Review of National Pollutant Inventory Methodologies for Coal-Fired Power Station Stack Emissions

NPI Methodology Review

04 February 2022

Project No.: 0607697

The business of sustainability

ERM

Document details	
Document title	Review of National Pollutant Inventory Methodologies for Coal-Fired Power Station Stack Emissions
Document subtitle	NPI Methodology Review
Project No.	0607697
Date	04 February 2022
Version	R2
Authors	Jing Wang, Bethany Warren Tania Haigh, James Grieve
Client Name	Australian Energy Council

Document history

Version	Revision	Authors	Reviewed by	ERM approval to issue		Comments
				Name	Date	
D1	00	Jing Wang, Bethany Warren Tania Haigh, James Grieve	K. Bradfield J.Grieve	K. Bradfield	15/11/2020	Draft
R1	01	Tania Haigh	K. Bradfield J.Grieve	K. Bradfield	23/12/2021	Final
R2	02	Tania Haigh	K. Bradfield J.Grieve	K. Bradfield	01/02/2022	Revised Final

Signature Page

04 February 2022

Review of National Pollutant Inventory Methodologies for Coal-Fired Power Station Stack Emissions

NPI Methodology Review

Karie Bradfield

Partner

Tania Haigh

Senior Consultant

ERM Australia Pacific Pty Ltd
Level 15, 309 Kent Street
Sydney NSW 2000

CONTENTS

List of Tables

List of Figures

Acronyms and Abbreviations

Name	Description
AEC	Australian Energy Council
CEMS	Continuous Emissions Monitoring System
EETM	Emission Estimation Technique Manual
EFR	Emission Factor Rating
ESP	Electrostatic Precipitator
IED	(European Union) Industrial Emissions Directive
IPCC	Intergovernmental Panel on Climate Change
IPPC	Integrated Pollution Prevention and Control
MJ	Megajoule
MWh	Megawatt hour
NATA	National Association of Testing Authorities
NEPM	National Environment Protection Measure
NGER	National Greenhouse and Energy Reporting
Nm^3	Normal cubic metre (i.e. 1 cubic metre at conditions of 273 K and 1 atmosphere)
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_x	Oxides of nitrogen
NPI	National Pollutant Inventory
NPI EETM	National Pollutant Inventory Emission Estimation Technique Manual for Fossil Fuel Power Generation
NSW EPA	New South Wales Environment Protection Authority
PI	Pollution Inventory
PM	Particulate matter
PM_{10}	Particulate matter less than 10 microns in aerodynamic diameter
$PM_{2.5}$	Particulate matter less than 2.5 microns in aerodynamic diameter
QA	Quality Assurance
RAA	Relative Accuracy Audit
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
STP	Standard temperature and pressure (US)
TSP	Total suspended particulate
US EPA	United States Environment Protection Agency

EXECUTIVE SUMMARY

ERM was engaged by the Australian Energy Council (AEC) to conduct a review of the methodologies used to report power station stack emissions (focusing on coal power) to the National Pollutant Inventory (NPI), involving the following scope of work:

- Review of NPI methodologies used by electricity generators to calculate the stack emissions.
- Explanation of the reasons for the choices of the NPI methodologies.
- Review of the variance in NPI methodologies used across each electricity generator.
- Discussion of the likely variation in emissions if each generation plant adopted an alternative method used at another facility.
- Analysis of the advantage and disadvantages of using site-specific methodologies compared to a uniform methodology being prescribed.

The outcomes of the review and supplementary investigations are summarised as follows:

Emission Estimation Methods

The NPI allows electricity generators to apply a range of estimation methods inclusive of the following, listed in decreasing order of potential reliability:

- Direct measurement (CEMS or stack tests)
- Source-specific emission factors derived from sampling events
- Engineering calculations
- Mass balances
- Published emission factors.

A survey of coal-fired power generators to determine the estimation methods currently used showed that methods vary by pollutant and plant, and were observed to meet the requirements of the NPI reporting framework. Of the 19 coal-fired power stations operating in Australia, sufficient information was provided for 14 of these to include in the review. It was observed that where emission monitoring is required as part of state-based regulatory requirements, the data is commonly incorporated into the emission estimates.

The results of the survey indicated that all the allowed methods are used, with CEMS and stack tests being most common. Direct measurement-based estimates for SO_2 and mercury were observed to be less common, and may be due to the higher confidence and low complexity of emission estimates based on coal composition and material balance assumptions for these pollutants. Conversely, particulate matter, and NO_x have a dependence on a wider range of operating conditions, and are more commonly estimated using direct measurement.

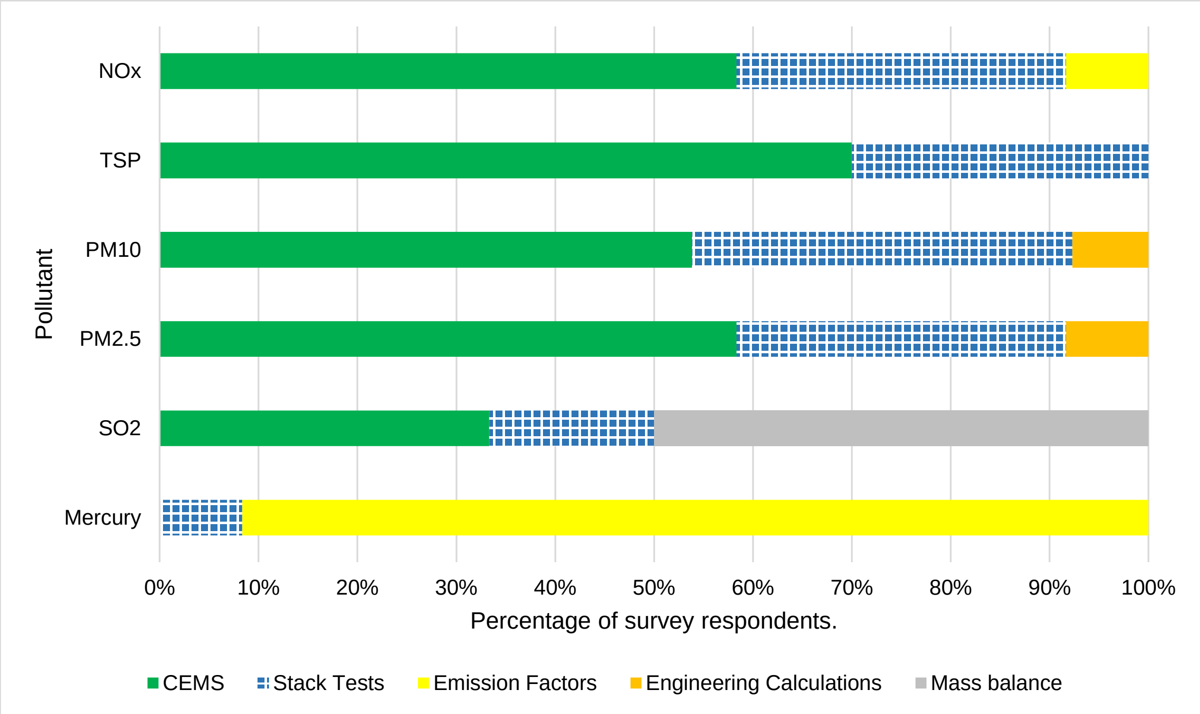

Figure E.1 Summary of Adopted NPI Emission Estimation Method by Pollutant

A review of the emission intensity was undertaken for each of the key pollutants, using the NPI reported emissions and NGER reported electricity output to establish the quantity of emissions per unit of electrical output (kg pollutant emission / MWh generated). Whilst there may be variations in the thermal efficiency of various plants, it is noted that overall, this analysis indicated:

- Variability between the emission intensity of plants. This is expected given variability in fuel types, operating loads, scale, and emission controls.
- A general consistency between average reported emission intensity, and the emission intensities derived from the default NPI emission factors.

