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.....
**European Wide Sector Specific
Calculation Method for Reporting to the
European Pollutant Release and Transfer
Register**

**VGB / EURELECTRIC
Recommendations**

.....
VGB European Working Group
“E-PRTR”
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European Pollutant Release and Transfer Register**

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VGB European Working Group “EPRTTR”
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1. Introduction

1.1 Regulatory Background

The UNECE Convention on Access to Information, Public Participation in Decision-making and Access to Justice in Environmental Matters was adopted on 25th June 1998 in the Danish city of Aarhus at the Fourth Ministerial Conference in the 'Environment for Europe' process [UNECE 1998].

The Aarhus Convention is a new kind of environmental agreement. It links environmental rights and human rights. It acknowledges that we owe an obligation to future generations. It establishes that sustainable development can be achieved only through the involvement of all stakeholders. It links government accountability and environmental protection. It focuses on interactions between the public and public authorities in a democratic context and it is forging a new process for public participation in the negotiation and implementation of international agreements.

The subject of the Aarhus Convention goes to the heart of the relationship between people and governments. The Convention is not only an environmental agreement, it is also a Convention about government accountability, transparency and responsiveness. The Aarhus Convention grants the public rights and imposes on Parties and public authorities obligations regarding access to information and public participation and access to justice.

An extra-ordinary meeting of the Parties was held on 21 May 2003 in Kiev, Ukraine in the framework of the fifth 'Environment for Europe' Ministerial Conference. The Meeting of the Parties adopted the Protocol on Pollutant Release and Transfer Registers [PRTR 2003], which was subsequently opened for signature. Thirty-six States and the European Community signed the Protocol in Kiev.

The Protocol is the first legally binding international instrument on pollutant release and transfer registers. Its objective is "to enhance public access to information through the establishment of coherent, nationwide pollutant release and transfer registers (PRTRs)." PRTRs are inventories of pollution from industrial sites and other sources.

To give effect to the Protocol adopted in Kiev the European Parliament and the Council of the European Union have adopted, on 18th January 2006, Regulation (EC) No 166/2006 concerning the establishment of a European Pollutant Release and Transfer Register and amending Council Directives 91/689/EEC and 96/61/EC (the 'E-PRTR Regulation'). A document providing guidance on the various reporting processes as set out in the E-PRTR Regulation has been published by the European Commission.

The E-PRTR obliges operators of industrial installations to provide data on pollutant release and transfer to their national competent authorities. The reports will be submitted to the European Commission to be included in the European Integrated Pollution Release and Transfer Register. The E-PRTR will become a publicly assessable electronic database on the Internet. The first reports by operators will take place in 2008 for the data collected by operators in 2007.

One of the significant sectors within the EU for reporting to the E-PRTR will be the electricity sector. It is important that this sector has a consistent, practical and cost effective means of reporting under this new regime, for all pulverised coal, large scale oil, gas fired and CHP power generation plant. For this reason the EURELECTRIC Working Group "Environmental Protection" has proposed the development of a European-wide Electricity Industry (EI) determination method for emissions and recommendations for reporting.

EURELECTRIC has commissioned VGB to facilitate this development by drawing on expertise from electricity companies across the EU.

Operators of facilities have to report all necessary information to the competent authorities in the Member States. Before submitting the data to the relevant competent authority, the operator should ensure an appropriate quality of the data. This can be demonstrated if the information is complete, consistent and credible. An important part of ensuring that the data meets these criteria is the choice of the source for the data.

Section 1.1.11 of the EC Guidance states that reporting of emissions to air, water and land and off-site transfers of waste and of pollutants in waste water shall be carried out based on measurement, calculation or estimation of releases and off-site transfers. The definition of these three options is as follows:

- Class M: Release data are based on measurements (“M”). Additional calculations are needed to convert the results of measurements into annual release data. For these calculations the results of flow determinations are needed. “M” should also be used when the annual releases are determined based on the results of short term and spot measurements. “M” is used when the releases of a facility are derived from direct monitoring results for specific processes at the facility, based on actual continuous or discontinuous measurements of pollutant concentrations for a given release route.
- Class C: Release data are based on calculations (“C”). “C” is used when the releases are based on calculations using activity data (fuel used, production rate, etc.) and emission factors or mass balances. In some cases more complicated calculation methods can be applied, using variables like temperature, global radiance etc.
- Class E: Release data are based on non-standardised estimations (“E”). “E” is used when the releases are determined by best assumptions or expert guesses that are not based on publicly available references or in case of absence of recognised emission estimation methodologies or good practice guidelines.

The EC Guidance does not impose a hierarchy upon the choice between M, C and E; however, the operator of the facility has to decide before collecting the data which determination methodology (M, C or E) for a certain pollutant results in "best available information" for the reporting. The operator does not have an unfettered choice of methodology for collecting the data. The EC guidance sets out the boundaries of the choice.

Section 1.1.11 first states that operators should prepare their data collection in accordance with internationally approved methodologies, where such methodologies are available. The guidance then qualifies this by stating that the operator may use "equivalent" methodologies other than internationally approved methodologies, even when available, if certain conditions are fulfilled. In the current context the condition of particular importance is Condition 6, which states:

“The methodology is a European-wide sector specific calculation method, developed by industry experts, which has been delivered to the European Commission (enveper@ec.europa.eu/env-prtr@ec.europa.eu), to the European Environment Agency (eper@eea.eu.int/prtr@eea.eu.int) and the relevant international organisations (e.g. IPCC: www.ipcc-ggip.iges.or.jp/mail; UN-ECE/EMEP: <http://tfeipsecretariat.org/unece.htm>).”

1.2 The Purpose of this Document

The purpose of this document is to draw on the experience of a group of industry experts who represent the leading practitioners of emission reporting across the member states of the EU. These experts have been brought together under the auspices of EURELECTRIC, which is a centre of strategic expertise for the electricity industry in Europe. The members of this working group are listed in Appendix A. The aim of the working group was to produce a European wide calculation method for emissions from the electricity-generating sector. This document describes a calculation method, including emission factors where appropriate. It is intended to review the document at regular intervals.

The working party has wide experience of the use of calculation methods, which make use of emission factors, for reporting emissions to environmental protection agencies throughout Europe. In many cases there has been a process of consultation between the competent authorities and relevant representatives from the electricity industry. An example of this is the methodology developed for reporting in the UK to the Pollution Inventory.

The competent authority for England & Wales, the Environment Agency, refer to this methodology in their guidance note [UK Environment Agency 2007] for reporting to the UK Pollution Inventory, which is now aligned with E-PRTR Regulation requirements. The Environment Agency states “In the absence of a mandatory methodology, you should use methods that have been agreed with us for your industrial sector, where available. An example of this is the UK Electricity Supply Industry (ESI) methodology that is developed for all pulverised coal, large scale oil, gas fired and CHP power generation plant.”

The Environment Agency’s guidance note, in which this statement appears, was produced using a consultative committee composed of industrial and Environment Agency sector experts. Similar approaches have been used across the EU. The working party have critically reviewed the methods of calculating emissions used in Germany, the UK, France, the Netherlands, Belgium, Finland, Austria and Denmark. These methods have been applied in those countries and accepted by the regulatory authorities as appropriate ways of assessing emissions for national reporting. Based upon this review a consensus was reached for a European wide calculation method for emissions from the electricity-generating sector. It is intended that the calculation method should be applicable for thermal power stations and other combustion installations with a heat input of more than 50 MW.

1.3 Justification for the Use of Emission Factors and Calculation Method

1.3.1 What the regulations require

The guidance document for the E-PRTR Regulation (reference 1) sets out in Section 1.1.12 how operators can demonstrate the quality assurance of the data they submit to their regulatory authority. The competent authorities have the duty to assess the quality of information provided by operators.

Operators are obliged to use the “best available data” when preparing their reports. In accordance with article 9(2) of the E-PRTR Regulation, data reported by operators should be of high quality in particular as regards its completeness, consistency and credibility as defined here:

Completeness means that the reported data should cover all releases and off-site transfers of all pollutants and wastes exceeding thresholds for all facilities with Annex I activities above the capacity thresholds. The purpose of the reporting threshold values is to minimise the reporting burden, although reporting of releases lower than the thresholds is also allowed.

Completeness means also that all additionally required information on the identification of the facility and Annex I activities is fully reported.

Consistency means that data shall be reported on the basis of unambiguous and uniform definitions, source identification and reliable methodologies for the determination of releases over several years. Consistent reporting by facilities will enable Member States to carry out consistent reporting in standardised formats to the Commission and the EEA. This will enable comparison of the reported data with previous release data of reporting facilities or with data of similar sources in other countries. In this respect a consistent use in every Member State of the identification number of facilities, including the indication of changes of the identification number, is essential.

