3]							2.5 - 14[5]	2.5[5]	1.4 - 14.8[4]
l	oil		gas	204	15.7 [1]	commercial, no PM[3]							2 - 3[5]	2.5[5]	0.6 - 14[4]
l	oil		diesel	205											
l	kerosene			206											14[4]
l	gasoline		motor	208											
l	naphtha			210											14[4]
l	black liquor			215											1 - 21.4[4]
g	gas		natural	301	2.4 [1]	commercial, no PM[3]								1 - 3[5]	0.1 - 3[4]
g	gas		liquified petroleum gas	303											2 - 4.3[4]
g	gas		coke oven	304											1.1 - 3[4]
g	gas		blast furnace	305											1.1 - 3[4]
g	gas		coke oven and blast furnace	306											
g	gas		waste	307											1.1 - 2.5[4]
g	gas		refinery	308										2.5[5]	2.5 - 14[4]
g	gas		biogas	309											1.4 - 2.5[4]
g	gas		from gas works	311											

[1] Radian 1990 /102/, IPCC 1994 /88/ [2] DeSoete 1993 /83/, IPCC 1994 /88/ [3] PM: Primary measure [5] CORINAIR90 data, point sources

[4] CORINAIR90 data on combustion plants as point sources with thermal capacity of > 300, 50 - 300, < 50 MW

Table 31: Heavy metal emission factors (g/Mg fuel) for combustion plants

					Thermal boiler capacity [MW]								
					>= 300				>= 50 and < 300				< 50
					Type of boiler				Type of boiler				
Type of fuel			NAPFUE code	Heavy metal element	DBB		WBB		DBB	WBB	FBC	GF	GF
					Dust control [1]	Dust control and FGD [2]	Dust control [1]	Dust control and FGD [2]					
s	coal	hc	101/102	Mercury	0.05 - 0.2	0.02 - 0.08	0.05 - 0.2	0.02 - 0.08					
				Cadmium	0.003 - 0.01	0.0001 - 0.004	0.01 - 0.07	0.004 - 0.03					
				Lead	0.02 - 1.1	0.007 - 0.5	0.3 - 3	0.1 - 1.2					
				Copper	0.01 - 0.4	0.006 - 0.2	0.05 - 0.4	0.05 - 0.2					
				Zinc	0.03 - 1.3	0.01 - 0.5	0.5 - 4	0.2 - 1.6					
				Arsenic	0.03 - 0.3	0.01 - 0.1	0.1 - 0.8	0.04 - 0.3					
				Chromium	0.04 - 0.2	0.02 - 0.06	0.05 - 0.4	0.02 - 0.2					
				Selen	0.01 - 0.03	0.004 - 0.01	-	-					
				Nickel	0.03 - 0.4	0.01 - 0.5	0.2 - 0.5	0.1 - 0.2					
s	coal	bc	105	Mercury	0.05 - 0.2	0.02 - 0.08							
				Cadmium	0.002 - 0.004	0.0008 - 0.001							
				Lead	0.003 - 0.06	0.001 - 0.02							
				Copper	0.004 - 0.02	0.002 - 0.01							
				Zinc	0.01 - 0.2	0.006 - 0.1							
				Arsenic	0.03 - 0.04	0.008 - 0.01							
				Chromium	0.003 - 0.07	0.001 - 0.03							
				Selen	-	-							
				Nickel	0.02 - 0.04	0.01							
l	oil, heavy fuel		203	Mercury	1.0[4]								
				Cadmium	1.0[4]								
				Lead	1.3[4]								
				Copper	1.0[4]								
				Zinc	1.0[4]								
				Arsenic	0.5[4]								
				Chromium	2.5[4]								
				Selen									
				Vanadium	4.4[5]								
				Nickel	35[4]								
g	gas, natural		301	Mercury	0.05 - 0.15 g/TJ[3]								

[1] clean gas particle concentration 50 mg/m [3] 2 mg/m^3 gas UBA 1980 /63/; 5 mg/m^3 PARCOM 1992 /101/ [5] Jockel 1991 /36/

[2] FGD = Flue gas desulphurisation, clean gas particle concentration 20 mg/m^3 [4] general emission factor according to Stobbelaar 1992 /37/

9 SPECIFIC PROFILES

9.1 SO_x emissions

Sulphur dioxide SO_2 and sulphur trioxide SO_3 are formed in the flame. Emissions of SO_2 and SO_3 are often considered together as SO_x. Due to the equilibrium conditions at furnace temperature, sulphur trioxide SO_3 normally decomposes to sulphur dioxide SO_2. Then the amount of SO_2 in the flue gas is approximately 99 %. Therefore, SO_x is given in this chapter as SO_2.

9.2 NO_x emissions

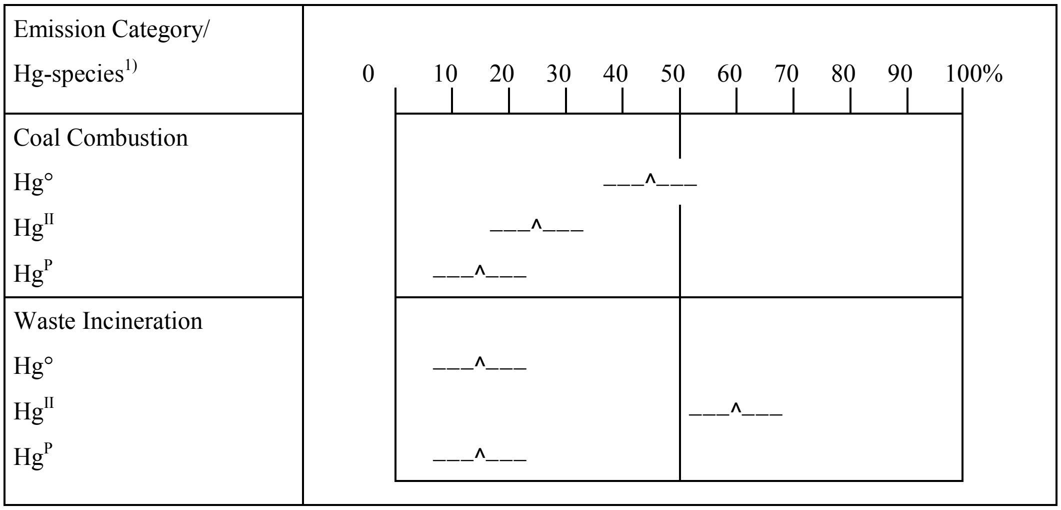
The most important oxides of nitrogen formed with respect to pollution are nitric oxide (NO) and nitrogen dioxide (NO_2), jointly referred to as NO_x. The main compound is NO, which contributes over 90 % to the total NO_x. Other oxides of nitrogen, such as dinitrogen-trioxide (N_2O_3), dinitrogen-tetroxide (N_2O_4), and dinitrogen-pentoxide (N_2O_5), are formed in negligible amounts. Nitrous oxide (N_2O) is considered separrately.

9.3 NMVOC emissions

Due to the minor relevance of NMVOC emissions for power plants no split of species is given.

9.4 Heavy metal emissions

The heavy metals, which are of most environmental concern, are: arsenic (As), cadmium (Cd), chromium (Cr), copper (Cu), mercury (Hg), nickel (Ni), lead (Pb), selenium (Se) and zinc (Zn). This selection has been laid down by the UN-ECE Task Force on Heavy Metals, the PARCOM/ATMOS programme (cf. /35/) and the HELCOM programme. In the case of heavy oil combustion, vanadium emissions (V) are also of importance. In fly ash particles most of these elements occur as oxides or chlorides. The contribution of various forms of mercury to the emissions from combustion source categories in Europe is given in the following Figure 2:



[1] Hg° elemental form
Hg^{II} oxidised form
Hg^{P} particle-bound

Figure 2: Contribution of various forms of mercury to the emissions from combustion source categories in Europe in 1987 (in % of total) /29/

10 UNCERTAINTY ESTIMATES

Uncertainties of emission data result from the use of inappropriate or inaccurate emission factors, and from missing or inappropriate statistical information concerning activity data. Uncertainty estimates discussed here are related to the use of emission factors with different background information. At this stage a quantification of the uncertainty related to the use of emission factors is not feasible, due to the limited availability of data. However, the precision of emission estimates can be improved by applying individually determined emission factors.

The aim of the following procedure is to show the Guidebook-user how a lack of information concerning the fuel and technical characteristics of a combustion facility gives rise to a high uncertainty in the allocation of the appropriate emission factor. The whole span of possible emission factors is defined by the specification of the type of fuel used, the type of boiler, and the type of primary and secondary measures. The more information about these topics can be gathered, the smaller the span of possible emission factors becomes.

The following diagram (Figure 3) gives as an example the range of NO_x emission factors [g/GJ] for pulverised coal combustion depending on the level of specification.

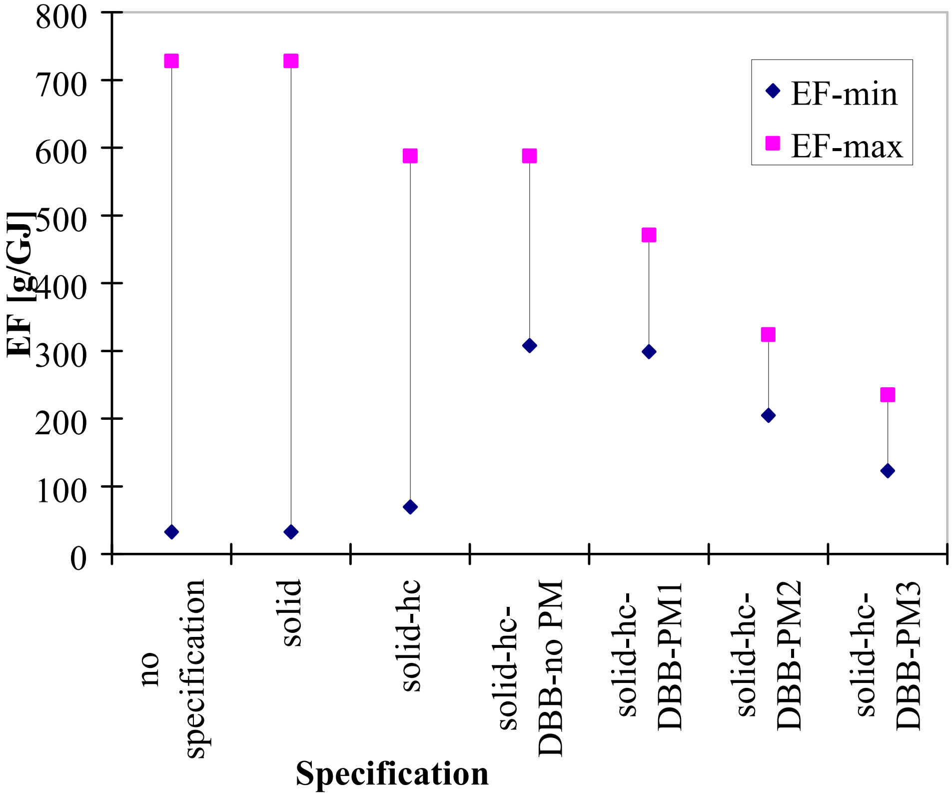


Figure 3: Ranges of NO_x emission factors for the combustion of pulverised coal

The level of specification is defined as follows:

- „no information“	- the whole range of combustion sources is taken into account,
- „solid“	- only solid fuels are taken into account,
- „solid-hc“	- only hard coal is considered,
- „solid-hc-DBB-no PM“	- hard coal and combustion technique are taken into account (here dry bottom boiler (DBB), without primary measures),
- „solid-hc-DBB-PM1“	- hard coal, DBB and primary measures are taken into account with a reduction efficiency of 0.2 ,
- „solid-hc-DBB-PM2“	- hard coal, DBB and primary measures are taken into account with a reduction efficiency of 0.45 ,
- „solid-hc-DBB-PM3“	- hard coal, DBB and primary measures are taken into account with a reduction efficiency of 0.6 .

In Figure 3 a large difference between minimum and maximum emission factors indicates high uncertainties in the allocation of appropriate emission factors. A specification of emission factors only concerning the type of fuel used (e.g. hard coal) is not sufficient. The range of NO_x emission factors for the combustion of pulverised coal is significantly reduced if technique related specifications are considered.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

The weakest aspects discussed here are related to the determination of emission factors. Methodological shortcomings are discussed in this section for the main pollutants SO_2, NO_X and heavy metals.

11.1 SO_2 emissions

The approach for the determination of SO_2 emission factors is based on a simple mass balance calculation as the formation mechanisms of sulphur dioxide within the boiler depend almost entirely on the sulphur input. Therefore, for the formation of sulphur dioxide, fuel characteristics are of main influence. The accuracy of this approach is determined by the following fuel parameters: lower heating value, fuel sulphur content and sulphur retention in ash (see Equation (5)). The sulphur content and the lower heating value can be highly variable between different fuel categories and can furthermore vary to a large extent within one fuel category. Therefore, default values for sulphur content and lower heating value should be avoided. However, if emission factors for SO_2 have to be calculated, representative values for the sulphur content and the lower heating value should be based on measured data from individual fuel analysis.

The sulphur retention in ash α_S depends mainly on the content of alkaline components of the fuel. This is only relevant for coal (e.g. CaO, MgO, Na_2O, K_2O) and for the case of additive injection. For a more precise determination of α_S, the Ca/S ratio (amount of calcium/sulphur content of fuel)[8], the particulate diameter, the surface character of CaO, the temperature (optimum ca. 800 °C), the pressure, the residence time, etc. should be taken into account. Therefore, the assessment of α_S should be based on an extended set of parameters.

Besides the fuel characteristics, the reduction efficiency and availability of secondary measures are of relevance for the determination of the SO_2 emission factors. Default values are proposed in Table 7, but measured data from individual combustion plants should preferably be used.

11.2 NO_X EMISSIONS

The approach for the calculation of NO_X emission factors is based on empirical relations. For fuel-NO only fuel characteristics are taken into account. The formation of thermal-NO increases exponentially with combustion temperatures above 1,300 °C (see /56/). At this

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[8] Alternatively the Ca/S ratio is defined as the amount of additives related to the sulphur content of the flue gas, and is given for a brown coal fired dry bottom boiler as 2.5 - 5 as an example, for a stationary FBC as 2 - 4, for a circulating FBC < 2 etc. /55/.

stage, no satisfactory result has been achieved to determine the thermal-NO formation by using kinetic equations. For inventory purposes, an empirical parameter γ has been introduced (see Annex 5), which represents the fraction of thermal-NO formed. At this stage default values of γ depending on the type of boiler are given. Further work should focus on a more precise determination of this factor.

Load dependence of the pollutant NO_x has been taken into account. For old installations a quantitative relation has been given as an example for German power plants. The validity of this relation should be verified for other countries.

Furthermore, the reduction efficiency of primary or secondary measures are of relevance for the determination of NO_x emission factors. Default values for reduction efficiencies and availabilities are proposed in Tables 10 and 11, but measured data from individual combustion plants should preferably be used.

11.3 Heavy metals

Heavy metals undergo complex transformations during the combustion process and downstream of the boiler, referring to e.g. fly ash formation mechanisms. The approaches for the determination of heavy metal emission factors are based on empirical relations, where fuel and technical characteristics are of main influence. The heavy metal contents can be highly variable between different fuel categories (e.g. coal and heavy fuel oil) and can furthermore vary to a large extent within one fuel category (up to 2 orders of magnitude). Therefore, default values for heavy metal contents in fuel should be avoided and measured values should be used as far as possible.

For inventory purposes, parameters, such as enrichment factors, fractions of fly ash leaving the combustion chamber, fraction of heavy metals emitted in gaseous form, have been introduced. Further work should be invested into a more precise determination of these parameters. In addition, it should be taken into account, that the reduction efficiency of (dust) abatement measures depends on the heavy metal. Heavy metal specific reduction efficiencies should be determined.

11.4 Other aspects

Emission factors for SO_2, NO_2 and CO, whether calculated or given in the tables, are related to full load conditions. In order to assess the relevance of start-up emissions, a detailed investigation has been accomplished by using measured values from different types of boiler (see also Annex 15). The qualitative and quantitative statements obtained in this approach should be verified.

The emission factors have been determined by considering the pollutants separately. Possible mutual interactions between the formation mechanisms of different pollutants (e.g. NO and N_2O) have been neglected and should be assessed in further work.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

This section is not relevant for combustion plants considered as point sources.

13 TEMPORAL DISAGGREGATION CRITERIA

The temporal disaggregation of annual emission data (top-down approach) provides a split into monthly, weekly, daily and hourly emission data. Temporal disaggregation of annual emissions released from combustion plants as point sources can be obtained from the temporal change of the production of electrical power or the temporal change of the consumption, taking into account a split into:

- summer and winter time,
- working days and holidays,
- standstill times,
- times of partial load behaviour and
- number of start-ups / type of load design.

This split should be carried out for defined categories of power plants which take into account the main relevant combinations of types of fuel used and types of boiler installed (similar split as used for the emission factor Tables in Section 8).

The disaggregation of annual emissions into monthly, daily or hourly emissions can be based on a step-by-step approach /76/ according to the following equations:

- Monthly emission:

$$E_{M_n} = \frac{E_A}{12} \cdot f_n \tag{25}$$

E_{M_n}	Emission in month n; n = 1, ..., 12 [Mg]
E_A	Annual emission [Mg]
f_n	Factor for month n; n = 1, ..., 12 [ ]

- Daily emission:

$$E_{D_{n,k}} = \frac{E_{M_n}}{D_k} \cdot f_k \cdot \frac{1}{CF_n} \tag{26}$$

$E_{D_{n,k}}$	Emission of day k in month n; k = 1, ..., D_k ; n = 1, ..., 12 [Mg]
E_{M_n}	Emission in month n; n = 1, ..., 12 [Mg]
D_k	Number of days in month n [ ]
f_k	Factor for day k; k = 1, ..., D_k [ ]
CF_n	Correction factor for month n [ ]

- Hourly emission:

$$E_{H_{n,k,l}} = \frac{E_{D_{n,k}}}{24} \cdot f_{n,l} \tag{27}$$

$E_{H_{n,k,l}}$	Emission in hour l in day k and month n; l = 1, ..., 24; k = 1, ..., D_k ; n = 1, ..., 12 [Mg]
$E_{D_{n,k}}$	Emission of day k in month n; k = 1, ..., D_k ; n = 1, ..., 12 [Mg]
$f_{n,l}$	Factor for hour l in month n; l = 1, ..., 24; n = 1, ..., 12 [ ]
D_k	Number of days in month n [ ]

The factors (relative activities) for month f_n, day f_k and hour $f_{n,l}$ can be related e.g. to the total fuel consumption or the net electricity production in public power plants. Figure 4 gives an example of a split for monthly factors based on the fuel consumption e.g. for Public Power Plants:

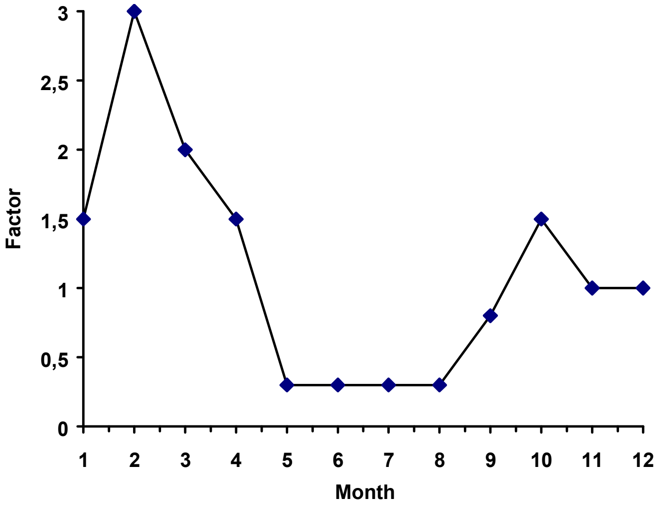
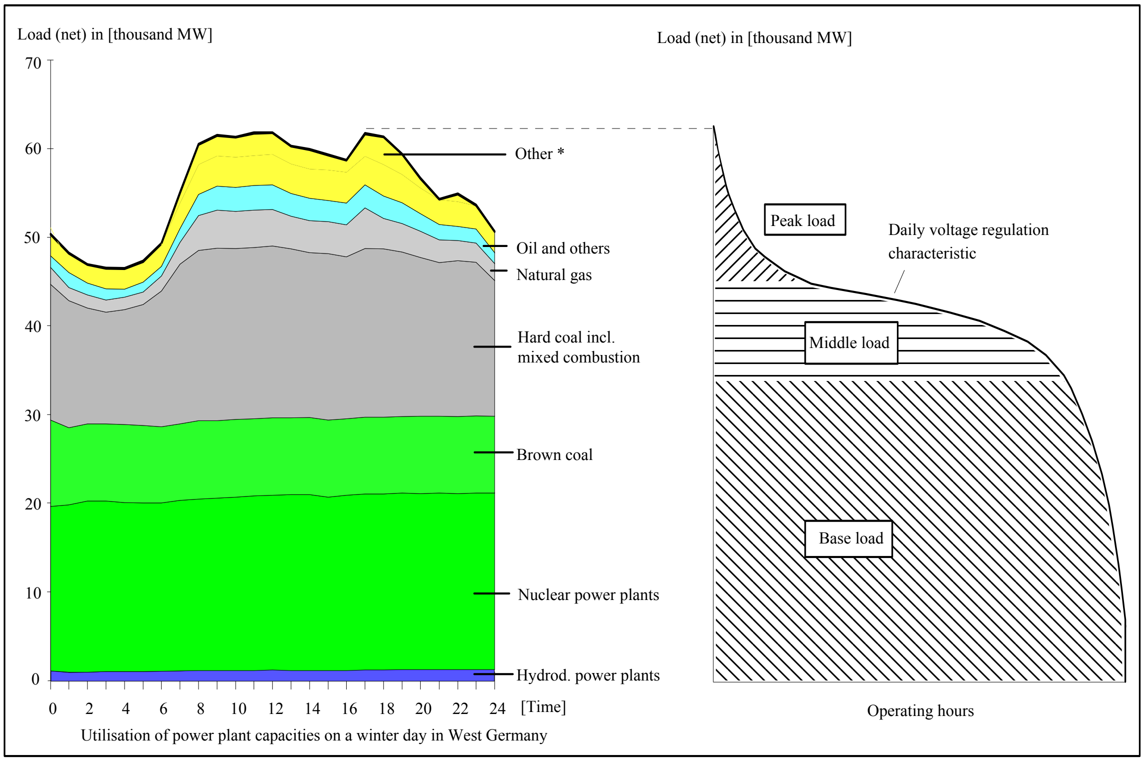


Figure 4: Example of monthly factors for total fuel consumption in Public Power Plants

A split concerning the load design, which determines the annual number of start-ups can be given as follows (see also Table 11):

- Base load: The boiler/plant is normally in continuous operation during the year; start-ups occur relatively seldom (ca. 15 times per year) depending on maintenance periods which occur mostly in summer. The fuel mostly used in base load boilers is brown coal.
- Middle load: The boiler/plant is in operation in order to meet the energy demand on working days (Monday until Friday); start-ups can occur up to 150 times per year. The fuel mostly used in middle load boilers is hard coal.
- Peak load: The boiler/plant is in operation in order to meet the short term energy demand; start-ups can occur up to 200 times per year. The fuels mostly used in peak load boilers are gas or oil.

The allocation of power plants to the different load designs is given as an example in Figure 5.



*Other includes: Storage pump power plants, power supply from industry etc.

Figure 5: Load variation and arrangement of power plants according to the voltage regulation characteristic (cf. /117/, /118/).

It can be assumed that all power plants of a country with the same allocation of fuel, boiler and load have the same temporal behaviour.

14 ADDITIONAL COMMENTS

15 SUPPLEMENTARY DOCUMENTS

15.1 Computer programme

A computer programme for the calculation of SO_2 and NO_2 emission factors for pulverised coal combustion has been designed, and is available on floppy disc. It has been designed under MICROSOFT EXCEL 4.0 (English version). Default values for the required input data are proposed to the user; a detailed users manual is given in Annex 14. For example, NO_X concentrations in [mg/m³] were calculated with the computer programme and presented together with the emission factors in [g/GJ] as listed in Annexes 10 and 11. An integral part of the computer programme is the calculation of the flue gas volume as given in Annex 6.

15.2 LIST OF ANNEXES

Annex 1: Example of different possible considerations of boilers as a common plant

Annex 2: Determination of SO_2 emission factors (flow sheet)

Annex 3: Determination of SO_2 emission factors (description)

Annex 4: Determination of NO_X emission factors (flow sheet)

Annex 5: Determination of NO_X emission factors (description)

Annex 6: Determination of the specific flue gas volume (flow sheet and description)

Annex 7: Composition and lower heating value (H_u) of hard coal in coal mining countries

Annex 8: Composition and lower heating value (H_u) of brown coal in coal mining countries

Annex 9: Conditions for exemplary calculation of NO_X emission factors

Annex 10: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for hard coal (see Annex 7)

Annex 11: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for brown coal (see Annex 8)

Annex 12: Comparison between measured and calculated SO_2 and NO_X emission data

Annex 13. Sensitivity analysis of the computer programme results

Annex 14: Users’ manual for the emission factor calculation programme (for version September, 1995)

Annex 15: Determination of start-up emissions and start-up emission factors.

Annex 16: List of abbreviations

16 VERIFICATION PROCEDURES

As outlined in the chapter “Concepts for Emission Inventory Verification“, different general verification procedures can be recommended. The aim of this section is to develop specific verification procedures for emission data from combustion plants as point sources. The verification procedures considered here are principally based on verification on a national and on a plant level. Moreover, it can be distinguished between the verification of activity data, of emission factors and of emission data.

16.1 Verification on a national level

For combustion plants as point sources, emissions and activities have to be verified. The total emissions from point sources are added together to obtain national total emissions (bottom-up approach). These national total emissions should be compared to emission data derived independently (top-down approach). Independent emission estimates can be obtained by using average emission factors and corresponding statistical data like the total fuel input for all sources, total thermal capacity, total heat or power produced, or by using emission estimates from other sources (e.g. organisations like energy agencies).

The total fuel consumption should be reconciled with energy balances, which often have break-downs for large point sources (e.g. electricity, heat generation and industrial boilers). Furthermore, the total number of plants installed as well as their equipment should be checked with national statistics.

Emission density comparisons can be achieved through comparison of e.g. emissions per capita or emissions per GDP with those of countries with a comparable economic structure.

16.2 Verification on a plant level

It should firstly be verified that separate inventories have been compiled for boilers, stationary engines, and gas turbines (according to SNAP code). The verification at plant level relies on comparisons between calculated emission factors and those derived from emission measurements. An example for such a comparison is given in Annex 12.

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20 POINT OF ENQUIRY

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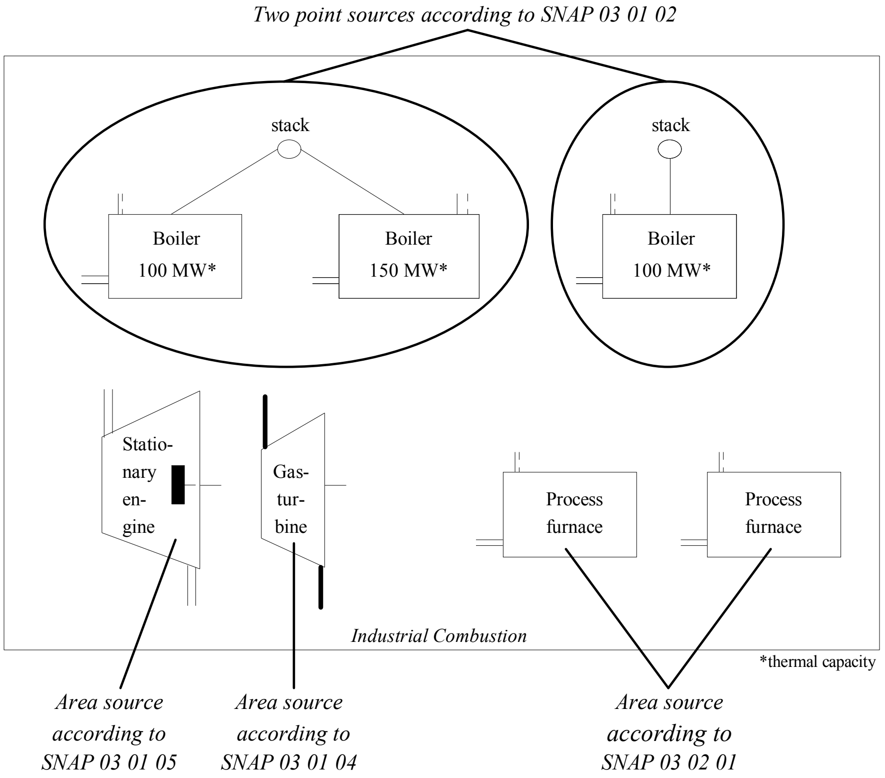
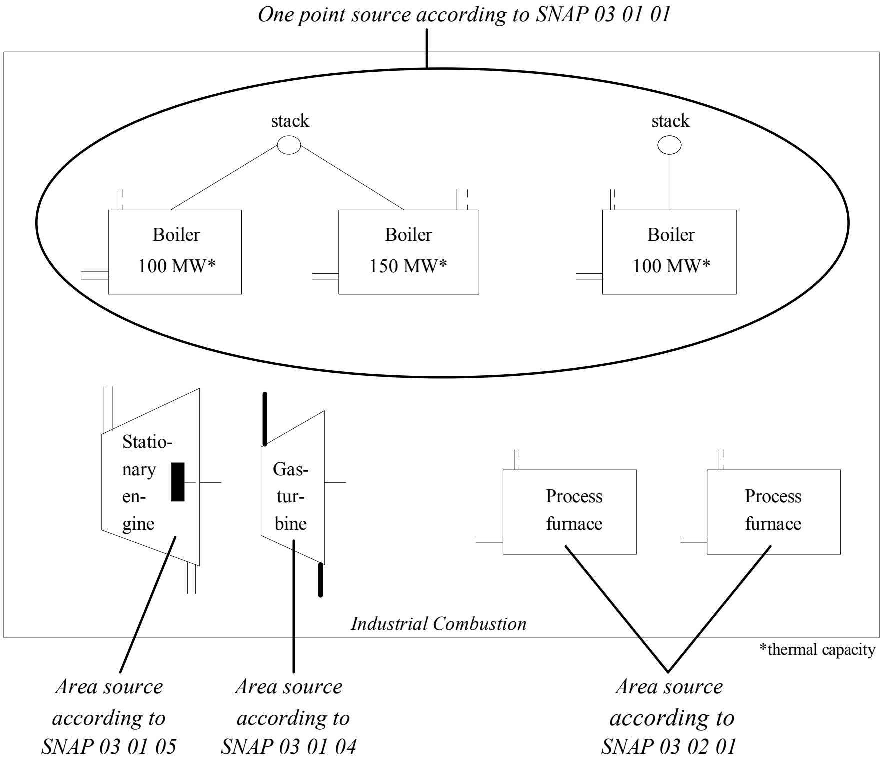
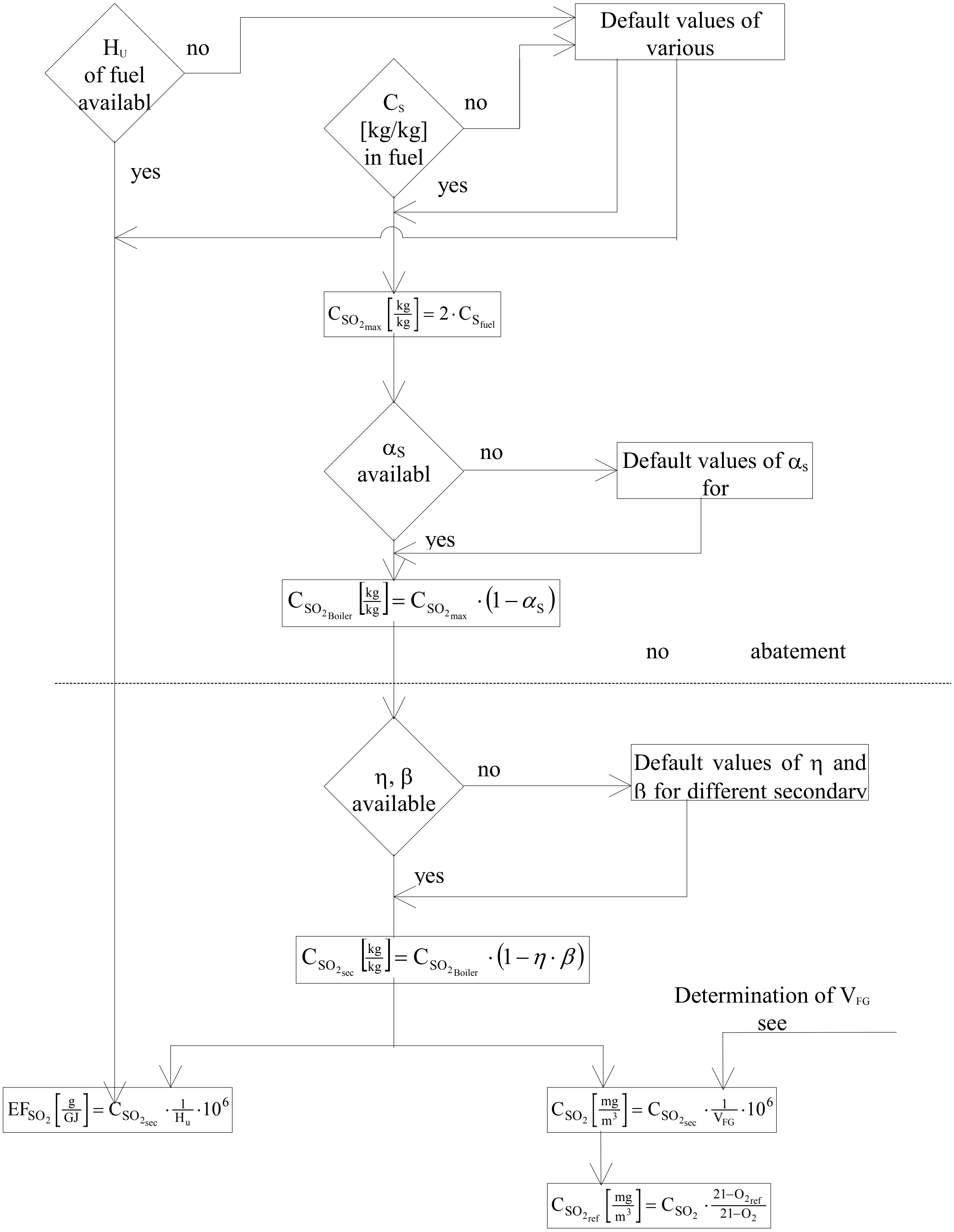
Annex 1: Example of different possible considerations for boilers as a common plant





Annex 2: Determination of SO_2 emission factors (flow sheet, for description see Annex 3)



Annex 3: Determination of SO_2 emission factors (description)

The calculation procedure is performed in three steps:

I The fuel sulphur reacts stoichiometrically with oxygen O_2 to sulphur dioxide SO_2. Default values for the sulphur content $C_{S_{fuel}}$ in hard and brown coal are given in Annexes 7 and 8. The result is the maximum attainable amount of sulphur dioxide $C_{SO_{2.max}}$ given by:

$$C_{SO_{2max}} = 2 \cdot C_{S_{fuel}} \quad (3\text{-}1)$$

$C_{S_{fuel}}$	sulphur content of fuel (in mass element/mass fuel [kg/kg])
$C_{SO_{2.max}}$	maximum attainable amount of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])

II The maximum attainable amount of sulphur dioxide $C_{SO_{2.max}}$ is corrected by the sulphur retention in ash α_S. As a result, the real boiler emission of sulphur dioxide $C_{SO_{2,boiler}}$ fuel is obtained:

$$C_{SO_{2boiler}} = C_{SO_{2max}} \cdot \left(1 - \alpha_s\right) \quad (3\text{-}2)$$

$C_{SO_{2.boiler}}$	real boiler emission of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])
$C_{SO_{2.max}}$	maximum attainable amount of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])
α_S	sulphur retention in ash [ ]

The sulphur retention in ash depends e.g. on fuel characteristics and temperature inside the boiler. If there is no data for α_S available, default values for various fuels are given in Table 8.

III The boiler emission of sulphur dioxide is corrected by the reduction efficiency η and availability β (for definition of β see Section 3.2) of the secondary measure installed, according to:

$$C_{SO_{2sec}} = C_{SO_{2boiler}} \cdot \left(1 - \eta \cdot \beta\right) \quad (3\text{-}3)$$

$C_{SO_{2.sec}}$	sulphur dioxide downstream secondary measure (in mass pollutant/mass fuel [kg/kg])
$C_{SO_{2.boiler}}$	real boiler emission of sulphur dioxide (in mass pollutant/mass fuel [kg/kg])
η	reduction efficiency of secondary measure [ ]
β	availability of secondary measure [ ]

The result is called secondary sulphur dioxide $C_{SO_{2.sec}}$. If there is no data for η and β available, default values for various flue gas desulphurisation techniques (FGD) are given in Table 7.

The obtained $C_{SO_{2.sec}}$ value is converted to C_{SO_2} in flue gas and to the emission factor EF_{SO_2} according to the following Equations:

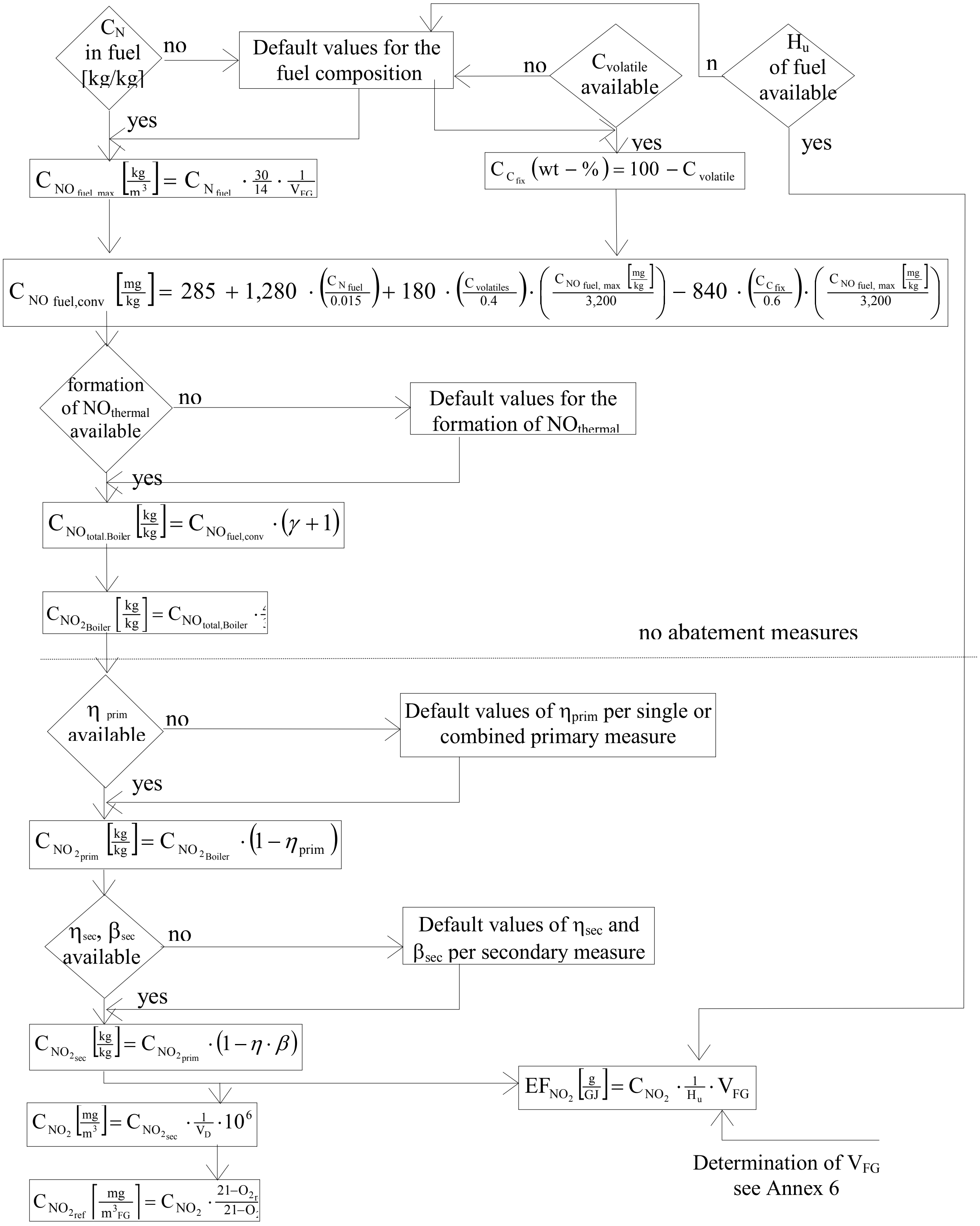
$$C_{SO_2} = C_{SO_{2.sec}} \cdot \frac{1}{V_{FG}} \cdot 10^6 \tag{3-4}$$

$$EF_{SO_2} = C_{SO_{2.sec}} \cdot \frac{1}{H_u} \cdot 10^6 \tag{3-5}$$

C_{SO_2}	sulphur dioxide in flue gas (in mass pollutant/volume flue gas [mg/m^3])
$C_{SO_{2.sec}}$	sulphur dioxide downstream of secondary measure (in mass pollutant/mass fuel [kg/kg])
V_{FG}	dry flue gas volume volume (in volume flue gas/mass fuel [m^3/kg])
EF_{SO_2}	emission factor for sulphur dioxide [g/GJ]
H_u	lower heating value [MJ/kg]

The dry flue gas volume V_{FG} can be determined according to Annex 6. Emission data in [mg/m^3] are useful to compare measured and calculated values. The same equations are used for the unit conversion of $C_{SO_{2.boiler}}$. Default values for the lower heating values of hard and brown coal are given in Annexes 7 and 8.

Annex 4: Determination of NO_x emission factors (flow sheet, for description see Annex 5)



Annex 5: Determination of NO_X emission factors (description)

The determination of NO_x emission factors takes into account the formation of fuel-NO and thermal-NO. The formation of fuel-NO is based on fuel parameters. But the total amount of fuel-nitrogen cannot be completely converted into fuel-NO (as obtained in Equation (5-1)). Therefore, the realistic formation of fuel-NO is described by an empirical relation (see Equation (5-2)). The formation of thermal-NO is expressed by an an additional fraction which depends on the type of boiler.

The calculation procedure of the NO_X emission factor is performed in three steps: In the first step the maximum NO emission resulting from stoichiometric conversion of fuel nitrogen is calculated. The NO emission obtained is further corrected by taking into account the formation of thermal-NO. NO is converted into NO_2 and primary and secondary measures are taken into account in steps two and three.

I The fuel-nitrogen reacts in a stoichiometric manner with oxygen O_2 to form nitrogen oxide. The default values for the nitrogen content $C_{N_{2fuel}}$ in hard and brown coal are given in Annexes 7 and 8. The maximum attainable amount of fuel nitrogen oxide $C_{NO_{fuel.max}}$ is obtained:

$$C_{NO_{fuel_{max}}} = C_{N_{fuel}} \cdot \frac{30}{14} \cdot \frac{1}{V_{FG}} \tag{5-1}$$

$C_{NO_{fuel.max}}$	maximum attainable amount of fuel nitrogen oxide (in mass pollutant/volume flue gas [kg/m^3])
$C_{N_{fuel}}$	nitrogen content in fuel (in mass nitrogen/mass fuel [kg/kg])
V_{FG}	specific flue gas volume (in volume flue gas/mass fuel [m^3/kg])[9]

The fuel-nitrogen content $C_{N_{fuel}}$ is not completely converted into $C_{NO_{fuel}}$. The converted part of fuel-nitrogen to fuel-NO $C_{NO_{fuel.conv}}$ can be determined by the following empirical formula /50, 51/ related to zero percent of oxygen in dry flue gas:

$$C_{NO_{fuel_{conv}}} = 285 + 1{,}280\left(\frac{C_{N_{fuel}}}{0.015}\right) + 180\left(\frac{C_{volatiles}}{0.4}\right)\left(\frac{C_{NO_{fuel_{max}}}}{3{,}200}\right) - 840\left(\frac{C_{C_{fix}}}{0.6}\right)\left(\frac{C_{NO_{fuel_{max}}}}{3{,}200}\right) \tag{5-2}$$

$C_{NO_{fuel.conv}}$	fuel-NO released (in mass pollutant/mass flue gas [mg/kg])[2]
$C_{N_{fuel}}$	nitrogen content in fuel (in mass nitrogen/mass fuel [kg/kg]), maf
$C_{volatiles}$	fuel content of volatiles (in mass volatiles/mass fuel [kg/kg]), maf
$C_{NO_{fuel.max}}$	maximum attainable amount of fuel nitrogen oxide (in mass pollutant/mass flue gas [mg/kg])[10]
$C_{C_{fix}}$	fixed carbon in fuel (in mass carbon/ mass fuel [kg/kg]), maf

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[9] The programme calculates stoichiometrically the specific flue gas volume based on the complete fuel composition.

[10] Note: $C_{NO.fuel.max}$ and $C_{NO.fuel.conv}$ are given in the unit (mass pollutant/mass flue gas [mg/kg]). For the conversion between (mass pollutant/mass flue gas [mg/kg]) and (mass pollutant/volume flue gas [kg/m3]) the flue gas density (in mass flue gas/volume flue gas [kg/m³]) has to be taken into account, which is calculated stoichiometrically from the fuel composition within the computer programme.

The fixed carbon in the fuel is determined according to the equation $C_{C_{fix}} = 1 - C_{volatiles}$. Equation (5-2) is valid for nitrogen oxide emissions from premixed flames; the coefficient of correlation is $r^2 = 0.9$ for 20 coals and $r^2 = 0.75$ for 46 coals /51/. The data has been obtained by field and pilot-scale measurements. Basically tests are conducted in a 70,000 Btu/hr (20.5 kW) refractory lined furnace with variable heat extraction. Coal was injected through special configurations. A nozzle produces an uniform heterogeneous mixture of coal and air prior to combustion and represents the limit of intensely mixed flames produced with high swirl. Further tests have been established in large scale furnaces. The results from all measurements combined with additional information based on literature data have been used to establish a correlation which predicts the relative dependence of nitrogen oxide emissions on fuel properties. /51/ Further calculations with Equation (5-2) based on measured data have been provided in /50/. The comparison between measured and calculated values has shown that the results from Equation (5-2) are very good for high volatile coals and are satisfactory for medium volatile coals /50/.

Assuming that the formation of fuel-NO is much more important than the formation of thermal-NO (fuel-NO amounts to 70 - 90 %), the content of thermal-NO formed can be expressed as a fraction γ (where γ depends on the type of boiler) of NO_{fuel}. The total content of nitrogen oxide formed in the boiler $C_{NO_{total.boiler}}$ is given by:

$$C_{NO_{total_{boiler}}} = C_{NO_{fuel_{conv}}} + C_{NO_{thermal}} = C_{NO_{fuel_{conv}}} \cdot \left(1+\gamma\right) \tag{5-3}$$

$C_{NO_{total.boiler}}$	total content of nitrogen oxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{fuel.conv}}$	fuel-NO released (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{thermal}}$	content of thermal-NO formed (in mass pollutant/mass flue gas [kg/kg])
γ	fraction for thermal-NO formed [ ]

The following default values for γ can be recommended: DBB $\gamma = 0.05$, WBB $\gamma = 0.3$. Furthermore, the amount of thermal-NO can be influenced by load (see also Section 11.2).

The total boiler emissions of nitrogen dioxide $C_{NO_{2.boiler}}$ can be calculated as follows:

$$C_{NO_{2_{boiler}}} = C_{NO_{total_{boiler}}} \cdot \frac{46}{30} \tag{5-4}$$

$C_{NO_{2_{boiler}}}$	total content of nitrogen dioxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])
$C_{NO_{total_{boiler}}}$	total content of nitrogen oxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])

II The total boiler content of nitrogen dioxide given by $C_{NO_{2.boiler}}$ is reduced by taking into account primary measures with the reduction efficiency η_{prim}. The result is the content of primary nitrogen dioxide $C_{NO_{2.prim}}$:

$$C_{NO_{2prim}} = C_{NO_{2boiler}} \cdot \left(1 - \eta_{prim}\right) \qquad (5\text{-}5)$$

$C_{NO_{2.prim}}$ content of primary nitrogen dioxide (in mass pollutant/mass flue gas [kg/kg])

$C_{NO_{2boiler}}$ total content of nitrogen dioxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])

η_{prim} reduction efficiency of primary measure(s) [ ]

As there is only incomplete data available for reduction efficiencies, default values are given for the individual and relevant combinations of primary measures for different types of boilers and fuels (see Table 8). In the case of combined primary measures with known individual reduction efficiencies $\eta_{prim,1}$, $\eta_{prim,2}$, etc., the following equation can be used:

$$C_{NO_{2prim}} = C_{NO_{2boiler}} \cdot \left(1 - \eta_{prim1}\right) \cdot \left(1 - \eta_{prim2}\right) \cdot \left(1 - \eta_{prim3}\right) \qquad (5\text{-}6)$$

$C_{NO_{2.prim}}$ content of nitrogen dioxide taking into account primary measures (in mass pollutant/mass flue gas [kg/kg])

$C_{NO_{2boiler}}$ total content of nitrogen dioxide formed in the boiler (in mass pollutant/mass flue gas [kg/kg])

η_{prim_k} individual reduction efficiency of primary measure k [ ]

It should be taken into account, that the reduction efficiencies of primary measures are not independent of each other.

III The emission of primary nitrogen dioxide $C_{NO_{2.prim}}$ is corrected by the reduction efficiency η_{sec} [ ] and the availability β_{sec} [ ] (for definition of β see Section 3.2) of the secondary measure installed, according to:

$$C_{NO_{2sec}} = C_{NO_{2.prim}} \cdot \left(1 - \eta_{sec} \cdot \beta_{sec}\right) \qquad (5\text{-}7)$$

$C_{NO_{2.sec}}$ nitrogen dioxide downstream of secondary measure (in mass pollutant/mass flue gas [kg/kg])

$C_{NO_{2.prim}}$ content of nitrogen dioxide taking into account primary measures (in mass pollutant/mass flue gas [kg/kg])

η_{sec} reduction efficiency of secondary measure [ ]

β_{sec} availability of secondary measure [ ]

If there is no data for η_{sec} and β_{sec} available, default values for various DeNOx techniques are given in Table 9.

The obtained value of $C_{NO_{2.sec}}$ is converted into C_{NO_2} and into the emission factor EF_{NO_2} according to the following equations:

$$C_{NO_2} = C_{NO_{2sec}} \cdot \frac{1}{V_D} \cdot 10^6 \qquad (5\text{-}8)$$

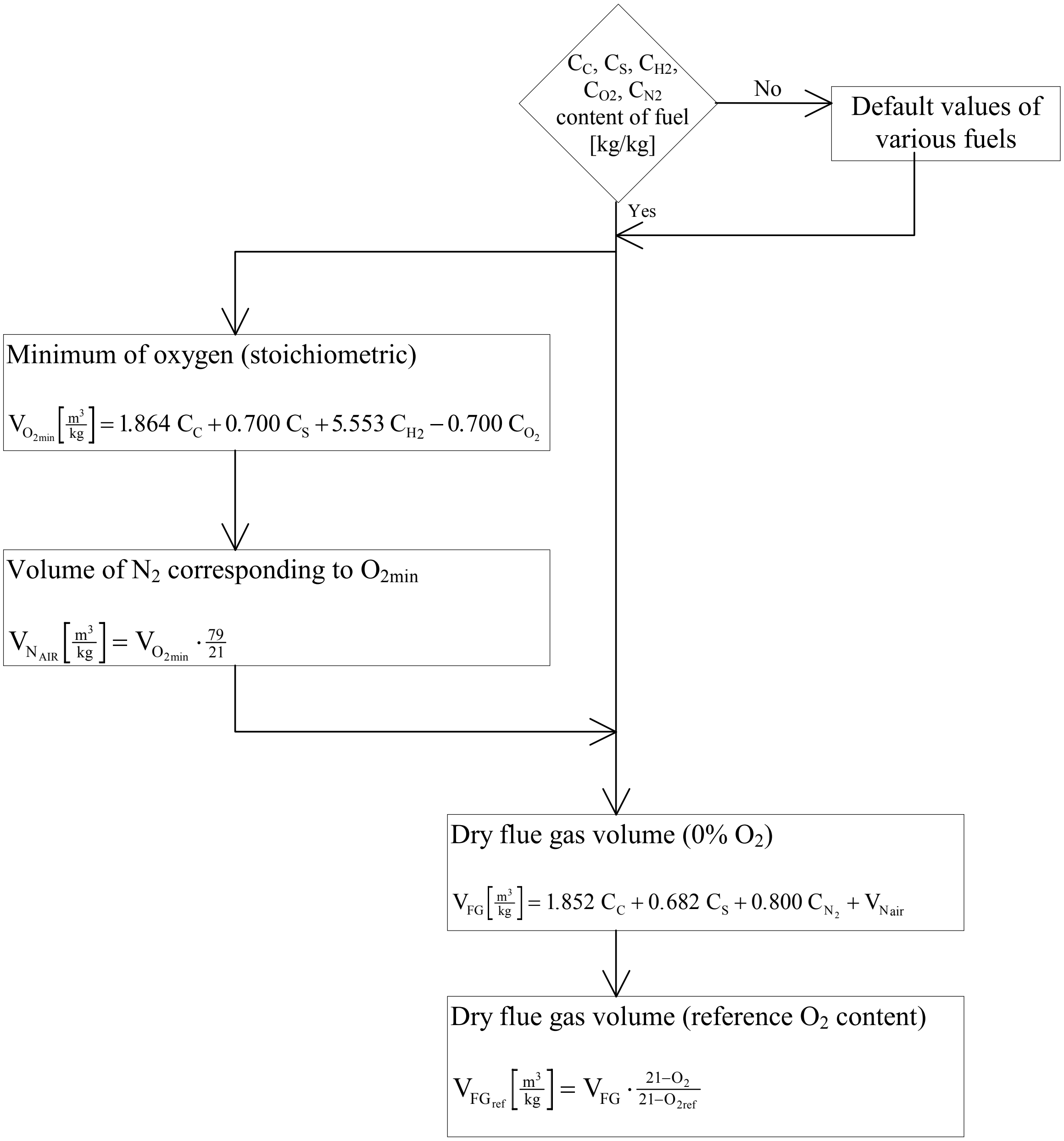
$$EF_{NO_2} = C_{NO_2} \cdot \frac{1}{H_u} \cdot V_{FG} \qquad (5\text{-}9)$$

C_{NO_2}	nitrogen dioxide in flue gas (in mass pollutant/volume flue gas [mg/m^3])
$C_{NO_{2sec}}$	nitrogen dioxide downstream of secondary measure (in mass pollutant/mass flue gas [kg/kg])
V_D	dry flue gas volume (in volume flue gas/mass flue gas [m^3/kg])
V_{FG}	specific dry flue gas volume (in volume flue gas/mass fuel [m^3/kg])
EF_{NO_2}	emission factor for nitrogen dioxide [g/GJ]
H_u	lower heating value [MJ/kg]

The specific dry flue gas volume V_{FG} can be determined according to Annex 6. Emission data expressed in [mg/m^3] are used for comparing measured and calculated values. Default values for lower heating values for hard and brown coal are given in Annexes 7 and 8.