Discussion with Regulatory Bodies

ERM contacted each of the state, territory and commonwealth contacts listed on the NPI website to collect information about emission estimation methodology preferences for power stack emissions. The responses provided by NPI representatives included:

- Direct measurement is generally the preferred basis for emission estimation as this is likely to provide the most representative emissions estimate, provided calibrations, maintenance and associated standards are adhered to, and plant conditions during testing are considered. One exception to this was noted, with particulate emissions preferred to be estimated with reference to the engineering calculations or default emission factors by the regulator in Queensland.
- The overall objective in method selection is to provide the most reliable and representative data.
- Common errors and discrepancies were either not observed, or minor in nature, with resolution of particulate size fractions, and translation of stack tests into annual profiles raised as potential areas for discrepancies.
- Difficulties in checking and reviewing emission submissions were observed in 2 of 6 responses, and related to the sourcing of input data for the submissions.

Summary of International Power Generation Inventory Reporting Methods

ERM has reviewed methodology information for several annual emission reporting inventories in the UK and US. Overall, these international jurisdictions consider the same range of methods as the NPI, showing general consistency in the available and preferred techniques.

The guidance documentation reviewed was generally consistent in the use of methods in the following order of preference:

1. Direct measurement methods
2. Engineering or mass balance where appropriate
3. Emission factors when no other methods are suitable.

The documentation reviewed also included discussion or guidance on:

- PM_{10} and $PM_{2.5}$ fraction assumptions.
- The need to take care with calculations involving normalisation of concentrations and flow rates, making sure reference and actual conditions are correctly accounted for.
- Ensuring appropriate calibration of monitoring equipment and relevance of monitoring standards.
- Quality Assurance (QA) checks on monitoring data, and evaluation of representativeness of data.
- If emission factors are to be used, the use of industry-specific or industry standard emission factors, or site-specific.

Overall, it was noted that the reviewed reporting methods showed consistency with the NPI methodologies, both in the estimation methods and reporting objectives.

1. INTRODUCTION

ERM has been engaged by the Australian Energy Council (AEC) to conduct a review of the methodologies used to report power station stack emissions (focussing on coal-fired power generation) to the National Pollutant Inventory (NPI). This report provides an overview of the methodology and findings of this process.

1.1 Background

The AEC represents the major electricity businesses that collectively generate the majority of electricity in Australia. These businesses report their annual emissions from the generation of electricity to the NPI. Recent scrutiny by the media and advocacy groups has led the AEC to request a third party to collate and summarise the industry methods used for reporting annual emissions.

The objective of this study is to provide the AEC and its members with transparency of the emission estimation methods used by the Australian power generators. In addition, the review is intended to provide context to the emission estimation methods, including practicalities, costs and advantages/disadvantages. The review is focused on coal combustion power stations (primarily black coal) but can be interpreted to other combustion-based power stations.

1.2 National Pollutant Inventory (NPI)

The NPI National Environment Protection Measures (NEPMs) identify 93 substances and their reporting emission thresholds (Commonwealth of Australia, 2015). If a facility triggers a threshold for a substance, it is required to estimate and report emissions to air (point and fugitive sources), water, and land and the transfer of substances to their final destinations.

Emissions are defined by the NPI as the release of an NPI substance to the environment, whether in pure form, or contained in other matter, and/or in solid, liquid or gaseous form.

Combustion of fuels (including coal) produce emissions of substances that are triggered for NPI reporting. These emissions are either formed from coincidental production or are impurities contained within the fuel that are then emitted through the combustion exhaust. The substances of focus for this review (key substances) include:

- Oxides of nitrogen (NO_x)
- Particulate matter (TSP, PM_{10}, $PM_{2.5}$)[1]
- Sulfur dioxide (SO_2)
- Mercury.

The NPI website states that the broader desired environmental outcomes of the program are to:

- Maintain and improve air and water quality;
- Minimise environmental impacts associated with hazardous waste, and
- Improve the sustainable use of resources.

The NPI website includes an *Interpretive Guide for NPI – a guide to understanding South Australian's NPI Data* (Ellson & Johnston, 2005) which contains discussion of uses and limitations of the data that are relevant to the inventory as a whole.

[1] TSP – total suspended particulate matter, PM_{10} – particulate matter with an aerodynamic diameter equal or less than 10 µm, $PM_{2.5}$ – particulate matter with an aerodynamic diameter equal or less than 2.5 µm

Key uses for industry, the public and government are noted:

- Industry uses include identifying cost reduction measures or improved system processes, benchmarking of performance and public relations.
- The public can use data to understand emissions in their area, track emissions from companies over time and learn about health and environmental risks of NPI pollutants.
- Government bodies can use the data for policy, planning and regulation.

The *Interpretive Guide for NPI* and NPI website also discuss a number of factors that may need to be considered when examining NPI data. For example, the guide notes that when interpreting the inventory data, information about the potential toxicity, exposure and environmental effects should be considered alongside the inventory. The inventory quantifies the amount of each pollutant released into the environment, but does not illuminate where or how the surrounding environment may be impacted. In addition, a number of reasons may exist for variation in emissions data from year to year, including emission factor changes, methodology changes, or real process changes at a facility. When examining trends over time, changes in the total number of facilities reporting to the inventory may also need to be considered. The accuracy of emission estimates is also noted, as this may vary between calculation methods.

1.3 Scope of Work

The scope of this work includes:

- Review of NPI methodologies used by electricity generators to calculate the stack emissions.
- Explanation of the reasons for the choices of the NPI methodologies.
- Review of the variance in NPI methodologies used across each electricity generator.
- Discussion of the likely variation in emissions if each generation plant adopted an alternative method used at another facility.
- Analysis of the advantage and disadvantages of using site-specific methodologies compared to a uniform methodology being prescribed.

2. EMISSION GENERATION THEORY

The review is limited to stack emissions of the key substances. The below sections discuss the emission generation theory to provide context for the potential variability between operations and estimation methodology.

2.1 Oxides of Nitrogen (NO_x)

NOx emissions from coal-fired power stations are generally formed in the burner due to three chemical mechanisms (Ravi K. Srivastava, 2005):

- Thermal NO_x
- Fuel NO_x
- Prompt NO_x.

