



National Pollutant Inventory

Emission Estimation Technique Manual

for

Combustion in Boilers Version 1.2 2 June 2003

*First published in February 1999
Version 1.1 – 16 August 2001
Version 1.2 – 2 June 2003*

ISBN: 06425 46975

www.npi.gov.au

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Erratum for Combustion in Boilers EET Manual (Version 1.2 – 2 June 2003).

Page	Outline of alteration
47 Table 38	Corrected typo in table.

Erratum for Combustion in Boilers EET Manual (Version 1.1 – 16 August 2001).

Page	Outline of alteration
20 Table 10	Changed table title to highlight that all emissions factors are for controlled and uncontrolled emissions.
21 Table 11	Added to note (a) that the control techniques typically used with boilers do not alter emissions of PAHs.
22 Table 12	Added to note (a) that the control techniques typically used do not alter emissions of SO ₂ and NO _x .
25 Table 13	Added to note (a) that the control techniques typically used do not alter emissions of CO and TVOCs.
29 Table 16	Changed '2,3,7,8 Tetrachlorodibenzodioxins' to '2,3,7,8 Tetrachlorodibenzodioxin' and added note (c) regarding Emission factors being for total dioxins and furans, not toxic equivalents.
44 Table 34	Added note (h) regarding Emission factors being for total dioxins and furans, not toxic equivalents.
47 Table 37	Deleted reference in table notes to polychlorinated dioxins and furans
51 Table 42	For the 2,3,7,8-Tetrachlorodibenzo-p-dioxin EF the factor was changed from 1.8E-011 to 1.8E-11. Changed EF for <i>TOTAL Polychlorinated dibenzo-p-dioxins and Polychlorinated dibenzo-p-furans</i> from 3.3E-08 to 2.1E-08 kg/tonne. Added the term 'Total 2,3,7,8 TCDD equivalents' to note d.
52 Table 43	Update of the emission factors for bagasse fired boilers.

**EMISSION ESTIMATION TECHNIQUES
FOR
COMBUSTION IN BOILERS
TABLE OF CONTENTS**

DISCLAIMER	I
ERRATUM FOR COMBUSTION IN BOILERS EET MANUAL (VERSION 1.1 – 16 AUGUST 2001).	II
1 INTRODUCTION	1
2 PROCESSES AND EMISSIONS	2
2.1 Process Description	2
2.2 Emission Sources and Control Technologies	4
2.2.1 Emissions to Air.....	4
2.2.2 Emissions to Water	7
2.2.3 Emissions to Land	7
3 EMISSION ESTIMATION TECHNIQUES	8
3.1 Direct Measurement	9
3.1.1 Sampling Data.....	10
3.1.2 Continuous Emission Monitoring System (CEMS) Data	12
3.2 Mass Balance	15
3.3 Engineering Calculations	15
3.3.1 Fuel Analysis	15
3.4 Emission Factors	16
3.4.1 Coal Combustion	18
3.4.2 Gas Combustion.....	35
3.4.3 Oil Combustion.....	37
3.4.4 Wood Combustion	47
3.4.5 Bagasse Combustion.....	52
3.4.6 Predictive Emission Monitoring (PEM)	52
4 EMISSION ESTIMATION TECHNIQUES: ACCEPTABLE RELIABILITY AND UNCERTAINTY	53
4.1 Direct Measurement	53
4.2 Mass Balance	53
4.3 Engineering Calculations	53
4.4 Emission Factors	54
5 GLOSSARY OF TECHNICAL TERMS AND ABBREVIATIONS	55
6 REFERENCES	56

COMBUSTION IN BOILERS
LIST OF FIGURES, TABLES AND EXAMPLES

Figure 1 – Basic Combustion Process	2
Table 1 – Size Categories for Oil and Liquefied Petroleum Gas (LPG) Fired Boilers¹	3
Table 2 – Size Categories for Natural Gas Fired Boilers¹	3
Table 3 – Common Air Emissions from Combustion Processes.....	5
Table 4 – Boiler Controls¹	6
Table 5 – List of Variables and Symbols	9
Table 6 – Stack Sample Test Results	12
Table 7 – Example CEM Output Averaged for a Boiler Firing Waste Fuel Oil.....	13
Table 8 - Controlled Emission Factors for Trace Elements from Coal Combustion^{a,1}	18
Table 9 - Controlled and Uncontrolled Emission Factors For Hydrogen Chloride (HCl) and Hydrogen Fluoride (HF) from Coal Combustion^{a,1,c}	19
Table 10 – Controlled and Uncontrolled Emission Factors for Various Organic Compounds from Coal Combustion^{a,1}	20
Table 11 - Controlled and Uncontrolled Emission Factors for Polycyclic Aromatic Hydrocarbons (PAHs) from Coal Combustion^{a,1}	21
Table 12 - Emissions Factors for SO₂ and NO_x from Bituminous and Sub-Bituminous Coal Combustion.....	22
Table 13 - Emission Factors for Carbon Monoxide (CO) and Total Volatile Organic Compounds (Total VOCs) from Bituminous and Sub-Bituminous Coal Combustion¹	25
Table 14 - Controlled and Uncontrolled Emission Factors for Filterable Particulate Matter (PM₁₀) from Bituminous and Sub-Bituminous Coal Combustion^{a,1}	26
Table 15 - Uncontrolled Emission Factors for Trace Elements from Bituminous and Sub-Bituminous Coal Combustion¹.....	28
Table 16 - Controlled Emission Factors for Polychlorinated Dibenzo-p-dioxins and Polychlorinated Dibenzo-p-furans from Bituminous and Sub-Bituminous Coal Combustion^{a,1}	29
Table 17 - Emission Factors for SO_x, NO_x, CO and Total VOCs from Lignite^{1,a}.....	30
Table 18 - Controlled and Uncontrolled Emission Factors for Filterable Particulate	31
Table 19 - Controlled Emission Factors for Polycyclic Aromatic Hydrocarbons from.....	31
Table 20 - Uncontrolled Emission Factors For Trace Elements from Lignite Combustion^{1,b}	32
Table 21 - Uncontrolled Emission Factors for CO, SO_x and NO_x from Anthracite Coal	32
Table 22 - Emission Factor for Organic Compounds from Stoker-Fired Boilers Firing Anthracite Coal^{1,d}	33
Table 23 - Emission Factors for Particulate Matter (≤ 10 μm, i.e. PM₁₀) from Anthracite Combustion¹	33
Table 24 - Emission Factors for Trace Elements from Anthracite Coal Combustion in	34

Table 25 - Controlled and Uncontrolled Combustion of Natural Gas - Emission Factors ...	35
Table 26 - Uncontrolled Emission Factors for PM₁₀ and Total VOCs from Natural Gas ...	36
Table 27 - Emission Factors for Organic Compounds from Natural Gas Combustion¹	36
Table 28 - Combustion of Natural Gas - Emission Factors for Trace Elements¹	37
Table 29 - Emission Factors for LPG Combustion^{1, d}	37
Table 30 - Emission Factors for Sulfur Dioxide (SO₂), Sulfur Trioxide (SO₃), and Oxides of Nitrogen (NO_x) from Fuel Oil Combustion.....	38
Table 31 - Emission Factors for Carbon Monoxide (CO) and Total Volatile Organic Compounds (Total VOCs) from Fuel Oil¹	40
Table 32 - Controlled and Uncontrolled Emission Factors for Particulate Matter £ 10mm.....	42
Table 33 - Emission Factors for Trace Elements from Fuel Oil Combustion Sources^{1,c}	43
Table 34 - Emission Factors for Organics from Residual Fuel Oil^a Combustion.....	44
Table 35 - Uncontrolled Emission Factors for Small Boilers firing Waste Oil¹	45
Table 36 - Emission Factors for Trace Elements from Small Boilers Firing Waste Oil^{1, c} ...	46
Table 37 - Emission Factors for Organic Compounds from Waste Oil Combustion^{1, b}	47
Table 38 - Emission Factors for NO_x and SO₂^a from Wood Waste Combustion¹.....	47
Table 39 - Emission Factors for Total VOCs and CO from Wood Waste Combustion¹	48
Table 40 - Emission Factors for Particulate Matter (PM₁₀), and Lead (Pb) from Wood Waste Combustion^{a,1}	49
Table 41 - Emission Factors for Trace Elements from Wood Waste Combustion¹.....	50
Table 42 - Emission Factors for Organics from Wood Waste Combustion^{a,1}	51
Table 43 - Emission Factors for Bagasse-Fired Boilers¹	52
Example 1 - Using Stack Sampling Data	12
2 - Using CEMS Data	14
3 - Calculating Sulfur Dioxide Emissions Using Fuel Analysis	16
4 - Using Emission Factors to Estimate NO _x Emissions	17

1 Introduction

The purpose of all Emission Estimation Technique (EET) Manuals in this series is to assist Australian manufacturing, industrial and service facilities to report emissions of listed substances to the National Pollutant Inventory (NPI). This Manual describes the procedures and recommended approaches for estimating emissions from facilities engaged in the combustion of fuel in boilers.

The activities covered by this Manual include facilities primarily engaged in the combustion of:

- Coal
- Gas
- Oil
- Wood
- Bagasse

EET MANUAL: Combustion in Boilers

This Manual was drafted by the NPI Unit of the Queensland Department of Environment on behalf of the Commonwealth Government. It has been developed through a process of national consultation involving State and Territory environmental authorities and key industry stakeholders.

2 Processes and Emissions

The following section presents a brief description of fuel combustion and boiler operation, and identifies likely sources of emissions.

2.1 Process Description

The combustion process is defined as the rapid oxidation of substances (fuels) with the evolution of heat. Boilers utilise the heat generated by combustion to produce hot water, steam or both. Figure 1 depicts a generalised combustion process:

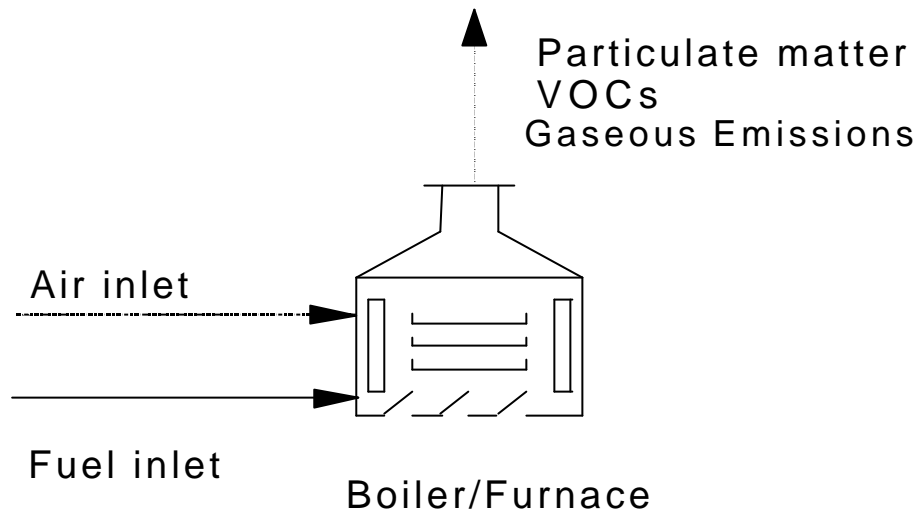


Figure 1 – Basic Combustion Process

Source: Queensland Department Environment and Heritage, 1998.

When fuels burn, they are converted into carbon dioxide (CO_2) and water. The non-combustible portion of the fuel remains as a solid residue, or ash. Products of incomplete combustion are also common, and can include carbon monoxide (CO), sulfur oxides (SO_2 , SO_3), oxides of nitrogen (NO_x), acid gases such as hydrogen chloride (HCl) and hydrogen fluoride (HF), and organic compounds such as formaldehyde, toluene, xylenes, polycyclic aromatic hydrocarbons, and polychlorinated dioxins and furans. Metals such as arsenic, mercury, cadmium, and lead, may also be entrained within the gas stream and emitted.

This Manual relates to boilers that fire coal, oil, natural gas, wood and bark, liquefied petroleum gas (LPG), and bagasse.

Table 1 and Table 2 show the general size categories for boiler classification. Coal fired boilers tend to be classified on the basis of their design characteristics rather than their size ratings.

Table 1 – Size Categories for Oil and Liquefied Petroleum Gas (LPG) Fired Boilers¹

Types of Boilers	Size ^a
Utility	>100 GJ/hour (>30 MW)
Industrial	10 – 100 GJ/hour (3 – 30 MW)
Commercial	0.3 – 10 GJ/hour (<3 MW)
Residential	<0.3 GJ/hour

^a 1 GigaJoule (GJ) = 10⁹ Joules

Source: USEPA 1998

Table 2 – Size Categories for Natural Gas Fired Boilers¹

Types of Boilers	Size ^a
Large Wall-Fired Boilers	>100 GJ/hour (>30 MW)
Small Boilers	0.3 – 100 GJ/hour (0.09 – 30 MW)
Residential Furnaces	<0.3 GJ/hour
Tangential-Fired Boilers	All sizes

^a 1 GigaJoule (GJ) = 10⁹ Joules

¹ Source: USEPA 1998

Coal is broadly classified into one of four types (anthracite, bituminous, sub-bituminous, and Victorian brown) based on differences in heating values and amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. However, the reader should recognise that Australian coals vary widely in composition within these four broad groups. Furnaces commonly used to fire coal are pulverised coal furnaces, cyclones, spreader stokers and fluidised bed combustors.