Annex 6: Determination of the specific flue gas volume (flow sheet and description)

The specific flue gas volume has to be determined in order to convert the emission factors, which have been obtained in [g/GJ], into [mg/m^3], which allows a comparison to measured data. The approach is given in the following flow sheet:



For the determination of the flue gas volume, the elemental analysis of the fuel (content of carbon C_C, sulphur C_S, hydrogen C_H, oxygen C_{O_2} and nitrogen C_N (maf)) has to be known. If no data of the elemental analysis is available, default values of hard and brown coals are proposed in Annexes 7 and 8. The volume of oxygen required for a stoichiometric reaction $V_{O_{2min}}$ can be determined as follows:

$$V_{O_{2min}} = 1.864 \cdot C_C + 0.700 \cdot C_S + 5.553 \cdot C_H - 0.700 \cdot C_{O_2} \qquad (6\text{-}1)$$

$V_{O_{2min}}$	volume of oxygen required for stoichiometric reaction (in volume oxygen/mass fuel [m^3/kg])
C_C	content of carbon in fuel (in mass carbon/mass fuel [kg/kg])
C_S	content of sulphur in fuel (in mass sulphur/mass fuel [kg/kg])
C_H	content of hydrogen in fuel (in mass hydrogen/mass fuel [kg/kg])
C_{O_2}	content of oxygen in fuel (in mass oxygen/mass fuel [kg/kg])

The constants in Equation (6-1) represent stoichiometric factors for the volume of oxygen required for the combustion of 1 kg carbon, sulphur or hydrogen in [m^3/kg]. The corresponding volume of nitrogen in the air $V_{N_{air}}$ is given by Equation (6-2):

$$V_{N_{air}} = V_{O_{2min}} \cdot \tfrac{79}{21} \qquad (6\text{-}2)$$

$V_{N_{air}}$	volume of nitrogen in the air (in volume nitrogen/mass fuel [m^3/kg])
$V_{O_{2min}}$	volume of oxygen required for stoichiometric reaction (in volume oxygen/mass fuel [m^3/kg])

The specific dry flue gas volume at 0 % oxygen V_{FG} can be determined by using Equation (6-3):

$$V_{FG} = 1.852 \cdot C_C + 0.682 \cdot C_S + 0.800 \cdot C_N + V_{N_{air}} \qquad (6\text{-}3)$$

V_{FG}	specific dry flue gas volume (in volume flue gas/mass fuel [m^3/kg])
C_C	content of carbon in fuel (in mass carbon/mass fuel [kg/kg])
C_S	content of sulphur in fuel (in mass sulphur/mass fuel [kg/kg])
C_N	content of nitrogen in fuel (in mass nitrogen/mass fuel [kg/kg])
$V_{N_{air}}$	volume of nitrogen in the air (in volume nitrogen/mass fuel [m^3/kg])

The constants in Equation (6-3) represent stoichiometric factors for the volume of oxygen required for the combustion of 1 kg carbon, sulphur or nitrogen in [m^3/kg]. The obtained values of V_{FG} at 0 % oxygen are converted to the reference content of oxygen in flue gas according to Equation (6-4):

$$V_{FG_{ref}} = V_{FG} \cdot \tfrac{21 - O_2}{21 - O_{2_{ref}}} \qquad (6\text{-}4)$$

$V_{FG_{ref}}$	volume of specific flue gas under reference conditions (in volume flue gas/mass fuel [m^3/kg])
V_{FG}	volume of specific flue gas obtained (in volume flue gas/mass fuel [m^3/kg])
O_2	content of oxygen in the flue gas obtained [%]
$O_{2_{ref}}$	content of oxygen in the flue gas under reference conditions [%]

Annex 7: Composition and lower heating value (H_u) of hard coal in coal mining countries

country	elemental analysis (maf) [wt.-%]										volatiles (maf) [wt.-%]		H_u (maf) [MJ/kg]	
	C		N		O		H		S					
	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation	value	standard deviation
Australia1)	84.6	2.26	1.8	0.15	7.8	2.08	5.2	0.29	0.6	0.21	34.0	5.94	33.70	1,03
Canada1)	86.6	1.8	1.4	0.15	6.1	1.5	5.1	0.56	0.9	0.43	33.9	6.34	33.04	2.32
China1)	81.9	1.95	1.1	0.32	11.4	2.4	4.9	0.21	1.05	0.35	36.3	2.32	32.06	0,80
Columbia1)	78.5	6.37	1.5	0.13	12.4	4.3	5.2	0.62	0.9	0.19	42.2	2.70	31.83	1.93
Czech Rep.2)	85.98	2.23	1.5	0.17	6.27	2.30	5.09	0.70	1.16	0.68	30.88	8.92	34.00	2.44
France2)	87.91	1.76	1.29	0.24	5.60	1.58	4.50	0.47	0.70	0.17	22.81	5.82	34.86	1.56
Germany RAG1)6)	90.2	1.77	1.6	0	3	1.41	4.4	0.56	0.9	-	15.8	9.60	35.23	0.29
Ger. others2)	87.00	2.44	1.49	0.27	5.75	1.94	4.76	0.68	1.02	0.32	25.52	6.58	30.10	1.75
CIS1)	77.5	0	0.7	0	16.1	0	5.4	0	0.3	0	39.0	3.20	31.85	1.66
Hungary2)	84.10	1.51	1.42	0.69	5.79	0.54	5.09	0.11	3.62	0.55	24.4	3.98	34.16	1.05
India1)	76.5	3.22	1.3	0.25	16.2	4	5.6	0.4	0.4	0.32	47.9	2.44	29.48	2.25
Poland4)	80.0		1.0		7.0		5.0		1.0		38.5		(21.00)5)	
Portugal3)	87.0		0.95		5.4		4.9		0.94		32.1		(27.58)5)	
South Africa1)	80.3	5.78	2.1	0.73	8.8	1.2	4.9	1.19	0.9	0.24	31.9	2.37	32.36	0.73
UK1)	84.5	0.6	1.8	0	n. a.		5.4	0.06	n. a.		38.2	1.84	33.80	0.58
USA1)	84.3	2	1.6	0.17	7.5	1.65	5.5	0.38	1.1	0.58	38.1	4.31	33.89	0.88
Venezuela1)	84.2	1.7	1.5	0.07	7.6	2.19	6	0.49	0.7	0	43.2	3.98	34.00	1.00

1) Association of German Coal Importers 1992 /72

2) Brandt 1981 /47/

n.a. - no data are available

3) Madeira: Personal communication, EDP-Electricielade Portugal, Lisboa, May 1994

4) Debsky: Personal communication, Energy Information Centre, Warsaw, May 1994

5) lower heating value as received (ar)

6) RAG= Ruhr coal

Annex 8: Composition and lower heating value (H_u) of brown coal in coal mining countries

country	elemental analysis (maf) [wt.-%]										volatiles (maf)		H_u (maf)	
	C		N		O		H		S		[wt.-%]		[MJ/kg]	
	value		value		value		value		value		value		value	
Czech Rep. 2)	70.09	3.32 4)	1.07	0.22 4)	21.74	3.42 4)	5.64	0.64 4)	1.48	0.82 4)	56.67	4.62 4)	28.2	2.39 4)
Germany														
-Rheinisch coal 1)	68	62-72 5)	1.0	0.7-1.3 5)	25.2	22-30 5)	5	4.5-5.5 5)	0.8	0.2-1.1 5)	38 6)	-	27.3	19.4-31.7 5)
-Middle Ger. 1)	72		0.8		18.3		5.5		3.4		57.5		28.8	
-East Ger. 1)	69.5		1.0		23.1		5.8		0.6		58.7		25.7	
Hungary 1) - 1	63.8		(1.1)		26.8		4.8		3.5		61.8		35.7	28.8-42.6 5)
Hungary 2) - 2	69.82	2.62 4)	1.06	0.45 4)	18.91	2.23 4)	5.54	0.12 4)	4.49	2.46 4)	39.30	1.04 4)	28.4	1.20 4)
Poland 7)	69.5	66-73 5)	1.1	0.7-1.5 5)	19	13-25 5)	6	5-7 5)	1		50		25	23 - 26 5)
Portugal 2)	67.44	1.01 4)	0.91	0.18 4)	22.61	2.89 4)	4.4	0.74 4)	4.62	2.43 4)	54.64	8.84 4)	24.8	2.6 4)
Turkey 1) - 1	61.4		0.8		29.6		5.1		5.1		n. a.		21.2	19.8-22.7 5)
Turkey 3) - 2	62.6	7.84 4)	2.0	0.67 4)	24.0	4.48 4)	4.9	0.56 4)	6.2	4.77 4)	56.0	3.93 4)	26.6	

1) IEA coal research - brown coal
2) Brandt
3) Kücükbayrak, S.; Kadioglu, E.: Desulphurisation of some Turkish lignites by pyrolysis, FUEL, Vol. 67, 6/1988
4) standard deviation
5) range
6) value recommended by RAG
7) Debsky: Personal communication, Energy Information Centre, Warsaw, May 1994
n. a. - no data available

Annex 9: Conditions for exemplary calculation of NO_x emission factors

Annex 9 presents the values which have been chosen for the calculation of NO_x emission factors (according to Section 4.2.1). The results of the calculations are given in the following Annexes 10 (for hard coal) and 11 (for brown coal). Both annexes contain emission factors in [g/GJ] as well as concentrations in [mg/m^3] which have been determined under the conditions given in Table 9-1:

Table 9-1: Selected input parameters for model calculations determining NO_X emission factors as given in Annexes 10 and 11

Type of coal[1]	Type of boiler	Fraction of thermal NO NO_{th} [ ]	Reduction efficiency of primary measures η_{prim}[2] [ ]	Reduction efficiency of secondary measures η_{sec} [ ]	Availability β_{sec} [ ]
hc	DBB	0,05	LNB 0,20 LNB/SAS 0,45 LNB/OFA 0,45 LNB/SAS/OFA 0,60	SCR 0,8	0,99
	WBB	0,30	LNB 0,20 LNB/SAS 0,45 LNB/OFA 0,40 LNB/SAS/OFA 0,60	SCR 0,8	0,99
bc	DBB	0,05	LNB 0,20 LNB/SAS 0,45 LNB/OFA 0,40 LNB/SAS/OFA 0,60	-	-

[1] Elementary analyses of hard and brown coal are given in Annexes 7 and 8.

[2] The reduction efficiency is given as an example for selected primary measures (see Section 4.2).
Abbreviations: hc = hard coal, bc = brown coal

For individual calculations of NO_X emission factors, the computer programme (users' manual see Section 15 and Annex 14) can be used.

Annex 10: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for hard coal (Annex 7)

Hard coal from	Type of boiler	Uncontrolled		Primary control[2)			Secondary control[3)	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1)	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Australia	DBB	568	1620	LNB	454	1300	95	270
				LNB/SAS	312	893	65	186
				LNB/OFA	312	893	65	186
				LNB/SAS/OFA	227	649	47	135
	WBB	703	2140	LNB	562	1720	117	357
				LNB/SAS	387	1180	80	245
				LNB/OFA	422	1290	88	268
				LNB/SAS/OFA	281	858	59	178
Canada	DBB	506	1390	LNB	405	1110	84	230
				LNB/SAS	278	762	58	158
				LNB/OFA	278	762	58	158
				LNB/SAS/OFA	202	554	42	115
	WBB	627	1830	LNB	501	1460	10	304
				LNB/SAS	345	1010	72	209
				LNB/OFA	376	1100	78	228
				LNB/SAS/OFA	251	732	52	152
China	DBB	413	1180	LNB	331	943	69	196
				LNB/SAS	227	648	47	135
				LNB/OFA	227	648	47	135
				LNB/SAS/OFA	165	472	34	98
	WBB	512	1560	LNB	409	1250	85	259
				LNB/SAS	281	856	59	178
				LNB/OFA	307	934	64	194
				LNB/SAS/OFA	205	623	43	130
Columbia	DBB	535	1570	LNB	428	1250	89	261
				LNB/SAS	294	861	61	179
				LNB/OFA	294	861	61	179
				LNB/SAS/OFA	214	626	45	130

for footnotes see bottom of this table

Annex 10 continued, for footnotes see bottom of this table

Hard coal from	Type of boiler	Uncontrolled		Primary control[2]			Secondary control[3]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Columbia	WBB	662	2070	LNB	529	1650	110	344
				LNB/SAS	364	1140	76	237
				LNB/OFA	397	1240	83	258
				LNB/SAS/OFA	265	827	51	172
Czech Republic	DBB	483	1370	LNB	387	1100	80	228
				LNB/SAS	266	753	55	157
				LNB/OFA	266	753	55	157
				LNB/SAS/OFA	193	548	40	114
	WBB	598	1810	LNB	479	1450	100	301
				LNB/SAS	329	995	68	207
				LNB/OFA	359	1080	75	226
				LNB/SAS/OFA	239	723	50	150
France	DBB	374	1080	LNB	299	863	62	180
				LNB/SAS	205	594	43	123
				LNB/OFA	205	594	43	123
				LNB/SAS/OFA	149	432	31	90
	WBB	463	1430	LNB	370	1140	77	237
				LNB/SAS	254	784	53	163
				LNB/OFA	278	855	58	178
				LNB/SAS/OFA	185	570	39	119
Germany RAG	DBB	384	1090	LNB	307	872	64	181
				LNB/SAS	211	600	44	125
				LNB/OFA	211	600	44	125
				LNB/SAS/OFA	154	436	32	90
	WBB	476	1440	LNB	381	1150	779	240
				LNB/SAS	262	792	54	165
				LNB/OFA	285	864	59	180
				LNB/SAS/OFA	190	576	40	120

Annex 10 continued, for footnotes see bottom of this table

Hard coal from	Type of boiler	Uncontrolled		Primary control[2]			Secondary control[3]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Germany others	DBB	495	1240	LNB	396	990	82	206
				LNB/SAS	272	681	57	142
				LNB/OFA	272	681	57	142
				LNB/SAS/OFA	198	495	41	103
	WBB	613	1630	LNB	490	1310	102	272
				LNB/SAS	337	899	70	187
				LNB/OFA	368	980	76	204
				LNB/SAS/OFA	245	654	51	136
Hungary	DBB	401	1150	LNB	320	920	67	191
				LNB/SAS	220	633	46	132
				LNB/OFA	220	633	46	132
				LNB/SAS/OFA	160	460	33	96
	WBB	496	1520	LNB	397	1220	82	253
				LNB/SAS	273	835	57	174
				LNB/OFA	298	911	62	190
				LNB/SAS/OFA	198	608	41	126
CIS	DBB	308	923	LNB	247	739	51	154
				LNB/SAS	169	508	35	106
				LNB/OFA	169	508	35	106
				LNB/SAS/OFA	123	369	26	77
	WBB	382	1220	LNB	305	975	64	203
				LNB/SAS	210	671	44	139
				LNB/OFA	229	732	48	152
				LNB/SAS/OFA	153	488	32	101
India	DBB	551	1540	LNB	441	1230	92	256
				LNB/SAS	303	845	63	176
				LNB/OFA	303	845	63	176
				LNB/SAS/OFA	220	615	46	128

Annex 10 continued, for footnotes see bottom of this table

Hard coal from	Type of boiler	Uncontrolled		Primary control[2)]			Secondary control[3)]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1)]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
India	WBB	682	2030	LNB	545	1620	113	338
				LNB/SAS	375	1120	78	232
				LNB/OFA	409	1120	85	253
				LNB/SAS/OFA	273	812	57	169
South Africa	DBB	569	1650	LNB	456	1320	95	275
				LNB/SAS	313	910	65	189
				LNB/OFA	313	910	65	189
				LNB/SAS/OFA	228	662	47	138
	WBB	705	2180	LNB	564	1750	117	364
				LNB/SAS	388	1200	81	250
				LNB/OFA	423	1310	88	273
				LNB/SAS/OFA	282	874	59	182
USA	DBB	563	1610	LNB	450	1290	94	268
				LNB/SAS	310	885	64	184
				LNB/OFA	310	885	64	184
				LNB/SAS/OFA	225	644	47	134
	WBB	697	2120	LNB	558	1700	116	353
				LNB/SAS	383	1170	78	243
				LNB/OFA	418	1270	87	265
				LNB/SAS/OFA	279	850	58	177
Venezuela	DBB	588	1670	LNB	471	1340	98	278
				LNB/SAS	324	919	67	191
				LNB/OFA	324	919	67	191
				LNB/SAS/OFA	235	668	49	139

Annex 10 continued

Hard coal from	Type of boiler	Uncontrolled		Primary control[2]			Secondary control[3]	
		EF [g/GJ]	Flue gas concentration [mg/m^3]	PM[1]	EF [g/GJ]	Flue gas concentration [mg/m^3]	EF [g/GJ]	Flue gas concentration [mg/m^3]
Venezuela	WBB	728	2210	LNB	583	1760	121	367
				LNB/SAS	401	1210	83	252
				LNB/OFA	437	1320	91	275
				LNB/SAS/OFA	291	882	61	184

[1] PM = primary measures

[2] primary measures as mostly used, see Table 8

[3] taking into account secondary measures mostly used: SCR: reduction efficiency = 0.8, availability = 0.99

Annex 11: Emission factors and flue gas concentrations for NO_X obtained by model calculations (see Annexes 4 and 5) for brown coal (see Annex 8)

Brown coal from	Type of boiler	Uncontrolled		Primary control		
		EF $\left[\frac{g}{GJ}\right]$	Conc. $\left[\frac{mg}{m^3}\right]$	PM[1]	EF $\left[\frac{g}{GJ}\right]$	Conc. $\left[\frac{mg}{m^3}\right]$
Czech Republic	DBB	506	1.480	LNB	405	1190
				LNB/SAS	278	816
				LNB/OFA	304	890
				LNB/SAS/OFA	202	593
Germany						
- Rheinisch coal	DBB	325	985	LNB	260	788
				LNB/SAS	179	542
				LNB/OFA	195	591
				LNB/SAS/OFA	130	394
- Middle Germany	DBB	504	1.250	LNB	403	996
				LNB/SAS	277	685
				LNB/OFA	302	747
				LNB/SAS/OFA	202	498
- East Germany	DBB	539	1.460	LNB	431	1.160
				LNB/SAS	296	801
				LNB/OFA	323	873
				LNB/SAS/OFA	215	582
Hungary - 1	DBB	379	1.590	LNB	303	1.270
				LNB/SAS	208	874
				LNB/OFA	227	953
				LNB/SAS/OFA	151	635
Hungary - 2	DBB	379	1.100	LNB	304	879
				LNB/SAS	209	604
				LNB/OFA	228	659
				LNB/SAS/OFA	152	439
Portugal	DBB	461	1.260	LNB	369	1.010
				LNB/SAS	254	696
				LNB/OFA	277	759
				LNB/SAS/OFA	185	506
Turkey - 2	DBB	725	2.240	LNB	580	1.790
				LNB/SAS	399	1.230
				LNB/OFA	435	1.340
				LNB/SAS/OFA	290	895

[1] PM = primary measures as given in Table 8

Annex 12: Comparison between measured and calculated SO_2 and NO_x emission data

The proposed methodology for the determination of SO_2 and NO_x emission factors is described in the Sections 4.1 and 4.2. Calculated flue gas concentrations in [mg/m^3] have been used for the derivation of emission factors in [g/GJ]. A comparison of measured concentrations in combustion plants in [mg/m^3] with calculated concentrations in [mg/m^3] can be used for verification purposes.

A comparison of measured concentrations with calculated flue gas concentrations downstream of the boiler is given as an example for some power plants in Table 12-1.

Table 12-1: Comparison of measured and calculated flue gas concentrations in raw gas of the boiler (taking into account primary reduction measures)[13)]

Type of boiler	Power plant	C_{SO_2} [mg/m^3]		C_{NO_2} [mg/m^3]	
		measured	calculated	measured	calculated
DBB	Altbach (FRG)[1)]	ca. 1,700	1,380 - 1,610	ca. 600	599 - 681
	Münster (FRG)[2)]	1,644 - 1,891	1,380 - 1,440	800 - 900	1,090
	Karlsruhe (FRG)[3)]	1,600 - 2,000	1,310 - 1,650	900 - 1,000	923 - 1,140
	Hanover (FRG)[4)]	1,600 - 1,800	1,610	ca. 800	681
	Mehrum (FRG)[5)]	ca. 2,700	1,610	ca. 800	990
	Nuremberg (FRG)[6)]	ca. 1,800	1,610	n. d.	1,240
	Heilbronn (FRG)[7)]	ca. 1,800	1,900 - 2,200	≤ 800	1,050 - 1,070
	IMATRAN (SF)[8)]	n. d.	1,480 - 1,700	ca. 225	516 - 747
	EPON (NL)[9)]	1,429 - 1,577	1,580 - 2,190	363 - 609	999 - 1,010
WBB	Aschaffenburg (FRG) [10)]	2,400	1,530	1,000	1,010
	Charlottenburg (FRG) [11)]	1,800	1,530	1,300	1,080
	Karlsruhe (FRG) [12)]	1,295 - 1,716	1,610	ca. 960	1,460

[1)] coal: Germany RAG, Germany others; reduction measures: WS; LNB/SAS, SCR; thermal capacity 1,090 MW

[2)] coal: Germany others, $\alpha_S = 0.15$; reduction measure: DESONOX ($\eta_{SO2} = 0.94$, $\eta_{NO2} = 0.82$); thermal capacity 100 MW

[3)] coal: individual data, $\alpha_S = 0.4$; reduction measures: WS ($\eta = 0.85$); LNB/opt. ($\eta = 0.3$); SCR; thermal capacity 1,125 MW

[4)] coal: Germany others; reduction measures: SDA; LNB/OFA, SCR; thermal capacity 359 MW

[5)] coal: Germany others; reduction measures: WS; LNB, SCR; thermal capacity 1,600 MW

[6)] coal: Germany others; reduction measures: SDA; SCR; thermal capacity 110 MW

[7)] coal: individual data; reduction measures: WS ($\eta = 0.95$); OFA, SCR; thermal capacity 1,860 MW

[8] coal: individual data; reduction measures: WS; LNB/OFA; electrical capacity 650 MW

[9] coal: individual data; reduction measures: FGD (η = 0.93); high temperature NO_x reduction (η = 0.4), electrical capacity 630 MW

[10] coal: Germany RAG; reduction measures: WS; SAS, SCR; thermal capacity 395 MW

[11] coal: Germany RAG; reduction measures: WS; OFA; thermal capacity 120 MW

[12] coal: individual data; reduction measures: WS (η = 0.88); SCR (η = 0.9; thermal capacity) 191 MW

[13] values refer to full load conditions

n. d. = no data available

Table 12-2: Comparison of measured and calculated flue gas concentrations downstream of secondary reduction measure (if installed)[13]

Type of boiler	Power plant	C_{SO_2} [mg/m^3]		C_{NO_2} [mg/m^3]	
		measured	calculated	measured	calculated
DBB	Altbach (FRG)[1]	ca. 250	150 - 176	ca. 200	125 - 142
	Münster (FRG)[2]	85 - 181	820 - 859	163 - 176	74
	Karlsruhe (FRG)[3]	240 - 300	208 - 261	190	192 - 238
	Hanover (FRG)[4]	200	176	150	142
	Mehrum (FRG)[5]	400	176	190	206
	Nuremberg (FRG)[6]	50 - 140	176	70 - 100	257
	Heilbronn (FRG)[7]	100 - 200	207 - 240	≤ 200	218 - 223
	IMATRAN (SF)[8]	n. d.	161 - 186	ca. 225	516 - 747
	EPON (NL)[9]	ca. 148	113 - 184	ca. 609	999 - 1,010
WBB	Aschaffenburg (FRG) [10]	70	167	200	209
	Charlottenburg (FRG) [11]	175	167	163	1,080
	Karlsruhe (FRG) [12]	47 - 165	207	ca. 150	159

[1] - [13] for footnotes see Table 12-1 above

n.d. = no data available

The quality and quantity of data obtained by the power plant operators vary greatly. For unknown compositions of coal and other missing parameters default values have been used (e.g. for coal compositions see Annexes 7 and 8).

The values in Table 12-1 are compared in the Figure 12-1 below:

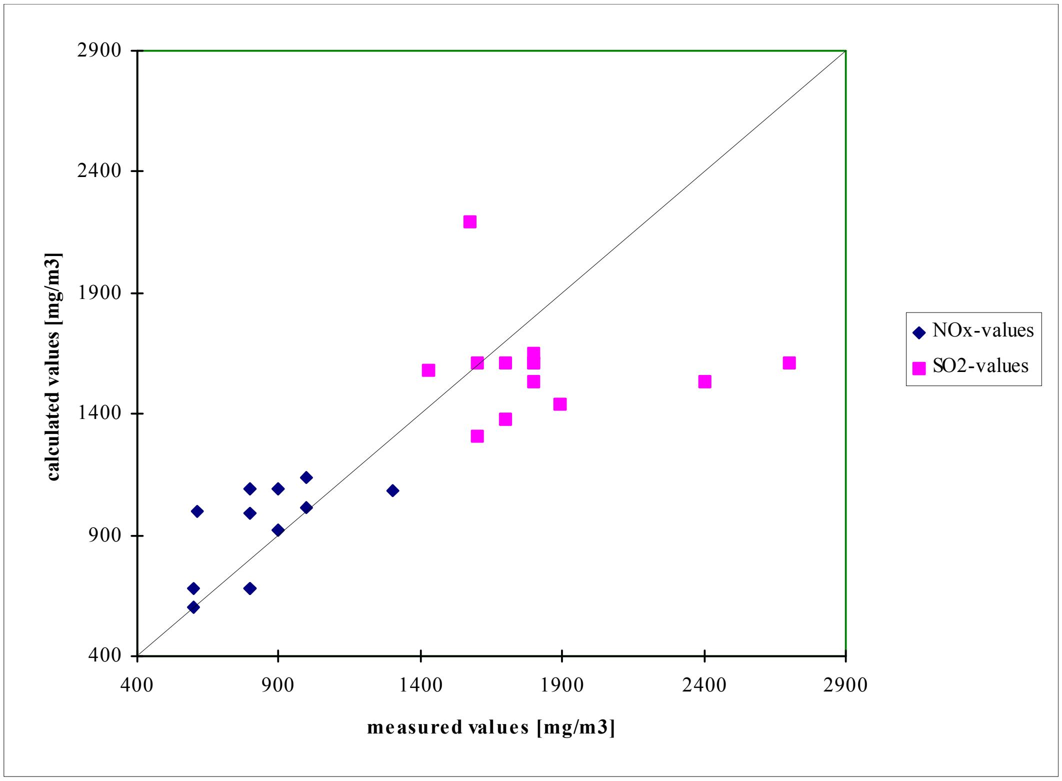


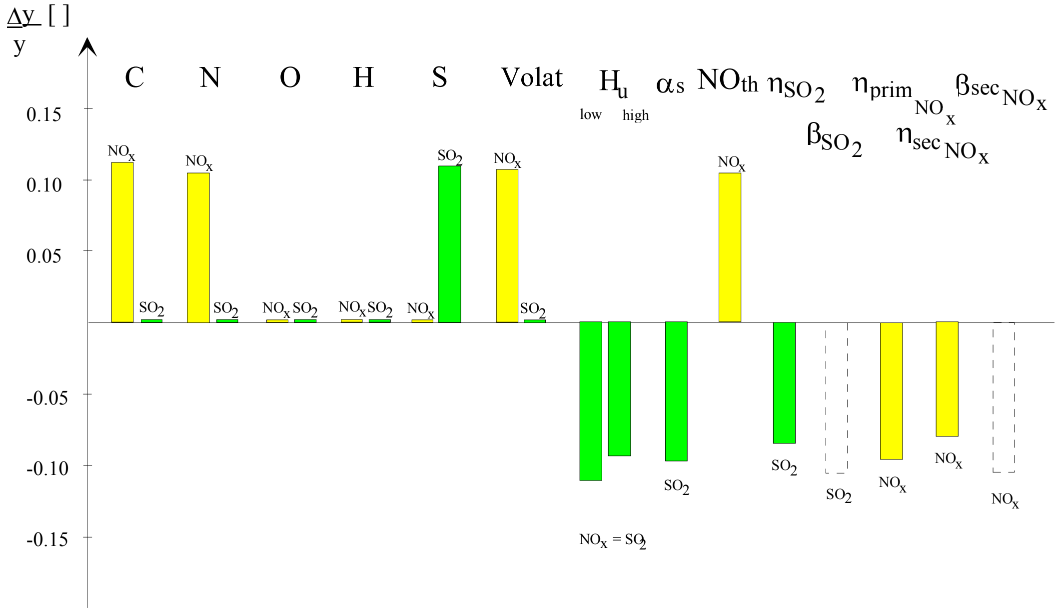
Figure 12-1: Comparison of measured flue gas concentrations [mg/m^3] and calculated flue gas concentrations [mg/m^3] downstream of the boiler

The comparison of measured flue gas concentrations and calculated flue gas concentrations shows that most values are scattered close to the middle axis.

Good correlations between measured and calculated values have been obtained for calculations which are only based on plant specific data provided by power plant operators. But for most calculations a mixture of plant specific data and default values for missing parameters has been used which leads to deviations from the middle axis. In particular strong differences occur for SO_2 emissions which show a tendency to be overestimated. The tendency can be explained by assumptions with regard to default values; e.g. the sulphur retention in ash varies greatly depending on the data availability.

Annex 13: Sensitivity analysis of the computer programme results

A sensitivity analysis was carried out with all model input parameters used. The 14 input parameters (fuel content of carbon C, nitrogen N, oxygen O, hydrogen H, sulphur S, volatiles Volat, lower heating value H_u, sulphur retention in ash α_S, fraction of thermal nitrogen oxide NO_{th}, reduction efficiency η and availability β of abatement measures) was arranged with respect to their influence on SO_2 and NO_X emissions. Each input parameter was varied by ±10 % except β_{SO2} and $\beta_{sec.NOx}$ which were varied only by - 4 % (dashed line); the variation of the calculated emission factors is presented in Figure 13-1.



Δy/y relative change of emission factors (pollutant as indicated)

Figure 13-1: Sensitivity analysis of the emission factor calculation programme results for pulverised coal combustion

For emission factors of SO_2 the sulphur content of fuel and the sulphur retention in ash are highly relevant. For emission factors of NO_X the fuel content of nitrogen, carbon and volatiles as well as the reduction efficiency of primary measures are highly relevant. The fuel contents of oxygen and hydrogen are not relevant. The relative change of emission factors concerning the lower heating value can be described for SO_2 and NO_X as an exponential curve: that means that uncertainties at lower levels of the heating values (e.g. for brown coal) influence the result stronger. The efficiency of secondary measures is of slightly less influence than the efficiency of primary measures. The availability of secondary measures is marked with a dashed line in Figure 13-1; a 4 % variation of this parameter has shown significant influence.

Annex 14: Users' manual for the emission factor calculation programme (for September 1995 version)

Determination of SO_2 and NO_x emission factors for large combustion plants

1 Computer specifications

This programme requires MICROSOFT WINDOWS 3.1, a 3½" floppy disc drive, and at least 200 Kbyte on the hard disc. The programme has been designed in MICROSOFT EXCEL 4.0 - English Version.

2 Installation

The floppy disc received contains 19 files. All these files have to be installed on the hard disc. The following users' guide is stored under README.DOC (written with MICROSOFT WORD FOR WINDOWS 2.1).

The software has to be installed on your hard disk "C" by using the following procedure:

- Create a new sub-directory with the name 'POWER_PL' by following the instructions:
  - in DOS go to C:\
  - type: MD POWER_PL
  - hit the <ENTER>-key
  - change into this sub-directory by typing: CD POWER_PL
  - hit the <ENTER>-key.
- To copy all the files from your floppy disc into the sub-directory 'POWER_PL' proceed as follows:
  - insert your disk into slot A (or B) of your PC
  - type COPY A: (or B:)*.*
  - hit the <ENTER>-key.

The installation of the programme is then complete.

3 How to work with the programme

3.1 Start the programme

- Start MICROSOFT WINDOWS 3.1 and MICROSOFT EXCEL 4.0 - English Version (or MICROSOFT EXCEL 5.0 - English Version).
- In 'FILE' - 'OPEN', go to hard disk 'C' and activate the sub-directory 'POWER_PL'. Then you will see all the necessary files in the programme in the left window.
- Choose the file 'POWER_PL.XLW' and hit the <ENTER>-key.
- Then the programme opens all the tables and macros needed.

3.2 Further proceedings with the programme

- When you see the first screen please type 'Ctrl'-'a' (or 'Strg'-'a') to start the programme. By hitting these two keys you start a macro, which takes you through all the levels of the programme. The input data for the programme are divided into background tables for the fuel used, for SO_2-specification and NO_x-specification.

  Fuel data input

  - First the programme asks for an identification of the model run. You are free to put in the name of the power plant, type of boiler, type of fuel (e. g. Heilbronn - dry bottom boiler - hard coal).
  - The next window requests the type of coal (hard coal or lignite).
  - The programme asks you to choose one of the fuel compositions listed. Select one of them by typing the corresponding number and hitting the 'OK'-key on the screen$^{1)}$. If the default values of the given fuel compositions do not correspond with your power plant, you have the possibility of putting in corrected values by choosing the last line of the table (line 17 or 10). Then the programme asks you to enter in the individual values. The values given by the 'question-window' can be kept by hitting the 'OK'-key on the screen.
  - Then the programme asks for the water content of the fuel and the reference-content of oxygen in the flue gas. The value given by the 'question-window' can be retained by hitting the 'OK'-key on the screen.

  SO_2 data specification

  - The programme asks you to choose one of the listed numbers as a value for the sulphur retention in ash. Please select one of them by typing the corresponding number and hitting the 'OK'-key on the screen1). If the default values for the sulphur retention in ash do not correspond with your power plant, you have the possibility of putting in corrected values by choosing the last line of the table (line 3). Then the programme asks you to put in the value.
  - The programme asks you to choose one of the listed secondary measures SO_2 . Please select one of them by typing the corresponding number and hitting the 'OK'-key on the screen$^{1)}$. If the default values of the efficiencies and availabilities of the secondary measures given do not correspond with those of your power plant, you have the possibility of putting put in corrected values by choosing the last line of the table (line 9). Then the programme asks you to put in the individual values.

    At this point the calculations for SO_2 are finished.

  NO_x data specification

  - The programme proceeds with the calculations of NO_2 by asking for a value for $NO_{thermal}$[1]. At this stage, the thermal NO (NOthermal) has to be put in as an exogenious value as given in the table. You have the possibility of putting in a new value by following the instructions on the screen.

- The next window requests the type of boiler (wet bottom boiler WBB- dry bottom boiler DBB).
- Then you have to choose a type of combination of primary measure installed. For some primary measures, reduction efficiencies are given as default values[11]. If you have better data available, you can put in new values choosing the last line of the table (line 17) and follow the instructions on the screen.
- Finally, you have to choose a type of combination of secondary measure installed[1]. As mentioned above, you can put in different values of efficiencies and availabilities by choosing one secondary measure from the table (typing the corresponding number). Or else you can put in your own values by selecting the last line of the table (line 6). Please follow the instructions on the screen.

At the end the following message appears on the screen: You can save the data-sheet named 'AINPUSO2.XLS' under a different name.

If you want to do further model runs, just type 'Ctrl'-'a' (or 'Strg'-'a') and the programme starts again.

In order to finish your calculation, just quit EXCEL without saving changes in any of the 19 basic files of this software.

---

[11] If the tables with the default values are overlapped by a 'question-window' you can move this window: point on the headline of this little window with your mouse-pointer, hold your left mouse-button and move it.

Annex 15: Frame conditions of the detailed investigation concerning start-up emissions and start-up emission factors /based on 116/

Approach

Start-ups have to be considered in a boiler-by-boiler approach. In order to determine the relevance of start-up emissions compared to full load emissions, measured emission data for SO_2, NO_2 and CO obtained from power plant operators have been analysed. Start-up emissions and start-up emission factors have been determined in principle by using the detailed methodology described in Section 5.

Technical specifications

The analysis of start-up emissions was accomplished by using measured values from dry bottom boilers, wet bottom boilers and a gas fired boiler. The interpretation of start-up emissions and start-up emission factors should take into account specifications in the design of the boilers and in the configuration of secondary measures installed. In the following, particularities of the boilers considered are given:

- *Dry bottom boiler (thermal capacity 1,050 MW and 1,147 MW, hard coal fuelled)*

  The smaller boiler is equipped with a primary measure for NO_x reduction (SAS). The SCR is arranged in a high dust configuration (SCR-precipitator-FGD). This boiler is often started slowly and directly connected to the FGD.

  The larger boiler is also equipped with a primary measure for NO_x reduction (SAS). The SCR is also arranged in a high dust configuration (SCR-precipitator-FGD). Due to special arrangements (individual construction of two heat exchangers without any slip between raw and clean flue gas) when this boiler is started up the FGD is by-passed. This boiler is also called „quick“ start-up boiler.

- *Wet bottom boiler (thermal capacity 499 MW each, hard coal fuelled)*

  One boiler is equipped with primary measures for NO_x (like OFA and improved coal mills). The other boiler is not equipped with primary measures. Both boilers are equipped with a common FGD. The SCR is arranged in a tail-end-configuration (precipitator-FGD-SCR) and equipped with a natural gas fired additional furnace. The type of FGD is wet scrubbing (WS). Both boilers are started up directly connected to the FGD.

- *Natural gas fired boiler (thermal capacity 1,023 MW)*

  This boiler is rarely used. It is designed for quick start-ups. As a primary measure, special NO_x burners are installed. As a secondary measure an SCR is installed. SO_x abatement is not necessary due to the fact that low sulphur fuels are used.

Boilers without secondary measures show start-up emissions which are below the emissions under full load conditions. During start-ups boilers with secondary measures often show significantly higher SO_2 emissions than during the same time under full load conditions. Start-up emissions are released until the secondary measures are working under optimal conditions (for

SO_2 and NO_2). CO emissions can be significant up to the time when the boiler operates at minimum load.

The relevance of start-up emissions depends on the following parameters which have to be considered when interpreting measured values (emissions or emission factors):

- the type of boiler (e.g. wet bottom boilers always release higher NO_x emissions than dry bottom boilers, due to higher combustion temperatures),
- the type of fuel used (e.g. SO_x emissions are directly related to the sulphur content of the fuel; fuel-nitrogen also contributes to the formation of NO_x),
- the status of the boiler at starting-time (hot, warm or cold start, see Table 11).
  - the specifications of any individual start-up, like
    - -- the duration and the velocity of the start-up,
    - -- load level obtained (reduced load or full load),
    - -- the configuration of secondary measures (e.g. the start-up time of the high-dust-configurations (SCR-precipitator-FGD) depends on the boiler load, due to the fact that the SCR catalyst is directly heated by the flue gas; tail-end-configurations (precipitator-FGD-SCR) can have shorter start-up times, due to the fact that the SCR catalyst can be preheated by an additional burner),
    - -- start-up of the flue gas desulphurisation directly or in by-pass configuration,
    - -- emission standards which have to be met (boiler-specific emission standards can be set up below the demands of the LCP Directive).

Annex 16: List of abbreviations

a	Content of ash in coal (wt.-%)
AC	Activated Carbon Process
ar	As received
bc	Brown coal
BFCB	Bubbling Fluidised Bed Combustion
CF_n	Correction factor for month n [ ]
CFBC	Circulating Fluidised Bed Combustion
CC	Combined Cycle
CI	Compression Ignition
$CM_{HM_{FA.raw}}$	Heavy metal concentration in raw gas fly ash $[\frac{g}{Mg}]$
$CM_{HM_{FA.clean}}$	Heavy metal concentration in fly ash in clean flue gas $[\frac{g}{Mg}]$
$\overline{C}$	Expected value (mean value) of the flue gas concentration $[\frac{mg}{m^3}]$
C_i	Concentration $[\frac{kg}{kg}]$, $[\frac{g}{Mg}]$, $[\frac{mg}{m^3}]$, $i = SO_2, S_{fuel}$ etc.
CODPOL	Code of pollutants according to CORINAIR
D_k	Number of days per month
DBB	Dry Bottom Boiler
DeNOx	Denitrification unit(s)
DESONOX	Type of simultaneous process for SO_2 and NO_x removal based on catalytic reaction
DSI	Dry Sorbent Injection
E	Emission within the period considered [Mg]
E^A	Emission during start-up period [Mg]
E^V	Emission for full load conditions during start-up period [Mg]
EF^A	Emission factor for start-up time [g/GJ]
$EF^{Reduced\ load}$	Emission factor for reduced load conditions [g/MWh]
EF^V	Emission factor under full load conditions [g/GJ]
EF_i	Emission factor, mostly in the unit $[\frac{g}{GJ}]$, $i = SO_2, NO_x, CO_2$ etc.
EF_f	Fly ash emission factor of raw gas [kg/Mg]
ESP	Electrostatic precipitator
f_a	Fraction of ash leaving combustion chamber as particulate matter (wt.-%)
f_e	Enrichment factor [ ]
f_g	Fraction of heavy metal emitted in gaseous form (wt.-%)
f_k	Factor of day k

f_n	Factor for month
$f_{n,l}$	Factor for hour
F^E	Ratio for start-up and full load emissions [ ]
F^{EF}	Ratio for start-up and full load emission factors [ ]
FBC	Fluidised Bed Combustion
FGD	Flue Gas Desulphurisation
FGR	Flue Gas Recirculation
g	Gaseous state of aggregation
GF	Grate Firing
GHV	Gross Heating Value
GT	Gas Turbine
hc	Hard coal
HM	Heavy metal, trace elements
H_u	Lower heating value $[\frac{MJ}{kg}]$
k^{load}	Ratio of reduced load to full load emission factor [ ]
K_c	Mean efficiency of dust control equipment (%)
K_t	Share of plant capacity connected to dust control equipment (%)
l	Liquid state of aggregation
L	Actual load
LCP	Large Combustion Plant
LIFAC	Special type of DSI, mostly used in Finland
LNB	Low NOx Burner
$\dot{m}^L$	Fuel consumption during periods at reduced load conditions [GJ]
$\dot{m}^V$	Fuel consumption during full load periods [GJ]
$\dot{m}_{fuel}$	Fuel consumption per time unit $[\frac{kg}{a}]$, $[\frac{kg}{h}]$
$\dot{m}_{FA}$	Average annually emitted fly ash $\left[\frac{Mg}{a}\right]$
$\dot{m}_q^A$	Fuel consumption during start-up period [GJ]; q= type of start-up (cold start, warm start, hot start)
maf	Moisture and ash free
NMVOC	Non-Methane Volatile Organic Compounds
No_{fuel}	Fuel based emission of nitrogen oxide
$NO_{thermal}$	Thermal nitric oxide
OFA	Overfire Air

P	Daily coal consumption $[\frac{\mathrm{Mg}}{\mathrm{d}}]$
PM	Primary Measure
RAG	Coal mined in Rhine area in Germany
s	Solid state of aggregation
SAS	Staged Air Supply
SC	Simple Cycle
SCR	Selective Catalytic Reduction
SI	Spark Ignition
SNAP	Selected Nomenclature of Air Pollutants
SNCR	Selective Non-Catalytic Reduction
SNOX	Technical specification of DESONOX-process
SPA	Spray Dryer Absorption
SPF	Split Primary Flow
ST	Stoker
Stat. E.	Stationary Engine
$\dot{V}$	Flue gas volume flow rate $[\frac{\mathrm{m}^3}{\mathrm{h}}]$
$\bar{\dot{V}}$	Average flow rate $[\frac{\mathrm{m}^3}{\mathrm{h}}]$
V_D	Dry flue gas volume per mass flue gas $[\frac{\mathrm{m}^3}{\mathrm{kg}}]$
V_{FG}	Dry flue gas volume per mass fuel $[\frac{\mathrm{m}^3}{\mathrm{kg}}]$
VOC	Volatile Organic Compounds
WAP	Walter Process
WBB	Wet Bottom Boiler
WL	Wellmann-Lord
WS	Wet Scrubbing
α_s	Sulphur retention in ash [ ]
β_{sec}	Availability of secondary abatement technique [ ]
γ	Fraction of thermal-NO formed [ ]
η_i	Reduction efficiency [ ], i = primary measure, secondary measure

SNAP CODES: (See below)

SOURCE ACTIVITY TITLE: COMBUSTION IN ENERGY & TRANSFORMATION INDUSTRIES
Combustion Plants as Area Sources

The following activities are taken into account when combustion plants are treated collectively as area sources. Boilers, furnaces (except process furnaces), gas turbines and stationary engines which may also be considered individually as point sources are covered by this chapter as well as by chapter B111 on "Combustion Plants as Point Sources".

	Combustion plants as area sources										
SNAP97 Codes	NOSE CODE	NFR CODE	Boilers/furnaces							Gas turbines	Stationary engines
			Thermal capacity [MW]	Public power and cogeneration plants	District heating	Industrial combustion	Commercial and institutional combustion	Residential combustion	Agriculture forestry and fishing		
01 01 02	101.02	1 A 1 a	≥ 50	X							
01 02 02	101.02	1 A 1 a	and		X						
01.03.02	101.02	1 A 1 b				X					
01.04.02	101.02	1 A 1 c				X					
01.05.02	101.02	1 A 1 c				X					
02 01 02	101.02	1 A 4 a	< 300				X				
02 02 01	101.02	1 A 4 b i						X			
02 03 01	101.02	1 A 4 c i							X		
03 01 02	101.02	1 A 2 a-f				X					
01 01 03	101.03	1 A 1 a	< 50	X							
01 02 03	101.03	1 A 1 a			X						
01 03 02	101.03	1 A 1 b				X					
01 04 02	101.03	1 A 1 c				X					
01 05 02	101.03	1 A 1 c				X					
02 01 03	101.03	1 A 4 a					X				
02 02 02	101.03	1 A 4 b i						X			
02 03 02	101.03	1 A 4 c i							X		
03 01 03	101.03	1 A 2 a-f				X					
01 01 04	101.04	1 A 1 a	Not							X	
01 02 04	101.04	1 A 1 a	Rele							X	
02 01 04	101.04	1 A 4 a	-vant							X	
02 02 03	101.04	1 A 4 b i								X	
02 03 03	101.04	1 A 4 c i								X	
03 01 04	101.04	1 A 2 a-f								X	

			Combustion plants as area sources								
SNAP97 Codes	NOSE CODE	NFR CODE	Boilers/furnaces							Gas turbines	Stationary engines
			Thermal capacity [MW]	Public power and cogeneration plants	District heating	Industrial combustion	Commercial and institutional combustion	Residential combustion	Agriculture forestry and fishing		
01 01 05	101.05	1 A 1 a	Not Relevant								X
01 02 05	101.05	1 A 1 a									X
02 01 05	101.05	1 A 4 a									X
02 02 04	101.05	1 A 4 b i									X
02 03 04	101.05	1 A 4 c i									X
03 01 05	101.05	1 A 2 a-									X

X : indicates relevant combination

1 ACTIVITIES INCLUDED

This chapter covers emissions from combustion plants treated collectively as area sources. However, e.g. if only a few units exist and thus only little data is available, the individual approach may be preferable also for small combustion plants.

The subdivision of the SNAP activities according to CORINAIR90 concerning combustion plants takes into account two criteria:

- the economic sector concerning the use of energy:
  - public power and co-generation,
  - district heating,
  - commercial, institutional and residential combustion,
  - industrial combustion,
    (Note: process furnaces are allocated separately.)
- the technical characteristics:
  - the installed thermal capacity,
    - ≥ 50 to < 300 MW,
    - < 50 MW,
  - other combustion technologies,
    - gas turbines,
    - stationary engines.

The emissions considered in this section are released by a controlled combustion process (boiler emissions, furnace emissions, emissions from gas turbines or stationary engines) and are mainly characterised by the types of fuels used. Furthermore, a technical characterisation of the combustion sources may be integrated according to the size and type of plants as well as on primary or secondary reduction measures.[1] Solid, liquid or gaseous fuels are used; whereby solid fuels comprise coal, coke, biomass and waste (as far as waste is used to generate heat or power). In addition a non-combustion process can be a source of ammonia emissions; namely the ammonia slip in connection with some NO_x abatement techniques.[1]

2 CONTRIBUTION TO TOTAL EMISSIONS

The contribution of area source emissions released by combustion plants to the total emissions in the countries of the CORINAIR90 inventory reported as areas sources is given as follows:

Table 1: Contributions of emissions from combustion plants as area sources to the total emissions of the CORINAIR90 inventory <u>reported as area sources</u>. See chapter ACOR for further information on CORINAIR 90 emissions for these SNAP activities taking point and area sources together

		Contribution to total emissions [%]							
Source category	SNAP code	SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
≥ 300 MW	01 01 01 01 02 01 03 01 01	0	0	0	0	0	0	-	0
50-300 MW	01 01 02 01 02 02 02 01 02 02 02 01 02 03 01 03 01 02	12.1	10.0	1.0	0.1	2.3	9.3	3.3	0.5
< 50 MW	01 01 03 01 02 03 02 01 03 02 02 02 02 03 02 03 01 03	71.3	46.7	41.1	7.2	49.8	66.4	21.8	0.7
Gas turbines	01 01 04 01 02 04 02 01 04 02 02 03 02 03 03 03 01 04	0.1	2.0	0.03	0.03	0.1	1.0	0.2	-
Stationary engines	01 01 05 01 02 05 02 01 05 02 02 04 02 03 04 03 01 05	0.6	2.0	0.2	0.02	0.1	0.4	0.2	0

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[1] Note: Small combustion installations are seldomly equipped with secondary measures.

- : no emissions are reported as area sources

0 : emissions are reported, but the exact amount is under the rounding limit

Plants with a thermal capacity < 50 MW are the major contributors. In particular, the contribution of small units in „Commercial, institutional and residential combustion“ with a thermal capacity < 50 MW (SNAP 020002) is significantly high: SO_x 37.0 %, NO_x 24.2 %, NMVOC 39.6 %, CH_4 6.9 %, CO 46.3 %, CO_2 44.4 %, N_2O 14.7 % and NH_3 0.6 % (related to total emissions of CORINAIR90 reported as area sources).
In the literature concerning heavy metal emissions in Europe, area source emissions are not reported separately. In order to show the relevance of the sector residential combustion, the share of the emissions of different heavy metals from this sector in the total emission in Germany is shown as an example in Table 2.

Table 2: Contribution of heavy metal emissions from residential combustion to national total emissions of former West Germany /1/

	Contribution in [wt.-%]	
Pollutant	**1982**	**1990**
As	5.8	15
Cd	3	4.4
Cr	n.d.	n.d.
Cu	4.2	6.4
Hg	1.9	2.8
Ni	4.5	7.7
Pb	0.2	0.4
Se	0.8	3.1
Zn	0.4	0.7

n.d. : no data are available

For Cd and Hg data are also available for Austria. The contribution to total emissions in 1992 was for Cd 38.4% and for Hg 27.8% /2/. The contribution of area sources, such as residential combustion, to total emissions has increased during recent years. This is caused by the fact that large emitters have been equipped with improved dust control facilities in Germany as well as in Austria, and hence the contribution from larger sources has been reduced.

For Particulate Matter:
Combustion Plants < 50 MW (boilers) are now covered in the new supplementary chapter Particulate emissions from smaller Combustion Plants (<50MWth) B111(S1).

Combustion Plants >= 50 and < 300 MW (boilers) are now covered in the new supplementary chapter Particulate emissions from large Combustion Plants (>50MWth) B111(S2).