Thermal NO_x occurs through the dissociation (separation) and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules due to high temperatures present in the combustion zone. The rate of formation is proportional to the exponent of temperature and the square root of the oxygen concentration. This means that the formation of NO_x is highly dependent on the gas temperature during combustion and the important operating variables including peak temperature residence time, and amount of excess air present (i.e. beyond that required for combustion reactions).

Fuel NO_x formation depends on the nitrogen content in the fuel and the amount of oxygen present during coal devolatilization in the early stages of combustion. The relationship between coal nitrogen content and fuel NO_x emission is complex and still unclear. Prompt NO_x is formed by capture of N_2 by hydrocarbon radicals, but this mechanism forms only a small contribution to NO_x emission from coal combustion.

Total NO_x emissions are primarily determined by the peak combustion temperature as the thermal NOx is the formation mechanism that can be influenced externally. Reductions in peak temperature will reduce overall NO_x emissions as fuel NO_x and prompt NO_x emissions are finite and cannot be avoided. Peak combustion temperatures can be reduced based on boiler configurations (i.e. dry/wet bottom, wall/tangential fired, etc.) and the addition of low NO_x burners controls.

2.2 Particulate Matter

Particulate matter emission from the combustion of fuels is a complex function of boiler firing configuration, boiler operation, power station load, control equipment, and fuel (i.e. coal) properties (US EPA, 1998b).

The boiler firing configuration that influences particulate matter formation relate to the ability to have complete combustion of the pulverised coal. Firing configurations as well as regular maintenance will influence the complete combustion of fuel which will avoid particulate matter formation.

Coal ash content directly relates to particulate matter emissions as this is not reduced during the combustion process. Ash may either settle out in the boiler as bottom ash, or exist in the exhaust gas as fly ash, and can be potentially be emitted through the power station stacks. The distribution of ash depends on the boiler firing method and furnace type (wet or dry bottom).

All coal fired power stations in Australia have particulate matter controls, either electrostatic precipitators (ESP) or fabric filter baghouses. ESPs remove fine particulate matter from exhaust gases using electrostatically charged plates which attract and trap the particulate matter. ESPs are more efficient at removing smaller particle sizes than larger particle sizes. Fabric filter baghouses pass exhaust gas through filter membranes to remove particulate matter through impaction, interception and Brownian diffusion.

Removal efficiencies for both control methods are dependent on operational specifications as well as the combustion exhaust properties. Due to the many variables associated with control efficiencies, equipment manufacturers typically report a minimum collection efficiency.

2.3 Sulfur Dioxide (SO_2)

SO_2 emission from fuel combustion is directly related to the sulfur content in the fuel. Coal contains a small amount of organic and pyritic sulfur, which during the combustion is primarily oxidized to gaseous species such as SO_2 (~95%) and a minor amount of and SO_3 (~5%) (R. K. Srivastava, 2004).

Reduction of SO_2 emissions can occur by desulfurisation of the fuel or scrubbing the exhaust gases. Australian coal fired power stations do not control SO_2 emissions as the majority of the combusted coal is considered to have a low sulfur content (<1%). It is noted that fabric filter baghouses have been documented as providing some emission reduction of SO_2.

2.4 Mercury

Mercury emissions from fuel combustion is directly related to the mercury content within the fuel. Coal is known to contain mercury and due to its volatility it is assumed to be primarily emitted through the combustion stack, in either gaseous or particulate phases.

Australian coal fired power stations do not have any control methods for mercury emissions. It is noted that ESPs and fabric filter baghouses have been documented as providing some emission reduction of mercury.

3. EMISSION ESTIMATION METHODS

There are a several methodologies available for calculating emissions. The NPI Guide (Commonwealth of Australia, 2015) defines four types of emission estimation techniques:

1. Mass balance
2. Fuel analysis or engineering calculations.
3. Sampling or direct measurement.
4. Emission factors.

The sections below provide a general overview of each method and the specific methods available for each substance in the methodology review.

3.1 Mass Balance

This technique is based on estimating the quantity of the NPI substance going into a facility, process or piece of equipment and comparing against the quantity of the NPI substance leaving the facility. Emissions are calculated as the difference between the input and output for each listed substance. Accumulation or depletion of the substance within equipment should be accounted for in the mass balance calculation.

3.2 Fuel Analysis or Engineering Calculations

This method uses the physical and/or chemical properties for a listed substance and incorporates information on such properties into mathematical relationships, such as the ideal gas law. Theoretical models for specific processes can also be used, although these can be complex. These methods may be assisted by site-specific fuel analysis.

3.3 Sampling or Direct Measurement

Sampling methods can be periodic or continuous measurements and are based on measured concentrations of the substance in a process or waste stream, and volume or flow rate of that stream. Some facilities are required to collect direct measurement data for other regulatory purposes and may select to use this data for NPI reporting. Additional sampling or measurement is not required by the NPI.

Stack test data to be used for NPI reporting should be performed under representative (i.e. normal) operational conditions, and in accordance with the relevant regulatory (Australian or International) methods. Selected stack testing frequency can be nominated by the facility or based on environmental licence conditions. Measurements can be used to derive pollutant mass emission rates, or combined with fuel burn rates to generate fuel-based emission factors. Stack testing is typically infrequent (e.g. quarterly or annual) and is therefore commonly extrapolated with reference to operating information to generate an annual emissions profile for a facility.

One commonly used method is the Continuous Emission Monitoring System (CEMS) which provides a continuous record of emissions over time, usually through measuring pollutant concentrations. Once the pollutant concentration is known, emission rates or emission factors can be calculated based on volumetric air throughputs or corresponding fuel burn rates. CEMS can report real-time hourly emissions automatically, however extrapolation over typically small time periods associated with maintenance and calibration (or instrument down time) may be necessary to infer emission rates to cover the whole NPI reporting period.

Prior to the use of stack testing or CEMS to report emissions, protocols for collecting and averaging the data needs to be developed to ensure that the estimates are representative of the facility emissions.

Noting the overlap between state regulatory-driven monitoring (e.g. as per planning approval and/or environmental licencing requirements), these protocols commonly follow relevant state guidance for the measurement and reporting of data, and include the following:

- Queensland: *Air Quality Sampling Manual* (DE, 1997)
- New South Wales: *Approved Methods for the Sampling and Analysis of Air Pollutants in New South Wales* (DEC NSW, 2007)
- Victoria: *A Guide to the Sampling and Analysis of Air Emissions and Air Quality* (EPA Victoria, 2002)
- South Australia: *Emission Testing Methodology for Air Pollution* (EPA South Australia, 2012)
- Western Australia: *Continuous Emission Monitoring System (CEMS) Code for Stationary Source Air Emissions* (DER Western Australia, 2016).

These frameworks include a number of requirements specific to each state, whilst also commonly referring to relevant Australian Standards, as well as relevant international methods, consisting primarily of promulgated US EPA test methods and performance specifications.

3.4 Emission Factors

Emission factors specify the quantity of an NPI substance(s) emitted from a source as a result of a specified activity and take into account relevant pollution control measures employed in carrying out the activity. Emission factors are usually expressed as the mass of the substance emitted per unit of activity (for example, kilograms of xylene emitted per cubic metre of paint or ink produced).