Credibility refers to the authenticity, reliability, comparability and transparency of the data. In the context of pollutant release and transfer registers credibility is closely linked to consistency. If the approaches and data sources used in an inventory development project are considered consistent, then users will have an acceptable degree of confidence in the releases data developed from those techniques. Furthermore it is important that the information in the E-PRTR is comparable to allow an objective and reliable comparison of releases and off-site transfers from different facilities within a country or amongst different countries. Detailing whether a release or off-site transfer was measured, calculated or estimated and the exact specification of which measurement or calculation methodology was used to determine the release or off-site transfer, helps to make the data transparent and ensures the credibility of the data.

1.3.2 How the calculation method meets the requirements

The calculation method, reported here, has been derived so that it meets the criteria for this as set out in Section 1.3.1 above. This can be summarised as follows.

Completeness - the reported data will cover all releases and off-site transfers of all pollutants exceeding thresholds for all facilities with Annex I activities above the capacity thresholds. All additionally required information, including site specific waste transfers, on the identification of the facility and Annex I activities will be fully reported.

Consistency - the calculation method, reported here, will require that data shall be reported on the basis of unambiguous and uniform definitions, source identification and reliable methodologies for the determination of releases over several years. The use of calculation methods and emission factors, which have been employed in a range of European countries for several years, will ensure consistent reporting by operators. Therefore Member States will be able to carry out consistent reporting in standardised formats to the Commission and the EEA.

Credibility - the calculation method, reported here, will, when used by operators, ensure that the data submitted will be authentic and reliable. It will also, by its use by the sector, ensure comparability of the data. Finally, the reference to the means by which the emission factors and calculation methods have been derived will ensure the transparency of the data. Detailing that a release or off-site transfer was calculated and the exact specification of which calculation methodology was used to determine the release or off-site transfer will make the data transparent and ensure the credibility of the data.

1.4 The Circumstances when the Calculation Method should be used

Operators will report to the regulatory authorities in their respective countries. These reports must be compliant with local legislation and regulations and operators should familiarise themselves with these as appropriate. The methods of reporting will have to be consistent

with the requirements of the E-PRTR. For each parameter which has to be reported the operator should exercise judgement as to the way of reporting the best available information. One of the options available to the operator will be the methodology described in the following sections of this document. If this option is chosen then Class C should be indicated for that parameter.

It is expected that, unless an operator has already installed measuring equipment to an appropriate standard or has chosen to use another calculation method which is demonstrably better, then the calculation method would represent the best available information.

2 Emissions to the Air

2.1 General

For calculating emissions it will sometimes be necessary to have figures for the Net Calorific Value (NCV) or the specific flue gas volume (SFV) of the fuel used. There are sometimes broad ranges for these parameters depending e.g. on the fuel composition. Wherever possible every operator should make use of his own data (e.g. those from the Greenhouse Gas Emissions Trading Scheme). However, if there are no data available, the data quoted below may be used as default values.

In the USA, the norm is to use Gross Calorific Value (GCV) (or Higher Heating Value, HHV) for a fuel, whilst in Europe the NCV (or Lower Heating Value, LHV) is usually quoted. In this report all heating values quoted are NCVs and all emission factors involving heat energy require the use of the corresponding fuel NCV, unless otherwise quoted.

NCV can be determined from GCV using the following (approximate) formulae, taking into account the correction factor for heat of vaporisation of water in the fuel.

$$\text{NCV} = \text{GCV} \times f_{\text{H}_2\text{O}}$$

For coal and oil: $f_{\text{H}_2\text{O}} = 0.95$

For gaseous fuels: $f_{\text{H}_2\text{O}} = 0.90$

Reference: [IEA 2004]

Typical NCVs of the most common fuels are given in Appendix A.

Where the fraction of subsidiary fuel burn (e.g. biomass or oil support fuel) is significant (i.e. greater than 10% of total heat input), its composition is taken into account in calculating the total input to the boiler. If the proportion of biomass, oil or subsidiary fuels is below 10% then their contribution is added to the coal burn as equivalent heat.

Specific flue gas volume (SFV)

The SFV represents the specific dry flue gas flow of the fuel at reference oxygen concentration. Typical SFV values are:

Coal (O_2 ref = 6%) SFV = 350 Nm^3/GJ

Fuel oil (O_2 ref = 3%) SFV = 280 Nm^3/GJ

Natural gas (O_2 ref = 3%) SFV = 270 Nm^3/GJ

(N: Normal conditions: 1013 hPa, 0°C)

Reference: [IEA 1997]

These fuel dependent specific flue gas volumes shall be converted for different reference oxygen concentrations, for instance:

Stationary diesel engines with O_2 ref = 5% SFV = 315 Nm^3/GJ

Stationary gas turbines burning domestic oil with O_2 ref = 15% SFV = 840 Nm^3/GJ

Stationary gas turbines burning natural gas with O_2 ref = 15% SFV = 810 Nm^3/GJ

The SFV may also be calculated from the fuel analysis if available. However it should be noted that the SFV depends only slightly on the fuel analysis when expressed in Nm³/GJ.

Ash and water content

The range of ash and water contents in fuels can be very broad, so no default values have been recommended.

Calculating emission factors from given concentrations

$$EF = C \times SFV / 1000$$

EF: Emission factor (g/GJ)

C: Concentration in the dry flue gas at reference oxygen content (mg/Nm³)

SFV: Specific flue gas volume, dry, at reference oxygen content (Nm³/GJ)

Relevant types of installations

This guidance deals with thermal power stations and other combustion installations with a heat input of more than 50 MW. Unless specified, the figures given for coal fired boilers in this guidance refer to pulverised coal fired, dry bottom boilers.

Relevant emission components

The following pollutants are or might be relevant for large combustion plants. These pollutants will be dealt with individually in Chapter 2.2. This list is based on the indicative list given in the guidance document (GD) for the E-PRTR for Sector 1c: Thermal Power Stations and other Combustion Installations. Although HFCs and Trichloroethylene are also listed in the GD sector specific indicative list for Thermal Power Stations and other Combustion Installations, it is the experts' view there are no emissions of these species from such plant and hence they are excluded from the list below. In contrast, although the GD sector specific indicative list does not list emissions of fluorine and its inorganic compounds, it is the experts' view that these are emitted from such plant and therefore are included in the scope of this document. Note that national reporting thresholds may vary from the E-PRTR thresholds quoted.

Relevant pollutants emitted to air	E-PRTR reporting threshold to air (kg)
CH ₄	100,000
CO	500,000
CO ₂	100,000,000
N ₂ O	10,000
NH ₃	10,000
NMVOC	100,000
NO _x (sum of NO and NO ₂ as NO ₂)	100,000
SF ₆	50
SO _x (sum of SO ₂ and SO ₃ as SO ₂)	150,000
As and compounds (as As)	20
Cd and compounds (as Cd)	10
Cr and compounds (as Cr)	100
Cu and compounds (as Cu)	100
Hg and compounds (as Hg)	10
Ni and compounds (as Ni)	50
Pb and compounds (as Pb)	200
Zn and compounds (as Zn)	100
PCDD+PCDF (dioxins & furans, as I-TEQ)	0.0001
Benzene	1,000
PAHs as sum of Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene and Indeno(1,2,3-cd)pyrene	50
Chlorine and its inorganic compounds (as HCl)	10,000
Fluorine and its inorganic compounds (as HF)	5,000
PM ₁₀	50,000

2.2 Components

2.2.1 Methane (CH₄)

General

CH₄ is a greenhouse gas which is emitted due to the incomplete combustion of fuel or from the deliberate or accidental venting of fuels. There are currently no present instruments which can measure CH₄ in stack gas reliably and continuously. However, relevant data may be available from extractive samples taken from stack gas at the plant in question and these should be used where available.

The threshold value for CH₄ is 100,000 kg/a.

Recommended emission factors for different fuels (without flue gas cleaning):

IPCC emission factors for utility boiler source (Tier 3 emission factors) are used when available (Ref: IPCC 2006).

Type of installation	EF (g/GJ)	Reference
Boiler, coal (PF, wall or T-fired)	0.7	[IPCC 2006]
Boiler, heavy fuel oil	0.8	[IPCC 2006]
Boiler, distillate oil	0.9	[IPCC 2006]
Boiler, natural gas	1	[IPCC 2006]
Stationary diesel engine, HFO	4	[IPCC 2006]
Stationary gas turbine, distillate oil	4	VGB experts group
Stationary gas turbine, natural gas	4	[IPCC 2006]
CFB, coal	1	[IPCC 2006]

Based on an emission factor of 0.7 g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 5.7 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

There is no impact on CH₄ emissions from either SCR or FGD.

Influence of plant type

Emissions of CH₄ vary according to fuel and plant type. Factors for the most common plant types are given above; further factors can be obtained by reference to the IPCC guidelines.