Within these broad groups, furnaces vary in their firing configuration (tangential, wall, vertical, turbo, arch or cell-fired), and the method of ash removal and handling (dry or wet bottom, flyash reinjection, etc.).

Fuel oils are broadly classified into two types: distillate and residual oils. Distillate oils are graded further into numbers 1 and 2. Residual oils are graded into numbers 5 and 6, where residual oil number 6 is sometimes referred to as Bunker C. Oil number 4 is either distillate, or a mixture of distillate and residual oils.

Oil-fired boiler configurations are generally watertube, firetube, cast iron and tubeless designs. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size.

Natural gas consists of a high percentage of methane and varying amounts of ethane, propane, butane, and inert gases (such as nitrogen, carbon dioxide and helium). There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube and cast iron. Liquefied petroleum gas consists of propane, propylene, butane and butylenes. Boilers firing LPG tend to be similar in design to those firing natural gas.

The burning of wood, bark and bagasse in boilers is mostly confined to situations where steady supplies of these substances are available as a by-product, or in close proximity to the boiler.

Various boiler firing configurations are used for burning wood waste, and the most common types of boilers used are Dutch ovens, fuel cell ovens, spreader stokers, suspension-fired boilers, and the fluidised bed combustors.

Auxiliary sources associated with boilers include fuel storage piles, fuel storage tanks, materials handling, and other sources of fugitive emissions. These sources are often overlooked and not reported as part of the facility emissions inventory. Additional NPI EET Manuals, such as *Fuel and Organic Liquid Storage*, are available to assist in estimating emissions from these sources.

2.2 Emission Sources and Control Technologies

2.2.1 Emissions to Air

Air emissions may be categorised as:

Fugitive Emissions

These are emissions that are not released through a vent or stack. Examples of fugitive emissions include dust from stockpiles, volatilisation of vapour from vats, open vessels, or spills, and materials handling. Emissions emanating from ridgeline roof-vents, louvres, and open doors of a building as well as equipment leaks and leaks from valves and flanges, are also examples of fugitive emissions. Emission factor EETs are the usual method for determining losses through fugitive emissions.

Point Source Emissions

These emissions are exhausted into a vent (excluding roof vents) or stack and emitted through a single point source into the atmosphere. Table 3 highlights common air emissions from combustion processes.

Table 3 – Common Air Emissions from Combustion Processes

Metals	Organic Substances	Other Substances
<ul style="list-style-type: none">• Antimony and compounds• Arsenic and compounds• Beryllium and compounds• Cadmium and compounds• Chromium compounds • Cobalt and compounds• Copper and compounds• Lead and compounds• Manganese and compounds• Mercury and compounds • Nickel and compounds • Selenium and compounds• Zinc and compounds	<ul style="list-style-type: none">• Benzene• Biphenyl• Carbon monoxide• Cyclohexane• Ethylbenzene • Formaldehyde• <i>n</i>-Hexane• Methyl ethyl ketone• Phenol • Polychlorinated dioxins and furans• Polycyclic aromatic hydrocarbons (PAHs)• Styrene• Tetrachloroethane• Toluene• Total Volatile organic compounds• Xylenes	<ul style="list-style-type: none">• Chloride• Fluoride compounds• Hydrogen chloride• Oxides of nitrogen• Particulate matter (=10µm) or PM₁₀• Sulfur dioxide

¹ Source: USEPA Document AP-42 (1996).

Air emission control technologies, such as electrostatic precipitators, fabric filters or baghouses, and wet scrubbers, are commonly installed to reduce the concentration of substances in process off-gases before stack emission. Where such emission abatement equipment has been installed, and where emission factors from uncontrolled sources have been used in emission estimation, the collection efficiency of the abatement equipment needs to be considered. Guidance on applying collection efficiencies to emission factor equations is provided in later sections. Table 4 outlines the general efficiencies of typical air emission control technologies.

Table 4 – Boiler Controls¹

Fuel	Pollutant	Device or Technique	Typical Efficiency² (%)
Coal	NO _x	SCR	80
		SNCR	50
		LEA	5 – 25
		LNB and OFA	5 – 25
	SO ₂	Spray Drying	70 – 90
		Wet Scrubber	80 – 95
		Low-Sulfur Coal	50
		Coal Washing	30
	PM and PM ₁₀	ESP	99
		Fabric Filter or Baghouse (with dry scrubber)	99
Multiple Cyclones		90	
Venturi Scrubbers		97	
Oil	NO _x	SCR	40 – 90
		SNCR	50
		LNB and OFA	20 – 50
		LEA	0 – 28
	SO ₂	Spray Drying	70 – 90
		Wet Scrubber	80 – 98
		Low-Sulfur Oil	80
	PM and PM ₁₀	Good Combustion	ND
Natural Gas	NO _x	SCR	80
		SNCR	50
		LNB	50
Wood Waste	PM and PM ₁₀	Wet Scrubber	ND
		ESP	ND
		Fabric Filter or Baghouse	ND

¹ Source: USEPA, 1995

ESP Electrostatic precipitator

LEA Low excess air

LNB Low NO_x burner

OFA Overfire air

SCR Selective catalytic reduction

SNCR Selective non-catalytic reduction

ND No data available

² With regards to emission controls for PM₁₀, in the absence of measured data, or knowledge of the collection efficiency for a particular piece of equipment, an efficiency of 90% should be used in the emission factor equation to calculate actual mass emissions. This default should only be used if there is no other available control efficiency.

Example 4 illustrates the use of control efficiencies when estimating emissions.

2.2.2 Emissions to Water

Emissions of substances to water can be categorised as discharges to:

- Surface waters (eg. lakes, rivers, dams, and estuaries);
- Coastal or marine waters; and
- Stormwater.

Because of the significant environmental hazards posed by emitting toxic substances to water, most facilities emitting NPI-listed substances to waterways are required by their relevant State or Territory environment agency to closely monitor and measure these emissions. This existing sampling data can be used to calculate annual emissions.

If no wastewater monitoring data exists, emissions to process water can be calculated based on a mass balance, or using site-specific emission factors.

The discharge of listed substances to a sewer or tailings dam does not require you to report to the NPI. However leakage and other emissions (including dust) from a tailings storage facility are reportable. (See also Section Three of *The NPI Guide*).

2.2.3 Emissions to Land

Emissions of substances to land on-site include solid wastes, slurries, sediments, spills and leaks, and storage and distribution of liquids, and may contain NPI-listed substances. These emission sources can be broadly categorised as:

- surface impoundment of liquids and slurries; and
- unintentional leaks and spills.

3 Emission Estimation Techniques

Estimates of emissions of NPI listed substances to air, water and land should be reported for each substance that triggers a threshold. The reporting list and detailed information on thresholds are contained in *The NPI Guide* at the front of this Handbook.

In general, there are four types of emission estimation techniques (EETs) that may be used to estimate emissions from your facility. The four types described in the *NPI Guide* are:

- sampling or direct measurement;
- mass balance;
- fuel analysis or other engineering calculations; and
- emission factors.

Select the EET (or mix of EETs) that is most appropriate for your purposes. For example, you might choose to use a mass balance to best estimate fugitive losses from pumps and vents, direct measurement for stack and pipe emissions, and emission factors when estimating losses from storage tanks and stockpiles.

If you estimate your emission by using any of these EETs, your data will be displayed on the NPI database as being of 'acceptable reliability'. Similarly, if your relevant environmental authority has approved the use of emission estimation techniques that are not outlined in this Handbook, your data will also be displayed as being of 'acceptable reliability'.

This Manual seeks to provide the most effective emission estimation techniques for the NPI substances relevant to this industry. However, the absence of an EET for a substance in this Manual does not necessarily imply that an emission should not be reported to the NPI. The obligation to report on all relevant emissions remains if reporting thresholds have been exceeded.

You are able to use emission estimation techniques that are not outlined in this document. You must, however, seek the consent of your relevant environmental authority. For example, if your company has developed site-specific emission factors, you may use these if approved by your relevant environmental authority.

In general, direct measurement is the most accurate method for characterising emissions and, where available, such data should be used in preference to other EETs presented in this Manual. However, additional direct measurement is not required under the NPI Measure. Direct monitoring may be undertaken as an element of other EETs.

You should note that the EETs presented in this Manual relate principally to average process emissions. Emissions resulting from non-routine events are rarely discussed in the literature, and there is a general lack of EETs for such events. However, it is important to recognise that emissions resulting from significant operating excursions and/or accidental situations (eg. spills) will also need to be estimated. Emissions to land, air and water from spills must be estimated and added to process emissions when calculating total emissions for reporting purposes. The emission resulting from a spill is the net

emission, i.e. the quantity of the NPI reportable substance spilled, less the quantity recovered or consumed during clean up operations.

The **usage**^a of each of the substances listed as Category 1 and 1a under the NPI must be estimated to determine whether the 10 tonnes (or 25 tonnes for VOCs) reporting threshold is exceeded. If the threshold is exceeded, **emissions** of these Category 1 and 1a substances must be reported for all operations/processes relating to the facility, even if the actual emissions of the substances are very low or zero.

^aUsage is defined as meaning the handling, manufacture, import, processing, coincidental production or other uses of the substances.

Table 5 lists the variables and symbols used throughout this Manual.

Table 5 – List of Variables and Symbols

Variable	Symbol	Units
Concentration	C	parts per million volume dry, ppmvd
Molecular weight	MW	kg/kg-mole
Molar volume @ STP (standard temperature and pressure)	V	22.4 m ³ /kg-mole @ 0°C and 101.3 kPa (1 atm)
Volumetric flow rate of stack gas	Q _w	wet cubic metres per second (m ³ /s)
Volumetric flow rate of stack gas	Q _d	dry cubic metres per second (m ³ /s)
Emissions of pollutant i	E _i	kg/hr
Annual emissions of pollutant i	E _{kpy,i}	kg/yr
Emissions of pollutant i per tonne of fuel consumed	E _{kpt,i}	kg/t
Filter catch	C _f	grams (g)
Fuel use	Q _f	typically, kg/hr
PM ₁₀ concentration	C _{PM}	g/m ³
Metered volume at standard temperature and pressure	V _{m,STP}	m ³
Moisture content	moist _R	%
Temperature	T	°C
Clinker production (Activity rate)	A	tonnes/year
Annual operating hours	OpHrs	hours/year

Source: Queensland Department of Environment and Heritage 1998

3.1 Direct Measurement

As indicated above, you may wish to use direct measurement in order to report to the NPI, particularly if you already do so in order to meet other regulatory requirements. For sampling data to be adequate and able to be used for NPI reporting purposes, it would need to be collected over a period of time and be representative of operations for the whole year.

3.1.1 Sampling Data

Stack sampling test reports often provide emissions data in terms of kg per hour or grams per cubic metre (dry). Annual emissions for NPI reporting can be calculated from this data. Stack tests for NPI reporting should be performed under representative (i.e. normal) operating conditions. You should be aware that some tests undertaken for a State or Territory license condition may require the test be taken under maximum emissions rating, where emissions are likely to be higher than when operating under normal operating conditions.

This Section shows how to calculate emissions in kg per hour based on stack sampling data, and how to convert this to an annual emissions figure. Calculations involved in determining particulate (PM) emissions are used as an example, although the same calculations are applicable for most of the substances listed on the NPI.

Equation 1 indicates how to calculate the concentration of a substance from the weight of the substance and the volume of air sampled:

Equation 1

$$C_{PM} = C_f / V_{m,STP}$$

where:

$$\begin{aligned} C_{PM} &= \text{concentration of PM or gram loading, g/m}^3 \\ C_f &= \text{filter catch, g} \\ V_{m,STP} &= \text{metered volume of sample at STP, m}^3 \end{aligned}$$

Equation 2 can be used to convert the concentration of a substance calculated in Equation 1 to an hourly emission of the substance:

Equation 2

$$E_{PM} = C_{PM} * Q_d * 3.6 * [273 / (273 + T)]$$

where:

$$\begin{aligned} E_{PM} &= \text{hourly emissions of PM, kg/hr} \\ C_{PM} &= \text{concentration of PM or gram loading, g/m}^3 \\ Q_d &= \text{stack gas volumetric flow rate, m}^3/\text{s, dry} \\ 3.6 &= \text{3600 seconds per hour multiplied by 0.001 kilograms per gram} \\ T &= \text{temperature of the gas sample, } ^\circ\text{C} \end{aligned}$$

The information from some stack tests may be reported in grams of particulate per cubic metre of exhaust gas (wet). Use Equation 3 to calculate the dry particulate emissions in kg/hr.

Equation 3

$$E_{PM} = Q_w * C_{PM} * 3.6 * (1 - \text{moist}_R/100) * [273 / (273 + T)]$$

where:

E_{PM}	=	hourly emissions of PM in kilograms per hour, kg/hr
Q_w	=	wet cubic metres of exhaust gas per second, m ³ /s
C_{PM}	=	concentration of PM or gram loading, g/m ³
3.6	=	3600 seconds per hour multiplied by 0.001 kilograms per gram
moist_R	=	moisture content, %
273	=	273 K (0°C)
T	=	stack gas temperature, °C

Total suspended particulates (TSP) are also referred to as total particulate matter (total PM). To determine PM₁₀ from total PM emissions, a size analysis may need to be undertaken. The weight PM₁₀ fraction can then be multiplied by the total PM emission rate to produce PM₁₀ emissions. Alternatively, assume that 100% of PM emissions are PM₁₀; ie assume that all particulate matter emitted to air has an equivalent aerodynamic diameter of 10 micrometres or less i.e. ≤10µm.