Gas Turbines are now covered in the new supplementary chapter Particulate emissions from gas turbines and internal combustion engines B111(S3).

3 GENERAL

3.1 Description

The emissions considered in this chapter are generated in boilers or in gas turbines and stationary engines regardless of the allocation of combustion plants to SNAP activities. In addition, residential combustion is relevant for this chapter. Emissions from process furnaces and from waste incineration are excluded.

3.2 Definitions

Integrated Coal Gasification Combined Cycle Gas Turbine (IGCC)	gas turbine fuelled by gas which is a product of a coal gasification process.
Boiler	any technical apparatus in which fuels are oxidised in order to generate heat for locally separate use.
Co-generation plant	steam production in (a) boiler(s) for both power generation (in a steam turbine) and heat supply.
Combined Cycle Gas Turbine (CCGT)	gas turbine combined with a steam turbine. The boiler can also be fuelled separately.
Furnace	fireplace in which fuels are oxidised to heat the direct surroundings.
Plant	element of the collective of emission sources (e.g. residential combustion) treated as an area source.
Stationary engines	spark-ignition engines or compression-ignition engines.

3.3 Techniques

3.3.1 Medium-sized combustion plants - boilers, gas turbines, stationary engines - (thermal capacity ≥ 50 and < 300 MW)

For the combustion of solid, liquid and gaseous fuels in medium-sized combustion plants techniques are used which have already been described in Section 3.3 of chapter B111 on “Combustion Plants as Point Sources”.

3.3.2 Small-sized combustion plants - boilers and furnaces - (thermal capacity < 50 MW)

Small sized combustion plants are divided here into industrial combustion and non-industrial combustion:

- Industrial combustion:
  The techniques used for the combustion of solid, liquid and gaseous fuels in industrial combustion plants have already been described in Section 3.3 of chapter B111 on

"Combustion Plants as Point Sources". The share of combustion techniques used is different: for the combustion of solid fuels mainly grate firing and stationary fluidised bed combustion are applied.

- Non-industrial combustion:
  Non-industrial combustion which includes other small consumers and residential combustion, is characterised by a great variety of combustion techniques.

  For the combustion of solid fuels e.g. mainly grate firing units are installed which can be distinguished by the type of stoking and the air supply. For example, in manually fed combustion units (such as single stoves) emissions mainly result from frequent start-ups/shut-downs; automatically fed combustion units are mainly emission relevant when the fuel is kept glowing. Normally, older combustion installations release more emissions than modern combustion installations. Furthermore, combustion installations which often operate with reduced load conditions are highly emission relevant: this operation mode occurs frequently in the case of over-dimensioned combustion units. /4, 5/

  For the combustion of liquid and gaseous fuels, in principle similar technologies are applied, such as those described in chapter B111 on "Combustion Plants as Point Sources" (Section 3.3).

3.4 Emissions

Relevant pollutants are sulphur oxides (SO_x), nitrogen oxides (NO_x), carbon dioxide (CO_2), carbon monoxide (CO), non-methane volatile organic compounds (NMVOC), methane (CH_4) and heavy metals (arsenic (As), cadmium (Cd), chromium (Cr), copper (Cu), mercury (Hg), nickel (Ni), lead (Pb), selenium (Se), zinc (Zn) and in the case of heavy oil also vanadium (V)). Emissions of nitrous oxide (N_2O) and ammonia (NH_3) are normally of less importance.

The main influencing parameters which determine the emissions and species profiles of some pollutants are given in Sections 3.4 and 9 of chapter B111 on "Combustion Plants as Point Sources". In particular for small combustion installations (e.g. residential combustion) emissions of NMVOC and CO can occur in considerable amounts; these emissions are mostly released from inefficiently working stoves (e.g. wood-burning stoves). VOC emissions released from domestic wood-fired boilers (0.5 - 10 MW) can be significant. Emissions can be up to ten times higher at 20 % load than those at maximum load /29/.

The emissions are released through the stack. The relevance of fugitive emissions (from seals etc.) can be neglected for combustion installations. Due to the fact that most references do not clearly distinguish between SO_x and SO_2, for the following sections it can be assumed that SO_2 includes SO_3, if not stated otherwise.

3.5 Controls

3.5.1 Medium-sized combustion plants - boilers, gas turbines, stationary engines - (thermal capacity ≥ 50 and < 300 MW)

It can be assumed, that the smaller the combustion installation considered are, the lower is the probability to be equipped with secondary measures. For cases where abatement technologies for SO_2, NO_x or heavy metals (controlled as particulates) are installed, the corresponding technical details are given in Section 3.5 of chapter B111 on "Combustion Plants as Point Sources". For SO_2 abatement in Germany, larger boilers are mainly controlled by the limestone wet scrubbing process. In the case of smaller facilities dry sorption processes are preferred.

3.5.2 Small-sized combustion plants - boilers and furnaces - (thermal capacity < 50 MW)

Small-sized combustion plants have been split into industrial combustion and non-industrial combustion:

- Industrial combustion:

  For cases where abatement technologies for SO_2, NO_x or heavy metals are installed the corresponding technical details are given in Section 3.5 of chapter B111 on "Combustion Plants as Point Sources". If NO_x reduction measures are installed mostly primary reduction measures (e.g. low NO_x burner) are applied.
- Non-industrial combustion:
  For small consumers / residential combustion only primary emission control measures are relevant. Emission reduction is mainly achieved by optimised operation conditions (older installations) and improved combustion efficiencies (modern installations).

4 SIMPLER METHODOLOGY

For combustion plants treated as area sources only a simpler methodology is given; a detailed methodology is not applicable (see Section 5). Here "simpler methodology" refers to the calculation of emissions based on emission factors and activities and covers all relevant pollutants (SO_2, NO_x, NMVOC, CH_4, CO, CO_2, N_2O, heavy metals). Emissions of NH_3 are of less relevance (they are only released as ammonia slip in connection with secondary measures for NO_x abatement).

The annual emission E is determined by an activity A and an emission factor:

$$E_i = EF_i \cdot A \qquad (1)$$

E_i annual emission of pollutant i
EF_i emission factor of pollutant i
A annual activity rate

The activity rate A and the emission factor EF_i have to be determined on the same level of aggregation depending on the availability of data. The activity A should be determined within the considered territorial unit by using adequate statistics (see also Section 6). The activity should refer to the energy input of the emission sources considered (fuel consumption in [GJ]). Alternatively, secondary statistics (surrogate data) can be used for the determination of the fuel consumption [GJ]. The quality of surrogate data can be characterised by two criteria:

- level of correlation
  The surrogate data should be directly related to the required data (e.g. fuel consumption of households derived from heat demand of households).

- level of aggregation
  The surrogate data should be provided on the same level of aggregation (e.g. spatial, sectoral and seasonal resolution).

Examples for activity rate and surrogate data and origins of possible inaccuracies are listed in the following:

- annual fuel consumption (recommended activity rate):
  - Statistics concerning the annual fuel consumption are often not further specified for different economic branches, and emission source categories, respectively. Furthermore, no technical split can be provided.

- annual fuel production [Gg], e.g. production of hard coal, lignite, natural gas:
  - The specifications of the fuel used (e.g. different types of coal) are not given. For the conversion of the unit [Gg] into unit [GJ] only an average heating value can be used.

- density of population, number of households:
  - Population statistics correspond to a very high level of aggregation. Further information has to be used (e.g. percentages of fuel consumed) in order to determine the activity rate for small consumers (e.g. residential combustion). In particular for fuels which are distributed by pipelines (e.g. natural gas) this assessment leads to an uncertainty in the activity rate determined.

- number of enterprises, number of employees, turnover of enterprises [Mio ECU]:
  - The statistical data on enterprise level are often allocated to the economic sector (e.g. “Production and Distribution of Electric Power, Production and Distribution of Steam, Hot Water, Compressed Air, District Heating Plants” /EUROSTAT, see Section 6/). On the other hand, emission factors are specified with regard to the type of fuel and often also to the type of boiler used.

- heat consumption:
  - The specific heat consumption per capita (e.g. [J/employee], [J/inhabitant]) or related to the area heated (e.g. [J/building], [J/m²]) can be determined by using area and branch specific data (e.g. differentiation between branches, number of employees, number of inhabitants).

The emission factor EF_i should be calculated as a mean value of all combustion installations within the territorial unit considered. In practice, a limited number of installations are selected to determine a representative emission factor which is applied to the total population of the installations considered. Usually, such emission factors are only specified as a function of fuel characteristics. However, further parameters should be taken into account, in particular the technology distribution as well as the size and age distribution of the boilers. Furthermore, evidence has been given that emissions are significantly affected by the operating conditions (e.g. inefficiently working stoves).

The emission factor EF_i (see Equation (1)) takes into account abatement measures (primary and secondary). If not stated otherwise the emission factors presented refer to full load conditions.

In the following a calculation procedure for SO_2 emission factors is proposed according to Equation (2):

$$EF_{SO_2} = 2 \cdot \overline{C}_{S_{fuel}} \cdot (1 - \overline{\alpha}_s) \cdot \frac{1}{\overline{H}_u} \cdot 10^6 \qquad (2)$$

EF_{SO_2}	emission factor for SO_2 [g/GJ]
$\overline{C}_{S_{fuel}}$	average sulphur content of fuel (in mass S/mass fuel [kg/kg])
$\overline{H}_u$	average lower heating value [Mg/kg]
$\overline{\alpha}_s$	average sulphur retention in ash [ ]

In cases where secondary reduction measures are installed, the reduction efficiency has to be integrated by applying one of the following assumptions:

- if the total population of combustion installations is equipped with secondary measures, a mean reduction efficiency of these measures should be used;
- if only few combustion installations are equipped with secondary measures, either these installations should be treated separately or the mean reduction efficiency should be calculated with regard to the total population.

Reduction efficiencies for different individual secondary measures are given in Tables 10 and 11 in chapter B111 on “Combustion Plants as Point Sources”.

Equation (2) can be used for all fuels, but for liquid and gaseous fuels the sulphur retention in ash α_s is not relevant. If certain input data of Equation (2) are not available, provided default values based on literature data can be used:

$\overline{C}_{S_{fuel}}$	sulphur contents of different fuels see Table 4[2] (in Section 8),
$\overline{\alpha}_S$	sulphur retention in ash of different types of boiler see Table 8[2] in chapter B111 on “Combustion Plants as Point Sources“,
$\overline{H}_u$	lower heating values of different types of fuels see Table 21[2] in chapter B111 on “Combustion Plants as Point Sources“.

For other pollutants, according to Equation (1) fuel and technology specific emission factors EF_i are given in Tables 5 - 12 based on literature data; for activity data see Section 6.

5 DETAILED METHODOLOGY

For combustion plants a detailed methodology means the determination of emissions based on measured data. This is not applicable to area sources as only few emission sources are monitored directly.

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[2] A mean value has to be calcutated with regard to the area concerned.

6 RELEVANT ACTIVITY STATISTICS

The following gives a list of available statistics on a national level for the determination of fuel consumption, installed capacities, socio-economic data, etc.:

- Office for Official Publication of the European Communities (ed.): Annual Statistics 1990; Luxembourg; 1992
- Statistical Office of the European Communities (EUROSTAT) (ed.): CRONOS Databank; 1993
- OECD (ed.): Environmental Data, Données OCDE sur l'environnement; Compendium; 1993
- Commission of the European Communities (ed.): Energy in Europe; 1993 - Annual Energy Review; Special Issue; Brussels; 1994
- EUROSTAT (ed.): Panorama of EU Industry'94; Office for official publications of the European Communities; Luxembourg; 1994

A brief discussion of potential surrogate data for the determination of the activity rate is given in Section 4.

7 POINT SOURCE CRITERIA

This section is not relevant since this chapter only covers area sources.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Medium-sized combustion plants (thermal capacity ≥ 50 and < 300 MW)

For medium combustion installations, emission factors for the pollutants NO_x, NMVOC, CH_4, CO, CO_2, N_2O and heavy metals are given in Tables 24 - 31 in chapter B111 on "Combustion Plants as Point Sources".

8.2 Small-sized combustion plants (thermal capacity < 50 MW)

Tables 4 - 12 contain emission factors for all pollutants except for SO_2 where sulphur contents of different fuels are given. All emission factor tables have been designed in a homogeneous structure: Table 3 provides a split of combustion techniques (types of boilers, etc.); this standard table has been used for all pollutants. The selection of fuels is based on the CORINAIR90 inventory.

For small-sized combustion installations, emission factors are given related to the type of fuel consumed and, if useful, related to technical specifications based on literature data. These emission factors normally refer to stationary operating conditions. Modifications are indicated as footnotes (instationary conditions e.g. due to manually fed boilers, etc.).

The sequence of the following emission factor tables is:

Table 3: Standard table for emission factors for different pollutants

Table 4: Sulphur contents of selected fuels

Table 5: NO_x emission factors [g/GJ]

Table 6: NMVOC emission factors [g/GJ]

Table 7: CH_4 emission factors [g/GJ]

Table 8: CO emission factors [g/GJ]

Table 9: CO_2 emission factors [kg/GJ]

Table 10: N_2O emission factors [g/GJ]

Table 11: NH_3 emission factors [g/GJ]

Table 12: Heavy metal emission factors (mass pollutant/mass fuel [g/Mg])

Table 3: Standard table of emission factors for the relevant pollutants

Fuel category[1]				NAPFUE code[1]	P1[2]	no technical specification	Technical specification									
							Industrial combustion							Non-industrial combustion		
							no specification[10]	DBB[3]	WBB[4]	FBC[5]	GF[6]	GT[7]	Stat. E.[8]	no specification	Small consumers	Residential combustion[9]
s	coal		no specification	-												
s	coal	hc[11]		101 - 103												
s	coal	bc[11]		106												
...	...	...	...	...												
s	biomass		wood	111												
...	...		...	...												
s	waste		municipal	114												
...	...		...	...												
l	oil		no specification	-												
l	oil		residual	201												
...	...		...	...												
g	gas		no specification	-												
g	gas		natural	301												
...	...		...	...												

[1] the fuel category is based on the NAPFUE-code

[2] P1 = sulphur content of fuel

[3] DBB = Dry bottom boiler

[4] WBB = Wet bottom boiler

[5] FBC = Fluidised bed combustion

[6] GF = Grate firing; ST1, ST2 = Type of stoker

[7] GT = Gas turbine

[8] Stat. E. = Stationary engine

[9] A differentiation between old and modern techniques can be made for the ranges of emission factors given so that e.g. the smaller values relate to modern units.

[10] Here only related to combustion in boilers; gas turbines and stationary engines are excluded.

[11] hc = hard coal, bc = brown coal

Table 4: Sulphur contents of selected fuels

Fuel category				NAPFUE code	Sulphur content of fuel	
					range	unit
s	coal	hc	coking, steam, sub-bituminous	101 - 103	0.4 - 6.2	wt.-% (maf)
s	coal	bc	brown coal/lignite	105	0.4 - 6.2	wt.-% (maf)
s	coal	bc	briquettes	106		
s	coke	hc, bc	coke oven, petroleum	107, 108, 110	0.5 - 1 [1][2]	wt.-% (maf)
s	biomass		wood	111	< 0.03[1]	wt.-% (maf)
s	biomass		peat	113		
s	waste		municipal	114		
s	waste		industrial	115		
l	oil		residual	203	0.3[3] - 3.5[4]	wt.-%
l	oil		gas	204	0.08 - 1.0	wt.-%
l	oil		diesel	205		
l	kerosene			206		
l	gasoline		motor	208	< 0.05[5]	wt.-%
g	gas		natural	301		
g	gas		liquified petroleum gas	303		
g	gas		coke oven	304		
g	gas		blast furnace	305		
g	gas		refinery	308	<= 8[6]	$g \cdot m^{-3}$
g	gas		gas works	311		

[1] Marutzky 1989 /25/

[2] Boelitz 1993 /24/

[3] Personal communication Mr. Hietamäki (Finland)

[4] Referring to NL-handbook 1988 /26/ the range is 2.0 - 3.5

[5] $\alpha_S = 0$

[6] NL-handbook 1988 /26/

Table 5: NO_x emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion							Non-industrial combustion		
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											60-232***
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	50 - 668[11]	155[13]							50[1,2]	150[9]	50[9]
s	coal	bc	brown coal/lignite	105	7.5 - 604[11]								12[2] - 100[1]		
s	coal	bc	briquettes	106	17 - 300[11]										100[9]
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	13 - 323[11]								45	50[9,10]	50[9,10]
s	biomass		wood	111	130 - 968[11]	206[13]				100-300*, 30-120**			12 - 80[1]	75[9]	50[9], 147-200[4]
s	biomass		peat	113	130 - 240[11]								100[1]		
s	waste		municipal	114	140 - 280[11]										
s	waste		industrial	115	100 - 193[11]										
s	waste		wood	116	80 - 258[11]										
s	waste		agricultural	117	80 - 100[11]										
l	oil		no specification	-									50[2]		
l	oil		residual	203	98 - 520[11]	165[13]					350[12]	75 - 1,889[12]			
l	oil		gas	204	55 - 1,624[11]	70[13]					100 - 531[12]	80 - 1,493[12]	50[1], 51[4]	48[9]	47[9]
l	oil		diesel	205	300 - 373[11]						380[12]	840[12],[13]			
l	kerosene			206	45 - 100[11]						120[12]	45 - 1,038[12]	50[1]		
l	gasoline		motor	208	80[11]							375[12]			
l	naphtha			210	24 - 1,085[11]										
g	gas		no specification	-									30[2]-50[3]		
g	gas		natural	301	32 - 307[11]	62[13]					81 - 360[12], 165[13,14]	75 - 1,200[12], 165[13]	50[1]	38[9]	30[8], 46[9]
g	gas		liquified petroleum gas	303	18 - 105[11]						120[12]		50[1],	57[9]	47[4], 69[9]
g	gas		coke oven	304	2 - 399[11]						250[12]		50[1]	38[9]	46[9]
g	gas		blast furnace	305	25 - 1,520[11]						250[12]				
g	gas		waste	307	52 - 238[11]										
g	gas		refinery	308	65 - 155[11]						55 - 357[12]				
g	gas		biogas	309	4 - 132[11]										
g	gas		from gas works	311	50 - 411[11]								50[1]		

[1] CORINAIR 1992 /8/

[2] LIS 1977 /15/

[3] UBA 1981 /21/, Kolar 1990 /14/

[4] Radian 1990 /18/, IPCC 1994 /12/

[11] CORINAIR90 data of combustion plants as area sources

[12] CORINAIR90 data, area sources

[13] UBA 1995 /30/

[14] at 50 % load: 130 g/GJ

[5] spruce wood

[6] chip board, phenol bonded

[7] chip board, urea bonded

[8] LIS 1987 /16/

[9] UBA 1995 /23/

[10] coke from hard coal

* 100[3,5], 120[3,6], 300[3,7] for underfeed stoker

** 30[3,5], 80[3,6], 120[3,7] for overfeed stoker

*** 60[8], 149[4], 232[4]

Table 6: NMVOC emission factors [g/GJ]

						Technical specification									
						Industrial combustion							Non-industrial combustion		
Fuel category				NAPFUE code	no technical specification	no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	1-511[5]								400[1] - 600[2]		50[3]
s	coal	bc	brown coal/lignite	105	1-800[5]										
s	coal	bc	briquettes	106	1.5-700[5]								150[1] [2]		225[3]
s		hc,bc	coke oven, petroleum	107,108, 110	0.5-700[5]								12[2]		225[3] [4]
s	biomass		wood	111	7-1,000[5]								150[2] - 800[1]		480[3]
s	biomass		peat	113	3-600[5]								150[1]		
s	waste		municipal	114	9-70[5]										
s	waste		industrial	115	0.5-134[5]										
s	waste		wood	116	48-600[5]										
s	waste		agricultural	117	50-600[5]										
l	oil		no specification	-									15[2]		
l	oil		residual	203	2.1-34[5]						3 - 4[6]	1.4 - 103.7[6]			
l	oil		gas	204	1.5-116[5]						0.7 - 5[6]	1.5 - 250[6]	15[1]		1.5[3]
l	oil		diesel	205	1.5-2.5[5]						5[6]	3.5[6]			
l	kerosene			206	1-14[5]						1[6]	1.5 - 244[6]	15[1]		
l	gasoline		motor	208	2[5]							437[6]			
l	naphtha			210	1-5[5]										
g	gas		no specification	-									1.5[2]		
g	gas		natural	301	0.3-205[5]						0.1 - 5.7[6]	0.3 - 47[6]	10[1]		2.5[3]
g	gas		liquified petroleum gas	303	0.3-14[5]						1[6]				3.5[3]
g	gas		coke oven	304	0.3-12[5]						2[6]		25[1]		2.5[3]
g	gas		blast furnace	305	0.2-1.5[5]										
g	gas		waste	307	2-16[5]										
g	gas		refinery	308	0.3-2.5[5]						2[6]				
g	gas		biogas	309	2.4-10[5]										
g	gas		from gas works	311	0.6-10[5]								25[1]		

[1] CORINAIR 1992 /8/

[2] LIS 1977 /15/

[3] UBA 1995 /23/

[4] coke from hard coal

[5] CORINAIR90 data, combustion plants as area sources with a thermal capacity of > 300, 50 - 300, < 50 MW

[6] CORINAIR90 data, area sources

Table 7: CH_4 emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion							Non-industrial Combustion		
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	2 - 511$^{4)}$										450$^{2)}$
s	coal	bc	brown coal/lignite	105	0.2 - 532$^{4)}$										
s	coal	bc	briquettes	106	1 - 350$^{4)}$										225$^{2)}$
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	1.5 - 200$^{4)}$										225$^{2)\,3)}$
s	biomass		wood	111	21 - 601$^{4)}$										74-200$^{1)}$, 320$^{2)}$
s	biomass		peat	113	5 - 400$^{4)}$										
s	waste		municipal	114	6 - 32$^{4)}$										
s	waste		industrial	115	0.3 - 38$^{4)}$										
s	waste		wood	116	30 - 400$^{4)}$										
s	waste		agricultural	117	10 - 400$^{4)}$										
l	oil		no specification	-											
l	oil		residual	203	0.1 - 10$^{4)}$						1 - 3$^{5)}$	0,02 - 7,5$^{5)}$			
l	oil		gas	204	0.1 - 19$^{4)}$						1 - 20,9$^{5)}$	0,04 - 14$^{5)}$			3.5$^{2)}$, 5$^{1)}$
l	oil		diesel	205	1.5 - 2.5$^{4)}$							3,5$^{5)}$			
l	kerosene			206	0.02 - 7$^{4)}$						1$^{5)}$	0,02 - 7,4$^{5)}$			
l	gasoline		motor	208	1							49$^{5)}$			
l	naphtha			210	0.02 - 5$^{4)}$										
g	gas		no specification	-									1$^{1)}$		
g	gas		natural	301	0.3 - 205$^{4)}$						0,3 - 22,5$^{5)}$	0,02 - 153$^{5)}$			2.5$^{2)}$
g	gas		liquified petroleum gas	303	0.02 - 6$^{4)}$						1$^{5)}$				1.1$^{1)}$, 1.5$^{2)}$
g	gas		coke oven	304	0.02 - 12$^{4)}$						2$^{5)}$				2.5$^{2)}$
g	gas		blast furnace	305	0.02 - 4$^{4)}$										
g	gas		waste	307	0.4 - 2.5$^{4)}$										
g	gas		refinery	308	0.02 - 2.5$^{4)}$						2$^{5)}$				
g	gas		biogas	309	0.4 - 10$^{4)}$										
g	gas		from gas works	311	0.6 - 10$^{4)}$										

1) Radian 1990 /18/, IPCC 1994 /12/

2) UBA 1995 /23/

3) coke from hard coal

4) CORINAIR90 data, combustion plants as area sources with a thermal capacity of > 300, 50 - 300, < 50 MW

5) CORINAIR90 data, area sources

Table 8: CO emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification										
						Industrial combustion						Non-industrial Combustion				
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-						178-196*, 100[2]-107[6]			185[5]		160-3,580**
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	9 - 5,000[11]	73[13]								500[9]	4,800[9]
s	coal	bc	brown coal/lignite	105	4 - 6,000[11]										
s	coal	bc	briquettes	106	11 - 5,200[11]								7,000[7]		4,300[9]
s	coke	hc,bc	coke oven, petroleum		2 - 5,500[11]									1,000[9][10]	4,800[9][10]
s	biomass		wood	111	82 - 10,000[11]	627[13]							7,000[7]	3,600[9]	5,790[9]
s	biomass		peat	113	65 - 10,000[11]										18-18,533***
s	waste		municipal	114	33 - 2,188[11]										
s	waste		industrial	115	15 - 510[11]										
s	waste		wood	116	61 - 8,500[11]										
s	waste		agricultural	117	200 - 8,500[11]										
l	oil		no specification	-									70[8]		
l	oil		residual	203	29 - 1,754[11]	10[13]					10 - 30.4[12]	11.7 - 438[12]	20[2]		13[4]
l	oil		gas	204	5.3 - 547[11]	10[13]					10 - 123[12]	12 - 691[12]		41[9]	43[9]
l	oil		diesel	205	12 - 547[11]						12[12]	190[12],[13]			
l	kerosene			206	3 - 151[11]						12[12]	3.4 - 669[12]			
l	gasoline		motor	208	12[11]										
l	naphtha			210	0.2 - 89[11]										
g	gas		no specification	-									70[8]		10[4]
g	gas		natural	301	2.4 - 500[11]	10[13]					8-123[12], 10[13][14]	2.4-335[12], 136[13]	252)	41[9]	25-250***
g	gas		liquified petroleum gas	303	3.3 - 250[11]									41[9]	10[4], 53[9]
g	gas		coke oven	304	3.3 - 279[11]						13[12]			41[9]	53[9]
g	gas		blast furnace	305	3 - 279[11]						13[12]				
g	gas		waste	307	8.8 - 27[11]										
g	gas		refinery	308	3.3 - 279[11]						2[12]				
g	gas		biogas	309	7.8 - 41[11]										
g	gas		from gas works	311	6.4 - 225[11]										

[1] EPA 1987 /10/, CORINAIR 1992 /8/

[2] CORINAIR 1992 /8/ for overfed stoker

[3] OECD 1989 /31/, CORINAIR 1992 /8/

[4] Radian 1990 /18/, IPCC 1994 /12/

[5] EPA 1987 /10/, CORINAIR 1992 /8/

[6] EPA 1985 /9/, CORINAIR 1992 /8/ for overfeed stoker

[7] LIS 1987 /16/

[8] LIS 1977 /15/

[9] UBA 1995 /23/

[10] coke from hard coal

[11] CORINAIR90 data, combustion plants as area sources with a thermal capacity of > 300, 50 - 300, < 50 MW

[12] CORINAIR90 data, area sources

[13] UBA 1995 /30/

[14] at 50 % load: 76 g/GJ

* 178[1], 190[2], 196[3] for underfeed stoker

**160[3], 484[4], 1,500[5], 1,607[6], 2,000[2], 3,400[3], 3,580[4]

*** 18[4], 53[9],4,949[4], 6,002[4], 18,533[4]

**** 25[2], 200[2], 250[2] (cooker)

Table 9: CO_2 emission factors [kg/GJ]

Fuel category				NAPFUE code	Emission factors		
					value	range	remarks
s	coal		no specification	-			
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	94[6]	93 - 99[5], 55.9 - 106.8[2]	
s	coal	bc	brown coal/lignite	105		74 - 105.5[5], 67.5 - 116[2]	
s	coal	bc	briquettes	106	97[6]	97 - 113[3], 85.6 - 110.9[2]	
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	105[6]	96 - 122[1][4], 85.6 - 151[2]	
s	biomass		wood	111		100 - 125[1] [4], 83 - 322.6[2]	
s	biomass		peat	113		98 - 115[2]	
s	waste		municipal	114		109 - 141[1], 15 - 117[2]	
s	waste		industrial	115		20 - 153.3[2]	
s	waste		wood	116		83 - 92[2]	
s	waste		agricultural	117		69 - 100[2]	
l	oil		no specification	-			
l	oil		residual	203		76 - 78[3] [4], 64 - 99[2]	
l	oil		gas	204	74[6]	73 - 74[5], 69 - 97[2]	
l	oil		diesel	205		73 - 74[2] [4]	
l	kerosene			206	73[5]	67.7 - 78.6[2]	
l	gasoline		motor	208	71[2], 73[5]	71 - 74[1][3][4]	
l	naphtha			210	73[3]	72.1 - 74[2]	
g	gas		no specification	-			
g	gas		natural	301	56[6]	55 - 61[3] [4] [5], 52 - 72[2]	
g	gas		liquified petroleum gas	303	65[6]	55 - 75.5[2]	
g	gas		coke oven	304	44[6], 49[5]	44 - 192[2]	
g	gas		blast furnace	305		105 - 290[2]	
g	gas		waste	307		62.5 - 87.1[2]	
g	gas		refinery	308		55 - 66[2]	
g	gas		biogas	309		60 - 103.4[2]	
g	gas		from gas works	311		52 - 56[2]	

[1] Schenkel 1990 /20/

[2] CORINAIR90 data, combustion plants as area sources with a thermal capacity of > 300, 50 - 300, < 50 MW

[3] IPCC 1993 /11/

[4] Kamm 1993 /13/

[5] BMU 1994 /7/

[6] UBA 1995 /30/

Table 10: N_2O emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification									
						Industrial combustion							Non-industrial combustion		
						no specification	DBB	WBB	FBC	GF	GT	Stat. E.	no specification	Small consumers	Residential combustion
s	coal		no specification	-											
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	5 - 30[1]										
s	coal	bc	brown coal/lignite	105	1.4 - 18.2[1]										
s	coal	bc	briquettes	106	1.4 - 14[1]										
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	1.4 - 14[1]										
s	biomass		wood	111	1.6 - 20[1]										
s	biomass		peat	113	2 - 14[1]										
s	waste		municipal	114	4[1]										
s	waste		industrial	115	2 - 5.9[1]										
s	waste		wood	116	4[1]										
s	waste		agricultural	117	1.4 - 4[1]										
l	oil		no specification	-											
l	oil		residual	203	0.8 - 46.5[1]						2.5 - 25[2]	1.1 - 2.1[2]			
l	oil		gas	204	0.6 - 17.8[1]						0.5 - 25[2]	0.6 - 14[2]			
l	oil		diesel	205	2 - 15.7[1]						15.7[2]	2 - 4[2]			
l	kerosene			206	2 - 14[1]						14[2]	2[2]			
l	gasoline		motor	208	14[1]							2[2]			
l	naphtha			210	12[1]										
g	gas		no specification	-											
g	gas		natural	301	0.1 - 14[1]						0.1-3[2]	0.1-3[2]			
g	gas		liquified petroleum gas	303	1 - 14[1]						14[2]				
g	gas		coke oven	304	1 - 12[1]						3[2]				
g	gas		blast furnace	305	0.8 - 34.6[1]						3[2]				
g	gas		waste	307	3.7 - 5[1]										
g	gas		refinery	308	1.5[1]						3[2]				
g	gas		biogas	309	1.5 - 3.7[1]										
g	gas		from gas works	311	2 - 3[1]										

[1] CORINAIR90 data, combustion plants as area sources with a thermal capacity of > 300, 50 - 300, < 50 MW

[2] CORINAIR90 data, area sources

Table 11: NH$_3$ emission factors [g/GJ]

Fuel category				NAPFUE code	no technical specification	Technical specification	
						Gas turbines	Stationary engines
s	coal		no specification	-			
s	coal	hc	coking, steam, sub-bituminous	101, 102, 103	0.14 - 0.48[1]		
s	coal	bc	brown coal/lignite	105	0.01 - 0.86[1]		
s	coal	bc	briquettes	106	0.01 - 0.86[1]		
s	coke	hc,bc	coke oven, petroleum	107, 108, 110	0.01 - 0.86[1]		
s	biomass		wood	111	5 - 9[1]		
s	biomass		peat	113			
s	waste		municipal	114			
s	waste		industrial	115			
s	waste		wood	116			
s	waste		agricultural	117			
l	oil		no specification	-			
l	oil		residual	203	0.01[1]		
l	oil		gas	204	0.01 - 2.68[1]		0.1 - 0.2[1]
l	oil		diesel	205			
l	kerosene			206			0.2[1]
l	gasoline		motor	208			
l	naphtha			210			
g	gas		no specification	-			
g	gas		natural	301	0.15 - 1[1]		
g	gas		liquified petroleum gas	303	0.01[1]		
g	gas		coke oven	304	0.87[1]		
g	gas		blast furnace	305			
g	gas		waste	307			
g	gas		refinery	308			
g	gas		biogas	309	15[1]		
g	gas		from gas works	311			

[1] CORINAIR90 data, combustion plants as area sources with a thermal capacity of > 300, 50 - 300, < 50 MW

Table 12: Heavy metal emission factors (mass pollutant/mass fuel [g/Mg])

Fuel category			NAPFUE code	Heavy metal element	no technical specification	Technical specification							
						Industrial combustion					Non-industrial combustion		
						no specification	DBB	WBB	FBC	GF	no specification	Small consumer	Residential combustion
s	coal	hc	101/102	Mercury		1.7 g/TJ 2)							0.3 1)
				Cadmium		0.1 g/TJ 2)							0.15 1)
				Lead		6.0 g/TJ 2)							2.5 1)
				Copper		3.1 g/TJ 2)							1.2 1)
				Zinc		10.5 g/TJ 2)							1 1)
				Arsenic		3.2 g/TJ 2)							1.2 1)
				Chromium		2.3 g/TJ 2)							0.9 1)
				Selen		0.5 g/TJ 2)							0.15 1)
				Nickel		4.4 g/TJ 2)							1.8 1)
s	coal	bc	105	Mercury		4.4 g/TJ 2)							0.1 2)
				Cadmium		0.4 g/TJ 2)							0. 04 2)
				Lead		3.9 g/TJ 2)							0.24 2)
				Copper		2.0 g/TJ 2)							
				Zinc		10.6 g/TJ 2)							0.14 2)
				Arsenic		4.2 g/TJ 2)							
				Chromium		3.1 g/TJ 2)							
				Selen									
				Nickel		3.9 g/TJ 2)							
l	oil, heavy fuel		203	Mercury		0.15-0.2 1)							
				Cadmium		0.1-1 1)							
				Lead		0.6-1.3 1)							
				Copper		0.05-1 1)							
				Zinc		0.02-0.2 1)							
				Arsenic		0.14-1 1)							
				Chromium		0.2-2.5 1)							
				Selen		0.003-1 1)							
				Nickel		17-35 1)							
g	gas		301	Mercury									

1) Winiwarter 1995 /6/ 2) Jockel 1995 /1/

9 SPECIES PROFILES

For species profiles of selected pollutants see Section 9 in chapter B111 on “Combustion Plants as Point Sources”.

10 UNCERTAINTY ESTIMATES

Uncertainties of emission data result from inappropriate emission factors and from missing statistical information on the emission generating activity. Those discussed here are related to emission factors. Usually uncertainties associated with emission factors can be assessed by comparing them with emission factors obtained by using measured data or other literature data. However, at this stage, the available emission factors based on literature data are often poorly documented without a specification concerning the area of application. A range of emission factors, depending on the parameters available (as given in chapter B111 on “Combustion Plants as Point Sources“, Section 10), can therefore not be given here.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Weakest aspects discussed here are related to emission factors.

The average emission factor of a territorial unit should integrate the diversity of the combustion techniques installed within the territorial unit. Therefore, the number and diversity of the selected combustion installations for the calculation of the average emission factor should correspond with the number and diversity of the installations within the territorial unit (target population). Further work should be carried out to characterise territorial units with regard to the technologies in place (technology distribution, age distribution of combustion technique, etc.).

For all pollutants considered, neither qualitative nor quantitative load dependencies have yet been integrated into the emission factors. In particular for oil, coal and wood fired small stoves, increased emissions occur due to a high number of start-ups per year (e.g. up to 1,000 times a year) or due to load variations (e.g. manual furnace charging). Emissions from residential firing can be highly relevant (e.g. combustion of wood in the Nordic countries, in particular for VOC and CO emissions). Further work should be invested to clarify this influence with respect to the emission factors published.

For the weakest aspects related to the determination of activities based on surrogate data see Section 4. Uncertainty estimates of activity data should take into account the quality of available statistics. In particular, emissions from the combustion of wood in single stoves may increase as some national statistics have underestimated wood consumption to date /3/.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

Spatial disaggregation of annual emission data (top-down approach) can be related

- for industrial combustion e.g. to the number of industrial employees in industrial areas and
- for residential combustion e.g. to the number of inhabitants in high density and low density areas and to the type of fuel.

In general the following disaggregation steps for emissions released from residential combustion can be used /cf. 27/:

- differentiation in spatial areas, e.g. administrative units (country, province, district, etc.), inhabited areas, settlement areas (divided in high and low density settlements),
- determination of regional emission factor per capita depending on the population density and the type of fuel used.

For emissions released from industrial combustion, spatial disaggregation takes into account the following steps:

- differentiation in spatial areas with regard to industrial areas,
- determination of emission factors related to the number of industrial employees.

13 TEMPORAL DISAGGREGATION CRITERIA

Temporal disaggregation of annual emission data (top-down approach) provides a split into monthly, weekly, daily and/or hourly emission data. For annual emissions released from combustion plants as area sources this data can be obtained for:

- industrial combustion by using in principle the disaggregation criteria and the procedure as described in Section 13 of chapter B111 on “Combustion Plants as Point Sources” by taking into account the number of plants in the area considered.
- non-industrial combustion (small consumer/residential combustion) by using a relation between the consumption of fuel and the heating degree-days.

The disaggregation of annual emissions released from non-industrial combustion (small consumers/residential combustion) has to take into account a split into:

- summer and winter time (heating periods),
- working days and holidays and
- daily fluctuations of load

for the main relevant fuels and, if possible, for the main relevant combustion techniques (manually fed stoves, etc.)

The procedure of disaggregation consists of the following step-by-step approach /cf. 28/:

- determination of the temporal variation of the heat consumption (based e.g. on user behaviour),

- determination of the fuel consumption e.g. by using statistics for district heat or consumption of gas, by using fuel balances for the estimation of coal and wood consumption (e.g. as given in /3/),
- correlation of the heating degree-days with the consumption of fuel (e.g. for gas, district heat). Typical heating degree-days are available in statistics. The correlation can be linear as given e.g. in /28/.
- determination of the relative activity (e.g. fuel consumption per hour per day) by using adequate statistics.

This approach makes it possible to determine annual, weekly and/or daily correction factors. For the determination of hourly emissions the following Equation (3) /cf. 28/ can be given as an example:

$$E_H(t) = \frac{E_A}{8{,}760\left[h\right]} \cdot f_a(t) \cdot f_w(t) \cdot f_d(t) \qquad (3)$$

E_H	emission per hour(s) [Mg/h]
E_A	annual emission [Mg]
f_a	annual correction factor [ ]
f_w	weekly correction factor [ ]
f_d	daily correction factor [ ]
t	time

The constant (8,760 h) in Equation (3) represents the number of hours per year.

14 ADDITIONAL COMMENTS

15 SUPPLEMENTARY DOCUMENTS

16 VERIFICATION PROCEDURES

As outlined in chapter B111 on ”Concepts for Emission Inventory Verification“ different verification procedures can be used. The aim of this section is to select those which are most adequate for emission data from combustion plants as area sources. Verification procedures considered here are principally based on the verification of emission data on a territorial unit level (national level).

The annual emissions related to a territorial unit can be compared to independently derived emission estimates. These independent emission estimates can be obtained by using econometric relations between annual emissions and exogenous variables, such as population equivalents, number of households, fossil fuel prices, etc.

Another possibility is to make emission density comparisons of e.g. emissions per capita or emissions per GDP between countries with comparable economic structures.

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19 RELEASE VERSION, DATE AND SOURCE

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Source : Otto Rentz; Dagmar Oertel
University of Karlsruhe (TH)
Germany

Updated with particulate matter details by:
Mike Woodfield
AEA Technology
UK
December 2006

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Annex 1: List of abbreviations

A_i	Activity rate of the emission source i
bc	Brown coal
CCGT	Combined Cycle Gas Turbine
CFBC	Circulating Fluidised Bed Combustion
DBB	Dry Bottom Boiler
E	Emission
EF_i	Emission factor of the emission source i, e.g. in [g/GJ]
f_a	Annual correction factor [ ]
f_d	Daily correction factor [ ]
f_w	Weekly correction factor [ ]
FBC	Fluidised Bed Combustion
g	Gaseous state of aggregation
GF	Grate Firing
GT	Gas Turbine
H	Lower heating value of fuel
hc	Hard coal
IGCC	Integrated Coal Gasification Combined Cycle Gas Turbine
l	Liquid state of aggregation
PFBC	Pressurised Fluidised Bed Combustion
s	Solid state of aggregation
S	Sulphur content of fuel
Stat. E.	Stationary Engine
t	Time
WBB	Wet Bottom Boiler

SNAP CODE:	**010104** **010204** **010304** **010404** **010504** **020104** **020203** **020303** **030104**

SOURCE ACTIVITY TITLE: **COMBUSTION IN ENERGY &TRANSFORMATION INDUSTRIES**
Gas Turbines

NOSE CODE:	**101.04**
NFR CODE:	**1 A 1 a** **1 A 1 b** **1 A 1 c** **1 A 2 a-f** **1 A 4 a** **1 A 4 b i** **1 A 4 c i**

The emission factors for these activities are actually contained in Chapters B111 and B112.

For particulate matter emissions please see chapter B111 (S3) Particulate emissions from gas turbines and internal combustion engines[1].

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Date: September 2006

Source: Carlo Trozzi
Techne Consulting
Italy

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[1] Updated with particulate matter details by: Mike Woodfield, AEA Technology, UK, December 2006

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SNAP CODE:	**010302** **010303** **010305**
SOURCE ACTIVITY TITLE:	**PETROLEUM AND/OR GAS REFINING PLANTS** ***Combustion Plants >= 50 and < 300 MW (boilers)*** ***Combustion Plants < 50 MW (boilers)*** ***Stationary Engines***
NOSE CODE:	**101.02** **101.03** **101.05**
NFR CODE:	**1 A 1 b**

The emission factors for these activities are actually contained in Chapters B111 and B112.

(These activities are not believed to be a significant source of $PM_{2.5}$ (as of December 2006)).[1]

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Email: carlo.trozzi@techne-consulting.com

SNAP CODE: **010306**

SOURCE ACTIVITY TITLE: **PETROLEUM AND/OR GAS REFINING PLANTS**
Process Furnaces

NOSE CODE: **104.08.03**

NFR CODE: **1 A 1 b**

1 ACTIVITIES INCLUDED

This chapter covers emissions released from combustion processes within a refinery for the heating of crude and petroleum products without contact between flame and products. Primary reduction measures are taken into account (if installed). The emission generating process is the combustion of heavy fuel oil, refinery gas and/or petroleum coke. Thermal cracking units are also taken into account.

The following activities are excluded: power plants installed within a refinery (producing steam and/or electricity) as well as internal combustion engines and gas turbines are considered in chapters B111 on “Combustion Plants as Point Sources” and B112 on “Combustion Plants as Area Sources”; fluid catalytic cracking/CO boilers are treated under SNAP 040102; sulphur recovery plants are covered by SNAP 040103; flaring in the oil industry is treated under SNAP 090204 (waste treatment and disposal). Process specific emissions from refineries are covered by SNAP 040104 “Storage and Handling of Petroleum Products in a Refinery”.

2 CONTRIBUTION TO TOTAL EMISSIONS

The contribution of emissions released from refinery process furnaces to the total emissions in countries of the CORINAIR90 inventory is given as follows:

Table 1: Contribution to total emissions of the CORINAIR90 inventory (*28 countries*)

Source-activity	**SNAP-code †**	**Contribution to total emissions [%]**								
		SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3	PM*
Process Furnaces without Contact	010306	1.4	0.5	0.2	0	0.1	1.0	0.2	-	-

0 = emissions are reported, but the exact value is below the rounding limit (0.1 per cent)
- = no emissions are reported
† = SNAP90 code 030201
* = PM (inclusive of TSP, PM_{10} and $PM_{2.5}$) is <0.1% of total PM emissions

In a modern refinery up to 80 %, in some cases even 90 %, of all SO_2 emissions and also a major part of the NO_x emissions and particulate emissions (combined with heavy metals) of the refinery are dependent or directly related to the types of fuel used and their respective shares of the total fuel consumption of the refinery /14/. A split of total refinery emissions can be given as an example for SO_2 and NO_x emissions (Western Europe) /cf. 1, 9/:

SO_2:	- Process heaters and boilers:	69 %	of total SO_2 emissions from refineries
	- FCC units (CO boilers):	7 %	”
	- sulphur recovery unit:	10 %	”
	- flares:	9 %	”
	- other sources (e.g. gas turbines, stationary engines):	6 %	”

NO_x:	- process heaters:	46 %	of total NO_x emissions from refineries
	- boilers:	17 %	”
	- FCC units (CO boilers):	16 %	”
	- engines (for pumps etc.):	11 %	”
	- gas turbines and combined cycle systems:	10 %	“

Process heaters contribute about 40 % to the total refinery emissions of SO_2 and NO_x, whereas the contribution of refineries to the total anthropogenic emissions is about 1 % (average for SO_2 and NO_x).

3 GENERAL

3.1 Description

The most relevant emission sources within this sector are process heaters. In most refining processes it is necessary to apply heat to raise the temperature of the feedstock to a required temperature. Process heaters are therefore used, and where processes are self-contained each process usually has its own separate process heater.

3.2 Definitions

Cracking	one of the process steps within a refinery for splitting long-chain hydrocarbons into short-chain hydrocarbons. Two types of cracking can be distinguished: catalytic and thermal. Catalytic cracking (e.g. FCC) is the most common type of cracking implemented in refineries. Thermal cracking is of less importance with the exception of visbreaking (thermal cracking of high-boiling residues).

3.3 Techniques

Process heaters are installed as for example pipe still or pre-heaters; they are mostly located at the atmospheric distillation, before the vacuum distillation, before the visbreaker, before the

FCC units, before thermal cracking units[1], and before the sulphur recovery units. The burners are mostly situated at the bottom of the installations. Refineries can have about 4 up to more than 40 process heaters depending on the complexity of operations. The refinery gas, produced by petroleum processing, provides a significant part of the fuel for process heaters. Different processes contribute varying amounts and varying compositions to the refinery gas. However, major components of the gas are hydrogen and light hydrocarbons. In principle, refineries use gaseous fuels (refinery gas, sometimes also natural gas /14/), which are supplemented by liquid fuels (heavy fuel oil or other residues) and solid fuels (petroleum coke). In many applications, dual-fuel burners are used with gas and liquid fuel being consumed by the same burners. The columns can also be heated by using the process steam generated in boilers. The fuel used for steam generation may be different from commercial fuel as its nature is determined by the optimal use of resources within each refinery at a given time. /cf. 1, 3/.

3.4 Emissions

Relevant pollutants are sulphur oxides (SO_x), nitrogen oxides (NO_x) and carbon dioxide (CO_2). SO_3 emissions are negligible for all fuels used. For normal operating conditions emissions of carbon monoxide (CO), nitrous oxide (N_2O), and heavy metals are of less relevance. Emissions of volatile organic compounds (non-methane VOC and methane (CH_4)) can occur, but they are often negligible. Normally, emissions of ammonia (NH_3) are not relevant.

Emissions considered here are associated with continuous operation of the refinery. Emissions are released through stacks. Nevertheless, frequent start-ups and shut-downs of process heaters may occur, due to unexpected changes in operating conditions or from regular non-operating times (e.g. for maintenance).

The emissions of sulphur dioxide (SO_2) are directly related to the sulphur content of the fuel(s) used. The sulphur content of refinery gas varies from 0.01 to 5 %, averaging 0.8 % /2/. Refinery gases are produced in almost all hydrocarbon processing installations. They can be classified as sulphur-free gases and gases containing sulphur: /14/

- sources of sulphur-free gases: [2]
  - isomerisation plants, catalytic reforming plants, hydrogen manufacturing plants, gasification of coke in some coke operations,
- sources of sulphur-containing gases: [3]

---

[1] Thermal cracking units are of less importance within refineries, but they are commonly used in the petrol chemistry (e.g. olefin cracking units).

[2] As a consequence of the use of sulphur sensitive catalysts in isomerisation and catalytic reforming, these processes require virtually sulphur free feedstocks. As a result, the gas streams from these units are nearly sulphur free. The gases produced in hydrogen manufacturing plants and from gasification units can also be desulphurised. /cf. 14/

[3] Most other gases produced in the refinery contain hydrogen sulphide (H_2S) and often small quantities of mercaptans.

-- crude distillation, hydro-treating/hydro-desulphurisation, catalytic cracking, thermal cracking/coking/visbreaking, residue conversion, flare gas recovery[4], gasification of coke from some coke operations /14/ [5]

Liquid fuels used in a refinery originate from various processes (e.g. crude oil distillation, high vacuum distillation, thermal or catalytical cracking). In general, the liquid fuels comprise the following components: atmospheric and vacuum residues, thermally cracked residues, heavy catalytically cracked cycle oil and hydrocracked residues. Sulphur contents of liquid refinery fuels and/or components are given in Table 2. /14/

Table 2: Sulphur contents of liquid refinery fuels (cf. /14/)

Residue	**Sulphur content of residues [wt.-%] from**	
	Crude oil from North Sea	**Crude oil from Middle East**
Atmospheric residue	0.6 - 1.1	2.3 - 4.4
Vacuum residue	1.1 - 1.8	3.6 - 6.1
Cracked residue	n. d.	3.5 - 6.5

n. d. : no data are available

However, lower amounts of sulphur in liquid refinery fuels may occur (e.g. Swedish refineries use fuel oil with a sulphur content of 0.4 - 0.5 wt.-% /cf. 15/.). An average sulphur content of fuel oil used in refineries is given as 2.8 wt.-% in /cf. 2/. A weighted average sulphur content of the mix of refinery gas and heavy fuel oil can be given as 1.7 wt.-% /2/.

The sulphur content of the petroleum coke produced and consumed by refineries depends on the type of crude oil/fractions used. In practice, the sulphur content of coke varies between ca. 0.93 wt.-% sulphur (petroleum coke produced mostly from delayed coking process) and ca. 1.4 wt.-% sulphur (petroleum coke produced mostly from fluid coking process) /cf. 6/.

The formation of nitrogen oxides (NO_x) can be split into “fuel-NO”, “thermal-NO” and “prompt-NO” as discussed in chapter B111 on “Combustion Plants as Point Sources” (Section 3). Within the temperature range under consideration, the formation of “prompt-NO” can be neglected. “Fuel-NO” results from the oxidation of the fuel nitrogen content. For liquid fuels, the content of nitrogen in heavy fuel oil varies between 0.1 and 0.8 wt.-% /7/. The content of nitrogen in gaseous fuels (refinery gas) as well as in solid fuels (petroleum coke contain ca. 0.2 wt.-% /6/) is negligible. Relatively high NO_x emissions may be released by thermal cracking units in petrochemical industry (e.g. at olefin cracking units

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[4] The flare gas recovery system is in fact a refinery safety device which under normal conditions has no flow /14/.

[5] For a description of selected units see chapter B411 on "Petroleum Products Processing".

concentrations of about 130 up to 1,600 mg/m^3 may occur /18/). The design of burner and furnace as well as the operating conditions determine the NO_x formation. NO_x emissions vary considerably for existing and new (optimised) furnaces in refineries (see Table 3).

Table 3: Ranges of NO_x concentrations for existing and new (optimised) furnaces in refineries (according to /14/)[1]

Type of process furnace	NO_x concentration [mg/Nm³]	
	Gas[2]	Refinery fuel[3]
Existing furnace	160 - 1,300	280 - 1,000
Furnace with optimal burner and furnace design	100 - 200	about 250[4]

[1] Apart from firing either gas or liquid fuel separately, mixed gas/liquid firing in the same furnace is also practised in refineries, and emission values may differ considerably from the values observed in the case of gas fired units /14/.

[2] The lower range relates to natural gas firing /14/.

[3] Thermally cracked residue /14/; liquid fuel

[4] However, low-NO_x-burners are reported not to be available for low grade liquid fuels. /cf. 14/

Emissions of carbon monoxide (CO), methane (CH_4) and non-methane volatile organic compounds (NMVOC) are mainly associated with poorly regulated combustion processes; they are small when processes are managed correctly.

Heavy metal emissions are mainly determined by the type of fuel used; only liquid and solid fuels are of relevance. Most of the heavy metals (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, Zn, V) are normally released as compounds (e.g. chlorides) in association with particulates (see also chapter B111 on “Combustion Plants as Point Sources”, Section 9). In the case of heavy fuel oil mainly Ni and V are of relevance. Particulate emissions originate from two different sources within a refinery; firstly from process heaters and boilers and secondly from FCC units (CO-boilers), which are not considered here. Their contribution to the total emissions is roughly equal. /cf. 8/.

3.5 Controls

SO_2 emissions from process furnaces are only controlled by the use of low sulphur fuels (e.g. by switching from liquid fuels to gaseous fuels, which contain less sulphur).

For the control of NO_x emissions from process furnaces only primary measures are installed (e.g. low-NO_x-burner, flue gas recirculation). The reduction efficiencies for low-NO_x-burners vary between 10 and 30 %, and for flue gas recirculation between 5 and 15 %. At thermal cracking units in petrochemical industry (e.g. olefine cracking units) also secondary abatement measures may be installed (e.g. SCR, SNCR) /18/.