Influence of mode of operation

No information on the impact of different modes of operation is available.

2.2.2 Carbon monoxide (CO)

General

As Carbon Monoxide is a key indicator of overall combustion conditions, it is often continuously measured by operators. Wherever possible, these measurements should be used for reporting.

The threshold value for CO is 500,000 kg/a.

Recommended emission factors (without flue gas cleaning)

Emissions factor are derived from installation operating at nominal loads.

Type of installation	EF (g/GJ)	Reference
Boiler, coal	9	[IPCC 1996]
Boiler, heavy fuel oil	15	[IPCC 1996]
Boiler, distillate oil	16	[IPCC 1996]
Boiler, natural gas	18	[IPCC 1996]
Stationary diesel engines, heavy fuel oil	150	VGB experts group
Stationary gas turbines, distillate oil	21	[IPCC 1996]
Stationary gas turbines, natural gas	46	[IPCC 1996]

Based on an emission factor of 9 g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 2.2 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

Type of equipment	Impact on CO emissions	Reference
FGD	No	
SCR	Possible (small reduction)	[IPCC 1996]
SCR with oxidation module ¹	Reduction by 90 %	[US EPA AP-42]
Water injection (gas turbines)	Yes	

Influence of plant types

The use of NO_x reduction measures such as LNB and/or OFA tends to increase CO emissions.

¹ Usually installed on gas turbine or diesel engines ; also decreases PAH and VOC emissions – including benzene

Influence of mode of operation

CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained. CO emissions may also reach high levels during start up for stationary gas turbines.

2.2.3 Carbon dioxide (CO₂)

CO₂ emissions should be reported according to the ETS monitoring guidelines [ETS Monitoring 2004].

The threshold value for CO₂ is 100 million kg/a.

2.2.4 Nitrous oxide (N₂O)

General

N₂O is a greenhouse gas. There are no commercially instruments that can reliably measure N₂O present in stack gas reliably and continuously. However, relevant data may be available from extractive samples taken from stack gas at the plant in question and these should be used where available.

The threshold value for N₂O is 10,000 kg/a.

Recommended emission factors (without flue gas cleaning):

IPCC emission factors for utility boiler source (Tier 3 emission factors) are used when available.

Type of installation	EF (g/GJ)	Reference
Boiler, coal, wall fired	0.5	[IPCC 2006]
Boiler, coal, tangentially fired	1.4	[IPCC 2006]
Boiler, heavy fuel oil	0.3	[IPCC 2006]
Boiler, distillate oil	0.4	[IPCC 2006]
Boiler, natural gas	1	[IPCC 2006]
Stationary diesel engine, heavy fuel oil	1.5	VGB experts group
Stationary gas turbine, distillate oil	1.5	VGB experts group
Stationary gas turbine, natural gas	1	[IPCC 2006]
CFB, coal	61	[IPCC 2006]

Based on an emission factor of 0.5 g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 0.8 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

Type of equipment	Impact on N ₂ O emissions	Reference
FGD	No	
SCR	Yes (Reduction of 60 % in the case of gas turbines)	[IPCC 1996]

Influence of mode of operation

No information on the impact of different modes of operation is available.

2.2.5 Ammonia (NH₃)

General

The reduction of NO_x in flue gases is carried out by selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) installations. Ammonia (NH₃) (or other selective reduction agents, e.g. urea) is injected into the flue gas and reduces NO_x to N₂. Due to incomplete reaction ammonia slip occurs. In the case of SCR ammonia slip depends on the mode of operation (injected amount in relation to NO_x in the flue gas) and on the activity of the catalyst. Measures are taken in power plants to limit the ammonia slip as much as possible.

The threshold value for NH₃ is 10,000 kg/a.

Calculation of the emission factor

The calculation is derived from NH₃ measurements on the power plant using the following formula:

$$EF = NH_3 \times SFV / 1000$$

EF: Emission factor (g/GJ)

NH₃: NH₃ concentration in the dry flue gas at reference oxygen content (mg/Nm³)

SFV: Specific flue gas volume, dry, at reference oxygen content (Nm³/GJ)

The NH₃ concentration in the flue gas is deemed to be zero in case of high dust SCR followed by a dust abatement device and a wet FGD plant. According to available measurement the NH₃ concentration in the flue gas is in the range of 0.3 mg/Nm³ for tail end SCR.

Influence of flue gas cleaning

NH₃ emissions are strongly influenced by the flue gas abatement installations downstream the SCR or SNCR installation. In air preheaters and dust abatement installations (ESP or bag house filter) the ammonia slip is almost totally adsorbed by the fly ash. The small amount not fixed by the fly ash is dissolved in the washing water of the FGD plant if installed and leaves the process via the desulphurisation waste water treatment plant.

Influence of mode of operation

In case of SCR ammonia emissions are strongly depending on the arrangement of the installation in the flue gas cleaning chain and are therefore plant-specific. High dust installations (ahead of ESP), low dust installations (after ESP but before FGD) and tail end installations (after ESP and FGD) exist. Whereas in high dust installations the deactivation of the catalysts causes a slow increase of ammonia slip nearly no deactivation takes place in low dust and tail end installations resulting in constantly low ammonia slip. Data for low dust installations are not available, yet.

2.2.6 Non-methane volatile organic compounds (NMVOC)

General

There are no commercially available instruments that can measure NMVOC present in stack gas reliably and continuously. However, relevant data may be available from extractive samples taken from stack gas at the plant in question and these should be used where available. NMVOC are usually determined by continuous flame ionisation detector method [EN 12619] or [EN 13526], depending on the concentration in the flue gas) and expressed in mass of carbon equivalent.

The threshold value for NMVOC is 100,000 kg/a.

Recommended emission factors

These emission factors are derived from extensive measuring campaigns. The measured emissions for coal and stationary gas turbines were below the detection limit.

Type of installation	EF (g/GJ)	Reference
Boiler, coal	0.4 ²	VGB experts group
Boiler, heavy fuel oil	0.6	VGB experts group
Stationary diesel engine, HFO	30	VGB experts group
Stationary gas turbine, distillate oil	1.5	VGB experts group
Stationary gas turbine, natural gas	0.5 ²	VGB experts group

Based on an emission factor of 0.4 g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 10.0 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

Water injection in stationary gas turbines typically decreases NMVOC emissions by 50 %. SCR with oxidation module typically decreases NMVOC emissions by 70 %.

² Upper limit, calculated from the detection limits used in the measurements

Influence of plant types

The emission of NMVOC is likely to vary depending on plant type (residence time/temperature) and therefore the factors for other types of plant (e.g. FBC, chain grate etc) might differ somewhat.

Influence of mode of operation

There is no information available on the impact of the mode of operation on emissions of NMVOCs.

2.2.7 Nitrogen oxides (NO_x) reported as NO₂

General

Nitrogen oxides (NO_x) is used to refer to the sum of nitric oxide (NO) and nitrogen dioxide (NO₂), expressed as nitrogen dioxide (NO₂). NO emissions can be converted to their NO₂ mass equivalent by multiplying by 46/30.

NO_x emissions are usually determined by continuous emission monitoring. Since NO₂ in the flue gas from boilers is normally below 5%, only NO is usually monitored. Note that CEMs data may not be valid during periods of start-up and shutdown and it may be necessary to use an alternative method during these periods. This is discussed in more detail in the question and answer section to this document.

NO₂ emissions are taken into account either through a constant NO_x correction factor or directly through the NO analyser calibration function (Cf. [EN 14181]). In some monitoring systems, particularly for gas turbines, NO₂ present is converted to NO before the analyser and so total NO_x is measured.

The threshold value for NO_x is 100,000 kg/a.

Calculation of the emission factor

As NO_x emissions are highly plant specific, no general emission factors can be given. If the installation is not equipped with NO continuous emission monitor, then a site-specific NO_x EF may be determined from discontinuous measurements using the following formula:

$$EF = NO_x \times SFV / 1000$$

EF: Emission factor (g/GJ)

NO_x: NO_x concentration in the dry flue gas at reference oxygen content (mg/Nm³)

SFV: Specific flue gas volume, dry, at reference oxygen content (Nm³/GJ)

Influence of flue gas cleaning

As NO_x is measured at the stack, no further impact on emissions due to mode of plant operation or flue gas cleaning will be observed.

2.2.8 Sulphur hexafluoride (SF₆)

General

SF₆, in contrast to many other pollutants from LCP, is not due to the combustion of fuels, but to losses from e.g. switchgears.

The threshold value for SF₆ is 50 kg/a.

Calculation of the emission factor

Different methods can be used:

A. Periodic inventory of the SF₆ quantities (refilling quantities)

The total annual emissions can be computed by filling the table hereunder.