Emission factors are published in NPI Emission Estimation Technique Manuals (EETMs) or can be sourced from international literature or databases, such as the US EPA AP-42 database (US EPA, 2021a), California Air Resources Board CATEF database (California Air Resources Board, 2021), and EMEP/EEA Air Pollutant Emission Inventory Guidebook (EEA, 2019). Default emission factors are typically based on measurements taken at multiple facilities, and so may not provide emissions estimates that are representative of an individual facility given the potential variations e.g. fuel composition or operating conditions.

Emission factors developed from measurements for a specific power station or process can sometimes be utilised to estimate emissions at other similar 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.

3.5 Other Estimation Techniques

Under certain circumstances emissions estimation techniques, other than the four techniques above, may be used for NPI reporting. The use of alternative techniques requires the written approval of the relevant state or territory environment agency. Approval is subject to the provision of robust and traceable data that validates the alternative technique(s). Written approval must be obtained before submission of the emissions report.

3.6 Emission Factor Ratings

Published emission factors are rated using the Emission Factor Rating (EFR) code. An A or B rating indicates a greater degree of certainty than a D or E rating, whilst a rating of U indicates that the emission factor uncertainty has not been rated. The EFR is based on both the quality of the test(s) or information of the source of the factor and on how well the factor represents the emission source. Higher ratings are for factors based on many unbiased observations, or on widely accepted test procedures.

EFR definitions are as follows (US EPA, 1998a):

- **A – Excellent:** Factor is developed from A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimise variability.
- **B - Above average:** Factor is developed from A- or B-rated test data from a "reasonable number" of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with an A rating, the source category population is sufficiently specific to minimize variability.
- **C – Average:** Factor is developed from A-, B-, and/or C-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
- **D - Below average**: Factor is developed from A-, B- and/or C-rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.
- **E – Poor**: Factor is developed from C- and D-rated test data, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.
- **U – Unrated:** The factor has not been subject to a rating process.

The ranking of these methods is supported using Figure 3.1 below, as sourced from the US EPA AP-42 guidance (US EPA, 1998a), in decreasing order of potential reliability:

1. Sampling or direct measurement of annual emissions (e.g. CEMs).
2. Generating source-specific emission factors from discrete sampling events (e.g. parametric source (stack) tests or single source tests).
3. Calculating emissions using engineering calculations.
4. Using a mass/material balance approach.
5. Using the published emission factors (e.g. state or industry factors, or NPI/AP-42).

Power station stack emissions are estimated using the above methods. The method selected should be based on the availability of reliable data to provide the most accurate emissions. This means the most reliable method should be used, even if a less reliable method produced lower/higher annual emissions compared to default method.

The NPI EETM states '*When available, it is preferable to use facility-specific information (e.g. monitoring data) for emission estimation*' pg 22 (SEWPaC, 2012). This statement indicates that the intention of the NPI is to use site specific data where possible and to use default emissions factors in cases where facility-specific data is not available.

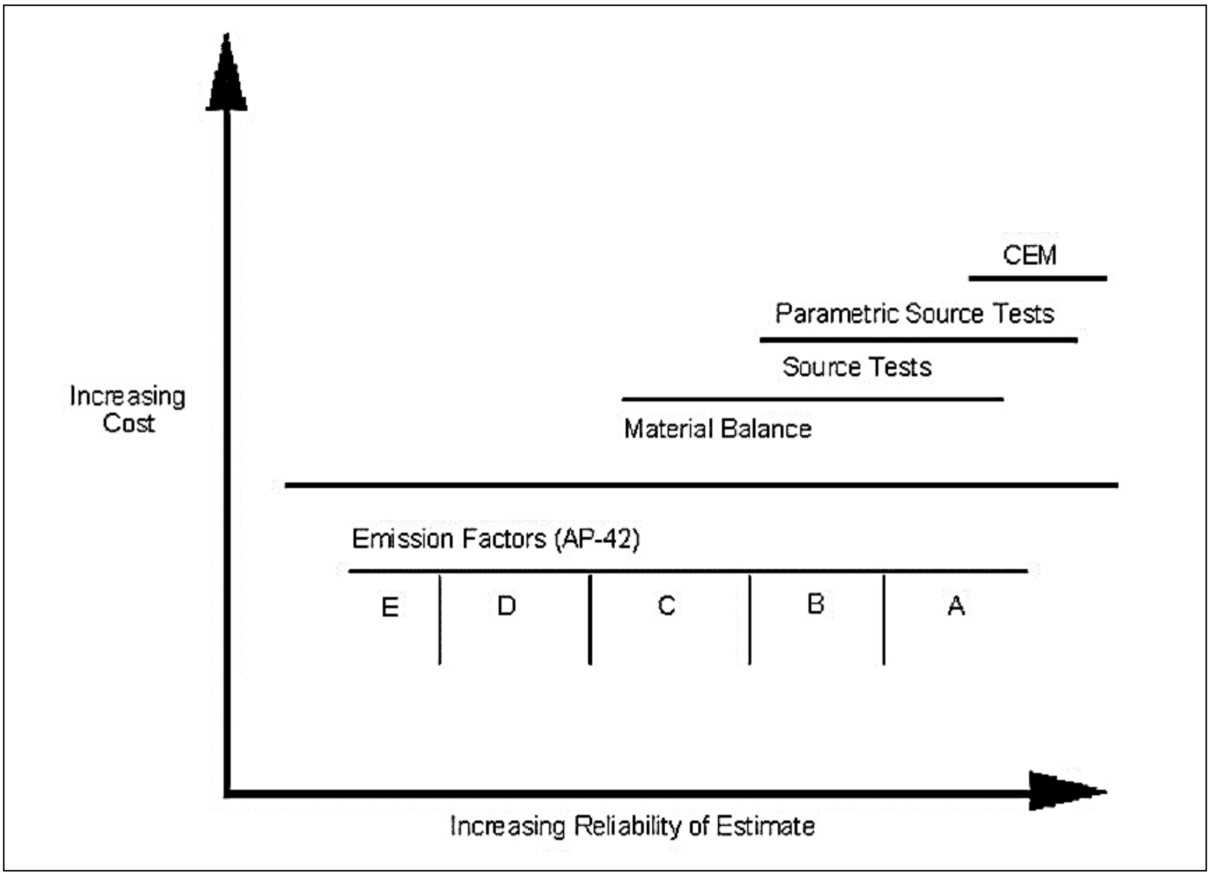

Figure 3.1: Reliability vs. Cost for Emissions Factor Estimation Techniques (adapted from US EPA AP-42 guidance (US EPA, 1998a))

4. POWER STATION STACK EMISSION ESTIMATION METHODOLOGIES

The available emission estimation methods for each substance in this review is summarised in the sections below.

The emission factors reviewed are from the NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation, Version 3.0 (SEWPaC, 2012) (hereafter referred to as 'the NPI EETM') as the relevant manual for use by power stations.

Where available, reliability and variability of the method is identified.

4.1 NO_x Estimation Methods

NO_x emissions from power stations can be estimated using the following methods.

- Sampling or direct measurement (stack testing or CEMS)
- Emission factors.