4/5 SIMPLER AND DETAILED METHODOLOGY

Here both approaches refer to the calculation of emissions based on emission factors and activities, which are jointly discussed in the following. The “simpler methodology” is considered as an overall approach, where activity data refer to production figures. The “detailed methodology” is considered as the recommended approach, where activity data concerning the fuel consumption in refinery process furnaces is available for individual plants. The simpler and the detailed methodologies cover all relevant pollutants.

The annual emission is determined according to Equation (1) by an activity and an emission factor:

$$E_i = EF_i \cdot A \tag{1}$$

E_i annual emission of pollutant i
EF_i emission factor of pollutant i
A activity

The activity A and the emission factor EF_i have to be determined on the same level of aggregation by using available data. The CORINAIR90 methodology requires for refinery process furnaces activity data, which is related to the type of fuel consumed in [GJ/a].

4.1 Simpler methodology

The simpler methodology corresponds to an approach, which takes into account activity rates derived from data of comparable installations or from literature data. Here, it is assumed, that the required activity data (according to CORINAIR90) are not available (see Equation (1)). In practice, statistical material (see also Section 6), which often provides only the throughput of crude oil in [Mg/a], has to be used. Some national statistics publications also provide throughputs per individual refinery.

In order to approximate activity data referring to the energy input into process heaters in [GJ/a] the specific energy consumption has to be taken into account as given e.g. in Equation (2):

$$A_{COR} = F \cdot A_{Stat} \tag{2}$$

A_{COR} activity in CORINAIR-compatible unit (energy input [GJ])
F specific energy consumption (energy input/mass crude oil [GJ/Mg])
A_{stat} activity directly obtained from statistics (mass crude oil [Mg])

For the determination of the specific energy consumption F, related to the throughput of crude oil, only the own consumption of the refinery has to be taken into account. The own consumption of a refinery amounts to about 5 % (average in 1990) of the input (crude oil and intermediate products) /3, 5/. For hydroskimming refineries[6] the fuel demand may vary between 2 and 3 wt.-% and for complex, high conversion refineries between 6 and 8 wt.-% /14/. About 40 % of the refinery fuel consumption is used for process heaters. The fuel split of refinery fuel for its own consumption can be given as: heavy fuel oil (ca. 35 %), petroleum coke (ca. 10 %) and refinery gas (ca. 55 %); the relevance of gas oil is < 1% and can be neglected /3/.

However, the simpler approach leads to significant uncertainties. Therefore, no emission factors are provided for this edition.

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[6] The simplest type of refineries, the so-called „hydro-skimming“ refineries, carry out very little conversion into various products. The product distribution is largely determined by the composition of the crude oil processed and cannot be influenced to a great extent by modifying the operating mode of the refineries. /14/

N.B There are no emission factors available for $PM_{2.5}$. The source is <0.1% of the total PM emissions for most countries.

4.2 Detailed methodology

The detailed methodology corresponds to a plant specific approach, which takes into account as far as possible plant specific information. Here, CORINAIR90 compatible activity data for refinery process furnaces (related to the type of fuel consumed in [GJ/a]) are directly available (Equation (1)).

The following two sections provide individual approaches for the determination of SO_2 and CO_2 emission factors.

4.2.1 SO_2 emission factors

Emission factors for SO_2 in [g/GJ] are given in Table 6 (see Section 8) based on literature data. SO_2 emissions can be directly correlated to the sulphur content of the fuel and the fuel consumption. Emission factors for SO_2 in [g/GJ] can be obtained by using Equation (2):

$$EF_{SO_2} = 2 \cdot C_{S_{fuel}} \cdot \frac{1}{H_u} \cdot 10^6 \qquad (2)$$

EF_{SO_2} emission factor of SO_2 [g/GJ]

$C_{S_{fuel}}$ sulphur content of fuel [wt.-%]

H_u lower heating value [MJ/kg]

If no data is available, default values are recommended:
- sulphur content of fuel: see Section 3.4,
- lower heating value: see Table 4.

Table 4: Lower heating values of refinery fuels

Fuel used	NAPFUE code	Lower heating value [MJ/kg] /10/
Petroleum coke	110	29.31
Gas oil	204	42.70
Heavy fuel oil	203	41.03
Refinery gas	308	48.36

4.2.2 CO_2 emission factors

Emission factors for CO_2 are given in Table 6 (Section 8) based on literature data. Own estimations can be made according to Equation (3) and by using an approximation for the composition of oil, gas and coke as given in Table 5:

$$EF_{CO_2} = \frac{M_{CO_2}}{M_i} \cdot \frac{1}{H_u} \cdot 10^6 \qquad (3)$$

EF_{CO_2} emission factor for CO_2 [g/GJ]

M_{CO_2} molecular weight of CO_2 [g/mol]

M_i molecular weight of fuel i (see Table 5) [g/mol]

H_u lower heating value [MJ/kg]

Table 5: Approximations for the molecular weight /3/

Fuel	**Approximation**	**Molecular weight [g/mol]**
Fuel oil	HC	13
Petroleum coke	C	12
Refinery gas	CH_4/C_2H_6	23[1]

[1] An assumption concerning the average molecular weight has been made as both fractions are included with a mass portion of 50:50.

4.2.3 Emission factors for other pollutants

Emission factors for the pollutants NO_x, CH_4, NMVOC, CO, and N_2O are given in Table 6 (see Section 8) based on literature data depending on the type of fuel used. Emission factors for heavy metals are given in Table 7 (see Section 8).

Should a key source analysis indicate this to be a major source of particulate matter (TSP, PM_{10} or $PM_{2.5}$) then installation level data should be collected using a measurement protocol such as that illustrated in Measurement Protocol Annex.

6 RELEVANT ACTIVITY STATISTICS

The following statistics can be used for the determination of the throughput of crude oil. The consumption of intermediate products has to be taken into account separately. In some national statistics also the total own consumption of fuels within the refineries is reported.

- Statistical Office of the European Communities (EUROSTAT) (ed.): CRONOS Databank; 1993 (Crude oil production XX 93 0603 3, Crude oil treated in refineries XX 93 0604 3)
- Office for Official Publication of the European Communities (ed.): Annual Statistics 1990; Luxembourg; 1992

Information concerning European refineries is also provided by Concawe (Den Haag).

7 POINT SOURCE CRITERIA

Refineries have to be treated as point sources according to the CORINAIR90 methodology. Process furnaces within a refinery have to be reported collectively as a part of a refinery.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

The following Table 6 contains emission factors for selected pollutants based on literature data.

Table 6: Emission factors of gaseous pollutants for process heaters in refineries [10]

Type of fuel			NAPFUE code	Emission factors						
				SO_2 [g/GJ]	NO_x [g/GJ]	NMVOC [g/GJ]	CH_4 [g/GJ]	CO [g/GJ]	CO_2 [kg/GJ]	N_2O [g/GJ]
s[1]	coke	petroleum	110		300[7]				101[5]	22[7] g/Mg
l[2]	oil	residual	203	245 - 1,962[9]	100 - 210[8] 75 - 328[9]	1 - 41[9]	0.1 - 3.5[9]	7 - 350[9]	78[5] 53 - 79[9]	22[7] g/Mg 2 - 22[9]
G	gas	natural	301	0.7 - 432[9]	1.4 - 140[9]	0.3 - 7[9]	0.3 - 4[9]	1.3 - 280[9]	53 - 55[9]	1.5 - 22[9],
G[3]	gas	liquified petroleum	303	1.7[9]		14[9]	6[9]	45[9]	64[9]	1.5[9]
G	gas	refinery	308	12.5 - 1,423[9]	90[8], 140[7], 155[6] 30 - 150[8] 35 - 756[9]	0.3 - 10[9]	0.3[6] 0.3 - 4[9]	280[6] 10 - 280[9]	60[4], [6] 10 - 57[9]	1.5[6], 0.3 - 22[9], 22[7] g/Mg
l/g	mixtur	of oil/gas	-	220[4] g/Mg	350[4] g/Mg					

[1] In CORINAIR90 also NAPFUE codes 103 and 105 have been reported

[2] In CORINAIR90 also NAPFUE code 204 has been reported

[3] In CORINAIR90 also NAPFUE code 303 has been reported

[4] CONCAWE /9/, range for SO_2 emission factors: 70 - 430 g/Mg

[5] BMU, Germany 1993 /12/

[6] BMU, Germany 1994 /16/

[7] CORINAIR /4/

[8] CONCAWE /1/

[9] CORINAIR90 data

[10] At this stage emission factors for thermal cracking units are not available.

Table 7: Heavy metal emission factors for gaseous fuels fired in refinery process heaters /13/

Source	Emission factor [g/TJ]			
	Cr (total)	Cr^{6+} (Hex)[1]	As	Cd
Process heater:				
- Single stage	0.10	0.19	0.03	0.01
- With LNB	0.05	0.01	0	0
- With air preheater	0.05	0	0	0.14
- Reformer	0.09	0.19	0	0

[1] Cr^{6+} is reported separately due to the high toxicity of this species.

For refinery process heaters, which are fed with fuel oil, emission factors for heavy metals are approximately the same as given in Table 31 in chapter B111 on “Combustion Plants as Point Sources”. Residues fuelled in refineries need not be comparable to heavy fuel oils as a product. Therefore, composition data of residues are needed in order to estimate heavy metal emissions /17/.
Table 8 contains the AP 42 emission factors for particulate matter (US EPA, 1996).

Table 8: AP 42 Particulate matter emission factors* for Process Furnaces /19/

Process (g/10^3 L fresh feed)	**PM**
Fluid catalytic cracking units: uncontrolled	695
Fluid catalytic cracking units: ESP and CO boiler	128
Moving-bed catalytic cracking units	4.9
Fluid cooking units: uncontrolled	1500
Fluid cooking units: ESP and CO boiler	19.6

* = In the absence of more appropriate data use the AP 42 emission factors

9 SPECIES PROFILES

Species profiles (oxides of sulphur and nitrogen) are comparable to those released from combustion installations. Details can be found in chapter B111 “Combustion Plants as Point Sources” (Section 9).

10 UNCERTAINTY ESTIMATES

At this stage no information is available.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Weakest aspects discussed here are related to emission factors and activities.

Data provided by CORINAIR90 project can only be used in order to give a range of emission factors. Further work should be invested to develop emission factors, which take into account technical specifications and fuel characteristics.

Most refineries process crude oil as well as intermediate products coming from other refineries. The energy demand for the processing of intermediate products differs from the energy demand for the processing of crude oil. The share of intermediate products processing varies strongly. Therefore, further work should be invested in providing characteristic profiles for the energy consumption (own consumption) of a refinery, which are suitable for inventorying purposes.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

13 TEMPORAL DISAGGREGATION CRITERIA

Temporal disaggregation of annual emission data (top-down approach) provides a split into monthly, weekly, daily and/or hourly emission data. Temporal disaggregation of annual emissions released from process furnaces in refineries can be obtained by taking into account the:

- time of operation and
- variation of load.

Data for the annual time of operation in refineries is available from statistics. In principle, refineries produce continuously during the whole year except during standstill time due to maintenance.

The load of the refinery is determined by the variation of production due to the varying demand for petroleum products. Information concerning the variation in the production or the demand for refinery products can only be obtained directly from refinery operators. (Note: the short time demand for refinery products is met by refinery products being stored in tanks.).

14 ADDITIONAL COMMENTS

15 SUPPLEMENTARY DOCUMENTS

16 VERIFICATION PROCEDURES

As outlined in the chapter on “Concepts for Emission Inventory Verification” different verification procedures can be recommended. Verification procedures considered here are principally based on the verification of emission data on a national level and on a plant level.
The verification on a plant level relies on comparisons between calculated emissions/emission factors and those derived from emission measurements.

17 REFERENCES

/1/ Concawe (ed.): Contribution of petroleum refineries to emissions of nitrogen oxides; report no. 9/84

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/3/ Personal communications with the German “Mineralölwirtschaftsverband”; 1993

/4/ CITEPA (ed.): CORINAIR - Emission Factor Handbook, part 1: Default Emission Factors from stationary sources; second edition; 1992

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/6/ Riediger, Bruno: Die Verarbeitung des Erdöls; Berlin, Heidelberg, New York; 1971

/7/ Kolar, Jürgen: Stickstoffoxide und Luftreinhaltung; Berlin, Heidelberg, New York; 1990

/8/ Concawe (ed.): Sampling and measurement of particulate emissions from refinery installations; report no. 4/80; Den Haag; 1986

/9/ Concawe (ed.): Sulphur dioxide emissions from oil refineries and combustion of oil products in western Europe in 1979 and 1982; Den Haag, 1985

/10/ MWV - Mineralölwirtschaftsverband (ed.): Mineralölzahlen, Hamburg; 1992

/11/ CORINAIR90 Emission Inventory (Proposals)-working paper for the 19 - 20 September 1991 meeting - Annex 4: Definition of Large Point Sources

/12/ Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (ed.): Umweltpolitik - Klimaschutz in Deutschland, Nationalbericht der Bundesregierung für die Bundesrepublik Deutschland in Vorgriff auf Artikel 12 des Rahmenübereinkommens der Vereinten Nationen über Klimaänderungen; 1993

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/14/ Technical note on the best available technologies to reduce emissions of pollutants into the air from the refining industry; Application of articles 7 & 13 of the Directive 84/360 EEC

/15/ Ms. Froste, Mr. Kvist, Mr. Jansson; personal communcation; February 1995

/16/ Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (ed.): Umweltpolitik - Klimaschutz in Deutschland, Erster Bericht der Regierung der Bundesrepublik Deutschland nach dem Rahmenübereinkommen der Vereinten Nationen über Klimaänderungen; 1994

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/18/ Mr. Drechsler (Umweltbundesamt, Berlin): Personal communication (paper); December 1995

/19/ US EPA (1996) Compilation of Air Pollutant Emission Factors Vol.1 Report AP-42 (5th ed.)

18 BIBLIOGRAPHY

19 RELEASE VERSION, DATE AND SOURCE

Version : 2.1

Date : December 1995

Source : Otto Rentz; Dagmar Oertel
University of Karlsruhe (TH)
Germany

Updated with particulate matter details by:
Mike Woodfield
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UK
December 2006

20 POINT OF ENQUIRY

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Abbreviations

FCC	Fluid Catalytic Cracking
g	gaseous state of aggregation
l	liquid state of aggregation
LNB	Low-NO_x-Burner
s	solid state of aggregation
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction

SNAP CODE:

010402
010403
010404
010405
010407

SOURCE ACTIVITY TITLE:

SOLID FUEL TRANSFORMATION PLANT
Combustion Plants >= 50 and < 300 MW (boilers)
Combustion Plants < 50 MW (boilers)
Gas Turbines
Stationary Engines
Other (coal gasification, liquefaction,...)

NOSE CODE:

101.02
101.03
101.04
101.05
104.08.02

NFR CODE: **1 A 1 c**

The emission factors for these activities are actually contained in Chapters B111 and B112.

For Particulate Matter[1]:
Combustion Plants < 50 MW (boilers) are now covered in the new supplementary chapter Particulate emissions from smaller Combustion Plants (<50MWth) B111(S1).

Combustion Plants >= 50 and < 300 MW (boilers) are now covered in the new supplementary chapter Particulate emissions from large Combustion Plants (>50MWth) B111(S2).

Gas Turbines are now covered in the new supplementary chapter Particulate emissions from gas turbines and internal combustion engines B111(S3).

1. RELEASE VERSION, DATE AND SOURCE

Version: 2
Date: September 2006

Source: Carlo Trozzi
Techne Consulting
Italy

---

[1] Updated with particulate matter details by: Mike Woodfield, AEA Technology, UK, December 2006

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SNAP CODES: **010406**
040201

SOURCE ACTIVITY TITLE: **SOLID FUEL TRANSFORMATION PLANTS**
Coke Oven Furnaces
Coke Oven (Door Leakage and Extinction)

NOSE CODE: **104.12**

NFR CODE: **1 A 1 c**
1 B 1 b

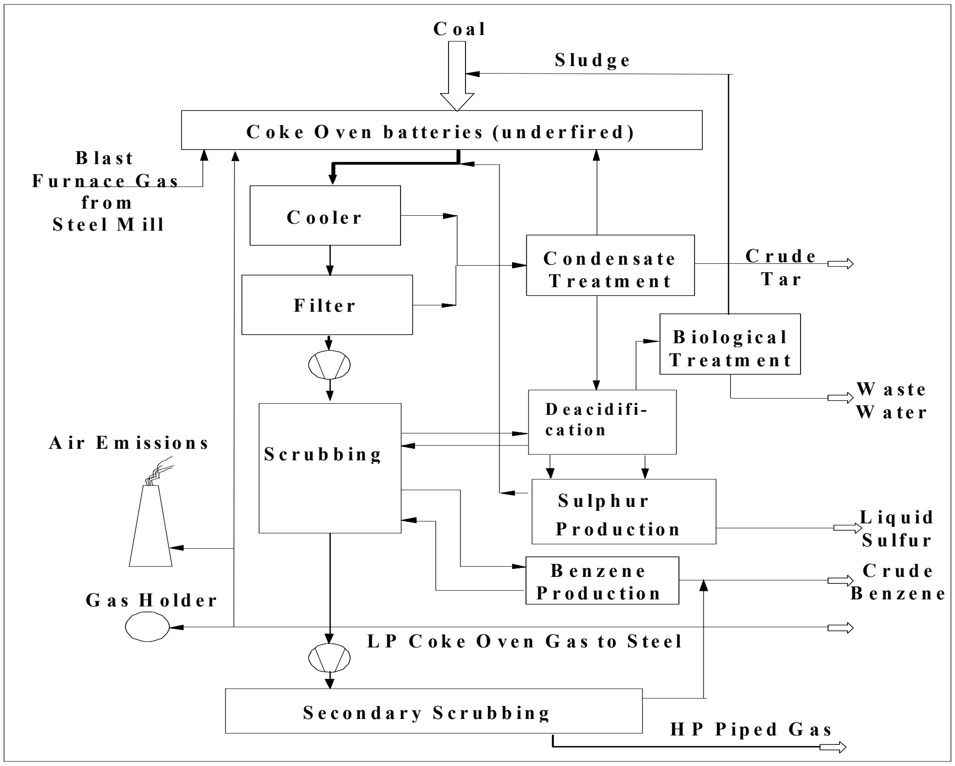
1 ACTIVITIES INCLUDED

Coke-production in general can be divided into the following steps:

Coal handling and storage, coke oven charging, coal coking, extinction of coke, and coke oven gas purification. Combustion in coke oven furnaces (SNAP 010406) is treated in this chapter as well as door leakage and extinction (SNAP 040201).

Figure 1-1 gives a key plan of a coke plant with emission relevant process steps and the by-product recovery section.

Figure 1-1: Key plan of a coke plant (Rentz et al. 1995)



2 CONTRIBUTION TO TOTAL EMISSIONS

Table 2-1: Contribution to total emissions of the CORINAIR90 inventory (*28 countries*)

Source-activity	**SNAP-code†**	**Contribution to total emissions [%]**								
		SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3	PM*
Coke Oven Furnaces	010406*	0.5	0.3	0	0	0.2	1.0	-	-	-
Coke Oven (Door Leakage and Extinction)	040201	0.1	0.1	0.2	0.1	0.5	0.1	-0.1	0.1-	-

0 = emissions are reported, but the exact value is below the rounding limit (0.1 per cent)
- = no emissions are reported
† = SNAP90 code 030202
* = PM (inclusive of TSP, PM_{10} and $PM_{2.5}$) is <0.1% of total PM emissions

Table 2-2: Contribution to total heavy metal emissions of the OSPARCOM-HELCOM-UNECE inventory for 1990 (up to 38 countries)

Source-activity	**SNAP-code**	**Contribution to total emissions [%]**							
		As	Cd	Cr	Cu	Hg	Ni	Pb	Zn
Coke Oven (Door Leakage and Extinction)	040201	0.3	1.3	1.3	0.2	1.0	0.1	0.1	0.1

The emissions of persistent organics are also relevant. According to this OSPARCOM-HELCOM-UNECE inventory, coke ovens contributed some 3.1 % to total emissions of PAH in 1990.

Coke production is unlikely to be a significant source of sulphurhexafluoride (SF6), hydrofluorocarbons (HFCs) or perfluorocarbons (PFCs), (ETC/AEM-CITEPA-RISOE 1997).

3 GENERAL

About 90 % of the coke consumed in the EU is used in pig iron production. The major part is used in blast furnaces, followed by iron foundries, non-ferrous smelters, and the chemical industry.

3.1 Description

Coke and coke by-products (including coke oven gas) are produced by the pyrolysis (heating in the absence of air) of suitable grades of coal. The process also includes the processing of coke oven gas to remove tar, ammonia (usually recovered as ammonium sulphate), phenol, naphthalene, light oil, and sulphur before being used as a fuel for heating the ovens (World Bank Group 1997).

For coke production, hard coal is crushed, mixed and sieved. The coal is transported to the coke oven, which is charged by the mixture. After heating for 14 to 36 hours at 1,150-1,350°C, in the absence of oxygen, the coked mixture is pressed out of the coke chambers into special wagons. Subsequently, the hot coke will be extinguished.

The emissions related to coke production can be attributed to four sub-processes, namely:

- Coal handling and storage: emitting coal dust,
- Coke production and extinction: emitting coal and coke dust and coke oven gas,
- Coke oven gas handling and purification: emitting benzene, toluene, xylene, phenol, PAH, H_2S, HCN and NH_3,
- Combustion of coke oven gas: emitting C_xH_y, SO_2, NO_x, CO, CO_2, HF and soot.

3.2 Definitions

Production of coke:	heating of coal mixtures in absence of oxygen at high temperatures
Extinction of coke:	cooling of the hot coke after removal from the coke-chambers
Coke oven gas:	the gas formed during coking of the coal

3.3 Techniques

In the coke making process, bituminous coal is fed (usually after processing operations, which control the size and the quality of the feed) into a series of ovens. The coke oven itself is a chamber, built of heat resistant bricks, generally 0.4-0.7 m wide, 4-8 m high and 12-18 m long. A chamber has two doors, one at each end, covering almost the full cross-sectional area. In the roof, there are 3-5 charging holes and a gas outlet ("ascension pipe"). Commonly 40 to 70 chambers, alternating with heating walls, form a coke oven battery (Dutch Notes on BAT 1997). Combustion of gases in burners in the flues between the ovens provides heat for the process. In order to improve the energy efficiency, regenerators are located right under the ovens, exchanging heat from flue gases with combustion air or fuel. Coke oven gas from the by-product recovery plant is the common fuel for underfiring the ovens at most plants, but blast furnace gas, and infrequently, natural gas may also be used (US-EPA 1985).

The ovens are sealed and heated at high temperatures. The generation of steam, gases, and organic compounds starts immediately after charging and they are exhausted via ascension pipes into the crude gas collecting system (Dutch Notes on BAT 1997). Volatile compounds are processed to recover combustible gases and other by-products. After coking, the vertical doors on each end of an oven are removed, a long ram pushes the coke from the oven into a rail quench car, which goes to a quench tower. There, large volumes of water are sprayed onto the coke mass to cool it, so that it will not continue to burn after being exposed to air. Alternatively, circulating an inert gas (nitrogen), also known as dry quenching can cool it. Coke is screened and sent to a blast furnace or for storage.

The raw coke oven gas exits at temperatures of about 760 to 870 °C and is shock cooled by spraying recycled flushing liquor in the gooseneck. This spray cools the gas to 80 to 100 C, precipitates tar, condenses various vapours, and serves as the carrying medium for the condensed compounds. These products are separated from the liquor in a decanter and are subsequently processed to yield tar and tar derivatives (US-EPA 1985b, van Osdell et al. 1979).

The gas is then passed either to a final tar extractor or an electrostatic precipitator for additional tar removal. When the gas leaves the tar extractor, it carries 75 % of the ammonia and 95 % of the light oil originally present when leaving the oven. The ammonia is recovered either as an aqueous solution by water absorption or as ammonium sulphate salt. The gas leaving the saturator at about 60°C is taken to final coolers or condensers, where it is typically cooled with water to approximately 24°C. During this cooling, some naphthalene separates and is carried along with the wastewater and recovered. The remaining gas is passed into a light oil or benzene scrubber, over which is circulated a heavy petroleum fraction called wash oil or a coal-tar oil, which serves as the absorbent medium. The oil is sprayed in the top of the packed absorption tower while the gas flows up through the tower. The wash oil absorbs about 2 to 3 % of its weight of light oil, with a removal efficiency of about 95 % of the light oil vapour in the gas. The rich wash oil is passed to a countercurrent steam stripping column. The steam and light oil vapours pass upward from the still through a heat exchanger to a condenser and water separator. The light oil may be sold as crude or processed to recover benzene, toluene, xylene, and solvent naphtha (US-EPA 1985b, van Osdell et al. 1979).

After tar, ammonia, and light oil removal, the gas undergoes final desulphurisation (e. g. by the Claus process) at some coke plants before being used as fuel. The coke oven gas has a rather high heating value, in the order of 20 kJ/m^3 (STP). Typically, 35 to 40 % of the gas is returned to fuel the coke oven combustion system, and the remainder is used for other plant heating needs (US-EPA 1985b, van Osdell et al. 1979).

Although most benzene is obtained from petroleum, some is recovered through distillation of coke oven light oil at coke by-product plants. Light oil is a clear yellow-brown oil which contains coal gas components with boiling points between 0 and 200°C. [30] Most by-product plants recover light oil, but not all plants refine it. About 13-18 l of light oil can be produced from coke ovens producing 1 Mg of furnace coke. Light oil itself contains from 60 to 85 % benzene (US-EPA 1985, Loibl et al. 1993).

3.4 Emissions

The coke oven is a major source of fugitive emissions into the air. The coking process emits sulphur oxides (SO_x), nitrogen oxides (NO_x), volatile organic compounds (non-methane VOC and methane (CH_4)), carbon dioxide (CO_2), carbon monoxide (CO), ammonia (NH_3), particulate matter, and heavy metals. In general, emissions of nitrous oxide (N_2O) are not relevant. Coke ovens are an important source of PAH emissions (polycyclic aromatic hydrocarbons).

The components of coke oven gas (raw gas) and their concentration can be given as follows.

Table 3.1: Composition of raw coke oven gas (Winnacker 1982)

Components of coke oven gas	Concentration [Vol.-%]
H_2	58 - 65
CH_4	24 - 29
CO	4.6 - 6.8
C_nH_m	2 - 4
CO_2	1.5 - 2.5

Besides these compounds, the following by-products are also components of the coke oven gas produced: tar, phenol, benzene, pyridine, ammonia, H_2S, HCN, CS_2 (carbon bisulphide) (Winnacker 1982). The by-product recovery section of a coking plant (e.g. ammonia processing, tar processing) may release significant amounts of NMVOC, CH_4, NH_3 and particulate matter (covered by SNAP code 040201).

Furthermore, continuous and discontinuous releases of emissions into the air can be distinguished (Dutch Notes on BAT 1997):

Continuous emissions to air:

- Emissions from storage and handling of raw materials and products,
- Oven door and frame seal leakage,
- Ascension pipe leakage,
- Charging holes leakage,
- Coke oven firing,
- Vent systems in gas treatment plant,
- Desulphurisation plant.
–

Discontinuous emissions to air:

- Oven charging,
- Coke pushing,
- Coke cooling.

3.5 Controls

Charging:
Dust particles from coal charging can be evacuated by the use of jumper-pipe system and steam injection into the ascension pipe or controlled by fabric filters (World Bank Group 1997).

Coking:
Emissions decrease with the increase of the size of the ovens. Large ovens increase batch size and reduce the number of chargings and pushings, thereby reducing associated emissions. Emissions are also reduced by constant coking conditions, cleaning, and a low-leakage door construction e. g. with gas sealings (Dutch Notes on BAT 1997).

Pushing:
Emissions from coke pushing can be reduced by maintaining a sufficient coking time thus avoiding the so-called "green push". Fugitive emissions can be controlled by sheds, enclosed

cars or travelling hoods. Captured gases should be treated in fabric filters (World Bank Group 1997).

Quenching:
Dry quenching creates lower emissions compared to wet quenching. Gases released from the dry quenching unit can be extracted and filtered. In the case of wet quenching, measures have to be taken to prevent pollutant transfer from wastewater to the air (Dutch Notes on BAT 1997).

By-product recovery:
In the processing of light oil, tar, naphthalene, phenol, and ammonia vapour recovery systems can be used. Tail gases from desulphurisation (Claus plant) can be returned to the coke oven gas system.

Combustion of coke oven gas:
Flue gases from coke oven firing contain NO_x, SO_2 and particulate matter as main pollutants. SO_2 emissions depend on the degree of desulphurisation of the coke oven gas. NO_x emissions may be reduced by low-NO_x-firing techniques.

4 SIMPLER METHODOLOGY

For the simpler methodology, where limited information is available, default emission factors may be used together with information on coke production in a given country or region without further specification of the type of process technology or efficiency of control equipment. This procedure does not distinguish combustion emissions and emissions from door leakage and extinction. Default emission factors are provided in Section 8.1.

N.B There are no emission factors available for $PM_{2.5}$. The source is <0.1% of the total PM emissions for most countries.

5 DETAILED METHODOLOGY

The assessment of emissions with the more detailed methodology requires knowledge of the four sub-processes of coke production. If detailed information about the local situation is available this should prevail over the use of default emission factors. Reference emission factors for comparison with users data are provided in Section 8.2.

Should a key source analysis indicate this to be a major source of particulate matter (TSP, PM_{10} or $PM_{2.5}$) then installation level data should be collected using a measurement protocol such as that illustrated in Measurement Protocol Annex.

6 RELEVANT ACTIVITY STATISTICS

Standard statistics on coke production and fuel consumption (e. g. International Energy Agency, United Nations, Eurostat, International Iron and Steel Institute etc.).

7 POINT SOURCE CRITERIA

Integrated iron and steel plants with production capacities of more than 3 million Mg/a have to be treated as point sources according to the CORINAIR90 methodology. Coke oven furnaces included in these integrated iron and steel plants have to be considered as a part of the point source.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Default emission factors for use with simpler methodology (Source: Pacyna et al, 2002)

Pollutant	**Emission factors**	**Units**
Arsenic	0.01	g/t coke
Cadmium	0.01	g/t coke
Chromium	0.15	g/t coke
Copper	0.1	g/t coke
Mercury	0.01	g/t coke
Nickel	0.1	g/t coke
Lead	0.25	g/t coke
Zinc	0.4	g/t coke

8.2 Detailed methodology

In table 8.2a average overall emission factors are presented for coke production. For reference (Emission Registration 1990), emissions due to coke oven gas purification and fuel combustion are included. In the other references from this table it is not clear if fuel combustion is included or not.

Table 8.2a: Overall emission factors for coke production (g/Mg coke produced)

Compound	**Plant type**	**Emission factor**	**Data Quality**	**Abatement type**	**Abatement efficiency**	**Fuel type**	**Country or region**	**Ref.**
Particulates	*All processes*	*500 - 900*	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany*	(Luftreinh. 1989)
Particulates	*All processes*	53	*E*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1990)
Particulates	*All processes*	800 - 5000	*E*	*n. a.*	*n. a.*	*n. a.*	*USA*	*(US-EPA 1990)*
VOC	*All processes*	730 - 2800 2)	*E*	*n. a.*	*n. a.*	*n. a.*	*Netherlands* *USA*	(E. Registr. 1990), *(US-EPA 1990)*
PAH	*All processes*	29	*E*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1990)
B(a)P	*All processes*	0.16 - 0.6	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands*	(Luftreinh. 1989), (E. Registr. 1990)
Arsenic	*All processes*	0.003 - 0.03, 0.32 1)	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany,* *USA*	(Luftreinh. 1989), *(US-EPA 1990)*
Cadmium	*All processes*	0.0007 - 0.8	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands*	(Luftreinh. 1989), (E. Registr. 1990)
Chromium	*All processes*	0.17 - 0.34	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands*	(Jockel W. 1991), (E. Registr. 1990)
Copper	*All processes*	0.09 - 0.05	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands*	(Jockel W. 1991), (E. Registr. 1990)
Mercury	*All processes*	0.004 - 0.04	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands*	(Luftreinh. 1989), (E. Registr. 1990)

Table 8.2a (continued): Overall emission factors for coke production (g/Mg coke produced)

Compound	**Plant type**	**Emission factor**	**Data Quality**	**Abatement type**	**Abatement efficiency**	**Fuel type**	**Country or region**	**Ref.**
Nickel	*All processes*	0.065 - 0.19	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands*	(Jockel W. 1991), (E. Registr. 1990)
Lead	*All processes*	0.08 - 0.6, 2.85$^{1)}$	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands* *USA*	(Luftreinh. 1989), (E. Registr. 1990), *(US-EPA 1990)*
Zinc	*All processes*	*0.22 - 0.58, 6.49*$^{1)}$	*E*	*n. a.*	*n. a.*	*n. a.*	*Germany* *Netherlands* *USA*	(Jockel W. 1991), (E. Registr. 1990), *(US-EPA 1990)*

1) calculated with EPA coke dust profile *(US-EPA 1990)*
2) expressed as methane

According to the detailed methodology emissions should be calculated individually for all sub-processes. Emission factors for the process steps listed below are summarised in table 8.2.b

In table 8.2c, emission factors are given for the detailed sub-processes for total particulate, NO_x, SO_2, CO, VOC and NH_3 as reported in the USA (US-EPA 1985).

8.2.1 Coal handling

Coal handling consists of transport, pulverising, screening, and blending of several types of coal and storage. Table 8.2 includes factors for emissions of coal dust from the total process of coal handling.

8.2.2 The coking process (without combustion)

Emissions during coking operations are caused by the charging of the coal into the ovens, the oven/door leakage during the coking period, and by pushing the coke out of the ovens. In table 8.2, overall emission factors for these activities are presented for VOC, NMVOC and PAH.

8.2.3 Coke oven gas purification

The coke oven gas collected from the ovens during the coking process is subjected to various operations for separating ammonia, coke oven gas, tar, phenol, benzene, toluene, xylene, pyridine etc. In table 8.2b, emission factors are given for the purification process of coke oven gas. The numbers are derived from data of a Dutch coke plant (Emission Registration 1992).

8.2.4 Combustion

Heat, necessary for the coking process, is generated by gas combustion in the flues between the ovens. Coke oven gas is the common fuel for underfiring the ovens at most plants but other gases (blast furnace gas, natural gas) may be used as well. The combustion also causes emissions. In table 8.2b, emission factors are given for combustion emissions, related to the thermal energy input.

Table 8.2b: Emission factors for sub-processes of coke production

Compound	**Plant type**	**Emission factor**	**Data Quality**	**Abatement type**	**Abatement efficiency**	**NAPFUE code**	**Country or region**	**Ref.**
Coal dust	*Coal handling*	*80 - 2500 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*USA*	*(US-EPA 1985)*
Coal dust	*Coal handling*	*150 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1981)
VOC	*Coking process*	*151 - 590 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1990) (E. Registr. 1992)
VOC	*Coking process*	*2880 g* CH_4*/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*USA 1967*	*(US-EPA 1985)*
VOC	*Coking process*	*1030 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Germany 1975*	*(Schade 1980)*
CH_4	*Coking process*	*122 - 639 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands, Germany*	(E. Registr. 1992), *(Schade 1980)*
NMVOC	*Coking process*	*29 - 400 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands, USA*	(E. Registr. 1992), *(Breidenbach 1982)*
PAH	*Coking process*	*10 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	*(Duiser et al. 1989)*
VOC	*Gas purification*	*213 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Benzene	*Gas purification*	*157 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Toluene	*Gas purification*	*27 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Xylene	*Gas purification*	*26 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
PAH - 16 EPA	*Gas purification*	*47 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
Phenol	*Gas purification*	*3.2 g/Mg coke produced*	*C*	*n. a.*	*n. a.*	*n. a.*	*Netherlands*	(E. Registr. 1992)
SO_2	*C. oven furnaces*	*0.5 g/GJ*	*C*	*n. a.*	*n. a.*	*301*	*Europe*	*CORINAIR90*

Table 8.2b (continued): Emission factors for sub-processes of coke production

SO_2	*C. oven furnaces*	*14 g/GJ*	*C*	*n. a.*	*n. a.*	*303*	*Europe*	*CORINAIR90*
SO_2	*C. oven furnaces*	*500 g/Mg coal; 650 g/Mg coke; 3.3 g/GJ*	*C*	*Desulphurisation*	*n. a.*	*304*	*Europe*	*(CITEPA 1992), CORINAIR90*
SO_2	*C. oven furnaces*	*1500 g/Mg coal; 3300 g/Mg coke; 1355 g/GJ*	*C*	*No desulphurisation*	*n. a.*	*304*	*Europe*	*(CITEPA 1992), CORINAIR90*
NO_x	*C. oven furnaces*	*100 - 250 g/GJ*	*C*	*n. a.*	*n. a.*	*301*	*Europe*	*CORINAIR90*
NO_x	*C. oven furnaces*	*90 g/GJ*	*C*	*n. a.*	*n. a.*	*303*	*Europe*	*CORINAIR90*
NO_x	*C. oven furnaces*	*14 - 250 g/GJ*	*C*	*n. a.*	*n. a.*	*304*	*Europe*	*CORINAIR90*
NO_x	*C. oven furnaces*	*30 - 178 g/GJ*	*C*	*n. a.*	*n. a.*	*305*	*Europe*	*CORINAIR90*
NMVOC	*C. oven furnaces*	*1 - 5 g/GJ*	*C*	*n. a.*	*n. a.*	*301, 303, 305*	*Europe*	*CORINAIR90*
NMVOC	*C. oven furnaces*	*1 - 133 g/GJ*	*C*	*n. a.*	*n. a.*	*304*	*Europe*	*CORINAIR90*
CH_4	*C. oven furnaces*	*0.02 - 2.5 g/GJ*	*C*	*n. a.*	*n. a.*	*301, 304*	*Europe*	*CORINAIR90*
CH_4	*C. oven furnaces*	*3 g/GJ*	*C*	*n. a.*	*n. a.*	*303*	*Europe*	*CORINAIR90*
CH_4	*C. oven furnaces*	*0.02 - 0.3 g/GJ*	*C*	*n. a.*	*n. a.*	*305*	*Europe*	*CORINAIR90*
CO	*C. oven furnaces*	*1 - 300 g/GJ*	*C*	*n. a.*	*n. a.*	*301, 305*	*Europe*	*CORINAIR90*
CO	*C. oven furnaces*	*20 g/GJ*	*C*	*n. a.*	*n. a.*	*303*	*Europe*	*CORINAIR90*
CO	*C. oven furnaces*	*2 - 518 g/GJ*	*C*	*n. a.*	*n. a.*	*304*	*Europe*	*CORINAIR90*
CO_2	*C. oven furnaces*	*42 - 56 kg/GJ*	*C*	*n. a.*	*n. a.*	*301, 303, 304*	*Europe*	*CORINAIR90*
CO_2	*C. oven furnaces*	*105 - 280 kg/GJ*	*C*	*n. a.*	*n. a.*	*305*	*Europe*	*CORINAIR90*
N_2O	*C. oven furnaces*	*1.1 - 3 g/GJ*	*C*	*n. a.*	*n. a.*	*301, 303, 304, 305*	*Europe*	*CORINAIR90*

Table 8.2c: PM emission factors for the coking sub-processes (kg/Mg coal) (US-EPA 2001)

Process	**Control**	**Emission factors, kg/Mg coal**					
		TSP	**Rating**	**PM_{10}**	**Rating**	**$PM_{2.5}$**	**Rating**
Charging	Uncontrolled	0.35	E	*0.17*	*E*	*0.085*	*E*
	Scrubber	0.007	E	*0.0053*	*E*	*0.0035*	*E*
	Modern	0.00031	E	*0.00031*	*E*	*0.00031*	*E*
Door leaks	Uncontrolled	0.26	E	*0.13*	*E*	*0.065*	*E*
	Older controlled	0.02	E	*0.015*	*E*	*0.01*	*E*
	Modern controlled	0.0079	E	*0.0079*	*E*	*0.0079*	*E*
Lid leaks	Uncontrolled	0.026	E	*0.013*	*E*	*0.065*	*E*
	Older controlled	0.0036	E	*0.0024*	*E*	*0.0018*	*E*
	Modern controlled	0.000048	E	*0.000036*	*E*	*0.000024*	*E*
Offtake leak	Uncontrolled	0.026	E	*0.013*	*E*	*0.065*	*E*
	Older controlled	0.0033	E	*0.0025*	*E*	*0.0017*	*E*
	Modern controlled	0.00016	E	*0.00016*	*E*	*0.00016*	*E*
Coke oven pushing	Uncontrolled	0.695	D	0.30	E	0.12	E
	Hood + fabric filter	0.19	B	*0.17*	*E*	*0.14*	*E*
	Hood + scrubber	0.19	A	0.17	E	0.14	E
	Shed + FF	0.19	B	*0.17*	*E*	*0.14*	*E*
Coke quenching	Uncontrolled, clean water	0.57	E	0.17	E	0.063	E
	Uncontrolled, dirty water	2.6	E	0.59	E	0.50	E
	Tall tower, Clean water	0.73	D	0.072	E	0.044	E
	Normal tower , clean water, maintained	0.15	D	*0.12*	*E*	*0.08*	*E*
	Tall tower/poorly maintained, dirty water	1.37	D	0.44	E	0.28	E
	Normal tower, dirty water, maintained	0.27	D	*0.20*	*E*	*0.14*	*E*
Combustion stack	Uncontrolled (BFG)	0.1	E	0.1	E	0.1	E
	Uncontrolled (raw COG)	0.2	B	*0.2*	*E*	*0.2*	*E*
	Uncontrolled (deS COG)	0.034	A	*0.034*	*E*	*0.034*	*E*
	Fabric filter (COG)	0.11	C	*0.11*	*E*	*0.11*	*E*
	Fabric filter/ESP (BFG)	0.031	D	*0.031*	*E*	*0.031*	*E*
Coal crushing	Cyclone	0.055	D	*0.041*	*E*	*0.028*	*E*
	Rotoclone	0.027	E	*0.020*	*E*	*0.014*	*E*
Coal mill	Building enclosure	*0.0009*	*E*	0.0009	E	*0.0009*	*E*
Preheater	Uncontrolled	1.8	D	1.8	E	1.1	E
	Scrubber	0.13	D	0.12	E	0.11	E
	ESP	0.006	D	*0.005*	*E*	*0.003*	*E*
Coke handling	Cyclone	0.003	D	*0.002*	*E*	*0.002*	*E*
Coke screening		0.011	E	*0.008*	*E*	*0.006*	*E*
Soaking		0.008	E	*0.006*	*E*	*0.004*	*E*
Combustion stack	Non-recovery oven	0.9	B	*0.9*	*E*	*0.9*	*E*
Charging	Non-recovery oven	0.013	D	0.0065	E	0.004	E

Data are from draft AP-42 update of 2001.

USEPA particle size data were collected primarily in 1970s and applicability to modern plant are unknown.

Information in italics is ‘expert judgement’ and extrapolation from USEPA particle size data.

9 SPECIES PROFILES

Table 9-1 presents profiles for VOC emissions of the coking process.

Table 9.1: VOC profiles for the coking process (% weight)

Compound	(Frohne)	(Fudal. 1992)	(VOC 1980)[1]	(Peter 1992)	(Emis. Registr 1992)	(Emis. Registr 1990)	(Emis. Registr 1990)	proposal
CH_4	72	66	45.3	45.4[4]	80.8	62.1	47.4	60
C2-C10 aliphates						17.8	13.6	16
C2	1.0	7.4	8	0.7[2]	4.2			5
C2=	1.1	18.1	27.7		1.0			1-10
C2=-	0.2	0.4	1.2					
C3	0.5	1.6	0.5	1.3[3]				
C3=	0.3	0.6	1.9					
C4	0.8	1.1		2.6				
C4=	0.1	0.4	0.6					
C4==								
C5	1.0			1.3				
C>5	1.0			14.0				
Benzene	7.7	3.4	14.1	11.5	9.7	5.9	4.5	7
Toluene	1.6	0.9	0.7	1.7	1.9	6.7	5.1	1-5
C8 aromatics	0.9			2.9				
C>8 aromatics	0.3			6.6				
Xylene		0.3		2.1	0.6	7.6	5.8	1-5
Styrene					0.3			
Aromatics + benzene							23.7	
Others	11.5			10.0	1.5			
Total	100	100	100	100	100	100	100	

[1] stack sample; probably only fuel combustion; [2] total c2;
[3] total c3; [4] calculated

In table 9.2, profiles of non-methane volatile organic compounds (NMVOC) emissions are given for the coking process.

Table 9.2: NMVOC profiles for the coking process (% weight)

Compound	(Frohne)	(Fudal. 1992)	(VOC 1980)[1]	(Peter 1992)	(Emis. Registr 1992)	(Emis. Registr 1990)	(Emis. Registr 1990)	(Altieri 1945)
C2-C10 aliphates						46.9	25.8	
C2	3.6	21.7	14.5	1.3[2]	22.1			30.3
C2=	3.9	53.0	50.4		5.2			58.0
C2=-	0.7	1.1	2.2					1.2
C3	1.8	4.8	0.9	2.3[3]				1.9
C3=	1.1	1.7	3.5					8.1
C4	2.9	3.4		4.8				0.5
C4=	0.36	1.1	1.1					
C4==								
C5	3.6			2.5				
C>5	3.6			25.6				
Benzene	27.5	9.9	25.6	21.0	50.7	15.5	8.5	
Toluene	5.7	2.5	1.3	3.8	10.0	17.7	9.7	
C8 aromatics	3.2			5.3				
C>8 aromatics	1.1			12.1				
Xylene		0.8		3.8	3.1	20.0	11.0	
Styrene					1.4			
Aromatics + benzene							45.0	
Others	41.1			18.3	7.5			
Total	100	100	100	100	100	100	100	100

[1] stack sample; probably only fuel combustion; [2] total c2; [3] total c3

Table 9.3: Species profiles for polycyclic aromatic hydrocarbons (PAH) expressed as percentage of total PAH

	(Bjorseth et al. 1978) battery personal top sampling (average)		(Eisenhut et al. 1982) oven doors	(Tonkelaar et al. 1983) near coke plant	(Duiser et al. 1989) proposal
total PAH emission factor (g/Mg)	15		2.5	8	10
fluorene	4.4	0.6			2
phenanthrene	19.8	2.6		45.9	30
anthracene	6.2	1.1		7.6	8
fluoranthene	12.8	11.9	1.5	14.3	14
3,6-dimethylphenanthrene				0.8	
benzo(b)fluorene	1.3	4.1		2.1	
pyrene	9.5	8.4	0.9	6.9	9
benzo(a)phenanthrene	0.8	2.8			2
benzo(a)anthracene	3.4	8.5	4.7	3.1	5
chrysene+trifenylene	4.4	11.0	5.9	3.4	4
total low mol PAH	88	62		84	74
benzo(b)fluoranthene	} 1.9	4.7	} 5.7	2.5	} 5
benzo(j)fluoranthene					
benzo(k)fluoranthene	2.2	7.7	2.1	1.1	
benzo(a)pyrene	1.8	4.3	7.1	2.5	5
benzo(e)pyrene	0.6	1.8	6.2	1.6	4
perylene	1.5	3.6	2.4	0.5	1
indeno(1,2,3,-cd)pyrene	1.3	2.9	6.2	1.8	3
benzo(g,h,i)perylene	0.9	1.7	6.2	4.4	3
anthanthrene	0.7	4.5		0.7	1
coronene					2
dibenzo(a,h)anthracene			4.4		} 2
dibenzo(a,j)anthracene				0.3	
dibenzo(a,i)pyrene				0.3	
3-methylcholanthene				0.3	
total high mol. PAH	12	38		16	26

10 UNCERTAINTY ESTIMATES

The quality classification of the emission factors is estimated to be B-C.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

Knowledge on abatement techniques, dust removal efficiencies and operating techniques is limited; measurement data on the composition of dust is poor.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

If treated on an area basis, national emission estimates can be disaggregated on the basis of plant capacity, employment or population statistics.

13 TEMPORAL DISAGGREGATION CRITERIA

Coke production can be considered as a continuous process.

14 ADDITIONAL COMMENTS

No additional comments are given

15 SUPPLEMENTARY DOCUMENTS

Environmental Protection Agency
Compilation of Air Pollutant Emission Factors AP 42

PARCOM-ATMOS Emission Factors Manual

16 VERIFICATION PROCESSES

Verification of the emissions can be done by measurements.

17 REFERENCES

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18 BIBLIOGRAPHY

For a detailed bibliography the primary literature mentioned in AP 42 or the PARCOM-ATMOS Manual may be used.

19 RELEASE VERSION, DATE AND SOURCE

Version: Draft 3

Date: May 2003

Updated by: Haydn Jones
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20 POINT OF ENQUIRY

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SNAP CODE:	**010502** **010503** **010504** **010505**
SOURCE ACTIVITY TITLE:	**COAL MINING, OIL/GAS EXTRACTION,** **PIPELINE COMPRESSORS** ***Combustion Plants >= 50 and < 300 MW (boilers)*** ***Combustion Plants < 50 MW (boilers)*** ***Gas Turbines*** ***Stationary Engines***
NOSE CODE:	**101.02** **101.03** **101.04** **101.05**
NFR CODE:	**1 A 1 c**

The emission factors for these activities are actually contained in Chapters B111 and B112.

(These activities are not believed to be a significant source of $PM_{2.5}$ (as of December 2006)).[1]

1. RELEASE VERSION, DATE AND SOURCE

Version: 2
Date: September 2006

Source: Carlo Trozzi
Techne Consulting
Italy

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[1] Updated with particulate matter details by: Mike Woodfield, AEA Technology, UK, December 2006

Email: carlo.trozzi@techne-consulting.com

SNAP CODE:

010203
020103
020202
020205
020302
020305
020106

SOURCE ACTIVITY TITLE: **SMALL COMBUSTION INSTALLATIONS**

NOSE CODE:

NFR CODE: 1A4a; 1A4bi; 1A4ci; 1A5a and small installations in 1A1a

Table 1: Relevant SNAP Codes

Source	**SNAP CODE**	**NFR category**
Small installations in district heating	010203	1A1a
Commercial / institutional	020103	1A4a
Residential	020202 020205	1A4bi
Agriculture / Forestry / Fishing	020302 020305	1A4ci
Other stationary (including military)	020106	1A5a

1 ACTIVITIES INCLUDED

This chapter covers emissions from small combustion installations, excluding industrial sources, with a thermal capacity ≤ 50 MW_{th}. However, some industrial sources of a lower capacity might have very similar emission characteristics to the ones described here in the category "medium size boilers". As long as there is no guidebook chapter addressing small industrial sources the data presented here might be used also as defaults for these sources.

Activities covered in this chapter are divided into the following categories:

- District heating
- Commercial and institutional
- Residential
- Agriculture / Forestry / Fishing, and
- Other (including military).

These activities can be further sub-divided considering the combustion techniques used:

- fireplaces
- stoves,
- small boilers (single household/domestic heating) – indicative capacity <50 kW$_{th}$,
- medium size boilers (<50 MW$_{th}$),
  - manual feeding (indicative capacity <1MW$_{th}$),
  - automatic feeding,
- combined heat and power generation (CHP).

The open-field burning of the agricultural residues and stationary internal combustion engines are not included in this chapter.

2 CONTRIBUTION TO TOTAL EMISSIONS

Tab 2.1. Contribution to total Particulate Matter emissions from 2004 EMEP database

NFR Sector	Data	PM_{10}	$PM_{2.5}$	TSP
1 A 1 a - Public Electricity and Heat Production[a]	No. of countries reporting	26	26	27
	Lowest Value	0.2%	0.2%	0.2%
	Typical Contribution	11.7%	10.1%	12.8%
	Highest Value	48.8%	47.8%	48.4%
1 A 4 a - Commercial / Institutional[a]	No. of countries reporting	23	23	23
	Lowest Value	0.1%	0.1%	0.1%
	Typical Contribution	3.9%	3.4%	4.5%
	Highest Value	19.3%	22.2%	29.5%
1 A 4 c - Agriculture / Forestry / Fishing	No. of countries reporting	23	23	23
	Lowest Value	0.1%	0.1%	0.2%
	Typical Contribution	4.3%	5.6%	3.4%
	Highest Value	17.4%	17.9%	21.9%
1 A 5 a - Other, Stationary (including Military)[a]	No. of countries reporting	7	7	7
	Lowest Value	0.0%	0.0%	0.0%
	Typical Contribution	0.1%	0.1%	0.1%
	Highest Value	0.5%	0.4%	0.6%

[a] Includes contribution from Chapter 111

This section covers emissions of CO, SO_2, NH_3, NO_x, NMVOC, TSP, PM10, PM2.5, heavy metals (arsenic, cadmium, chromium, copper, mercury, nickel, lead, selenium, zinc), PCDD/Fs, PAHs: benzo[a]pyrene, benzo[b]fluorantene, benzo[k]fluorantene and indeno[1,2,3-cd]pyrene.