To calculate moisture content use Equation 4

Equation 4

Moisture percentage = 100 % * weight of water vapour per specific volume of stack gas/ total weight of the stack gas in that volume.

$$\text{moist}_R = \frac{100\% * \left(\frac{g_{\text{moist}}}{(1000 * V_{m,STP})} \right)}{\left(\frac{g_{\text{moist}}}{(1000 * V_{m,STP})} \right) + \rho_{STP}}$$

where

moist_R	=	moisture content, %
g_{moist}	=	moisture collected, g
$V_{m,STP}$	=	metered volume of sample at STP, m ³
ρ_{STP}	=	dry density of stack gas sample, kg/m ³ at STP {if the density is not known a default value of 1.62 kg/m ³ may be used. This assumes a dry gas composition of 50% air, 50% CO ₂ }

An example of test results is summarised in Table 6. The table shows the results of three different sampling runs conducted during one test event. The source parameters measured as part of the test run include gas velocity and moisture content, which are used to determine exhaust gas flow rates in m³/s. The filter weight gain is determined gravimetrically and divided by the volume of gas sampled, as shown in Equation 1 to determine the PM concentration in grams per m³. Note that this example does not present the condensable PM emissions.

Table 6 – Stack Sample Test Results

Parameter	Symbol	Test 1	Test 2	Test 3
Total sampling time (sec)		7 200	7 200	7 200
Moisture collected (g)	g_{MOIST}	395.6	372.6	341.4
Filter catch (g)	C_f	0.0851	0.0449	0.0625
Average sampling rate (m ³ /s)		$1.67 * 10^{-4}$	$1.67 * 10^{-4}$	$1.67 * 10^{-4}$
Standard metered volume (m ³)	$V_{m, \text{STP}}$	1.185	1.160	1.163
Volumetric flow rate (m ³ /s), dry	Q_d	8.48	8.43	8.45
Concentration of particulate (g/m ³)	C_{PM}	0.0718	0.0387	0.0537

Source: Queensland Department of Environment and Heritage 1998

Example 1 – Using Stack Sampling Data

PM emissions have been calculated using Equation 1 and Equation 2, and the stack sampling data for Test 1 (presented in Table 6, and an exhaust gas temperature at 25°C {298 K}). This is shown below:

$$\begin{aligned}
 C_{\text{PM}} &= C_f / V_{m, \text{STP}} \\
 &= 0.0851 / 1.185 \\
 &= 0.072 \text{ g/m}^3
 \end{aligned}$$

$$\begin{aligned}
 E_{\text{PM}} &= C_{\text{PM}} * Q_d * 3.6 * [273 / (273 + T)] \\
 &= 0.072 * 8.48 * 3.6 * [273/423\text{K}] \\
 &= 1.42 \text{ kg/hr}
 \end{aligned}$$

3.1.2 Continuous Emission Monitoring System (CEMS) Data

A continuous emission monitoring system provides a continuous record of emissions over time, usually by reporting pollutant concentration.

Once the pollutant concentration is known, emission rates are obtained by multiplying the pollutant concentration by the volumetric gas or liquid flow rate of that pollutant.

It is important to note that prior to using CEMS to estimate emissions, you should develop a protocol for collecting and averaging the data in order that the estimate satisfies your relevant environmental authority's requirement for NPI emissions estimations.

Table 7 – Example CEM Output Averaged for a Boiler Firing Waste Fuel Oil

Time	O ₂	Concentration (C) (ppm _{v,d})				Gas Flow	Combustion Rate (A)
	(% by volume)	SO ₂	NO _x	CO	VOC	Rate (Q)	(tonnes /hour)
1	10.3	150.9	142.9	42.9	554.2	8.52	290
2	10.1	144.0	145.7	41.8	582.9	8.48	293
3	11.8	123.0	112.7	128.4	515.1	8.85	270

Source: Queensland Department of Environment and Heritage, 1998.

*ppmvd = parts per million volume dry

Hourly emissions can be based on concentration measurements as shown in Equation 5.

Equation 5

$$E_i = (C * MW * Q * 3\ 600) / [22.4 * \{(T + 273)/273\} * 10^6]$$

where:

- E_i = emissions of pollutant i, kg/hr
- C = pollutant concentration, ppm_{v,d}
- MW = molecular weight of the pollutant, kg/kg-mole
- Q = stack gas volumetric flow rate, m³/s
- 3 600 = conversion factor, s/hr
- 22.4 = volume occupied by one mole of gas at standard temperature and pressure (0°C and 101.3 kPa), m³/kg-mole
- T = temperature of gas sample, °C

Actual annual emissions can be calculated by multiplying the emission rate in kg/hr by the number of actual operating hours per year (OpHrs) as shown in Equation 6 for each typical time period and summing the results.

Equation 6

$$E_{kpy,i} = \sum (E_i * OpHrs)$$

where:

- E_{kpy,i} = annual emissions of pollutant i, kg/yr
- E_i = emissions of pollutant i, kg/hr (from Equation 5)
- OpHrs = operating hours, hr/yr

Emissions in kilograms of pollutant per tonne of oil consumed can be calculated by dividing the emission rate in kg per hour, by the oil consumption rate (tonnes per hour) during the same period (Equation 7) as shown below. It should be noted that the emission factor calculated below assumes that the selected time period (i.e. hourly) is representative of annual operating conditions and longer time periods should be used for NPI reporting where they are available. Use of the calculation is shown in Example 2.

Equation 7

$$E_{kpt,i} = E_i / A$$

where:

$$\begin{aligned} E_{kpt,i} &= \text{emissions of pollutant } i \text{ per tonne of oil consumed, kg/t} \\ E_i &= \text{hourly emissions of pollutant } i, \text{ kg/hr} \\ A &= \text{oil consumption rate, t/hr} \end{aligned}$$

Example 2 illustrates the application of Equation 5, Equation 6 and Equation 7

Example 2 - Using CEMS Data

This example shows how SO₂ emissions can be calculated using Equation 5 based on the CEMS data for Time Period 1 shown in Table 7, and an exhaust gas temperature of 150°C (423 K).

$$\begin{aligned} E_{SO_2,1} &= (C * MW * Q * 3\,600) / [(22.4 * (T+273/273)) * 10^6] \\ &= (150.9 * 64 * 8.52 * 3\,600) / [22.4 * (423/273) * 10^6] \\ &= 296\,217\,907 / 34\,707\,692 \\ &= 8.53 \text{ kg/hr} \end{aligned}$$

For Time Period 2, also at 150°C

$$E_{SO_2,2} = 8.11 \text{ kg/hr}$$

For Time Period 3, also at 150°C

$$E_{SO_2,3} = 7.23 \text{ kg/hr}$$

Say representative operating conditions for the year are:

$$\begin{aligned} \text{Period 1} &= 1500 \text{ hr} \\ \text{Period 2} &= 2000 \text{ hr} \\ \text{Period 3} &= 1800 \text{ hr} \end{aligned}$$

Total emissions for the year are calculated by adding the results of the three Time Periods using Equation 6:

$$\begin{aligned} E_{kpy,SO_2} &= E_{SO_2,1} * \text{OpHrs} + E_{SO_2,2} * \text{OpHrs} + E_{SO_2,3} * \text{OpHrs} \\ &= (8.53 * 1500) + (8.11 * 2000) + (7.23 * 1800) \text{ kg} \\ &= 42021 \text{ kg/yr} \end{aligned}$$

Emissions, in terms of kg/tonne of oil consumed when operating in the same mode as Time Period 1, can be calculated using Equation 7

$$\begin{aligned} E_{kpt,SO_2} &= E_{SO_2} / A \\ &= 8.53 / 290 \\ &= 2.94 * 10^{-2} \text{ kg SO}_2 \text{ emitted per tonne of oil consumed} \end{aligned}$$

When the boiler is operating as in Time Periods 2 or 3, similar calculations can be undertaken for emissions per tonne

3.2 Mass Balance

A mass balance identifies the quantity of substance going in and out of an entire facility, process, or piece of equipment. Emissions can be calculated as the difference between input and output of each listed substance. Accumulation or depletion of the substance within the equipment should be accounted for in your calculation.

3.3 Engineering Calculations

An engineering calculation is an estimation method based on physical/chemical properties (eg. vapour pressure) of the substance, and mathematical relationships (e.g. ideal gas law).

3.3.1 Fuel Analysis

Fuel analysis is a particular type of engineering calculation and can be used to predict SO₂, metals, and other emissions based on application of conservation laws, if fuel rate is measured. The presence of certain elements in fuels may be used to predict their presence in emission streams. This includes elements such as sulfur that may be converted into other compounds during the combustion process.

The basic equation used in fuel analysis emission calculations is the following:

Equation 8

$$E_{kpy,i} = Q_f * \text{pollutant concentration in fuel}/100 * (MW_p/EW_f) * \text{OpHrs}$$

where:

$E_{kpy,i}$	=	annual emissions of pollutant i, kg/yr
Q_f	=	fuel use, kg/hr
OpHrs	=	operating hours, hr/yr
MW_p	=	molecular weight of pollutant emitted, kg/kg-mole
EW_f	=	elemental weight of pollutant in fuel, kg/kg-mole
		Concentration of pollutant i in fuel expressed as weight percent, %

For instance, SO₂ emissions from fuel oil combustion can be calculated based on the concentration of sulfur in the fuel oil. This approach assumes complete conversion of sulfur to SO₂. Therefore, for every kilogram of sulfur (EW = 32) burned, two kilograms of SO₂ (MW = 64) are emitted. The application of this EET is shown in Example 3

Example 3 - Calculating Sulfur Dioxide Emissions Using Fuel Analysis

This example illustrates how SO₂ emissions can be calculated from oil combustion based on fuel analysis results and the fuel flow information from a boiler. The boiler is assumed to operate 1500 hours per year.

Fuel flow = 2000 kg/hr

Weight percent sulfur in fuel = 1.17

$$\begin{aligned} E_{kpy,SO_2} &= Q_f * \text{pollutant concentration in fuel}/100 * (MW_p / EW_f) \\ &= (2000) * (1.17 / 100) * (64 / 32) \\ &= (46.8 \text{ kg/hr} * 1500 \text{ hr/yr}) \\ &= 70\,200 \text{ kg/y} \end{aligned}$$

3.4 Emission Factors

An emission factor is a tool that is used to estimate emissions to the environment. In this Manual, it relates the quantity of substances emitted from a source to some common activity associated with those emissions. Emission factors are obtained from US, European, and Australian sources, and are usually expressed as the weight of a substance emitted, divided by the unit weight, volume, distance, or duration of the activity emitting the substance (eg. kilograms of sulfur dioxide emitted per tonne of coal fired).

Emission factors are used to estimate a facility's emissions by the general equation:

Equation 9

$$E_{kpy,i} = [A * OpHrs] * EF_i * -1 - (CE_i/100)$$

where :

$E_{kpy,i}$ = emission rate of pollutant i, kg/yr

A = activity rate, t/hr

OpHrs= operating hours, hr/yr

EF_i = uncontrolled emission factor of pollutant i, kg/t

CE_i = overall control efficiency for pollutant i, %.

Emission factors developed from measurements for a specific process may sometimes be used to estimate emissions at other sites. Should a facility have several processes of similar operation and size, and emissions are measured from one process source, an emission factor can be developed and applied to similar sources. You are required to have the emission factor reviewed and approved by State or Territory environment agencies prior to its use for NPI estimations.

Example 4 - Using Emission Factors to Estimate NO_x Emissions

In this example, emissions of oxides of nitrogen (NO_x) from a cyclone furnace firing bituminous coal are estimated using an emission factor. From purchasing records, it has been determined that 600 tonnes of coal have been used in the boiler over the reporting year. The boiler also has a selective catalytic reduction system with an efficiency of 80% as a control device for NO_x emissions. The emission factor used in this example comes from Table 12.

Operating hours are not included in this equation because the activity rate is already expressed in tonnes per year: Thus, using a variation of Equation 9:

$$\begin{aligned} E_{kpy,i} &= A * EF_i * [1 - (CE_i/100)] \\ E_{kpy,NOx} &= 600 \text{ t/yr} * 16.5 \text{ kg/t} * [1 - (80/100)] \\ &= 9900 * 0.2 \\ &= 1980 \text{ kg/yr} \end{aligned}$$

The following section outlines emission factors for combustion processes based on different fuels and boiler configurations. In most circumstances, emission factors are relevant to boiler usage irrespective of the industry type. For ease of reference, this section is divided into the type of fuel fired (eg. coal, gas, oil, wood and bagasse).

Scaling Emissions According to Heating Value

The emission factors presented in the following tables are based on the volumetric quantity of fuels burned in each boiler/furnace. These factors are based on fuels with standard heating (calorific) values, and are listed as follows:

Fuel oil no's 4, 5 and 6 - 41.8 GJ/m³;
Fuel oil no. 2 and distillate - 39 GJ/m³; and
Fuel gas - 37.2 MJ/m³.