Change in inventory	Purchases/Acquisitions	Sales/Disbursements	Change in name-plate capacity
1. Beginning of Year	3. SF ₆ purchased from producers or distributors in cylinders	6. Sales of SF ₆ to other entities, including gas left in equipment that is sold	10. Total nameplate capacity (proper full charge) of new equipment
2. End of Year	4. SF ₆ provided by equipment manufacturers with/inside equipment	7. Returns of SF ₆ to supplier	11. Total nameplate capacity (proper full charge) of retired or sold equipment
	5. SF ₆ returned to the site after off-site recycling	8. SF ₆ sent to destruction facilities	
		9. SF ₆ sent off-site for recycling	
A = (1 - 2)	B = (3+4+5)	C = (6+7+8+9)	D = (10 - 11)
Total annual emissions : (A+B-C+D)			

B. Specific emission factor x nameplate capacity

Where a detailed approach is not feasible and the entity has already determined a global SF₆ leak rate, this emission factor must be used to determine the SF₆ emissions.

For practicality, the name-plate capacity to be considered is the capacity at year end (31st of December). If however this figure is not representative for the capacity of the sites during the reporting year, a yearly average can be calculated with the following formula:

Yearly average capacity = Sum of 1/52 x nameplate capacity week i (for i = 1 - 52)

C. Default emission factor x nameplate capacity

Where a detailed approach is not feasible and no specific Emission Factor is determined, the reporting unit will use an emission factor of 2 % per year of the total name-plate capacity.

A dataset analyzed by the US EPA showed that the leak rates are between 0.2 and 2.5 % per year.

References: [EPA 2006-1], [EPA 2006-2], [IEC 2002]

2.2.9 Sulphur oxides (SO_x) reported as SO₂

General

For reporting, SO_x is the sum of SO₃ and SO₂, reported as SO₂. At many combustion plants there are already continuous emission monitors (CEMs) present that can reliably measure sulphur dioxide concentrations and a methodology for reporting annual mass emissions based on these CEMs data may be appropriate where it is available. Note that CEMs data may not be valid during periods of start-up and shut-down and it may be necessary to use an alternative method based on sulphur content of fuel and fuel consumption during these periods. Whilst the CEMs measure SO₂ only, SO₃ concentrations are generally low and can be accounted for by use of a calibration factor.

In the absence of CEMs data, the sulphur content of the fuel may be used to report total emissions of oxides of sulphur. Sulphur in the fuel is assumed to be quantitatively converted to SO₂, although a small fraction may be retained on ash due to its alkalinity (see below).

The threshold value for SO_x is 150,000 kg/a.

Calculation of emission factor

Where CEMS data is not available, a site-specific emission factor should be calculated from the sulphur content in the fuel as follows:

$$EF = 64/32 \times S \times 1/NCV \times (100 - \text{retention in ash (\%)})/100 \times (100 - \text{retention in FGD (\%)})/100$$

S: Concentration of sulphur in fuel (mg/kg)

NCV: Net calorific value of fuel (GJ/tonne)

Influence of flue gas cleaning

ESPs and DENO_x systems are not expected to impact on SO_x emissions. Where fitted, FGD will lead to substantial reductions, as shown below.

FGD and Ash Retention Factors

- Retention in ash: Dry bottom boiler firing bituminous coal 5 % [CORINAIR 2007]
Dry bottom boiler firing brown coal 30% [CORINAIR 2007]
Wet bottom boiler firing bituminous coal 1% [CORINAIR 2007]
- FGD: Wet lime/limestone scrubber 92% [VGB experts group]
Spray Drier Absorption 90% [VGB experts group]
Dry Sorbent Injection 45% [CORINAIR 2007]

Influence of plant types

The type of boiler will influence the retention of sulphur in the ash (see above).

Influence of mode of operation

There is no information available on the impact of the mode of operation on emissions of SO_x.

2.2.10 Trace Elements (As, Cd, Cr, Cu, Hg, Ni, Pb, Zn)

2.2.10.1 Solid fuels

General

There are no commercially available instruments that can measure trace elements present in stack gas reliably and continuously and in the absence of these measurements a methodology based on the volatility of individual trace elements may be used. Trace elements are either involatile or partially volatile during combustion. In the first case, 100% of the element is fixed in the dust (i.e. a retention factor of ~1) and in the second case a proportion of the element in the fuel is emitted as a vapour to the atmosphere. The latter category comprises mercury only and for this element, the retention factor is 0.5, i.e. <1. For all the other elements the retention factor is ~1. Very fine dust particles are enriched in most trace elements compared to the precipitator inlet dusts due to the large specific surface area of fine particulate on to which vapours can condense. As emitted dust tends to be finer than bulk precipitator dust, this effect is addressed by using enrichment factors.

Element	Retention factor (F)	Enrichment factor (E)	Reference
Arsenic	1	6	[KEMA 2007]
Cadmium	1	7.6	[KEMA 2007]
Chromium	1	1.6	[KEMA 2007]
Copper	1	2.4	[KEMA 2007]
Mercury	0.5	4.0	[KEMA 2007]
Nickel	1	3.2	[KEMA 2007]
Lead	1	4.6	[KEMA 2007]
Zinc	1	5.6	[KEMA 2007]

The threshold values for the trace elements are

Element	Threshold value (kg/a)
Arsenic (As)	20
Cadmium (Cd)	10
Chromium (Cr)	100
Copper (Cu)	100
Mercury (Hg)	10
Nickel (Ni)	50
Lead (Pb)	200
Zinc (Zn)	100

Calculation of the mass emission

The mass emissions of trace elements are calculated from the station's particulate emission corrected by factors representing the concentration of the trace element in the fuel and the behaviour of the trace element in the boiler as described above using the following equations

For non-volatile elements:

$$\text{Mass emission} = \text{Average concentration in fuel (mg/kg dry)} \times (100 / \text{average ash \%}) \times F \times E \times \text{particulate emission}$$

For an element also present as vapour the following is added:

$$\text{Mass emission} = \text{Average concentration in fuel (mg/kg dry)} \times (1 - F) \times \text{fuel burn}$$

F: Retention factor in ash

E: Enrichment factor (as listed above)

Where the average concentration of trace elements in the fuel burnt at the site is known, then this data should be used. In the absence of site-specific data then the use of company-wide average data is acceptable. In the absence of any data on trace element content of fuels, then the following analysis can be taken as typical.

Element	Concentration in bituminous coal (mg/kg, dry)
Arsenic	5
Cadmium	0.2
Chromium	25
Copper	25
Mercury	0.1
Nickel	30

Lead	20
Zinc	25

Influence of flue gas cleaning

The principles outlined above can also be applied to plant fitted with FGD. Work has shown that a proportion of trace elements entering the FGD plant are removed. Removal of dust by the FGD plant is accounted for by the reduced dust mass emission and therefore there is an FGD retention factor for the vapour phase only. The FGD retention factor is the proportion of the element that is retained by the FGD. Where SCR is not fitted, on average 50% of the vapour phase mercury is removed in the FGD plant.

SCR catalysts have been shown to promote formation of oxidised mercury (Hg²⁺) which is water-soluble and removed in FGD plant. At plant which is installed with both SCR and FGD, it is therefore appropriate to apply a higher FGD retention factor of 70% to account for this fact.

The vapour phase mass emission of mercury can hence be calculated using the following equation:

$$\text{Mass emission} = \text{Average concentration in fuel (mg/kg dry)} \times (1 - F) \times \text{fuel burn} \times (100 - \text{retention in FGD plant (\%)})/100$$

F: Retention factor in ash (i.e. 0.5 for mercury)

Influence of plant types

The above information and factors are based on data from coal-fired dry-bottom furnaces. Behaviour of trace elements in other types of plant (e.g. wet-bottom boiler, FBC, chain grate) is likely to be altered.

Influence of mode of operation

Note that elevated carbon in ash levels can profoundly increase mercury retention in ash. In addition, chlorine and calcium content of the fuel may influence mercury speciation and hence subsequent capture in downstream air pollution control devices.

Recommended emission factors for different solid fuels

Note that the above information and factors are almost all based on data obtained from 100% coal-fired plant. However, testing has indicated that when co-firing up to 10% by mass of a secondary fuel (e.g. biomass) then the behaviour of the elements remains the same as for 100% coal firing and the above factors remain valid.

2.2.10.2 Liquid fuels

General

For the threshold values cf. Chapter 2.2.10.2.

Recommended emission factors

The emission factors for heavy fuel oil are derived from measurements on boilers and large stationary diesel engines firing heavy fuel oil with a sulphur content lower than 1 %. The emission factors for distillate oil are derived from measurements on large gas turbines firing distillate oil. All the measurements used were carried out by accredited independent laboratories. The emission factors hence determined by the VGB experts group are consistent with US EPA AP 42 figures (slightly higher except for Zn and Ni).