The contribution of emissions from small combustion installations to the total emissions varies and depends on pollutants type and given country. A very important role is played by the emissions from small residential installations which are typically responsible for more than a third of the total particulate matter emissions of stationary combustion (UBA, 1998a; APEG, 1999; Olendrzynski et al., 2002) but in some countries this sector may dominate, e.g., in Austria (in 1995) more than 70% of PM emissions from stationary combustion are thought to have originated from this source (Winiwarter et al., 2001). The non-industrial SCI emission inventory for PM10 (which shows a similar trend for PM2.5) highlights the decrease in emissions from 2000 to 2020, predominantly due to the decline in the use of solid fuel. This source, however, remains significant due to the continued use of biomass. Emissions from this source are projected to decline overall due in main to the increased use of automatic feed boilers (Pye et al., 2004). In the year 2000, non-industrial combustion sources (i.e., in the residential and commercial sector) made the largest single contribution to total PM2.5 emissions in the 15 old Member States of the European Union (EU15), Norway and Switzerland (32 %), (Cofala et al., 2006). The emission source structure in the New Member States of the European Union is distinctively different to that of the EU-15+2 countries. Non-industrial combustion sources made by far the largest single contribution to total PM2.5 emissions in the EU-10 countries (45 %). The contribution of fuel combustion in commercial, residential and other small capacity installations to the total heavy metals emission in Europe in 1990 was for As 12.4%, for Cd 15.9% and for Hg 27.8% (Berdowski et al., 1997). Pye at al., (2005) have showed that the contribution Hg emission from SCIs account for 16% of total European emissions. Over half of emissions are from the industrial sector, with just over 20% coming from the residential sector. The major contribution by fuel type is from solid fuels, although biomass appears to be important in certain countries. Also emissions of PAH and PCDD/F from those activities are significant. For instance, residential use of solid fuels and biomass accounts for about half of the emissions of polycyclic aromatic hydrocarbons (COM(2003) 423 final) and one third of dioxin emissions in the EU (Quass U., et al., 2000). Those are characterized by seasonal variations, as it was reported that emission of B[a]P in winter is 10% higher than in summer (Baart et al., 1995). Many countries using coal (but also biomass) as a major part of domestic and commercial heating requirements have serious air pollution problems, one such a example is Poland; the TSP emissions from small combustion sources is 35% of the national total emissions, and up to 90% of the total TSP emissions from combustion activities (Olendrzynski et al., 2002). It was reported that the main source of PCDD/F (68% of national total) and PAH emission (87%) in Poland are non-industrial combustion plants (residential, district heating, agriculture, forestry). The share of heavy metals emissions such as Cd, As, Cr, Cu, Ni, Zn due to high emissions of TSP is also higher (respectively: 55%, 36%, 27%, 25%, 50%, 30%). In Belarus small combustion sources provide abut 40% of total PCDD/F emissions, and about 80% of indicator PAH emission (Kakareka et al., 2003). In general those sources have a more important contribution to the above-mentioned pollutants where a higher share of solid fuels exists in the fuel mix of the residential sector.

The estimated contribution of emissions released from small combustion installations to the total European emissions is presented in Table 2.2. These sources represent one of the strongest sources of particulate matter and even in the future they might remain an important contributor and their share might even increase for some pollutants and for some scenarios. It is also worthwhile to note that there are significant regional differences, e.g., in the EU-15, the share of this sector in particulate emissions has been typically below 20 % and is expected to decline further to about 12 and 17 % for PM10 and PM2.5, respectively; in the accession countries this share was in the 90's above 30 % and is expected to decline to about 22 and 28 % for PM10 and PM2.5, respectively. Projections presented for 2010 are for illustrative purpose only and refer to the European energy scenarios developed by the PRIMES model (CEC, 2003 and CEPMEIP, 2002) and implemented in the RAINS model recently.

The emission contribution of residential sources in the future will depend strongly from the assumptions about fuel switching (coal to gas) that has been happening in the last decade, a trend that is expected to continue and eventually lead to lower emissions of particulate matter but possibly at a cost of increased emissions of other pollutants as for example NO_x. At the same time biomass becomes a more and more popular fuel used in the residential sector; its use is strongly encouraged in some countries and is seen as a part of the strategy to achieve reductions of CO_2, however installations burning biomass are often characterized by higher emissions of particulates (Williams et al., 2001; Kubica et al., 1997/2 and 2001/1; Houck et al., 1998/1). All this indicates that air emissions from this source will remain an important source and more attention is required to be focused on them.

Tab.2.2. Contribution to total emissions (RAINS model results)

Pollutant	**Year**		
	1990	**1995**	**2010**
Oxides of nitrogen	4.5%	5%	7%
Sulphur dioxide	11%	8%	7%
Ammonia	About 0.5% - 1%		
NMVOC(1)	7%	7%	7%
$PM_{2.5}$(2)	25%	25%	19%
PM_{10}(2)	22%	20%	15%

(Source: IIASA, 2004)

(1) Contributions vary widely from country to country, e.g. 1% - 3% in the Netherlands or Italy, 10%-15% in Austria and 25%-30% in Sweden,

(2) Contributions vary widely from country to country, e.g. 2%-4% in the Netherlands and 40%-50% in Austria and Sweden,).

Furthermore the influence of those sources on the local air quality could be significant due to the low height of the flue gas releases, even where their share in total emissions is not dominant. This is particularly the case in the regions where solid fuels are predominately used in the residential sector. For instance, the occasional exceeding of the SO_2 ambient air target value could still be expected in the UK in some areas after the year 2000 (The Air Quality Strategy for UK; 2000) because of this reason.

3 GENERAL

3.1 Description

The small combustion installations included in this chapter are mainly intended for space heating and preparation of the hot water in residential and commercials/institutional sectors. In the residential sector some of these installations are also used for cooking. In the agricultural sector the heat generated by the installations is used also for crops drying and for heating the greenhouses.

The attention should be turned on small combustion installations due to their huge number, different type of combustion techniques employed, and because of the difficult auditing of their performance. Considerable part of them have none or low efficiency dedusting equipment. In some countries, particularly those with economies in transition, plants and equipment are outdated, polluting and inefficient. Especially in the residential sector the installations are very diverse, strongly depending on country and region, local fuel supply and in certain cases still reflecting the traditional heating practices.

3.2 Definitions

Automatic feed boiler:	boiler with fully automated fuel supply and adjustment of combustion air
Boiler:	any technical apparatus in which fuels are oxidised in order to generate thermal energy, which is transferred to water or steam
Briquettes:	refers to patent fuels from hard/sub-bituminous coal (NAPFUE 104) and brown coal briquettes (NAPFUE 106)
Brown coal:	refers to brown coal/lignite (NAPFUE 105) of gross caloric value (GHV) less than 17435 kJ/kg and containing more than 31 % volatile matter on a dry mineral matter free basis
Charcoal:	refers to temperature treated wood (NAPFUE 112)
Chimney:	brick, metal or concrete stack used to carry the exhaust gases into the free atmosphere and to generate drought
CHP:	in this chapter refers to a co-generation installation (Combined Heat and Power production) where steam produced in a boiler is used for both, power generation (in a steam turbine) and heat supply
Coke:	refers to the solid residue obtained from hard coal (NAPFUE 107) or from brown coal (NAPFUE 108) by processing at high temperature in the absence of air
Efficiency:	is the ratio of produced of output heat energy to energy introduced with the fuel, with reference to net (low) calorific value of fuel
Fireplace:	usually very simple combustion chamber, with or without front door, in which fuels are oxidized to obtain thermal energy, which is transferred to the dwelling mainly by radiation
Gaseous fuels:	refers to natural gas (NAPFUE 301), natural gas liquids (NAPFUE 302) and liquefied petroleum gases (LPG; NAPFUE 303), biogas (NAPFUE 309)
Hard coal:	refers to coal of a gross caloric value greater than 17435 kJ/kg on ash-free but moisture basis that is: steam coal (NAPFUE 102, GHV>23865 kJ/kg), sub-bituminous coal (NAPFUE 103, 17435 kJ/kg<GHV<23865 kJ/kg) and anthracite

Installation:	refers to any technical apparatus (fireplace, stoves, boiler) designed to generate heat energy
Liquid fuels:	refers to kerosene (NAPFUE 206), gas oil (gas/diesel oil; (NAPFUE 204), residual oil, residual fuel oil (NAPFUE 203) and other liquid fuels (NAPFUE 225)
Manual feed boiler:	boiler with manual periodical fuel supply
Patent fuels:	refers to manufactured smokeless fuels from hard/sub-bituminous coal (NAPPFUE 104)
Peat:	refers to peat-like fuels (NAPFUE 113)
Solid biomass fuel:	refers to wood fuels which are wood and similar wood wastes (NAPFUE 111) and wood wastes (NAPFUE 116) and agricultural wastes used as fuels (straw, corncobs, etc; NAPFUE 117)
Solid fuels:	refers to the subcategory of hard coal, brown coal, patent fuels, brown coal briquettes, coke, charcoal, peat, solid biomass fuels
Stove:	simple appliance in which fuels are combusted to obtain thermal energy, which is transferred to the interior of the building by radiation and convection
Wood fuels:	refers to wood and similar wood wastes (NAPFUE 111)

Some additional information on fuel properties could be found in Chapter Combustion Plants as Point Sources B111 and Combustion Plants as Point Sources B112.

3.3 Techniques

3.3.1 General

In small combustion installations a wide variety of fuels are used and several combustion technologies are applied. Especially older single household's installations are of very simple design, while some modern installations of all capacities are significantly improved. Emissions strongly depend on the fuel, combustion technologies as well as on operational practices and maintenance.

For the combustion of liquid and gaseous fuels, the technologies used are similar to those for production of thermal energy in industrial combustion activities, with the exception of the simple design of smaller appliances like fireplaces and stoves.

On the contrary the technologies for solid fuels and biomass utilization widely vary due to different fuel properties and technical possibilities. Small combustion installations employ mainly fixed bed combustion technology i.e. grate-firing combustion (*GF*) of solid fuels.

Solid fuels as well as a mixture of coal and biomass solid fuels, with grain size from a few mm to 80 mm, can be used.

The fluidised bed combustion technology can be also applied in small combustion installations. It is sporadically used within small combustion activities especially in district heating utilizing solid biomass.

A more detailed description of techniques is included in the EUR report Kubica, et al., 2004.

3.3.2 Fireplaces

Fireplaces were the first simple combustion devices, which were used by human beings. Fireplaces are used as supplemental heating appliances primarily for aesthetic reasons in residential dwellings. Based on the type of fuel used, the fireplaces can be subdivided into solid and gas fuelled fireplaces. Regarding the combustion conditions the fireplaces can be divided into open, partly closed and closed fireplaces. Based on the type of construction materials used, they can be divided into cut stone, and/or brick (masonry fireplaces), and cast iron or steel ones. Masonry fireplaces are usually built on site integrated into the building structure, while iron or steel are prefabricated.

3.3.2.1 Solid fuelled fireplaces

Regarding combustion techniques the solid fuelled fireplaces can be listed among the fixed bed combustion appliances. The user intermittently adds solid fuels to the fire by hand. They can be distinguished into:

Open fireplaces: this type of fireplaces is of very simple design - basic combustion chamber, which is directly connected to the chimney. Fireplaces have large openings to the fire bed. Some of them have dampers above the combustion area to limit the room air intake and resulting heat looses when fireplace is not being used. The heat energy is transferred to dwelling mainly by radiation. Open fireplaces are usually of masonry type and have very low efficiency while having significant emissions of TSP, CO, NMVOC and PAH resulting from the incomplete combustion of the fuels.

Partly closed fireplaces are equipped with louvers and glass doors to reduce the intake of combustion air. Some masonry fireplaces are designed or retrofitted in that way in order to improve their overall efficiency.

Closed fireplaces are equipped with front doors and may have distribution of combustion air to primary and secondary as well as a system to discharge the exhaust gases. They are prefabricated and installed as stand-alone units or as a fireplace inserts installed in existing masonry fireplaces. Because of the design and the combustion principle, closed fireplaces resemble stoves and their efficiency usually exceeds 50 %. They have similar emissions like stoves, i.e., lower than open, as well as, partly closed fireplaces. For this reason they can be rated among stoves.

Fuels used in solid fuel fireplaces are mainly: log, lump wood, biomass briquettes, and charcoal, coal and coal briquettes.

Traditional solid-fuelled fireplaces have high emissions and for that reason upgrade to a closed fireplace by installing inserts or their conversion to gas could reduce its emissions. Fireplaces might also be equipped with catalytic converters in an effort to limit emissions, but the control options are described in details later in chapter 3.5.

3.3.2.2 Gas fuelled fireplaces

The gas fireplaces are also of simple design; materials and equipment are similar to those of solid fuels fireplaces, yet equipped with a gas burner. Because of the simple valves employed for adjustment of fuel/air ratio and non-premixing burners, NO_x emissions are lower but emissions of CO and NMVOC are higher in comparison to the boilers using the same fuel.

3.3.3 Stoves

Stoves are simple appliances in which hand supplied fuels are combusted; useful heat is transmitted to the surroundings by radiation and convection. Depending on the main mode of heat transfer they are generally classified as radiating stoves or convection stoves (circulating, heat storing – heat accumulating). They can vary widely due to fuels type, application, design and construction materials, and also combustion process organisation. Due to the fuel properties they can be divided into the following subgroups:

- solid fuels
- liquid fuels
- gaseous fuels

The stoves utilizing solid fuels are usually used for heating of the rooms, but also for cooking, and hot water preparation (bath stove/furnace), while liquid and gas stoves are used for heating only.

3.3.3.1 Solid fuel stoves

The solid fuel stoves are classified on the basis of the combustion principle, which primarily depends on the airflow path through the charge of fuel in a combustion chamber. Two main types exist: up-draught (under-fire, down-burning combustion) and downdraught (up-burning combustion). The vast majority of older stoves are of the up-draught type, which is of simpler design, but has higher emissions.

The stoves can be made as prefabricated iron or steel appliances or masonry stoves, which are usually assembled on site with bricks, stone or ceramic materials. Regarding the main mode of heat transfer, solid fuel stoves can be divided into two main subgroups which are: radiating stoves, and heat storing - heat accumulating stoves.

Radiating stove; usually prefabricated iron or steel appliances; some of them used as cooking stoves. Radiating ordinary stoves are characterized by high emissions. The development of their design resulted in new constructions such as pellet stoves and stoves with advanced combustion process organization having higher efficiency and lower emissions. Considering the combustion process organization they can be differentiated as follows:

- *Conventional stoves* have poorly organised combustion process resulting in low efficiency (40% to 50%) and significant emissions of pollutants mainly originating from incomplete combustion (TSP, CO, NMVOC and PAH). Their autonomy is low, lasting from 3 to 8 hours. Those, which are equipped with hot plate zones, are used also for cooking - kitchen stoves. Some of them could also be used for hot water preparation.
- *Classic energy efficient stoves*; due to the utilization of secondary air in the combustion chamber their efficiency is between 55% to 75% and emission of pollutants are lower, their autonomy ranges from 6 to 12 hours.
- *Advanced combustion stoves*: These stoves are characterized by multiple air inlets and pre-heating of secondary combustion air by heat exchange with hot flue gases. This design results in increased efficiency (near 70% at full load) and reduced CO, NMVOC and TSP emissions in comparison with the conventional stoves.
- *Pellet stoves*: They can be fed only with pelletised fuels such as wood pellets, which are distributed to the combustion chamber by a fuel feeder from a small fuel storage. Pellets stoves are equipped with a fan and electronic control system for supply of the combustion air. For this reason they are characterized by high efficiency (above 80% up to 90%) and low emissions of CO, NMVOC, TSP and PAH.

Heat storing, heat accumulating stoves; depending on a country and regional tradition, masonry stoves are made of bricks, stones or combinations of both together with fireproof materials, such as ceramic (chamotte, faience). Sometimes they are made as prefabricated devices. Heat accumulating stoves are characterized with relatively low emissions of pollutants compared with the classical radiating stoves. Efficiency of masonry heating stoves ranges between 60% and 80%. Due to its function they can be diversified into:

- *Room heating stoves*; some more advanced of them employ contraflow system (Kubica et al, 2004) for heat transfer.
- *Heat accumulating cooking stoves* can be divided into two categories: simple residential cooking and boiler cooking stoves. The first ones are equipped with a combustion chamber with hot plate zones for food preparation and room heating; the second ones are simultaneously used as kitchen stove, room heating and hot water preparation (e.g. *"Russian stoves"*).

Catalytic combustor stove; Stoves, in particular for wood combustion, can be equipped with a catalytic converter in order to reduce emissions caused by incomplete combustion. Due to more complete oxidation of the fuels also energy efficiency increases. Catalytic combustors are not common for coal stoves.

Different kinds of solid fuels are used such as: coal and its products (usual anthracite, hard coal, brown coal, patent fuels, and brown coal briquettes) and biomass - lump wood and biomass pellets and briquettes. Coals of different grain sizes are used usually 20-40mm, and above 40mm, or mixtures of both. Peat is also occasionally used.

3.3.3.2 Liquid/gas fuelled stoves

The liquid/gas stoves have simple design; materials are alike for solid fuels stoves. Gas stoves are equipped with simple valves for fuel/air ratio adjustment and non-pre-mixing burners. For that reason emissions NO_x from these are lower in comparison to boilers. Simple liquid fuel stoves use evaporation systems for preparation of fuel/air mixture.

Regarding construction material and design, liquid and gas stoves are generally less diversified than those for solid fuels. They are made of steel and prefabricated.

3.3.4 Small boilers (single household/domestic heating) – indicative capacity ≤ 50 kW_{th}

Small boilers of this capacity are used in flats and single houses. All types of fuels could be used. They are mainly intended for generation of heat for the central heating system, but also hot water supply or combination of both.

3.3.4.1 Solid fuel small boilers

Small boilers for central heating for individual households are more widespread in temperate regions and usually have a nominal capacity between 12kW_{th} to 50kW_{th}. They use different types of solid fossil fuels and biomass usually depending on their regional availability. They could be divided into two broad categories regarding the organisation of combustion process: overfeed boiler (overfeed burning - over-fire and under-fire -, down-burning) and underfeed boiler (underfeed burning - upper-fire). They can be differentiated between conventional and advanced combustion boilers.

Conventional, coal/biomass boilers

Over-fire boilers: Over-fire boilers are commonly used in residential heating due to their simple operation and low investment cost. An incomplete combustion process takes place due to the non-optimal combustion air supply, which is usually generated by natural draught. The fuel is periodical fed onto the top of the burning fuel bed. The efficiency of the over-fire boiler is similar to the efficiency of conventional stoves, and is usually between 50% and 65%, depending on construction design and load. The emission of pollutants resulting from incomplete combustion of fuel may be very high particularly if they are operated at low load.

Under-fire boilers: Under-fire boilers have manual fuel feeding systems, and stationary or sloping grates. They have a two-part combustion chamber. The first part is used for storage of fuel and for partial devolatilization and combustion of the fuel layer. In the second part of the combustion chamber the combustible gases are oxidized. In the old design boilers natural draught is used. Combustion in under-fire boilers is more stable than in over-fire boilers, due to continuous gravity feed of fuel onto the fire bed. This results in higher energy efficiency (60-70%) and lower emissions in comparison to overfeed combustion.

Over-fire and under-fire boilers use all types of solid fuels except pellets, wood chips and fine-grained coal.

Advanced combustion boilers

Advance, under-fire coal boilers: In general the design and the combustion technique are similar to the conventional under-fire boiler. The main difference is that a fan controls the flue gases flow. Control system for the primary and secondary air might lead to increase in efficiency above 80% (usually between 70% and 80%).

Downdraught wood boilers: This type of boiler is considered state of the art in the lump wood combustion. It has two chambers, first one where the fuel is fed for partial devolatilisation and combustion of the fuel layer, and a secondary chamber, where burning of the released combustible gases occurs. The advantage of this boiler is that the flue gases are forced to flow down through holes in a ceramic grate and thus are burned at high temperature within the secondary combustion chamber and ceramic tunnel. Owing to the optimised combustion process, emissions due to incomplete combustion are low.

Stoker coal burners: The fuel with low ash contents and the grain size of between 4 mm up to 25 mm is automatically fed into to a retort by a screw conveyor. Stoker boiler is characterized by higher efficiency, usually above 80%. The advantage of stoker boiler is that it can operate with high efficiency within load range from 30% to nominal capacity. In a properly operated stoker, emissions of pollutants resulting from incomplete combustion are significantly lower, however NO_x increases due to the higher combustion temperature.

Wood pellet boiler has a fully automatic system for feeding of pellet fuels and for supply of combustion air, which is distributed into primary and secondary. The boilers are equipped with a smaller pellet storage, which is fuelled manually or by an automatic system from larger chamber storage. The pellets are introduced by screw into burner. These boilers are characterised by a high efficiency (usually above 80%) and their emissions are comparable to those of liquid fuel boilers.

3.3.4.2 Liquid/gas fuelled small boilers

These are usually two-function appliances used for hot water preparation and for heat generation for the central heating system. In the capacity range below 50 kW_{th} they are used mainly in single households. *Water-tube* low temperature boilers (temperature of water below 100^{o}C) (see 3.3.5.2) with open combustion chamber are usually used. These devices can be made of cast iron or steel. The boilers of capacity below 50 kW_{th}, can be divided into two main groups, i.e., standard boiler and condensation boilers.

Standard boilers; with open combustion chamber, having a maximum energy efficiency above 80%, because of the fact that flue gases are discharged at a temperature above 200^{o}C and the inlet/return water temperature is usually above 60^{o}C. Due to very simple design of combustion process automation system they are characterized by higher emission of CO and VOC in comparison to medium size boilers and industrial installations.

Condensation boilers; with closed combustion chamber; can operate with efficiency more than 90%. Recovering part of the latent heat from flue gases contributes to increased energy efficiency. It is achieved by condensation of the water vapour from the flue gases, which, in the optimal operation, have a temperature below 60°C at the chimney inlet. Gaseous fuels are mainly used in condensation boilers.

3.3.5 Boilers with indicative capacity between 50 kW_{th} and 50 MW_{th}

Boilers of such a capacity are used in multiresidential houses, block of flats and are the most commonly found small sources in commercial and institutional sector as well as in agriculture.

3.3.5.1 Solid fuels fuelled boilers

Fixed bed combustion technology is mainly used for combustion of solid fuels in this capacity range. This is a well-established technology, and a great variety of fixed bed layer and moving layer boilers (travelling grate combustion, stokers) are in use. Installations are differentiated into two main subgroups:

- manually fuelled
- automatically fuelled

In addition to fixed bed combustion also fluidised bed combustion boilers are in use in this capacity range, mostly for biomass combustion.

3.3.5.1.1 Manual feed boilers

Due to economical and technical reasons manual feeding boilers usually have a nominal capacity lower than $1MW_{th.}$

Coal/wood boilers

Manually fed boilers in this capacity range apply two combustion techniques, under-fire and upper-fire, similar as in boilers of lower capacity range (see 3.3.4.1).

Overfeed boilers, under-fire boilers: Coal fuels of different grain size (usually between 5mm and 40 mm) or lump wood are used in this type of installations. Their thermal efficiency ranges from 60% to 80% and depends on the air distribution into primary/secondary system and secondary sub-chamber design. The emissions of pollutants, i.e., CO, NMVOC, TSP and PAH resulting from incomplete combustion are generally high.

Overfeed boilers, upper-fire boilers: Fine coal, or mixture of fine coal with biomass chips, which are periodically moved into combustion chamber are used in this type of boilers. The ignition of fuel charge is started from its top. Their efficiency ranges from 75% to 80%. The emissions of pollutants of TSP, CO, NMVOC, PAH are lower in comparison to overfeed boilers due to different combustion process organization, which is similar to stoker combustion.

Both the under-fire and upper-fire boilers, in this capacity range, have better organisation of the combustion air compared with the ones used in single households.

Biomass/straw boilers

Overfeed boilers, biomass/straw fixed grate boilers: These are developed and applied for straw and cereal bale combustion. The straw bales are fed to the combustion chamber by hand. Because of very fast combustion of this kind of biomass these installations contain hot water accumulation system. For this reason they are used only in small-scale applications up to a nominal boiler capacity of 1,5 MW_{th}. They are very popular in the agricultural regions due to their relatively low costs and simple maintenance.

3.3.5.1.2 Automatic feed boilers

The automatic feed boilers usually have a capacity above $1MW_{th}$, but nowadays also lower capacity boilers are equipped with automatic feeding. In addition these installations have in general better control of the combustion process compared with manually fed ones. They typically require fuels of standardised and stable quality. These installations might also have dedusting equipment.

Moving bed (GF) combustion: They are commonly classified according to the way in which fuel is fed to the grate, as spreader stokers, overfeed stokers, and underfeed stokers.

The coal of smaller granulation or fine wood (e.g., chips or sawdust) is charged on a mechanical moving grate. The combustion temperatures are between 1000°C and 1300°C. The grate-fired installations are used also for co-combustion of coal with biomass. General applications are aimed at production of heat and/or hot water, and/or low-pressure steam for commercial and institutional users, in particular for district heating. Due to highly controlled combustion process of solid fuels in moving bed techniques and usually fully automatic process control systems the emissions of pollutants, resulting from incomplete combustion, is significantly lower in comparison to manual feed boilers.

Advanced techniques:

Underfeed coal/wood boilers; upper-fire burning, stoker boilers, underfeed rotating grate; are used for both coal and wood combustion. The process principle is combustion in underfeeding stoker. The fuel with low ash contents (wood chips, sawdust, pellets; particle sizes up to 50 mm, or coal up to 30 mm) is fed into the combustion chamber through a screw conveyor and is transported to a retort when is oxidised.

Cigar straw boiler is developed and applied for combustion of straw and cereal bales. The fuel bales are automatically transported to the combustion chamber by a hydraulic piston through an inlet tunnel into the combustion chamber.

Indirect combustor, gasification of wood biomass uses a separate gasification system for the chipped wood fuels, and the successive combustion of the product fuel gases in the gas boiler. An advantage of this technology is a possibility to use wet wood fuels of varying quality. This technique has low emissions of pollutants resulting from incomplete combustion of fuels.

Pre-ovens combustion system: Wood chip combustion installations are used in some countries, especially in the countryside, heating larger houses and farms. This system contains automatic chips fuel feeding by a screw and pre-ovens (well-insulated chamber) and could be connected to an existing boiler. Pre-ovens system applies full automatic combustion process and consequently emissions are low.

3.3.5.1.3 Fluidised bed combustion

The fluidised bed combustion (FBC) can be divided into bubbling fluidised bed (BFB) and circulating fluidised bed combustion (CFB), depending on the fluidisation velocity. The solid fuels are injected with combustion air through the bottom of the boiler into a turbulent bed. FBC is in particular adapted to poor quality, rich in ash coal. The FBC is most appropriate installation for co-combustion of coal with biomass and/or with waste fuels, or combustion of biomass. There are only few medium size installations of this type in operation.

3.3.5.2 Liquid/gas fuels

For gas and oil boilers the fuel and air are introduced as a mixture in the combustion chamber. The main distinction between gas/oil and coal pulverized combustion is the design of the individual burners of the boiler.

Boilers fired with gaseous and liquid fuels are produced in a wide range of different designs and are classified considering especially: burner configuration (injection burner or blow burner), material they are made of, the type of medium transferring heat (hot water, steam) and their power, the water temperature in the water boiler which can be: low temperature $\leq 100^{o}$C; medium-temperature $>100^{o}$C to $\leq 115^{o}$C; high-temperature $> 115^{o}$C), the heat transfer method (water-tube, fire -tube) and the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent over tube).

Cast iron boilers produce mainly low-pressure steam or hot water. Typically, they are used in residential and commercial/institutional sectors up to a nominal boiler capacity of about 1,5 MW_{th}.

Steel boilers are manufactured, up to a nominal capacity of 50 MW_{th}, from steel plates and pipes by means of welding. Their characteristic feature is the multiplicity of their design considering the orientation of heat transfer surface. The most common are: water-tube boilers, fire-tube boilers, furnace-fire-tube boilers and condensation boilers.

Water-tube boilers; are equipped with external, cubicle, steel water jacket. Water-tubes (water flows inside, exhaust gasses outside) are welded in the opposite walls of the cubicle.

Fire-tube boilers; in these boilers combustion gasses flow inside smoke tube, which are surrounded by the water. They are designed as cylinder or cubicle.

Furnace-fire-tube boilers made of steel; these devices are produced as the horizontal cylinders. The cylinder made of rolled steel plate ends at both sides with bottoms. The front bottom in its lower part (under the cylinder axis) is equipped with a furnace tube, which plays the role of combustion chamber.

Condensation boilers partly utilize the latent heat of the water vapour in the flue gases due to its condensation in the heat exchanger. For that reason their efficiency is higher than for other boiler systems. Their efficiency is more than 90%. They could efficiently operate at lower inlet water temperatures. Besides high efficiency their advantage is also lower emission of NO_x.

3.3.6 Combined Heat and Power (CHP)

Requirements to increase the efficiency of the energy transformation and the use of renewable energy sources have led to the development of the smaller CHP units using in particular biomass and other by-products as fuels. The steam produced by the boiler is used by backpressure steam turbine (ST) with subsequent heat utilization. Electricity generation efficiency is slightly reduced, however the overall efficiency is improved compared with separate generation of power and heat. CHP using internal combustion engines are not covered in this chapter.

3.4 Emissions

Relevant pollutants are SO_2, NO_x, CO, NMVOC, particulate matter, heavy metals, PAH and PCDD/F. Emission of ammonia (NH_3) is of lower importance.

For solid fuels generally the emissions due to incomplete combustion are many times greater in small appliances than in bigger plants. This is particularly valid for manually fed appliances and poorly controlled automatic installations.

For both, gaseous and liquid fuels, the emissions of pollutants are not significantly higher in comparison to industrial scale boilers due to the quality of fuels and design of burners and boilers, except for gaseous and liquid fuelled fireplaces and stoves because of their simple organization of combustion process. For the above-mentioned installations the same pollutants are generated as for solid fuels but their quantities are in general significantly lower.

Emissions caused by incomplete combustion are mainly a result of insufficient mixing of combustion air and fuel in the combustion chamber (local fuel-rich combustion zone), an overall lack of available oxygen, too low temperature, short residence times and too high radical concentrations (Kubica, 1997/1 and 2003/1). The following components are emitted to the atmosphere as a result of incomplete combustion in small combustion installations: CO, PM and NMVOCs, PAHs as well as PCDD/F. Small amounts of NH_3 may also be released as a result of incomplete conversion of NH_3.

The main influencing parameters, which determine the emissions and species profiles of some pollutants from combustion plants, are given in Section 3.4 and 9 of chapter B111 on

"Combustion Plant as Point Sources". Because pollutants from incomplete combustion, in particular from solid fuels use, have a significant share they are further discussed here together with heavy metals since their emissions from biomass are different.

NH_3 – Small amounts of ammonia may be emitted as a result of incomplete combustion process of all solid fuels containing nitrogen. This occurs in cases where the combustion temperatures are very low (fireplaces, stoves, old design boilers). NH_3 emissions generally can be reduced by primary measures aiming to reduce products of incomplete combustion and increase of efficiency.

TSP, PM10, PM2.5 –Particulate matter in flue gases from combustion of fuels (in particular of solid fuels and biomass) might be defined as carbon, smoke, soot, stack solid or fly ash. Emitted particulate matter can be classified into three groups of fuel combustion products.

The first group is formed via gaseous phase combustion or pyrolysis as a result of incomplete combustion of fuels (the products of incomplete combustion - PIC): soot and organic carbon particles (OC) are formed during combustion as well as from gaseous precursors through nucleation and condensation processes (secondary organic carbon) as a product of aliphatic, aromatic radical's reactions in a flame reaction zone in the presence of hydrogen and oxygenated species: CO and some mineral compounds as catalytic species, and VOC, tar/heavy aromatic compounds species as a results of incomplete combustion of coal/biomass devolatilization/pyrolysis products (from the first combustion step), and secondary sulphuric and nitric compounds. Condensed heavy hydrocarbons (tar substances) are an important, and in some cases, the main contributor to the total level of particles emission, in small-scale solid fuels combustion appliances such as fireplaces, stoves and old design boilers.

The next groups (second and third) may contain ash particles or cenospheres that are largely produced from fuels mineral matter, they contain oxides and salts (S, Cl) of Ca, Mg, Si, Fe, K, Na, P, and heavy metals, and unburned carbon form from incomplete combustion of carbonaceous material (black carbon or elemental carbon – BC; Kupiainen, et al., 2004); this is called carbon-in-ash (or loss on ignition).

Particulate matter emission from SCIs, mainly from different residential and commercial solid fuel appliances is typically combined with high emission of PICs associated and/or adsorbed. Size distribution depends on combustion conditions. Optimization of solid fuel combustion process by introduction of continuously controlled conditions (automatic fuel feeding, distribution of combustion air) leads to decrease of TSP emission and to change of PM distribution (Kubica, 2002/1 and Kubica et al., 2004/4). Application of co-combustion of coal and biomass leads to decrease of TSP, mainly PIC that are OC, (Kubica et al., 1997/2 and Kubica, 2004/5). Several studies have shown that the use of modern and "low-emitting" residential biomass combustion technologies leads to particle emissions dominated by submicron particles (< 1μm) and the mass concentration of particles larger than 10 μm is normally < 90 % for SCIs Boman et al., 2004 and 2005; Hays et al., 2003.

Heavy metals (HM) – Most of heavy metals considered (As, Cd, Cr, Cu, Hg, Ni, Pb, Se, and Zn) are usually released as compounds associated and/or adsorbed with particles (e.g. sulfides, chlorides or organic compounds). Hg, Se, As and Pb are at least partially present in the vapour phase only. Less volatile elements tend to condensate onto the surface of smaller particles in the exhaust gases. Therefore the emission of heavy metals strongly depends on their contents in the fuels. Coal and its derivatives normally contain amounts several orders of magnitude higher than in oil (exceptionally for Ni and V in heavy oils) and in natural gas (about 2-5 $\mu g/m^3$; van der Most *et al.,* 1992). All “virgin” biomass also contains heavy metals. Their content depends on the type of biomass. Higher emission of Cd, and Zn were observed in comparison to those from coal. During the combustion of coal and biomass, particles undergo complex changes, which lead to vaporization of volatile elements. The rate of volatilization of heavy metal compounds depends on technology characteristics (type of boilers; combustion temperature) and on fuel characteristics (their contents of metals, fraction of inorganic species, such as chlorine, calcium, etc.). The chemical form of the mercury emitted may depend in particular on the presence of chlorine compounds. The nature of the combustion appliance used and any associated abatement equipment will also have an effect (Pye et al., 2005/1). Mercry emitted form SCIs, similarly to emission from large scale combustion, occurs in elementary form (elemental Mercury vapour Hg^0), reactive gaseous form (Reactive Gaseous Mercury, RGM) and total particulate form (Total Particulate Mercury, TPM), Pacyna et al, 2004. Whereas it Has been show by Pye et al., 2005, that In case of SCIs distribution of particular species of emitted mercury is different to the one observed under large scale combustion. Contamination of biomass fuels, such as impregnated or painted wood may cause significantly higher amounts of heavy metals emitted (e.g. Cr, As). Heavy metals emissions can be reduced by secondary emission reduction measures, with the exception of Hg, As, Cd and Pb . Pye et al., 2005, have showed that limited technical abatement options (e.g. removal of mercury from flue gases after combustion) were identified specifically for SCIs, and those that were tended to be via abatement equipment that would normally be implemented for other pollutants, and which would have only indirect benefits for mercury emission reduction.

PCDD/F – The emissions of dioxins and furans are highly dependent on the conditions under which cooling of the combustion and exhaust gases is carried on. Carbon, chlorine, a catalyst and oxygen excess are necessary for the formation of PCDD/F. They are found to be consequence of the de-novo synthesis in the temperature interval between 180°C and 500°C (Karasek et al., 1987). Coal fired stoves in particular were reported to release very high levels of PCDD/F when using certain kinds of coal (Quass U., et al., 2000). The emission of PCDD/F is significantly increased when plastic waste is co-combusted in residential appliances or when contaminated/treated wood is used. The emissions of PCDD/F can be reduced by introduction of advanced combustion techniques of solid fuels (Kubica, 2003/3).

PAH – Emissions of polycyclic aromatic hydrocarbons results from incomplete (intermediate) conversion of fuels. As for CO, and NMVOC emissions of PAH depend on the organization of the combustion process, particularly on the temperature (too low temperature favourably increases their emission), the residence time in the reaction zone and the availability of oxygen (Kubica K., 1997/1, 2003/1). It was reported that coal stoves and old type boilers (hand fuelled) emit several times higher amounts of PAH in comparison to new design boilers (capacity below $50kW_{th}$), such as boilers with semi-automatic feeding (Kubica K., 2003/1, 2002/1,3). Technology of co-combustion of coal and biomass that can be applied in commercial/institutional and in industrial SCIs leads to reduction of emission PAHs, as well as TSP, NMVOCs and CO, Kubica et al., 1997/2 and 2004/5).

CO – Carbon monoxide is found in gas combustion products of all carbonaceous fuels, as an intermediate product of the combustion process and in particular for under-stoichiometric conditions. CO is the most important intermediate product of fuel conversion to CO_2; it is oxidized to CO_2 under appropriate temperature and oxygen availability. Thus CO can be considered as a good indicator of the combustion quality. The mechanisms of CO formation, thermal-NO, NMVOC and PAH are in general similarly influenced by the combustion conditions. The emissions level is also a function of the excess air ratio as well as of the combustion temperature and residence time of the combustion products in the reaction zone. Hence, small combustion installations of capacity above $1MW_{th}$, mainly with automatic feeding, have favourable conditions to achieve lower CO emission. Thus the emissions of CO from solid fuels fuelled small appliances are several thousand ppm in comparison to 50-100 ppm for industrial combustion chambers, used in power plants.

NMVOC – They are all intermediates in the oxidation of fuels. They can adsorb on, condense, and form particles. Similarly as for CO, emission of NMVOC is a result of too low temperature, too short residence time in oxidation zone, and/or insufficient oxygen availability. The emissions of NMVOC tend to decrease as the capacity of the combustion installation increases, due to the use of advanced techniques, which are typically characterized by improved combustion efficiency.

3.5 Controls

Reduction of emissions from combustion process can be achieved by either avoiding formation of such substances (primary measures) or by removal of pollutants from exhaust gases (secondary measures).

Primary measures. These actions, preventing or reducing emission comprise of several possibilities (Kubica, 2002/3, Pye et al., 2004):

- replacing of coal by upgraded solid derived fuel, biomass, oil, gas
- modification of fuels composition and improvement of their quality; preparation and improvement of quality of solid fuels, in particular of coal (in reference to S, Cl, ash contents, and fine sub-fraction contents); modification of the fuels granulation by means of compacting - briquetting, pelletizing; pre-cleaning – washing; selection of grain size in relation to the requirements of the heating appliances (stove, boilers) and supervision of its distribution; partial replacement of coal with biomass (implementation of co-combustion technologies enabling reduction of SO_2, and NOx), application of combustion modifier; catalytic and S-sorbent additives (limestone, dolomite), reduction and modification of the moisture contents in the fuel, especially in the case of solid biomass fuels
- selection of the combustion appliances type: replacement of low effective heating appliances with newly designed appliances, and supervision of their distribution by obligatory certification system; chimney sweeper supervision over residential and communal system heating
- improved construction of the combustion appliances; implementation of advanced technologies in fire places, stoves and boilers construction (implementation of BAT for combustion techniques and good combustion practice)

- control optimization of combustion process, mainly in small combustion installations capacity above 1MW$_{th}$.

Co-combustion of coal and biomass that can be applied in commercial/institutional and in industrial SCIs leads to reduction of TSP and PIC emission, mainly PAHs, NMVOCs and CO, Kubica et al., 1997/2 and 2004/5).

Secondary emission reduction measures: For small combustion installations a secondary measure can be applied to remove emissions, in particular PM. In this way emissions of pollutants linked with the PM, such as heavy metals, PAHs and PCDD/F can also be significantly reduced due to their removal together with particulate matter. These measures/controls are characterized by various dedusting efficiency (Perry at al., 1997 and Bryczkowski at al., 2002) and may be used mainly in medium size sources in small combustion installations (capacity at least 1 MW$_{th}$), due to technical reasons. For particulate matter the following options can be considered:

- settling chambers; gravity separation where the low collection efficiency (about 35% of fine dust, which contains 90% PM below 75 µm) is the main disadvantage,
- cyclone separators; disadvantage - low collection efficiency - their efficiency for fine particles is 78-85% - when compared to other filtration options, such as electrostatic precipitators or fabric filters, also tar substances may condense inside the apparatus,
- for higher effectiveness (94-99%) units with multiple cyclones (cyclone batteries) are applied, and multi-cyclones for increased gas flow rates,
- electrostatic precipitators (their efficiency is between 99,5% to 99,9%) or fabric filters (with efficiency about 99,9%) are typically not used in medium combustion plants due to their high costs. Fabric filters, which are relatively cheaper, also have the added constraint of operating temperatures below 200ºC and high-pressure drop.

Wood combustion appliances, stoves in particular, can be equipped with a catalytic converter in order to reduce emissions caused by incomplete combustion. The catalytic converter (a cellular or honeycomb, heat ceramic monolith covered with a very small amount of platinum, rhodium, or combination of these) is usually placed inside the flue gas channel beyond the main combustion chamber. When the flue gas passes through catalytic combustor, some pollutants are oxidized. The catalyst efficiency of emission reduction depends on the catalyst material, its construction – active surface, the conditions of flue gases flow inside converter (temperature, flow pattern, residence time, homogeneity, type of pollutants). For wood stoves with forced draught, equipped with catalytic converter (Hustad, *et al.*, 1995) the efficiency of emission reduction of pollutants is as follows: CO 70-93%,, CH_4 29-77%, other hydrocarbons more than 80%, PAH 43-80% and tar 56-60%. Reduction of CO emissions from stoves equipped with catalytic converter is significant in comparison to an advanced downdraught staged-air wood stove under similar operating conditions, (Skreiberg, 1994). However, the catalysts needs frequent inspection and cleaning. The lifetime of a catalyst in a wood stove with proper maintenance is usually about 10,000 hours.

Secondary measures with reference to, NO_x and SO_2 cannot be applied for small combustion installations from a technical and economical point of view. Because of the significant share of PM and the linked substances, technical methods for their reduction are currently under intense development especially for small sources of capacity below 1MW$_{th}$.

Due to the heterogeneity of SCIs across Europe, and the difference in energy markets, it is clear that technical measures for emission reduction will be implemented on a country-by-country basis, taking into consideration such differences. Primary (preventative) technical controls (such as replacement of appliance or change in type of fuel) will be used for smaller SCIs, while secondary abatement measures will be more applicable to larger institutional and industrial plant, Pye et al., 2005/1.

4 SIMPLER METHODOLOGY

4.1 General

This simpler methodology is intended for calculating and reporting emissions when the contribution of sources **1A1a; 1A4a; 1A4bi; 1A4ci; 1A5a (and small installations in 1A1a)** in the national totals is small or for the first assessment of emissions from these sources when there are no data available for application of the detailed methodology.

The simpler methodology described in this chapter refers to the calculation of the emissions, based on the split of the small combustion sources in the relevant sectors only with regard to the fuel used and anticipates the application of default emission factors. It covers all relevant emissions that are: SO_2, CO, NMVOC, NO_x, NH_3, TSP, PM10, PM2.5, heavy metals, PCDD/PCDF and PAH.

4.2 Applicability

The simpler methodology does not take into account differences in the emissions due to the wide variety of technologies, which is present among these sources, neither the different level of maintenance nor the influence of locally specific fuels. This is why the simpler approach might lead to a significant uncertainty in the estimated emissions. Moreover this approach does not take into account the penetration of new technologies, and thus might not represent appropriately the trends in emissions. **Therefore the simpler methodology should be applied only if the contribution of these sources in the national totals is small or for the first assessment of emissions from these sources when there are no data available for application of the detailed methodology.** In most cases when the share of solid fuels in covered sector is significant, the detailed methodology should be applied.

4.3 Methodology

The simpler methodology involves applying an appropriate emission factor to activity data given at the level of sectors (commercial/institutional, residential, agriculture and others). Within each sector only different fuels are distinguished. Default emission factors to facilitate this approach are provided in section 8.1.

Emissions can be estimated at different levels of complexity; it is useful to think in terms of three tiers[1]:

Tier 1: a method using readily available statistical data on the intensity of processes ("activity rates") and default emission factors. These emission factors assume a linear relation between the intensity of the process and the resulting emissions. The Tier 1 default emission factors also assume an average or typical process description.
Tier 2: is similar to Tier 1 but uses more specific emission factors developed on the basis of knowledge of the types of processes and specific process conditions that apply in the country for which the inventory is being developed.
Tier 3: is any method that goes beyond the above methods. These might include the use of more detailed activity information, specific abatement strategies or other relevant technical information.

By moving from a lower to a higher Tier it is expected that the resulting emission estimate will be more precise and will have a lower uncertainty. Higher Tier methods will need more input data and therefore will require more effort to implement.

For the Tier 1 simpler methodology, where limited information is available, a default emission factor can be used together with activity information for the country or region of interest with limited or no specification on the type of technology or the type and efficiency of control equipment. For a Tier 2 approach an approximation may be made of the most representative technologies, thereby allowing the use of more appropriate default factors if more detailed activity data are available.

Consequently the simplest methodology (Tier 1) is to combine an activity rate (AR) with a comparable, representative, value of the emissions per unit activity, the emission factors (EF). The basic equation is:

$$\text{Emission} = \text{AR} \times \text{EF}$$

In the energy sector, for example, fuel consumption would be activity data and mass of material emitted per unit of fuel consumed would be a compatible emission factor.

NOTE: The basic equation may be modified, in some circumstances, to include emission reduction efficiency (abatement factors).

The Tier 2 methodology is a modified version of this basic equation:

$$\text{Emission} = \sum((\text{AR}_1 \times \text{EF}_1) + (\text{AR}_2 \times \text{EF}_2) + \ldots.(\text{AR}_n \times \text{EF}_n))$$

Default emission factors for this purpose are provided in Sections 8.1 and 8.2.

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[1] The term "Tier" is used in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories and adopted here for easy reference and to promote methodological harmonization.

4.4 Emission factors

The simpler methodology envisages the use of default emission factors, which are given for all relevant pollutants. The default emission factors to be used within simple methodology for residential sector are given in Table 8.1a. For commercial/ institutional, agriculture and other sectors, where installations have on average higher capacity, default emission factors are given in Table 8.1b. These default emission factors were derived for conventional technologies.

However the default emission factors for SO_2 for fossil liquid and solid fuels should be used only in exceptional cases even within the simpler methodology. Sulphur content of the coal fuels used may vary significantly from country to country. Similarly there could be pronounced differences in sulphur content of the liquid fuels due to different levels of standards and legislation applied.

In the following a calculation procedure for SO_2 emission factor for coals and heating oils is proposed:

$$EF_{SO_2,k} = 2 \cdot \overline{Cs_k} \cdot \left(1 - \overline{\alpha_{S,k}}\right) \cdot \frac{1}{H_k} \cdot 10^6 , \qquad (2)$$

$EF_{SO2,k}$	emission factor for SO_2 for fuel type k [g/GJ]
$\overline{Cs_k}$	average sulphur content of fuel type k (mass S/mass fuel [kg/kg])
H_k	average lover heating value for fuel type k [MJ/kg]
$\overline{\alpha_{s,k}}$	average sulphur retention in ash

Average sulphur retention in ash $\overline{\alpha_{s,k}}$ is not relevant for liquid fuels and for these fuels should be taken as zero. For the coal fuels the default value of 0.1 should be taken in the absence of national data.

4.5 Activity data

In most cases the statistical information include data on annual fuels consumption in households, services and agriculture. Only in some cases data on fuels used by small consumers are available, which might include all sectors except mobile sources, industry and energy transformation. To fill these data gaps the following sources could be used:

- Information from the fuel suppliers and individual companies
- Energy conservation/climate change mitigation studies for relevant sectors
- Residential, commercial/institutional and agriculture sector surveys
- Energy demand modelling

The data from various sources should be compared taking into account their inherent uncertainties in order to obtain the best assessment. To improve reliability of the activity data appropriate efforts should be made in order to ensure that the institution responsible for national energy statistics includes evaluation and reporting of the fuel consumption at the adequate level of sectorial disaggregation in their regular activity.

Also when data on the fuel consumption are provided at an appropriate level of sectorial split, they should be checked for possible anomalies. Wood and other type biomass and in some cases also gas oil consumption in the households requires particular consideration.

The self-supply and direct purchase of the wood from farmers might not be taken into account when energy statistics are based mainly on the data obtained from the fuel suppliers. This could lead to a significant underestimation of the wood consumption especially in the countries with abundant wood supplies and greater share of heating with stoves and small solid fuel boilers. In that case the data on wood consumption should be adjusted. Consultation with the forestry experts and/or energy demand modelling is recommended. Wood consumption should be consistent with the related data reported to the UNFCCC.

Activity data may also be affected by the improper sectorial attribution of gas oil consumption. Due to the tax difference cheaper gas oil sold to households might be in particular circumstances used instead of diesel oil in vehicles and off–road machinery. In that case not only sectorial distribution of emissions is affected, but also emissions of certain pollutants at the national level could be underestimated due to the difference in emission factors. Evidence of such a situation could be obtained by energy demand modelling of the households and complementary bottom–up modelling of the fuel consumption of the mobile sources. Irregular changes in the time series of the gas and diesel oil quantities sold, not correlated with changes in economic situation could also indicate such phenomena. Inventorying agencies are encouraged to make most appropriate adjustments, however they have to be well documented.

5 DETAILED METHODOLOGY

5.1 General

This detailed methodology is intended for calculating emissions when the contribution of sources **1A1a; 1A4a; 1A4bi; 1A4ci; 1A5a (and small installations in 1A1a)** in the national totals is significant or data are available which enable its application.

The detailed methodology described in this chapter refers to the calculation of the emissions, based on the split of the small combustion sources not only to different fuel types, but also to different types of installations, which are found in those sectors. Default emission factor given for the detailed methodology, national emission factors or combination of both could be used.

The detailed methodology applies the same approach like the simpler methodology by using activity data and emission factors to estimate the emissions. The main difference is that the detailed methodology involves more country specific information like the specific emission factors for main installation types, further subdivision of the main installation types including those with control measures and/or use of the locally specific fuels. Development of the detailed methodology has to be focused to the combinations of the main installation types/fuels used, which consume most fuels and/or have the greatest share of the emissions from the considered sources.

5.2 Applicability

The detailed methodology envisages a more detailed split of the combustion installations. For that reason the national circumstances are taken more into account, especially if national emission factors are used. **The detailed methodology should be used when the considered sources have significant share of the national totals or significant changes of emissions are expected. However the application of the detailed methodology is recommended always when a country has more detailed or more specific, yet reliable enough information than those needed for the simpler methodology.**

5.3 Methodology

The annual emission is determined by an activity data and an emission factor:

$$E_i = \sum_{j,k} EF_{i,j,k} \cdot A_{j,k} \quad , \qquad (1)$$

where

E_i annual emission of pollutant i

$EF_{i,j,k}$ default emission factor of pollutant i for source type j and fuel k

$A_{j,k}$ annual consumption of fuel k in source type j

The main source types are:

- fire places,
- stoves,
- small boilers (single household/domestic heating) – indicative capacity <50 $\mathrm{kW_{th}}$,
- medium size boilers (<50 $\mathrm{MW_{th}}$),
  - manual feeding (indicative capacity <1$\mathrm{MW_{th}}$),
  - automatic feeding,

All those source types are not relevant for all sectors, as for instance fireplaces and stoves are mainly used in the residential sector.

The detailed methodology (equivalent to Tier 3) to estimate emissions of pollutants from combustion plant >50 $\mathrm{MW_{th}}$ is based on measurements or estimations using plant specific emission factors - guidance on determining plant specific emission factors is given in the Measurement Protocol Annex.

In many countries, operators of combustion plant >50MWth will report emissions to comply with regulatory requirements and this data can be used to help compile the national inventory.

The recommended detailed methodology to estimate emissions of PM from combustion activities is based on measurements and/or estimations using technology-specific emission factors.

Information on the type of the process and activity data, for example combustion and abatement technologies, is required to assign appropriate emission factors.

5.4 Emission factors

The detailed methodology envisages the use of default emission factors (Tables 8.2 a-g) developed for this purpose or their substitution/complementing with national emission factors.

The development of national emission factors should be focused on a combination of installation types and fuels, where specific national circumstances exist and/or contribution to the emission is the highest. When deriving specific emission factors the emphasis has to be given in taking into account also start–up emissions. These could, especially in the case of stoves and solid fuel small boilers, significantly influence the emissions of the total combustion cycle. For medium size installations data obtained from environmental inspectorates could be used taking into account whether there are representative or not.

5.5 Activity data

The detailed methodology requires further allocation of the fuel consumed according to the installation types. Those data are generally not available in the regular statistics reports. In most cases the inventorying agency would have to use surrogate data to assess the activity data at the required level of desegregation. National approaches have to be developed depending on the availability and quality of surrogate data. Some examples of surrogate data sources are:

- Residential, commercial/institutional and agriculture sector surveys
- Energy conservation/climate change mitigation studies for relevant sectors
- Energy demand modelling
- Information from the fuel suppliers
- Information from producers and sellers of heating appliances
- Chimney sweeping organisations

Particularly in the case of households it should be emphasised, that the surveys have to be based on a representative sample. In some countries the means of heating of the households are regionally very inhomogeneous with significantly greater share of solid fuel stoves and boilers in traditionally coal mining regions and at some rural areas. Additional data could be obtained from the chimneysweeper organisations and from environmental inspectorates particularly for the commercial-institutional sector.

