Australian Government

Department of Sustainability, Environment, Water, Population and Communities

NPi

National Pollutant Inventory

Emission estimation technique manual
for

Fossil Fuel Electric Power Generation
Version 3.0

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Disclaimer

The Manual was prepared in conjunction with Australian States and Territories according to the *National Environment Protection (National Pollutant Inventory) Measure 1998.*

While reasonable efforts have been made to ensure the contents of this Manual are factually correct, the Australian Government does not accept responsibility for the accuracy or completeness of the contents and shall not be liable for any loss or damage that may be occasioned directly or indirectly through the use of, or reliance on, the contents of this Manual.

EMISSION ESTIMATION TECHNIQUES
FOR
FOSSIL FUEL ELECTRIC POWER GENERATION

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FOSSIL FUEL ELECTRIC POWER GENERATION

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1   Introduction

The purpose of all emission estimation technique (EET) manuals is to assist Australian 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 fossil fuel electric power generation. It considers combustion and non-combustion sources of emissions to air, water and land for the fossil fuel electric power generation industry. Other NPI guidance materials can be used to estimate the emissions from facilities that are not covered in this manual.

The activities covered by this Manual apply to facilities primarily engaged in the conversion of fossil fuels (particularly coal, natural gas, and liquid hydrocarbons) into electricity.

EET MANUAL: Fossil Fuel Electric Power Generation
ANZSIC 2006   2611

Please note that the ANZSIC code is part of NPI reporting requirements. *The NPI Guide* contains an explanation of the ANZSIC code.

The Electricity Supply Association of Australia Ltd (ESAA) (now **esaa,** the Energy Supply Association of Australia) wrote this Manual on behalf of and in conjunction with the Australian Government. It has been developed through a process of national consultation involving state and territory environment departments and key industry stakeholders.

The Manual was revised by ESAA in March 2002. The review document proposed a number of changes to the Manual based on recently available information and improved emission estimation techniques. The scientific review report (Reference: Pacific Power International 2002) and detailed references are held in the library of the Australian Department of Sustainability, Environment, Water, Population and Communities. The library can be contacted via the Department's Internet site (www.environment.gov.au).

The manual was again revised in December 2011, with changes made to emission factors for Mercury and mercury compounds, Particulate Matter ≤2.5μm and Polychlorinated dioxins and furans.

2   Process Description

The production of electricity occurs via chemical and mechanical actions, in Australia a majority of electricity is generated by converting the chemical energy stored within fossil fuels to electricity. Based on the 2009/2010 financial year, Australia's energy generation mix was approximately 242 TWh, 180 Twh (75%) from coal, 36 TWh (15%) from natural gas and 19 TWh (8%) from renewable sources (ABARE 2011). This guidance material documents the processes for the generation of electricity via the combustion of fossil fuels.

The process by which this occurs is as follows, chemical energy stored in solid fuel is used to generate steam. This steam then drives turbine that drives a generator to produce electricity. This process takes stored chemical energy to kinetic to electrical energy. This is similar to the way that power can be harnessed using hydro-electric and wind turbines.

Types of fossil fuel electricity generation facilities commonly found in Australia include:
- steam cycle facilities (commonly used for large base load facilities);
- open cycle gas turbines (commonly used for moderate sized peaking facilities);
- cogeneration and combined cycle facility (the combination of gas turbines or internal combustion engines with heat recovery systems); and
- internal combustion engines (commonly used for small remote sites or stand-by (emergency) generation).

Each of these facility types is considered in more detail in sections 2.1 to 2.4.

The combustion processes in fossil fuel power generation lead to the coincidental production of a number of NPI category 1 substances. Refer to *the NPI Guide* for more information about coincidental production and determining NPI reporting requirements (www.npi.gov.au).

For most Category 1 organic compounds, the coincidental production during combustion of fossil fuel will be below NPI threshold levels. In such cases, reporting may only be required if these organics are used in some other process at the facility. For example, reporting of some Category 1 substances may be triggered by liquid fuel use, in which case all emissions, including emissions from combustion, must be reported.

NPI reportable emissions from fossil fuel power stations are largely emissions from stacks, with water emissions from wet ash dams from some facilities also being a source of reportable emissions.

Chemical use within power stations tends to be relatively modest. Bulk chemicals are used to treat boiler water and cooling water for steam cycle facilities. Facilities need to assess whether the use of substances such as ammonia, chlorine and sulfuric acid will lead to the NPI reporting threshold being exceeded for those substances.

Coal storage and handling as well as ash storage may result in fugitive particulate emissions.

While maintenance activities such as degreasing of metal components may lead to emissions to air and water, the use of degreasers alone is unlikely to lead to the NPI reporting thresholds being exceeded for substances contained in these products.

This manual will assist you to estimate the emissions you may need to report to the NPI. It is your responsibility to report to the NPI if your facility exceeds reporting thresholds for NPI substances.

Refer to *the NPI Guide* (www.npi.gov.au) for further information NPI reporting thresholds and the steps involved in reporting to the NPI.

2.1 Steam Cycle Facility

Most of the electricity generated in Australia is produced by steam cycle facility. Figure 1 is a basic flow diagram for a steam cycle facility.

In the Australian context, a steam cycle facility is based on the combustion of fossil fuel in a boiler to produce high pressure and high temperature steam that is expanded through a steam turbine coupled to an electricity generator. The steam is condensed for reuse in the cycle. Steam cycle facilities are typically used for large base load electricity generation. Fuels commonly used in Australia are black coal in New South Wales, Queensland and Western Australia, brown coal (or lignite) in South Australia and Victoria and natural gas in South Australia, Victoria, and Western Australia.

Fuel oil, lighter oils, natural gas, brown coal briquettes, or liquefied petroleum gas (LPG) are commonly used as auxiliary fuels (e.g. during start-up procedures).

The boiler water is commonly treated to reduce corrosion and scaling in the boiler tubes. Cooling water used to condense the steam is often treated to reduce algal growth. Australian electricity generating companies (Reference: Personal communication from Electricity Supply Association 2004) highlight that the typical ranges of chemicals used in steam cycle power stations are:

Sulfuric acid	−up to 3840 tonnes per year
Ammonia	−up to 400 tonnes per year
Chlorine	−up to 102 tonnes per year

Wet cooling towers, commonly used to dissipate heat from the cooling water, may also be a minor source of particulate emissions.

Figure 1   Flow diagram for a steam cycle facility
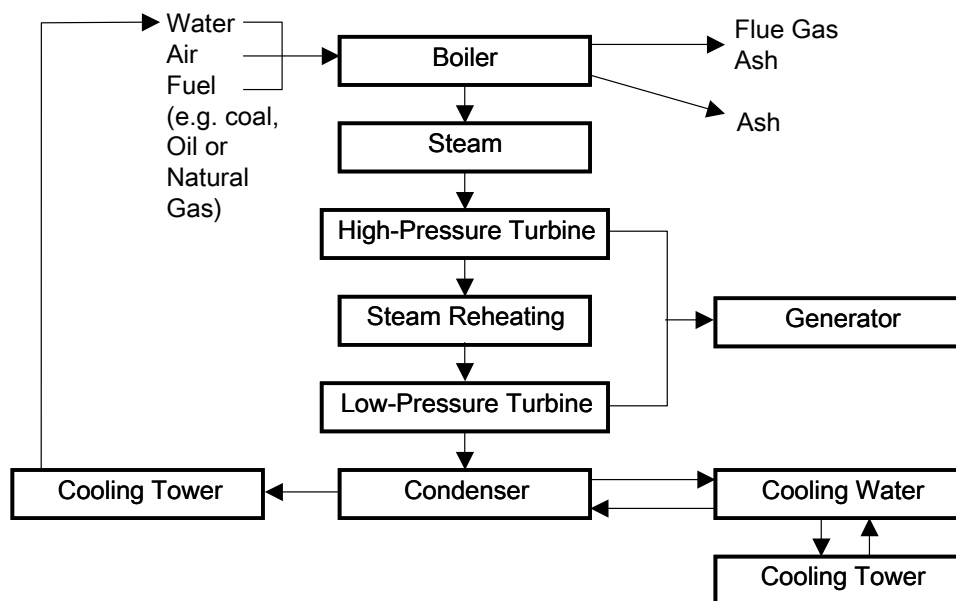
2.1.1   Coal-Fired Steam Cycle

The characteristics and composition of coal vary more than those for other fuels commonly used in electricity production. Indicative properties and composition of Australian coals used for electricity generation in Australia are included in Appendix B. Because of the variation in coal properties it is sometimes necessary to characterise different emission factors based on the different regions of coals in Australia.

Coals are usually pulverised prior to combustion. Particulate material (e.g. fly ash) in gas streams from the combustion process are captured by electrostatic precipitators or fabric filters (FF – also called baghouses). Ash is also extracted from the bottom of the boiler (bottom ash). Ash is transported to ash dams as a slurry, dense phase (paste), or dry. Fly ash from some power stations can be used as a resource, such as blending with cement.

Ash is composed of modified coal mineral matter, i.e. primarily compounds of silicon, aluminium, iron, calcium, manganese, potassium, sodium and titanium which form a matrix for traces of compounds of other metals. Ash composition depends on the coal properties, combustion technology and combustion conditions. Usually only very small amounts of ash are released to air.

The major emissions to air include carbon monoxide (CO), oxides of nitrogen (NO_x), sulfur dioxide (SO_2), emissions of metals (usually reported as metal & compounds for the NPI),organic compounds, carbon dioxide (CO_2) and water vapour. Carbon dioxide and water vapour are not NPI substances and are not reported to the NPI.

Coal and ash storage and handling facilities, and bulk hydrocarbon storage associated with power station operations, can lead to fugitive dust (i.e. coal or ash) and hydrocarbon emissions to air respectively.

2.1.2 Gas and Oil-Fired Steam Cycle

A major difference between coal-fired facilities and gas or oil-fired facilities, is that gas and oil facilities burn the fuel with minimal on-site processing before combustion. Generally, they do not have control equipment to collect particulate matter, as emissions of particulate matter are low for gas and generally low for oil.

Emissions to air include carbon dioxide (CO_2), water vapour, oxides of nitrogen (NO_x), carbon monoxide (CO), minor emissions of metals and metal compounds and organics, and sulfur dioxide (SO_2) for oil firing. Carbon dioxide and water vapour are not NPI substances and are not reported to the NPI.

Bulk hydrocarbon storage can be a source of emissions of Total Volatile Organic Compounds (Total VOCs) and of individual hydrocarbon substances due to evaporative losses from storage tanks.

2.2 Gas Turbine

The gas turbine cycle relies on the expansion of very high temperature compressed gas through a gas turbine connected to an electricity generator. To achieve this, air is compressed and mixed with the fuel (usually natural gas or distillate), and burnt in a combustion chamber(s) prior to expansion through the turbine. Figure 2 illustrates a simple open cycle gas turbine facility.

Gas turbine facilities are generally physically smaller and generally produce less electricity than steam cycle facilities and can be operated with short start-up periods. They are commonly used to generate electricity at intermediate and peak load periods. Gas turbines are also used as standby (i.e. emergency) facilities. Occasionally, gas turbine facilities are used for base load operations.

Emissions to air from a gas turbine facility include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), and minor emissions of metals and metal compounds and organics. Carbon dioxide and water vapour are not NPI substances and are not reported to the NPI.

Emissions to water from gas turbine facilities tend to be minor and relate to maintenance activities. Bulk hydrocarbon storage can be a source of emissions.

Figure 2 Flow diagram for a gas turbine facility

2.3   Cogeneration, including Combined Cycle Gas Turbine

Cogeneration is a special application of gas turbine or stationary engine technology. Cogeneration utilises the heat from the exhaust of the gas turbine, engine, or boiler, to heat water or raise stream for either domestic or industrial processes.

In combined cycle gas turbine facility, hot exhaust gases from the gas turbine are used to raise steam in a heat recovery steam generator. The steam is used to drive a steam turbine and electrical generator.

Cogeneration and combined cycle facilities can operate for considerable periods (to supply the heat and electricity requirements) and have overall thermal efficiencies (measure of energy utilisation) greater than simple gas turbines or stationary engine facilities.

Emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), hydrocarbons, and minor emissions of metals and metal compounds. Due to the higher conversion efficiencies achieved, emissions per unit of energy output from cogeneration/combined cycle facility are significantly lower than from an open cycle facility.

Emissions to water sources relate to the specific configuration of the heat recovery system, which may include water treatment and facility maintenance.

2.4   Internal Combustion (Stationary) Engines

Internal combustion engines using either petrol, natural gas, distillate, or LPG, coupled to electricity generators. Engines are commonly used to provide electricity in remote sites and stand-by (emergency) facilities.

Usually, internal combustion engines are relatively small units compared to those considered above.

Emissions to air include carbon dioxide (CO_2), water vapour, carbon monoxide (CO), oxides of nitrogen (NO_x), hydrocarbons, and minor emissions of metals and metal compounds. Bulk organic liquid storage may be a source of emissions.

Minor emissions to water can relate to engine cooling systems and facility maintenance.

3 Sources of Emissions

This section examines the emissions to the destination of air, land and water from fossil fuel electric power generation facilities. When reporting to the destination of pollutant emissions needs to be determined. For additional information about the destination of pollutant emissions see the *NPI Guide* (www.npi.gov.au).

3.1 Emissions to Air

Emissions to air can be categorised as either point sources, such as stacks, or fugitive sources, such as stockpiles.

Fugitive emissions

Fugitive emissions are emitted to air from sources not associated with a specific process, but scattered throughout the plant. Examples of fugitive emissions include dust from stockpiles, volatilisation of vapour from open vessels, and material 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. With appropriate management, these emission sources are expected to be minor for power stations. Emission factors are the usual method for estimating emissions from fugitive sources.

Refer to the *Fugitive Emissions NPI manual* for more information about estimating emissions from fugitive sources.

Point source emissions

Point source emissions are emitted from a stack or vent to air, usually for a specific section of a facility. Emission control equipment (e.g. an electrostatic precipitator or fabric filter (baghouse)) can be used to decrease point source emissions.

Summary of sources of emissions to air

Sources of emission to air for fossil fuel electric power generation include:

- fuel combustion products (from stacks);
- fugitive emissions from coal stockpiles and handling equipment;
- fugitive emission from ash storage;
- additives used for water treatment;
- organic compounds from bulk hydrocarbon storage tanks; and
- solvents used for degreasing metal components.

Table 1 summarises the emissions to air from fossil fuel electric power generation that are likely to be reportable to the NPI.