Therefore, emissions calculated using the emission factors provided in Section 3.4 must be scaled according to a ratio of the actual heating value to the standard values. Emission factors provided in the tables should be applied using the following generic formula:

$$\text{Emission (kg/hr)} = EF * \text{Fuel Usage (m}^3\text{/hr)} * (H_a/H_s)$$

where: EF = emission factor (kg/m³)
H_a = actual heating value of the fuel (GJ/m³)
H_s = standard heating value of the fuel (GJ/m³)

It is important to ensure that the units of the actual heating value are consistent with those shown for the standard heating values above.

3.4.1 Coal Combustion

The emission factors presented below are for representative (i.e. normal) operating conditions, and include start-up, shut-down, and any other operational phase.

3.4.1.1 General Emission Factors for Coal Combustion

The following emission factors relate to the combustion of various coals (predominantly, they are relevant to sub-bituminous, bituminous and lignite coals). A foot note at the end of each table indicates the coal types to which the emission factors apply.

Table 8 - Controlled Emission Factors for Trace Elements from Coal Combustion^{a,1}

Substance	Emission Factor (kg/tonne) ^b	Emission Factor Rating
Antimony	9.0E-06	A
Arsenic	2.05E-04	A
Beryllium	1.05E-05	A
Cadmium	2.55E-05	A
Chromium	1.3E-04	A
Chromium (VI)	3.95E-05	D
Cobalt	5.0E-05	A
Lead	2.1E-04	A
Magnesium	5.5E-03	A
Manganese	2.45E-04	A
Mercury	4.15E-05	A
Nickel	1.4E-04	A
Selenium	6.5E-04	A

¹ Source: USEPA (1998)

^a The emission factors were developed from emissions data at eleven facilities firing bituminous coal, fifteen facilities firing sub-bituminous coal, and from two facilities firing lignite. The factors apply to boilers utilising either venturi scrubbers, spray drier absorbers, or to wet limestone scrubbers with an electrostatic precipitator (ESP) or fabric filter (FF). In addition, the factors apply to boilers using only an ESP, FF, or venturi scrubber.

^b Factor units are kilogram of substance emitted per tonne of coal burnt. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

Table 9 - Controlled and Uncontrolled Emission Factors For Hydrogen Chloride (HCl) and Hydrogen Fluoride (HF) from Coal Combustion^{a, 1, c}

Firing Configuration	HCl	HF
	Emission Factor (kg/tonne) ^c	Emission Factor (kg/tonne) ^c
PC-fired, dry bottom	0.6	0.075
PC-fired, dry bottom, tangentially fired	0.6	0.075
PC-fired, wet bottom	0.6	0.075
Cyclone Furnace	0.6	0.075
Spreader Stoker	0.6	0.075
Overfeed Stoker	0.6	0.075
Underfeed Stoker	0.6	0.075
FBC, Bubble Bed	0.6	0.075
FBC, Circulating Bed	0.6	0.075
Hand-fired	0.6	0.075

¹ Source: USEPA (1998)

^a Factors apply to both controlled and uncontrolled sources, and were developed from bituminous, sub-bituminous and lignite coal combustion emissions data.

^b Factor units of kg of substance emitted per tonne of coal burnt.

^c Emission Factor Ratio - g - B (See Section 4.4).

Table 10 - Controlled and Uncontrolled Emission Factors for Various Organic Compounds from Coal Combustion^{a,1}

Substance	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c
Acetaldehyde	2.9E-04	C
Benzene	6.5E-04	A
Carbon disulfide	6.5E-05	D
Chloroform	3.0E-05	D
Cumene	2.7E-06	E
Cyanide	1.3E-03	D
Dichloromethane	1.5E-04	D
Ethylbenzene	4.7E-05	D
Formaldehyde	1.2E-04	A
<i>n</i> -Hexane	3.4E-05	D
Methyl ethyl ketone	2.0E-04	D
Methyl methacrylate	1.0E-05	E
Phenol	8.0E-06	D
Tetrachloroethylene	2.2E-05	D
Toluene	1.2E-04	A
Styrene	1.3E-05	D
Xylenes	1.9E-05	C

¹ Source: USEPA (1998)

^a Factors were developed from emissions data from ten sites firing bituminous coal, eight sites firing sub-bituminous coal, and from one site firing lignite. Factors apply to boilers utilising both wet limestone scrubbers or spray dryers with an electrostatic precipitator (ESP) or fabric filter (FF). The factors also apply to boilers using only an ESP or FF. as these control techniques do not impact the release of the organic compounds listed above.

The factors apply to:

- pulverised coal -fired, dry bottom boilers
- pulverised coal, dry bottom, tangentially-fired boilers
- cyclone boilers
- atmospheric fluidised bed combustors, circulating bed

^b Factor units are kg of substance emitted per tonne of coal fired. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^c See Section 4.4.

Table 11 - Controlled and Uncontrolled Emission Factors for Polycyclic Aromatic Hydrocarbons (PAHs) from Coal Combustion^{a,1}

Substance	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c
Acenaphthene	2.6E-07	B
Acenaphthylene	1.3E-07	B
Anthracene	1.1E-07	B
Benzo(a)anthracene	4.0E-08	B
Benzo(a)pyrene	1.9E-08	D
Benzo(b,j,k)fluoranthene	5.5E-08	B
Benzo(g,h,i)perylene	1.4E-08	D
Biphenyl	8.5E-07	D
Chrysene	5.0E-08	C
Fluoranthene	3.6E-07	B
Fluorene	4.6E-07	B
Indeno(1,2,3-cd) pyrene	3.1E-08	C
5-Methyl chrysene	1.1E-08	D
Naphthalene	6.5E-06	C
Phenanthrene	1.4E-06	B
Pyrene	1.7E-07	B
Total Polycyclic Aromatic Hydrocarbons (PAHs)	1.1E-05	D

Note: Only total annual emissions of polycyclic aromatic hydrocarbons (PAHs) require reporting to the NPI. Individual emission factors are provided to assist in assessment and validation of the factors provided.

¹ Source: USEPA (1998)

^a Factors were developed from emissions data from six sites firing bituminous coal, four sites firing sub-bituminous coal, and from one site firing lignite. Factors apply to boilers utilising both wet limestone scrubbers or spray dryers with an electrostatic precipitator (ESP) or fabric filter (FF). The factors also apply to boilers using only an ESP or FF as these control techniques do not impact the release of the PAH compounds listed above.

^b Factor units are kg of substance emitted per tonne of coal burnt. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^c See Section 4.4.

3.4.1.2 Emission Factors for Bituminous and Sub-bituminous Coal Combustion

The following emission factors relate to the firing of bituminous and sub-bituminous coals only.

Table 12 - Emissions Factors for SO₂ and NO_x from Bituminous and Sub-Bituminous Coal Combustion^{a,1}

Firing Configuration	SO ₂ ^c		NO _x	
	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c
PC-fired, dry bottom, wall-fired, bituminous Pre-NSPS ^d	19S	A	11	A
PC, dry bottom, wall-fired, bituminous Pre-NSPS ^d with low-NO _x burner	19S	A	5.5	A
PC, dry bottom, wall-fired, bituminous NSPS ^d	19S	A	6	A
PC, dry bottom, wall-fired, sub-bituminous, Pre-NSPS ^d	17.5S	A	6	C
PC, dry bottom, wall-fired, sub-bituminous NSPS ^d	17.5S	A	3.7	A
PC, dry bottom, cell burner fired, bituminous	19S	A	15.5	A
PC, dry bottom, cell burner fired, sub-bituminous	17.5S	A	7	E
PC-fired, dry bottom, tangentially fired, bituminous, Pre-NSPS ^d	19S	A	7.2	A
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS ^d with low-NO _x burner	19S	A	4.9	A

Table 12 - Emissions Factors for SO₂ and NO_x from Bituminous and Sub-Bituminous Coal Combustion^{a,1} (cont.)

Firing Configuration	SO ₂ ^c		NO _x	
	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c
PC, dry bottom, tangentially fired, bituminous, NSPS ^d	19S	A	5	A
PC, dry bottom, tangentially fired, sub-bituminous, Pre-NSPS ^d	17.5S	A	4.2	A
PC, dry bottom, tangentially fired, sub-bituminous, NSPS ^d	17.5S	A	3.6	A
PC, wet bottom, wall-fired, bituminous, Pre-NSPS ^d	19S	A	15.5	D
PC-fired, wet bottom, tangentially fired, bituminous, Pre-NSPS ^d	19S	D	7.0	E
PC, wet bottom, wall-fired, sub-bituminous	17.5S	A	12	E
Cyclone furnace, bituminous coal	19S	A	16.5	A
Cyclone furnace, sub-bituminous coal	17.5S	A	8.5	C
Spreader stoker, bituminous	19S	B	5.5	B
Spreader stoker, sub-bituminous	17.5S	B	4.4	B
Overfeed stoker, bituminous	19S	B	3.75	A
Overfeed stoker, sub-bituminous	17.5S	B	3.75	A
Underfeed stoker	15.5S	B	4.75	A
Hand-fed units	15.5S	D	4.55	E

Table 12 - Emissions Factors for SO₂ and NO_x from Bituminous and Sub-Bituminous Coal Combustion^{1,a} (cont.)

Firing Configuration	SO ₂ ^c		NO _x	
	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c	Emission Factor (kg/tonne) ^b	Emission Factor Rating ^c
FBC, circulating bed	e	E	2.5	D
FBC, bubbling bed	e	E	7.6	D

¹ Source: USEPA (1998)

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal as fired. The factors also apply to boilers using only an ESP or FF as these control techniques do not impact the release of the compounds included above.

^b Factor units are kilogram of substance emitted per tonne of coal burnt.

^c Expressed as SO₂ and includes SO₂, SO₃ and gaseous sulfates. In all cases, the S is the weight % sulfur content of the coal as fired. Emission factors are calculated by multiplying the weight % sulfur in the coal by the numerical value preceding S. For example if the coal type is 1.2% sulfur, then S = 1.2.

^d NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are constructed with overfire air and/or low excess air designs to meet the US New Source Performance Standards (NSPS) as defined in 40CFR60 Subpart D, and with a heat input rate greater than 73 MW (constructed after August 1971). Subpart Da boilers are constructed with overfire air and/or low excess air designs to meet the US New Source Performance Standards as defined in 40CFR60, Subpart Da (constructed after September 1978).

^e SO₂ emission factors for fluidised bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: kg SO₂/tonne coal = 19.8(S)(Ca/S)^{-1.9}. In this equation, S is the weight percent sulfur in the fuel, and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used, and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the SO₂ emissions. In this case, the emission factor ratings are E for both bubbling and circulating unit

- See Section 4.4.

Table 13 - Emission Factors for Carbon Monoxide (CO) and Total Volatile Organic Compounds (Total VOCs) from Bituminous and Sub-Bituminous Coal Combustion¹

Firing Configuration	CO ^b		Total VOCs ^{b,c}	
	Emission Factor (kg/tonne) ^a	Emission Factor Rating*	Emission Factor (kg/tonne) ^a	Emission Factor Rating*
PC-fired, wet bottom	0.25	A	0.02	B
PC-fired, dry bottom, wall-fired	0.25	A	0.03	B
PC-fired, dry bottom, cell burner fired	0.25	A	ND	-
PC-fired, dry bottom, tangentially fired	0.25	A	0.03	B
Cyclone furnace	0.25	A	0.055	B
Spreader stoker	2.5	A	0.025	B
Overfeed stoker	3	B	0.025	B
Underfeed stoker	5.5	B	0.65	B
Hand-fed units	138	E	5	E
FBC, circulating bed	9	E	0.025	E
FBC, bubbling bed	9	D	0.025	E

¹ Source: USEPA (1998)

^a Factors represent uncontrolled emissions unless otherwise specified. Control techniques do not impact the release of the compounds included above. Units represent kilograms of substance emitted per tonne of coal feed, as fired.

^b Nominal values achievable under normal operating conditions. Values 1 or 2 orders of magnitude higher can occur when combustion is not complete.

^c Total volatile organic compounds (VOCs) are expressed as C₂ to C₁₆ alkane equivalents. Because of limited data, the effects of firing configuration on total VOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverised coal units, cyclones, spreaders, and overfeed stokers.

*See Section 4.4.

Table 14 - Controlled and Uncontrolled Emission Factors for Filterable Particulate Matter (PM₁₀) from Bituminous and Sub-Bituminous Coal Combustion^{a,1}

Firing Configuration	Emission Factor^b (kg/tonne)	Emission Factor Rating*
Pulverised bituminous and sub-bituminous coal, dry bottom:		
- uncontrolled	1.15A	C
- multiple cyclones ^g	0.3A	E
- scrubber ⁱ	0.21A	D
- electrostatic precipitator ^j	0.027A	D
- baghouse ^k	0.01A	E
Pulverised bituminous coal, wet bottom:		
- uncontrolled	1.3A	E
- multiple cyclones ^h	0.65A	E
- electrostatic precipitator ^j	0.021A	E
Pulverised sub-bituminous coal, wet bottom:		
- uncontrolled	1.3A	E
Cyclone furnace, bituminous coal:		
- uncontrolled	0.13A	E
- multiple cyclones ^h	0.056A	E
- electrostatic precipitator ^j	0.006A	E
Cyclone furnace, sub-bituminous coal:		
- uncontrolled	0.13A	E
Spreader stoker, bituminous coal:		
- uncontrolled	6.6	C
- multiple cyclones with flyash reinjection	6	E
- multiple cyclones without flyash reinjection	3.9	C
- electrostatic precipitator ^j	0.22	E
- baghouse ^k	0.036	C
Spreader stoker, sub-bituminous coal:		
- uncontrolled	6.6	E
- multiple cyclones with flyash reinjection	6.2	E
- multiple cyclones without flyash reinjection	3.9	E

Table 14 - Controlled and Uncontrolled Emission Factors for Filterable Particulate Matter (PM₁₀) from Bituminous and Sub-Bituminous Coal Combustion¹ (cont.)