Another important source of data could be dwelling statistics. Within the scope of national census the data on dwellings, occupied by the households are usually collected. Data on individual dwelling might include:

- number of residents,
- area of the dwelling,
- type of building (individual house, attached house, block of flats),
- construction year,
- existence or not of central heating,
- central heating boiler in the flat or common for block of flats
- fuels used for heating.

Dwelling statistics could be used to extrapolate results of the household survey or to perform detailed energy demand/emission modelling. Especially in the case where household emissions represent an important share in national totals or are of a great relevance due to local air pollution it is recommended to perform such an exercise. Detailed energy demand/emission modelling may be usually performed at local or regional level, however the extension to the national level does not pose significant additional requirements. To justify the additional effort required for energy demand/emission modelling of the households, the emission inventorying agency might find it appropriate to initiate a common project with other stakeholders, as for instance agencies competent for energy conservation, climate change mitigation or energy supply.

In the following a **brief outline of the energy demand/emission modelling** based on a dwelling census is given. The demand for useful energy for space heating could be calculated from the area of the flat and specific heat loses which depend on building code implied by the construction year of the building and ratio of outer building surface to dwellings surface. The latter could be characterised by the type of the building.

Required useful energy depends on the climatologically parameters, which are characterised by heating degree-days and the level of the heating, which is higher when the dwelling is equipped with the central heating. The heating energy demand is partly covered by gains of energy due to use of household electrical appliances and heat released directly by the residents. The heat gains could be considered as proportional to the number of residents. The remaining part of the required useful energy is supplied by the heating system. The fuel consumption depends on efficiency of the heating installation, which is characterised by the installation type and fuel used.

Where fossil fuels or biomass are used and no central heating exists it could be considered that stoves are used for space heating. The data on the use of fireplaces (i.e. number and average fuel use) has to be obtained from other sources, where relevant. Preparation of the hot water in households has also to be taken into the account, as it is at least partly supplied by the central heating boilers or special small boilers using natural gas.

Model parameters as for instance specific heat losses have to be determined at the national level due to differences in building code and practices. In some cases where there are significant climatic differences within the country, which are reflected in the different building codes for certain regions, it might be necessary, to derive and apply regionally specific heat loses. In almost all cases the heating degree-days have to be used at higher spatial resolution than country level.

Energy demand/emission modelling is the most appropriate to be performed at the level of the individual flat. In principle it could be possible to obtain data from the National Statistical office at such a level of details, however with individual dwellings located at the level of statistical district or within a grid large enough to satisfy the criteria of security of personal and individual data.

The census is usually performed once every 10-years. Thus the method has to be developed to periodically up-date the input data, most preferably on the basis of household surveys extrapolation complemented by the data from the fuel suppliers.

6 RELEVANT ACTIVITY STATISTICS

National or international statistics should be used e.g. fuels use and consumption. The following statistical publications could be recommended:

Statistical Office of the European Communities (EUROSTAT): NEWCRONOS database

Statistical Office of the European Communities (EUROSTAT): Energy Consumption in households – European Union and Norway, 1995 survey - Central and eastern European countries, 1996 survey

Statistical Office of the European Communities (EUROSTAT): Energy Consumption in the service sector – Surveys of EU Member states

7 POINT SOURCE CRITERIA

This section is not relevant since this chapter covers area sources only.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

Default emissions factors contained in the following tables are estimated representative values derived from collected data that are quoted later in Annex 1 as well as national experts judgments.

For the calculation of default emission factors for a simple methodology for residential sources, NFR: 1A4bi (Table 8.1a) the share of fireplaces, stoves and boilers fuelled by solid coal fuels, biomass and gaseous fuels was assumed as 5%, 65% and 30%, respectively and the emissions factors were taken from the detailed methodology tables. Within solid coal fuels a figure of about 5% was assumed for briquettes. For liquid fuels the share of stoves was assumed as 10% and boilers as 90%. Because the share of biomass and coal advanced stove and boilers was assumed to be currently lower than 5% in most of the countries they haven't been taken into consideration. For the activities NFR: 1A4a, 1A4ci, 1A5a and 1A1a (table 8.1b) the share of coal, gas and oil boilers with capacity between 50kW and 1MW and from 1MW to 50MW was assumed as 50% and 50% respectively. For coal fuels boilers the share of briquettes was assumed to be 5% similar to activity NFR 1A4bi. However the share of wood boilers with capacity between 50kW and 1MW and above 1MW to 50MW was assumed to be 60% and 40% respectively.

Automatic fuelled solid and biomass installations, as stokers and other automatic feed boilers, especially those larger than 1 MW, are usually equipped with some particulate matter control equipment. In this case mainly settling chambers and cyclones to reduce primary coarse particles and related pollutants. They are characterised by low collection efficiency, i.e., about 35% and 85% of dust, respectively. This collection efficiency refers to the 90% of PM below 75 μm. The default emission factors for the detailed methodology (Tables 8.2d, 8.2e and 8.2f) make allowance for using of this type of dedusting systems. In the modern installations also advanced dedusting equipment are employed.

8.1 Default Emission Factors For Use With Simpler Methodology

A summary of default emission factors for uses the simpler methodology for estimating emissions is provided in the following Tables.

Table 8.1a Default emission factors for the simple methodology of residential sources, NFR: 1A4bi

Pollutant	Emission factors				Units
	Solid coal fuels 1)	**Gaseous fuels 2)**	**Liquid fuels 3)**	**Wood 4)**	
Ammonia	0,3	Neg.	Neg.	3,8	g/GJ
Sulphur dioxide	900 5)	0,5	140 6)	20,0	g/GJ
Nitrogen dioxide	109,7	57,0	68,0	74,5	g/GJ
Total suspended particulate matter	443,6	0,5	6,0	730,0 8)	g/GJ
PM10	404,1	0,5	3,7	695,3 8)	g/GJ
PM2.5	397,5	0,5	3,7	694,8 8)	g/GJ
Arsenic	2,5	NA. 7)	0,9	1,0	mg/GJ
Cadmium	1,5	NA	1,5	1,4	mg/GJ
Chromium	11,2	NA	15,5	2,9	mg/GJ
Copper	22,3	NA	7,9	8,6	mg/GJ
Mercury	5,1	0,0	0,0	0,5	mg/GJ
Nickel	12,7	NA	240,0	4,4	mg/GJ
Lead	130,0	NA	15,5	40,0	mg/GJ
Selenium	120,0	NA	0,0	0,5	mg/GJ
Zinc	220,0	NA	8,5	130,0	mg/GJ
Dioxins and furans	800,0	0,5	10,0	700,0	I-Teqng/GJ
PAH Σ 1-4	800,0	NA	75,0	700,0	mg/GJ
Benzo(a)pyrene	230,0	NA	22,0	210,0	mg/GJ
Benzo(b)fluoranthene	330,0	NA	25,7	220,0	mg/GJ
Benzo(k)fluoranthene	130,0	NA	12,5	130,0	mg/GJ
Indeno(1,2,3_cd)pyrene	110,0	NA	14,8	140,0	mg/GJ
Carbon monoxide	4602,5	31,0	46,0	5300,0	g/GJ
Non methane VOC	484,3	10,5	15,5	925,0	g/GJ

N.B: The emission factors in this table reflect the finding that much of the combustion equipment used in a domestic environment is relatively old, manually fuelled, and the penetration of new technologies is slow.

1) Use this "Solid coal fuels" default for all raw coals as well as for the derived coal fuels such as patent fuels, coke and other manufactured coal fuels
2) Use this "Gaseous fuels" default for natural gas, liquefied petroleum gas (LPG), and other gaseous fuels
3) Use this "Liquid fuels" default for gas oil (gas/diesel oil), fuel oil (residual oil, residual fuel oil) and other liquid fuels
4) Use this "Wood" default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)
5) 900 g/GJ of sulphur dioxide corresponds to 1.2 % S of coal fuel of lower heating value on a dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY
6) 140 g/GJ of sulphur dioxide corresponds to 0.3 % S of liquid fuel of lower heating value 42 GJ/t. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY. Because the sulphur content of liquid fuels is defined also by national regulations, compilers of the emission inventory should consider the national standards for sulphur content as well as information on average sulphur content on the market, if available
7) NA - not applicable
8) Emission factors, from more recent European and North American work, indicate the figures for burning prepared wood fuel are considerably lower, possibly by a factor of 2-3.

Table 8.1b Default emission factors for the simple methodology of the sources, NFR: 1A4a, 1A4ci, 1A5a and 1A1a

Pollutant	Emission factors				Units
	Solid coal fuels [1]	Gaseous fuels [2]	Liquid fuels [3]	Wood [4]	
Ammonia	NA [5]	NA	NA	NA	g/GJ
Sulphur dioxide	839,5 [6]	0,5	140 [7]	38,4	g/GJ
Nitrogen dioxide	173,1	70,0	100,0	150,0	g/GJ
Total suspended particulate matter	124,2	NA	27,5	156,4	g/GJ
PM10	117,2	NA	21,5	149,9	g/GJ
PM2.5	107,7	NA	16,5	149,1	g/GJ
Arsenic	4,0	NA	1,0	1,4	mg/GJ
Cadmium	1,8	NA	0,3	1,8	mg/GJ
Chromium	13,5	NA	12,8	6,5	mg/GJ
Copper	17,5	NA	7,2	4,6	mg/GJ
Mercury	7,9	0,0	0,1	0,7	mg/GJ
Nickel	13,0	NA	260,0	2,0	mg/GJ
Lead	134,2	NA	16,0	24,8	mg/GJ
Selenium	1,8	NA	NA	NA	mg/GJ
Zinc	200,0	NA	8,0	113,6	mg/GJ
Dioxins and furans	202,6	2,0	10,0	326,0	I-Teq ng/GJ
PAH Σ 1-4	146,7	NA	17,6	155,2	mg/GJ
Benzo(a)pyrene	45,5	NA	5,2	44,6	mg/GJ
Benzo(b)fluoranthene	58,9	NA	6,2	64,9	mg/GJ
Benzo(k)fluoranthene	23,7	NA	4,0	23,4	mg/GJ
Indeno(1,2,3_cd)pyrene	18,5	NA	2,2	22,3	mg/GJ
Carbon monoxide	931,0	25,0	40,0	1596,0	g/GJ
Non methane VOC	88,8	2,5	10,0	146,4	g/GJ

N.B The table assumes a 20% penetration rate for new technologies.

[1] Use this "Solid coal fuels" default for all raw coals as well as for the derived coal fuels such as patent fuels, coke and other manufactured coal fuels

[2] Use this "Gaseous fuels" default for natural gas, liquefied petroleum gas (LPG), and other gaseous fuels

[3] Use this "Liquid fuels" default for gas oil (gas/diesel oil), fuel oil (residual oil, residual fuel oil) and other liquid fuels

[4] Use this "Wood" default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)

[5] NA - not applicable

[6] 900 g/GJ of sulphur dioxide corresponds to 1.2 % S of coal fuel of lower heating value on a dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY

[7] 140 g/GJ of sulphur dioxide corresponds to 0.3 % S of liquid fuel of lower heating value 42 GJ/t. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY. Because the sulphur content of liquid fuels is defined also by national regulations, compilers of the emission inventory should consider the national standards for sulphur content as well as information on average sulphur content on the market, if available.

8.2 Default emission factors which could be used with Detailed Methodology

A summary of default emission factors that could be used within the detailed methodology for estimating emissions is provided in the following Tables.

Table 8.2a Default emission factors for fireplaces

Pollutant	Emission factors			Units
	Coal fuels 1)	Gaseous fuels 2)	Wood 3)	
Ammonia	5	NA 4)	10	g/GJ
Sulphur dioxide	500 5)	0,5	10	g/GJ
Nitrogen dioxide	60	50	50	g/GJ
Total suspended particulate matter	350	0.5	900	g/GJ
PM10	330	0.5	860	g/GJ
PM2.5	330	0.5	850	g/GJ
Arsenic	1.5	NA	0.5	mg/GJ
Cadmium	0,5	NA	2	mg/GJ
Chromium	10	NA	1	mg/GJ
Copper	20	NA	8	mg/GJ
Mercury	3	0.01	0.4	mg/GJ
Nickel	10	NA	2	mg/GJ
Lead	100	NA	40	mg/GJ
Selenium	1	NA	0.5	mg/GJ
Zinc	200	NA	100	mg/GJ
Dioxins and furans	500	1,5	800	I-Teq ng/GJ
PAH Σ 1-4	450	NA	600	mg/GJ
Benzo(a)pyrene	100	NA	180	mg/GJ
Benzo(b)fluoranthen	170	NA	180	mg/GJ
Benzo(k)fluoranthen	100	NA	100	mg/GJ
Indeno(1,2,3-cd)pyrene	80	NA	140	mg/GJ
Carbon monoxide	5000	50	6000	g/GJ
Non methane VOC	600	20	1300	g/GJ

1) Use this “Solid coal fuels” default for all raw coals as well as for the derived coal fuels such as patent fuels, coke and other manufactured coal fuels

2) Use this “Gaseous fuels” default for natural gas, natural gas liquids, and liquefied petroleum gas (LPG), and other gaseous

3) Use this “Wood” default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)

4) NA - not applicable

5) 500 g/GJ of sulphur dioxide is adequate to 0.8 % S of coal fuels of lower heating value of fuel on a dry basis 29 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY.

Table 8.2b Default emission factors for domestic stoves

Pollutant	Emission factors					Units
	Coal fuels 1)	Briquettes 2)	Gaseous fuels 3)	Liquid fuels 4)	Wood 5)	
Ammonia	NA 6)	NA	NA	NA	5	g/GJ
Sulphur dioxide	900 7)	500 8)	0.5	140 9)	10	g/GJ
Nitrogen dioxide	100	100	50	50	50	g/GJ
Total suspended particulate matter	500	200	0.5	15	850	g/GJ
PM10	450	100	0.5	10	810	g/GJ
PM2.5	450	100	0.5	10	810	g/GJ
Arsenic	1.5	1	NA	0.5	0.5	mg/GJ
Cadmium	1	0.7	NA	0.3	1	mg/GJ
Chromium	10	5	NA	5	2	mg/GJ
Copper	20	10	NA	3	8	mg/GJ
Mercury	5	3	0.01	0.03	0.4	mg/GJ
Nickel	10	7	NA	100	2	mg/GJ
Lead	100	70	NA	5	40	mg/GJ
Selenium	2	0.5	NA	NA	0.5	mg/GJ
Zinc	200	120	NA	5	100	mg/GJ
Dioxins and furans	1000	300	1.5	10	800	I-Teq ng/GJ
PAH Σ 1-4	920	220	NA	180	820	mg/GJ
Benzo(a)pyrene	250	50	NA	50	250	mg/GJ
Benzo(b)fluoranthen	400	90	NA	60	240	mg/GJ
Benzo(k)floranthene	150	40	NA	30	150	mg/GJ
Indeno(1,2,3_cd)pyrene	120	40	NA	40	180	mg/GJ
Carbon monoxide	5000	4000	30	100	6000	g/GJ
Non methane VOC	600	300	10	20	1200	g/GJ

1) Use this “Coal fuels” default for all raw coals

2) Use this “Briquettes” default for patent fuels, coke and other manufactured coal fuels

3) Use this “Gaseous fuels” default for natural gas, natural gas liquids, and liquefied petroleum gas (LPG), and other gaseous

4) Use this “Liquid fuels” default for burning oil (kerosene), gas oil (gas/diesel oil), fuel oil (residual oil, residual fuel oil) and other liquid fuels

5) Use this “Wood” default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)

6) NA - not applicable

7) 900 g/GJ of sulphur dioxide is adequate to 1.2 % S of coal fuel of lower heating value on a dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY.

8) 500 g/GJ of sulphur dioxide is adequate to 0.8 % S of briquettes of lower heating value of fuel on a dry basis 29 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY.

9) 140 g/GJ of sulphur dioxide corresponds to 0.3 % S of liquid fuel of lower heating value 42 GJ/t. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY Because the sulphur content of liquid fuels is defined also by national regulations, compilers of the emission inventory should consider the national standards for sulphur content as well as information on average sulphur content on the market, if available.

Table 8.2c Default emission factors for small (single household scale, capacity ≤50 kWth) boilers

Pollutant	Emission factors					Units
	Coal fuels [1]	Briquettes[2]	Gaseous fuels[3]	Liquid fuels[4]	Wood[5]	
Ammonia	NA[6]	NA	NA	NA	NA	g/GJ
Sulphur dioxide	900 [7]	500 [8]	0.5	140 [9]	30	g/GJ
Nitrogen dioxide	130	200	70	70	120	g/GJ
Total suspended particulate matter	400	120	0.5	5 [10]	500	g/GJ
PM10	380	100	0.5	3 [10]	475	g/GJ
PM2.5	360	100	0.5	3 [10]	475	g/GJ
Arsenic	5	3	NA	1	2	mg/GJ
Cadmium	3	0,7	NA	2	2	mg/GJ
Chromium	15	10	NA	20	5	mg/GJ
Copper	30	20	NA	10	10	mg/GJ
Mercury	6	3	0.01	0.03	0.6	mg/GJ
Nickel	20	13	NA	300	10	mg/GJ
Lead	200	120	NA	20	40	mg/GJ
Selenium	2	1.5	NA	NA	0.5	mg/GJ
Zinc	300	200	NA	10	200	mg/GJ
Dioxins and furans	500	200	NA	10	500	I-Teq ng/GJ
PAH Σ 1-4	710	150	NA	30	510	mg/GJ
Benzo(a)pyrene	270	50	NA	10	130	mg/GJ
Benzo(b)fluoranthen	250	50	NA	11	200	mg/GJ
Benzo(k)fluoranthen	100	30	NA	5	100	mg/GJ
Indeno(1,2,3_cd)pyrene	90	20	NA	4	80	mg/GJ
Carbon monoxide	4000	3000	30	40	4000	g/GJ
Non methane VOC	300	200	10	15	400	g/GJ

[1] Use this "Coal fuels" default for all raw coals

[2] Use this "Briquettes" default for patent fuels, coke and other manufactured coal fuels

[3] Use this "Gaseous fuels" default for natural gas, natural gas liquids, and liquefied petroleum gas (LPG), and other gaseous

[4] Use this "Liquid fuels" default for burning oil (kerosene), gas oil (gas/diesel oil), fuel oil (residual oil, residual fuel oil) and other liquid fuels

[5] Use this "Wood" default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)

[6] NA - not applicable

[7] 900 g/GJ of sulphur dioxide is adequate to 1.2 % S of coal fuel of lower heating value on a dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY

[8] 500 g/GJ of sulphur dioxide is adequate to 0.8 % S of briquettes of lower heating value on a dry basis 29 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY.

[9] 140 g/GJ of sulphur dioxide corresponds to 0.3 % S of liquid fuel of lower heating value 42 GJ/t. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY Because the sulphur content of liquid fuels is defined also by national regulations, compilers of the emission inventory should consider the national standards for sulphur content as well as information on average sulphur content on the market, if available.

[10] Proposed emission factor is representative for light fuel oil; typical emissions from residential boilers burning heavy fuel oil would be about 10 times higher than this value.

Table 8.2d Default emission factors for medium size (>50 kWth to ≤1 MWth) boilers

Pollutant	Emission factors					Units
	Coal fuels 1)	Briquettes 2)	Gas fuels 3)	Liquid fuels 4)	Wood 5)	
Ammonia	NA 6)	NA	NA	NA	NA	g/GJ
Sulphur dioxide	900 7)	500 8)	0,5	140 9)	50	g/GJ
Nitrogen dioxide	160	150	70	100	150	g/GJ
Total suspended particulate matter	200	100	NA	5 10)	250	g/GJ
PM10	190	80	NA	3 10)	240	g/GJ
PM2.5	170	80	NA	3 10)	240	g/GJ
Arsenic	5	4	NA	1	2	mg/GJ
Cadmium	3	0.7	NA	0.3	2	mg/GJ
Chromium	15	10	NA	20	10	mg/GJ
Copper	30	20	NA	10	5	mg/GJ
Mercury	7	3.5	0.01	0.1	0.6	mg/GJ
Nickel	20	13	NA	300	2	mg/GJ
Lead	200	100	NA	20	30	mg/GJ
Selenium	2	1.5	NA	NA	NA	mg/GJ
Zinc	300	160	NA	10	150	mg/GJ
Dioxins and furans	400	100	2	10	500	I-Teq ng/GJ
PAH; Σ 1-4	320	90	NA	26	280	mg/GJ
Benzo(a)pyrene	100	30	NA	8	80	mg/GJ
Benzo(b)fluoranthen	130	40	NA	9	120	mg/GJ
Benzo(k)fluoranthen	50	10	NA	6	40	mg/GJ
Indeno(1,2,3-cd)pyrene	40	10	NA	3	40	mg/GJ
Carbon monoxide	2000	1500	30	40	3000	g/GJ
Non methane VOC	200	100	3	15	250	g/GJ

1) Use this “Coal fuels” default for all raw coals

2) Use this “Briquettes” default for patent fuels, coke and other manufactured coal fuels

3) Use this “Gaseous fuels” default for natural gas, natural gas liquids, and liquefied petroleum gas (LPG), and other gaseous

4) Use this “Liquid fuels” default for burning oil (kerosene), gas oil (gas/diesel oil), fuel oil (residual oil, residual fuel oil) and other liquid fuels

5) Use this “Wood” default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)

6) NA - not applicable

7) 900 g/GJ of sulphur dioxide is adequate to 1.2 % S of coal fuel of lower heating value on a dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY

8) 500 g/GJ of sulphur dioxide is adequate to 0.8 % S of briquettes of lower heating value on a dry basis 29 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY

9) 140 g/GJ of sulphur dioxide corresponds to 0.3 % S of liquid fuel of lower heating value 42 GJ/t. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY Because the sulphur content of liquid fuels is defined also by national regulations, compilers of the emission inventory should consider the national standards for sulphur content as well as information on average sulphur content on the market, if available.

10) Proposed emission factor is representative for light fuel oil; typical emissions from residential boilers burning heavy fuel oil would be about 10 times higher than this value.

Table 8.2e Default emission factors for medium size (>1 MWth to ≤50 MWth) boilers

Pollutant	Emission factors				Units
	Coal fuels[1]	Gaseous fuels[2]	Liquid fuels[3]	Wood fuels[4]	
Ammonia	NA[5]	NA	NA	NA	g/GJ
Sulphur dioxide	900 [6]	0.5	140 [7]	30	g/GJ
Nitrogen dioxide	180	70	100	150	g/GJ
Total suspended particulate matter	80	NA	50 [8]	70	g/GJ
PM10	76	NA	40 [8]	67	g/GJ
PM2.5	72	NA	30 [8]	65	g/GJ
Arsenic	4	NA	1	1	mg/GJ
Cadmium	1	NA	0,3	2	mg/GJ
Chromium	15	NA	2	3	mg/GJ
Copper	10	NA	3	5	mg/GJ
Mercury	9	0.01	0.1	0.8	mg/GJ
Nickel	10	NA	200	2	mg/GJ
Lead	100	NA	10	20	mg/GJ
Selenium	2	NA	NA	NA	mg/GJ
Zinc	150	NA	5	80	mg/GJ
Dioxins and furans	100	2	10	200	I-Teq ng/GJ
PAH Σ 1-4	45	NA	5	40	mg/GJ
Benzo(a)pyrene	13	NA	1	12	mg/GJ
Benzo(b)fluoranthen	17	NA	2	14	mg/GJ
Benzo(k)fluoranthen	9	NA	1	8	mg/GJ
Indeno(1,2,3-cd)pyrene	6	NA	1	6	mg/GJ
Carbon monoxide	200	20	40	300	g/GJ
Non methane VOC	20	2	5	60	g/GJ

[1] Use this “Coal fuels” default for all raw coals

[2] Use this “Gaseous fuels” default for natural gas, natural gas liquids, and liquefied petroleum gas (LPG), and other gaseous

[3] Use this “Liquid fuels” default for burning oil (kerosene), gas oil (gas/diesel oil), fuel oil (residual oil, residual fuel oil) and other liquid fuels

[4] Use this “Wood” default for wood, peat and similar wood fuels (wood wastes) and agricultural wastes use as fuels (straw, corncobs, etc)

[5] NA - not applicable

[6] 900 g/GJ of sulphur dioxide is adequate to 1.2 % S of coal fuel of lower heating value on dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY.

[7] 140 g/GJ of sulphur dioxide corresponds to 0.3 % S of liquid fuel of lower heating value 42 GJ/t. If data on the sulphur content exist use equation No (2); see: 4. SIMPLER METHODOLOGY Because the sulphur content of liquid fuels is defined also by national regulations, compilers of the emission inventory should consider the national standards for sulphur content as well as information on average sulphur content on the market, if available.

[8] Proposed emission factor is more representative for heavy fuel oil; typical emissions from boilers burning light fuel oil would be about 10% of this value, see table 8.2c.

Table 8.2f Default emission factors for advanced coal combustion techniques <1MWth

Pollutant	Emission factors			Units
	Advanced stove	Manual boiler	Authomatic boiler	
Ammonia	NA[1)]	NA	NA	g/GJ
Sulphur dioxide	450 [2)]	450 [2)]	450 [2)]	g/GJ
Nitrogen dioxide	150	200	200	g/GJ
Total suspended particulate matter	250	150	80	g/GJ
PM10	240	140	76	g/GJ
PM2.5	220	130	72	g/GJ
Arsenic	1.5	4	0.5	mg/GJ
Cadmium	1	2	2	mg/GJ
Chromium	10	10	1	mg/GJ
Copper	15	15	8	mg/GJ
Mercury	5	6	8	mg/GJ
Nickel	10	15	2	mg/GJ
Lead	100	150	80	mg/GJ
Selenium	2	2	0.5	mg/GJ
Zinc	200	200	100	mg/GJ
Dioxins and furans	500	200	40	I-Teq ng/GJ
PAH Σ 1-4	510	290	50	mg/GJ
Benzo(a)pyrene	150	90	17	mg/GJ
Benzo(b)fluoranthen	180	110	18	mg/GJ
Benzo(k)fluoranthen	100	50	8	mg/GJ
Indeno(1,2,3-cd)pyrene	80	40	7	mg/GJ
Carbon monoxide	2000	1500	400	g/GJ
Non methane VOC	300	100	20	g/GJ

[1)] NA - not applicable

[2)] 450 g/GJ of sulphur dioxide is adequate to 0.6 % S of coal fuel of lower heating value on a dry basis 24 GJ/t and average sulphur retention in ash as value of 0.1. If data on the sulphur content exists use equation No (2), see: 4. SIMPLER METHODOLOGY.

Table 8.2g Default emission factors for advanced wood combustion techniques <1MW

Pollutant	Emission factors					Units
	Advanced fireplaces	Advanced stove	Pellet stove	Manual boiler	Authomatic boiler	
Ammonia	NA[1]	NA[1]	NA	NA	NA	g/GJ
Sulphur dioxide	20	20	20	20	20	g/GJ
Nitrogen dioxide	90	90	90	150	150	g/GJ
Total suspended particulate matter	250	250	80	80	70	g/GJ
PM10	240	240	76	76	66	g/GJ
PM2.5	240	240	76	76	66	g/GJ
Arsenic	0.5	0.5	0.5	1	0.5	mg/GJ
Cadmium	1.0	1.0	0.5	0.3	0.5	mg/GJ
Chromium	8	8	3	2	4	mg/GJ
Copper	2	2	1	3	2	mg/GJ
Mercury	0.4	0.4	0.4	0.5	0.6	mg/GJ
Nickel	2	2	2	200	2	mg/GJ
Lead	30	30	20	10	20	mg/GJ
Selenium	0.5	0.5	NA	NA	NA	mg/GJ
Zinc	80	80	80	5	80	mg/GJ
Dioxins and furans	300	300	50	300	30	I-Teq ng/GJ
PAH Σ 1-4	290	290	50	150	40	mg/GJ
Benzo(a)pyrene	100	100	15	50	12	mg/GJ
Benzo(b)fluoranthen	90	90	16	60	14	mg/GJ
Benzo(k)fluoranthen	40	40	10	20	8	mg/GJ
Indeno(1,2,3-cd)pyrene	60	60	9	20	6	mg/GJ
Carbon monoxide	4500	3000	500	3000	300	g/GJ
Non methane VOC	450	250	20	250	20	g/GJ

[1] NA - not applicable

Table 8.2.h Default mercury emission factor speciation for different fuels

Fuel	Installation	Hg^0 (gas)	Hg^{+2}	Hg (partic.); Hg^{PM}
Hard Coal	Stove / Fireplaces	0.3	0.35	0.35
	Boiler manual fuelled - all SCI sectors	0.4	0.4	0.2
	Boiler autom. (stoker) - all SCI sectors	0.5	0.4	0.1
Biomass	Manual fuelled (stove boiler) - all SCI sectors	0.6	0.3	0.1
	Automatic fuelled- all SCI sectors	0.65	0.3	0.05
Liquid fuels	SCIs (all sectors) Light fuel oil	0.75	0.2	0.05
	SCIs AFF, Com-Inst Heavy fuel oil	0.65	0.35	0.1
Natural gas	SCIs (all sectors)	0.8	0.15	0.05

9 SPECIES PROFILES

See section 8.2 for reference emission factors for species profiles.

10 UNCERTAINTY ESTIMATES

Uncertainties of emission data result from the uncertainties related to both the emission factors and the statistical information on the activities covered by small combustion installations.

The uncertainty of emission factors from small combustion installation sources is a function of the combustion technique, calibration and sampling frequency of direct measurements, and how representative the tested installation is for the whole population of sources (often referred as a typical source). In addition some of the measurement standards and sampling systems used currently for small combustion installations were developed for large-scale installations. For that reason the typical range of the uncertainty of an individual measurement for small combustion installations is greater than in larger installations. Emissions caused by combustion of solid fuels in particular, depend on the combustion technique used, the type of installation and its maintenance, capacity and age. In addition also operation condition such as load, the period of combustion cycle - start-up, steady state and shut down conditions, as well as quality of fuels and the stability of its properties play an important role.

Experimental emission data sets (described in various reports referring to specific measurement campaigns, journal articles, modelling work, and compilations) which were used in this chapter to derive typical emission factors are often lacking detailed description/characterization of various parameters, e.g., data on fuel quality used, the operational parameters, and the methodology used to measure concentration of pollutants in the flue gases as well as methodology for emission factor calculation. In accordance with the quality rating of uncertainty estimation (Pulles T. at al., 2001) these uncertainties data could be estimated for each pollutant, fuels and techniques as presented in Table 10.1, where:

- A – an estimate based on a large number of measurements made at a large number of facilities that fully represent the sector
- B – an estimate based on a large number of measurements made at a large number of facilities that represent a large part of the sector
- C - an estimate based on a number of measurements made at a small number of representative facilities, or an engineering judgement based on a number of relevant facts
- D - an estimate based on single measurements, or an engineering calculation derived from a number relevant

Tab.10.1. Uncertainties rating of emission factors from small combustion installations

Pollutants	Gas and liquid fuels		Solid fuel			
			Manual fuelled		Automatic fuelled	
	Rating	Typical error range, %	Rating	Typical error range %	Rating	Typical error range %
Oxides of nitrogen	B	20 - 60	B	20 - 60	B	20 – 60
Sulphur dioxide	B	20 - 60	B	20 - 60	B	20 – 60
Ammonia	C	50 - 150	C	50 - 150	C	50 – 150
PM	C	50 - 150	C	50 - 150	C	50 – 150
Heavy metals 1)	C	50 - 150	C	50 - 150	C	50 – 150
PAH	C	50 - 150	C	50 - 150	C	50 – 150
Dioxins	D	100-300	D	100 -300	D	100-300
CO	B	20 - 60	B	20 - 60	B	20 – 60
NMVOC	C	50 - 150	C	50 - 150	C	50 – 150

1) Uncertainty of evaluation of mercury emission factors for small of biomass combustion installations (manual and automatic fuelled appliances) was rated at 100 – 300% (D), Pye et al., (2005)

The table above gives a rough qualitative estimation of the typical uncertainty of default emission factors. The uncertainty estimation represents an application of qualitative data rating schemes for all pollutants in this chapter and main group of techniques. Any such qualitative summary is subjective and individual opinions may differ.

Activity data for fossil fuels for the sources covered in this chapter typically have higher uncertainties than those for other stationary combustion sources. For biomass fuels consumption estimates are less accurate than for fossil fuels, in particularly where self-supply and direct purchase from farmers prevail.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHODOLOGY

The weakest aspects discussed here are mainly related to emission factors, but also to the estimation of activities.

11.1 Emission factors

Improvement of emission factors is necessary in order to obtain more accurate emission estimates for residential activities due to a wide variety of employed combustion techniques and different types of fuels used. Type of installation and fuel used is critical to emissions of air pollutants, especially in the case of coal and biomass combustion where high levels of pollutants such as TSP, CO, NMVOC and PAH come from incomplete combustion.

This improvement should focus on preparing individual emission factors for individual techniques currently used, both old and new. The emission factors of pollutants such as TSP, CO, NMVOC and PAH, affected by the poor performance of the used combustion technology, can be reduced by introducing measures (or new technologies) to improve combustion efficiency, although some pollutants, e.g., NO_x and heavy metals (Hg, Cd, As) might increase.

For particulate matter (especially fine fraction), PAHs, PCDD/Fs, NMVOCs, and heavy metals small combustion installations contribute a high proportion of total emission and generation of specified data for this source should be the priority. The fuel specific emission factors cited from different sources (Annex 1, table A1 1 – A1 48) are often not representative and refer to the typically observed range. Establishing a measurement program that would allow characterisation of techniques and fuels used as well as development of inventory for small sources should be of high priority. Such a program could also investigate national and regional specific parameters (climatic, cultural, level of control, etc.) relevant for emissions.

Emission factors are related usually to full load conditions. Due to common low load of the small combustion installations and a high number of start-ups per year (e.g up to 1,000 times a year for solid fossil fuels and biomass stoves with manual fuel charging) the emissions are higher in comparison to full load conditions.

In order to assess the relevance of start–ups and low load conditions, a detailed investigation should be performed for small combustion installation, in particular manual fuelled with capacity of below 1 MW_{th}.

Sampling methods developed for industrial and other larger combustion plants are not suitable for small residential sources, especially for particulate matter and particulate related pollutants like PAH, heavy metals and PCDD/F. Further work should be invested to clarify this influence as well as influence of laboratory conditions (mainly regarding to the natural and forced draught) with respect to the emission factors published.

11.2 Activities

Collecting more reliable information on actual consumption of biomass, in particular “virgin” wood, waste wood, and straw, is essential in order to improve the accuracy of emission estimates for this sector. Uncertainties also occur due to the fact, that fuel such as coal or wood can be also used as mixtures. Also methodologies for estimation of the quantity of contaminated/ treated wood combusted, crucial for PAH and dioxin emissions, have to be developed. The same is valid also for the assessment of the residential waste combusted in the residential sector.

Further work should be carried out to differentiate between fuel coal used in manual and automatic boilers with capacity below $1MW_{th,}$ as well as to distinguish between various fuel wood types, e.g., log wood, chips and pellets.

Since the current international (and possibly a number of national) statistics do not represent this sector well, the establishment of a “communication line” with the respective agencies to discuss ways of improving collection and reporting of activity data in this sector should be considered.

12 SPATIAL DISAGGREGATION CRITERIA FOR AREA SOURCES

Spatial disaggregation of annual emissions when using top-down approach could be performed by using surrogate data. For the residential sector the emissions could be taken as proportional to the population density. Because in most countries the means of heating in residential greatly differs among urban and rural settlements and also among the regions (usually coal is much more used in traditionally mining regions), this approach could be taken only as a last resort. In general the following steps could be taken for disaggregation of the emissions from the residential sector (Loibel, 1993):

- Differentiated in spatial areas: administrative units, inhabited areas, settlement areas divided in low and high density populated
- Determination of per capita emission factor depending on population density, type of fuel and main installation types used in for each spatial area

If emissions have been determined by bottom-up energy modelling, the spatial disagreagation is straightforward.

For commercial/institutional sector emissions could be disaggregated according to the number of employees in the considered spatial unit. It has however to be checked that the number of employees are given as actually employed per spatial unit and not according to the headquarters site.

13 TEMPORAL DISAGGREGATION CRITERIA

Most heating related emissions covered in this chapter are released due to heating of buildings and are therefore released predominantly during the heating season. In the residential sector a smaller part of emissions are released year-round due to preparation of hot water. In agriculture crops drying and greenhouse heating is seasonal.

Building heating demand is related to ambient temperature and user behaviour. Influence of ambient temperature is correlated to heating degree-days, which could be found usually in publications of meteorological services for different towns/cities. The user behaviour is reflected in different load and emissions during workdays and weekends. Daily fluctuations of load depend also on combustion techniques, for instance manually feed stoves and boilers, and on working hours distribution, and are for that reason country specific.

14 ADDITIONAL COMMENTS

The default emission factors given in the tables in Section 8 are derived from various measurements, of which some are laboratory measurements and some are in-field measurements. In order to derive representative default emission factors from available data, expert judgement is necessary. This has taken into account the variations in fuels, technologies and firing practices as well as the various conditions due to national conditions, to the best of our current knowledge. The default emission factors are general and derived to be as representative as possible for real conditions with the current knowledge. More in-field measurement would improve the basis for and the quality of the default emission factors.

15 SUPPLEMENTARY DOCUMENTS

16 VERIFICATION PROCEDURES

Verification of the emissions can be undertaken by calculating the emissions using the default factors given in Section 8.1 of this chapter and comparing the results with a mean profile.

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ANNEX 1: COMPILATION OF EMISSION DATA

In this annex compilation of various emission data is given to enable users comparison with their own data.

Table A1 1 Emission factors for coal small combustion installations

Installation	***Pollutants***						
	g/GJ					***mg/GJ***	
	SO_2	***NOx***	***CO***	***NMVOC$^{1)}$***	***VOC$^{1)}$***	***PAH***	***BaP***
Domestic open fire	n.d	n.d	n.d.	14$^{1)}$	n.d.	n.d.	n.d.
Domestic closed stoves	2) 420	75	1500	n.d.	60	n.d.	n.d.
	3) 104$^{1)}$	8$^{1)}$	709$^{1)}$	n.d.	n.d.	n.d.	n.d.
Domestic boiler	4) 17.2$^{1)}$	6.2$^{1)}$	1.8$^{1)}$	n.d.	0.02$^{1)}$	n.d.	n.d.
Small commercial or institutional boiler	n.d.	n.d.	416$^{2)}$	n.d.	n.d.	n.d.	0.1$^{2)}$

Source: Hobson M., et al., 2003; $^{1)}$ none information about NMVOC and VOC standard reference usual CH_4 or C_3H_8 are used; $^{2)}$ Original data in g/kg; $^{3)}$ Original data in g/kg for recalculation H_u of 24 GJ/t (d.b.) was assumed; 4) coal stove; 5)-roomheater 12.5 kW, anthracite; 6)-boiler, bituminous coal; n.d.- no data;

Table A1 2 Emission factors for combustion of manufactured solid fuels

Installation	***Pollutants***						
	g/GJ					***Mg/GJ***	
	SO_2	***NO_x***	***CO***	***NMVOC$^{1)}$***	***VOC$^{1)}$***	***PAH***	***BaP***
Domestic open fire	2) n.d	n.d	n.d.	n.d.	5.0 – 20	n.d.	n.d.
Domestic closed stoves	3) n.d.	n.d.	121-275$^{2)}$	10.5$^{2)}$; 16.1$^{2)}$	n.d.	n.d.	n.d.
	4) 75$^{2)}$ and 127$^{2)}$	4$^{2)}$ and 7$^{2)}$	1125$^{2)}$; 1193$^{2)}$	n.d.	n.d.	n.d.	n.d.
Domestic boiler	5) 371	382	12,400	n.d.	91	n.d.	n.d.
	6) n.d.	64-73	140-7,400	n.d.	0-500$^{7)}$	n.d.	n.d.
Small commercial or institutional boiler	8) n.d.	35	270	n.d.	2$^{7)}$	n.d.	n.d.

Source: Hobson M., et al., (2003; $^{1)}$ none information about NMVOC and VOC standard reference usual CH_4 or C_3H_8 are used; $^{2)}$ Original data in g/kg; 3) 10kW open fire, smokeless coal brands; 4)-stoves, charcoal and char briquettes; 4) 12.5kW roomheater, coke and manuf. briq.; 5)-UNECE TFEIP: Dutch fig. for coke use; 6)-UNECE TFEIP: Sweden, pellet boilers, 1.8-2MW; $^{7)}$ as THC: 8) UNECE TEFIP: Sweden, briquette boilers 1.8-2MW; n.d.- no data

Table A1 3 Range of emissions value from coal small appliances, which employ fixed bed combustion with counter-current techniques (manually fuelled)

Types of	***Efficie***	***Assort***	***Emissions factor of pollutants***

appliances	*ncy %*	*ment of fuel*	*CO G/GJ*	*SO_2*$^{a)}$ *g/GJ*	*NO_x G/GJ*	*TSP g/GJ*	*16 PAH g/GJ*	*B(a)P mg/GJ*	*VOC (C_3) g/GJ*
Standard stove	45 – 75	Un-assortment coal	3,500 – 12,500	200 – 800	100 – 150	700 – 900	20 – 40	200 – 600	500 – 700
Masonry stove	60 – 75		2500 – 11,000	200 – 800	100 – 200	600 – 1,200	15 – 25	150 – 350	400 – 800
Kitchen stove	40 – 60		3,600 – 11,000	200 – 800	50 – 150	300 – 1000	50 – 90	400 – 650	500 – 1100
Standard boiler	50 – 67		1,800 – 7,000	200 – 800	50 – 150	150 – 500	30 – 90	600 – 900	400 – 1200
Advanced boiler	76 – 82	Assortment coal,	200 – 1,500	200 – 800	150 – 200	50 – 100	0.2 – 0.6	2 – 30	60 – 120

Source: Kubica, 2003/1; $^{a)}$ Emission factor of sulphur dioxide strongly depends on sulphur content of fuel; this emission factors are for of sulphur content between 0.5% and 1.0% with oxidation efficiency of sulphur about 90%.

Table A1 4 Range of emissions from coal small appliances, which employ fixed bed combustion with co-current techniques (in principle automatic fuelled)

Types of appliances	*Efficiency %*	*Assortment of fuel*	*Emissions factor of pollutants*						
			CO g/GJ	*SO_2*$^{a)}$ *g/GJ*	*NO_x G/GJ*	*TSP g/GJ*	*16 PAH g/GJ*	*B(a)P mg/GJ*	*VOC (C_3) g/GJ*
Advanced boiler $^{b)}$	76 – 80	Fine coal	2,800 – 1,100	250 – 750	150 – 200	50 – 200	0.2 – 0.8	3 – 50	100 – 250
Burners boiler	77 – 84	Fine coal	1,500 – 400	250 – 750	150 – 250	30 – 120	0.2 – 2.0	5 – 50	2 – 50
Stoker, retort boiler	77 – 89	5 – 25$^{c)}$ mm	120 – 800	130 – 350	150 – 300	30 – 60	0.1 – 0.7	1 – 20	1 – 50

Source: Kubica, 2003/1; $^{a)}$ Emission factor of sulphur dioxide strongly depends on sulphur content of fuel; this emission factors are for of sulphur content between 0.5% and 1.0% with oxidation efficiency of sulphur about 90%; $^{b)}$ – manually fuelled; $^{c)}$ – for capacity above 50kW grain size 5 – 30 mm.

Table A1 5 Emission value of coal combustion in stove and small boilers derived from measurement campaign in Poland

Parameter	*Unit*	*Advance under-fire boiler 30 kW*		*Advance upper-fire, retort boiler*		*Stove 5.7 kW*	
		Coal J	*Coal W*	*50 kW*	*150 kW*	*Coal J*	*Coal W*
Thermal efficiency	%	67,8	70,9	82,9	82,0	54,7	51,2
CO	g/GJ	3939	2994	48	793	3271	2360
SO_2	g/GJ	361,6	282,8	347,8	131,5	253,0	211,0

NO_x as NO_2	g/GJ	190,3	162,3	172,9	160,0	81,2	104,0
VOCs (C_3)	g/GJ	514,2	483,1	6,1	4,8	486,0	700,0
Dust; TSP	g/GJ	227,0	294,0	267	30,0	523,0	720,0
16 PAHs	Mg/GJ	26688	29676	87,2	0,2	39500	32800
PCDD/F	Ng I-Teq/GJ	285.0	804.1	n.d.	n.d.	n.d.	n.d.

Source: Kubica, UN-ECE TFEIP, 2002/1; n.a. = no data

Table A1 6 Emission factors for advanced coal fire small boilers (< 1MW) in Poland. Voluntary standard requirements

Pollutants	***Advanced under-fire boilers; manual fuelled***	***Advanced upper-fire boilers, automatic fuelled***
	Emission factors (g/GJ)	
Carbon monoxide, CO	≤2000	≤1000
Nitrogen dioxide; NOx as NO_2	≤150	≤200
Sulphur dioxide; SO_2 [1)]	≤400	≤400
Dust; TSP	≤120	≤100
TOC [2)]	≤80	≤50
16 PAHs acc. EPA	≤1.2	≤0.8
Benzo(a)pyrene; B(a)P	≤0.08	≤0.05

Source: Kubica, 2003/1; Kubica, UN-ECE TFEIP, (2002/1); [1)] Emission factor of sulphur dioxide strongly depends on sulphur content of fuel; this emission factors was established for sulphur content of content <0.6%; [2)] TOC is a sum of organic pollutants both in the gaseous phase, as well as on particles organic solvent soluble except $C_1 – C_5$ (Kubica 2003/1)

Table A1 7 Emission values of co-combustion of coal and wood in small and medium boilers in Poland

Parameter	***Unit***	***Automatic fuelled burner boiler 25 kW***		***Fluidized bed boiler 63 MW***		***Travelling grate combustion; 10 MW***		***Travelling grate combustion, 25 MW***	
		Coal	***80%m/m coal 20% wood***	***Coal***	***91% w/w coal 9% wood***	***Coal***	***92% w/w coal; 8% wood***	***Coal***	***97% w/w coal 3% dry sewage sludge***
Thermal efficiency	%	79.1	81.6	87.4	86.2	81.1	81.4	84.4	85.7
CO	g/GJ	254	333	35.2	41.5	120	63	23.8	24.7
SO_2	g/GJ	464	353	379	311	290	251	490	557
NO_x as NO_2	g/GJ	269	232	109	96	150	155	137	141
VOCs (C_3)	g/GJ	14.0	9.5	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.

Dust; TSP	g/GJ	50.3	37.6	6.6	7.7	735	948	133	111
16 PAHs	Mg/GJ	401	207	346	121	126	117	269	63

Source: Kubica, et al*.,* 2003/2; n.d. = no data

Table A1 8 Emission factors for combustion of biomass; comparison between poor and high standard furnace design

Emissions	*Poor standard*	*High standard*
Excess air ratio, λ	2 – 4	1.5 – 2
CO; g/GJ	625 – 3125	13 – 156
CxHy[2)]; g/GJ	63 – 312	< 6
PAH; mg/GJ	62 – 6250	< 6.2
Particles, after cyclone; g/GJ	94 – 312	31 – 94

Source: van Loo, 2002; [1)] Original data in mg/m^3_o at 11% O_2, for recalculation H_u of 16 GJ/t and 10m^3/kg of flue gases were assumed; [2)] none information about CxHy standard reference usual CH_4 or C_3H_8 are used

Table A1 9 Emission factors for pellet burners in Sweden

Type of the burners	*TSP (g/GJ)*	*CO_2 (%)*	*O_2 (%)*	*THC[1)] (g/GJ)*	*NOx (g/GJ)*	*Effect (kW)*
Pellet burner (continuous operation)						
Nominal effect	22	9.5	11.1	3	73	10.7
6kW capacity	4	6.0	14.6	78	70	6.2
6kW generated power*	28	4.8	15.8	31	68	6.2
3kW generated power	65	3.7	16.9	252	66	3.2
Pellet burner (electric ignition)						
Nominal effect	16	13.0	7.4	1	70	22.2
6kW generated power	64	9.1	11.3	60	64	6.1
6kW generated power+	-	10.6	9.7	41	174	6.3
3kW generated power	15	8.6	11.9	10	67	3.1

Source: Bostrom, 2002; [1)] none information about THC standard reference usual CH_4 or C_3H_8 are used
*High ventilation, [+] Wood with high ash content

Table A1 10 Emission factors for wood boiler in Sweden

Type of the burners	*TSP (g/GJ)*	*CO_2 (%)*	*O_2 (%)*	*THC[1)] (g/GJ)*	*CO (g/GJ)*	*NOx (g/GJ)*
Water cooled boiler						
Intermittent log burning	89	6.8	13.4	1111	4774	71
Water cooled boiler						
Operation using accumulator	103	8.3	11.8	1500	5879	67
Intermittent log burning	n.d.	5.6	13.4	4729	16267	28
Cold-start	2243	6.9	14.6	2958	8193	64

Source: Bostrom; (2002); [1)] none information about THC standard reference usual CH_4 or C_3H_8 are used; n.d.= no data

Table A1 11 Arithmetic average emission values for wood combustion. The data were collected from investigations in various IEA countries (Norway, Switzerland, Finland, UK and Denmark)

Techniques	*NO_X (g/GJ)*	*CO (g/GJ)*	*VOC$^{a)}$ (g/GJ)*	*THC as CH_4 (g/GJ)*	*Particles, TSP (g/GJ)*	*PAH (mg/GJ)*
Cyclone furnaces	333	38	2.1	n.d.	59	n.d.
Fluidized bed boilers	170	0	n.d.	1	2	4
Pulverised fuel burners	69	164	n.d.	8	86	22
Grate plants	111	1846	n.d.	67	122	4040
Stoker burners	98	457	n.d.	4	59	9
Wood boilers	101	4975	n.d.	1330	n.d.	30
Modern wood-stoves	58	1730	n.d.	200	98	26
Traditional wood-stoves	29	6956	671	1750	1921	3445
Fireplaces	n.d.	6716	520	n.d.	6053	105

Source: van Loo, (2002); [a)] none information about VOC standard reference usual CH_4 or C_3H_8 are used; n.d. – no data

Table A1 12 Arithmetic averages of emission value from biomass combustion in small-scale applications

Techniques	*Load [kW]*	*Excess air ratio*	*CO [g/GJ]*	*$C_xH_y^{a)}$ [g/GJ]*	*Part. TSP [g/GJ]*	*NO_X [g/GJ]*	*Temp. [^oC]*	*Efficiency [%]*
Wood – stoves	9.33	2.43	3116	363	81	74	307	70
Fire place inserts	14.07	2.87	2702	303	41	96	283	74
Heat storing stoves	13.31	2.53	1723	165	34	92	224	78
Pellet stoves	8.97	3.00	275	7	28	92	132	83
Catalytic wood-stoves	6.00	n.d.	586	n.d.	n.d.	n.d.	n.d.	n.d.

Source: van Loo, 2002; Original date in mg/m^3_o at 13% O_2, for recalculation H_u of 16 GJ/t and 10m^3/kg of flue gases were assumed; [a)] none information about CxHy standard reference usual CH_4 or C_3H_8 are used; n.d. – no data

Table A1 13 Emissions from small industrial wood chips combustion applications in the Netherlands (g/GJ)

Type of operation	*Combustion principle*	*Draught control*	*Capacity kW*	*CO*	*CxHy$^{a)}$*	*NO_x*	*TSP*	*Efficiency %*
Manual	Horizontal grate	Natural uncontrolled	36	1494	78	97	13	85
		Forced uncontrolled	34.6	2156	81	108	18	83.5
			30	410	13	114	21	90
Automatic	Stoker boiler	Forced controlled	~40	41	2	74	50	85.4
			320	19	2	116	32	89.1

Source: van Loo, 2002; Original date in mg/m^3_o at 11% O_2, for recalculation H_u of 16 GJ/t and 10m^3/kg of flue gases were assumed; [a)] none information about CxHy standard reference usual CH_4 or C_3H_8 are used; n.d. – no data

Table A1 14 Emission value from biomass combustion in small-scale applications derived from measurement campaign in Poland

Techniques	*Capacity [kW]*	*SO_2 [g/GJ]*	*CO [g/GJ]*	*VOC as C_3 [g/GJ]*	*TSP [g/GJ]*	*NO_X [g/GJ]*	*16 PAH g/GJ*	*Efficiency [%]*
Wood – log, stoves	5.7	9.8	6290	1,660	1,610	69	33,550	64.4
Upper fire stocker, pellet combustion	25	29	200	21	9.9	179	71	80.4
Pellet burners	20.5	6.0	58.5	7.2	29.7	295	122	85.7
Gasifire, pre-oven	20.0	21.0	1226	6.8	15.6	78.9	480	83.9

Source: Kubica, et al., 2002/2

Table A1 15 Emission value of biomass combustion in small and medium boilers derived from measurement campaign in Poland

Parameter	*Unit*	*Straw fixed grate boiler 65 kW*		*Advance under-fire boiler 30 kW*		*Automatic boilers*	
						3,5 MW	*1,5 MW*
		Rape straw	*Wheat straw*	*Briquettes of sawdust*	*Lump pine wood*	*Mixture of cereal straws*	
Thermal efficiency	%	81.	84.2	81.3	76	90.1	84.3
CO	g/GJ	2230	4172	1757	2403	427	1484
SO_2	g/GJ	127,1	66,5	15,9	4,8	74,6	151,0
NO_x (as NO_2)	g/GJ	105,3	76,1	41,6	31,7	110,1	405,0
VOC (as C_3)	g/GJ	n.a.	n.a.	176,1	336,4	n.a.	n.a.
TSP	g/GJ	654,0	901,0	39,0	116,0	31,5	109,0
TOC [1)]	g/GJ	59,4	39,4	98,6	176,0	18,1	39,0
16 PAHs acc EPA	Mg/GJ	9489	3381	9100	9716	197	0,4
PCDD/F	ng I-TEQ/GJ	840.9	746.2	107.5	1,603	n.a.	n.a.