Table 1 - Likely emissions to air from fossil fuel electric power generation

Technology/Fuel	Inputs	Potential emissions to air
Gas turbine/distillate	distillate, auxiliary fuel (LPG), lubricants, degreasers, demineralised water water (cogeneration/combined cycle)	NO_X, SO_X, CO, particulates (including PM_{10} & $PM_{2.5}$), trace metals & compounds, Organic Compounds
Gas turbine/natural gas	natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers, demineralised water (cogeneration /combined cycle)	NO_X, SO_X (very low), CO, Organic Compounds and trace metals & compounds
Internal combustion engine/distillate	distillate, lubricants, degreasers, coolant	NO_X, SO_X, CO, trace metals & compounds, Organic Compounds, and PM_{10} & $PM_{2.5}$),
Internal combustion engine/natural gas, LPG	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	NO_X, SO_X (very low), CO, Organic Compounds, PM_{10}, and trace metals & compounds.
Steam cycle/natural gas	natural gas, auxiliary fuel (fuel oil, distillate, LPG), demineralised water, cooling water, lubricants, degreasers, water treatment chemicals	NO_X, CO, SO_X (very low), PM_{10} & $PM_{2.5}$,, Organic Compounds, and trace metals & compounds.
Steam cycle/oil	fuel oil, auxiliary fuel (natural gas, distillate, LPG), demineralised water, lubricants, degreasers	NO_X, SO_X, CO, particulates (including PM_{10} & $PM_{2.5}$), trace metals & compounds, Organic Compounds,
Steam cycle/pulverised coal	coal, demineralised water, auxiliary fuel (fuel oil, natural gas, briquettes), lubricants, degreasers, water treatment chemicals	NO_X, CO, SO_X, particulates (including PM_{10} & $PM_{2.5}$), fugitive dust, trace metals & compounds, Organic Compounds,

Notes:
1. CO - carbon monoxide
2. NO_X - oxides of nitrogen; include NO (nitric oxide) and NO_2 (nitrogen dioxide)
3. OCs - organic compounds; include total volatile organic compounds, and polycyclic aromatic hydrocarbons (PAHs)
4. SO_X - sulfur oxides; include SO_2 (sulfur dioxide), SO_3 (sulfur trioxide) and gaseous sulfates
5. PM_{10} – particulate matter that is less than 10 micrometres diameter
6. $PM_{2.5}$– particulate matter that is less than 2.5 micrometres diameter

3.2 Emissions to Water

For more information about emissions to water see *the NPI Guide* (www.npi.gov.au). Table 2 summarise possible emissions to water from fossil fuel electric power generation. There is currently no emission factors included for emissions to water. Sources of emissions to water are primarily from steam cycle facilities and can include:

- Ash transport wastewater and discharge from wet ash dams;
- Boiler and cooling tower blowdown;
- Coal stockpile runoff;
- Floor drains;

- Metal and boiler cleaning waste (gas and water sides); and
- Water treatment facility discharges.

Table 2 - Potential emissions to water from fossil fuel electric power generation

Technology/Fuel	Inputs	Potential emissions to water
Gas turbine/natural gas, distillate	Natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers, detergents, cooling system inhibitors	oil spills[1], degreasers[1], cooling system inhibitors, detergents
Internal combustion engine / natural gas, LPG, distillate	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	waste coolant[1], oil spills[1], degreasers[1], detergents
Steam cycle / pulverised coal, natural gas, oil	coal, demineralised water, auxiliary fuel (fuel oil, natural gas, briquettes), lubricants degreasers, water treatment chemicals/effluent, detergents	Chlorine, acids, alkalis, suspended solids, nitrogen, phosphorus, trace metals & compounds, oil spills[1], degreasers[1], detergents
Note: 1. due to infrequent, unplanned incidents		

3.3   Emissions to Land

For general information about emissions to land see *the NPI Guide* (www.npi.gov.au). Emissions to land are to the land on which the facility is located. Emissions to land include solid wastes, slurries, sediments, liquid spills and leaks, and chemicals used to control various environmental issues where these chemicals contain NPI-listed substances. These emission sources can be broadly categorised as:

- Groundwater;
- Surface impoundments of liquids and slurries; and
- Unintentional leaks and spills.

Table 3   Potential emissions to land from fossil fuel electric power generation

Technology/Fuel	Inputs	Potential emissions to land
Gas turbine/natural gas, distillate	natural gas, auxiliary fuel (distillate, LPG), lubricants, degreasers	oil spills[1], wastes
Internal combustion engine/natural gas, LPG, distillate	natural gas (or LPG), auxiliary fuel (distillate), lubricants, degreasers, coolants	oil spills[1], wastes
Steam cycle/pulverised coal, natural gas, oil	coal, demineralised water, auxiliary fuel (fuel oil, natural gas, briquettes), lubricants, degreasers, water treatment chemicals	ash, oil/chemical spills[1], metals & compounds, wastes
Note: 1. due to infrequent unplanned incidents		

4 NPI reporting thresholds.

The NPI has six different threshold categories and each NPI substance has at least one reporting threshold. If the 'use' of any NPI substance exceeds the threshold, all of the emissions of that substance from the facility must be reported. In the case of fossil fuel electricity generation, the main 'uses' are related to the combustion of fuel, mining of fuel and treatment of waste water. The transfer of wastes may also be applicable.

- *The NPI Guide* outlines detailed information on thresholds and identifying emission sources. The method involves identifying any NPI substances that may be used by your facility, or are components of materials used by your facility, and then calculating whether the quantity used exceeds the NPI threshold.

5 Emission Estimation Techniques - EETs

There are five types of emission estimation techniques (EETs) that may be used to estimate emissions from your facility:

- mass balance;
- engineering calculations (e.g. based on fuel composition);
- sampling or direct measurement;
- emission factors; and
- approved alternative EET.

More information about the five EET types can be found in *the NPI Guide*.

5.1 Using direct measurement to estimate NPI pollutant emissions

Stack sampling test reports often provide emissions data in terms of kg/hr or grams/$m^3_{STP,dry}$ (dry standard cubic metre). Annual emissions for NPI reporting can be calculated from this data using Equations (1) or (2) below. Stack tests for NPI reporting should be performed under representative (i.e. normal) operating conditions, and in accordance with the methods, or standards, approved by the relevant environmental authority. Tests conducted specifically for the NPI may differ from stack tests undertaken for a State or Territory licence condition, which may require the test be taken under maximum emissions rating (i.e. where emissions are likely to be higher than when operating under normal operating conditions). However, the acceptability of using existing monitoring program data and test methods should be checked with your local environmental regulatory authority.

This Section shows how to calculate emissions in kg/hr based on stack sampling data, and how to convert this to an annual emission figure. Calculations involved in determining PM_{10} emissions are used as an example, although the same general methodology is applicable for most of the substances listed on the NPI.

Concentration

$$\mathbf{C_{PM}} \quad = \quad \mathbf{C_f / V_{m,\,STP}} \qquad\qquad\qquad \textbf{Equation 1}$$

where:

C_{PM}	=	concentration of PM_{10} or gram loading (g/m^3)
C_f	=	filter catch (g)
$V_{m,STP}$	=	metered volume of sample at STP (m^3), dry.
STP	=	standard temperature and pressure. 1 atmosphere (101.325) kPa and 273 degrees Kelvin.

(The mass concentration of a gas (C_{gas}) is obtained directly by measurement results in units g/m^3, or converted from units such as g/m^3, or parts per million by volume (ppmv), which may be on a wet or dry basis.)

Emission

$$\mathbf{E_{PM_{10}}} \quad = \quad \mathbf{C_{PM} \times Q_d \times 3.6} \qquad\qquad\qquad \textbf{Equation 2}$$

where:

$E_{PM_{10}}$	=	hourly emissions of PM_{10} in kg/hr
Q_d	=	stack gas volumetric flow rate ($m^3_{STP,dry}$/s)
3.6	=	3,600 seconds per hour multiplied by 0.001 kilograms per gram

With regards to emission controls for PM_{10}, in the absence of measured data, or knowledge of the collection efficiency for a particular piece of equipment, default values can be used. The default values are:

- 99.2% for electrostatic precipitators; and
- 99.8% for fabric filters.

Other Efficiency rates for different control devices can be found in the NPI Emission estimation technique manual for combustion in boilers (http://www.npi.gov.au/publications/emission-estimation-technique/fboilers.html)

Example 1   Estimating PM$_{10}$ and PM$_{2.5}$ emission factors from monitoring information

PM$_{10}$ emissions calculated using Equations 1 and 2, and the stack sampling data based on USEPA Method 201A, for the following monitoring information:

Total sampling time	7,200 sec
Moisture collected	395.6 g
PM$_{2.5}$ cyclone (C$_{pm2.5}$)	0.01
PM$_{10}$ cyclone (C$_{pm10}$)	0.05
Filter catch (C$_f$)	0.0851 g
Average sampling rate	1.67E-04 m$^3_{STP,dry}$/s
Standard metered volume (V$_{m,STP}$)	1.185 m$^3_{STP,dry}$
Volumetric flow rate (Q$_d$)	8.48 m$^3_{STP,dry}$/s
Exhaust gas temperature	25°C {298K}).

$$C_{Total\ PM} = (C_f + C_{pm10} + C_{pm2.5}) / V_{m,\ STP}$$
$$= (0.085 + 0.05 + 0.01) / 1.185$$
$$= 0.122\ g/m^3_{STP,dry}$$

$$E_{Total\ PM} = C_{Total\ PM} \times Q_d \times 3.6$$
$$= 0.122 \times 8.48 \times 3.6$$
$$= \mathbf{3.74\ kg/hr}$$

$$C_{PM10} = (C_{pm10}) / V_{m,\ STP}$$
$$= (0.05) / 1.185$$
$$= 0.042\ g/m^3_{STP,dry}$$

$$E_{pm10} = C_{PM10} \times Q_d \times 3.6$$
$$= 0.042 \times 8.48 \times 3.6$$
$$= \mathbf{1.29\ kg/hr}$$

$$C_{PM2.5} = (C_{pm2.5}) / V_{m,\ STP}$$
$$= (0.01) / 1.185$$
$$= 0.008\ g/m^3_{STP,dry}$$

$$E_{pm2.5} = C_{PM2.5} \times Q_d \times 3.6$$
$$= 0.008 \times 8.48 \times 3.6$$
$$= \mathbf{0.26\ kg/hr}$$

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

To convert actual exhaust flows into STP, dry use:

$$Q_d \quad = \quad Q_a \text{ x } (1 - MC/100) \text{ x } (273/(T + 273)) \text{ x } (P_s/101.325) \qquad \textbf{Equation 3}$$

Where
Q_d	=	stack gas volumetric flow rate ($m^3{}_{STP,dry}$/s)
Q_a	=	actual gas volumetric flow rate (m^3/s)
MC	=	moisture content of stack gas (% by volume)
T	=	actual stack gas temperature (°C)
P_s	=	Absolute stack gas pressure (kPa)

(Source: South Australian Environment Protection Agency, 1995)

The most appropriate method for determining emissions to the environment via wastewater is to use direct measurement. However, you may use other EETs, particularly mass balances, for the purposes of reporting to the NPI.

Concentration and flow data already measured for environmental compliance conditions, such as discharge licences, can be used as a cost effective EET. Alternatively, the current sampling and analysis program may be modified to include the flows and concentrations of NPI substances that the facility is obliged to report.

Identifying all the emissions to water, followed by a review of the NPI list of substances, should indicate the materials that require reporting. The next step is to determine the most appropriate EET for the substances for which you are required to provide a report.

While discharges to groundwater are generally not allowed by environmental legislation, any known discharges may be relevant to the NPI.

5.2   Using CEMS Data

Using CEMS (Continuous Emission Monitoring Systems) data to estimate emissions can be applicable to power stations with suitable equipment installed, or for facilities that undertake medium term monitoring that is representative of the power station operations over a year.

To monitor SO_2, NO_x, Total VOCs, and CO emissions using a CEMS, you use a pollutant concentration monitor that measures concentration in parts per million by volume dry air (ppmvd). Flow rates should be measured using a volumetric flow rate monitor. Emission rates (kg/hr) are then calculated by multiplying the stack gas concentrations by the stack gas flow rates.

While it is possible to determine from this data the total emissions of an individual pollutant over a given time period (assuming the CEM operates properly all year long), an accurate emission estimate can be derived by adding the hourly emission estimates if the CEMS data is representative of typical operating conditions.

Although CEMS can report real-time hourly emissions automatically, it may be necessary to manually estimate annual emissions from hourly concentration data. This section describes how to calculate emissions for the NPI from CEMS concentration data. The selected CEMS data should be representative of operating conditions. When possible, data collected over longer periods should be used.

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 the facility's State or Territory environment authority as a requirement for NPI emission estimations.

Table 4   Example CEM Output Averaged for a Power Facility Firing Fuel Oil

Measurement	O$_2$ (%V)	Concentration (C) (ppmvd)				Gas Flow Rate (Q) (m$^3_{stp,dry}$/s)	Oil Use Rate (AR$_{hr}$) (tonnes/ hour)
		SO$_2$	NO$_X$	CO	TVOCs		
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

Hourly emissions can be based on concentration measurements as shown in Equation (4) and Example 2.

$$E_i = (C_i \times MW \times Q \times 3{,}600) / (V \times 1{,}000{,}000) \qquad \textbf{Equation 4}$$

where:

E_i	=	emissions of pollutant i, kg/hr
C_i	=	pollutant concentration in ppmvd
MW	=	molecular weight of the pollutant (kg/kg-mole)
Q	=	stack gas volumetric flow rate in m$^3_{(STP,dry)}$/s
3,600	=	3,600 seconds per hour
V	=	volume occupied by one mole of gas at standard temperature and pressure (22.4 m^3/kg-mole at 0°C and 1 atmosphere)

This may be applied to each hour that CEMS data is available for a year, and modified to account for time CEMS data is unavailable (weighted by load).