Firing Configuration	Emission Factor^b (kg/tonne)	Emission Factor Rating[*]
Overfeed stoker, bituminous coal:		
- uncontrolled	3.0	C
- multiple cyclones ^g	2.5	E
Overfeed stoker ^d , sub-bituminous coal:		
- uncontrolled	3.0	E
- multiple cyclones ^g	2.5	E
Underfeed stoker		
- uncontrolled	3.1	E
- multiple cyclones ^e	3.1	E
Hand-fed units	3.1 ^f	E
Fluidised Bed Combustor:		
- circulating bed ^c	6.2	E
- bubbling bed ^c	6.2	E

¹ Source: USEPA (1998).

^a Factor units are kilograms of particulate matter $\leq 10\mu\text{m}$ (PM₁₀) emitted per tonne of coal burnt.

^b Where particulate is expressed in terms of coal ash content (A), the factor is determined by multiplying the weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8% ash is fired in an uncontrolled PC-fired, dry bottom unit, the PM₁₀ emission factor would be 1.15 * 8, or 9.2 kg per tonne.

^c No data found; emission factor for spreader stoker with multiple cyclones and reinjection used.

^d Includes travelling grate, vibrating grate, and chain grate stokers.

^e Accounts for fly ash settling in breaching downstream of boiler outlet.

^f No data found; emission factor for underfeed stoker used.

^g Estimated control efficiency of multiple cyclones is 80%.

^h Estimated control efficiency of multiple cyclones is 94%.

ⁱ Estimated control efficiency of scrubber is 94%.

^j Estimated control efficiency of electrostatic precipitator 99.2%.

^k Estimated control efficiency of baghouse is 99.8

* See Section 4.4.

Table 15 - Uncontrolled Emission Factors for Trace Elements from Bituminous and Sub-Bituminous Coal Combustion¹

Firing Configuration	Emission Factors (kg/PJoule)								
	Arsenic	Beryllium	Cadmium	Chromium	Lead	Manganese	Mercury	Nickel	Formaldehyde
Pulverised coal, configuration unknown	ND	ND	ND	826	ND	ND	ND	ND	48
Pulverised coal, wet bottom	231	35	19-30	439-675	218	347-1281	6.9	361-555	ND
Pulverised coal, dry bottom	294	35	19	538-675	218	98-1281	6.9	443-555	ND
Cyclone furnace	49	<35	12	91-646	218	98-559	6.9	75-555	ND
Stoker, configuration unknown	ND	31	ND	8-129	ND	933	6.9	333-555	ND
Spreader stoker	114-233	ND	9-18	405-675	218	ND	ND	ND	95
Overfeed stoker, travelling grate	233-443	ND	18-35	ND	218	ND	ND	ND	60

¹ Source: USEPA (1998). All emission factors rated 'E'. (See Section 4.4)

Note: When an emission factor is shown within a range, the reporter should make his/her selection based on known operational practices, and knowledge of boiler maintenance, age etc.

^a Factor units are kilograms of substance emitted per PetaJoule (10¹⁵) of energy produced.

Table 16 - Controlled Emission Factors for Polychlorinated Dibenzop-dioxins and Polychlorinated Dibenzop-furans from Bituminous and Sub-Bituminous Coal Combustion^{a,1}

Substance	FGD-SDA ^d and Fabric Filter		Electrostatic Precipitator OR Fabric Filter	
	Emission Factor (kg/tonne)	Emission Factor Rating*	Emissions Factor (kg/tonne)	Emission Factor Rating*
2,3,7,8-Tetrachloro-dibenzodioxin	ND	-	7.2E-12	E
Total Tetrachloro-dibenzodioxins	1.97E-10	E	4.6E-11	D
Total Pentachloro-dibenzodioxins	3.53E-10	E	2.2E-11	D
Total Hexachloro-dibenzodioxins	1.5E-09	E	1.4E-11	D
Total Heptachloro-dibenzodioxins	5.0E-09	E	4.2E-11	D
Octachloro-dibenzodioxins	1.44E-08	E	2.1E-10	D
Total Polychlorinated dibenzo-p-dioxins^b	2.14E-08	E	3.3E-10	D
2,3,7,8-Tetrachloro-dibenzofuran	ND	-	2.6E-11	D
Total Tetrachloro-dibenzofurans	1.25E-09	E	2.0E-10	D
Total Pentachloro-dibenzofurans	2.42E-09	E	1.8E-10	D
Total Hexachloro-dibenzofurans	6.35E-09	E	9.6E-11	D
Total Heptachloro-dibenzofurans	2.20E-08	E	3.8E-11	D
Octachloro-dibenzofurans	6.85E-08	E	3.3E-11	D
Total Polychlorinated dibenzo-p-furans^c	1.01E-07	E	5.5E-10	D
TOTAL dioxins and furans	1.22E-07	E	8.8E-10	D

Note: Only total annual emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzo-p-furans require reporting to the NPI. Individual emission factors are provided to assist in validation of the factors provide

¹ Source: USEPA (1998)

^a Factor units are kg of substance emitted per tonne of coal burnt. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Total Polychlorinated dibenzodioxins is the sum of Total Tetrachloro-dibenzodioxins through Total Octachloro-dibenzodioxins.

^c Total Polychlorinated dibenzofurans is the sum of Total Tetrachloro-dibenzofurans through Total Octachloro-dibenzofurans.

^d FGD-SDA = flue gas desulfurisation spray drier absorber.

^e Emission factors are for total dioxins and furans, not toxic equivalents (Total 2,3,7,8 TCDD equivalents).

ND = no data

* See Section 4.4

3.4.1.3 Emission Factors for Lignite Coal Combustion

Table 17 - Emission Factors for SO_x, NO_x, CO and Total VOCs from Lignite^{1,a}

Firing Configuration	Emission Factor ^b (kg/tonne)			
	SO _x	NO _x	CO	Total VOCs ^g
Pulverised coal, dry bottom, tangential	15S	3.55 ⁱ	ND	0.02
Pulverised coal, dry bottom, wall-fired ^d , pre-NSPS ^h	15S	6.5	0.13	0.02
Pulverised coal, dry bottom, wall-fired ^d , NSPS ^h	15S	3.15	0.13	0.02
Cyclone	15S	7.5	ND	0.04
Spreader stoker	15S	2.9	ND	0.02
Travelling Grate Overfeed stoker	15S	ND	ND	0.02
Atmospheric fluidised bed	5S ^f	1.8	0.08 ^e	0.02
<i>Subpart D boilers:</i>				
Pulverised coal, tangential-fired, with overfire air	ND	3.4	ND	ND
Pulverised coal, wall-fired, overfire air and low NO _x burners	ND	2.3	0.24 ^j	ND
Pulverised coal, spray dryer	3.7S ⁱ	ND	ND	ND
Pulverised coal, wet scrubber	8.4S	ND	ND	ND
<i>Subpart Da boilers:</i>				
Pulverised coal, tangential-fired, overfire air	ND	3.0	0.05 ^j	ND
Pulverised coal, spray dryer	4.0S ⁱ	ND	ND	ND
Pulverised coal, wet scrubber	1.9S	ND	ND	ND

¹ Source: USEPA (1998).

^a Factors units are kg of substance emitted per tonne of coal burnt.

^b S = weight percent sulfur content of lignite, wet basis. For example, if the sulfur content equals 3.4%, then S= 3.4.

^c Emission Factor Rating - C (except as noted) (See Section 4.4).

^d Wall-fired includes front and rear all-fired units, as well as opposed wall-fired units.

^e Emission factor is for circulating fluidised bed only.

^f Using limestone bed material.

^g Total volatile organic compounds (VOCs) are expressed as C₂ to C₁₆ alkane equivalents. Emission factors were derived from bituminous coal data in the absence of lignite data assuming emissions are proportional to coal heating value. Because of limited data, the effects of firing configuration on total VOC emission factors could not be distinguished. As a result, all data was averaged to develop a single average emission factor for pulverised coal units, cyclones, spreaders, and overfeed stokers.

^h NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are constructed with overfire air and/or low excess air designs to meet the US New Source Performance Standards (NSPS) as defined in 40CFR60 Subpart D and with a heat input rate greater than 73 MW (constructed after August 1971). Subpart Da boilers are constructed with overfire air and/or low excess air designs to meet the US New Source Performance Standards as defined in 40CFR60, Subpart Da (constructed after September 1978).

ⁱ Emission Factor Rating A. (See Section 4.4).

^j Emission factor rating D. (See Section 4.4).

Table 18 - Controlled and Uncontrolled Emission Factors for Filterable Particulate Matter (PM₁₀) from Lignite Combustion¹

Firing Configuration	Emission Factor ^b (kg/tonne) ^a	Emission Factor Rating*
Pulverised lignite, tangential-fired:		
- uncontrolled	1.15A	E
- multiple cyclone ^c	0.44A	E
Pulverised lignite, wall-fired:		
- uncontrolled	0.91A	E
- multiple cyclone ^c	0.35A	E
Spreader stokers:		
- uncontrolled	0.8A	E
- multiple cyclone ^c	0.33A	E

¹ Source: USEPA (1998)

^a Factor units are kg of substance emitted per tonne of coal burnt.

^b A = weight percent ash content of lignite, wet basis. For example if the ash content is 5%, then A=5.

^c Estimated control efficiency for multiple cyclone is 80%, averaged over all particle size

* See Section 4.4.

Table 19 - Controlled Emission Factors for Polycyclic Aromatic Hydrocarbons from Lignite Combustion^{1, d}

Firing Configuration	Control Device	Emission Factor (kg/PJ) ^a
Pulverised coal	High efficiency cold-side ESP	1
Pulverised coal, dry bottom	Multi-cyclones ESP	0.-7 - 7.74 ^b 1.1 ^b
Cyclone furnace	ESP	0.0- ^c - 0.69 ^b
Spreader stoker	Multi-cyclones	6.45 ^c

¹ Source: USEPA (1998)

^a Factor units are kilograms of substance emitted per PetaJoule (10¹⁵) of energy produced.

^b Primarily trimethyl propenyl naphthalene.

^c Primarily biphenyl.

^d Emission Factor Rating - E (See Section 4.4).

Table 20 - Uncontrolled Emission Factors For Trace Elements from Lignite Combustion^{1,b}

Firing Configuration	Emission Factors (kg/PJoule) ^a						
	Arsenic	Beryllium	Cadmium	Chromium	Manganese	Mercury	Nickel
Pulverised coal, wet bottom	1174	56	-1 - 33	5-5 - 808	18-6 - 6988	9	66- 500
Pulverised coal, dry bottom	598	56	21	6-5 - 808	6966	9	4-0 - 500
Cyclone furnace	1-1 - 272	56	13	1-9 - 808	1617	9	-8 - 500
Stoker, configuration unknown	ND	51	ND	ND	5074	9	ND
Spreader stoker	2-1 - 473	ND	9-9 - 20	4-6 - 808	ND	ND	3-0 - 500
Overfeed stoker, travelling grate	4-3 - 903	ND	20-39	ND	ND	ND	ND

¹ Source: USEPA (1998)

^a Factor units are kilograms of substance emitted per PetaJoule (10¹⁵) of energy produced.

^b Emission Factor Rating - E. (See Section 4.4).

3.4.1.4 Emission Factors for Anthracite Coal Combustion

Table 21 - Uncontrolled Emission Factors for CO, SO_x and NO_x from Anthracite Coal Combustion^{a,1}

Firing Configuration	SO _x		NO _x		CO	
	Emission Factor (kg/tonne)	Emission Factor Rating*	Emission Factor (kg/tonne)	Emission Factor Rating*	Emission Factor (kg/tonne)	Emission Factor Rating*
Stoker-fired boilers	19.5S ^b	B	4.5	C	0.3	B
FBC boilers ^c	1.45	E	0.9	E	0.3	E
Pulverised coal boilers	19.5S ^b	B	9.0	B	ND	-

¹ Source: USEPA (1996)

^a Factor units are kg of substance emitted per tonne of coal burnt.

^b Expressed as SO₂, and includes SO₂, SO₃ and gaseous sulfates. In all cases, the S is the weight % sulfur content of the coal as fired. Emission factors are calculated by multiplying the weight % sulfur in the coal by the numerical value preceding S. For example, if the coal type is 1.2% sulfur, then S = 1.2.

^c FBC = Fluidised Bed Combustion. FBC boilers burning culm (anthracite dust) fuel; all other sources burning anthracite coal.

* See Section 4.4.