Emission factors in g/GJ :

Element	HFO	Distillate oil	Reference
Arsenic	0.002	0.002	VGB experts group
Cadmium	0.002	0.002	VGB experts group
Chromium	0.008	0.008	VGB experts group
Copper	0.008	0.008	VGB experts group
Mercury	0.0003	0.0003	VGB experts group
Nickel	0.2	0.002	VGB experts group
Lead	0.02	0.006	VGB experts group
Zinc	0.04	0.04	VGB experts group

2.2.11 Polychlorinated Dioxins and Furans (PCDD and PCDF)

General

There are no commercially available instruments that can measure dioxins and furans present in stack gas reliably and continuously. However, relevant data may be available from extractive samples taken from stack gas at the plant in question and these should be used where available. In the absence of site-specific data, then emission factors for dioxins and furans based on average concentrations determined during test campaigns at similar sites throughout Europe should be used. Dioxins and furans are reported as the sum of congeners expressed as toxic equivalent factors.

The threshold value for PCDD/F is 0.0001 kg/a.

Recommended emission factor

The average emission factor of dioxin and furans for coal-fired plant has been determined from over 25 measurement campaigns. For oil-fired plant, in the absence of other data, the same emission factor as for coal has been assumed: this is expected to be worst-case for these plant. Gas plant are not expected to emit dioxins and furans.

Type of installation	EF (g I-TEQ/GJ)	Reference
Boiler, Coal	6.0×10^{-10}	VGB experts group
Boiler, Heavy Fuel Oil	6.0×10^{-10}	VGB experts group

Note that this is assuming that all species found to be below the detection limit are present at the detection limit without subtraction of the method blank (i.e. worst case)

Based on an emission factor of 6×10^{-10} g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 6.7 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

There is no data to indicate that FGD or SCR have an effect on emissions of dioxins and furans.

Influence of plant types

The above information and factors are based on data from dry-bottom furnaces firing 100% coal and co-firing up to 10% secondary fuels. Formation of dioxins and furans is likely to vary depending on plant type (residence time/ temperature) and therefore the factors quoted above are unlikely to be applicable to other types of plant (e.g. FBC, chain grate etc) and fuel types.

Influence of mode of operation

Chlorine is required for dioxin and furan formation, so higher chlorine content fuels may have a propensity for higher emissions, but this is relatively unproven. The biggest impact on emissions is likely to be from plant design, in particular the time/temperature profile in the air heater region of the furnace.

2.2.12 Benzene

General

There are no commercially available instruments that can measure benzene present in stack gas reliably and continuously. However, relevant data may be available from extractive samples taken from stack gas at the plant in question and these should be used where available. In the absence of site-specific data, emission factors for benzene based on the values from the US EPA-AP42 program can be used.

The threshold value for Benzene is 1,000 kg/a.

Recommended emission factors

The emission factors below have been derived from the US EPA AP-42 programme.

Type of installation	EF (g/GJ)	Reference
Boiler, coal	2.5×10^{-2}	[US EPA AP-42]
Boiler, heavy fuel oil	6.2×10^{-4}	[US EPA AP-42]
Stationary diesel engine, HFO	3.3×10^{-1}	[US EPA AP-42]
Stationary gas turbine, distillate oil	2.4×10^{-2}	[US EPA AP-42]
Stationary gas turbine, natural gas	5.0×10^{-3}	[US EPA AP-42]
Wood (technology unspecified)	1.8	[US EPA AP-42]

Based on an emission factor of 2.5×10^{-2} g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 1.6 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

There is no information available regarding the influence of flue gas cleaning.

Influence of plant types

The emission of benzene is likely to vary depending on plant type (residence time/temperature) and therefore the factors for other types of plant (e.g. FBC, chain grate etc) might differ somewhat.

Influence of mode of operation

No different modes of operation are specified. The emission factor for coal is also applicable to co-firing (e.g. biomass) in coal-fired power plants.

2.2.13 Polycyclic Aromatic Hydrocarbons (PAHs)

General

There are no commercially available instruments that can measure PAHs present in stack gas reliably and continuously. However, relevant data may be available from extractive samples taken from stack gas at the plant in question and these should be used where available. In the absence of site-specific data, then emission factors for PAHs based on average concentrations determined during test campaigns at similar sites should be used.

There are many different individual molecules that could be classed as PAHs, but for power plant emissions into the air only the following components are considered relevant:

Benzo(a)pyrene
Benzo(b)fluoranthene
Benzo(k)fluoranthene
Indeno(1,2,3-cd)pyrene

These are reported to the E-PRTR as a sum mass.

The threshold value for PAH is 50 kg/a.

Recommended emission factor

The coal emission factor for the sum of these species has been determined from a number of measurement campaigns on dry bottom PC boilers firing 100% coal and up to 10% of a secondary fuel. Note that these values assume that all species found to be below the detection limit are present at the detection limit and the method blanks are not subtracted (i.e. worst case).

Type of installation	EF (g/GJ)	Reference
Boiler, coal	8.8×10^{-5}	VGB experts group
Boiler, heavy fuel oil	7.0×10^{-5}	VGB experts group
Stationary diesel engine, HFO	1.0×10^{-2}	VGB experts group
Stationary gas turbine, distillate oil	2.0×10^{-4}	VGB experts group

Based on an emission factor of 8.8×10^{-5} g/GJ and a coal NCV of 25 GJ/tonne, an annual coal burn of 22.8 Mt (as received) would be required to reach the reporting threshold.

Influence of flue gas cleaning

There is no information to indicate that flue gas cleaning equipment such as ESPs, FGD or SCR has an impact on PAH emissions.

Influence of plant types

For coal-fired plant, the above information and factor on coal is based on data from dry-bottom furnaces firing 100% coal and co-firing up to 10% secondary fuels. Formation of PAHs is likely to vary depending on plant type (residence time/ temperature) and combustion conditions, therefore the factors quoted above are unlikely to be applicable to other types of plant (e.g. FBC, chain grate etc).

Influence of mode of operation

The biggest impact on emissions is likely to be from overall combustion conditions and excess air levels.

2.2.14 Chlorine and inorganic compounds (as HCl)

General

Although there are approved devices which can measure HCl concentration continuously, HCl is normally calculated from the chlorine content in the fuel.

The threshold value for HCl is 10,000 kg/a.

Calculation of the emission factor

Where CEMS data is not available, a site-specific emission factor should be calculated from the fuel chlorine content.

The assumption is made that 100% of the fuel chlorine is converted into HCl. For coal-fired plant, a percentage of the emission will be retained in the ash.

$$EF = 36.5/35.5 \times Cl \times 1/NCV \times (100 - \text{retention in ash (\%)})/100 \times (100 - \text{retention in FGD (\%)})/100$$

Cl: Concentration of Cl in fuel (mg/kg)

NCV: Net calorific value of the fuel (GJ/tonne)

Influence of flue gas cleaning

ESPs and DENOx systems are not expected to impact on HCl emissions. Where fitted, FGD will lead to substantial reductions, as shown below.

Retention in FGD and ash

- Retention in ash: 1 %
- Retention in FGD: 90 % with gas/gas heat exchanger
95 % without gas/gas heat exchanger

Reference: [KEMA 2007]

Influence of plant type and mode of operation

No impact of plant type or mode of operation is expected, with the exception of the retention by coal ash noted above.

2.2.15 Fluorine and inorganic compounds (as HF)

General

Although there are devices which can measure HF concentration continuously, HF is normally calculated from the fluorine content in the fuel.

The threshold value for HF is 5,000 kg/a.

Calculation of the emission factor

Where CEMS data is not available, a site-specific emission factor should be calculated from the fuel fluorine content.

The assumption is made that 100% of the fuel fluorine is converted into HF. For coal-fired plant, a percentage of the emission will be retained in the ash.

$$EF = 20/19 \times F \times 1/NCV \times (100 - \text{retention in ash (\%)})/100 \times (100 - \text{retention in FGD (\%)})/100$$

F: Concentration of F in fuel (mg/kg)

NCV: Net calorific value of the fuel (GJ/tonne)

Influence of flue gas cleaning

ESPs and DENOx systems are not expected to impact on HF emissions. Where fitted, FGD will lead to substantial reductions, as shown below.

Retention in FGD and ash

- Retention in ash : 20 %
- Retention in FGD : 70 % with gas/gas heat exchanger
: 95 % without gas/gas heat exchanger

Reference: [KEMA 2007]

Influence of plant type and mode of operation

No impact of plant type or mode of operation is expected, with the exception of the retention by coal ash noted above.

2.2.16 Particulate Matter (PM₁₀)

General

Although there are approved devices which can measure PM₁₀ concentration continuously in the ambient air, such instrumentation is not yet industrially available to measure the PM₁₀ fraction of the flue gas. In general, for coal and oil-fired plant, continuous emission monitors for total particulate are installed in the stack and the PM₁₀ emission is derived from this total PM measurement.