4.1.1 NO_x Sampling or Direct Measurement (Stack Testing or CEMs)

Stack testing for NO_x should follow the US EPA Method 7, 7A, 7B, 7C, 7D 7E, USEPA Method 20 or ISO Method 10396 or NSW TM-11. If alternative methods are used, then an effort to understand the results comparability to the identified methods should be performed prior to use for NPI reporting.

The US EPA Method 7 identifies a minimum measurement concentration of 2 mg/m^3 (dry, standard temperature and pressure). The uncertainty of individual stack test measurements is provided by the stack test provider and is dependent on the test method, sampling location and sampled data variability. Based on review of available stack test results, a combined measurement uncertainty of 12% is commonly quoted. It is anticipated that the data uncertainty will increase when using discrete stack test results in the calculation of annual NPI emissions. Depending on operational conditions, uncertainty may be minimised by using multiple stack tests, either during the reporting year or multiple years, to determine annual emissions.

Where a NO_x CEMS is used, instrumentation should be installed and operated as per the instrument manufacturer's instructions and relevant regulatory requirements. Australian guidance for operation of NO_x CEMS is varied by State, and commonly refers back to US EPA methods with specific requirements for implementation, whilst also including specific regulatory requirements such as cycling times, data recording requirements, averaging periods and minimum data capture, and supplementary performance specifications (to the US EPA methods).

The US EPA provides performance specifications for NO_x CEMS (US EPA, 2019) and quality assurance procedures in 40 CFR Part 60 Appendix F (US EPA, 2020). A best practice approach, for the ongoing evaluation of CEMS should include well defined, rigorous quality assurance procedures, coupled with regular relative accuracy audits (RAAs), such as those described in US EPA performance specifications. RAAs determine the difference between emission concentrations measured by CEMS and concentrations measured using a reference method. A typical acceptable RAA is within 10% of stack test measurements. Due to the increased measurement frequency, the uncertainty associated with estimating annual emissions is limited to the RAA results.

This measurement data can be combined with combustion air volumes (measured or calculated) to derive pollutant mass emission rates. When combined with fuel burn rates, these emission rates can be used to generate fuel-based emission factors.

4.1.2 NO_x Emission Factors

The NPI EETM includes emission factors for the combustion of black coal and brown coal in boilers for electricity generation. Table 4-1 presents these NPI NO_x emission factors. Based on the review of coal-fired power station reporting methods, the most commonly used emission factors are in bold.

The NO_x emission factors and EFRs listed in the NPI Manual (SEWPaC, 2012) are primarily based on the US EPA AP-42 Chapter 1: External Combustion Sources Section 1.1 Bituminous and Subbituminous Coal Combustion (US EPA, 1998a). These emission factors were recommended by the Pacific Power Review of the NPI EETM (Pacific Power, 2002). The NO_x emission factors are based on 30 tests conducted across 6 sites in the US (US EPA, 1993). All factors represent emissions at baseload operation (i.e., 60 to 110% load) and no NO_x control measures.

As detailed in Section 3.6, each emission factor has been given an EFR, consistent with those reported in the US EPA AP-42 (US EPA, 1998a). An EFR of A indicates a reliable emission factor based on a significant amount of data. A review of the background sampling data used to determine the emission factors, showed the variance in the sampling data to be around 20%. Considering that this sampling was conducted at US-based coal-fired power stations over 20 years ago, there is potential that application of this data to Australian coal-fired power stations would result in an uncertainty of greater than 20%.

Facility-specific emission factors for NO_X (based on energy input) are given in Table 4-2 as presented in the NPI EETM, which includes several now-decommissioned power stations. Our review found that coal-fired power stations are not currently using these emission factors.

Table 4-1: NPI EETM NO_x Emission Factors for Coal Combustion (SEWPaC, 2012)

Boiler / Fuel Type	Emission Factor: NO_x as NO_2 (kg/t)	EFR
Black Coal Combustion		
Uncontrolled, dry bottom, wall fired, bituminous	**11**	**A**
Low NO_x burner, dry bottom, wall fired, bituminous	**5.5**	**A**
Uncontrolled, dry bottom, wall fired, sub-bituminous	6	A
Dry bottom, wall fired. Post-1978*	6	A
Dry bottom, wall fired, sub-bituminous. Post-1978*	3.7	A
Uncontrolled, dry bottom, tangentially fired, bituminous	7.5	A
Low NO_x burner, dry bottom, tangentially fired, bituminous	4.9	A
Uncontrolled, dry bottom, wall fired, sub-bituminous	4.2	A
Dry bottom, wall fired, sub-bituminous. Post-1978*	3.6	D
Uncontrolled, wet bottom, wall fired, bituminous	15.5	E
Wet bottom, tangentially fired, bituminous. Post-1978*	7	E
Wet bottom, wall fired, sub-bituminous	12	A
Cyclone furnace, bituminous	16.5	C
Cyclone furnace, sub-bituminous	8.5	D
Fluidised bed, circulating	2.5	D
Fluidised bed, bubbling	7.6	D
Brown Coal Combustion		
Dry bottom, tangentially fired	3.5	C
Tangentially fired, overfire air	3.4	C
Dry bottom wall fired. Pre 1978*	6.5	C

Boiler / Fuel Type	Emission Factor: NO_x as NO_2 (kg/t)	EFR
Dry bottom, wall fired. Post 1978*	3.2	C
Wall fired, overfire air, low NOx burners	2.3	C
Cyclone furnace	7.5	
Atmospheric fluidised bed	1.8	

Notes:

- Derived from Reference: US EPA 1998a (unless otherwise stated).
- Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters
- *Refer to Table 1.1-3 AP-42 (Reference: US EPA 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

Table 4-2: Facility-Specific Emission Factors for Oxides of Nitrogen Emissions from Coal Combustion (SEWPaC, 2012)

Power Station	Emission Factor: NO_x as NO_2 (kg/PJ)
Black Coal	
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
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
Brown Coal	
Hazelwood, Victoria *	1.51E+05
Loy Yang A, Victoria	1.36E+05
Loy Yang B, Victoria	1.36E+05
Morwell, Victoria *	1.51E+05
Yallourn, Victoria	1.06E+05
Northern, South Australia*	1.36E+05

Data source: Table 6 and 10 of the *NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation* (Commonwealth of Australia, 2011)

* Now decommissioned. Data presented for completeness as it is provided in the NPI EETM.

4.2 Particulate Matter Estimation Methods

Particulate matter emissions from power stations can be estimated using the following methods.

- Sampling or direct measurement (stack testing or CEMS)
- Emission factors.

4.2.1 Particulate Matter Sampling or Direct Measurement

Concentration Measurement – Discrete Stack Test

Stack testing for particulate matter should follow the US EPA Method 5, Modified Method 5 or NSW TM-15. If alternative methods are used, then an effort to understand the results comparability to the identified methods should be performed prior to use for NPI reporting.

Particle Size Fraction Measurement

Stack testing for particle size faction (i.e. PM_{10} and $PM_{2.5}$) should follow the US EPA Method 201, 201A or NSW OM-5.