Alternatively, a estimation of emissions in kilograms per year can be calculated by multiplying the emission rate in kg/hr, by the number of actual operating hours (OpHrs) as shown in Equation (5) and Example 2.

$$E_{kpy,i} = (E_i \times OpHrs) \qquad \textbf{Equation 5}$$

where:

$E_{kpy,i}$	=	annual emissions in kg/year of pollutant i
E_i	=	hourly emissions in kg/hr of pollutant i
OpHrs =		annual operating hours in hr/yr

Emissions in kilograms of pollutant per tonne of fuel consumed can be calculated by dividing the emission rate in kg/hr, by the fuel consumption rate (tonnes/hr) during the same period (Equation (6)) as shown below. It should be noted that the emission factor calculated below assumes that the selected time period (that is, 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.

$$(E_{kpt,i})_1 = E_i / AR_{hr} \qquad \textbf{Equation 6}$$

where:

$(E_{kpt,i})_{1\,0}$	=	emissions of pollutant i per tonne of fuel oil consumed, kg/tonne
E_i	=	hourly emissions of pollutant i, kg/hr
AR_{hr}	=	fuel oil consumption, tonnes/hr

Example 2   Estimating sulfur dioxide emissions using CEMS data

This example shows how SO_2 emissions can be calculated using Equation (4) based on the average CEMS data for Time Period 1 shown in the Table 4.

$$E_{SO_2} = (C \times MW \times Q \times 3\ 600) / (V \times 1.0E+06)$$
$$C = 150.9 \text{ ppmv}$$
$$MW = 64$$
$$Q = 8.52 \text{ m}^3_{stp,dry}/s$$
$$V = 22.4 \text{ m}^3/\text{kg-mole}$$

$$E_{SO_2} = (150.9 \times 64 \times 8.52 \times 3\ 600) / (22.4E+06)$$
$$= 296\ 217\ 907 / 22\ 400\ 000$$
$$= 13.22 \text{kg/hr}$$

For time Period 2
$$E_{SO_2} = 12.56 \text{ kg/hr}$$

For time Period 3
$$E_{SO_2} = 11.2 \text{ kg/hr}$$

Say representative operating conditions for the year are:
Period 1   =   1,500 hr
Period 2   =   2,000 hr
Period 3   =   1,800 hr

Total emissions for the year   = $(13.22 \times 1500) + (12.56 \times 2000) + (11.2 \times 1800)$ kg
$$E_{kpy,SO_2} = 65\ 110 \text{ kg/yr}$$

Emissions, in terms of kg/tonne of oil consumed for time period 1, are calculated using Equation (6):

$$E_{kpt,SO_2} = E_{SO2} / AR_{hr}$$
$$= 13.22 / 290$$
$$= 4.56E-02 \text{ kg } SO_2 \text{ emitted per tonne of fuel oil consumed}$$

Similar calculations could be undertaken for the other time periods.

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

5.3   Using Fuel Analysis Data

Fuel analysis can be used to predict SO_2, metals and metal compounds, and other emissions based on application of mass conservation laws.

It is important if using fuel analysis data to ensure that data are collected and reported in an approved and consistent manner from representative fuel samples. Standards Australia AS 1038 Coal and Coke – Analysis and Testing (Reference: Standards Australia 2002) provides a useful guide to sampling and analysing coal and coke.

AS 1038 includes recommended procedures for the analysis of trace elements in coal and ash samples. Also included are required detection and precision limits. It is recommended that this document and its future drafts be referenced by facilities undertaking coal and or ash analysis.

Should relevant, recent coal concentration data not be available facilities have the option of using data in Table 17 and Table 18 of the Manual to obtain default concentration data. Data for some elements are presented as a concentration range in these tables.

EETs in tables in following sections are generally presented as either:

- kg/tonne – kilograms emitted per tonne of coal burnt on an "as received" basis. Attention should be paid to ensuring that coal data, including trace element concentration data, are reported on an as received basis. If reported on some other basis, such as dry ash free, moisture and ash characteristics should be obtained to enable conversion to an as received basis; or

- kg/PJ – kilograms emitted per petajoule of coal burnt on a higher heating value (HHV) basis.

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:

$$E_{kpy,i}   =   Q_f \times C_i \times (MW_p /EW_f) \times 1E\text{-}06 \times OpHrs \qquad \textbf{Equation 7}$$

where:

$E_{kpy,i}$	=	emissions of pollutant i, kg/yr
Q_f	=	fuel use (kg/hr)
C_i	=	pollutant concentration in fuel – ppm or mg/kg
MW_p	=	molecular weight of pollutant emitted (kg/kg-mole)
EW_f	=	elemental weight of pollutant in fuel (kg/kg-mole)
$OpHrs$	=	annual operating hours in hr/yr

For instance, sulfur dioxide emissions from oil combustion can be calculated based on the concentration of sulfur in the oil. This approach assumes complete conversion of sulfur to sulfur dioxide. Therefore, for every kilogram of sulfur (EW = 32) burned, two kilograms of SO_2 (MW = 64) are emitted. The application of this EET is shown in Example 3.

Example 3   Estimating sulfur dioxide emissions using fuel analysis data

This example shows how SO_2 emissions can be calculated from oil combustion, based on fuel analysis results, and the fuel use information. The power station is assumed to operate 150 hours per year on oil and the sulfur content of the oil is 1.17% (11,700 ppm).

$E_{kpy,SO2}$ can be calculated using Equation (7)

Assume:

Q_f	=	2,000 kg/hr
C_i	=	17,700 ppm
OpHrs	=	150 hr/yr

E_{kpy,SO_2}	=	Q_f x C_i x (MW_p / EW_f) x 1.0E-06 x OpHrs
	=	(2,000) x 11,700 x (64 / 32) x 1E-06 kg/hr x OpHrs
	=	46.8 kg/hr x 150 hr/yr
	=	7.0E+03 kg/year or 7,000 kg

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Equation 7 is based on the assumption that the pollutant in the fuel is emitted to atmosphere and is therefore most appropriate for volatile elements in coal, such as sulfur, fluorine and chlorine. For elements that are captured effectively, either in bottom ash or fly ash (i.e. most metals with the possible exception of mercury) equation 7 can result in overestimation of emissions. If coal concentrations and ash fractions are known, emission estimates may be able to be calculated without stack measurements by utilising mass balance techniques. See Section 5.4 for a discussion of the mass balance technique.

Fuel analysis data can also be used in emission factors and equations – See Sections 5.5 and 5.6 for discussion of these EETs.

5.4   Using a mass balance approach – Trace element behaviour during combustion

Trace elements have been classified into 3 general, overlapping classes according to their behaviour during combustion. To assist in estimating emissions of some elements, the following information on behaviour during combustion is relevant. The following summarises the characteristics of the three classes (Clarke and Sloss 1992).

Class I: Elements which are concentrated in the coarse residues (bottom ash) or are partitioned equally between coarse residues and flyash which is generally trapped by the particulate control systems.

Class II: Elements concentrated more in the flyash compared with coarse residues. Also enriched in fine-grained particles that may escape the particle control systems.

Class III: Elements which volatilise most readily. They may be concentrated in the vapour phase and depleted in the solid phases.

The NPI substances boron & compounds, mercury & compounds, fluorine compounds, chlorine and selenium & compounds may be emitted substantially in the gas phase: that is these five substances

generally fall into Class III or are intermediate between Classes II and III. For these substances, it may be worth analysing ash as well as coal samples to enable emissions to be determined via mass balance approach.

NPI substances such as mercury & compounds may be able to be determined by examining the mercury levels in the coal and ash. The mass balance approach requires the collection of reliable, representative data on element concentrations in coal and ash. It assumes that the difference between the quantity of the element measured in coal and collected in ash is emitted to the atmosphere. It is understood that this method is used by some American utilities in reporting mercury emissions to the USEPA Toxics Release Inventory (the US program similar to the NPI).

$$E_{\text{kg/tonne}} = \{C_i - [(A \times F \times CF) + (A \times B \times CB)]\} \times 1,000 \qquad \textbf{Equation 8}$$

Where:
E	=	emission of substance to air (kg/tonne)
C_i	=	concentration of element (substance) in coal (ppm or mg/kg)
A	=	weight fraction of ash in coal (as received)
F	=	fly ash fraction of total ash
B	=	bottom ash fraction of total ash
CF	=	fly ash concentration of element (substance) (ppm or mg/kg)
CB	=	bottom ash concentration of element (substance) (ppm or mg/kg)

Where possible, attempts should be made to ensure that the ash and coal samples analysed are derived from the source coal.

The approach could be simplified and made more conservative by ignoring the small amount of these elements that might be expected to report to bottom ash (i.e. B or CB above is zero).

Based on the reported variability in the emission of these elements, it is expected that coal and ash samples could also show considerable variability. If a mass balance approach were to be pursued, it is recommended that at least 6 coal and ash samples initially be collected and analysed for a statistically meaningful relationship.

Example 4 shows an example of the use of Equation 8.

Example 4   **Estimating fluoride compounds emissions based on fluoride levels in coal and ash**

This example shows how fluoride compounds emissions can be calculated using a mass balance approach.

$$E_{kg/tonne\ HF} = \{C - [(A \times F \times CF) + (A \times B \times CB)]\} \times 1E\text{-}03$$

Where: C = 250 mg fluoride / kg of coal
       A = 0.20
       F = 0.9
      CF = 500 mg fluoride /kg of coal
      B = 0.1
     CB = 50 mg/kg of bottom ash

$$E_{kg/tonneHF} = \{250 - [(0.20 \times 0.9 \times 500) + (0.2 \times 0.1 \times 50)]\} \times 1E\text{-}03$$

$$E_{kg/tonneHF} = \{250 - (90 + 1)\} \times 1E\text{-}03$$

$$E_{kg/tonneHF} = 0.159\ kg/tonne$$

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

5.5   Emission Factors

Emission factors usually relate 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 for a unit mass, volume, distance, or duration of the activity emitting the substance (e.g. kilograms of sulfur dioxide emitted per tonne of coal fired).

When available, it is preferable to use facility-specific information (e.g. monitoring data) for emission estimation.

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

$$E_{kpy,i} = AR \times EF_i \times [1 - (CE_i/100)] \qquad \textbf{Equation 9}$$

where :
    $E_{kpy,i}$ = emission rate of pollutant i, kg/yr
    AR = activity rate (fuel use), t/yr (AR = t/hr x Ophrs)
    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 are based on either fuel consumption (kg/tonne of fuel consumed), or energy consumption (kg/PJ or tonne/PJ of energy input). Where the emission factor is based on energy consumption, use:

Energy   =   [fuel consumption (tonnes/year) x higher heating value (MJ/kg)]/10^6
consumption (PJ/year)

Emission factors developed from measurements for a specific power station or process can sometimes be used to estimate emissions at other sites. If a company has 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. The emission factor must be approved by State or Territory environmental authorities prior to its use for NPI estimations.

Emission factors are commonly available for emissions to air, but currently are rarely available for emissions to water or land.

Many of the emission factors are derived from the *Compilation of Air Emission Factors, AP-42, Fifth Edition, Volume 1: Stationary Point and Area Sources* (Reference: USEPA 1995). Sections within AP-42 are updated at different times and hence the references to AP-42 may vary in date. The version adopted for this manual was current in 2011, including updates to the fuel oil combustion.

A discussion of the rating of emissions factors is contained in *the NPI Guide*.

There are currently no emission factors for emissions to land. It is recommended that other EETs, particularly direct measurement and mass balance, be applied to these emissions.

5.6   Using Engineering Calculations

There are engineering equations available to enable emissions of a number of trace metals and metal compounds, from black and brown coal combustion, to be estimated with a high degree of confidence. The advantage of these emission equations over simple generic emission factors is that they require the input of facility-specific information relating to fuel type and operating conditions.

The form of the emission equations is shown in Equation 10

$$\mathbf{E_{kg/PJ}} \quad = \quad \mathbf{K \ x \ [(C/A) \ x \ PM]^e \ kg/PJ} \qquad\qquad \textbf{Equation 10}$$

Where:

$E_{kg/PJ}$	=	emission factor for substance
K	=	a constant
C	=	concentration of metal in the coal, part per million by mass (as received basis)
A	=	weight fraction of ash in the coal. (10% ash is 0.1 ash fraction)
e	=	an exponent
PM	=	facility-specific emission factor for total particulate matter (kg/GJ) i.e. particulate matter emitted per GJ heat input.

$$\mathbf{PM_{kg/GJ}} \quad = \quad \mathbf{A \ x \ F \ x \ ER \ x \ 1,000/SE} \qquad\qquad \textbf{Equation 11}$$

Where:

A	=	weight fraction of ash in coal
F	=	fly ash fraction of total ash
ER	=	fraction of flyash emitted
SE	=	specific energy GJ/tonne as received

The application of these equations is demonstrated in example 5.

Example 5   Engineering calculations to estimate cadmium & compounds emissions from coal combustion

This example shows how cadmium & compounds emissions can be calculated using the relevant emission equation.

$$E_{kg/PJ\ Cd} \quad = \quad 2.17 \times [(C/A) \times PM]^{0.5}$$

Where:

C	=	0.5 mg/kg
A	=	0.2 (20% ash)
F	=	0.9 (90% flyash)
CE	=	99.8% (default for fabric filters)
ER	=	1- 99.8/100
	=	0.002
SE	=	24 GJ/tonne

PM	=	0.2 x 0.9 x 0.002 x1000 / 24
	=	0.015 kg/GJ

$$E_{kg/PJ\ Cd} \quad = \quad 2.17 \times [(0.5/0.2) \times 0.015]^{0.5}$$

$$= 0.42 \text{ kg cadmium \& compounds/PJ}$$

Should relevant, recent coal concentration data not be available facilities can use default concentration data from Table 17 and Table 18. Data for some elements are presented as a concentration range in these tables.

6   Emission Factors and Equations

Section 7 contains emission factors and equations for the estimation of NPI substances from electricity production. The list of tables below show the location of various emission factors and equation for different types of fossil fuel powered electricity generation processes. Emission factors are one of the techniques that can used to estimate emissions for the NPI.

The emission factors are applied as per the units of each factor and notes in the table. The equations from Table 5 to Table 18 are described in section 5.4 of this manual. Some of the emission factors are derived from equations.

In the Appendices, Table 16 indicates the NPI listed substances that are relevant to the fossil fuel electric power generation industry. Table 17 and Table 18 contain information on coal properties that may be useful for applying the equations to estimate emissions.

6.1   Emission Factors for Black Coal Combustion (Steam Cycle)

Table 5 to Table 7 include emission factors for NPI pollutant emissions to air for the combustion of black coal in boilers for electricity generation. Black coal includes bituminous and sub-bituminous coals. For this application, bituminous coals generally have volatile matter (VM) 14% or more dry, ash free (DAF), and heating values (gross specific energy) 26.5 MJ/kg ash-free, moist (AFM) or more (24.0 MJ/kg or more provided that the crucible swelling number is 1 or less). For sub-bituminous coals, the heating value range is 19 MJ/kg to 23.98 MJ/kg (AFM) inclusive, or to 26.48 MJ/kg (DAF) inclusive, provided that the crucible swelling number is zero or half (Reference: Standards Association of Australia 1987).

For a number of substances, equations to determine emissions factors are provided as well as generic emission factors. Where a facility has available facility-specific coal, coal ash data (such as coal ash levels (A) and concentration of the substance in coal (C)) and particulate collection efficiency data, these equations could be used instead of the simpler generic emission factors. Table 5 includes equations for antimony & compounds, arsenic & compounds, beryllium & compounds, boron & compounds, cadmium & compounds, chromium (III) compounds, chromium (VI) compounds, cobalt & compounds, copper & compounds, lead & compounds, manganese & compounds, mercury & compounds, nickel & compounds, $PM_{10,}$ sulfuric acid, and zinc & compounds.

For a number of substances, including boron & compounds, hydrogen fluoride, hydrochloric acid and mercury & compounds it is considered that a simple mass balance approach may yield reliable emission estimates (See Section 5.4).