Table 22 - Emission Factor for Organic Compounds from Stoker-Fired Boilers Firing Anthracite Coal^{1,d}

Substance	Emission Factor (kg/tonne) ^a
Total VOCs ^b	0.15
Polycyclic Aromatic Hydrocarbons ^c :	
Biphenyl	1.25E-02
Naphthalene	6.5E-02
Phenanthrene	3.4E-03

Note: Only total annual emissions of polycyclic aromatic hydrocarbons (PAHs) require reporting to the NPI. Individual emission factors are provided to assist in assessment and validation of the factors provide

¹ Source: USEPA (1996)

^a Factor units are kilogram of substance emitted per tonne of coal burnt. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Total VOCs = total volatile organic compounds.

^c Other polycyclic aromatic hydrocarbons are likely to be present in emissions. However, insufficient data is available to determine emission factors.

^d Emission Factor Rating - E. (See Section 4.4)

Table 23 - Emission Factors for Particulate Matter (≤ 10 mm, i.e. PM₁₀) from Anthracite Combustion¹

Firing Configuration	PM ₁₀ Emission Factor (kg/tonne) ^{a,b}
Dry bottom, burning pulverised coal:	
- uncontrolled	1.15A
- multiple cyclone ^c	0.55A
- baghouse ^c	0.007A
Stoker-fired boilers ^d	0.4A

¹ Source: USEPA (1996)

^a Factor units are kilogram of substance emitted per tonne of coal burnt.

^b Where particulate is expressed in terms of coal ash content (A), the factor is determined by multiplying the weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8% ash is fired in an uncontrolled PC-fired, dry bottom unit, the PM₁₀ emission factor would be 1.15 * 8, or 9.2 kg per tonne.

^c Estimated control efficiency for multiple cyclone is 80%; for baghouse, 99.8%.

^d A = ash content of fuel, weight %. For example, if the ash content is 5%, then A = 5.

^e Emission Factor Rating - D (See Section 4.4).

Table 24 - Emission Factors for Trace Elements from Anthracite Coal Combustion in Stoker Fired Boilers¹

Metal	Emission Factor (kg/tonne)^a	Emission Factor Rating^b
Arsenic	B-L - 1.2E-04	E
Antimony	BDL	E
Beryllium	1.5E-5 - 2.7E-04	E
Cadmium	2.3E-5 - 5.5E-05	E
Chromium	3.0E-3 - 2.5E-02	E
Lead	4.5E-03	E
Manganese	4.9E-4 - 2.7E-03	E
Mercury	4.4E-5 - 8.5E-05	E
Nickel	3.9E-3 - 1.8E-02	E
Selenium	2.4E-4 - 1.1E-03	E

¹ Source: USEPA (1996)

^a Factor units are kilogram of element emitted per tonne of coal burnt. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

BDL = below detectable limit

^b See Section 4.4

3.4.2 Gas Combustion

The following section supplied emission factors that apply to the combustion of natural and liquefied petroleum gas.

3.4.2.1 Emission Factors for Natural Gas Combustion

Table 25 - Controlled and Uncontrolled Combustion of Natural Gas - Emission Factors for SO₂, NO_x, and CO¹

Combustor Description (Size 10 ³ MJ/hr heat input)	SO ₂ (kg/10 ⁶ m ³)		NO _x (kg/10 ⁶ m ³)		CO (kg/10 ⁶ m ³)	
	Emission Factor ^a	Factor Rating ^c	Emission Factor ^a	Factor Rating ^c	Emission Factor ^a	Factor Rating ^c
Large Wall-Fired Boilers:						
- Uncontrolled (pre-NSPS) ^b	2.09S	U	4480	A	1344	B
- Uncontrolled (post-NSPS) ^b	2.09S	U	3040	A	1344	B
- Low NO _x burners	2.09S	U	2240	A	1344	B
- Flue gas recirculation	2.09S	U	1600	D	1344	B
Small Boilers (0.3-100):						
- uncontrolled	2.09S	U	1600	B	1344	B
- Low NO _x burners	2.09S	U	800	D	1344	B
- Low NO _x burners /flue gas recirculation	2.09S	U	512	C	1344	B
Tangential-fired boilers (all sizes):						
- uncontrolled	2.09S	U	2720	A	384	C
- Flue gas recirculation	2.09S	U	1216	D	1568	D
Residential boilers (<0.3)	2.09S	U	1504	B	640	B

¹ Source: USEPA AP-42 Section 1.4-7 (1998).

Units are in kg of substance emitted per 10⁶ m³ of gas consumed. S = Sulfur concentration in natural gas. For Vic, S = 4 mg/m³ (i.e. 4 kg/10⁶ m³). Obtain indicative figure for S from your State gas agency or use 4 kg/10⁶ m³ as default.

^b NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are constructed with overfire air and/or low excess air designs to meet the US New Source Performance Standards (NSPS) as defined in 40CFR60 Subpart D, and with a heat input rate greater than 73 MW (constructed after August 1971). Subpart Da boilers are constructed with overfire air and/or low excess air designs to meet the US New Source Performance Standards as defined in 40CFR60, Subpart Da (constructed after June 1984).

^c See Section 4.4.

Table 26 - Uncontrolled Emission Factors for PM₁₀ and Total VOCs from Natural Gas Combustion¹

Substance	Emission Factor (kg/10 ⁶ m ³) ^a	Emission Factor Rating ^c
Total VOCs ^b	88	C
Particulate matter =10µm (PM ₁₀)	121.6	D

¹ Source: USEPA (1998)

^a Units are in kg of substance emitted per million (10⁶) m³ of gas consumed.

^b Total VOCs = total volatile organic compounds.

^c See Section 4.4.

Table 27 - Emission Factors for Organic Compounds from Natural Gas Combustion¹

Substance	Emission Factor (kg/10 ⁶ m ³) ^a	Emission Factor Rating ^b
<i>NPI-listed substances:</i>		
Benzene	3.4E-02	B
Formaldehyde	1.2E+00	B
<i>n</i> -Hexane	2.9E+01	E
Toluene	5.4E-02	C
<i>Polycyclic Aromatic Hydrocarbons:</i>		
2-Methylnaphthalene	3.8E-04	D
3-Methylchloranthrene	<2.9E-05	E
7,12-Dimethylbenz(a)anthracene	<2.6E-04	E
Acenaphthene	<2.9E-05	E
Acenaphthylene	<2.9E-05	E
Anthracene	<3.8E-05	E
Benz(a)anthracene	<2.9E-05	E
Benzo(a)pyrene	<1.9E-05	E
Benzo(b)fluoranthene	<2.9E-05	E
Benzo(g,h,i)perylene	<1.9E-05	E
Benzo(k)fluoranthene	<2.9E-05	E
Chrysene	<2.9E-05	E
Dibenzo(a,h)anthracene	<1.9E-05	E
Fluoranthene	4.8E-05	E
Fluorene	4.5E-05	E
Indeno(1,2,3-cd)pyrene	<2.9E-05	E
Naphthalene	9.8E-03	E
Phenanthrene	2.7E-04	D
Pyrene	8.0E-05	E
Total PAHs	1.1E-02	E

Note: Only total annual emissions of polycyclic aromatic hydrocarbons (PAHs) require reporting to the NPI. Individual emission factors are provided to assist in assessment and validation of the factors provided

¹ Source: USEPA (1998).

^a Units are in kg of substance emitted per million (10⁶) m³ of gas consumed. Emission factors preceded with a less-than symbol are based on method detection limits. 'E-05' etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b See Section 4.4.

Table 28 - Combustion of Natural Gas - Emission Factors for Trace Elements¹

Metal	Emission Factor (kg/10 ⁶ m ³) ^a	Emission Factor Rating ^b
Arsenic	3.2E-03	E
Beryllium	<1.9E-04	E
Cadmium	1.8E-02	D
Chromium	2.2E-02	D
Cobalt	1.3E-03	D
Copper	1.4E-02	C
Lead	8.0E-03	D
Manganese	6.1E-03	D
Mercury	4.2E-03	D
Nickel	3.4E-02	C
Selenium	<3.8E-04	E
Zinc	4.6E-01	E

¹ Source: USEPA (1998)

^a Units are in kg of metal emitted per 10⁶ m³ of gas consumed. Data is for all natural gas combustion sources. Emission factors preceded by a less-than symbol are based on method detection limits. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'.
e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b See Section 4.4

3.4.2.2 Emission Factors for Liquefied Petroleum Gas (LPG) Combustion

Table 29 - Emission Factors for LPG Combustion^{1, d}

Substance	Butane Emission Factor (kg/10 ³ L) ^a		Propane Emission Factor (kg/10 ³ L) ^a	
	Industrial Boilers ^c	Commercial Boilers ^c	Industrial Boilers ^c	Commercial Boilers ^c
PM ₁₀	0.07	0.06	0.07	0.048
SO ₂ ^b	1.9E-04S	1.9E-04S	2.1E-04S	2.1E-04S
NO _x	2.52	1.80	2.28	1.68
CO	0.43	0.25	0.38	0.23
Total VOCs	0.07	0.07	0.06	0.06
<i>n</i> -Hexane	0.00072	0.00072	0.0006	0.0006
Cyclohexane	0.00072	0.00072	0.0006	0.0006
Formaldehyde	0.00576	0.00576	0.0048	0.0048
Benzene	0.00288	0.00288	0.0024	0.0024
Toluene	0.00144	0.00144	0.0012	0.001

Source: USEPA (1996).

^a Units are expressed as kilograms of substance emitted per thousand (10³) litres of LPG consumed.

^b S equals the sulfur content. The Australian average sulfur content of LPG is 0.045 g/m³ fuel burned. This national average figure should be used as a default for sulfur content where information on exact sulfur content of LPG is unavailable.

^c Industrial boilers are classed as having a heat input of -0 - 100 GJ/hr, a commercial boiler is classed as having a heat input of 0-3 - 10 GJ/hr.

^d Emission Factor Rating - E (See Section 4.4)

3.4.3 Oil Combustion

The following emission factors relate to the combustion of fuel and waste oils.

3.4.3.1 Emission Factors for Fuel Oil Combustion

Table 30 - Emission Factors for Sulfur Dioxide (SO₂), Sulfur Trioxide (SO₃), and Oxides of Nitrogen (NO_x) from Fuel Oil Combustion

Combustion Type ^c	Emission Factor (kg/10 ³ L) ^a					
	SO ₂ ^b	Rating ^e	SO ₃ ^b	Rating ^e	NO _x ^d	Rating ^e
Boilers >100GJ/hr:						
No. 6 oil fired, normal firing	18.8S	A	0.68S	C	5.6	A
No. 6 oil fired, normal firing, low NOx burner	18.8S	A	0.68S	C	4.8	B
No. 6 oil fired, tangential firing	18.8S	A	0.68S	C	3.8	A
No. 6 oil fired, tangential firing, low NOx burner	18.8S	A	0.68S	C	3.1	E
No. 5 oil fired, normal firing	18.8S	A	0.68S	C	5.6	B
No. 5 oil fired, tangential firing	18.8S	A	0.68S	C	3.8	B
No. 4 oil fired, normal firing	18S	A	0.68S	C	5.6	B
No. 4 oil fired, tangential firing	18S	A	0.68S	C	3.8	B
No. 2 oil fired	17S	A	0.68S	C	2.9	D
No. 2 oil fired, LNB/FGR	17S	A	0.68S	A	1.2	D

Table 30 - Emission Factors for Sulfur Dioxide (SO₂), Sulfur Trioxide (SO₃), and Oxides of Nitrogen (NO_x) from Fuel Oil Combustion (cont.)

Combustion Type ^c	Emission Factor (kg/10 ³ L) ^a					
	SO ₂ ^b	Rating ^e	SO ₃ ^b	Rating ^e	NO _x ^d	Rating ^e
Boilers < 100GJ/hr:						
No. 6 oil fired	18.8S	A	0.24S	A	6.6	A
No. 5 oil fired	18.8S	A	0.24S	A	6.6	A
No. 4 oil fired	18S	A	0.24S	A	2.4	A
Distillate oil fired	17S	A	0.24S	A	2.4	A
Residential furnace:	17S	A	0.24S	A	2.2	A

¹ Source: USEPA (1998)

^a Units are kilograms of substance emitted per thousand (10³) litres of fuel oil fired.

^b S = the weight % of sulfur in the oil and indicates that this should be multiplied by the value given. For example, if the fuel contains 1% sulfur, then S = 1.

^c Nos. 1 and 2 are distillate oils, Nos. 5 and 6 (sometimes referred to as Bunker C) are residual oils, and no. 4 oils are either distillate, or a mixture of distillate and residual oils.

^d NO_x emission factors are expressed as NO₂. Note that a more accurate method to estimate NO_x emissions from industrial and commercial combustion sources (< 3 - 30 MW) is using the following equation: kg NO₂/m³ oil fired = 2.465 + 12.526(N), where N is the weight percent of nitrogen in the oil. This equation should be used for industrial or commercial boilers if the nitrogen content of the fuel burnt is known.

^e See Section 4.4.