The threshold value for PM₁₀ is 50,000 kg/a.

Calculation of the emission factor

For coal and oil-fired plant the emission factor for PM₁₀ is calculated as a ratio of the emission of total particulate.

$$EF = r (PM_{10}) \times PM \times SFV / 1000$$

- r (PM₁₀): ratio of (PM₁₀/ PM) (plant specific)
- PM: Concentration of total particulate in the dry flue gas, at reference oxygen content (mg/Nm³) (from CEMS where available)
- SFV: Specific flue gas volume, dry, at reference oxygen content (Nm³/GJ)

For coal and oil plant, three methodologies are possible.

The first one should be applied for the plants with a significant yearly PM₁₀ emission
The last one should be used for LCP without CEMS.

1. CEMS for PM + local evaluation of r (PM₁₀)
2. CEMS for PM + default r (PM₁₀)
3. Annual evaluation of PM + default r (PM₁₀)

Recommended default values of the r (PM₁₀) for different types of plant

Solid fuel plants without FGD: $r(\text{PM}_{10}) = 0.8$
Solid fuel plants with FGD: $r(\text{PM}_{10}) = 0.95$
Liquid fuel plants without ESP: $r(\text{PM}_{10}) = 0.75$
Liquid fuel plants with ESP: $r(\text{PM}_{10}) = 0.85$
Gas fuel plants: $r(\text{PM}_{10}) = 1.0$

Source: [CORINAIR 2007]

Impact of plant type, flue gas cleaning and mode of operation

Since PM is measured in the stack, there will be no further impact of plant type or mode of operation. The proportion of PM₁₀ will be site specific and depend on plant type as well as flue gas clean up equipment such as particulate control equipment and FGD.

3 Discharges to Water

Regarding discharges to water from fossil fired power plants the pollutants as listed below could be relevant:

Relevant pollutants discharged into the water	E-PRTR reporting threshold to water (kg/year)
Total nitrogen	50,000
Total phosphorus	5,000
As and compounds (as As)	5
Cd and compounds (as Cd)	5
Cr and compounds (as Cr)	50
Cu and compounds (as Cu)	50
Hg and compounds (as Hg)	1
Ni and compounds (as Ni)	20
Pb and compounds (as Pb)	20
Zn and compounds (as Zn)	100
Halogenated organic compounds (as AOX)	1000
PCDD+PCDF (dioxins & furans, as I-TEQ)	0.0001
Total organic carbon (TOC; as total C or COD/3)	50,000
Chlorides (as total Cl)	2,000,000
Fluorides (as total F)	2,000

Phenols (as total C), PAHs, Fluoranthene and Benzo(g,h,i)perylene mentioned in the GD indicative list (additionally to those listed above) to be relevant for power plants are not considered to be relevant in general by the group of experts.

Whereas much of the methodology for calculating the releases to atmosphere is common, the methodology for releases to water is very site specific. Therefore, only the general principles are addressed here. The first step is for each site to consider whether it brings any of the substances identified by the list above on to site (e.g. in the fuel, chemicals or for other purposes) or whether they are produced on site.

If a monitoring of the water discharges is subject of the plant license or if monitoring is agreed between the competent authorities and the operator for other purposes the results of this monitoring should be used for the reporting to E-PRTR. If a monitoring of water discharges does not exist the following recommendations should be taken into consideration.

Having reduced the list down to those substances that might conceivably be found in any of the discharges from a typical power station, the next step is to be more specific about the particular outfalls/sewers. This involves identifying each outfall and characterising the flow

through it using the site's drainage map. The aim here is to identify which substances are likely to be found in the flow and hence to be able to focus the sampling/measurement programme. Hence for each flow, it is necessary to identify whether, for example,

- it only carries rainwater
- it is potentially contaminated by contact with fuel or ash
- it receives waste water from specific parts of the plant such as chimney washings or flue gas desulphurisation waste water treatment plant.

From this and the initial list of substances that are potentially present, it is possible to identify which species are likely to be present in each outfall. For each outfall/sewer, it is necessary to develop a list of substances that will need to be included in the testing schedule (The Discharge Point Test List).

Having identified which outfalls are significant, in use and not just for emergency, the next step is to measure the flow. Various techniques are available here, from continuous monitoring, pump running hours to rainfall assessments. The initial aim is to provide data that are in the right 'ballpark' so that an assessment can be made on the significance of the discharge. If the mass flow calculation indicates that a particular outfall creates a substantial fraction of the discharge into the local ecosystem, then a more accurate flow measurement system may, eventually, be warranted.

The level of accuracy required from the flow measurement should be commensurate with the nature of the discharge and its potential environmental impact. The accuracy expected for flows that drain clean areas would not be as great as that expected for discharges from water treatment works.

Problems will occur with intermittent flows such as outfalls that only run after significant rainfall or those which contain stagnant water in contact with ash or fuel. An element of pragmatism is necessary here, to develop a flow measuring regime that will give credible results over a year's operation.

Where practicable, estimations based on a mass balance approach should be considered. This is likely to be considerably simpler and more accurate than measurements of concentration and flow data. Examples of where this approach may be appropriate are for the Hg/Cd present as an impurity in Water Treatment Plant (WTP) chemicals as well as chloride from plant using hydrochloric acid in the WTP. Mass balances are also suitable for "notifiable emissions" (those emissions that occur because of an unplanned event such as an accident or plant failure).

In order to establish a suitable sampling regime, a fixed sampling time will have to be identified and the schedule maintained. This schedule will need to be integrated with the flow measurement regime (see above). It will, initially at least, be necessary to ensure that measurements are made when the plant is operating under conditions representative of 'normal' conditions and then gradually build up a picture of concentration data under different operational conditions in order to generate confidence in the data collection process.

The frequency of sampling will depend on (*inter alia*) the variability of the data. Initially it may be necessary to take several samples and average the mass flow to yield an annual result. If, however, the results indicate a concentration and a flow to be reasonably constant; then there is a good argument for reducing the frequency of sampling to a practicable minimum of once per year.

Having taken the samples, they should be analysed against all the possible substances identified in the Discharge Point Test List. If the data indicate that the concentration is

consistently below the level of detection, then these can be entered as BRT (below minimum reporting threshold) in the report. If the majority of data is below the limit of detection, but with limited data above the detection limit, then the 'non-detect' data should be assumed to be 50% of the detection limit for averaging purposes.

The laboratory used to analyse the samples should be at the choice of the site and should return data, using routinely available techniques. There are recognised to be different levels of accuracy obtainable from different water sources - for example detection limits in sea water are appreciably higher than in fresh waters. It is considered impracticable to generate accurate data for suspended solids entering and leaving the site in the aqueous flows and hence the mass discharge only considers dissolved species.

It is essential that consideration is given to the concentration of impurities in water abstracted from the river/sea. This means that samples of inlet river/sea water are taken along with the outfall samples and corrections made to establish the mass differential for which the site is responsible. For some sites, it may be realistic to introduce a time delay between measuring inlet and outlet - repeated analysis of the relative concentrations is necessary to derive the optimum delay.

An appropriate differential is determined as follows:

- a) If a laboratory returns a consistent 'not detected' result on the water, then the concentration is regarded as zero.
- b) If a laboratory returns the majority of values 'not detected', but with some above the detection limit, then for the 'non-detect' values, the concentration should be assumed to be 50% of the detection limit in the averaging process.
- c) The measured concentrations at abstraction and discharge should be inspected to ensure that they are significantly different. At the 95% Confidence Interval the two concentrations are different if the difference is greater than $\sqrt{2}$ times the 95%ile measurement uncertainty.
- d) If the intake and outfall concentrations are significantly different then the mass increase attributable to the station is calculated from:

$$\text{Concentration Increase} = \text{OC-IC} \times \text{EV}$$

OC: Concentration in the outfall

IC: Intake concentration

EV: Evaporation factor: - the ratio of the volume abstracted to that discharged.

The difference between the intake and discharge concentration should also be examined in the light of historic variations in background concentration, i.e. could the difference between intake and discharge be due to variation in intake concentrations.

The final step is to multiply the annual water flow by the appropriate concentration increase and, if the resulting annual mass flow is more than the threshold value, then it will have to be declared on the report. The mass discharge for each species for each outfall is calculated from:

$$\text{Average differential} \times \text{total flow} = \text{mass flow}$$

The total mass flow from the site for each substance is the sum of all the individual outfall mass flows.

The only species expected to be found in any detectable amount in aqueous discharges from most coal-fired power station sites are listed above. Chlorides and fluorides are assumed to be emitted entirely in the vapour phase from non-FGD fitted plant. FGD fitted plant will emit chloride and fluoride in aqueous discharges and do report these numbers based on regular sampling regimes. In the absence of data, discharges of nitrogen, phosphorous, AOX and TOC are assumed to be zero.