Facility-specific emission factors for NO_X are given in Table 6. For a number of other substances it is expected that facilities may have facility-specific estimation techniques, which could be used in preference to the EETs presented in Table 5, as long as these facility-specific techniques have been approved by the environmental authority in the jurisdiction where the facility is located.

Example 6 shows how to estimate sulfur dioxide emission factor based on the sulfur level in coal.

Table 5   Emission Factors for Black Coal Combustion

Substance	Threshold category	Emission Estimation Technique (a) (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (b)
Ammonia	1	2.8E-04 (**6.0**)	U
Antimony & compounds	1	$0.675 \times [(C/A) \times PM]^{0.63}$ kg/PJ (**6.1**) 9E-06 (**l**)	A
Arsenic &compounds	1/2b	$2.73 \times [(C/A) \times PM]^{0.85}$ kg/PJ (**6.2**) 2.1E-04 (**l**)	A
Benzene	1	3.4 kg/PJ (**6.3**)	U
Beryllium & compounds	1/2b	$1.31 \times [(C/A) \times PM]^{1.1}$ kg/PJ (**6.4**) 1.1E-05 (**l**)	A
Boron & compounds	1	C x 1E-03 x 0.5 (**c**) (**6.5**)	U
Cadmium & compounds	1/2b	$2.17 \times [(C/A) \times PM]^{0.5}$ kg/PJ (**6.6**) 2.6E-05 (**l**)	A
Carbon monoxide	1/2a	2.5E-01 (**6.7**)	A
Chromium (III) compounds	1/2b	$0.95 \times 2.6 \times [(C/A) \times PM]^{0.58}$ kg/PJ (**c**) (**6.8**) 1.3E-04	A
Chromium (VI) compounds	1/2b	$0.05 \times 2.6 \times [(C/A) \times PM]^{0.58}$ kg/PJ (**c**)(**6.8**) 9.0E-05 (**l**)	A
Cobalt & compounds	1	$1.31 \times [(C/A) \times PM]^{0.69}$ kg/PJ (**6.9**) 5E-05 (**l**)	A
Copper & compounds	1/2b	$1.31 \times [(C/A) \times PM]^{1.1}$ kg/PJ (**6.10**)	U
Cumene	1	2.7E-06 (**6.11**)	U
Cyanide (inorganic) compounds	1	1.3E-03 (**6.12**)	D
Cyclohexane	1	3.4E-05 (**6.13**)	
Ethylbenzene	1	4.7E-05 (**14**)	U
Fluoride compounds	1/2b	7.5E-02 (**6.15**)	B
n-Hexane	1	3.4E-05 (**6.16**)	U
Hydrochloric acid	1/2a	0.6 (**6.17**)	B
Lead & compounds	1/2b	$2.87 \times [(C/A) \times PM]^{0.8}$ kg/PJ (**6.18**) 2.1E-04 (**l**)	A
Magnesium oxide fume	1/2b	0 (**6.19**)	U
Manganese & compounds	1	$2.71 \times [(C/A) \times PM]^{0.6}$ kg/PJ (**6.20**) 2.5E-04 (**l**)	A
Mercury & compounds	1/2b	**C x 8.1 E-04** for fabric filter and Electrostatic Precipitator plant (**l**) (**6.21**) **3.16 E-05** **For facility specific factors, refer to Table 7**	A
Nickel & compounds	1/2b	$2.84 \times [(C/A) \times PM]^{0.48}$ kg/PJ (**6.22**) 1.4E-04 (**l**)	A
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion (**e**) (**6.23**)	U
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion (**e**) (**6.23**)	U

Substance	Threshold category	Emission Estimation Technique (a) (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (b)
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2) (**f**)	1/2a	11.0 Uncontrolled, dry bottom, wall fired, bituminous	A
		5.5 Low NOx burner, dry bottom, wall fired, bituminous	A
		6.0 Uncontrolled, dry bottom, wall fired, sub-bituminous	A
		6.0 Dry bottom, wall fired. Post 1978 (**f**)	A
		3.7 Dry bottom, wall fired, sub-bituminous. Post 1978 (**f**)	A
		7.5 Uncontrolled, dry bottom, tangentially fired, bituminous	A
		4.9 Low NOx burner, dry bottom, tangentially fired, bituminous	A
		4.2 Uncontrolled, dry bottom, wall fired, sub-bituminous	A
		3.6 Dry bottom, wall fired, sub-bituminous. Post 1978 (**f**)	D
		15.5 Uncontrolled, wet bottom, wall fired, bituminous	E
		7.0 Wet bottom, tangentially fired, bituminous. Post 1978 (**f**)	E
		12.0 Wet bottom, wall fired, sub-bituminous	A
		16.5 Cyclone furnace, bituminous	C
		8.5 Cyclone furnace, sub-bituminous	D
		2.5 Fluidised bed, circulating	D
		7.6 Fluidised bed, bubbling	
		(**6.24**) See also Table 6	
PM_{10}	1/2a	A x 1000 x F x (1-ER/100) x FP (**c**) (**6.25**) 0.34 for fabric filter plant 0.96 for ESP plant	A
$PM_{2.5}$	2a	A x 1000 x F x (1-ER/100) x FP (**c&m**) (53%/92%) x 0.34 = 0.20 for fabric filter plant (29%/67%) x 0.96 = 0.42 for ESP plant	A
Polychlorinated dioxin & furans (g) (n)	2b	1E-05 kg/PJ 2.46E-10 kg/tonne for NSW Black Coal 2.34E-10 kg/tonne for Queensland Black Coal 2.04E-10 kg/tonne for WA Black Coal	D
Polycyclic aromatic hydrocarbons (**i**)	2a	1.0E-05 (**6.27**)	B-D
Selenium & compounds	1	6.5E-04 (**6.28**)	A
Sulfur dioxide	1/2a	19 x S for Bituminous coal 17.5 x for S. Sub-Bituminous coal (**6.29**)	A
Sulfuric acid	1	0.2 x S (**j**) (**6.30**)	U
Toluene (methylbenzene)	1	1.2E-04 (**6.31**)	U
TVOCs (**k**)	1a/2a	3E-02 dry bottom boilers, wall and tangentially fired 2E-02 wet bottom boilers 6.0E-01 cyclone furnace (**6.32**)	B
Xylenes	1	1.9E-05 (**6.33**)	U
Zinc and compounds	1	2.84 x $[(C/A) \times PM]^{0.48}$ kg/PJ (**6.34**)	U

Notes:

*Derived from Reference: USEPA 1998a (*unless otherwise stated).

a.   Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters

b.   Emission Factor Rating

c.   Pacific Power International 2002

d.   USEPA 2001

e.   For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

f.   Refer to Table 1.1-3 AP-42 (Reference: USEPA 1998a) for explanation and additional factors, if required. Post 1978 refer to boilers which, after this date, were required to meet the US New Source Performance Standards (NSPS)

g. Reference: USEPA AP-42, 1998a, lists the following as constituents of total PCDD/PCDF: total TCDD, total PeCDD, total HxCDD, total HpCDD, total OCDD, total TCDF, total PeCDF, total HxCDF, total HpCDF and total OCDF

h. Reference: UNEP 2001

i. Polycyclic Aromatic Hydrocarbons (PAHs) listed in AP-42 (Reference: USEPA 1998a) include: biphenyl, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(b,j,k)fluoranthene, benzo(g,h,i)perylene, chrysene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene, 5-methyl chrysene. It should be noted that this list is similar, but slightly different, to the NPI list of PAHs

j. Reference: USEPA 1998a

k. Total non-methane organic compounds from AP-42 (Reference: USEPA 1998a). Similar but slightly different from the NPI Total VOCs definition

l. Factors based on coal feed, as fired, and apply to controlled coal combustion for boilers utilising electrostatic precipitators or fabric filters

m. Refer to Table 1.1-6 AP-42 (Reference:USEPA 1998a) Cumulative Mass %

n. Converted to kg/tonne based on mean heating value in Table 17

C =   concentration of metal in the coal, part per million by mass or mg/kg (as received basis)

A =   weight fraction of ash in the coal. (10% ash is 0.1 ash fraction). Use 0.2 as default

F =   flyash fraction of total ash. Assume 0.9 as default

ER =   emission reduction efficiency (%). Defaults 99.8% for fabric filters and 99.2% for ESP

FP = PM_{10} fraction of emitted particles on a mass basis. Use 0.67 and 0.92 for ESP and fabric filters as default values respectively.

PM =   facility-specific emission factor for total particulate matter (kg/GJ) i.e. particulate matter emitted per GJ heat input (See example 5)

S =   percentage sulfur content of coal as fired (If sulfur content = 0.5%, S= 0.5)

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Example 6   Estimating sulfur dioxide emissions using emission factors

A power station with wall firing boilers uses 2 million tonnes per year of sub-bituminous coal. Estimate the annual emission of sulfur dioxide if the coal sulfur content is 0.5% (as fired). There is no sulfur reduction control.

Using Equation 9

$$E_{kpy,i} = AR \times EF \times [1 - (CE_i/100)]$$

$E_{kpy,SO2}$	=	emission of SO_2
CE_i	=	0
AR	=	2E+06 tonnes
EF	=	17.5S kg/tonne (from Table 5)
S	=	0.5%

Therefore,

Ekpy,i =		2E+06 x 17.5 x 0.5 x [1 - 0/100] kg/year
	=	1.75E+07 kg/year

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10-2 or 0.0738.

The facility-specific emission factors included in Table 6 are based on energy input (fuel consumption by higher heating value).

Table 6   Facility-Specific Emission Factors for Oxides of Nitrogen Emissions from Black Coal Combustion

POWER STATION	Emission Factor (kg/PJ)
NSW - Bayswater	2.20E+05
NSW - Eraring	2.20E+05
NSW - Mt Piper	2.20E+05
NSW - Liddell	2.60E+05
NSW - Munmorah	2.60E+05
NSW - Vales Point	2.60E+05
NSW - Wallerawang	2.60E+05
Queensland - Callide	5.23E+05
Queensland - Collinville	5.23E+05
Queensland - Gladstone	5.23E+05
Queensland - Stanwell	5.23E+05
Queensland - Swanbank	5.23E+05
Queensland - Tarong	5.23E+05
Western Australia - Muja A/B	4.62E+05

POWER STATION	Emission Factor (kg/PJ)
Western Australia - Muja C/D	3.06E+05
Western Australia - Collie	3.24E+05
Western Australia - Kwinana A	4.62E+05
Western Australia - Kwinana C	3.06E+05

Notes:
1. Reference: Department of the Environment, Sport and Territories 1996
2. Oxides of nitrogen expressed as nitrogen dioxide (NO_2)
3. Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Example 7   Determining oxides of nitrogen emissions for a power station using an emission factor

Determine the annual NO_X emissions for a power station with the same emission factor as Bayswater Power Station (operates 5,000 hours per year), with an emission factor of 220 tonne/PJ. Fuel higher heating value is 24 MJ/kg and fuel consumption is 50 tonnes/hour.

EFuel input (PJ/year) = [fuel usage (tonnes/year) x higher
                heating value (MJ/kg)]/10^6
                        = [50 (tonnes/hr) x 5000 (hr) x 24 MJ/kg)]/10^6
                        = 6.0 PJ/year

NO_X emissions ($E_{kpy,NOx}$)   = AR x EF x [1 - (CE_i/100)]   (Equation 9)

        AR   = Activity (energy input)
                        = 6.0 PJ/year
        CE_i = 0
        $E_{kpy,NOx}$ = 6.0 (PJ/year) x 220 (tonne/PJ) x 10^3 kg/year
                        = 1.32E+06 kg/year

Note:
Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Table 7   Coal-Specific Emission Factors for Mercury and compounds Emissions from Black Coal Combustion

POWER STATION	Emission Factor (kg/tonne)
NSW - Mt Piper	2.52E-05
NSW - Vales Point	9.10E-05
NSW - Wallerawang	1.86E-05
Queensland - Tarong	2.84E-05
Western Australia - Collie	3.04E-05
Western Australia - Muja A/B	3.03E-05
Western Australia - Kwinana	2.33E-05

6.2   Emission Factors for Brown Coal Combustion (Steam Cycle)

Brown coal or lignite is a low rank coal used for electricity generation in Victoria and South Australia. Brown coal usually has a high moisture content and low heating value (<19 MJ/kg (afm)). A small quantity of Victorian brown coal is converted into briquettes with low moisture content. Brown coal based briquettes are used as auxiliary fuel in some Victorian power stations.

(afm: ash free, moist) (Reference: Standards Association of Australia 1987).

Table 8 and Table 9 contain generic emission factors sourced from AP-42 for lignite and in some cases for black (bituminous and sub-bituminous) coal.

Where emission factors are derived from AP-42 factors for combustion of lignite, it is suggested that the factors be adjusted for Australian conditions, as shown in Equation 12. This is primarily because AP-42 factors are derived from tests from a number of facilities burning black coal and lignite. US lignite has moisture content of 20 – 40%, compared with ~ 40 - 60% for Victorian brown coal and ~28% for South Australian coal. Further, it should be recognised that fuel concentrations of relevant elements are likely to differ between Australian and US coals, making the emission factors less reliable than EETs based on local coal data, as discussed later in this section.

Adjustments to the AP-42 derived factors expressed as kg/tonne could be made. This includes factors for the following substances: PAH, polychlorinated dioxins and furans, trace metals, hydrochloric acid, hydrogen fluoride and category one organic substances.

Assuming that the AP-42 factors are based on coal with an average moisture content of 15%, Equation 12 describes how the AP-42 emission factors can be modified according to local moisture content.

Revised factor   = existing factor x ((100 – M1)/ (100 – 15))   Equation 12

Where:

$\quad\quad$ M1 $\quad$ = local moisture content (%)

For some substances in Table 8 and Table 9 equations can be used to derive the emission factors and are given as well as generic emission factors. Where a facility has available facility-specific coal concentration, coal ash fraction and particulate collection efficiency data, these detailed emission equations could be used instead of the simpler generic emission factors. Table 8 and Table 9 includes emission factor equations for antimony, arsenic & compounds, beryllium & compounds, boron & compounds, cadmium & compounds, chromium (III) compounds, chromium (VI) compounds, cobalt & compounds, copper & compounds, lead & compounds, manganese & compounds, mercury & compounds, nickel & compounds, PM_{10}, sulfuric acid, and zinc & compounds. These equations are the same as those recommended for black coal combustion, are based on AP-42 (Reference: USEPA 1998a) and require coal concentration, ash fraction and particulate collection efficiency data. As the equations are based on energy input they are applicable to all coal types, as noted in AP-42.

For a number of substances, including boron & compounds, hydrogen fluoride, hydrochloric acid and mercury & compounds it is considered that a simple mass balance approach could yield reliable emission estimates (See Section 6.4).