The US EPA Method 5 and Method 201 identifies a minimum measurement concentration to be based on the gravimetric balance used for filter weights. Based on review of available stack test results, a 3% uncertainty is commonly quoted for total suspended particulate and 9% for PM_{10} and $PM_{2.5}$. Given likely variability in this parameter under varied operating conditions, this data uncertainty will increase when using the stack test results to calculate the annual NPI emissions. Uncertainty may be minimised by using multiple stack tests, either during the reporting year or multiple years such as a rolling average of previous years' results, to determine annual emissions.

An alternative method for measurement of PM_{10}:TSP and $PM_{2.5}$:TSP particle size ratios is the use of in-house laser diffraction-based methods. This method involves capturing solid particulate matter and dispersing within a liquid suspension, allowing the particle diameter to be measured using laser diffraction. The method used for reporting has instrument manufacturer-based quality audit standards and measurement protocols. There is no NATA accreditation for this measurement method. Selected power stations have compared the results of the laser sizing method to the US EPA Method 201A and found comparable ratios (i.e. within 10% of the size ratio measured using Method 201A).

Opacity CEMS

Opacity CEMS instrumentation should be installed and operated as per the instrument manufacturer's instructions. There is limited Australian guidance for operation of opacity CEMS, but NSW does identify cycling times, data recording requirements, averaging periods and minimum data capture on their website[2]. The US EPA provides quality assurance procedures in 40 CFR Part 60 Appendix F (US EPA, 2020). A best practice approach, for the ongoing evaluation of CEMS, should include well defined, rigorous quality assurance procedures coupled with regular relative accuracy audits (RAAs), such as those described in US EPA performance specifications. RAAs determine the difference between emission concentrations measured by CEMS and concentrations measured using a reference method. A typical acceptable RAA is within 25% of stack test measurements. Due to the increased measurement frequency, the uncertainty associated with estimating annual emissions is limited to the RAA results.

[2] https://www.epa.nsw.gov.au/your-environment/air/industrial-emissions/sampling-analysing-air-emissions

Opacity CEMS measures for total suspended particulate emissions only. The smaller particle size ratios will need to be determined using an alternative method, potentially using default or site-specific particle size ratios.

This concentration data can be combined with combustion air volumes (measured or calculated) to derive pollutant mass emission rates. When combined with fuel burn rates, these emission rates can be used to generate fuel based emission factors.

4.2.2 Particulate Matter Emission Factors

The NPI EETM includes emission factors for the combustion of black coal and brown coal in boilers for electricity generation. Table 4-3 presents the emission factors for black coal combustion.

The 2002 review of NPI EETM emission factors found that the particulate matter emission factors from the US EPA AP-42 Chapter 1: External Combustion Sources Section 1.1 Bituminous and Subbituminous Coal Combustion (US EPA, 1998a) were overly simplistic for Australian coal conditions (Pacific Power, 2002). The review recommended that semi-empirical emission factors be developed based on the background data supporting the US EPA AP-42 Chapter 1. The semi-empirical emission factors take into account the amount of fly ash generated which allows the emission factor to be applied to more boiler configuration types.

As detailed in Section 3.6, each emission factor has been given an EFR. The EFRs of A indicate a reliable emission factors based on a significant amount of data. The assignment of the EFR A is not clearly justified as the 2002 review did not detail the number of sampling data points used to generate the semi-empirical emission factors. As the supporting background data is currently not available for review, no emission factor variability can be determined.

The NPI EETM emission factor includes variables for the control method and the identified default control methods, based on the US EPA data (US EPA, 1998a), are:

- 99.8 % for fabric filter
- 99.2% for ESP.

ESP Performance

ESP technology is applicable to a variety of coal combustion sources. Because of their modular design, ESPs can be applied to a wide range of system sizes and should have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, as well as precipitator voltage and current. Other factors that influence the ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies greater than 99 percent for fine (less than 0.1 µm) and coarse particles (greater than 10 µm). This data shows a reduction in collection efficiency for particle diameters between 0.1 and 10 µm.

Fabric Filter Performance

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of fabric filters is dependent on a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include inlet particle concentration and size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. In addition, the particle collection efficiency and size distribution can be affected by certain fabric properties (e. g., structure of fabric, fibre composition, and bag properties). Collection efficiencies of fabric filters can be as high as 99.9 percent.

The 2002 review stated that these default control factors are likely to underestimate collection efficiency and therefore result in conservative estimates (pg 7 (Pacific Power, 2002)). Due to this factor, if possible, site specific control factors should be used.

Site-specific control factors are rarely available, as stacks are typically not designed for stack testing pre and post controls. Section 5.5 reviews the theoretical control factors for Australian power stations based on sites that provided sufficient information and the NSW EPA review of coal fired power station emissions (NSW EPA, 2018).

Particle size ratios

The NPI EET emission factor includes variables for the exhaust particle size ratios and the identified default size, based on the US EPA cumulative site distribution data (US EPA, 1998a), which are:

- PM_{10} fraction of total particulate matter: 92% for fabric filter plant
- $PM_{2.5}$ fraction of total particulate matter: 53% for fabric filter plant
- PM_{10} fraction of total particulate matter: 67% for ESP
- $PM_{2.5}$ fraction of total particulate matter: 29% for ESP.

The particle size distribution data in US EPA AP-42 Chapter 1 has an EFR of D for ESP and an EFR of E for baghouses. These EFRs indicate that the ratios are below average to poor and may not represent the emission source well.

Particle size distribution data from Australian coal fired boilers have indicated significant variations from these default size distributions. The PM_{10} fraction has been measured as less than half the default ratio and the $PM_{2.5}$ fraction as less than 20% of the default ratio. This does indicate that the default ratio, while not necessarily accurate or representative, is conservative.

It is noted that the NPI manual uses the US EPA AP-42 Chapter 1.1 background document data to establish an emission factor for particulate matter size fractions with controls, and identifies an EFR of A. This EFR is in direct contrast to the EFRs provided in the AP-42 Chapter 1.1. In table 1.1-6 of the US EPA AP-42 Chapter 1.1 which identifies that the uncontrolled particulate matter size fraction emissions have an EFR of C. When controls are included in the emission factors the EFR reduced to D for ESP and E for baghouse filters. These lower EFRs indicate that the confidence in the emission factors are reduced when considering particle size distributions and even further reduced when considering particulate matter controls method and particle size fractions.

The reference material for Table 1.1-6 (External Combustion Particulate Emissions: Source Category Report, EPA/600/7-86/043, November 1986) is from measurement data gathered prior to 1986. The dataset to determine the uncontrolled particle size fractions (EFR of C) was from 124 samples where the PM_{10} fraction ranged from 0.1-1 and the PM2.5 size fraction ranged from 0.01-1. The dataset to determine the ESP controlled particle size fractions (EFR of D) was the average of 88 samples where the PM_{10} fraction ranged from 0.34-1 and the PM2.5 size fraction ranged from 0.03-0.94. The dataset to determine the baghouse controlled particle size fractions (EFR of E) was the average from 2 samples.

Considering the source of the data to establish the NPI coal combustion emission factors are from pre-1986 measurement, the advancement of operational and control methods, the very limited size sample for some controls, the wide variation in particle size fractions and the US EPA did not provide and EFR greater than C, the EFR of A in the NPI manual should be considered an error and the emission factor taken as a very loose estimation of potential actual emissions. Site specific data, gathered using responsible and robust methods should be considered more accurate and precise than the default NPI emission factor estimates.