Table 31 - Emission Factors for Carbon Monoxide (CO) and Total Volatile Organic Compounds (Total VOCs) from Fuel Oil¹

Combustion Type ^c	Emission Factor (kg/10 ³ L) ^a			
	CO ^b	Rating ^e	Total VOCs ^d	Rating ^e
Utility Boilers:				
No. 6 oil fired, normal firing	0.6	A	0.09	A
No. 6 oil fired, normal firing, low NOx burner	0.6	A	ND	-
No. 6 oil fired, tangential firing	0.6	A	0.09	A
No. 6 oil fired, tangential firing, low NOx burner	0.6	A	ND	-
No. 5 oil fired, normal firing	0.6	A	0.09	A
No. 5 oil fired, tangential firing	0.6	A	0.09	A
No. 4 oil fired, normal firing	0.6	A	0.09	A
No. 4 oil fired, tangential firing	0.6	A	0.09	A
No. 2 oil fired	0.6	A	ND	-
No. 2 oil fired, LNB/FGR	0.6	A	ND	-
Industrial:				
No. 6 oil fired	0.6	A	0.03	A
No. 5 oil fired	0.6	A	0.03	A
No. 4 oil fired	0.6	A	0.02	A
Distillate oil fired	0.6	A	0.02	A

Table 31 - Emission Factors for Carbon Monoxide (CO) and Total Volatile Organic Compounds (Total VOCs) from Fuel Oil1 (cont.)

Combustion Type ^c	Emission Factor (kg/10 ³ L) ^a			
	CO ^b	Rating ^e	Total VOCs ^d	Rating ^e
Commercial/institutional/ residential combustors:				
No. 6 oil fired	0.6	A	0.14	A
No. 5 oil fired	0.6	A	0.14	A
Distillate oil fired	0.6	A	0.04	A
No. 4 oil fired	0.6	A	0.04	A
Residential furnace:	0.6	A	0.09	A

¹ Source: USEPA (1998)

^a Units are kilograms of substance emitted per thousand (10³) litres of fuel oil fired.

^b CO emissions may increase by factors of 10 to 100 if the unit is improperly operated, or not well maintained.

^c Nos. 1 and 2 are distillate oils, Nos. 5 and 6 (sometimes referred to as Bunker C) are residual oils, and no. 4 oils are either distillate or a mixture of distillate and residual oils.

^d Total VOCs = total volatile organic compounds. VOC emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

^e See Section 4.4.

Table 32 - Controlled and Uncontrolled Emission Factors for Particulate Matter $\leq 10\mu\text{m}$ (PM_{10}) from Fuel Oil Combustion¹

Firing Configuration ^c	Emission Factor ($\text{kg}/10^3\text{L}$) ^a	
	PM_{10} ^b	Rating ^e
Utility Boilers:		
Residual oil fir-d - uncontrolled	0.7A	C
Residual oil fir-d - electrostatic precipitator	0.005A	E
Residual oil fir-d - scrubber	0.06A	D
Industrial Boilers:		
Residual oil fir-d - uncontrolled	0.86A	D
Residual oil fir-d - multiple cyclone controlled	0.19A	E
Distillate oil fir-d - uncontrolled	0.12	E
Commercial Boilers:		
Residual oil fir-d - uncontrolled	0.62A	D
Distillate oil fir-d - uncontrolled	0.13	D
Residential furnaces	ND	-

¹ Source: USEPA Document AP-42 (1996).

^a Units are kilograms of substance emitted per thousand (10^3) litres of fuel oil fired.

^b "A" depends on the fuel oil grade and sulfur content:

No. 6 oil^d: $A = 0.13(S) + 0.05 \text{ kg}/10^3 \text{ L}$, where S is the weight % of sulfur in the oil

No. 5 oil^d: $A = 0.14 \text{ kg}/10^3 \text{ L}$

No. 4 oil^d: $A = 0.1 \text{ kg}/10^3 \text{ L}$

No. 2 oil^d: $A = 0.03 \text{ kg}/10^3 \text{ L}$

^c Estimated control efficiency for electrostatic precipitator is 99.2%, scrubber is 94%, multiple cyclone is 80%.

^d Nos. 1 and 2 are distillate oils, Nos. 5 and 6 (sometimes referred to as Bunker C) are residual oils, and no. 4 oils are either distillate or a mixture of distillate and residual oils.

^e See Section 4.4.

Table 33 - Emission Factors for Trace Elements from Fuel Oil Combustion Sources^{1,c}

Metal	No. 6 Fuel Oil Fired		Distillate Oil Fired	
	Emission Factor (kg/10 ³ L) ^b	Emission Factor Rating ^d	Emission Factor (kg/PJ) ^a	Emission Factor Rating ^d
Antimony	6.3E-04	E	ND	-
Arsenic	1.58E-04	C	1.7	E
Beryllium	3.33E-06	C	1.3	E
Cadmium	4.78E-05	C	1.3	E
Chloride	4.16E-02	D	ND	-
Chromium	1.01E-04	C	1.3	E
Chromium(VI)	2.98E-05	C	ND	-
Cobalt	7.22E-04	D	ND	-
Copper	2.11E-04	C	2.6	E
Fluoride	4.48E-03	D	ND	-
Lead	1.81E-04	C	3.9	E
Manganese	3.60E-04	C	2.6	E
Mercury	1.36E-05	C	1.3	E
Nickel	1.01E-02	C	1.3	E
Selenium	8.20E-05	C	6.5	E
Zinc	3.49E-03	D	1.7	

¹ Source: USEPA (1998). ND = No data.

^a Factor units are kilograms of substance emitted per PetaJoule (10¹⁵) of energy produced. 'E-05' etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Units are kilograms of substance emitted per 1000 L of oil fired.

^c For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by the fraction of water (eg. for fuel with 9% water by volume, multiply emission factor by 0.91).

^d See Section 4.4.

Table 34 - Emission Factors for Organics from Residual Fuel Oil^a Combustion

Substance	Emission Factor (kg/10 ³ L) ^c	Emission Factor Rating ^g
<i>NPI-listed substances:</i>		
Benzene	2.57E-05	C
Ethylbenzene	7.63E-06	E
Formaldehyde ^d	3.96E-03	C
Formaldehyde ^e	2.88E-3 - 7.32E-03	E
Formaldehyde (Distillate) ^f	4.2E-3 - 7.32E-03	E
Toluene	7.44E-04	D
o-Xylene	1.31E-05	E
<i>Polycyclic Aromatic Hydrocarbons:</i>		
Naphthalene	1.36E-04	C
Acenaphthene	2.53E-06	C
Acenaphthylene	3.04E-08	D
Anthracene	1.46E-07	C
Benz(a)anthracene	4.81E-07	C
Benzo(b,k)fluoranthene	1.78E-07	C
Benzo(g,h,i)perylene	2.71E-07	C
Chrysene	2.86E-07	C
Dibenzo(a,h)anthracene	2.00E-07	D
Fluoranthene	5.81E-07	C
Fluorene	5.36E-07	C
Indo(1,2,3-cd)pyrene	2.57E-07	C
Phenanthrene	1.26E-06	C
Pyrene	5.10E-07	C
<i>Total PAH's</i>	<i>1.43E-04</i>	<i>E</i>
<i>Polychlorinated Dioxins and Furans:</i>		
Octachlorodibenzodioxin (OCDD)	3.72E-10	E

Note: Only total annual emissions of polycyclic aromatic hydrocarbons (PAHs) and polychlorinated dioxins and furans require reporting to the NPI. Individual emission factors are provided to assist in assessment and validation of the factors provided.

¹ Source: USEPA (1996).

^a Nos. 1 and 2 are distillate oils, Nos. 5 and 6 (sometimes referred to as Bunker C) are residual oils, and no. 4 oils are either distillate or a mixture of distillate and residual oils.

^b For No. 6 fuel oil only.

^c Units are kilograms of substance emitted per 1000 L of oil fired. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^d The formaldehyde emission factor presented is based only on data from utilities using No. 6 oil.

^e The formaldehyde emission factor presented is based on data from utility, commercial, and industrial boilers for no. 6 fuel oil only.

^f The formaldehyde emission factor presented is based on data from utility, commercial and industrial boilers firing distillate oil.

^g See Section 4.4.

^h Emission factors are for total dioxins and furans, not toxic equivalents (Total 2,3,7,8 TCDD equivalents).

3.4.3.2 Emission Factors for Waste Oil Combustion

Table 35 - Uncontrolled Emission Factors for Small Boilers firing Waste Oil¹

Substance	Emission Factor (kg/10 ³ L) ^b	Emission Factor Rating ^f
Small Boilers:		
Particulate Matter (PM ₁₀)	6.12A ^c	C
Oxides of Nitrogen (NO _x)	2.28	C
Sulfur Dioxide (SO ₂)	17.6S ^d	C
Hydrogen Chloride (HCl)	7.9Cl ^e	C
Carbon Monoxide (CO)	0.6	D
Volatile Organic Compounds (Total VOCs)	0.12	D
Space Heaters - Vapourising burner:		
Particulate Matter (PM ₁₀)	ND	-
Oxides of Nitrogen (NO _x)	1.32	D
Sulfur Dioxide (SO ₂)	12S ^d	D
Hydrogen Chloride (HCl)	ND	-
Carbon Monoxide (CO)	0.2	D
Volatile Organic Compounds (Total VOCs)	0.12	D
Atomising burner:		
Particulate Matter (PM ₁₀)	6.8A ^c	E
Oxides of Nitrogen (NO _x)	1.92	D
Sulfur Dioxide (SO ₂)	12.8S ^d	D
Hydrogen Chloride (HCl)	ND	-
Carbon Monoxide (CO)	0.25	D
Volatile Organic Compounds (Total VOCs)	0.12	D

¹ Source: USEPA Document AP-42 (1996).

^b Units are kilograms of pollutant per thousand litres of blended waste oil burned.

^c A = weight % ash in fuel. Multiply numeric value by A to obtain emission factor. For example, if ash content is 5%, then A = 5.

^d S = weight % sulfur in fuel. Multiply numeric value by S to obtain emission factor. For example, if the sulfur content is 3.4%, then S = 3.4.

^e Cl = weight % chlorine in fuel. Multiply numeric value by Cl to obtain emission factor. For example, if the chlorine content is 3%, then S = 3.

^f See Section 4.4.

Table 36 - Emission Factors for Trace Elements from Small Boilers Firing Waste Oil^{1, c}

Metal	Small Boilers Emission Factor (kg/m ³) ^a	Space Heaters	
		Vapourising Burner (kg/m ³) ^a	Atomising Burner (kg/m ³) ^a
Antimony	BDL	4.1 E-05	5.4 E-04
Arsenic	1.3 E-02	3.0 E-04	7.2 E-03
Beryllium	BDL	BDL	2.2 E-04
Cadmium	1.1 E-03	1.8 E-05	1.4 E-03
Chromium (total)	2.4 E-03	2.3 E-02	2.2 E-02
Cobalt	2.5 E-05	6.8 E-04	6.2 E-04
Lead ^b	6.6L	0.05L	6L
Manganese	8.2 E-03	2.6 E-04	6.0 E-03
Nickel	1.3 E-03	6.0 E-03	1.9 E-02
Selenium	BDL	BDL	BDL

¹ Source: USEPA Document AP-42 (1996). Metals listed in this table represent metal species measured for waste oil combustors. Other metal species may also have been emitted, but were either not measured, or were present at concentrations below analytical detection limits.

^a Units are kg of metal emitted / m³ of waste oil burned. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b L = weight % lead in fuel. Multiply numeric value by L to obtain emission factor. For example, if lead content is 5%, then L = 5.

BDL = below detectable limit.

^c Emission Factor Rating - D. (See Section 4.4)

Table 37 - Emission Factors for Organic Compounds from Waste Oil Combustion^{1, b}

Substance	Space Heaters Emission Factor (kg/m ³) ^a	
	Vapourising Burner	Atomising Burner
<i>NPI-listed substances:</i>		
Phenol	2.9E-04	3.4E-06
Trichloroethylene	ND	ND
<i>Polycyclic aromatic hydrocarbons:</i>		
Naphthalene	1.6E-03	1.1E-05
Phenanthrene	1.3E-03	1.2E-05
Anthracene	1.3E-03	1.2E-05
Pyrene	8.5E-04	1.0E-06
Benz(a)anthracene	4.8E-04	ND
Chrysene	4.8E-04	ND
Benzo(a)pyrene	4.8E-04	ND
Total PAH's	6.5E-03	3.6E-05

Note: Only total annual emissions of polycyclic aromatic hydrocarbons (PAHs) require reporting to the NPI. Individual emission factors are provided to assist in assessment and validation of the factors provided

¹ Source: USEPA (1996). ND = no data. Substances in this table represent organic species measured for waste oil combustors. Other organic species may also have been present, but were either not measured, or were present at concentrations below analytical detection limits.

^a Units are kilograms of substance emitted per cubic meter (m³) of waste oil burned. 'E-05' etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Emission Factor Rating - D. (See Section 4.4)

3.4.4 Wood Combustion

Table 38 - Emission Factors for NO_x and SO₂^a from Wood Waste Combustion¹

Source	NO _x		SO ₂ ^b	
	Emission Factor (kg/tonne)	Emission Factor Rating ^c	Emission Factor (kg/tonne)	Emission Factor Rating ^c
Fuel cell/Dutch oven boiler	1.7E-3 to 0.8	C	0.005 - 0.1	B
Stoker boilers	0.33 - 1.8	C	0.005 - 0.1	B
FBC boilers	1.0	D	0.005 - 0.1	B

¹ Source: USEPA (1998). Emission factors are based on wet, as-fired wood waste with average properties of 50 weight % moisture and approximately 10.5 MJ/kg higher heating value. Before applying the factors to wood with moisture content other than 50%, or with a heating value other than 10.5 MJ/hr, multiply the factor by the appropriate ratio:

(100-M)/50, where M is the percent moisture;

(H/10.5), where H is the heating value.