Table 9 contains emission factors specific to the combustion of Victorian brown coal. The factors are based on emission testing undertaken at the Victorian power stations, in the Latrobe Valley and at Anglesea, over a 3-year period. These factors are reported as emissions per tonne of fuel burnt (as received). The development of the emission factors involved a number of stack sampling tests in accordance with USEPA published methods described in Reference: Pacific Power International 2002.

Facility-specific emission factors for NOx and carbon monoxide are given in Table 10. For a number of other substances it is expected that facilities may have facility-specific estimation techniques, which could be used in preference to the EETs presented in Table 8 and Table 9, as long as these facility-specific techniques have been endorsed by the appropriate environmental authority.

Table 8   Emission Factors for Brown Coal Combustion

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (a)
Ammonia	1	1.3E-03 (**b**) (**6.37**)	U
Antimony & compounds	1	0.675 x [(C/A) x PM]$^{0.63}$ kg/PJ 1.75 E-06 (**c**) (**e**) (**6.1**)	A A
Arsenic &compounds	1/2b	2.73 x [(C/A) x PM]$^{0.85}$ kg/PJ 3.0E-06 (**c**) (**e**) (**6.2**)	A A
Benzene	1	3.6 E-06	A
Beryllium & compounds	1/2b	1.31 x [(C/A) x PM]$^{1.1}$ kg/PJ 1.7E-06 (**c**) (**e**) (**6.4**)	A A
Boron & compounds	1	C x 1E-03 x 0.5 (**b**) (**6.5**) 6.2E-03	U
Cadmium & compounds	1/2b	2.17 x [(C/A) x PM]$^{0.5}$ kg/PJ 2.5 E-06 (**c**) (**e**) (**6.6**)	A A
Carbon monoxide	1/2a	0.13 wall fired uncontrolled combustion (**d**) 0.24 wall fired, overfire air, Low NOx burners 0.05 tangentially fired, overfire air 0.08 atmospheric fluidised bed See also Table 9 (**6.7**)	C D D
Chromium (III) compounds	1/2b	0.95 x 2.6 x [(C/A) x PM] $^{0.58}$ kg/PJ (**b**) 9.0E-06 (**c**) (**e**) (**6.8**)	A A
Chromium (VI) compounds	1/2b	0.05 x 2.6 x [(C/A) x PM]$^{0.58}$ kg/PJ (**b**) 6.1E-06 (**c**) (**e**) (**6.8**)	A D
Cobalt & compounds	1	1.31 x [(C/A) x PM]$^{0.69}$ kg/PJ 2.7E-06 (**c**) (**e**) (**6.9**)	A A
Copper & compounds	1/2b	1.31 x [(C/A) x PM]$^{1.1}$ kg/PJ (**6.10**) 6.2E-06	U
Cumene	1	5.8E-08 (**6.12 & 6.37**)	U
Cyanide (inorganic) compounds	1	3.6E-06 (**6.37**)	D
Cyclohexane	1	3.6E-06 (**6.13 & 6.37**)	U
Ethylbenzene	1	3.6E-06 (**6.14 & 6.37**)	U
Fluoride compounds (as hydrogen fluoride)	1/2b	3.5E-02 (from a mass balance) (**6.15**)	B
n-Hexane	1	3.6E-06 (**6.16 & 6.37**)	U
Hydrochloric acid	1/2a	4.6E-01 (from a mass balance) (**6.17 & 6.37**)	B
Lead & compounds	1/2b	2.87 x [(C/A) x PM]$^{0.8}$ kg/PJ 8.1E-06 (**6.37**)	A A
Magnesium oxide fume	1/2b	0 (**6.19**)	
Manganese & compounds	1	2.71 x [(C/A) x PM]$^{0.6}$ kg/PJ 2.1E-04 (**6.37**)	A A
Mercury & compounds	1/2b	C x 9.8E-04 2.6E-05 (**6.37**)	A A
Nickel & compounds	1/2b	2.84 x [(C/A) x PM]$^{0.48}$ kg/PJ 3.4E-05 (**6.37**)	A A

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (a)
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion **(g) (6.23)**	U
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion **(g) (6.23)**	U
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2) **(h)**	1/2a	3.5 Dry bottom, tangentially fired 3.4 Tangentially fired, overfire air 6.5 Dry bottom wall fired. Pre 1978 **(i)** 3.2 Dry bottom, wall fired. Post 1978 **(i)** 2.3 Wall fired, overfire air, low NOx burners 7.5 Cyclone furnace 1.8 Atmospheric fluidised bed **(6.24)** Refer also to Table 9.	C C C C C
PM_{10}	1/2a	A x 1000 x F x (1-ER/100) x FP **(b) (6.25)** 1.7 x A for fabric filter 4.8 x A for ESP	A
$PM_{2.5}$	1/2a	A x 1000 x F x (1-ER/100) x FP **(b&o)** (53%/92%) x 1.7 x A = 0.98 x A for fabric filter plant (29%/67%) x 4.8 x A = 2.1x A for ESP plant	A
Polychlorinated dioxin & furans **(j)**	2b	1E-05 kg/PJ **(f) (6.26)** 9.48E-11 kg/tonne for Victorian Brown Coal 1.42E-10 kg/tonne for SA Brown Coal	U D
Polycyclic aromatic hydrocarbons **(l)**	2a	8.0 E-07 **(e) (6.27)**	B-D
Selenium & compounds	1	7.8 E-06 **(c) (e)** 0.7 kg/PJ **(6.28 & 6.37)**	A
Sulfur dioxide	1/2a	15 x S 5 x S (fluidised bed using limestone bed material) **(6.29)**	C C
Sulfuric acid	1	1.6 E-03 **(6.37)** 0.2 x S **(6.30) (m)**	U
Toluene (methylbenzene)	1	3.6 E-06 **(6.31 & 6.37)**	A
TVOCs **(n)**	1a/2a	2 E-02 wall and tangential firing 3.5 E-02 cyclone furnace 1.5 E-02 fluidised bed **(6.32)**	C C C
Xylenes	1	3.6 E-06 **(6.33 & 6.37)**	C
Zinc and compounds	1	7.4 E-05 **(6.37)** 2.84 x [(C/A) x PM]$^{0.48}$ kg/PJ **(6.34)**	U U

Notes:
Derived from Reference: USEPA 1998a (unless otherwise stated).

a.   Emission Factor Rating

b.   Reference: Pacific Power International 2002

c.   Factors based on coal feed, as fired, and apply to controlled coal combustion for boilers utilising electrostatic precipitators or fabric filters.

d.   Consider using wall-fired factor for tangentially fired boilers.

e.   Based on test results from facilities firing black coal (26 facilities) and lignite (1-2 facilities). Consider adjusting for moisture differences using Equation 12, with M1 =15

f.   Reference: USEPA 2001

g.   For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

h.   Refer to Table 1.1-3 AP-42 Reference: USEPA 1998a for explanation and additional factors, if required.

i.   Post 1978 refer to boilers which, after this date, were required to meet the US New Source Performance Standards (NSPS)

j.   AP-42 lists the following as constituents of total PCDD/PCDF: total TCDD, total PeCDD, total HxCDD,

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (a)

total HpCDD, total OCDD, total TCDF, total PeCDF, total HxCDF, total HpCDF and total OCDF

k.   Reference: UNEP 2001

l.   Polycyclic Aromatic Hydrocarbons (PAHs) listed in AP-42 include: biphenyl, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(b,j,k)fluoranthene,benzo(g,h,i)perylene, chrysene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene, 5-methyl chrysene. It should be noted that this list is similar, but slightly different, to the NPI list of PAHs

m.   Reference: USEPA 1998a

n.   Total non-methane organic compounds from AP-42 (Reference: USEPA 1998a). Similar but slightly different from the NPI Total VOCs definition

o.   Refer to Table 1.1-6 AP-42 (Reference:USEPA 1998a) Cumulative Mass %

p.   Converted to kg/tonne based on mean heating value in Table 18

C =   concentration of metal in the coal, part per million by mass or mg/kg (as received basis)

A =   weight fraction of ash in the coal. (10% ash is 0.1 ash fraction). See Appendix B-2 for default values for Latrobe, Anglesea and Leigh Creek coal.

F =   flyash fraction of total ash. Assume 0.9 as default.

ER =   emission reduction efficiency (%). Defaults 99.8 for fabric filters, 99.2 for ESP and 80 for cyclones

FP = PM_{10} fraction of emitted particles on a mass basis. Use 0.67 for ESP, 0.92 for Fabric filters and 0.67 for cyclones as default values.

PM =   facility-specific emission factor for total particulate matter (kg/GJ) i.e. particulate matter emitted per GJ heat input (See example 4)

S =   percentage sulfur content of coal as fired (If sulfur content = 0.5%, S= 0.5). For high sodium ash (Na2O>8%) use 11S. For low sodium ash (Na2O<2%) use 17S. If ash sodium content is unknown, use 15S.

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Table 9   Emission Factors for Victorian Brown Coal Combustion

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated (b)	EFR (a)
Ammonia	1	1.3E-03 **(6.37) (b)**	U
Antimony & compounds	1	1.7E-06 **(6.37) (c)**	U
Arsenic &compounds	1/2b	3.0E-06 **(6.37) (c)**	U
Benzene	1	3.6E-06 **(6.3) (6.37) (d)**	U
Beryllium & compounds	1/2b	1.7E-06 **(6.37) (c)**	U
Boron & compounds	1	6.2E-03 **(6.37) (b)**	U
Cadmium & compounds	1/2b	2.5E-06 **(6.37) (c)**	U
Carbon monoxide	1/2a	See Table 8& Table 10 **(6.7)**	
Chromium (III) compounds	1/2b	See Table 8	
Chromium (VI) compounds	1/2b	6.1E-06 **(6.37)**	U
Cobalt & compounds	1	2.7E-06 **(6.37) (c)**	U
Copper & compounds	1/2b	6.2E-06 (**6.37**)	U
Cumene	1	5.6E-08 **(6.11) (6.37) (d)**	U
Cyanide (inorganic) compounds	1	3.6E-06 **(6.12) (6.37) (c)**	U
Cyclohexane	1	3.6E-06 **(6.13) (6.37) (d)**	U
Dichloromethane	1	3.6E-06 **(6.37) (d)**	U
Ethylbenzene	1	3.6E-06 **(6.14) (6.37) (d)**	U
Fluoride compounds	1/2b	4.8E-04 **(6.37)**	B
n-Hexane	1	3.6E-06 **(6.16) (6.37)**	U
Hydrochloric acid	1/2a	See Table 8	
Lead & compounds	1/2b	8.1E-06 **(6.37) (b)**	U
Magnesium oxide fume	1/2b	0	
Manganese & compounds	1	2.1E-04 **(6.37) (b)**	U
Mercury & compounds	**1/2b**	**2.6E-05 (6.37) (c)**	**U**
Nickel & compounds	1/2b	3.4E-05 **(6.37) (b)**	U
Nickel carbonyl	1/2b	0 (Not emitted during electricity generation by combustion) **(e)**	
Nickel subsulfide	1/2b	0 (Not emitted during electricity generation by combustion) **(e)**	
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2)	1/2a	See Table 8 & Table 10. **(6.24)**	
PM_{10} & $PM_{2.5}$	1/2a	See Table 8	
Polychlorinated dioxin & furans	2b	See Table 8	
Polycyclic aromatic hydrocarbons	2a	8.0E-07 **(6.37)**	U
Selenium & compounds	1	7.8E-06 **(6.37) (c)**	U

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated (b)	EFR (a)
Sulfur dioxide	1/2a	See Table 8	
Sulfuric acid	1	1.6E-03 **(6.37) (b)**	U
Tetrachloroethylene	1	3.6E-06 **(6.37) (d)**	U
Toluene (methylbenzene)	1	3.6E-06 **(6.31) (6.37) (d)**	U
Total VOCs	1a/2a	See Table 8	
Trichloroethylene	1	3.6E-06 **(6.37)**	U
Xylenes	1	3.6E-06 **(6.33) (6.37) (d)**	U
Zinc and compounds	1	7.4E-05 **(6.37) (c)**	U

Notes:

Emission factors presented in Reference: Pacific Power International 2002, as provided by the Victorian electricity generators

a. Emission Factor Rating
b. Emission factors are based on typical Australian facility measurements.
c. Emission factors are based on typical Australian facility measurements. Measured values ranged from less than detection limit to actual values. Emission factors based on the median of the range of values. Less than detection limit values were halved.
d. Emission factors are based on typical Australian facility measurements. Measured values all less than detection limit. Emission factors based on the median of half detection limit values.
e. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10-2 or 0.0738.

Example 8   Estimating sulfur dioxide emissions using an engineering calculation based on the fuel composition

Calculate the annual sulfur dioxide emission to air from a brown coal fired power station using 4 million tonnes of brown coal per year. The coal has a sulfur content of 0.8% (as fired). 10% of the sulfur is retained in the ash.

Using Equation 5

$$E_{kpy,i} = AR \times EF [1 - (CE_i/100)]$$

$E_{kpy,SO2}$ =   emission of SO_2
CE_i =   10%
AR =   4.0E+06 tonnes/yr
EF =   15 x S kg/tonne (from Table 10)
S =   0.8%

Therefore,

$E_{kpy,i}$ =   4.0E+06 x 15 x 0.8 [1 - (10/100)] kg/year
        =   4.32E+07 kg/year

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10-2 or 0.0738.

Table 10 emission factors are based on energy input.

Table 10   Power Station Specific Emission Factors for Brown Coal Combustion (NO$_X$, CO)

POWER STATION	EMISSION FACTOR (kg/PJ)	
	NO$_X$ (note 3)	CO
Hazelwood, Victoria	1.51E+05	1.4E+04
Loy Yang A, Victoria	1.36E+05	1.8E+04
Loy Yang B, Victoria	1.36E+05	1.8E+04
Morwell, Victoria	1.51E+05	1.4E+04
Yallourn, Victoria	1.06E+05	2.0E+04
Northern, South Australia	1.36E+05	1.7E+04
Notes: 1. Reference: Department of the Environment, Sport and Territories 1996 2. PJ petajoule (1E+15 joule) 3. Oxides of nitrogen expressed as nitrogen dioxide (NO$_2$) Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.		

6.3   Emission Factors for Natural Gas Combustion (Steam Cycle)

The default emission factors in Table 10 are primarily derived from the Compilation of Air Emission Factors (Reference: USEPA 1998a), and hence relate to United States natural gas. Where possible, data for the facility specific natural gas supply should be used

Table 10 also has emission factors for the primary or criteria combustion pollutants (sulfur dioxide, nitrogen oxides, carbon monoxide, PM$_{10}$ and Total VOCs), which, in some cases, have been updated since the Manual was first published. In addition, Table 10 includes emission factors for a number of Category 1 organic substances: benzene, formaldehyde, toluene and n-Hexane. The use or emission of these substances may not exceed the 10 tonne reporting threshold – it is estimated that at least 13PJ of gas would need to be burnt at a facility to trigger the threshold for n-hexane, which has the highest factor of the four substances. Gas burning facilities should check their fuel use to determine whether the reporting threshold for these Category 1 substances is exceeded.