The background data used for determining the NPI manual particulate matter emission factors do report significant variations in the particle size emissions at controlled outlets, meaning that large variations between coal combustion sources should not be unexpected.

Table 4-3 Particulate Matter Emission Factors for Coal Combustion (SEWPaC, 2012)

Substance	Emission Estimation Technique (a) (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR
Black Coal		
PM_{10}	A x 1000 x F x (1-ER/100) x FP (**b**) (**6.25**) 0.34 for fabric filter plant 0.96 for ESP plant	A
$PM_{2.5}$	A x 1000 x F x (1-ER/100) x FP* (53%/92%) x 0.34 = 0.20 for fabric filter plant (29%/67%) x 0.96 = 0.42 for ESP plant	A
Brown Coal		
PM_{10}	A x 1000 x F x (1-ER/100) x FP (**b**) (**6.25**) 1.7 x A for fabric filter plant 4.8 x A for ESP plant	A
$PM_{2.5}$	A x 1000 x F x (1-ER/100) x FP* (53%/92%) x 1,7 x A = 0.98 x A for fabric filter plant (29%/67%) x 4.8 x A = 21 x A for ESP plant	A

Notes:

- Derived from Reference: USEPA 1998a (unless otherwise stated).
- Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters
- *Refer to Table 1.1-6 AP-42 (Reference: USEPA 1998a) Cumulative Mass %

A= weight fraction of ash in the coal. (10% ash is 0.1 ash fraction). Use 0.2 as default
F= fly ash fraction of total ash. Assume 0.9 as default
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.

4.3 SO_2 Estimation Methods

SO_2 emissions from power stations can be estimated using the following methods.

- Mass balance
- Sampling or direct measurement (stack testing or CEMS).
- Emission factor.

4.3.1 SO_2 Mass Balance

The mass balance method for estimating SO_2 emission depends on the sulfur content in the coal combusted and the proportion that is assumed oxidised to SO_2 in stack gases. The sulfur content of the coal is often measured on a daily basis as it is an important parameter for the operation of the power station. The more frequent the sulfur content measurements, the more accurate the estimated mass balance will be. It is typically assumed that the 95% of the sulfur is oxidised to SO_2, while 5% is converted to SO_3/H_2SO_4.

This method may provide the most reliable estimates of SO_2 emissions if there is a higher frequency of sulfur coal content measurement when compared to the stack testing frequency.

4.3.2 SO_2 Sampling or Direct Measurement (Stack Testing or CEMs)

Stack testing for SO_2 should follow the US EPA Method 6, 6A, 6B, 6C, ISO Method 7935, 10396, 11632 or NSW TM-4. If alternative methods are used, then an effort to understand the results comparability to the identified methods should be performed prior to use for NPI reporting.

The US EPA Method 6 identifies a minimum measurement concentration of 3.4 mg/m^3. The uncertainty in an individual stack test result is provided by the stack test provider and is dependent on the test method, sampling location and sampled data variability. As consistent with NO_x, for available stack test results, a combined measurement uncertainty of 12% is commonly quoted. It is anticipated that the data uncertainty will increase when using discrete stack test results in the calculation of annual NPI emissions. Depending on operational conditions, uncertainty may be minimised by using multiple stack tests, either during the reporting year or multiple years, to determine annual emissions.

Where a SO_x CEMS is used, instrumentation should be installed and operated as per the instrument manufacturer's instructions. There is limited Australian guidance for operation of SOx CEMS, but NSW does identify cycling times, data recording requirements, averaging periods and minimum data capture[3], whilst also referencing the US EPA performance specification. The US EPA provides performance specifications for SO_x CEMS (US EPA, 2019) and quality assurance procedures in 40 CFR Part 60 Appendix F (US EPA, 2020). A best practice approach for the ongoing evaluation of CEMS should include well defined, rigorous quality assurance procedures coupled with regular RAAs, such as those described in US EPA performance specifications. RAAs determine the difference between emission concentrations measured by a CEMS and concentrations measured using a reference method. A typical acceptable RAA is within 10% of stack test measurements. Due to the increased measurement frequency, the uncertainty associated with estimating annual emissions is limited to the RAA results.

Based on the measured concentrations, either the time based emission rates or fuel based emission factors can be calculated based on volumetric air throughputs or corresponding fuel burn rates.

4.3.3 SO_2 Emission Factor

The NPI EETM includes emission factors for the combustion of black coal and brown coal in boilers for electricity generation.

[3] https://www.epa.nsw.gov.au/your-environment/air/industrial-emissions/sampling-analysing-air-emissions

Table 4-4 presents the SO_x emission factors for black coal combustion. Based on the review of power station reporting methods, the most commonly used emission factors are shown in bold font.

The SO_2 emission factors and EFRs listed in the NPI Manual (SEWPaC, 2012) are primary based on the US EPA AP-42 Chapter 1: External Combustion Sources Section 1.1 Bituminous and Subbituminous Coal Combustion (US EPA, 1998a). These emission factors were recommended by the Pacific Power Review of the NPI emission Estimation Technique Manual for Fossil Fuel Electric Power Generation (Pacific Power, 2002). The emission factors are similar to the mass balance assumptions except that the different types of coal are assumed to convert to SO_2 at a different percentage. Based on US coal properties, on average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, while the rest is SO_3 and gaseous sulfate or retained in bottom ash. With subbituminous coal, 87.5% of the fuel sulfur converts to SO_2 as more sulfur is retained in the bottom ash due to the alkaline nature of the coal ash.

The US EPA AP-42 (US EPA, 1993) emission factor is determined based on 36 test runs conducted across 9 sites in coal fired power stations in the US. The boiler types of the tested sites included cyclone, FBC-BB, FBC-C, hand-fed, PC-fired and PC-T fired. The sulfur contents of the tested coal ranged from 0.44% to 5.96%.

As detailed in Section 3.6, each emission factor has been given an EFR, consistent with those reported in the US EPA AP-42 (US EPA, 1998a). The EFRs of A indicate a reliable emission factor based on a significant amount of data. Review of the background sampling data found that the variability of the sampling results was around 2%. Considering that the tests were of US power stations conducted over 20 years ago, there is potential for the variability of the measurement data to represent Australian power stations to be higher than the 2%.

Table 4-4: SO_2 Emission Factors for Coal Combustion (SEWPaC, 2012)

Substance	Emission Estimation Technique (a) (number in brackets refers to supporting information in Reference: Pacific Power International 2002) kg/tonne unless otherwise indicated	EFR (b)
Black Coal		
Sulfur dioxide	19 x S for Bituminous coal 17.5 x S for Sub-Bituminous coal	A A
Brown Coal		
Sulfur dioxide	15 x S 5 x S (fluidised bed using limestone bed material (**6.29**)	C C

Notes:

- Derived from Reference: USEPA 1998a (unless otherwise stated).
- Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters
- S = percentage sulfur content of coal as fired (If sulfur content = 0.5%, S= 0.5)

4.4 Mercury Estimation Methods

Mercury emissions from power stations can be estimated using the following methods.