4 Questions and answers

This chapter lists some questions which might arise in the area of EPRTR reporting. The corresponding answers express the experts' view.

1. *What emissions do you report if measured values are below the determination limits?*

First it has to be distinguished between “detection limit” and “determination limit”:

Detection limit :

Most analytical instruments produce a signal even when a blank (matrix without analyte) is analyzed. This signal is referred to as the noise level. The detection limit is the amount of analyte that will produce a signal distinguishable from noise 99% of the time that it is analyzed or better.

In practice, it is the lowest concentration of a substance in the flue gas that the measuring instrument can detect. However, the concentration may not be great enough for a quantitative measurement to be made, within the quality assured specification of the instrument. The BREF “Monitoring” [BREF Monitoring 2003] lists five different possibilities for handling values below the detection limit.

Determination limit :

In the E-PRTR Guidance Document, the determination limit is defined as the "minimum concentration or amount of an analyte for which specified requirements for a given set of relevant quality criteria are fulfilled".

In practice, it is the lowest concentration of a substance in the flue gas at which the measuring method can make a quantitative measurement, within the quality assured specification of the instruments. In the BREF “Monitoring” the term “determination limit” does not exist but there is the - possibly identical – term “LOQ – the lowest quantifiable amount of a compound”. There are no proposals in the BREF for handling such values.

Reporting: If the concentration is below the detection limit then a zero emission should be reported.

2. *How do you take into account the pre-load when extracting and releasing water?*

According to the „Guidance Document for the Implementation of the European PRTR (GD)” of 31st May 2006, No. 1.1.4, it is allowed to subtract the background load (or pre-load) of a certain pollutant in the extracted water from the load being released from the facility with the water if it is released in the same river, lake or sea. There is no provision made for releasing into another water body. The possibility of subtracting the pre-load is excluded for the cases of extracting groundwater or drinking-water.

In 1.1.4 of the GD it is defined clearly that there is the duty to report exclusively the releases which stem from all activities at the site of the facility. For the sake of a better orientation such activities are related to a “Typical release spectrum” (see GD, Appendices 4 and 5). This kind of view is directed to the emissions caused by the polluter and is conform to the guiding idea of PRTR to give the citizens the opportunity to inform themselves selectively of the pollutants annually emitted from the installations. The transparency caused in this way shall contribute to the goal that the operators improve the environmental performance of their installations.

The improvement of the environmental performance in this connection can only concern the release spectrum which comes from the installation and not relate to the pre-load of the water. This pre-load is out of the operators' responsibility regarding the above definition. This has to be valid also for such cases when the water bodies for extraction and release are not identical. The same holds for the extraction of ground water or drinking water. The transfer of pollutant loads from one water body into another one may not be related to emissions allocated to the type of operation of an installation. In the end a prohibition to subtract the pre-load would result in the fact that emissions from identical installations at different locations cannot be compared objectively and reliably.

As the Guidance Document excludes the possibility of subtracting the pre-load in the cases of extracting groundwater or drinking-water the pre-load should at least be subtracted if the water is released into the same river catchment system. The load transfer from one water body into another one caused by the water usage of an installation can be indicated by a comment in the text field offered.

3. *Should accuracy be reported with the emissions data?*

Accuracy data is not required when reporting emissions data.

4. *How to deal with diffuse emissions?*

According to Art. 5 of the E-PRTR Directive the releases to be reported shall include all releases from all sources included in Annex 1 at the site of the facility. This means that also diffuse emissions from fuel handling and storage (e.g. transport, transshipment and storage of coal) have to be determined. There is a clear difference between the meaning of the diffuse emissions mentioned above and the emissions from diffuse sources in Art. 8. The diffuse sources mentioned in Art. 8 relate to e.g. road traffic and domestic heating (see GD, Introduction) and have to be reported by the authorities.

For the determination of the diffuse sources at facility site usually emission factors are used. Regarding coal storage, the emissions are nearly zero when applying good practice, e.g. watering or compacting. Releases from coal transshipment in harbours outside the power plant site are not relevant for the power plant emissions and belong to the kind of diffuse sources according to Art. 8. Emissions from oil fuel tanks are not relevant.

Diffuse emissions from power plants have only local impact.

At present there is insufficient information to allow the recommendation of emission factors for diffuse emissions.

5. *How to deal with start-up and shut-down periods?*

According to the EPRTR regulation reported releases and off-site transfers are totals of releases and off-site transfers from all deliberate, accidental, routine and non-routine activities at the site of the facility have to be reported. Non-routine activities are extraordinary activities that are carried out under controlled operation of Annex I activities and that may lead to increased releases of pollutants; for example shut-down and start-up processes before and after maintenance operations. Because of the nature of operations, emissions to water and to land are not sensitive to changes during start-up and shut-down. However, for emissions to air start-up and shut-down should be considered, especially for plant that may operate infrequently.

For most species, emissions are calculated from the total fuel burn, which will include fuel used during start-up and shut-down. Separate calculation of emissions during start-up and

shut-down is only required for those species measured continuously. For SO_x, NO_x and dust a protocol has been developed by the UK's Joint Environmental Programme and has been agreed with the UK Regulator for adoption for use in LCPD reporting [Salway 2007]. The methodologies are based on estimates of the amount of fuel burnt during start-up and shut-down.

For sulphur dioxide the emission is calculated based on the sulphur content of the fuels used. For NO_x, emissions are based on start-up and shut-down fuel consumption and type and a NO_x emission factor. Three possible approaches are considered to estimate the NO_x emission factor: plant specific emission factors; an estimate based on CEM readings at minimum stable generation or a detailed calculation based on concentration data measured during a number of start-ups. Analysis of the uncertainties in the estimates suggests that all of these approaches in deriving the NO_x factor would be acceptable since the contribution of start-up shut-down to total emissions is small. The default JEP approach is the use of existing plant specific emission factors.

For particulate emissions, approximate methods are proposed, since CEMs data show high uncertainty. For opted-out plant, a simple approach based on start-up shut-down fuel consumption is proposed. For plant fitted with FGD a simple approach based on a default emission factor is proposed.

In order to apply this approach the duration of start-up and shut-down must be defined. In addition, the consumption of fuel during start-up and shut-down operation during the reporting period must be estimated. Start-up is defined as operation from the commencement of the start-up sequence to reaching the level of minimum stable generation (MSG). Shut-down is defined as operation below stable operating point (SOP) from the commencement of the shut-down sequence. For FGD plants with by-pass, the appropriate value of MSG is the load at which the FGD dampers operate during each individual start. For these plants, SOP will be defined by the point at which the FGD is taken out of service.

If an operator's fuel management system can provide an estimate of start-up shut-down fuel consumption consistent with the definitions above, then this should be used. Plant heat accountancy systems may provide an estimate of 'off load' fuel or pre-synchronisation fuel consumption. However, this definition omits the fuel consumption between synchronisation and MSG that is required. Alternatively an estimate may be made from data the operator may have recording the number and type of start-ups and data on the average fuel consumption per start-up.

For species other than SO_x, NO_x and dust it can be assumed that the use of emission factors together with the total fuel burn, including start-up and shut-down, will provide a robust method for calculating the total emissions.

Another version of this approach is provided by the EMEP/CORINAIR Emission Inventory Guidebook [CORINAIR 2007]. This was prepared by the UNECE/EMEP Task Force on Emissions Inventories and Projections provides a comprehensive guide to state-of-the-art atmospheric emissions inventory methodology. Its intention is to support reporting under the UNECE Convention on Long-Range Transboundary Air Pollution and the EU directive on national emission ceilings.

In the section dealing with combustion in energy and transformation industries chapter 4 deals with the calculation of emissions, based on emission factors and activities. Sub-section 4.1.2 of that chapter addresses the issue of start-up and shut-down. The concept of emission factors differing for start-up and shut-down compared to full load running is introduced. Sub-sections 4.2, 4.3 and 4.5 then list enhanced emission factors for those periods for SO_x, NO_x and CO. For other species no differentiation is given.

6. *How to deal with accidental releases?*

Accidental releases (e.g. due to a fuel oil leakage to the river) are too case-specific to deal with them.

7. *How do you determine the flue gas volume?*

There are three essential ways to determine the flue gas flow: input calculations (e.g. fuel consumption), output calculations (e.g. electric power output) and measurements. CEN TC 264 WG 23 will prepare standards for determining the stack flow.