Facility specific emission factors are in Table 15.

Table 11   Emission Factors for Natural Gas Combustion – Steam cycle

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated	EFR (a)
Ammonia	1	1.3E+02 (**6.0**)	U
Antimony & compounds	1	No data	
Arsenic &compounds	1/2b	8.5E-02	E
Benzene	1	8.8E-01	B
Beryllium & compounds	1/2b	5.1E-03 (**b**)	E
Boron & compounds	1	No data	
Cadmium & compounds	1/2b	4.6E-01	D
Carbon monoxide	1/2a	3.5E+04 Wall fired 1.0E+04 Tangential firing - uncontrolled 4.1E+04 Tangential – flue gas recirculation See also Table 11	B
Chromium (III) compounds (**c**)	1/2b	5.6E-01 (**6.8**)	D
Chromium (VI) compounds (**c**)	1/2b	3.0E-02 (**6.8**)	D
Cobalt & compounds	1	3.5E-02	D
Copper & compounds	1/2b	3.6E-01	D
Cyanide (inorganic) compounds	1	No data	
Formaldehyde	1	3.2 E+01	B
Fluoride compounds	1/2b	No data	
n-Hexane	1	7.6E+02 Note AP-42 (Reference: USEPA 1998a) factor is for hexane not n-Hexane	E
Hydrochloric acid	1/2a	No data	
Lead & compounds	1/2b	2.4E-01	D
Magnesium oxide fume	1/2b	No data (**6.19**)	
Manganese & compounds	1	1.6E-01	D
Mercury & compounds	1/2b	1.1E-01	D
Nickel & compounds	1/2b	8.8E-01	C
Nickel carbonyl	1/2b	0 Not emitted during electricity generation by combustion (**d**)(**6.23**)	U
Nickel subsulfide	1/2b	0 Not emitted during electricity generation by combustion (**d**) (**6.23**)	U
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2)	1/2a	**Large Wall fired boilers** (>100 GJ/hr heat input) 11.8E+04 Uncontrolled (**e**) 8.0E+04 Uncontrolled (**e**) 5.9E+04 Controlled - Low NOx burners 4.2E+04 Controlled – Flue gas recirculation **Small wall fired** (<100 GJ/hr heat input) 4.2E+04 Uncontrolled 2.1E+04 Controlled – Low NOx burners 1.3E+04 Controlled - Low NOx /flue gas recirc. **Tangential-fired boilers (All sizes)** 7.2E+04 Uncontrolled 3.2E+04 Controlled – Flue gas recirculation See also Table 11 (**6.24**)	A A A D B D C A D
PM_{10} & $PM_{2.5}$(**f**)	1/2a	3.2E+03 Uncontrolled (AP-42 Reference: USEPA 1998a)	D
Polychlorinated dioxin & furans	2b	5E-07 kg/PJ (**g**) (**6.26**)	U
Polycyclic aromatic hydrocarbons (**b**,**h**)	2a	2.9E-01 kg/PJ(**6.27**)	E
Selenium & compounds	1	1.0E-02 (**b**)	E

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated	EFR (a)
Sulfur dioxide	1/2a	2.5E+02 (**i**)	A
Sulfuric acid	1	No data (**6.30**)	
Toluene	1	1.4	C
TOCs	1a/2a	2.3E+03	C
Zinc and compounds	1	1.2E+01	E

Notes:

Reference: USEPA 1998a (Tables 1.4-1 to 1.4-4) and assuming an average higher heating value of 38 MJ/Nm^3

a. Emission Factor Rating

b. Based on method detection limits

c Total chromium assumed to be 0.95% chromium(III) and 5% chromium(VI). Reference: Pacific Power International 2002

d. For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

e. NSPS = New Source Performance Standard (USA). Post NSPS are boilers greater than 250 GJ/hr heat input which commenced after August 1971, and boilers between 100 and 250 GJ/hr heat input which commenced after June 1984

f. Total PM – assumes all PM_{10} and $PM_{2.5}$ and included filterable and condensable fractions.

g. Reference: UNEP 2001

h. Polycyclic Aromatic Hydrocarbons (PAHs) listed in AP-42 include: biphenyl, acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(b,j,k)fluoranthene,benzo(g,h,i)perylene, chrysene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene, 5-methyl chrysene. . It should be noted that this list is similar, but slightly different, to the NPI list of PAHs.

h. Derived from Table 1.4-2, AP-42 (Reference: USEPA 1998a), assuming 100% conversion of sulfur to SO_2, a natural gas sulfur content of 4,600 g/1E+06Nm^3 and higher heating value of 38 MJ/Nm^3

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

Table 12   Facility Specific Emission Factors for Natural Gas Combustion (NO$_X$, CO and Total VOCs)

SUBSTANCE	EMISSION FACTOR (kg/PJ)			
	Wall-fired	**Rating**	**Tangentially fired**	**EFR (e)**
Carbon monoxide (CO)	6.0E+03 (**b**)	U	3.5E+04 (**a**)	U
	1.6E+04 (**c**)	U		
Oxides of nitrogen (NO$_X$ expressed as nitrogen dioxide, NO$_2$)	1.17E+05 (**b**)	U	9.7E+04 (**a**)	U
	2.26E+05 (**c**)	U		
Total Volatile Organic Compounds (Total VOCs)	6.0E+02 (**b**)	U	6.0E+02 (**a**)	U
	6.0E+02 (**c**)	U		

Notes:
 Emission factors are in tonnes of emissions per PJ of heat input (based on the higher heating value)
a.   for Newport Power Station, Victoria (1)
b.   for Torrens Island Power Station, South Australia (1)
c.   for Kwinana B Power Station, Western Australia (1)
d.   Reference: Department of the Environment , Sport and Territories 1996
e.   Emission Factor Rating

Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10^{-2} or 0.0738.

6.4   Emission Factors for Oil Combustion (Steam Cycle)

Fuel oil and distillate are commonly used as auxiliary fuels in steam cycle boilers. Hence, their use is relatively minor when compared with coal and natural gas. The following tables give emission factors for fuel oil and distillate.

Table 13   Emission Factors for Oil (fuel oil and distillate) Combustion: Steam Cycle

Substance Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated					
	Fuel Oil			**Distillate**		
	kg/PJ	**kg/kL**	**EFR (a)**	**kg/PJ**	**kg/kL**	**EFR**
Ammonia	2.4E+03 (**6.0**)	9.6E-02	U	No data (**r**)	No data (**r**)	
Antimony & compounds	1.6E+01	6.3E-04	E	No data (**r**)	No data (**r**)	
Arsenic &compounds	4.0	1.6E-04	C	1.7	8.5E-05	E
Benzene	6.4E-01	2.6E-05	C	No data (**r**)	No data (**r**)	
Beryllium & compounds	8.3E-02	3.3E-06	D	1.3	5.1E-05	E
Boron & compounds	No data (**r**)	No data (**r**)		No data (**r**)	No data (**r**)	
Cadmium & compounds	1.2	4.8E-05	C	1.3	5.1E-05	E
Carbon monoxide (**b**)	1.5E+04	6.0E-01	A	1.5E+04	6.0E-01	A
Chromium (III) compounds	1.8 (**c**)	7.2E-05	U	9.0E-01 (**d**)	3.6E-05	U
Chromium (VI) compounds	7.4E-01	3.0E-05	C	3.9E-01 (**d**)	1.5E-05	U
Cobalt & compounds	1.8E+01	7.2E-04	D	No data (**r**)	No data (**r**)	
Copper & compounds	5.3	2.1E-04	C	2.6	1.0E-04	E
Cumene	No data (**r**)	No data (**r**)		No data (**r**)	No data (**r**)	

Substance Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated					
	Fuel Oil			Distillate		
	kg/PJ	kg/kL	EFR (a)	kg/PJ	kg/kL	EFR
Cyanide (inorganic) compounds	No data (r)	No data (r)		No data (r)	No data (r)	
Cyclohexane	No data (r)	No data (r)		No data (r)	No data (r)	
Ethylbenzene	1.9E-01	7.6E-06	U	No data (r)	No data (r)	
Fluoride compounds	1.1E+02	4.5E-03	D	No data (r)	No data (r)	
Formaldehyde (methyl aldehyde)	9.9E+01	4.0E-03	C	No data (r)	No data (r)	
n-Hexane	No data (r)	No data (r)		No data (r)	No data (r)	
Hydrochloric acid	No data (r)	No data (r)		No data (r)	No data (r)	
Lead & compounds	4.5	1.8E-04	C	3.9	1.5E-04	E
Magnesium oxide fume	No data (r)	No data (r)		No data (r)	No data (r)	
Manganese & compounds	9.0	3.6E-04	C	2.6	1.0E-04	E
Mercury & compounds	3.4E-01	1.4E-05	C	1.3	5.1E-05	E
Nickel & compounds	2.5E+02	1.0E-02	C	1.3	5.1E-05	E
Nickel carbonyl – (Not emitted during electricity generation by combustion) (e)	0		U	0	0	U
Nickel subsulfide – (Not emitted during electricity generation by combustion) (e)	0		U	0	0	U
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2) (f)	Boilers > 100 GJ/hr 1.4E+05 (g) 1.2E+05 (h) 9.7E+04 (i) 7.9E+04 (j) Boilers < 100 GJ/hr 1.6E+05	5.6 4.8 3.8 3.1 6.6	A B A E A	6.1E+04	2.4	A
PM_{10}	1.8E+04 x A (uncontrolled) 1.8E+02 x A (k, l & o)	7.1E-01 x A 7.1E-03 x A	C E	3.0E+03 3.0E+01	1.2E-01 1.2E-03 (l)	E U
$PM_{2.5}$	1.2E+04 x A (uncontrolled) 1.2E+02 x A (k, l & o)	4.6E-01 x A 4.6E-03 x A	C E	7.2E+02 7.2E+00	2.9E-02 2.9E-04 (l)	E U
Polychlorinated dioxin & furans (m)	2.5E-06	1.02E-10	U	5E-07	2.01E-11	U
Polycyclic aromatic hydrocarbons (n)	1.8E-01	7.3E-06	C	No data (r)	No data (r)	
Selenium & compounds	2.0	8.2E-05	C	6.5	2.6E-04	E
Sulfur dioxide	4.7E+05 x S (o)	1.9+01 x S	A	4.3E+05 x S (o)	1.7+01 x S	A
Sulfuric acid (p)	No data (r)	No data (r)		No data (r)	No data (r)	
Toluene (methylbenzene)	1.9E+01	7.4E-04	U	No data (r)	No data (r)	
TVOCs (p)	2.3E+03	9.2E-02	A	6.1E+02	2.4E-02	A
Xylenes	3.3E-01	1.3E-05	U	3.3E-01	1.3E-05	U
Zinc and compounds	8.7E+01	3.5E-03	D	1.7	6.8E-05	E

Notes:

Reference: USEPA 1998c unless otherwise noted

Emission factors for fuel oil are those applicable to low-grade oil No 6 residual oil. Based on an energy value of 40.1 GJ/kL

a.   Emission Factor Rating
b.   For Bell Bay use 1.5E+04 kg/PJ Reference: Department of the Environment, Sport and Territories 1996
c.   Chromium (III) determined from factors for Total Chromium and Chromium. Chromium (III) = Total Cr(III + VI) – Cr(VI).
d.   Chromium (III) assumed to be 0.7 x Total chromium, based on speciated results for fuel oil combustion. (Total Chromium 1.3 kg/PJ)
       Chromium (VI) assumed to be 0.3 x Total chromium, based on speciated results for fuel oil combustion. (Total Chromium 1.3 kg/PJ)
e.   For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000
f.   For Bell Bay use 1.9E+05 kg/PJ Ref. (1)
g.   Normal firing
h.   Normal firing with Low NO_x burners
i.   Tangential firing
j.   Tangential firing with Low NOx burners.
k.   Particulate emission factors for residual oil combustion without emission control are, on average, a function of fuel oil grade and sulfur content. Use A = 1.12 x (S) + 0.37 (see note o. below)
l.   Assuming control efficiency of 99%
m.   Reference: UNEP 2001 using a TEF conversion factor of 17
n.   PAHs listed in Reference: USEPA 1998a include acenaphthene, acenaphthylene, anthracene, benz(a)anthracene, benzo(b,k)fluoranthene, benzo(g,h,i)perylene, chrysene, dibenzo(a,h)anthracene, fluoranthene, fluorene, indo(1,2,3-cd)pyrene, naphthalene, phenanthrene, pyrene. It should be noted that this list is similar, but slightly different, to the NPI list of PAHs
o.   **S** indicates that the weight percentage of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1
p.   Reference: USEPA 1998a
q.   Taken as non-methane total organic compounds. For Bell Bay Power Station, Tasmania use 2.1E+03 kg/PJ Reference: Department of the Environment, Sport and Territories 1996
r.   The emission factor is zero unless there is relevant information in other NPI manuals or NPI documentation, or the operators of the reporting facility are aware of other information that allows them to estimate the facility's emissions
s.   Reference: USEPA 2010 1.3-6
       $PM_{2.5}$ emissions are based on a ratio of 56/86 = 0.65 for Residual fuel oil
       $PM_{2.5}$ emissions are based on a ratio of 12/50 = 0.24 for Distillate oil

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

6.5 Emission Factors for LPG Combustion (Steam Cycle)

Liquefied petroleum gas (LPG) (mixture of propane, butane and similar hydrocarbons) is occasionally used as an auxiliary fuel for steam cycle facility. Relevant emission factors are included below.

Table 14   Emission Factors for LPG Combustion (SO_2, NO_X, CO, and PM_{10}): Steam Cycle

SUBSTANCE	EMISSION FACTOR (kg/1000 L)[a]			
	Butane	EFR (f)	Propane	EFR (f)
Carbon monoxide (CO)	4.3E-01	E	3.8E-01	E
Oxides of nitrogen (NO_X)[c]	2.5	E	2.3	E
PM_{10}[d]	7.2E-02	E	7.2E-02	E
Sulfur dioxide (SO_2)[b]	1.9E-03 x S	E	2.1E-03 x S	E
Total Volatile Organic Compounds (TVOCs)[e]	7.2E-02	E	6.0E-02	E
Notes: From Reference: USEPA 1995 (Table 1.5-1) Emissions (kg/year) = [emission factor (kg/1,000 L) x fuel usage (1,000 L/year)] L = Litre a. Derived from Table 1.5-1 Reference: USEPA 1995 (Table 1.5-1) for industrial boilers b. S equals sulfur content of gas in g/10³ L c. Expressed as NO_2 d. All particulate matter less than 10 μm in nominal diameter e. Derived from Table 1.5-1 Reference: USEPA 1995 (Table 1.5-1), for total organic compounds f. Emission Factor Rating Scientific notation is used; e.g. 7.38E-02 represents 7.38 x 10⁻² or 0.0738.				