Source: Kubica, 2003/1; Kubica, UN-ECE TFEIP, (2002/1

Table A1 16 Emission factors for 1.75 MW and 2 MW boilers in Sweden

Fuel	*Effect (%)*	*O_2 (%)*	*CO (g/GJ)*	*THC (g/GJ)[a)]*	*CH_4 (g/GJ)*	*TSP (g/GJ)*	*NO_X (g/GJ)*	*NH_3 (g/GJ)*
Pellets	20	4	7400	500	400	43	17	6
Pellets	50	7	1600	17	<1	43	27	1
Pellets	100	4	140	<1	<1	32	37	<1
Briquettes	100	6.3	270	2	<1	36	35	<1
Logging residue	100	6.5	42	<1	<1	71	74	<1

Wood chips	100	7.2	3900	48	31	51	25	2

Source: Bostrom C-A, UN-ECE TFEIP (2002); [a] none information about CxHy standard reference usual CH_4 or C_3H_8 are used

Table A1 17 Emission factors for biomass small combustion installations

Installation	*Pollutants*						
	g/GJ					*mg/GJ*	
	SO$_2$	*NOx*	*CO*	*NMVOC*	*VOC*	*PAH*	*BaP*
Domestic open fire	n.d	n.d	4,000	n.d	90-800	13,937; 10,062; 7,937[1,2]	n.d
Domestic closed stoves	3) n.d.	29	7,000	1750[5]	670	3,500	n.d
	4) n.d.	58	1,700	200[5]	n.d	26	n.d
Domestic boiler	6) n.d.	101	5,000	1,330[5]	n.d	n.d	n.d
Small commercial or institutional boiler	7) n.d.	25	3,900	n.d	n.d.	n.d.	n.d.
	8) n.d	n.d.	n.d.	480	n.d	n.d.	n.d.
	9) n.d.	n.d.	n.d.	96	n.d.	n.d.	n.d.

Source: Hobson M., et al., 2003; [1] none information about NMVOC and VOC standard reference usual CH_4 or C_3H_8 are used [2] Original data in g/kg for recalculation H_u of 16 GJ/t was assumed and PAH that is ∑16 PAH; 3) traditional wood stove; 4) modern wood stove; [5] THC as CH_4; 6)-wood boilers; 7) wood chips boilers 1.8-2MW; 8) wood, charcoal, 120 kW boiler, benchmark; 9) wood, charcoal, 120kW, improved boiler; n.d.- no data

Table A1 18 Emission factors for domestic combustion processes (g/GJ) in the Netherlands

Pollutant	*Fuel*				
	Natural gas	*Oil*	*LPG*	*Petroleum*	*Coal*
VOC[1]	6.3	15	2	10	60
SO$_2$	0.22	87	0.22	4.6	420
N$_2$O	0.1	0.6	0.1	0.6	1.5
NOx (as NO$_2$)	57.5	50	40	50	75
CO	15.8	60	10	10	1500
CO$_2$	55920	73000	66000	73000	103000
TSP	0.3	5	10	2	200
PM10	0.3	4.5	2	1.8	120
Particles >PM10	-	0.5	-	0.2	80

Source: Hesling D., 2002; [1] none information about VOC standard reference - usual CH_4 or C_3H_8 are used

Table A1 19 Emission factors for small combustion installations of gas and oil fuels (g/GJ) derived from measurement campaign in Poland

Pollutant	*Fuel*							
	Natural gas				*Oil*			
	35 kW	*218 Kw*	*210 kW*	*650 kW*	*35 kW*	*195 kW*	*400 kW*	*650 kW*
NMVOC as C$_3$ [1]	8.9	7.8	6.2	0.6	5	4.2	10	2.1
SO$_2$ [1]	-	-	-	-	110	112	140	120.3
NOx (as NO$_2$) [1]	142	59,1	24.6	38.4	43	56.4	60	56.7

CO 1)	10.3	30.9	21.2	15.3	46	44	45	33.6
TOC 1)	5.5	6.4	4.2	4.5	25	20.8	15	7.5
SO_2 2)	n.d.	-	-	-	115-145 aver.130	-	-	-
NOx (as NO_2) 2)	17 – 22 aver. 20	-	-	-	35 – 55 aver. 40	-	-	-
CO 2)	7 - 12 aver. 9	-	-	-	10-12 aver.11	-	-	-

Source: 1) Kubica et al., 1999; 2) Kubica et al., 2005/2 The measurements were done in the field; n.d. – no data

Table A1 20 Emission factors for small combustion installations of gas and oil fuels (g/GJ) derived from measurement campaign in Poland

Pollutant	*Fuel*						
	Natural gas					*Oil*	
	2.1 MW	***11.0 MW***	***5.8 MW***	***4.6 MW***	***2.3 MW***	***1.7 MW***	***2.2 MW***
NOx (as NO_2)	64	30	29	38	23	66	63
CO	3.1	0.0	0.0	3.6	0.4	0.0	1.4
SO_2	n.m.	n.m.	n.m.	n.m.	n.m.	105	69
TSP	n.m.	0.2	0.2	n.m.	0.1	n.m.	0.2

Source: Czekalski B et al., 2003

Table A1 21 Emission factors for gas fired small combustion installations

Installation	*Pollutants*						
	g/GJ					*mg/GJ*	
	SO_2	***NOx***	***CO***	***NMVOC 1)***	***VOC 1)***	***PAH***	***BaP***
Open fire	0.5	50	20	6	n.d.	n.d	n.d.
Close stoves	0.5	50	10	3	n.d.	n.d.	n.d.
Domestic boiler	0.2; 0.5	40.2; 57.5	8.5; 15.8	3.0; 15.0	5 – 30	n.d	1.5 2)
Small commercial or institutional boiler	n.d.	n.d.	n.d.	1.0; 5.0	5.0	n.d.	0.1 1) 38 3)
Agricultural heater	0.22	65	10	n.d.	30	n.d.	n.d.
CHP Steam, gas turbine;	n.d.	179	43	2.1	n.d.	n.d.	n.d.

Source: Hobson M., et al., 2003; 1) none information about VOC standard reference usual CH_4 or C_3H_8 are used 1) Original data in mg/t for recalculation H_u of 35 GJ/t was assumed; 2) $mg/1000xm^3$; n.d. - no data

Table A1 22 Emission factors for LPG small combustion installations

Installation	*Pollutants*						
	g/GJ					*mg/GJ*	
	SO_2	***NOx***	***CO***	***NMVOC 1)***	***VOC 1)***	***PAH***	***BaP***
Open fire	None						
Close stoves	n.d.	n.d.	454 1)	447 1)	n.d	n.d	n.d
Domestic boiler	0.22	40	10	n.d.	2	n.d.	n.d.

Small commercial or institutional boiler	n.d.	n.d.	n.d.	n.d.	2	n.d.	n.d.
Agricultural heater	0.22	40	10	n.d.	2	n.d.	n.d.
CHP Steam, gas turbine;	None						

Source: Hobson M., et al., 2003; $^{1)}$ none information about VOC standard reference usual CH_4 or C_3H_8 are used
$^{1)}$ Original data in g/kg for recalculation H_u of 42 GJ/t was assumed; n.d.- no data

A1 23 Emission factors for burning oil (kerosene) small combustion installations

Installation	***Pollutants***						
	g/GJ					***mg/GJ***	
	SO_2	***NOx***	***CO***	***NMVOC$^{1)}$***	***VOC $^{1)}$***	***PAH***	***BaP***
Domestic open fire	None						
Domestic closed stoves	n.d.	n.d.	421$^{2)}$; 1,478$^{2)}$	354$^{2)}$; 1,457$^{2)}$	n.d	n.d	n.d
Domestic boiler	87	50	60	1.5; 7.5	15	n.d.	0.1
Small commercial or institutional boiler	n.d.	n.d.	n.d.	1.0; 5.0	n.d.	n.d.	n.d.
Agricultural heater	0.22	50	10	n.d.	10	n.d.	n.d.
CHP Steam, gas turbine;	None						

Source: Hobson M., et al., 2003; $^{1)}$ none information about VOC standard reference usual CH_4 or C_3H_8 are used
$^{2)}$ Original data in g/kg t for recalculation Hu of 42 GJ/t was assumed; n.d.- no data

Table A1 24 Emission factors for fuel oil small combustion installations

Installation	***Pollutants***							
	g/GJ						***Mg/GJ***	
	SO_2	***NOx***	***CO***	***PM10***	***NMVOC$^{1)}$***	***VOC$^{1)}$***	***PAH***	***BaP***
Domestic open fire	None							
Domestic closed stoves	None							
Domestic boiler	n.d.	n.d.	n.d.	8.0-50	n.d.	10	n.d.	0.08$^{2)}$
Small commercial or institutional boiler	$^{3)}$ 449	62.4	15.6	3.1	n.d.	0.6	n.d.	n.d.
	$^{4)}$ 467	61.4	15.4	18.5	n.d.	0.6	n.d..	n.d.
	$^{5)}$ 488	169	15.4	26.4	n.d.	0.9	n.d.	n.d.
	n.d	n.d	n.d.	3-23	n.d.	8	n.d.	0.1$^{2)}$; 0.5$^{2)}$; 0.5$^{2)}$
Agricultural heater	n.d.	n.d.	n.d.		n.d.	n.d.	n.d.	0.08$^{2)}$
CHP $^{6)}$	n.d	186	14		2.1	6.8	n.d.	0.1$^{2)}$

Source: Hobson M., et al., 2003); 1) none information about VOC standard reference, usual CH_4 or C_3H_8 are used; 2) Original data in g/Mt for recalculation H_u of 42 GJ/t was assumed; 3) 1.5 % of S; 4) 4.5 % of S; 5) 5.5 % of S; 6) power station; n.d.- no data

Table A1 25 Emission of pollutants for gaseous, liquid and coal fuels for small combustion installations in Italy

Installation		***Pollutants***						
		g/GJ						
		SO_2	***NOx***	***CO***	***VOC1)***	***TSP***	***PM10***	***PM2.5***
Natural gas	Range	0.22-0.5	7.8-350	20-50	0.5-10	0.03-3	0.03-3	0.03-0.5
	Aver.	0.5	50	25	5	0.2	0.2	0.2
LPG	Range	9.7-150	30-269	20-40	0.1-15	0.2-50	0.2-50	0.2-50
	Aver.	100	50	20	3	5	5	5
Burning oil	Range	69-150	24-370	5-40	1.1-48	1.5-60	1.5-60	1.5-50
	Aver.	150	150	16	10	40	40	30
Coal	Range	60 – 2,252	45-545	100-5,000	3-600	70-350	10-400	30-200
	Aver.	650	150	2,000	200	150	140	70

Source: Caserini S. 2004; 1) none information about VOC standard reference usual CH_4 or C_3H_8 are used

Table A1 26 Sectoral emission factors for firing appliances in Germany in the household and small consumer sectors, in 1995 (Pfeiffer et al. 2000)

Sector	***Fuel***	***Pollutants***				
		g/GJ				
		SO_2	***NOx as NO_2***	***CO***	***CO_2***	***TSP***
Household	High rank coal and products	456	51	4,846	95,732	254
	High rank coals	380	49	5,279	95,930	278
	Briquettes	561	54	4,246	95,457	221
	Coke from high rank coals	511	60	6,463	106,167	15
	Brown coal briquettes	261	71	3,732	96,021	86
	Natural wood	7	50	3,823	103,093	42
	Distillate oil	77	46	25	73,344	1.6
	Natural gas	0.5	38	14	55,796	0.03
Small consumers	High rank coal and products	419	108	564	95,930	278
	High rank coals	419	108	564	95,930	278
	Coke from high rank coals	370	61	1.498	106,167	12
	Brown coal briquettes	234	87	4.900	95,663	59
	Natural wood and wood wastes	9.1	78	2.752	101,099	45
	Distillate oil	77	47	14	73,344	1.7

	Residual oil	384	162	9.9	75,740	38
	Natural gas	0.5	31	11	55,796	0.03

Table A1 27 Emission factors of CO, NOx and SO_2 for advanced combustion techniques of coal and biomass

Source	***Installation/Fuel***	***Pollutants [g/GJ]***		
		SO_2	***NOx as NO_2***	***CO***
BLT, 2000/1	Wood boilers with two combustion chambers and sonar Lambda	n.d.	100	141
BLT, 2005/1	Wood pellets and chip boiler 25 kW 100%; 33% of capacity	n.d.	127; n.d.	186; 589
	Pellets and wood chips boiler 43 kW - 100% and 33% of capacity	n.d.	110; 71	60; 37
	Wood boiler 60 kW, air dry oak 100% and 33% of capacity	n.d.	79; n.d.	127; 720
	Boiler, wood chips 25kW 100% and 33% of capacity	n.d.	115; n.d.	23; 358
	Pellets boiler 46.7 kW 100% and 33% of capacity	n.d.	110; 118	118; 172
BLT, 2003	Pellets and briq., boiler 7.7 – 26 kW 100% and 33% of capacity	n.d.	67; n.d.	7; 44
BLT, 1999	Wood chips, boiler 500kW 100% and 33% of capacity	n.d.	123; n.d.	16; 126
BLT, 2004/1	Wood chips, boiler 20kW 100% and 33% of capacity	n.d.	44; n.d.	17; 108
BLT, 2004/2	Wood log and briq., boiler 50kW 100% and 33% of capacity	n.d.	109; n.d.	44; n.d.
BLT, 2000/2	Wood briq., chamber boiler 60 kW 100% and 33% of capacity	n.d.	88; n.d.	30; 120
BLT, 2005/2	Wood log, chamber boiler 27 kW	n.d.	78	131
Houck et al., 2001[1)]	Fireplaces; dry wood	n.d.	n.d.	4010
Hübner et al.,2005[1,2)]	Boiler < 50kW; Pelleted wood	n.d.	n.d.	120
	Boiler; Chopped wood log	n.d.	n.d.	790 – 1,400
	Boiler; Coke	n.d.	n.d.	2,400
	Boiler; Wood and coke	n.d.	n.d.	3,500
	Boiler; Wood, brown coal briquettes	n.d.	n.d.	4,200
	Boiler; Wood logs (beech, spruce)	n.d.	n.d.	3,800
	Boiler; Wood (beech, spruce), coke	n.d.	n.d.	2,100
	Stove; Wood, brown coal briquettes wood	n.d.	n.d.	2100
	Stove; Beach wood logs	n.d.	n.d.	2100 - 4,700
	Stove; Wood	n.d.	n.d.	1500
	Stove; Spruce wood (small logs)	n.d.	n.d.	2,400
	Stove; Wood (small logs)	n.d.	n.d.	1,600

	Stove; Wood briquettes	n.d.	n.d.	4,600
Johansson at al., 2001 1)	Pellet boilers with fixed grates with moving scrapes 1,75 – 2,5 MW	n.d.	30 - 50	20 - 100
Houck et al., 2000 1)	Conventional stove, cordwood	n.d.	n.d.	7,200
	Pellet stoves, softwood	n.d.	n.d.	1,400 – 1,630
	Pellets stove, hardwood	n.d.	n.d.	125; 188; 219
	Pellets boiler, top-feed, softwood	n.d.	n.d.	146; 449; 510
	Pellets boiler, bottom-feed softwood	n.d.	n.d.	112; 169
Boman et al., 2005	Pellet stove 4.8 kW (high load)	n.d.	31 – 36; aver. 33	52 – 100; aver. 88
	Pellet stove 4.8 kW (low load 2.3 kW)	n.d.	29 – 33; aver. 31	243 – 383; aver. 299
	Natural-draft wood stove, 9 kW; Birch Pine Spruce	n.d.	37 – 71; aver. 50	1,200–7,700; aver. 3,800
	Pellet stove, 4- 9,5 kW; Pine and Spruce (high load)	n.d.	57 – 65; aver. 61	110 – 170; aver. 140
	Pellet stove, 4- 9,5 kW; Pine and Spruce (low load 30%)	n.d.	52 – 57; aver. 54	320 – 810; aver. 580
Kubica, 2004/2	Pellet boilers			
Kubica at al., 2005/4	Automatic fuelled coal boilers - stocker; Pea coal (qualified size)	120-450; aver. 260	96 – 260; aver. 190	90 – 850 aver. 280
	Automatic fuelled coal boilers; Fine coal (qualified coal size)	355–600 aver. 420	70 – 200 aver. 145	60 – 800 aver. 450
Kubica K.; 2004/1	Conventional stove 5kW	253	81	2272
Kubica, 2004/2	Boiler, stocker; wood pellets	n.d.	n.d.	300 – 500
	Chamber boiler, top feed; fine coal	250 - 700	100 - 150	1,100-2,800
	Automatic boiler, stocker; pea coal	130 - 350	100 - 250	120 – 800
	Automatic coal boiler; fine coal	250 - 700	100 - 250	400 – 1500
	Chamber boiler, advanced techniq.; qualified size coal	150 - 550	150 - 250	50 – 100
Kubica et al., 2005/1	Boilers with moving grate 5-32 MW	n.d.	116 - 137	10 – 24
	Boilers with moving grate 0.3 – 0.6MW	n.d.	146 - 248	36 – 363 4)
	Automatic fuelled coal boiler, fine coal	n.d.	140	130
	Automatic fuelled coal boiler – stocker	n.d.	70 – 220	120 – 800
	Boiler, bottom feed, nut coals	n.d.	150 - 200	200 – 1500
	Boiler, top feed, nut coals	n.d.	50 - 150	1,800 – 3,500
	Boiler, bottom feed, log wood	n.d.	32	2403
	Boiler, bottom feed, wood briquettes	n.d.	42	1757
	Automatic fuelled boiler – stocker 30 kW, pellets	n.d.	200	200
	Automatic fuelled boiler, wood chips	n.d.	150	880

Kubica at al., 2005/2[3]	Automatic fuelled coal boiler – stoker, ≤25 kW (120 pieces); Pea coal	n.d.	67 – 207; aver. 161	104 – 320; aver. 150
	Automatic fuelled coal boiler, ≤35 kW (68 pieces); Fine coal,	155– 496 aver. 252	64 – 208; aver. 122	119 – 435; aver. 232

[1] Original factors in g/kg of fuels, for recalculation H_u of 24 GJ/t (d.b.) for hard coal was, of 17 GJ/t (d.b.) for lignite and brown coal, of 30 GJ/t (d.b.) for anthracite, of 30 GJ/t (d.b.) for coke; of 16 GJ/t for wood, of 42 GJ/t for oil and of 35 GJ/t for natural gas were assumed; (2) Capacity of all boilers < 50kW and all stove <10kW; [3] A measurements was done in the field; n.d. – no data

Table A1 26 Wood Burning Appliance Emission Factors in British Columbia (Gulland, 2003)

Installation	***Pollutants [1]***						
	g/GJ						
	SO_2	***NOx***	***CO***	***VOC[1]***	***TSP***	***PM10***	***PM2.5***
Fireplace							
Conventional With Glass Doors	12.5	87.5	6,162.5	1,312.5	843.75	812.5	806.25
Convent. Without Glass Doors	12.5	87.5	4,856.3	406.3	1,206.3	1,156.3	1,156.3
Advanced Technology	12.5	87.5	4,400	437.5	318.75	300	300
Insert; Conventional	12.5	87.5	7,212.5	1,331.3	900	850	850
Insert; Catalytic	12.5	87.5	4,400	437.5	318.8	300	300
Insert; Advanced Technology	12.5	87.5	4,400	437.5	318.8	300	300
Woodstove							
Conventional	12.5	87.5	6,250	2,218.8	1,537.5	1,450	1,450
Conventional, Not Air-Tight	12.5	87.5	6,250	2,218.8	1,537.5	1,450	1,450
Conventional, Air-Tight	12.5	87.5	7,212.5	1,331.3	900	850	850
Advanced Technology	12.5	87.5	4,400	437.5	318.8	300	300
Catalytic	12.5	87.5	4,400	437.5	318.8	300	300
Pellet Stove	12.5	87.5	550	94	75	69.7	64
Boilers							
Central Furnace/ Boiler (inside)	12.5	87.5	4,281.3	1,331.3	881.3	831.3	831.3
Central Furnace/ Boiler (outside)	12.5	87.5	4,281.3	1,331.3	881.3	831.3	831.3
Other Equipment	12.5	87.5	7,212.5	1,331.3	900	850	850

[1] Original factors in kg/tonne of fuels, for recalculation H_u of 16 GJ/t for wood was assumed

Table A1 29 Emission factors for particulate matter reported in the literature for coal and manufactured solid fuels combustion [g/GJ]

Source	*Installation type*	*PM2.5*	*PM10*	*TSP*
BUWAL, 2001 1)	Small furnaces	n.d.	110	270
	Domestic boiler	n.d.	90	150
CEPMEIP, 2002 1)	Residential, brown coal	70	140	350
	Residential, hard coal ('high')	60	120	300
	Residential, hard coal ('low')	25	50	100
	Residential, low grade hard coal	100	200	800
Pfeiffer et al., 2000 1)	Residential, hard coal	n.d.	n.d.	260 – 280
	Residential, brown coal briquettes	n.d.	n.d.	120 – 130
	Residential, coke	n.d.	n.d.	14
Spitzer et al., 1998 1)	Residential heating	n.d.	n.d.	153±50%
	Single family house boiler, stoves	n.d.	n.d.	94±54%
Winiwarter et al, 2001 1)	Residential plants	75	85	94
	Domestic stoves, fireplaces	122	138	153
UBA, 1999a 1)	Domestic furnaces, hard coal	n.d.	n.d.	250
	Domestic furnaces, brown coal	n.d.	n.d.	350
EPA, 1998a 1)	Small boilers, top loading	n.d.	n.d.	291
	Small boilers, bottom loading	n.d.	n.d.	273
	Hard coal, stoker firing	n.d.	n.d.	1,200
	Pulverized lignite boilers	n.d.	n.d.	1,105
Meier & Bischoff, 1996 1)	Grate firing, lignite	n.d.	n.d.	2,237
Hobson M. et al, 2003	Domestic open fire; <10 kW, coal	n.d.	375 2)-459 2)	n.d.
	Domestic open fire; <10 kW, smokeless coal brands	n.d.	38-67 2)	n.d.
	Domestic open fire; <10 kW, pet coke blends	n.d.	96-117 2)	n.d.
	Domestic open fire; <5 kW coal	n.d.	1,683 2)	n.d.
	Domestic closed stove; US EPA, developing stoves charcoal	n.d.	n.d.	100 2)
	Domestic closed stove; US EPA, developing stoves char briquette	n.d.	n.d.	121 2)
	Domestic closed stove; CRE; <10 kW, smokeless coal brands	n.d.	42-50 2)	n.d.
	Domestic closed stove; CRE; <10 kW, pet coke blends	n.d.	108-133 2)	n.d.
	Domestic boilers; ERA research, Boiler Efis, bituminous coal	n.d	250 2)	n.d.
	Domestic boilers; UNECE TFEIP, Dutch figures for coke use	n.d.	6	n.d.
	UNECE TFEIP; Sweden, briquette boilers 1.8-2 MW	n.d.	n.d.	36
Kubica, 2004/1	Conventional stove 5kW	n.d.	n.d.	523
	Chamber boiler, top feed; fine coal	n.d.	n.d.	50 - 200

Source	*Installation type*	*PM2.5*	*PM10*	*TSP*
Kubica, 2004/2	Automatic fuelled coal boiler, stocker	n.d.	n.d.	30 - 60
	Automatic fuelled boiler, fine coal	n.d.	n.d.	30 - 120
	Chamber boiler, qualified size coal; distribution of combustion air	n.d.	n.d.	50 - 150
Kubica et al., 2005/1	Boilers with moving grate 5-32 MW	n.d.	n.d.	58 - 133
	Boilers with moving grate 0.3 – 0.6MW	n.d.	n.d.	51 - 64
	Automatic fuelled coal boiler, fine coal	n.d.	n.d.	50
	Automatic fuelled coal boiler – stocker	n.d.	n.d.	30 - 60
	Boiler, bottom feed, nut coals	n.d.	n.d.	50 - 100
	Boiler, top feed, nut coals	n.d.	n.d.	300 - 1100
Kubica at al., 2005/2 3)	Automatic fuelled coal boiler – stocker, 25 kW (120 pieces)	n.d.	n.d.	54- 133 aver. 78
	Automatic fuelled coal boiler, fine coal, 25 and 35 kW (68 pieces)	n.d.	n.d.	70 – 380 aver. 187
Kubica et al., 2005/3	Hard coal; stoves and boilers < 1MW	25-100 aver.65	25-1050 aver.270	30-1,200 aver.360
	Hard coal; boilers > 1MW <50MW	70-122 aver.70	90-250 aver.110	25-735 aver.140
	Brown coal Residential/Commercial/Institutional/	140	260	350
	Coke Residential/Commercial/Institutional/	30 -80 aver.80	96-108 aver.90	14-133 aver.110
Krucki A. et al., 2006 2)	Automatic fuelled coal boiler – stocker, 100 kW	n.d.	n.d.	98
	Automatic fuelled coal boiler, fine coal, 25 kW	n.d.	n.d.	13
	Automatic fuelled coal boiler, fine coal, 90 kW	n.d.	n.d.	16
Lee et al., 2005 2)	Open fire place	n.d.	1,200	n.d.

1) as quoted in Klimont et al., 2002; 2) Original data in g/kg for recalculation Hu of 24 GJ/t (d.b.) was assumed.
3) The measurements were done in the field; n.d. – no data

Table A1 30 Particulate matter size fractions reported in the literature for coal combustion [percent of TSP emissions]

Source	*Installation type*	*$PM_{2.5}$*	*PM_{10}*	*TSP*
UBA, 1999a 1)	Domestic furnaces, hard coal	n.d.	90 %	100 %
EPA, 1998a 1)	Small boilers, top loading	14 %	37 %	100 %
	Small boilers, bottom loading	25 %	41 %	100 %
Hlawiczka et al., 2002	Domestic furnaces, hard coal	n.m.	76 % 2)	100 %

1) as quoted in Klimont et al., 2002
2) Original data 76 % of PM was emitted as the size fractions up to 12 µm.

Table A1 31 Particulate matter emission factors reported in the literature for wood burning [g/GJ]

Source	***Installation type***	***$PM_{2.5}$***	***PM_{10}***	***TSP***
BUWAL, 2001 [1)]	Domestic open fire places	n.d.	150	150
	Domestic furnaces	n.d.	150	150
	Domestic small boilers, manual	n.d.	50	50
	Small boilers, automatic loading	n.d.	80	80
Karvosenoja, 2000 [1)]	Domestic furnaces	n.d.	n.d.	200 – 500
Dreiseidler, 1999 [1)]	Domestic furnaces	n.d.	n.d.	200
Baumbach, 1999 [1)]	Domestic furnaces	n.d.	n.d.	50 – 100
Pfeiffer et al., 2000 [1)]	Residential and domestic	n.d.	n.d.	41-65
CEPMEIP, 2002 [1)]	‘High emissions’	270	285	300
	‘Low emissions’	135	143	150
Winiwarter et al, 2001 [1)]	Residential plants	72	81	90
	Domestic stoves, fireplaces	118	133	148
NUTEK, 1997 [1)]	Single family house boiler, conventional	n.d.	n.d.	1,500
	Single family house boiler, modern with accumulator tank	n.d.	n.d.	17
Smith, 1987 [1)]	Residential heating stoves <5 kW	n.d.	n.d.	1,350
	Residential cooking stoves <5 kW	n.d.	n.d.	570
BUWAL, 1995 (1992 Swiss limit value) [1)]	up to 1 MW	n.d.	n.d.	106
Spitzer et al., 1998 [1)]	Residential heating	n.d.	n.d.	148±46%
	Single family house boiler, stoves	n.d.	n.d.	90±26%
Zhang et al., 2000 [1)]	Firewood in China	n.d.	n.d.	760-1,080
Houck and Tiegs, 1998/1 [3)]	Conventional stove	n.d.	n.d.	1,680
	Conventional stove with Densified Fuel	n.d.	n.d.	1,200
	Non-catalytic stove	n.d.	n.d.	490
	Catalytic stove	n.d.	n.d.	440
	Masonry Heater	n.d.	n.d.	250
	Pellet stove	n.d.	n.d.	130
	Fireplace, conventional	n.d.	n.d.	8,600
	Double-Shell Convection, Nat. Draft	n.d.	n.d.	4,600
	ConvectionTubes, “C” Shaped, Glass Door	n.d.	n.d.	4,000
	Double-Shell Convection, Blower, Glass Doors	n.d.	n.d.	1,900
	Masonry Fireplace with Shaped Fire Chambers and Gladd Doors	n.d.	n.d.	1,200
	Fireplace, non-catalytic insert	n.d.	n.d.	500
	Fireplace, catalytic insert	n.d.	n.d.	450
	Fireplace, pellet insert	n.d.	n.d.	130
EPA, 1998b (1,2)	Open fireplaces	n.d.	805	875
	Wood stove	n.d.	724	787

Source	***Installation type***	***$PM_{2.5}$***	***PM_{10}***	***TSP***
Hobson M. et al, 2003	UNECE TFEIP,Sweden, wood chips boilers 1.8-2 MW	n.d.	n.d.	51
	Open fire <5kW, seas. Hardwood 2)	n.d.	494	n.d.
	Domestic open fire: hundreds of sources studies 2)	n.d	n.d.	738
CITEPA, Paris, 2003	Open fire places	698	713	750
	Conventional closed fireplaces and inserts	288	295	310
	Conventional closed stoves and cooking	288	295	310
	Hand stoked log wood boiler	233	238	250
	Automatically stoked wood boiler	9	10	10
EPA, 1998a 4)	Boilers, bark	n.d.	n.d.	2,266
Lammi et al., 1993 4)	Fluidized bed in large boilers	n.d.	n.d.	1,000-3,000
	Grate firing in large boilers	n.d.	n.d.	250-1,500
Tullin et al.; 2000	Wood/pellet boilers and stoves	n.d.	n.d.	50
	Old wood boiler	n.d.	n.d.	1,000
Hays et al. (2003) 2)	Wood stove	143.8 – 637.5	n.d.	n.d.
	Fireplaces	537.5	n.d.	n.d.
BLT, 2000/1	Wood boilers with two combustion chambers and sonar Lambda	n.d.	n.d.	20
BLT, 2005/1	Wood pellets and chip boiler 25 kW	n.d.	n.d.	14
	Pellets and wood chips boiler 43 kW - 100% and 33% of capacity	n.d.	n.d.	23; 9
	Wood boiler 60 kW	n.d.	n.d.	28
	Boiler, wood chips 25kW	n.d.	n.d.	18
	Pellets boiler 46.7 kW- 100% and 33% of capacity	n.d.	n.d.	5; 12
BLT, 2003	Pellets and briq., boiler 7.7 – 26 kW	n.d.	n.d.	4
BLT, 1999	Wood chips, boiler 500kW	n.d.	n.d.	28
BLT, 2004/1	Wood chips, boiler 20kW	n.d.	n.d.	8
BLT, 2004/2	Wood log and briq., boiler 50kW	n.d.	n.d.	16
BLT, 2000/2	Wood briq., chamber boiler 60 kW	n.d.	n.d.	10
BLT, 2005/2	Wood log, chamber boiler 27 kW	n.d.	n.d.	12
McDonald et. al., 2000 2)	Fireplaces	As PM2.5.	n.d.	180 – 560; aver. 380
	Woodstove	n.d.	n.d.	140 – 450; aver. 270
Lee et al., 2005 2)	Open fire place	n.d.	425	n.d.
Gullet et al., 2003	Fireplace, Pine	n.d.	n.d.	147
	Fireplace, Artificial logs (wax and sawdust)	n.d.	n.d.	483
	Stove, Oak	n.d.	n.d.	504
Fine et al.; 2002 2)	Fireplaces; Hardwood - Yellow Poplar	n.d.	n.d.	425 ± 50
	Fireplaces; Hardwood - White Ash	n.d.	n.d.	206 ± 19

Source	***Installation type***	***$PM_{2.5}$***	***PM_{10}***	***TSP***
	Fireplaces; Hardwood - Sweetgum	n.d.	n.d.	218 ± 25
	Fireplaces; Hardwood - Mockernut Hickory	n.d.	n.d.	425 ± 56
	Fireplaces; Softwood - Loblolly Pine	n.d.	n.d.	231 ± 25
	Fireplaces; Softwood - Slash Pine	n.d.	n.d.	100 ± 19
Fine et al.; 2001 [2)]	Conventional masonry fireplaces; Hardwood - Red Maple Northern	n.d.	n.d.	206 ± 19
	Conventional masonry fireplaces; Hardwood - Red Oak	n.d.	n.d.	356 ± 19
	Conventional masonry fireplaces; Hardwood – Paper Birch	n.d.	n.d.	169 ± 19
	Conventional masonry fireplaces Softwoods - Eastern White Pine	n.d.	n.d.	713 ± 125
	Conventional masonry fireplaces Softwoods - Eastern Hemlock	n.d.	n.d.	231 ± 25
	Conventional masonry fireplaces Softwoods - Balsam Fir	n.d.	n.d.	300 ± 31
	Fireplaces; wood	170 -710	n.d.	n.d.
Boman et al., 2004	Pellet burner boilers 10-15 kW, overfeeding of the fuel; Sawdust, Logging Residues and Bark	n.d.	n.d.	114-377 aver. 240
	Pellet burner boilers 10-15 kW, horizontal feeding of the fuel; Sawdust, Logging Residues and Bark	n.d.	n.d.	57-157 aver. 95;
	Pellet burner boilers 10-15 kW, underfeeding of the fuel; Sawdust, Logging Residues and Bark	n.d.	n.d.	64-192 aver. 140
Broderick et al. 2005 [2)]	All masonry and factory-built (zero clearance)	n.d.	n.d.	590
	Fireplaces, all cordwood	n.d.	n.d.	810
	Fireplaces, all dimensional lumber	n.d.	n.d.	410
	Fireplaces, all with closed doors	n.d.	n.d.	350
	Fireplaces, all with open doors	n.d.	n.d.	690
	Fireplaces, all masonry fireplaces	n.d.	n.d.	660
	Fireplaces, all factory-built fireplaces	n.d.	n.d.	580
	Fireplaces, cordwood, factory-built, open doors	n.d.	n.d.	870
	Fireplaces, dimensional lumber, factory built, open doors	n.d.	n.d.	510
	All fireplaces, all wood types	n.d.	n.d.	Aver. 590
	All factory-built fireplaces with open door, cordwood	n.d.	n.d.	Ave. 840
Gaegauf et al., 2001	Wood roomheaters	n.d.	n.d.	70 ± 25
	Wood accumulating stoves	n.d.	n.d.	167 ±44
	Wood log boilers	n.d.	n.d.	28 ±11
	Pellet boilers	n.d.	n.d.	20 ±0.4
	Pellet roomheaters	n.d.	n.d.	54 ± 3

Source	***Installation type***	***$PM_{2.5}$***	***PM_{10}***	***TSP***
	Wood chip boilers - dry fuel	n.d.	n.d.	94 ± 13
	Wood chip boilers - wet fuel	n.d.	n.d.	48 ± 6
	Wood chip boilers - residuals	n.d.	n.d.	64 ± 7
Johansson at al., 2001 [7)]	Pellet boilers with fixed grates with moving scrapes 1,75 – 2,5 MW	n.d.	n.d.	35 – 40
Nussbaumer, 2001 [2)]	All automatic wood furnaces	n.d.	n.d.	< 110
	Understoker furnaces	n.d.	n.d.	< 55
	Log wood boilers	n.d.	n.d.	34
	Wood chips boiler [5)]	n.d.	n.d.	68
	Wood residues, boiler [5)]	n.d.	n.d.	70
	Urban waste wood, boiler [6)]	n.d.	n.d.	1.5
Houck et al., 2000 [2)]	Conventional stove, cordwood	n.d.	n.d.	750
	Pellet stoves, softwood	n.d.	n.d.	80 – 170
	Pellets stove, hardwood	n.d.	n.d.	125; 190;220
	Pellets boiler, top-feed, softwood	n.d.	n.d.	27.5; 37.5; 62.5
	Pellets boiler, bottom-feed softwood	n.d.	n.d.	16.3; 25.0
Houck et al., 2005 [2)]	Conventional Stove Woodstove	890	n.d.	n.d.
	Catalytic Certified Woodstove	430	n.d.	n.d.
	Noncatalytic Certified Woodstove	330	n.d.	n.d.
	Pellet Stove Exempt	160	n.d.	n.d.
	Certified Pellet stove	160	n.d.	n.d.
Boman et al., 2005	Pellet stove 4.8 kW (high load)	n.d.	n.d.	11 – 20 aver. 15
	Pellet stove 4.8 kW (low load 2.3 kW)	n.d.	n.d.	32 – 81 aver. 51
	Natural-draft wood stove, 9 kW; Birch Pine Spruce	n.d.	n.d.	37 – 350 aver. 160
	Pellet stove, 4- 9,5 kW; Pine and Spruce (high load)	n.d.	n.d.	15 – 17; aver. 16
	Pellet stove, 4- 9,5 kW; Pine and Spruce (low load 30%)	n.d.	n.d.	21 – 43 aver. 34
Krucki et al., 2006 (2)	Biomass boiler, two stage combustor 95 kW, log wood	n.d.	n.d.	34
	Biomass boiler, two stage combustor 22 kW, log wood	n.d.	n.d.	13
Kubica, 2004/1	Conventional stove 5kW	n.d.	n.d.	1,610
Kubica, 2004/2	Pellet burner/boilers	n.d.	n.d.	20 – 60
	Chamber boiler (hand fuelled), log wood	n.d.	n.d.	70 – 175
Kubica et al., 2005/1	Boiler, bottom feed, log wood	n.d.	n.d.	116
	Boiler, bottom feed, wood briquettes	n.d.	n.d.	39
	Automatic fuelled boiler – stocker 30 kW, pellets	n.d.	n.d.	6
	Automatic fuelled coal boiler, wood chips	n.d.	n.d.	60

Source	***Installation type***	***$PM_{2.5}$***	***PM_{10}***	***TSP***
Kubica et al., 2005/3	Residential/Commercial/Institutional/	9-698 aver.450	10-713 aver.490	17-4000 aver.520
	Boilers > 1MW <50MW	9-170 aver.80	60-214 aver.80	20-500 aver.100
Hedberg et al., 2002 2)	Commercial soapstone stove, birch logs	6 – 163 aver. 81	n.d.	n.d.
Johansson et al, 2006	Single family house boiler, modern with accumulator tank	n.d.	n.d.	26-450
Johansson et al, 2006	Single family house boiler, conventional	n.d.	n.d.	73-260
Johansson et al, 2004 a	Single family house boiler, modern with accumulator tank	n.d.	n.d.	23-89
Johansson et al, 2004 a	Single family house boiler, conventional	n.d.	n.d.	87-2200
Johansson et al, 2006	Single family house boiler, conventional	n.d.	n.d.	73-260
Johansson et al, 2004 a	Pellets burners/boiler	n.d.	n.d.	12-65
Ohlström, 2005	Wood log stove	90 8)	n.d.	100
	Sauna	190 8)	n.d.	200
	Pellets burner	70 8)	n.d.	n.d.
	Pellets burner	25 8)	n.d.	35
	Wood chips/pellets boiler 30-50 kW	15 8)	n.d.	20
	Wood chips boiler 30-50 kW	10 8)	n.d.	20
	Pellets boiler 30-50 kW	10 8)	n.d.	15
	Wood chips/pellets stoker[6] 50-500 kW	20 8)	n.d.	40
	Wood chips stoker 30-500 kW[6]	30 8)	n.d.	50
	Pellets stoker 50-500 kW[6]	10 8)	n.d.	20
	Wood chips grate boiler 5-20 MW	20-55 6)		
	Wood chips Fluidized bed 20-100 MW	2-20 7)		
	Wood chips grate boiler 20-100 MW[7]	3-10		
	Wood chips grate boiler 10 MW[6]	3 8)	n.d.	10
Paulrud et al. 2006.	Wood log stove	n.d	n.d	22-181
Johansson et al, 2004b	Pellets stove	30-55	30-58	n.d.
	Pellets burner/boiler	10-60	10-75	n.d.
Glasius et al, 2005	Wood stove	n.d.	n.d.	200-5500
Schauer et. al., 2001	Open fire place	330-630	n.d.	n.d.
Purvis et. al., 2000	Open fire place	n.d.	n.d.	170-780
Wierzbicka, 2005	Moving grate 1.5 MW Saw dust, low load	36 6,8)	n.d.	
	Moving grate 1.5 MW Saw dust, Medium load	28 6,8)	n.d.	
	Moving grate 1.5 MW Saw dust, high load	25 6,8)	n.d.	n.d.
	Moving grate 1.5 MW pellets, low load	20 6,8)	n.d.	n.d.

Source	*Installation type*	*PM$_{2.5}$*	*PM$_{10}$*	*TSP*
	Moving grate 1.5 MW pellets, medium load	19 6, 8)	n.d.	n.d.
	Moving grate 1 MW forest residue, medium load	676 6,8)	n.d.	n.d.
	Moving grate 1 MW forest residue, high load	57 6,8)	n.d.	n.d.
Strand. et al, 2004	Moving grate 6 MW forest residue, high load	43 6,8)	n.d.	n.d.
	Moving grate 12 MW forest residue, high load	77 6,8)	n.d.	n.d.
	Moving grate 0.9 MW pellets, low load	10 6, 8)	n.d.	n.d.

1) as quoted in Klimont et al., 2002; (2) Original factors in lb/ton or in g/kg for recalculation H_u of 16 GJ/t were assumed; 3) Original factors are estimated per Unit of Heat Delivered no conversion was made; 4) The data for large scale combustion for illustration only; 5) Cyclone separator-dust control; 6) Filter separator-dust control; 7) PM mainly 0.1-0.3 μm; 7) Typically more than 80 % of all particles are smaller than 1 μm. The mean particle size is typically around 0.1 μm (between 50 nm to 200 nm); 8) Measured as PM1 n.d. – no data

!!! Yellow color indicates the data obtained from Karin and Susanne. Because I didn't receive complete description of references (Name, year, title and source) I could not to add them to point 7 References. May be some of them are the same as I introduced. **References are added (SP)!!!**

Table A1 32 Particulate matter size fraction distribution reported in the literature for wood burning [percent of TSP emissions] (as quoted in Klimont et al., 2002)

Source	*Sector*	*PM$_{2.5}$*	*PM$_{10}$*	*TSP*
Dreiseidler, 1999	Domestic furnaces	n.d.	90 %	100 %
	Wood pellets	84.4 %	94.6 %	100 %
EPA, 1998b1)	Residential wood except for pellet stove	93 %	97 %	100 %
Baumbach, 1999	Domestic furnaces	96 %	99.7 %	100 %
UMEG, 1999	Small boilers	79 %	92 %	100 %

1) Houck et al., 1998

Table A1 33 Particulate matter emission factors used in RAINS for wood burning in Europe [g/GJ] (as quoted in Klimont et al., 2002)

Sector	*PM$_{2.5}$*	*PM$_{10}$*	*TSP*
Eastern Europe			
Fireplaces, stoves	279	288	300
Small domestic boilers	93 – 230	96 – 240	100 – 250
Large residential boilers	77 – 150	89 – 0.180	100 – 200
Industry 1)	185	214	240
Western Europe			
Fireplaces, stoves	67 – 186	70 – 192	72 – 200
Small domestic boilers	60 – 167	62 – 170	65 – 180
Large residential boilers 1)	50 – 120	60 – 134	65 – 150

Industry [1)]	185	214	240

[1)] The data are enclosed for illustration

Table A1 34 Particulate matter emission factors reported in the literature for stationary combustion of heavy fuel oil [g/GJ]

Source	*Sector*	*$PM_{2.5}$*	*PM_{10}*	*TSP*
UBA, 1989 [1)]	Residential	n.d.	45	50
UBA, 1998 (2)	Residential	n.d.	8-27	9-30
CEPMEIP, 2002 [1)]	Residential	40	50	60
Pfeiffer et al, 2000 [1)]	Residential	n.d.	n.d.	38
Lammi et al, 1993 [1)]	5-50 MW	n.d.	n.d.	25-150
Ohlström, 1998 [1)]	5-50 MW	n.d.	n.d.	1-390 (4)
Berdowski et al., 1997 [1)]	Residential	30	50	n.d.
Hobson M. et al, 2003	Small com. or institutional boilers; ERA research; boiler 1.5% S	n.d.	3.1	n.d.
	Small com. or institutional boilers; ERA research; boiler 4.5% S	n.d.	18.5	n.d.
	Small com. or institutional boilers; ERA research; boiler 5.5% S	n.d.	26.4	n.d.

[1)] as quoted in Klimont et al., 2002;
[2)] as quoted in Dreiseidler et al., 1999;
[3)] as quoted in Berdowski et al., 1997;
[4)] Average value 32 g/GJ.

Table A1 35 Particulate matter size fraction distributions reported in the literature for stationary combustion of heavy fuel oil [percent of TSP] (as quoted in Klimont et al., 2002)

Source	*Sector*	*$PM_{2.5}$*	*PM_{10}*	*TSP*
EPA, 1998a	Residential boilers	23 %	62 %	100 %
CEPMEIP, 2002	Residential	67 %	83 %	100 %

Table A1 36 Particulate matter emission factors reported in the literature for stationary combustion of light fuel oil [g/GJ] (as quoted in Klimont et al., 2002)

Source	*Sector*	*$PM_{2.5}$*	*PM_{10}*	*TSP*
BUWAL, 2001	Domestic furnaces	n.d.	1	1
	Domestic boilers	n.d.	0.2	0.2
CEPMEIP, 2002	Residential and domestic	5	5	5
UBA, 1989	Industry, residential	n.d.	n.d.	1.5
UBA, 1998	All	n.d.	n.d.	1.5
Pfeiffer et al., 2000	Residential	n.d.	n.d.	1.7
	Domestic	n.d.	n.d.	1.6
Ohlström, 1998	0-50 MW plants	n.d.	n.d.	3 - 100(1)

Berdowski et al., 1997	Residential sector	30	30	n.d.

[1] Average value 70 g/GJ

Table A1 37 Particulate matter size fraction distributions reported in the literature for stationary combustion of light fuel oil [%](as quoted in Klimont et al., 2002)

Source	*Sector*	*$PM_{2.5}$*	*PM_{10}*	*TSP*
EPA, 1998a	Domestic boilers	42%	55%	100%
APEG, 1999 (1)	Residential sector	76-94%	100 %	n.d.
Berdowski et al., 1997 (1)	Domestic	60 %	100 %	n.d.

[1] The values refer to PM10 and not to TSP

Table A1 38 Percentage of particle fraction PM10 referring to the sectoral emission factors for particles [%]

Source	*Fuel*	*Households*	*Small consumers*	*Households and Small consumers*
Struschka et al., 2003	High rank coals and products	100	97	99
	Brown coal briquettes	96	n.d.	96
	Wood	97	94	96
	Distillate oil	100	100	100
Ehrlich et al., 2001	Biomass	n.d.	n.d.	> 90
Gaegauf et al., 2001	Biomass	n.d.	n.d.	95 [1]
Houck et al., 2005	Biomass	n.d.	n.d.	84 [2]
Boman et al., 2005	Biomass (pellet burners)	n.d.	n.d.	100 [3]

[1] 95% PM below 0.4 µm; [2] Approximately 81% of PM is PM2.5; [3] It was found, in principle, that all PM can be considered as PM_1 with an average PM1 of 89.5% ± 7.4% of total PM.

Table A1 39 Particulate matter emission factors reported in the literature for stationary combustion of natural gas [g/GJ]

Source	*Sector*	*$PM_{2.5}$*	*PM_{10}*	*TSP*
BUWAL, 2001 [1]	Domestic furnaces	n.d.	0.5	0.5
	Domestic boilers	n.d.	0.2	0.2
CEPMEIP, 2002 [1]	Residential and domestic	0.2	0.2	0.2
Pfeiffer et al., 2000 [1]	Residential and domestic	n.d.	n.d.	0.03
UBA, 1989; UBA, 1998 [1]	All	n.d.	0.095	0.1
Hobson M. et al, 2003	UNECE TFEIP; Dutch date for domestic gas use	n.d.	0.3	n.d.
	ERA; research boiler Efs.	n.d.	4.8	n.d.
	UNECE TFEIP; Dutch date for agricultural gas use	n.d.	0.15	n.d.

EPA, 1998a [1)]	All, no control	n.d.	n.d.	0.9

[1)] as quoted in Klimont et al., 2002; n.d. – no data

Table A1 40 Particulate matter emission factors used in the RAINS model for residential stationary combustion of liquid and gaseous fuels [g/GJ] (as quoted in Klimont et al., 2002)

Fuel	*PM2.5*	*PM10*	*TSP*
Heavy fuel oil	9.5	24.7	38
Light fuel oil	0.7	0.9	1.7
Natural gas	0.03-0.2	0.03-0.2	0.03-0.2

Table A1 41 Emission factors of heavy metals from coal and wood combustion in advanced underfeed burning boiler 30kW (a), and from straw combustion in fixed grate boiler 65kW (b), [mg/GJ]

Heavy metals	*Coal/J 20-40mm (a)*	*Coal/W 20-40mm (a)*	*Coal/W 5-30mm (a)*	*Briquette / sawdust (a)*	*Lump wood (a)*	*Rape straw (b)*	*Wheat straw (b)*
As	7.4	1.7	4.5	9.5	5.3	3.7	14.3
Cd	5.5	2.0	3.3	25.6	22.0	21.1	13.5
Cr	16.5	3.0	15.8	13.4	6.6	3.6	13.5
Cu	37.6	476	52.6	92.8	34.8	3154	60.8
Hg	1.9	11.7	1.4	0.1	1.2	0.7	1.0
Ni	41.8	20.4	16.0	22.8	14.8	138.4	21.2
Pb	787	375	252	218	191	54.1	68.0
Se	3.0	2.4	3.2	1.0	1.2	0.8	5.1
Zn	275	n.m.	155	178	261	195	282
TSP; g/GJ	227	294	126.2	39	116	654	901

Source: Wiliams et al., 2001

Table A1 42 Heavy metals emission factors from oil combustion, [mg/GJ]

Source	*As*	*Cd*	*Cr*	*Cu*	*Hg*	*Ni*	*Pb*	*Zn*
All combustion (Pacyna J., and Pacyna, 2001)	0.5	1.2	23.8	11.9	1.4	476	47.6	23.8
Small combustion (Berdowski et al., 1997)	23.8	7.1	59.5	13.1	n.d.	833	23.8	23.8
Distillate fuel oil (Compilation of Air.., 1996)	1.7	4.5	23.8	n.d.	1.2	7.4	3.8	n.d

No6 fuel oil (Compilation of Air.., 1996)	3.6	0.9	0.2	4.8	0.2	229	4.0	79.0
Emission Factors Manual, 1993	14.3	11.9	33.3	11.9	3.6	714	26.2	14.3
Small and medium boilers-non controlled (authors estimates)	0.5	1.2	11.4	8.6	1.2	1,047	30.0	38.6

Source: Kakareka et al., 2003; Original factors in g/ton, for recalculation H_u of 42 GJ/t was assumed; n.d. = no data

Table A1 43 Heavy metals emission factors from coal combustion, [mg/GJ]

Source	*As*	*Cd*	*Cr*	*Cu*	*Hg*	*Ni*	*Pb*	*Zn*
All combustion (Pacyna J., and Pacyna, 2001)	8.3	4.2	70.8	58.3	20.8	83.3	41.7	62.5
Small combustion (Berdowski et al., 1997)	10.4	4.2	29.2	41.7	9.2	52.1	208	417
High level of abatement (Compilation of Air..,1996)	8.3	1.2	5.4	n.d	1.7	5.8	8.8	n.d.
Domestic furnaces (Determination of Mean… 1996)	6.7	6.7	n.d.	n.d.	n.d.	n.d.	27.5	n.d
Small consumers (Determination of Mean… 1996)	7.9	4.2	2.5	3.3	n.d.	n.d.	238	12.5
Small and medium boilers-non controlled (authors estimates)	125	1.7	51.8	58.3	8.3	21.7	54.2	225
Small and medium boilers - limited controlled (authors estimates)	37.5	0.4	15.4	17.5	8.3	6.3	16.7	67.5

Source: Kakareka et al., 2003; Original factors in g/ton, for recalculation H_u of 24 GJ/t (d.b.) was assumed; n.d. = no data

Table A1 44 Heavy metals emission factors from wood combustion, mg/GJ.