5. Literature

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6 Appendices

Appendix A - Typical net calorific values of fuels

Fuel	NCV (GJ/t)	Reference
Bituminous coal	25.8	[IPCC 2006]
Petroleum coke	32.5	[IPCC 2006]
Anthracite	26.7	[IPCC 2006]
Sub-bituminous coal	18.9	[IPCC 2006]
Lignite	11.9	[IPCC 2006]
Heavy fuel oil (residual fuel oil)	40.4	[IPCC 2006]
Light fuel oil (distillate fuel oil)	43.0	[IPCC 2006]
Orimulsion	27.5	[IPCC 2006]
Natural gas liquids	44.2	[IPCC 2006]
Liquefied petroleum gases	47.3	[IPCC 2006]
Natural gas	48.0	[IPCC 2006]

Wood: no figures because range is too broad

Appendix B - Glossary of acronyms used in the document

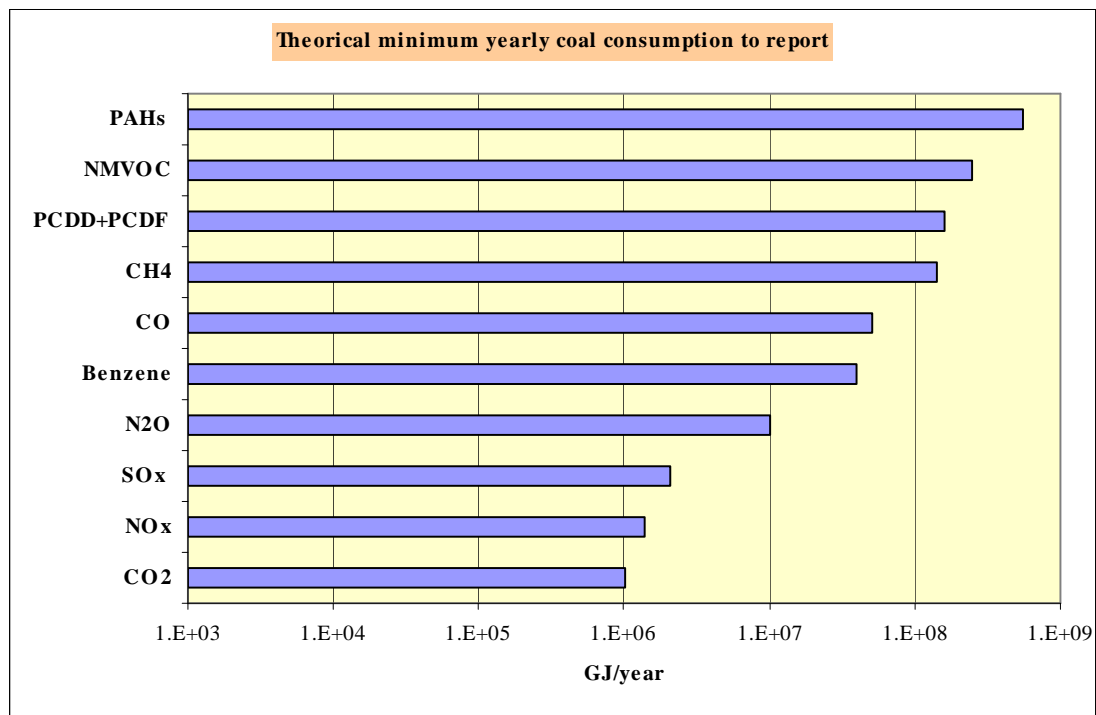
ASTM	American Society for Testing and Materials
BREF	Best available technique reference document
BRT	Below minimum reporting threshold
C	Concentration
CCGT	Combined cycle gas turbine
CEM	Continuous emission monitor(ing)
CFB	Circulating fluidized bed
CHP	Combined heat and power
DENOX	Denitrification (plant)
EEA	European Environment Agency
EF	Emission factor
EI	Electricity industry
EMEP	Cooperative programme for monitoring and evaluation of the long-range transmission of air pollutants in Europe
EPA	(US) Environmental Protection Agency
E-PRTR	European Pollution Release and Transfer Register
ESP	Electrostatic precipitator
ETS	Emissions trading scheme
EV	Evaporation factor
FBC	Fluidized bed combustion
FGD	Flue gas desulphurisation
GCV	Gross calorific value
GD	(E-PRTR) guidance document
HFO	Heavy fuel oil
HHV	Higher heating value

IC	Intake concentration
IEA	International Energy Agency
IPCC	International Panel on Climate Change
I-TEQ	International toxicity equivalent
JEP	(UK) Joint Environmental Programme
LCP	Large combustion plant
LHV	Lower heating value
LNB	Low NO _x burner
MSG	Minimum stable generation
NCV	Net calorific value
OC	Concentration in the outfall
OECD	Organisation for Economic Co-operation and Development
OFA	Over fire air
PC	Pulverized coal
PM	Particulate matter
PM ₁₀	Particulate matter less than 10 µm diameter
r (PM ₁₀)	Ratio of PM ₁₀ / PM
SCR	Selective catalytic reduction
SFV	Specific flue gas volume
SOP	Stable operating point
UNECE	United Nations Economic Commission for Europe
WTP	Water treatment plant

Appendix C - Theoretical yearly fuel consumption for the threshold value

Coal

Relevant pollutants emitted to air	Theoretical minimum consumption	E-PRTR reporting threshold	Emission factors
	GJ Coal	kg	Coal g/GJ
CO ₂	1,000,000	100,000,000	95000
NO _x	1,400,000	100,000	70 ¹⁾
SO _x	2,100,000	150,000	70 ¹⁾
N ₂ O	10,000,000	10,000	1 ²⁾
Benzene	40,000,000	1,000	0.025
CO	50,000,000	500,000	9
CH ₄	140,000,000	100,000	0.7
PCDD+PCDF	160,000,000	1.E-04	6E-10
NMVO C	250,000,000	100,000	0.4
PAHs	560,000,000	50	8.8E-05

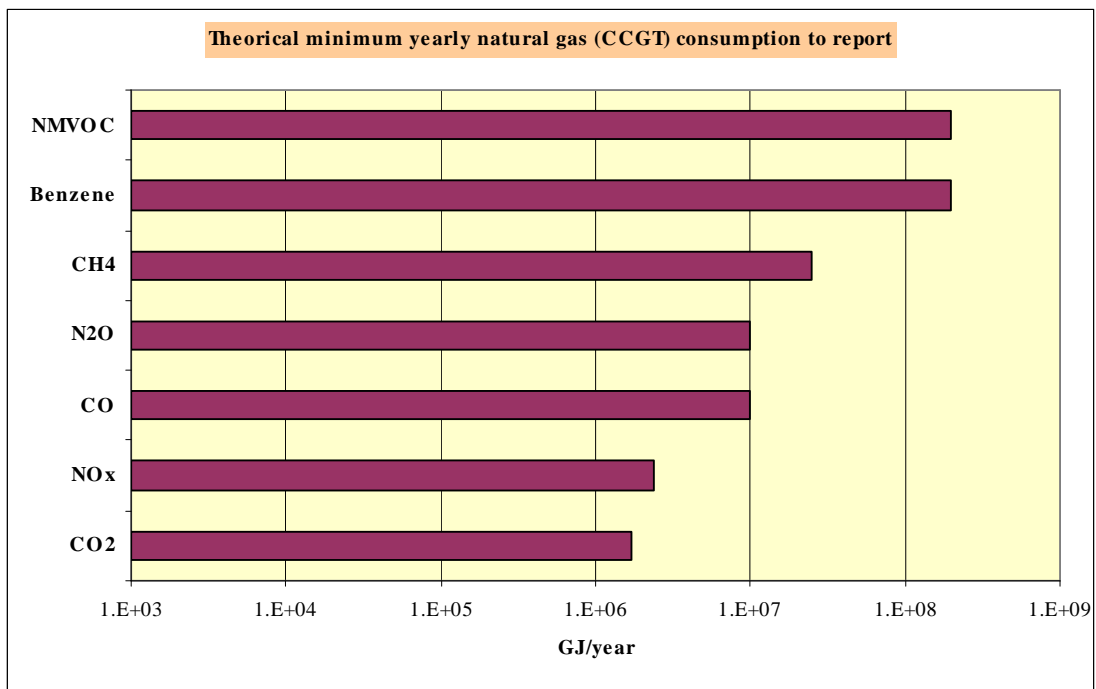


1) Assumption: concentration in flue gas 200 mg/m³

2) wall firing 0.5 g/GJ, tangential firing 1,4 g/GJ

CCGT natural gas

Relevant pollutants emitted to air	Theoretical minimum consumption	E-PRTR reporting threshold	Emission factors
	GJ nat Gas CCGT	kg	CCGT g/GJ
CO ₂	1,700,000	100,000,000	56000
NO _x	2,400,000	100,000	40.5 ¹⁾
CO	10,000,000	500,000	46
N ₂ O	10,000,000	10,000	1
CH ₄	25,000,000	100,000	4
Benzene	200,000,000	1,000	0.005
NMVOOC	200,000,000	100,000	0.5



1) Assumption: concentration in flue gas 50 mg/m³



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