6.6 Emission Factors for Stationary Gas Turbines (Natural gas and distillate fuels)

Table 15 provides emission factors for the primary or criteria combustion pollutants (sulfur dioxide, oxides of nitrogen, carbon monoxide, PM_{10} and Total VOCs). Combustion of natural gas or distillate in gas turbines is unlikely to trigger the reporting threshold of 10 tonnes for any Category 1 substance, based on the size of existing and potential facilities. Therefore, only Category 2a/2b substances are relevant to gas turbines.

In the absence of specific emission factors for combined cycle gas turbine (CCGT) facilities, the emission factors in this section should be applied to open cycle and CCGT facilities. This is consistent with AP-42 documentation, which includes CCGT technology in the section on stationary gas turbines. Supplementary duct firing associated with a CCGT facility, if relevant, would need to be considered in addition to emissions arising from the gas turbine.

Emissions of a number of substances from gas turbines, including oxides of nitrogen and carbon monoxide, are particularly dependent upon the combustion technology employed and whether post-combustion controls are employed. The control of NO_X emissions from gas turbines is evolving rapidly, with recent advances in dry low NO_X burners capable of producing significantly lower NO_X emissions than combustion technologies of less than a decade ago.

While the review includes a number of updated, default emission factors it is recommended that facilities report NO_X and CO emissions, where possible, using information specific to the gas turbine in use.

Emission factors for gas turbines utilising exhaust gas control technology are included for the technologies listed.

- Water or steam injection where water/steam is injected into the combustion chamber(s) to reduce the flame temperature and NO_X emissions.
- Combustion control to reduce NO_X emissions through lean combustion, reduced combustor residence time, two-stage lean/lean combustion or two-stage rich/lean combustion.

NOx emissions can be further reduced by the use of Selective Catalytic Reduction (SCR) or Selective Non Catalytic Reduction (NSCR). Use of these technologies may be associated with an increase in ammonia and formaldehyde emissions. Emission factors for these substances are not included, as emissions are dependent on the technology type and degree of NO_X control achieved. Users of these technologies should ascertain their performance characteristics with respect to all relevant substances.

Table includes general emission factors, whereas Table 15 contains facility-specific emission factors for NO_X, CO, and Total VOCs.

Table 15   Emission Factors for Combustion in a Stationary Gas Turbine: Natural Gas and Distillate

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated				
		Natural gas		Distillate		
		kg/PJ	EFR (a)	kg/PJ	kg/kL	EFR
Arsenic &compounds (b)	1/2b	no data (s)		4.7	1.9E-04	D
Beryllium & compounds (b)	1/2b	no data (s)		1.3E-01	5.3E-06	D
Cadmium & compounds (b)	1/2b	no data (s)		2.1	8.2E-05	D
Carbon monoxide	1/2a	3.5E+04 uncontrolled 1.3E+04 water-steam injection 6.5E+03 lean premix	A A D	1.4E+03 uncontrolled 3.3E+04 water-steam injection	5.6E-02 uncontrolled 1.3 water-steam injection	C C
Chromium (III) compounds(b)	1/2b	no data (s)		3.3	1.3E-04	D
Chromium (VI) compounds (b)	1/2b	no data (s)		1.4	5.6E-05	D
Cobalt and compounds		no data (s)		no data (s)	no data (s)	
Copper & compounds (b)	1/2b	no data (s)		no data (s)	no data (s)	
Fluoride compounds	1/2b	no data (s)		no data (s)	no data (s)	
Hydrochloric acid	1/2a	no data (s)		no data (s)	no data (s)	
Lead & compounds (b)	1/2b	no data (s)		6.0	2.4E-04	D
Magnesium oxide fume	1/2b	0		0		
Manganese and compounds		no data (s)		3.4e+02	1.3E-02	
Mercury & compounds (b)	1/2b	no data (s)		5.2E-01	2.0E-05	D
Nickel & compounds (b)	1/2b	no data (s)		2.0	7.9E-05	D
Nickel carbonyl (6.23)	1/2b	0		0	0	
Nickel subsulfide (6.23)	1/2b	0		0	0	
Oxides of nitrogen (expressed as nitrogen dioxide, NO_2)	1/2a	1.4E+05 uncontrolled 5.6E+04 water-steam injection 4.3+04 lean premix	A A D	3.8E+05 uncontrolled 1.0E+05 water-steam injection	1.5E+01 uncontrolled 4.1 water-steam injection	C B
PM_{10} (b)	1/2a	2.8E+03 uncontrolled	C	5.2E+03 uncontrolled	2.0E-01 uncontrolled	C
$PM_{2.5}$ (b&v)	1/2a	2.7E+03 uncontrolled	C	4.9E+03 uncontrolled	1.9E-01 uncontrolled	C

Substance	Threshold category	Emission Estimation Technique (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/PJ unless otherwise indicated				
		Natural gas		Distillate		
		kg/PJ	EFR (a)	kg/PJ	kg/kL	EFR
Polychlorinated dioxin & furans **(j)**	2b	5E-07	U	5E-07	2.01E-11	U
Polycyclic aromatic hydrocarbons	2a	9.5E-01	C	1.7E+01	6.8E-04	C
Sulfur dioxide **(l)**	1/2a	4.1E+05 x S 2.5E+02	B	4.4E+05 x S	1.7E+01 x S	B
TVOCs **(m)**	1a/2a	9.1E+02	D	1.8E+02	7.0E-03	E

Notes:

Reference: USEPA 2000 unless otherwise noted

a.   Emission Factor Rating

b.   Emission factors for trace and their compounds from natural gas combustion sourced from Reference: USEPA 1998a section 1.4 Natural Gas Combustion (steam cycle)

c.   Compound was not detected. Emission factor based on half detection limit

d.   It is recognised that the uncontrolled emission factor for CO is lower than the controlled factors, contrary to expectations. USEPA has not identified the reason for this behaviour.

e.   Chromium(III) assumed to be 0.95 x Total chromium. Reference: Pacific Power International 2002

f.   Chromium (VI) assumed to be 0.05 x Total chromium. Reference: Pacific Power International 2002

g.   From natural gas combustion (steam cycle)

h.   From distillate combustion (steam cycle)

i.   Assuming a collection efficiency of 99%

j.   Reference: UNEP 2001 using a TEF conversion factor of 17

k.   Individual PAHS included not specified

l.   All sulfur in fuel assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content is 2.5%, then S= 2.5. If S is not available use defaults (equations are more accurate).

m.   Total VOCs emissions are assumed to equal the sum of organic emissions.

t.   The emission factor is zero unless there is relevant information in other NPI manuals or NPI documentation, or the operators of the reporting facility are aware of other information that allows them to estimate the facility's emissions

u.   For a discussion of emissions of nickel subsulfide and nickel carbonyl see Reference: Rae 2000

v. $PM_{2.5}$ emissions are based on a ratio of 0.95 for natural gas

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

Table 16   Specific Power Station Emission Factors for Gas Turbines (NO$_X$, CO, and TVOCs)

Power Station	Emission Factor (kg/PJ)		
	CO	**NO$_X$ (a)**	**TVOCs (b)**
Northern Territory - Channel Island,	4.6E+04	1.9E+05	2.4E+03
South Australia - Dry Creek, **(c)**	Use default factors	Use default factors	2.4E+03 Use default factor.
South Australia - Mintaro, **(c)**	Use default factors	Use default factors	2.4E+03 Use default factor.
Victoria - Jeeralang A,	2.9E+04	1.7+05 **(c)**	6.0E+02
Victoria - Jeeralang B,	2.9E+04	7.2E+04	6.0E+02
Western Australia – Geraldton,	4.6E+04	1.9E+05	2.4E+03
Western Australia - Kalgoorlie,	4.6E+04	1.9E+05	2.4E+03
Western Australia - Kwinana,	4.6E+04	1.9E+05	2.4E+03
Western Australia – Mungarra,	4.6E+04	1.9E+05	2.4E+03
Western Australia - Pinjar,	4.6E+04	1.9E+05	2.4E+03
Various (distillate fuelled)	3.5+05	1.3E+06	4.5E+04

Notes:

Reference: Department of the Environment, Sport and Territories 1996

Total VOCs   Volatile organic compounds

a.   Oxides of nitrogen expressed as nitrogen dioxide, NO$_2$
b.   Non-methane volatile organic compounds
c.   Reference: Pacific Power International 2002

Scientific notation is used; e.g. 7.38E-02 represents 7.38×10^{-2} or 0.0738.

6.7   Emission Factors for Stationary Engines

The Emission Estimation Technique Manual for Combustion Engines describes the procedures and recommended approaches for estimating emissions from combustion engines. This Manual has been significantly revised since it was first published in 1999.

The following points are noted with respect to emissions from combustion engines:

- Based on an engine size of 10 MW, combustion engines is unlikely to trigger the Category 1 threshold for the substances listed in isolation.
- A combustion engine burning diesel or gas of a rated capacity of about 120 kW is likely to trigger the Category 2a reporting threshold of 400 tonnes of fuel use per year (assuming 100 % capacity factor and 20% conversion efficiency).
- A combustion engine burning diesel or gas rated at 600 kW is likely to trigger the Category 2b reporting threshold of 2,000 tonnes of fuel use per year (assuming 100 % capacity factor and 20% conversion efficiency).
- Currently emission factors are available for many category 2b substances (the *latest Combustion engines EET manual* should be checked to determine if factors are available).

It is recommended that facilities operating combustion engines determine the appropriate level of reporting based on the category thresholds and use the relevant emission factors in the Emission Estimation Technique Manual for Combustion Engines, if more appropriate EETs are not available.

6.8   Biomass Co-Firing

Biomass is assumed to include bark, sawdust, shavings, woodchips, mill rejects, sanderdust or wood trim. Heating values for this residue range from 10MJ/kg of fuel on a wet, as-fired basis, to about 18MJ/kg for dry wood. Moisture contents may vary from 5 to 75% w/w depending on the residue type and storage conditions.

Please note that biomass excludes treated or manufactured timber products.

There is limited data available on emissions from co-firing with biomass. In a Dutch study (Reference: Meij 2000) eleven test series were performed at coal-fired power facilities and four at a test facility where co-combustion of secondary fuels such as sewage sludge, wood etc. was effected. The tests focussed on the emission of relevant trace elements. In these test series all the relevant streams were monitored and compared with the situation without co-combustion. Under test conditions, with a maximum of 10weight% of co-combustion, all the relative parameters were comparable to the results obtained with 100% coal firing.

The concentration of trace elements is generally lower in biomass than in coal. Evidence from facilities co-firing biomass in NSW indicates that operational parameters will limit biomass to a maximum of about 5% of the fuel input, on a mass basis. From the above considerations, it is recommended that for co-firing up to 10% biomass with coal (on a mass basis) the EETs for coal only combustion be adopted.

In the event of co-firing biomass in excess of 10%, it is recommended that emissions from the biomass and coal fractions be calculated separately using the relevant emission factors. Emission factors for biomass combustion can be obtained from AP-42 Wood Residue Combustion in Boilers (Reference: USEPA 1998a).

6.9   Emission Factors for Solvent Degreasing

Solvent degreasing within the fossil fuel electric power generation industry is related to maintenance activities. The Emission Estimation Technique Manual for Ferrous Foundries (National Pollutant Inventory, 1998) contains emission factors for solvent emissions for these activities.

6.10   Emission Factors for Storage Tanks

Facilities that have bulk storage for hydrocarbons should refer to the *Fuel and Organic Liquid Storage Manual*. The use of liquid fuels may result in the reporting threshold for a number of Category 1 substances being exceeded, depending on the quantity of fuel burnt and the concentration of relevant substances in the fuel. Table 2 of the *Fuel and Organic Liquid Storage Manual* shows the amounts of liquid fuel that would need to be used (kL) in any one year for the reporting threshold of 10 tonnes to be exceeded for the listed fuel constituents.

6.11   Emission Factors for Fugitive Dust

The Emission Estimation Techniques for Fugitive Emissions (1999) describes a range of processes and activities that potentially result in fugitive emissions of NPI listed substances. The Fugitive Emissions Manual generally does not include EETs but rather directs users to other appropriate Emission Manuals.

The activities and processes that are most relevant to fossil-fuel electricity generation and the appropriate emission estimation technique manuals are:

Fugitive Process/activity	Relevant Emission Estimation Technique Manual
• Evaporation from fuel storage tanks	Fuel and Organic Storage / Organic Chemical Processing Industries
• Vehicle movement and exhaust	Mining
• Storage piles	Mining
• Bulk material handling	Mining

7 Control Technologies

Emission control technologies commonly used in the Australian fossil fuel electric power generation industry are described below. These technologies are combined with environmental management systems on many facilities to reduce the overall adverse environmental impact of fossil fuel electric power generation.

7.1 Control Technologies for Emissions to Air

The control of emissions to air effected at any of the following stages in the production of electricity:

- Pre-combustion (fuel treatment);
- Combustion control; and
- Post-combustion.

Pre-combustion processes are the "cleaning" of undesirable substances from the fuel prior to combustion. The selection of fuels that can result in reduced emissions of particular substances, such as low sulfur coal could also be considered as a pre-combustion process. Pre-combustion processes have limited application for the Australian fossil fuel electric power generation industry.

Combustion control processes generally control emissions of oxides of nitrogen (NO_X) and carbon monoxide (CO) by controlling flame temperature and the fuel/air ratio used to ensure complete combustion. Common techniques include low NO_X burners, and the use of overfire air.

Post-combustion processes used in Australia primarily control the release of particulate matter (PM_{10} and Total Suspended Particulates (TSP)). Generally, this is achieved by the use of ESPs and FFs. Collection efficiencies commonly exceed 99% of the input particulate load.

With regards to emission controls for PM_{10}, in the absence of measured data, or knowledge of the collection efficiency for a particular piece of equipment, default values can be used. The default values are:

- 99.2% for electrostatic precipitators; and
- 99.8% for fabric filters.

In some circumstances, the collection efficiency of electrostatic precipitators can be improved by the injection of either sulfur trioxide or ammonia into the flue gas streams. A small fraction of the conditioning substance will pass through the ESP without reacting with flyash and be emitted to the atmosphere. Facilities injecting sulfur trioxide or ammonia in excess of the reporting threshold of 10 tonnes, should estimate the quantity of the substance that is emitted to the atmosphere. However, no emission factors have been found during this review, as the amount of substance emitted is dependent on facility-specific factors.