Source	*As*	*Cd*	*Cr*	*Cu*	*Hg*	*Ni*	*Pb*	*Zn*
Industrial combustion (Berdowski et al., 1997)	n.d	6.3	1.9	12.5	6.3	1.9	12.5	125
Small combustion (Berdowski et al., 1997)	n.d.	2.5	10.6	15.0	6.3	1.9	15.0	125
Traditional domestic wood furnace (Compilation of Air.., 1996)	n.d.	0.7	<0.1	n.d.	n.d.	0.4	n.d.	n.d.
Domestic furnace (Determination of Mean.., 1996)	0.2	1.9	5.6	10.0	n.d	1.1	11.9	263

Small consumers (Determination of Mean.., 1996)	1.9	2.5	13.1	17.5	n.d	0.9	83.8	428.1
Wood combustion (Emission Factors Manual .., 1993)	n.d.	<6.3	n.d.	<6.3	0 – 12.5	<3.1	<3.1	125
Small and medium boilers - non controlled (authors estimates) 1)	0	1.3	3.8	13.8	0	2.5	15.6	269
Small and medium boilers - limited controlled (authors estimates) 1)	0	1.3	1.3	4.4	0	0.6	5.0	81.3
Household furnaces – non controlled (auth. estimates) 1)	0	0.6	1.9	7.5	0	1.9	9.4	156.3
Commercial soapstone stove, birch logs 2)	2.5 – 29 aver. 16	0 – 99 Aver. 38	2.5– 131 aver. 39	4.3 – 5.0 aver. 4.4	16 -269 aver.119	0.6 – 19 aver. 4	4.5 – 58 aver. 21	93 - 769 aver.469
Chips diff. type of wood 3)	n.d.	0.03-1.2 aver. 0.4	3.2 – 4.4 aver. 3.8	0.6 - 1.3 aver. 1.1	0.8-2.1 aver. 1.3	0.2 – 0.5 aver. 0.4	0.7-3.0 aver.1.8	44-4.2 aver.18

Source: 1) Kakareka et al., 2003, 2) Hedberg et al., 2002, Kubica, 2006 3); Original factors in g/ton, for recalculation H_u of 16 GJ/t was assumed; n.d. – no data

Table A1 45 Heavy metals emission factors from peat combustion, g/GJ.

Source	*As*	*Cd*	*Cr*	*Cu*	*Hg*	*Ni*	*Pb*	*Zn*
Industrial combustion (Berdowski et al., 1997)	4.2	10.5	3.2	21.1	6.3	3.2	21.1	5.3
Small combustion (Berdowski et al., 1997)	4.2	4.2	17.9	25.3	6.3	17.9	25.3	5.3
Small and medium boilers - non controlled (authors estimates)	13.7	7.4	40	47.4	n.d.	37.9	54.7	210
Small and medium boilers - limited controlled (authors estimates)	4.2	2.1	11.6	14.7	n.d	10.5	15.8	63.2
Household furnaces – non controlled (authors estimates)	6.3	3.2	17.9	22.1	n.d.	15.8	25.3	94.7

Source: Kakareka et al., 2003; Original factors in g/ton, for recalculation H_u of 9.5 GJ/t was assumed; n.d. = no data

Table A1 46 Review of range and estimated average mercury emission factor for different type of fuels (without abatement) Pye S. et al; 2005

Fuel	*Range (kg/TJ)*		*Average (kg/TJ)*	*Uncertainty 1)*
	Low	*High*		
Natural gas	0.0000006	0.00015	0.00001	C
Gasoline	0.0000050	0.00047	0.00003	C
Diesel oil	0.0000095	0.000071	0.000025	
Light fuel oil	0.0000024	0.00012	0.000025	
Heavy fuel oil	0.000006	0.015	0.0001	

Bituminous coal	0.00039	0.070	0.009	C
Smokeless fuel	0.00064	0.00099	0.00075	C
Coke	0.00060	0.015	0.0035	
Brown coal (Lignite)	0.005	0.13	0.007	C
Wood	0.00010	0.00188	0.0005	D
Waste wood	0.00025	0.0034	0.0008	
Straw	0.00007	0.0022	0.001	

1) Pulles et al., 2001

Table A1 47 Mercury emission factors by sector-fuel-technology; Pye et al., (2005) and Kubica et al., (2006/1)

Sector	*Fuel*	*Technology*	*Emission factors in kg/TJ*
AFF	Biomass	Medium boilers (automatic) <50 MW using wood, waste, biomass	0.0008
		Medium boilers (manual) <1 MW using wood, waste, biomass	0.0006
		Single house boilers (automatic) <50 kW using wood, waste, biomass	0.00055
		Single house boilers (manual) <50 kW using wood, waste, biomass	0.0008
	Gaseous fuel	LPG	0
		Natural Gas	0.00001
	Liquid fuel	Diesel / Light fuel oil	0.000025
		Gasoline	0.00003
		Heavy fuel oil	0.0001
	Solid fuel	Medium boilers (automatic) <50 MW using brown coal	0.007
		Medium boilers (automatic) <50 MW using coke / briquettes	0.0035
		Medium boilers (automatic) <50 MW using hard coal	0.009
		Medium boilers (manual) <1 MW using brown coal	0.0055
		Medium boilers (manual) <1 MW using coke / briquettes	0.003
		Medium boilers (manual) <1 MW using hard coal	0.007
		Single house boilers (manual) <50 kW using brown coal	0.006
		Single house boilers (manual) <50 kW using coke / briquettes	0.0035
		Single house boilers (manual) <50 kW using hard coal	0.009
Commercial-Institutional	Biomass	Medium boilers (automatic) <50 MW using wood, waste, biomass	0.0008
		Medium boilers (manual) <1 MW using wood, waste, biomass	0.00055
	Gaseous fuel	LPG	0
		Natural Gas	0.00001
	Liquid fuel	Diesel / Light fuel oil	0.000025
		Gasoline	0.00003
		Heavy fuel oil	0.0001
	Solid fuel	Medium boilers (automatic) <50 MW using brown coal	0.007
		Medium boilers (automatic) <50 MW using coke / briquettes	0.0035
		Medium boilers (automatic) <50 MW using hard coal	0.009
		Medium boilers (manual) <1 MW using brown coal	0.006

		Medium boilers (manual) <1 MW using coke / briquettes	0.003
		Medium boilers (manual) <1 MW using hard coal	0.007
Residential	Biomass	Fireplaces using wood, waste, biomass	0.0004
		Single house boilers (automatic) <50 kW using wood, waste, biomass	0.00055
		Single house boilers (manual) <50 kW using wood, waste, biomass	0.0005
		Stoves using wood, waste, biomass	0.0004
	Gaseous fuel	LPG	0
		Natural Gas	0.00001
	Liquid fuel	Diesel / Light fuel oil	0.000025
		Gasoline	0.00003
		Heavy fuel oil	NA
	Solid fuel	Fireplaces	0.003
		Single house boilers (manual) <50 kW using brown coal	0.007
		Single house boilers (manual) <50 kW using coke / briquettes	0.003
		Single house boilers (manual) <50 kW using hard coal	0.006
		Single house boilers (automatic) <50 kW using hard coal	0.009
		Stoves using brown coal	0.004
		Stoves using hard coal	0.006

Table 208 Mercury emission factor speciation for different fuels (as quoted in Pye et al., 2005)

Fuel	***Installation***	***Hg^0 (gas)***	***Hg^{+2}***	***Hg (partic.); Hg^{PM}***	***Uncertainty$^{1)}$***	***Source***
Hard Coal	Power plant	0.5	0.4	0.1	-	Pacyna et.al., 2004
	Residential	0.5	0.4	0.1	C	
	General	0.5	0.4	0.1	-	Senior, 2004
	Power plant	0.5	0.4	0.1	-	
	Power station stack monit.	0.269	0.695	0.036	-	Pye, 2005/2
	Domestic coal burning	0.4	0.4	0.2	C	
	FBC $^{a)}$	0.55-0.6	0.4	<0.05	-	Moritomi, 2005
	FBC $^{b)}$	0.05 – 0.10	0.8	0.15 – 0.10	-	
	Research facility design to replicate typical power plant	0.2	0.8	-	-	Tan et a., 2004
	Stove	0.6		0.4	-	Bartle et al., 1996
	Power plant	0.42	0.58	-	-	Hlawiczka, et al., 2003
	Stove / Fireplaces	0.3	0.35	0.35	C	Pye et al., 2005/1
	Boiler manual fuelled - all SCI sectors	0.4	0.4	0.2	C	
	Boiler autom. (stoker) - all SCI sectors	0.5	0.4	0.1	C	

Brown coal	Power plant	0.61	0.39	~ 0.01	-	Hlawiczka, et al., 2003
Biomass	Manual fuelled (stove boiler) - all SCI sectors	0.6	0.3	0.1	D	Pye et al., 2005/1
	Automatic fuelled- all SCI sectors	0.65	0.3	0.05	D	Pye et al., 2005/1
Liquid fuels	General for oil	0.5	0.4	0.1	-	Pacyna et.al., 2004
		0.5	0.4	0.1	-	Senior, 2004
		0.51	0.39	0.1	-	Pye, 2005/2
	SCIs (all sectors) Light fuel oil	0.75	0.2	0.05	C	Pye et al., 2005/1
	SCIs AFF, Com-Inst Heavy fuel oil	0.65	0.35	0.1	C	Pye et al., 2005/1
Natural gas	SCIs (all sectors)	0.8	0.15	0.05	C	Pye et al., 2005/1

[a] high content of volatile matter in coal (about 40%) of Cl; [b] coal rich Cl (2304 ppm) content; [1]Pulles et al., 2001; An uncertainty rating has not been given to non-SCI categories (as indicated by the dashes in the uncertainty column).

Table A1 49 Average emission values of PAHs [mg/GJ] and PCDD/F [ng I-Teq/GJ] from solid fuels combustion in stove

Fuel	*PAH Σ 1-4*	*B(a)P* [x]	*B(b)F* [x]	*B(k)F* [x]	*I_P* [x]	*PCDD/F*
Cokes	13.4	4.3	3.8	3.2	2.0	1,470
Coal	145.4	41.8	45.3	19.2	39.1	7,740
Wood	35.2	10.4	10.8	5.0	9.0	320

Source: Thanner G., et al., 2002; [x] the factors were assessed by recalculation original data in ng/Nm^3.

Table A1 50 Emission factors of PCDD/F reported in the literature for small combustion installations [ng I-Teq/GJ]

Source	*Sector*	*Fuel*	*PCDD/Fs*
Hobson M., et al., 2003	Domestic open fire	Yorkshire housecoal; CPL Research, open fire <5 kW	120.8[1]
		Hardwood seasoned; CPL Research, open fire <5 kW	14.4[1]
	Small commercial or institutional boiler	Bituminous coal; AEAT Research; coal boiler, rated 500 kW	2,125[1]
		Wood; AEAT Research; 1,5MW boiler with cyclone abatement	787.5
Davies M., et al., (1992)	Domestic open fire	Smokeless fuel, bituminous coal, anthracite	87.5 – 238[1]
	Small commercial institutional inst.	Traveling grate 5.8 MW	66.7[1]
		Traveling grate 63 MW	29.2[1]

UNEP Chemicals (2003)	Stoves	Coal	70
		Contaminated wood/biomass	1,500
		Virgin wood/biomass	100
		Oil	10
		Natural gas	1.5
	Boilers, motors – turbines. Flaring	Landfill/biogas combustion$^{2)}$	8
Geueke K.-J. et al 2000$^{1)}$	Stoves	Lignite Germany	70; 58$^{1)}$
		Lignite Czech Rep	20; 21$^{1)}$
		Anthracite	95; 175$^{1)}$
		Hard coal Poland	633; 1,430$^{1)}$
Pfeiffer F. et al., 2000 $^{3)}$	Stoves	Wood; masonry heater, 32.5kW	39
		Wood; Tiled with insert, 5.5-14.3kW	9; 27; 49
		Gas heater old convection,4.3kW	1.5
		Gas heater new convection6.2kW	1.7
		Gas old water heater 23.3kW	4.1
		Gas new water heater 19.2kW	2.0
		Oil heater, tiled stove-old burner,8.3kW	3.2
		Oil heater, tiled stove-new burner, 9 kW	1.6
	Domestic boilers	Gas boilers -old, 36.6kW	1.2
		Gas boilers, new,15.8kW	2.3
		Gas boilers, new, 19.0kW	1.8
		Gas boilers, new, 17.5kW	1.4
		Gas boilers, new, 19.9kW	2.0
		Oil boilers - old, 25.6kW	2.9
		Oil boiler, old, solid and gas also, 19.4kW	2.9
		Oil boiler, old, solid and gas also, 20.8kW	0.6
		Oil boiler new, cast iron, 20.2 kW	1.0
		Oil boiler new, steel-20.1-0.9	0.9
Grochowalski A. (2002)	Stoves	Coal stoves	6,000; 11,500 $^{1)}$
	Small commercial institutional and district heating	Moving grate firing boiler; new construction – 1985	11.8; 49.0 $^{1)}$
		Moving grate firing boiler; old construction – 1950	90.0; 151.0 $^{1)}$
		Fluidized bed combustion	104.6; 274.2$^{1)}$
Kubica (2002/1, 2003/1)	Household boilers	Coal automatic fuelled, stoker boiler, upper fire, 30 kW	57.2
Williams, et al. (2001)	Household, advanced manual fuelled boiler, 30 kW	Coal J	285.0
		Coal W	804.0; 540.1
		Pine wood log	1603.3
		Sawdust briquette	107.4
		Coal and pine sawdust briquette (33%)	431.1
		Coal and sewage sludge briquette (13.8%)	277.1
		Mixture of coal and sawdust	795.6
		Mixture of coal and rape straw	740.9

	Household boilers, agricultural small comb. installation	Straw (rape) manual fuelled boiler, 65kW	840.3
		Straw (wheat) manual fuelled boiler, 65kW	746.2
Quass U., et al. 2000	Stoves, simple design	Lignite Germany	117.6
		Lignite Czech Rep.	39.4
		Anthracite	145.0
		Hard coal briquette Germany	310.4
		Coke Germany	26.6
		Hard coal Poland	1,127
	Stoves, modern design	Lignite Germany	192.9
		Lignite Czech Rep.	69.4
		Anthracite	364.3
		Hard coal briquette Germany	186.7
		Coke Germany	90.3
		Hard coal Poland	3,687
Kakareka, (2003)	Household stoves:	Peat	263
		Wood	312.5
	Small and medium boiler	Oil	5
		Coal: non controlled combustion	104
		Coal; partly controlled combustion	42
		Peat: non controlled combustion	263
		Peat; partly controlled combustion	105
		Wood: non controlled combustion	312.5
		Wood: partly controlled combustion	62.5
Casserini S. et al. (2003)	Residential heating	Liquid fuel	3.9
		Wood	500
		Coal	3.2
Pfeiffer F., et al. (2000)[3)]	Households (Germany)	High rank coal and products	27.4
		High rank coals	20.3
		Briquettes	37.3
		Coke from high rank coals	39.4
		Brown coal briquettes	23.3
		Natural wood	29.5
		Distillate oil	2.5
		Natural gas	1.9
	Small consumers (Germany	High rank coal and products	5.1
		High rank coals	5.1
		Coke from high rank coals	23.7
		Brown coal briquettes	12.8
		Natural wood	411.5
		Distillate oil	2.8
		Residual oil	n.d.
		Natural gas	1.6
Lee et al., 2005	Open fire place	Coal	90
	Open fire place	Wood	11
Gullet et al., 2003	Fireplace	Oak	18
	Fireplace	Pine	74

	Fireplace	Artificial logs (wax and sawdust)	70
	Woodstove	Oak	13
Hübner et al., 2005	Boilers	Pelleted wood	21
		Chopped wood log	3- 2000
		coke	87
		Wood and coke	280
		Wood brown coal briquettes	380
	Stove	Hard coal, brown coal briquettes wood	48 – 2400
		Beach wood logs	45 – 4500
		Wood	2300
		Spruce wood (small logs)	1000
		Small wood logs	150
		Wood briquettes	27
	Boilers	All solid fuels	750
	Stove	All solid fuels	380

1) Original factors in g/kg of fuels, for recalculation H_u of 24 GJ/t (d.b.) for hard coal was, of 17 GJ/t (d.b.) for lignite and brown coal, of 30 GJ/t (d.b.) for anthracite, of 30 GJ/t (d.b.) for coke; of 16 GJ/t for wood, of 42 GJ/t for oil and of 35 GJ/t for natural gas were assumed; (2) The date for comparison to natural gas combustion only; 3) PCDD/F given as toxicity equivalent according to the NATO/CCMS (1988) calculation method; n.d. – no data

Table A1 51 Average emission values of PAHs [mg/GJ] from solid fuels combustion in small combustion installations

Source	***Installation type***	***PAH Σ 1-4***	***B(a)P***	***B(b)F***	***B(k)F***	***I_P***
Kakareka, (2003)1)	Household stoves:					
	- peat	336	84	168	42	42
	- wood	1,280	312	643	169	156
	Small and medium boiler: - oil	0.6	0.1	0.2	0.1	0.2
	Small and medium boiler coal:					
	- non controlled	342	83.3	150	58.3	50.0
	- partly controlled	102.5	25.0	45.0	17.5	15
	Small and medium boiler peat:					
	- non controlled	336.4	84.2	168	42.1	42.1
	- partly controlled	101	25.3	50.5	12.6	12.6
	Small and medium boiler wood:					
	- non controlled	1,280	312	643	169	156
	- partly controlled	385	93.8	194	50.0	46.9
Kubica K. et al; (1994)	Household stoves with water jacket:					
	- coal	6,742	938	5,696		108
	- briquette/smokeless fuel	195.7	21.3	153		21.4
Kubica K., (1996)	Conventional stove:					
	- coal A	590	180	210	90	110
	- coal B	1,410	290	710	200	210

Kubica K. et al; (1997/3; 2002/2)	Conventional stove:					
	- wood log	1,210	390	380	180	260
	- wood pellets	267.7	131.1	65.0	30.4	41.2
	Advanced wood pellets burner	15.3	4.4	6.3	3.3	1.3
	Upper-fire, automatic stocker boiler:					
	- pellet	33	5	18	8	2
	Advanced under fire coal boiler 20kW:					
	- fine coal	56	13	22	9	12
	- fine coal/chips wood (80/20)	17	6	5	1	5
Kubica K.; (2003/1)	Conventional coal boiler 30kW	1,520	450	750	170	150
	Advanced coal boiler manual fuelled 30 kW	326	82	130	80	34
	Automatic fuelled coal boiler 30 kW	33	5	18	8	2
Williams, et al. (2001)	Advanced under-fire boiler, manual 30kW					
	- coal WI	850	290	280	120	60
	- wood	610	120	220	180	90
	- sawdust briquettes	120	50	50	20	10
	- coal WI briquettes	42	10	20	10	2
	- straw (65 kW)	165	80	50	20	15
Kubica K., et al, (1997/3)	Manual fuelled coke boiler 150 kW	21.3 1)	6.0	12	3.3	n.d.
	Automatic fuelled coal boiler, retort; 150 kW	95 1)	27	40	19	9
Kubica K. et al; (2003/3)	Commercial, institutional and district heat.; Moving grate firing coal boiler 10MW	13.2	5.2	4.4	2.0	1.6
	Commercial, institutional and district heat; Moving grate firing coal boiler 10MW	8.0	2.5	4.4	1.0	0.1
	Fluidized bed combustion	21.0	6.7	8.5	4.0	1.8
EPA (1996) 1)	Conventional stove	375.0	125.0	187.5	62.5	0.0
	Non-catalytic stove	1062.5	187.5	125.0	125.0	625.0
	Catalytic stove	500.0	125.0	125.0	125.0	125.0
Pfeiffer F., et al (2000) Households (Germany) 3)	High rank coal and products	270	n.d.	n.d.	n.d.	n.d.
	High rank coals	60	n.d.	n.d.	n.d.	n.d.
	Briquettes	580	n.d.	n.d.	n.d.	n.d.

	Coke from high rank coals	100	n.d.	n.d.	n.d.	n.d.
	Brown coal briquettes	440	n.d.	n.d.	n.d.	n.d.
	Natural wood	490	n.d.	n.d.	n.d.	n.d.
	Distillate oil	1.8	n.d.	n.d.	n.d.	n.d.
Pfeiffer F., et al (2000) Small consumers (Germany) [3]	Coke from high rank coals	130	n.d.	n.d.	n.d.	n.d.
	Natural wood	210	n.d.	n.d.	n.d.	n.d.
	Distillate oil	0.2	n.d.	n.d.	n.d.	n.d.
Lee et al., 2005 1)	Open fire place, coal	830	330	210	100	190
	Open fire place, wood	97	40	19	13	25
Gullet et al., 2003	Fireplace, Oak	101	36	21	26	18
	Fireplace, Pine	62	19	14	17	12
	Fireplace, Artificial logs (wax and sawdust)	115	34	26	31	24
	Woodstove, Oak	94	35	23	28	8
Kubica K.; (2004/1)	Conventional stove 5kW	6,3050	2,240	3,630		480
	Conventional coal boiler manual fuelled 30kW	335.0	68.1	209.8		67.1
	Advanced coal boiler manual fuelled 30 kW	13.1	4.5	8.1		1.5
	Automatic fuelled coal boiler – stocker 30 kW	6.3	3.6	2.2		0.5
Boman et al., 2005	Natural-draft wood stove Wood	683-6,500 aver.1,950	16-2,400 aver. 610	30-2,500 aver. 680	9.3-1,000 aver. 250	13-1,500 aver. 410
	Pellet stove (high load); modern certified Swedish	0.9-3.47 aver. 1.1	0.84-0.17 aver. 0.3	0.06 - 1.1 aver.0.6		0.0-3.3 aver. 0.8
	Pellet stove (low load); modern certified Swedish	6.8 – 65 aver. 28.1	1.8-16 aver. 6.7	3.6 - 32 aver. 14		1.4 – 17 aver. 7.4
	Pellet stove (high load); classic North American	0.9-3.47 aver. 1.1	0.84-0.17 aver. 0.3	0.06 - 1.1 aver.0.6		0.0-0.09 aver.0.04
	Pellet stove (low load); classic North American	0.87-5.1 aver.2.7	0.32– 1.3 aver.0.75	0.55 – 1.8 aver. 1.1		0.00-2.00 aver.0.81
Oanh et al., 1999	Stove, charcoal	33.8	5.5	0.5	27.8	n.d.
	Stove, coal briquettes	106.6	12.6	24	70	n.d.
	Open burning in pile wood	144.1	43.0	28.4	23.6	49.1
Hedberg et al., 2002 1)	Commercial soapstone stove, birch logs	38 -2,630 aver. 610	13-1,000 aver. 225	19-1,630 aver. 380	<6 - <6 <6	n.d.
Kubica, 2004/2	Residential; coal	765	248	323	124	69

	Residential; wood	712	211	216	131	154
	Residen./Comm./Institut. Coal	563	195	245	68	55
	Residen./Comm./Institut. Coal	458	143	171	73	71

$^{1)}$ Original factors in g/kg of fuels, for recalculation H_u of 24 GJ/t (d.b.) for coal was, of 16GJ/t for wood, of 42GJ/t for oil and of 35GJ/t for natural gas were assumed; $^{(2)}$ The original date of PAH without the description of PAH type; $^{3)}$ PAH it is the sum of the 8 cancerogenic PAHs: anthracene, benzo(a)pyrene, benzo(a)anthracene, indeno(1,2,3-cd)pyrene, chrysene (+triphenylene), dibenzo(a,h)antracene, benzo(b+j+k)fluoranthene and benzo(ghi)perylene; n.d. – no data

Table A1 52 Emission factors of VOC and NMVOC [as C_3H_8] reported in the literature for small combustion installations [g/GJ]

Source	*Sector/appliances*	*Fuel*	*VOC*	*NMVOC*
Hobson M., et al., 2003	Domestic open fire	Bituminous coal; BCC Research, domestic open grate	n.d.	583$^{1)}$
		Manufactured fuels; BCC Research, domestic coke use	5-20	n.d.
		Wood; BCC Research; UK use of wood in domestic appliances	90-800	n.d.
	Domestic boilers	Bituminous coal; BCC Research, 17 kW underfeed boiler	n.d.	25
		Bituminous coal; BCC Research, 13 kW, gravity feed, anthracite	n.d.	71
		Hard coal 35kW boiler, benchmark	n.d	195
		Hard coal 35kW boiler, improved	n.d.	40
		Brown coal 35kW boiler, bench.	n.d.	380
		Brown coal 35 kW boiler, improved	n.d.	76
		Coke, 35 kW boiler, benchmark	n.d.	220
		Coke, 35 kW boiler, improved	n.d.	44
		Wood, charcoal, 35 kW boiler, benchmark	n.d.	480
		Burning oil, 35 kW boiler, benchmark	n.d.	7.5
		Burning oil, 35 kW boiler, improved	n.d.	1.5
		Kerosene; BCC Research; UK use of kerosene in dom. appliances	15	n.d.
		Gas, 35 kW boiler, benchmark	n.d.	15
		Gas, 35 kW boiler, improved	n.d.	3
		Gas; BCC Research; UK use of gas in domestic appliances	5.0-30	n.d.
	Small commercial or institutional boiler	Bituminous coal; BCC Research; 0.9-48 MW boilers	n.d.	2.1
		Hard coal 200kW boiler, benchm.	n.d	30
		Hard coal 200kW boiler, improved	n.d.	6
		Brown coal 200kW boiler, benchm	n.d.	30

		Coke; BCC Research; industrial coke use	1.0-30	n.d.
		Coke, 200 kW boiler, benchmark	n.d.	30
		Coke, 200 kW boiler, improved	n.d.	6
		Fuel oil; BCC Research; UK use of residual fuel oil in industry	8	n.d.
		Burning oil, 200 kW boiler, benchm	n.d.	5.0
		Burning oil, 200 kW boiler, benchm	n.d.	1.0
		LPG; BCC Research; UK use of LPG in commercial appliances	5	n.d.
		GAS; BCC Research; UK use of gas in commercial appliances	5	n.d.
		Gas, 200 kW boiler, benchmark	n.d.	5.0
		Gas, 200 kW boiler, improved	n.d.	1.0
	CHP	Fuel oil; BCC Research; UK use of fuel oil in power plant	6.8	n.d.
		Oil, 200 kW boiler, impr. & abate	n.d.	1
CITEPA (2003)	Open fireplaces	Wood combustion	n.d.	1,700
	Closed fireplaces and inserts			1,600
	Conventional stoves		n.d.	1,600
	Advanced stoves		n.d	30
	Non-certified boilers		n.d.	1,600
	Advanced boilers class 1		n.d.	400
	Advanced boilers class 3		n.d.	40
Kubica, UN-ECE TFEIP, (2002/1)	Stove	Coal J	486	n.d.
		Coal W	700	n.d.
		Wood log	1,660	n.d.
Williams, et al. (2001)	Boiler manual fuelled, 30kW	Coal J	514.2	n.d.
		Coal W	483.1	n.d.
		Coal WII	448.9	n.d.
		Pine wood log	336.4	n.d.
		Sawdust briquette	176.1	n.d.
		Coal and pine sawdust briquette (33%)	214.7	n.d.
		Coal and sewage sludge briquette (13.8%)	1058.9	n.d.
		Mixture of coal and sawdust	286.4	n.d.
		Mixture of coal and rape straw	326.8	n.d.
Kubica K., (2002/2)	Stocker boiler, 25kW	Coal	14.0	n.d.
		Wood pellet	21.0	n.d.
Pfeiffer F., (2000) [a)]	Households (Germany)	High rank coal and products	342	137
		High rank coals	324	130

		Briquettes	366	146
		Coke from high rank coals	13	7.9
		Brown coal briquettes	296	217
		Natural wood	393	301
		Distillate oil	1.3	1.3
		Natural gas	1.6	0.71
	Small consumers (Germany)	High rank coal and products	11	4.5
		High rank coals	11	4.5
		Coke from high rank coals	36	21
		Brown coal briquettes	427	350
		Natural wood	258	186
		Distillate oil	2.6	2.6
		Residual oil	n.d.	n.d.
		Natural gas	0.51	0.39
EPA (Environmental Protection Agency); 1996	Wood stove	Conventional	n.d.	1656
		Non-catalytic	n.d.	375
		Catalytic	n.d.	469
BLT, 2005/1 a)	Boiler 25 kW	Wood pellets and chips	7	n.d.
	Boiler 43 kW; 100% and 33% of capacity	Pellets and wood chips	2	n.d.
	Boiler 60 kW	Wood	27	n.d.
	Boiler, 25kW	Wood chips	6	n.d.
	Boiler 46.7 kW; 100% capacity; 33% of capacity	Wood pellets	3; 5	n.d.
BLT, 2003 a)	Boiler 7.7 – 26 kW	Wood pellets and briquettes	1	n.d.
BLT, 1999 a)	Boiler 500kW	Wood chip; 100% and 30% of capacity	<1; 1	n.d.
BLT, 2004/1 a)	Boiler 20kW	Wood chips	2	n.d.
BLT, 2004/2 a)	Boiler 50kW	Wood logs and briquettes	4	n.d.
BLT, 2000/1 a)	Boilers, two chambers and sonar Lambda	Wood logs	3	n.d.
BLT, 2000/2 a)	Chamb. boiler 60kW	Wood briquettes	2	n.d.
BLT, 2005/2 a)	Chamber boiler 27 kW	Wood logs	9	n.d.
McDonald et. al., 2000 1)	Fireplaces		1.4–14.5 aver. 7.5	n.d.
	Woodstove		6.2-55.3 aver. 23	n.d.
Johansson at al., 2001	Boilers, fixed grates, moving scrapes 1.75– 2.5 MW	Wood pellets	1.4	n.d.
Boman et al., 2005	Natural-draft stove, 9 kW	Wood; Birch Pine Spruce	n.d.	1 – 2500 aver. 600

	Pellets stove 4- 9,5 kW; (high load)	Pellets: Pine Spruce	n.d.	0,85 – 2 aver. 2
	Pellet stove, 4- 9,5 kW; (low load 30%)	Pellets: Birch Pine Spruce	n.d.	14 – 22 aver. 19
Kubica, 2004/2	Pellet boilers	Wood pellets; Pine	5–18 aver.7	n.d.
	Chamber boiler, top feed	Fine coal	100 - 250	n.d.
	Automatic coal boiler, stocker	Pea coal (qualified coal size)	1- 50 aver.11	n.d.
	Automatic coal boiler	Fine coal (qualified coal size)	2 – 50 aver.20	n.d.
	Chamber boiler, advanced techniq.	Qualified size coal	60 - 120	n.d.

1) Original factors in g/kg of fuels, for recalculation H_u of 24 GJ/t (d.b.) for coal was, of 16GJ/t for wood, of 42GJ/t for oil and of 35GJ/t for natural gas were assumed; n.d. – no data; a) VOC and NMVOC as C; b) VOC as OGC

Table A1 53 Emission factors for the CHP plant types and aggregated emission factors for the decentralized CHP plants

Pollutants	*Unit*	*Natural gas engines*	*Biogas engines*	*Gas turbine*	*Municipal waste CHP*	*Straw CHP*	*Wood CHP*	*Decentr. CHP plants*
NH_3	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.	n.d.
NO_x	g/GJ	168	540	124	124	131	69	154
NMVOC	g/GJ	117	13	1.4	<1	<0.8	<3.4	55
CO	g/GJ	175	>273	6	<8	63	79	98
SO_2	g/GJ	n.d.	19	n.d.	<24	47	<1.8	10
TSP	g/GJ	0.76	2.63	0.10	<2.02	3.97	7.94	1.6
PM10	g/GJ	0.189	0.451	0.061	1.126	0.133	1.944	0.6
PM2.5	g/GJ	0.161	0.206	0.051	1.084	0.102	1.226	0.5
PCDD/F	I-Teq ng/GJ	n.d.	n.d.	n.d.	157	22	1	47
PAH [B(a)P-eq.]	mg/GJ	<0.023	<0.003	<0.005	<0.006	<0.154	<0.008	<0.020
B(a)P	mg/GJ	0.003	0.001	<0.009	<0.022	<0.003	<0.003	<0.003
B(b)F	mg/GJ	0.042	0.001	0.001	0.002	0.157	0.002	<0.026
B(k)F	mg/GJ	0.024	<0.0004	<0.002	<0.0008	<0.091	<0.003	<0.015

I_P	mg/GJ	0.006	<0.0011	<0.003	<0.0009	<0.023	<0.002	<0.004
As	mg/GJ	n.d.	n.d.	n.d.	<6.8	<2.1	<2.4	2.2
Cd	mg/GJ	n.d.	n.d.	n.d.	<4.8	<0.8	<1	1.5
Cr	mg/GJ	n.d.	n.d.	n.d.	<2.5	<1.6	<2.4	0.9
Cu	mg/GJ	n.d.	n.d.	n.d.	<10.1	<1.7	<2.7	3.1
Hg	mg/GJ	n.d.	n.d.	n.d.	<7.4	<0.6	<0.8	2.2
Ni	mg/GJ	n.d.	n.d.	n.d.	<4.8	<1.7	<2.4	1.6
Pb	mg/GJ	n.d.	n.d.	n.d.	<123	<6.2	<3.7	36.3

Source: Nielsen M. *et al.*, (2003); 1) none information about NMVOC standard reference usual CH_4 or C_3H_8 are used; n.d. - no data

Abbreviations

B[a]P	benzo[a]pyrene,
B[b]F	benzo[b]fluorantene,
B[k]F	benzo[k]fluorantene
CxHy	volatile hydrocarbons could be expressed as THC, see below
I_P -	indeno[1,2,3-cd]pyrene
I-Teq	in line with DRAFT GUIDELINES FOR ESTIMATING AND REPORTING EMISSIONS DATA, EB.AIR/GE.1/2002/7; 2 July 2002 the emissions of different congeners of PCDD/F are given in toxicity equivalents I-Teq in comparison to 2,3,7,8,-TCDD by using the system proposed by the NATO Committee on the Challenges of Modern Society (NATO-CCMS) in 1988
H_u (d.b.)	lower heating value of fuel on a dry basis
NMVOC	Non-methane volatile organic compounds (VOC) means any organic compound except methane having at 293.15 K a vapor pressure of 0.01 kP or more, or having a corresponding volatility under the particular conditions of use.
PM10	Particulate matter with an aerodynamic diameter less than 10 μm
PM2.5	Particulate matter with an aerodynamic diameter less than 2.5 μm
PAH	Polycyclic Aromatic Hydrocarbons
PCDD/F	Polychlorinated dioxins and furans
TSP	Total suspended particulate matter
THC	in line with EPA Method 25A as well as EN 12619 THC (Total Hydrocarbon Compounds) means “total gaseous organic concentration of vapors consisting primarily of alkanes, alkenes, and/or arenes (aromatic hydrocarbons). They are determined by using on-line flame ionisation analyser (FID). The concentration is expressed in terms of propane (or other appropriate organic calibration gas) or in terms of carbon.” Gaseous organic concentration (ppm v/v) usually expressed in terms of propane or methane in this case the relation is about 1.8:1.

VOC	Volatile organic compounds means any organic compound except methane having at 293.15 K a vapor pressure of 0.01 kP or more, or having a corresponding volatility under the particular conditions of use.

SNAP CODES:

050601
050603
010506

SOURCE ACTIVITY TITLES:

GAS DISTRIBUTION NETWORKS
Pipelines
Distribution Networks
Pipeline Compressors

NOSE CODE:

106.06.01
106.06.02

NFR CODE:

1 B 2 b
1 A 3 e i

1 ACTIVITIES INCLUDED

This chapter considers emissions from the transmission of gaseous fossil fuel from terminals to consumers via pipelines, compressor stations and networks. Most of the information in this chapter is based on data for natural gas.

Emissions from gas terminals are covered in the chapter on Extraction and first treatment of liquid and gaseous fuels (50200/50300).

2 CONTRIBUTION TO TOTAL EMISSIONS

Methane and NMVOCs are the pollutants that are likely to be emitted from gas distribution networks in significant quantities.

Table 2.1 refers to the UK only and to the year 1992. Data are from the UK Digest of Environmental Protection & Water Statistics 1994. The NMVOC component of natural gas was calculated using the UK species profile given in Section 9.

Table 2.1 - UK emissions from gas distribution networks (1992)

	Methane	NMVOC	Total
Emission due to natural gas leakage (kt)	375	42	417
Total emission (kt)	4736	2556	7292
Natural gas leakage as % of total emission	7.9	1.6	5.7

Table 2.2: Contribution to total emissions of the CORINAIR90 inventory *(up to 28 countries)*

Source-activity	**SNAP-code**	**Contribution to total emissions [%], (including emissions from nature)**							
		SO_2	NO_x	NMVOC	CH_4	CO	CO_2	N_2O	NH_3
Gas distribution networks	050600			0.5	6.0				

0 = emissions are reported, but the exact value is below the rounding limit of 0.1 per cent
- = no emissions are reported

These activities are not believed to be a significant source of $PM_{2.5}$ (as of December 2006).

3 GENERAL

3.1 Description

Natural gas is a combustible gas that occurs in porous rock of the earth's crust and is often found with or near accumulations of crude oil. It may also occur alone in separate reservoirs. Gas wells exist on land and offshore. Some countries may also use gas derived from coal. Coal gasification has been practised since the early nineteenth century and can be done using a number of different processes.

The main use of natural gas is heating buildings and processes and as a chemical feedstock, for example in the manufacture of ammonia and fertilisers. Also, it is increasingly being used as a fuel for power generation.

Natural gas is transferred from the well to a processing plant where it is separated by cryogenic distillation to give 'sales' gas of the required specification as well as possibly other products such as liquid hydrocarbon fractions. After this it is transferred via a network of pipelines and networks or 'mains' to consumers ranging from large factories to small dwellings. Natural gas may also be transported in liquefied form by ship, in which case it is loaded and unloaded at specially designed marine terminals.

A gas transmission network covering a country or region consists of pipelines and mains of a variety of different sizes, materials, and pressures. It will also contain storage facilities, pumping stations and pressure reduction stations. Pipes will also make use of different types of joint.

Transmission systems

Gas transmission systems can conveniently be divided into two interconnecting systems; the national transmission system, which consists of large diameter high pressure pipelines spanning distances of hundreds of kilometres, forms the backbone of the network and takes gas from the terminals to each of many regional supply systems, which consist of smaller diameter intermediate and low pressure pipelines and mains.

Pipelines & mains

Pipelines and mains are made from the following materials:

- Welded steel
- Cast Iron
- Ductile Iron
- Polyethylene

Pipelines and mains are operated under a variety of different pressure regimes, usually classified as follows:

- High pressure - up to 75 bar
- Intermediate pressure - 2 to 7 bar
- Medium pressure - 2 bar to 75 mbar
- Low pressure - < 75 mbar

Service pipes, which transfer gas from a main to a customer's meter, are always at low pressure.

Pipelines and mains can also be classified as jointed or unjointed. Jointed pipes have joints which consist of flanges bolted together or similar arrangements. In unjointed pipes the sections are welded together.

Storage

The gas transmission system incorporates a number of different types of storage elements. These include high pressure liquid storage, underground salt cavities and gas holders.

Losses

Losses can occur in many different ways from the network. For example, losses due to leakage and losses due to the purging of sections of pipe and items of equipment during commissioning, decommissioning and maintenance. Leakage can be further classified according to whether it is due to some malfunction, such as a crack in a pipe or a failure of a joint, or whether it occurs in fully functioning equipment as a direct consequence of its design and operation.

Emissions from gas transmission networks arise from a large number of small sources spread over a large area (fugitive). It is estimated that up to 20% of the gas escaping from leaky pipelines and mains is oxidised in the soil by micro-organisms.

3.2 Definitions

Compressor stations

These are pumping stations designed to either raise or maintain the pressure in the pipeline or main.

Distribution System
The term ‘distribution’ usually refers to the low pressure part of a country’s gas supply network rather than describing the system as a whole.

High pressure LNG storage
Large vessels in which natural gas is stored in liquid form under pressure.

Mains
Transmission pipes on a local level. Typically the sort of gas pipes found under the streets. Classified as low, medium or intermediate pressure.

Pipeline
The term pipeline is generally restricted to the large diameter, high pressure pipes used in national transmission systems and the high pressure parts of regional transmission systems. The smaller pipes branching off from these are referred to as mains.

Ports
A facility at which liquid natural gas is loaded onto and off ships.

Service mains
Also referred to as service pipes or ‘services’. These are the narrow, low pressure pipes leading directly to a customers premises.

STP
Standard Temperature & Pressure - refers to a temperature of 373.15 K and a pressure of 101325 Pa.

Terminals
A facility for storing and processing gas at the end of a pipeline from a well. The well can be either on shore or offshore.

3.3 Techniques

The technology which forms part of a typical gas transmission network is described in Sections 3.1, Description, and 3.2, Definitions, above.

3.4 Emissions

The pollutants emitted by the various parts of a typical gas transmission network are described in Section 9, Species Profiles, below and the various emission sources within a gas transmission network are described in Sections 3.1, Description, and 3.2, Definitions, above. As mentioned in Section 3.1 above it is estimated that up to 20% of the gas escaping from leaky pipelines and mains is oxidised in the soil by micro-organisms. However, since it is not possible to measure how much of the gas gets oxidised in this way it is recommended that this phenomenon is ignored in the estimation of emissions.

3.5 Controls

End of pipe techniques are inapplicable because the emissions cannot be collected together in a pipe or duct, instead they arise from a geographically diverse array of small sources emitting directly to the atmosphere. Consequently the only way is to reduce emissions by:

- the use of better materials for pipes, joints and seals
- the quicker detection and rectification of leaks
- improved maintenance
- measures to collect gas purged during commissioning, decommissioning & other maintenance activities

4 SIMPLER METHODOLOGY

In the absence of data characterising the transmission network, an emission can be estimated from the total sales of gas in the region or country. Emission factors can be expressed either as a percentage of total gas sales in tonnes or using an emission factor in tonnes per PJ of energy.

5 DETAILED METHODOLOGY

The detailed methodology requires much greater information on the gas transmission system. This information is normally available from the distribution company.

The first step is to divide the pipeline network of the country into categories. The categories should be chosen so that data on the installed length (i.e. number of km) of each category of pipeline is available and also so that pipelines in each category have common emission characteristics. Table 5.1 lists a suggested scheme of pipeline categories and Table lists a suggested scheme of point sources.

Equation 1 is a calculation to estimate the emission. It refers to m different categories of pipeline and p categories of point source, e.g. gas holders, compressor stations etc. In the rest of this document m = 7 and p = 3. However, these numbers may differ for different countries according to the choice of categories of pipeline and point source. Examples of the allocation of suffixes in equation 1 are shown in Table 5.1 and Table 5.2.

$$E = \sum_{i=1}^{m} l_i p_i f_i + \sum_{k=1}^{p} n_k F_k \qquad (1)$$

Where: l_i = the length, in km, of pipeline of type i

p_i = the pressure, in mbar, of the gas in pipeline of type i

f_i = an emission factor, in tonnes per year per km per mbar

n_i = number of point sources of category i

F_i = leak rate in tonnes per year

Table 5.1 - Pipeline Types

Suffix	Pipeline Category
1	high pressure pipeline
2	jointed low pressure and service mains
3	unjointed low pressure and service mains
4	jointed medium pressure mains
5	unjointed medium pressure mains
6	jointed intermediate pressure mains
7	unjointed intermediate pressure mains

Table 5.2 - Point Sources

Suffix	Point Source
1	high pressure LNG storage facilities
2	compressor stations
3	gas holders

6 RELEVANT ACTIVITY STATISTICS

For the simpler method, only the energy value of the gas consumed is required.

For the detailed method, the activity statistics that appear in equation 1 are needed.

For breaking down the emission into individual compounds the local composition of the natural gas is also required.

7 POINT SOURCE CRITERIA

Storage facilities and processing plants should always be treated as point sources.

Compressor stations may be treated as point sources if sufficient data are available.

Further geographical disaggregation is discussed in Section 12 below.

8 EMISSION FACTORS, QUALITY CODES AND REFERENCES

8.1 Simpler Method

Table 8.1: Default Emission Factors for Simpler Method

Compound	Emission factor (tonnes per PJ of energy)	Data Quality	Abatement type	Abatement efficiency	Fuel type	Country or region	Reference
Methane	14.8 - 27	E	NA	NA	NA	Western Europe	4
Total emission	19 - 35	E	NA	NA	NA		†
Methane	39.6 - 104	E	NA	NA	NA	US & Canada	4
Total emission	51 - 130	E		NA	NA		†
Methane	218 - 568	E	NA	NA	NA	Former USSR, Central & Eastern Europe	4
Total emission	280 - 730	E	NA	NA	NA		†
Methane	40 - 96	E	NA	NA	NA	Other Oil Exporting Countries	4
Total emission	51 - 120	E	NA	NA	NA		†
Methane	40 - 96	E	NA	NA	NA	Rest of World	4
Total emission	51 - 120	E	NA	NA	NA		†

† derived from methane figures by assuming that the gas is 78 wt% methane

Error limits: ± >100% of emission estimate.

8.2 Detailed Method

8.2.1 High pressure storage facilities, F_2

The preferred way to estimate the emission factor is to carry out ambient concentration measurements and calculate the source strength from these. Alternatively a component-emission factor may be used. If this method is used the error limits on the emission factor will be ± 10% of the emission factor.

There is currently no default emission factor to propose for this source

8.2.2 Compressor station, F_3

Determine by ambient concentration measurements as for 8.2.1 above. If this method is used the error limits on the emission factor will be ± 10% of the emission factor
Default emission factor: 71.5 t/y (from reference 1)

8.2.3 Gas holder, F_4

This can be determined by isolating a gas holder and measuring its loss in height over a given time period. If this method is used the error limits on the emission factor will be ± 100% of the emission factor

Default emission factor: 4 t/y (from reference 1)

8.2.4 High pressure pipeline, f_1

Only determine if the high pressure pipeline system is old and considered to be leaky. Emission factors can be estimated by carrying out pressure decay experiments on isolated sections of pipeline. The technique for doing this is described in Section 16.1. If this method is used the error limits on the emission factor will be ± 10% of the emission factor.

Default emission factor: 0 t/y (from reference 1)

8.2.5 Medium & intermediate pressure pipeline & main, f_4, f_5, f_6 & f_7.

Determine by pressure decay experiments on isolated sections of pipe as described in Section 16.1.

Default emission factors 0.04 m^3/km/mbar/year for jointed pipes and 0.00004 m^3/km/mbar/year for unjointed pipes. Calculate tonnages using the ideal gas equation and the average molecular weight of the gas determined from its composition (from reference 1).

8.2.6 Low pressure main & service pipes f_2, f_3.

Determine by pressure decay experiments on isolated sections of pipe. This should be carried out as described in Section 16.1.

Table 8.2: Default Emission Factors for Detailed Method

Compound	Source	Symbol	Value	Unit	Data Quality	Abatement type	Abatement efficiency	Fuel type	Country or region	Reference
methane	high pressure storage facilities	F_2	no data	t/y	E	NA	NA	NA	UK	1
methane	high pressure pipeline	f_1	0	t/y/km	E	NA	NA	NA	UK	1
methane	jointed intermediate pressure main	f_6	0.04	m^3/km/mbar/year	E	NA	NA	NA	UK	1
methane	unjointed intermediate pressure main	f_7	0.00004	m^3/km/mbar/year	E	NA	NA	NA	UK	1
methane	jointed medium pressure main	f_4	0.04	m^3/km/mbar/year	E	NA	NA	NA	UK	1
methane	unjointed medium pressure main	f_5	0.00004	m^3/km/mbar/year	E	NA	NA	NA	UK	1
methane	jointed low pressure main & service pipes	f_2	88	m^3/km/year/mbar	E	NA	NA	NA	UK	2
methane	unjointed low pressure main & service pipes	f_3	88	m^3/km/year/mbar	E	NA	NA	NA	UK	2
methane	compressor station	F_3	71.5	t/y	E	NA	NA	NA	UK	1
methane	gas holder	F_4	4	t/y	E	NA	NA	NA	UK	1

SPECIES PROFILES

Species profiles can be estimated by assuming that the composition of the emission is the same as the composition of the gas, although in practice for some types of emission, e.g. leaks from underground pipes, some components of the gas may get adsorbed, e.g. by the soil. However, we recommend that these effects are ignored because they cannot be quantified. Table 9.1 lists typical species profiles for a number of countries:

Table 9.1: Typical species profiles for emissions from gas distribution networks

	UK*	Netherlands†	Germany††	France††
Carbon Dioxide(CO_2)	0.5	5.0	2.2	0.9
Nitrogen(N_2)	2.5	6.1	7.6	4.5
Methane(CH_4)	92.5	84.7	85.5	88.6
Ethane(C_2H_6)	2.9	3.8	3.3	4.7
Propane(C_3H_8)	0.9	0	0.9	0.8
2-methylpropane (C_4H_{10})	0.2	0.1	0	0
Butane(C_4H_{10})	0.2	0.1	0.4	0.2
2,2-dimethylpropane(C_5H_{10})	0.1	0	0	0
2-methylbutane(C_5H_{12})	0.1	0.1	0	0
Pentane(C_5H_{12})	0.1	0.0	0.1	0.3
Hydrogen Sulphide (H_2S)	0	0.1	0	0
Total mole %	100	100	100	100

* reference 5
† reference 6
†† reference 7

The data in Table 9.1 are mole percentages.

The following default profile has been derived from the above profiles by taking the average and rounding to the nearest whole percent:

Table 9.2: Default species profile for emissions from gas distribution networks

	mole %	**wt %**
Carbon Dioxide(CO_2)	2	5
Nitrogen(N_2)	5	8
Methane(CH_4)	88	78
Ethane(C_2H_6)	4	7
Propane(C_3H_8)	1	2

In the absence of any other data this profile should be used.

10 UNCERTAINTY ESTIMATES

10.1 Simpler method

For the simpler method the only available way of estimating the degree of uncertainty is by intuition based on experience. The uncertainty limits for the estimates derived using the simpler method are about a factor of 2.

10.2 Detailed method

The detailed method requires the determination of emission factors for various sources within the gas transmission network and the error in the final emission estimate will depend on the way in which these factors are determined. Section 8.2, suggests error limits for each of the methods discussed. However, in practice the error limits may differ from these if the techniques used to estimate the emission factors are not identical to those described in Section 8.2. Section 8.2 also gives error limits for the default emission factors.

The error limits for the emission factors should be combined with the error limits for the activity statistics (which should be available from the source of the statistics) according to the usual rules of the propagation of errors to give an error limit for the total emission.

11 WEAKEST ASPECTS/PRIORITY AREAS FOR IMPROVEMENT IN CURRENT METHOD

11.1 Simpler method

This method depends on the default emission factor. However, better estimates of the emission factor can only be obtained by using the detailed method.

11.2 Detailed method

The main weakness of the detailed method is that it can be quite effort intensive to determine accurate emission factors.

12 SPATIAL DISAGGREGATION

The gas transmission system can be divided into two, the two parts being the national transmission system consisting of a relatively small number of high pressure pipelines covering distances of hundreds of kilometres, the second part being the rest of the transmission system. Data on the locations of the various pipelines which form the national transmission system should be readily available for most countries. These can then be regarded as line sources. Emissions from the rest of the system can be broken down into a mixture of area sources, proportional to population density, and point sources corresponding to the locations of major installations such as terminals, storage, processing plants and larger compressor stations.

13 TEMPORAL DISAGGREGATION CRITERIA

Leakage rate is a function of pressure rather than throughput. It is therefore safe to assume that the leakage rate is constant.

14 ADDITIONAL COMMENTS

No additional comments.

15 SUPPLEMENTARY DOCUMENTS

No supplementary documents are required.

16 VERIFICATION PROCEDURES

The emission factors for the detailed method can be checked by carrying out pipeline leak tests as described in Section 16.1.

16.1 Pipeline Leak Tests

Identify a representative sample of pipes to test. The best way of doing this is to compile a table such as the figure below dividing up the national network into a number of categories based on pipe diameter and material:

Table 16.1: Example table for pipeline leak tests

Diameter	**Steel**	**Pit Cast**	**Spun Cast**	**Ductile**	**PE**
≤8cm					
10-13cm					
15-18cm					
20-28cm					
≥30cm					

The categories described in the above figure are for illustration only. Different diameters and materials may be more appropriate in different countries.

Start by entering into the table the number of kilometres of pipe of each category in the entire distribution system. Next, decide how many sections of pipeline from each category should be chosen for the experiments. The aim is to identify a sample of experimental pipeline sections which are representative of the network as a whole. The number of test sections in each category should generally be proportional to the number of kilometres in the network and to the expected variability of leakage rates. The leakage rates from PE pipes are expected to be less variable than those from cast iron pipes and so fewer tests are required for a given size of population for PE pipes than for cast iron to establish the leak rate to the same level of uncertainty.

For each section of ‘main’ identified agreement will be needed from the customer supplied by that main to allow interruption of their supply for the duration of the test. Each section of pipe to be isolated should be approximately 1km long. The service pipe should be capped on the customer’s side of the meter isolation valve.

Two pressure decay experiments are required for each isolated section of pipe. In one test a leak of known magnitude is introduced into the pipeline under test and a pressure decay curve plotted. In the other the control leak is stopped. From the two pressure decay curves it is possible to calculate the rate of gas leakage from the test section without prior knowledge of the internal volume of the section.

Leak rates should be determined in this way for a number of different pressures, both above, below and at the normal operating pressure of the main.

The leak rate should also be determined with the service pipe disconnected from the main. This allows separate leak rates to be calculated for the service pipe. Service pipes are made of a number of different materials and the sample of test mains should include service pipes of all the materials used.

Default emission factor: 88 m^3/km/year/mbar including leakage from service pipes. The emission factors f_{Lj}, and f_{Lu} can be calculated from these figures using the pressure in the pipe and the composition of the gas (to estimate the weight of $1m^3$ of gas), (from reference 2)

17 REFERENCES

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20 POINT OF ENQUIRY

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