^a Units are kilograms of substance emitted per tonne of wood waste burned. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Lower limit of range (in parenthesis) should be used for wood only and higher values for bark only. FBC = fluidised bed combustion.

^c See Section 4.4.

Table 39 - Emission Factors for Total VOCs and CO from Wood Waste Combustion¹

Source Category	Total VOCs ^b		CO	
	Emission Factor (kg/tonne) ^a	Emission Factor Rating ^c	Emission Factor (kg/tonne) ^a	Emission Factor Rating ^c
Fuel cell / Dutch oven boiler	0.09	C	0.-3 - 10.5	C
Stoker boilers	0.11	C	1-0 - 40	C
FBC boilers	ND	-	0.-4 - 1.2	

¹ Source: USEPA (1998). Emission factors are based on wet, as-fired wood waste with average properties of 50 weight % moisture and approximately 10.5 MJ/kg higher heating value. Before applying the factors to wood with moisture content other than 50%, or with a heating value other than 10.5 MJ/hr, multiply the factor by the appropriate ratio:

(100-M)/50, where M is the percent moisture;

(H/10.5), where H is the heating value.

^a Units are kilogram of substance emitted per tonne of wood waste burned.

^b Total VOCs = total volatile organic compounds. Emissions measured as total hydrocarbons.

FBC = fluidised bed combustion.

ND = no data.

^c See Section 4.4.

Table 40 - Emission Factors for Particulate Matter (PM₁₀), and Lead (Pb) from Wood Waste Combustion^{a,1}

Source	PM ₁₀		Lead	
	Emission Factor (kg/tonne)	Emission Factor Rating ^e	Emission Factor (kg/tonne)	Emission Factor Rating ^e
Bark-fired boilers:				
Uncontrolled	8.5	D	1.5 E-03	D
Mechanical collect-r - with flyash reinjection	5.5	D	ND	-
- without flyash reinjection	1.6	D	ND	-
Wet scrubber	1.3	D	ND	-
Wood/bark-fired boilers:				
Uncontrolled	3.3	E	ND	-
Mechanical collect-r - with flyash reinjection	2.8	E	1.6 E-04 ^b	D
- without flyash reinjection	0.85	E	1.6 E-04 ^b	D
Wet scrubber	0.24	E	1.8 E-04	D
Electrostatic precipitator	ND	-	8.0 E-06	D
Dry electrostatic granular filter ^d	0.12	E	ND	-
Wood-fired boilers:				
Uncontrolled	ND	-	ND	-
Mechanical collect-r - without flyash reinjection	1.3 ^c	D	1.6E-04	D
Electrostatic precipitator	ND	-	5.5E-04	D

¹ Source: USEPA (1998). Emission factors are based on wet, as-fired wood waste with average properties of 50 weight % moisture and approximately 10.5 MJ/kg higher heating value. Before applying the factors to wood with moisture content other than 50%, or with a heating value other than 10.5 MJ/hr, multiply the factor by the appropriate ratio:

(100-M)/50, where M is the percent moisture;

(H/10.5), where H is the heating value.

^a Units are kilograms of substance emitted per tonne of wood waste burned. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Due to lead's relative volatility, it is assumed that flyash reinjection does not have a significant effect on lead emissions following mechanical collectors.

^c Based on one test in which 61% of emitted PM was less than 10 micrometres in size.

^d From data on Dutch ovens. Assumed control efficiency is 94%.

ND = no data.

PM₁₀ = particulate matter less than 10 micrometres in aerodynamic diameter.

^e See Section 4.4.

Table 41 - Emission Factors for Trace Elements from Wood Waste Combustion¹

Trace Elements ^b	Average Emission Factor (kg/tonne) ^a	Emission Factor Rating ^d
Arsenic	4.27 E-05	B
Boron	4.0 E-04 ^c	D
Cadmium	1.06 E-05	B
Chlorine	3.9 E-03 ^c	D
Chromium (Total)	7.8 E-05	B
Chromium (VI)	2.3 E-05	D
Cobalt	6.5 E-05 ^c	D
Copper	1.87 E-04	B
Lead	2.23 E-04	B
Manganese	6.3 E-03	B
Mercury	2.58 E-06	C
Nickel	3.45 E-05	B
Selenium	2.3 E-05 ^c	E
Zinc	1.26 E-03	B

¹ Source: USEPA (1996). Emission factors are based on wet, as-fired wood waste with average properties of 50 weight % moisture and approximately 10.5 MJ/kg higher heating value. Before applying the factors to wood with moisture content other than 50%, or with a heating value other than 10.5 MJ/hr, multiply the factor by the appropriate ratio:

(100-M)/50, where M is the percent moisture;
(H/10.5), where H is the heating value.

- ^a Units are kilograms of substance emitted per tonne of wood waste burned. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. Eg. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.
- ^b Substances in this table represent metal species measured for wood waste combustors. Other metal species may also have been emitted, but were either not measured, or were present at concentrations below analytical limits.
- ^c Based on data from one test source.
- ^d See Section 4.4.

Table 42 - Emission Factors for Organics from Wood Waste Combustion^{a,1}

CASR Number	Substance ^b	Average Emission Factor (kg/tonne)	Emission Factor Rating ^g
Polycyclic Aromatic Hydrocarbons (PAHs)			
83-32-9	Acenaphthene	2.1 E-06	C
86-73-7	Fluorene	4.1 E-06	C
85-01-8	Phenanthrene	2.5 E-05	B
120-12-7	Anthracene	1.7 E-06	C
206-44-0	Fluoranthene	9.2 E-06	B
56-55-3	Benzo(a)anthracene	1.6E-06	C
207-08-9	Benzo(k)fluoranthene	3.8 E-07	E
	Benzo(b,k)fluoranthene	1.5 E-05	C
	Benzo(f)fluoranthene	5.4 E-07 ^c	E
50-32-8	Benzo(a)pyrene	3.4 E-08 ^c	E
191-24-2	Benzo(g,h,i)perylene	7.1 E-07	D
56-55-3	Benzo(a)phenanthrene	2.1 E-07	C
218-01-9	Chrysene	2.3 E-07	C
193-39-5	Indeno(1,2,3,c,d)pyrene	1.8 E-07	D
208-96-8	Acenaphthylene	2.4 E-05	B
	Methyl anthracene	7.0 E-05 ^c	D
91-20-3	Naphthalene	1.7E-03	C
129-00-0	Pyrene	8.4 E-06	B
	<i>TOTAL PAHs</i>	<i>1.9E-03</i>	<i>U</i>
Other NPI-Listed Substances			
108-95-2	Phenols	7.4 E-05	C
50-00-0	Formaldehyde	4.1 E-03	B
75-07-0	Acetaldehyde	9.6 E-04	B
71-43-2	Benzene	5.0 E-03	B
Polychlorinated dioxins and furans			
	2,3,7,8-Tetrachlorodibenzo-p-dioxin	1.8 E-11	D
	Total polychlorinated dibenzo-p-dioxins	6.0 E-09 ^{d,e}	C
	Total polychlorinated dibenzo-p-furans	1.5 E-08 ^{d,f}	C
	<i>TOTAL Polychlorinated dibenzo-p-dioxins and Polychlorinated dibenzo-p-furans</i>	<i>2.1E-08</i>	<i>U</i>

Note: Only total annual emissions of polycyclic aromatic hydrocarbons (PAHs) and dioxins and furans require reporting to the NPI. Individual emission factors are provided to assist in assessment and validation of the factors provided.

¹ Source: USEPA (1998). Emission factors are based on wet, as-fired wood waste with average properties of 50 weight % moisture and approximately 10.5 MJ/kg higher heating value. Before applying the factors to wood with moisture content other than 50%, or with a heating value other than 10.5 MJ/hr, multiply the factor by the appropriate ratio:

(100-M)/50, where M is the percent moisture;

(H/10.5), where H is the heating value.

^a Units are kilograms of substance emitted per tonne of wood waste burned. 'E-05', etc. indicates that you should multiply the preceding value by 10 to the power of the number after the 'E'. e.g. 2.8E-04 = 2.8 * 10⁻⁴, or 0.00028.

^b Substances in this table represent organic compounds measured for wood waste combustors with particulate controls. Other organic compounds may also have been emitted, but either were not measured, or were present at concentrations below analytical limits.

^c Based on data from one source test.

^d Emission factors are for total dioxins and furans, not toxic equivalents (Total 2,3,7,8 TCDD equivalents).

^e Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 6.5 E-07 kg/t with a D rating.

^f Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 2.75 E-07 kg/t with a D rating.

^g See Section 4.4

3.4.5 Bagasse Combustion

Bagasse is the matted cellulose fibre residue from sugar cane that has been processed in a sugar mill. Bagasse is a fuel of varying composition, consistency, and heating value. These characteristics depend on the climate, type of soil in which the cane is grown, variety and quality of cane, harvesting method, and the efficiency of the milling operations and boiler. In general, bagasse has a calorific value between 7 and 9 megajoules per kilogram.

Table 43 - Emission Factors for Bagasse-Fired Boilers¹

Substance	Emission Factor (kg/tonne) ^a	Emission Factor Rating ^b
PM ₁₀ (Dry Collector)	0.83	B
PM ₁₀ (Wet Collector)	0.18	B
SO ₂	<0.3	U
CO	2.64	B
NO _x	0.71	B
Total Uncontrolled PAHs ^b	0.001	

¹ Source: Sugar Research Institute, Mackay, Queensland (1998)

^a Units are kilograms of substance emitted per tonne of bagasse fired.

^b See Section 4.4

3.4.6 Predictive Emission Monitoring (PEM)

Predictive emission monitoring is based on developing a correlation between pollutant emission rates and process parameters. A PEM allows facilities to develop site-specific emission factors, or emission factors more relevant to their particular process.

Based on test data, a mathematical correlation can be developed which predicts emissions using various parameters.

Emission Estimation Techniques: Acceptable Reliability and Uncertainty

This section is intended to give a general overview of some of the inaccuracies associated with each of the techniques. The National Pollutant Inventory encourages the use of the most accurate emission estimation techniques possible. This section attempts to evaluate the available emission estimation techniques with respect to accuracy.

Several techniques are available for calculating emissions from boilers. The technique chosen is dependent on available data, and resources, and the degree of accuracy sought by the facility in undertaking the estimate. In general, site-specific data that is representative of normal operations is more accurate than industry-averaged data, such as the emission factors presented in Section 3.4 of this Manual

4.1 Direct Measurement

The use of stack and/or workplace health and safety sampling data is likely to be a relatively accurate method of estimating air emissions from boilers. However, collection and analysis of samples from facilities can be very expensive, and especially complicated where a variety of NPI-listed substances are emitted, and most of these emissions are fugitive in nature. Sampling data from one specific process may not be representative of the entire manufacturing operation, and may provide only one example of the facility's emissions.

To be representative, sampling data used for NPI reporting purposes needs to be collected over a period of time, and to cover all aspects of boiler operation.

In the case of CEMS, instrument calibration drift can be problematic, and uncaptured data can create long-term incomplete data sets. However, it may be misleading to assert that a snapshot (stack sampling) can better predict long-term emission characteristics. It is the responsibility of the facility operator to properly calibrate and maintain monitoring equipment and the corresponding emissions data

4.2 Mass Balance

Calculating emissions from boilers using a mass balance is likely to require a number of assumptions relating to the operation efficiency and procedures. Inaccuracies associated with the behaviour of individual substances during the combustion process, or other generalised assumptions made during calculations, can result in large deviations of emissions for boilers.

4.3 Engineering Calculations

Theoretical and complex equations or *models* can be used for estimating emissions from boilers.

Use of emission equations to estimate emissions from fuel combustion is a more complex and time-consuming process than the use of emission factors. Emission equations require more detailed inputs than the use of emission factors, but they do provide an emission estimate that is based on facility-specific conditions.

4.4 Emission Factors

Every emission factor has an associated emission factor rating (EFR) code. This rating system is common to EETs for all industries and sectors and therefore, to all Industry Handbooks. They are based on rating systems developed by the United States Environmental Protection Agency (USEPA), and by the European Environment Agency (EEA). Consequently, the ratings may not be directly relevant to Australian industry. Sources for all emission factors cited can be found in Section 5.0 of this document. The emission factor ratings will not form part of the public NPI database.

When using emission factors, you should be aware of the associated EFR code and what that rating implies. An A or B rating indicates a greater degree of certainty than a D or E rating. The less certainty, the more likely that a given emission factor for a specific source or category is not representative of the source type. These ratings notwithstanding, the main criterion affecting the uncertainty of an emission factor remains the degree of similarity between the equipment/process selected in applying the factor, and the target equipment/process from which the factor was derived.

The EFR system is as follows:

A	-	Excellent
B	-	Above Average
C	-	Average
D	-	Below Average
E	-	Poor
U	-	Unrated

5 Glossary of Technical Terms and Abbreviations

Term	Definition
C	Concentration
EF	Emission Factor
NO _x	Oxides of Nitrogen
NPI	National Pollutant Inventory
PAHs	Polycyclic Aromatic Hydrocarbons
TVOCs	Total Volatile Organic Compounds

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The following Emission Estimation Technique Manual is available at the NPI Homepage (<http://www.environment.gov.au/epg/npi/home.html>) and from your local Environment Protection Authority:

Emission Estimation Technique Manual for Fuel and Organic Liquid Storage.