Currently, no fossil fuel electricity generators in Australia utilise selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) for the control of NO_X emissions. These control technologies utilise ammonia injection with or without a catalyst and some ammonia "slippage" is to be expected. A US report (Battye 1994) indicates slippage of 15 ppm and 30 ppm for SCR and SNCR respectively. The same report includes emission factors for ammonia for SCR and SNCR.

7.2   Control Technologies for Emissions to Water

Emissions to water include: discharges from a boiler water demineralising facility, cooling water blowdown, ash transport water, and floor and site drainage.

A range of techniques is used to reduce the adverse environmental impact of such discharges. Examples of techniques include:

- neutralising acid discharges;
- dense-phase ash transport (no ash transport water to dispose of);
- impoundment of site drainage e.g. settling ponds;
- "zero discharge" operations by evaporating excess water;
- use of marine disposal for saline water;
- control of floor drains discharges via oil and silt interceptors;
- mechanical condenser cleaning systems; and
- chemical substitution e.g. non solvent cleaning techniques.

7.3   Control Technologies for Emissions to Land

Emissions to land are limited to waste material and ash (for a coal fired facility). Control techniques include:

- Utilisation of flyash for cement products;
- Controlled waste landfill or disposal off-site;
- Wet ash dams (not impacted by wind erosion);
- Twin ash dams (ash disposed to landfill or mine overburden areas); and
- Bunding of oil and chemical storages (reduce the risk of spillage to soil).

8   Next steps for reporting

This manual has been written to reflect the common processes employed in XYZ industry. To ensure a complete report of the emissions for your facility, it may be necessary to refer to other EET manuals. These include:

- *Combustion in boilers;*
- *Combustion in engines;*
- *Fuel and organic liquid storage; and*
- *Fugitive emissions.*

When you have a complete report of substance emissions from your facility, report these emissions according to the instructions in *The NPI Guide.*

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25. USEPA, *Compilation of Air Pollutant Emission Factors AP-42: Chapter 3.1 Stationary Gas Turbines, Fifth Edition, Volume 1: Stationary Point and Area Sources,* http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf at http://www.epa.gov/ttn/chief/ap42/, April 2000.

26. USEPA, *Emergency Planning and Community Right to Know Section 313 Guidance for Reporting Toxic Chemicals: Mercury and Mercury Compounds Category*, Office of Environmental Information, EPA 260-B-01-004, http://www.epa.gov/tri/guide_docs/2001/hg2001.pdf, 2001.

27. UNEP Chemicals, *Standardized Toolkit for Identification and Quantification of Dioxin and Furan Releases (draft)*, 2001.

10 Glossary and Abbreviations

AP-42	Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume 1: Stationary Point and Area Sources (USEPA)
CEMS	Continuous emission monitoring system
CO	Carbon monoxide
EETs	Emission Estimation Techniques
EFR	Emission Factor Rating
ESP	Electrostatic precipitator
FF	Fabric filter (also called a baghouse)
g	Gram
GJ	Gigajoule (1E+09^9 joule)
h	Hour
K	Kelvin
kg	Kilogram (1,000 gram)
L	Litre
LPG	Liquefied petroleum gas
MJ	Megajoule (1E+06 joule)
ML	Megalitre (1E+06 litre)
N_2O	Nitrous oxide
NEPM	National Environment Protection Measure
NO_X	Oxides of nitrogen
NPI	National Pollutant Inventory
OCDD	Octachloro dibenzodioxin
OCDF	Octachloro dibenzofuran
Ocs	Organic compounds
PAHs	Polycyclic aromatic hydrocarbons
PCDD	Polychlorinated dibenzo-p-dioxins
PCDF	Polychlorinated dibenzofurans
PEM	Predictive emission monitoring
PJ	Petajoule (10^{15} joule)
PM_{10}	Particulate matter with aerodynamic equivalent diameter equal to or less than 10 μm
$PM_{2.5}$	Particulate matter with aerodynamic equivalent diameter equal to or less than 2.5 μm
SO_X	Sulfur dioxide
STP	Standard temperature (0°C) and pressure (101.325 kPa)
TCDD	total tetrachloro dibenzodioxin
TCDF	total tetrachloro dibenzofuran
TDS	Total dissolved solids
TEQ	Toxic Equivalent
TSP	Total suspended particulates
Total VOCs	Total volatile organic compounds
USEPA	United States Environment Protection Agency

Appendix A   NPI Substances Relevant To Fossil Fuel Electric Power Generation

Table 17 lists the NPI listed substances that may need to be reported to the NPI by the fossil fuel electric power generation industry. This is a subset of the NPI substances. If the facility includes other unit processes some or all of the other NPI substances may need to be considered. The full list of NPI substances is in *the NPI Guide*.

Table 17   NPI Substances expected to be relevant to Fossil Fuel Electric Power Generation

prefix	COLUMN 1 SUBSTANCE	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
	Ammonia (total)	1	10 tonnes per year
	Antimony & compounds	1	10 tonnes per year
	Arsenic & compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Benzene*	1	10 tonnes per year
	Beryllium & compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Boron & compounds	1	10 tonnes per year
	Cadmium & compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Carbon monoxide	1	10 tonnes per year
		2a	400 tonnes per year, or 1 tonne per hour
	Chlorine	1	10 tonnes per year
	Chromium (III) compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Chromium (VI) compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Cobalt & compounds	1	10 tonnes per year
	Copper & compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Cumene (1-methylethylbenzene)	1	10 tonnes per year
	Cyanide (inorganic) compounds	1	10 tonnes per year
	Cyclohexane	1	10 tonnes per year
	Dichloromethane	1	10 tonnes per year
	Ethylbenzene	1	10 tonnes per year
	Fluoride compounds*	1	10 tonnes per year
		2a	400 tonnes per year, or 1 tonne per hour
	Formaldehyde (methyl aldehyde)	1	10 tonnes per year
n-	Hexane	1	10 tonnes per year
	Hydrochloric acid	1	10 tonnes per year
		2a	400 tonnes per year, or 1 tonne per hour
	Lead & compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Magnesium oxide fume	1	10 tonnes per year

prefix	COLUMN 1 SUBSTANCE	COLUMN 3 THRESHOLD CATEGORY	COLUMN 4 THRESHOLD
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Manganese & compounds	1	10 tonnes per year
	Mercury & compounds	1b	5 kg per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Nickel & compounds	1	10 tonnes per year
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Nickel carbonyl	1	10 tonnes per year
	Nickel subsulfide	1	10 tonnes per year
	Oxides of Nitrogen	2a	400 tonnes per year, or 1 tonne per hour
	Particulate Matter 10.0 μm	2a	400 tonnes per year, or 1 tonne per hour
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Particulate Matter 2.5 μm	2a	400 tonnes per year, or 1 tonne per hour
		2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Polychlorinated dioxins and furans	2b	2,000 tonnes per year, or 60,000 megawatt hours, or rated at 20 megawatts
	Polycyclic aromatic hydrocarbons	2a	400 tonnes per year, or 1 tonne per hour
	Selenium & compounds	1	10 tonnes per year
	Styrene (ethenylbenzene)	1	10 tonnes per year
	Sulfur dioxide	1	10 tonnes per year
		2a	400 tonnes per year, or 1 tonne per hour
	Sulfuric acid	1	10 tonnes per year
	Tetrachloroethylene	1	10 tonnes per year
	Toluene (methylbenzene)	1	10 tonnes per year
	Total Nitrogen	3	15 tonnes per year
	Total Phosphorus	3	3 tonnes per year
	Total Volatile Organic Compounds	1a	25 tonnes per year, or a design capacity of 25 kilotonnes for bulk storage facilities
		2a	400 tonnes per year, or 10 tonne per hour
	Trichoroethylene	1	10 tonnes per year
	Xylenes (individual or mixed isomers)	1	10 tonnes per year
	Zinc and compounds	1	10 tonnes per year

Reference: *National Environment Protection Council 2008 - National Environment Protection (National Pollutant Inventory) Measure 1998 as varied Table 1*

Appendix B   Australian Coal Properties

Table 18 and Table 19 list properties of coals commonly used by the fossil fuel electricity generation industry. The tables list the composition range for many components, including for trace elements. This is due to the heterogeneous nature of coal.

These coal characteristics may be used to estimate emissions of trace elements in the absence of better data. Facilities using indicative coal concentration data included in the following tables, rather than facility-specific data, for reporting purposes should use the upper range values (in bold) unless an alternative approach has been approved by a relevant environmental jurisdiction.

Table 18   Indicative Coal Properties for Black Coals used in the Electricity Generation Industry

COAL CONSTITUENT (as fired basis)	COAL		
	NSW [a]	QUEENSLAND [a]	WESTERN AUSTRALIA [a]
	Range	Range	Range
% Carbon	57.1 - 64.5	53.2 - 80.5	48.1 – 52.7
% Hydrogen	3.54 - 4.1	2.6 - 6.5	2.1 – 3.4
% Nitrogen	1.15 - 1.5	0.8 - 1.5	0.8 – 0.9
% Sulfur	0.34 - 0.55	0.15 - 0.75	0.3 –0.9
% Moisture	1.9 - 7.7	5.0 - 19.0	22.0 – 29.0.
% Ash	17.4 - 25.8	11.7 - 28.0	2.5 – 10.0
OTHER ELEMENTS (mg/kg)[b]			
Antimony	<0.05 - **1.7**	0.2 - **1.41**	<1 - **2**
Arsenic	<1 - **5**	0.69 - **3.5**	<1 - **2**
Beryllium	0.8 - **7**	0.6 - **2.8**	<1 - **3**
Boron	<5 - **36**	10.0 - **38.0**	2 - **5**
Cadmium	<0.2 - **0.4**	0.04 - **0.10**	0.1 - **1.4**
Chlorine	35 - **270**	0.02 - **540**	<50 - **230**
Chromium[c]	7 - **23**	9.8 - **28.0**	1 - **10**
Chromium III	ND	ND	ND
Chromium VI	ND	ND	ND
Cobalt	1.7 - **98**	4.0 - **7.3**	2 - **18**
Copper	4 - 14	14.0 - **37.0**	1 - **13**
Fluoride	75 - **168**	51.0 - **160.0**	16 - **55**
Lead	6.7 - **16**	5.0 - **8.7**	<1 - **10**
Magnesium	ND	670 - **11,900**	ND
Manganese	5 - **360**	7.1 - **438**	<1 - **43**
Mercury	0.02 - **0.11**	0.01 - **0.1**	ND
Nickel	5 - **50**	5.1 - **16.0**	2 - **22**
Selenium	<1 - **2**	0.12 - **0.53**	ND
Zinc	6 - **370**	10.5 - **31.0**	1 - **72**
HEAT VALUE			
Higher Heating Value (MJ/kg)	22.9 - 26.27	19.3 - 27.4	19.2 – 21.5

Notes

Facilities using indicative coal concentration data, rather than facility-specific data, for reporting purposes should use the upper range values (**in bold**) unless an alternative approach has been approved by a relevant environmental jurisdiction.

ND   no data available
<   less than indicates the limit of detection for the element for the technique applied
a   personal communication with NSW, Queensland and West Australian electricity generating companies
b   includes compounds
c   chromium (III & VI)

Table 19   Indicative Coal Properties for Brown Coals used in the Electricity Generation Industry

COAL CONSTITUENT (as fired basis)	COAL	
	VICTORIA [a]	SOUTH AUSTRALIA [a]
	Latrobe Valley and Anglesea	Leigh Creek
	Range	Range
% Carbon	23.8 - 24.9	37.5
% Hydrogen	1.7 - 1.8	2.34
% Nitrogen	0.19 - 0.22	0.65
% Sulfur	0.09 - 0.14	0.2-0.3
% Moisture	61.3 - 66.5	26.2
% Ash	0.5-1.1	20.6
OTHER ELEMENTS (mg/kg)[b]		
Antimony	<0.005 - **0.01**	0.2 – **1.9**
Arsenic	0.02 - **0.07**	0.5 – **4.4**
Beryllium	<0.02 - **0.09**	<0.7 - **1.1**
Boron	1.1 - **8.6**	30 - **220**
Cadmium	0.005 - **0.11**	0.05 - **0.08**
Chlorine	220 - **290**	370 – **12,500**
Chromium[c]	0.1 - **1.4**	4 - **60**
Chromium III	ND	ND
Chromium VI	ND	ND
Cobalt	0.07 - **0.3**	<1.5 - **18**
Copper	0.1 - **2.2**	2 - **44**
Fluoride	2.9 - **13**	140 - **270**
Lead	0.1 - **0.7**	<1.5 - **37**
Magnesium	ND	0.21 - **0.33**
Manganese	0.2 - **25**	<1.5 - **370**
Mercury	0.02 - **0.12**	0.09 - **0.20**
Nickel	0.43 - **1.4**	3 - **44**
Selenium	0.1 - **0.2**	<0.4 – **0.7**
Zinc	0.4 - **7**	11 - **150**
HEAT VALUE		
Higher Heating Value (MJ/kg)	8.76 - 10.2	14.2

Notes:

Facilities using indicative coal concentration data, rather than facility-specific data, for reporting purposes should use the upper range values (**in bold**) unless an alternative approach has been approved by a relevant environmental jurisdiction.

ND   no data available
a   personal communication with Victorian and South Australian electricity generating companies
b   includes compounds
c   chromium (III & VI)

Appendix C   Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 3.0 – January 2012).

Page	Outline of alteration
All	Emission factors for two substances, Mercury and compounds and Polychlorinated dioxins and furans, have been reviewed against national and international programs and literature. Updates were made to Polychlorinated dioxins and furans emission factors for black coal, brown coal, Victorian brown coal, natural gas (Steam cycle), oil (steam cycle) and stationary gas turbine combustion. Updates were also made to Mercury and compounds emission factors for black coal, brown coal and Victorian brown coal combustion.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.4 – 15 March 2005).

Page	Outline of alteration
Table 14	Corrected oxides of nitrogen emission factor for natural gas.

Technique EET Manual (Version 2.3 – 14 September 2004).

Page	Outline of alteration
Table 14	Corrected PM_{10} emission factor for diesel.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.2 – 8 September 2004).

Page	Outline of alteration
Tables 7, 12 and 14	Corrected or updated emission factors.
References	Added more precise references for tables 12 and 14.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.1 – 12 July 2004).

Page	Outline of alteration
Table 12 page 45	The manual was missing the emission factors relating to PM_{10} emissions from oil and distillate combustion.

Erratum for Fossil Fuel Electric Power Generation Emission Estimation Technique EET Manual (Version 2.0 – 12 December 2003)

Page	Outline of alteration
all	The manual has been completely revised and updated with emissions factors for most electric power generation facilities. The data has been obtained through a monitoring/testing program to replace some emission factors sourced from the United States Environmental Protection Agency (USEPA).