- Mass balance
- Sampling or direct measurement (stack testing or CEMs)
- Emission factor.

4.4.1 Mercury Mass Balance

The mass balance method for estimating mercury emissions depends on the mercury content on the coal combusted and an assumed percentage volatilised and exhausted via the stack. The mercury content of the coal is often only measured on a six monthly basis as it is a parameter typically only important for environmental reporting. The percent volatilisation would either be based on an assumption or measured concentration of mercury in the coal.

4.4.2 Mercury Sampling or Direct Measurement (Stack Testing or CEMs)

Stack testing for mercury should follow the US EPA Method 29 or NSW TM-12. If alternative methods are used, then an effort to understand the results comparability to the identified methods should be performed prior to use for NPI reporting.

The US EPA Method 29 identifies a method detection limit for mercury of 0.56 ug/m^3. The uncertainty in individual stack test results is provided by the stack test provider and are dependent on the test method, sampling location and sampled data variability.

Based on a review of available stack test results, a 15% uncertainty is commonly quoted. It is anticipated that the data uncertainty will increase when using the stack test results to calculate the annual NPI emissions. Depending on operational conditions and variability of the mercury concentration in coal, uncertainty may be limited by using multiple stack tests, either during the reporting year or multiple years, to determine annual emissions.

This concentration data can be combined with combustion air volumes (measured or calculated) to derive pollutant mass emission rates. When combined with fuel burn rates, these emission rates can be used to generate fuel-based emission factors.

4.4.3 Mercury Emission Factor

The NPI EETM includes emission factors for the combustion of black coal and brown coal in boilers for electricity generation. Table 4-5 presents the mercury emission factors for black coal combustion.

The 2002 review of NPI EETM emission factors found that the mercury emission factors from the US EPA AP-42 Chapter 1: External Combustion Sources Section 1.1 Bituminous and Subbituminous Coal Combustion (US EPA, 1998a) are not relevant to the Australian coal conditions (Pacific Power, 2002). The review recommended the emission factor from US EPA document Emergency Planning and Community Right-to-Know Act section 313: Guidance for Reporting Toxic Chemical: Mercury and Mercury Compound Categories (US EPA, 2001). These emission factors assume a percentage of the mercury will be emitted through the stack while the rest is contained in the fly and bottom ash.

As detailed in Section 3.6, each emission factor has been given an EFR, consistent with those reported in the US EPA AP-42 (US EPA, 1998a). The EFRs of A indicate a reliable emission factor based on a significant amount of data. The supporting background data that the emission factors is currently not available for review so no variability can be determined.

Facility-specific emission factors for mercury (based on coal throughput) are given in Table 4-6: Mercury Site-Specific Emission Factors for Black Coal Combustion . Our review found that coal-fired power stations are not currently using these facility-specific emission factors, instead using the default emission factors with monthly, six-monthly or historical measurements of mercury content in the coal used on-site (detailed in Section 5.3). This data does indicate the mercury emissions can vary between coal type and power station Australia by 4.8 times, which indicates high variability and low reliability of an emission factor.

Table 4-5: Mercury Emission Factors for Coal Combustion (SEWPaC, 2012)

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
Black Coal			
Mercury	1/2b	C x 8.1 E-04 for fabric filter and Electrostatic Precipitator plant (6.21) 3.16 E-05	A
Brown Coal			
Mercury	1/2b	C x 9.84 E-04 2.6 E-05 (**6.37**)	A A

Notes:

- Derived from Reference: USEPA 1998a (unless otherwise stated).
- Emission factors apply to coal feed, as fired for pulverised coal fired, dry bottom boilers with emissions controlled by electrostatic precipitators, or fabric filters
- C = Concentration of metal in the coal, part per million by mass or mg/kg (as received basis)

Table 4-6: Mercury Site-Specific Emission Factors for Black Coal Combustion (SEWPaC, 2012)

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

Data source: Table 7 of the *NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation* (Commonwealth of Australia, 2011).
*Power station decommissioned. Data presented for completeness as it is available in the NPI EETM.

4.5 Summary of Methods

Table 4-7 summarises the methods available for each reviewed substance, the complexity of estimation, cost indication and reliability of estimate.

Table 4-7: Available Emission Estimation Methods and Reliability

Substance	EET	Method	Complexity	Cost	Reliability
NOx	Sampling or Direct Measurement	Stack Testing	Minimal – third party	$$	High (variability >=12%) [1]
		CEMS	High – internal maintenance and third party calibration obligations	$$$$	High (to be based on RAA results, <10% typically acceptable)
	Emission factor	NPI EET Manual	Low	$	High (for most commonly used emission factors, variability >=20%) [2]
TSP	Sampling or Direct Measurement	Stack Testing	Low – third party	$$	High (variability >=3%) [3]
		CEMS	High – internal maintenance, third party calibration obligations	$$$$	High (to be based on RAA results, <25% typically acceptable)
PM_{10}	Sampling or Direct Measurement	Stack Testing	Low – third party	$$	High (variability >=9%) [3]
	Emission factor	NPI EET Manual	Low	$	Low [4]
$PM_{2.5}$	Sampling or Direct Measurement	Stack Testing	Low – third party	$$	High (variability >=9%) [3]
	Emission factor	NPI EET Manual	Low	$	Low [4]

Substance	EET	Method	Complexity	Cost	Reliability
SO_2	Mass balance	Fuel sulfur testing	Low	$	High (depending on measurement frequency)
	Sampling or Direct Measurement	Stack Testing	Low – third party	$$	High (variability >=12%) [1]
		CEMS	High – internal maintenance and third party calibration obligations	$$$$	High (to be based on RAA results, <10% typically acceptable)
	Emission factor	NPI EET Manual	Low	$	High (variability >=2%) [2]
Mercury	Mass balance	Fuel mercury content testing	Low to medium – typically measured six monthly	$	High
	Sampling or Direct Measurement	Stack Testing	Medium – third party	$$	High (variability >=15%) [1]
	Emission factor	NPI EET Manual	Low	$	Not determined[5]

Table notes:

[1] Based on review of stack test results.

[2] Based on variability of samples in background sampling data used to derive US EPA emission factors.

[3] Review of stack test results indicates uncertainty of 3% for TSP, 9% for PM_{10}. Variability in annual emission estimate based on this data is expected to be higher.

[4] Below average to poor EFRs for PM_{10} and $PM_{2.5}$ fraction of TSP in the US EPA AP-42 for ESP and baghouses, respectively, and unknown reliability of the underlying EF equation.

[5]Emission factors do not appear to be commonly used for the estimation of mercury emissions from Australian coal-fired power stations.

5. POWER STATION NPI METHDOLOGY REVIEW APPROACH

5.1 Power Stations

As agreed with AEC and other stakeholders, all coal-fired power stations across Australia were contacted with a request for information. Responses were received from16 out of 19 power stations, and sufficient information was provided to include 14 power stations in this review. The geographic distribution of these 14 power stations are shown in Table 5-1.

Table 5-1 Power Stations Reviewed in Each State

State	Number of Power Stations Included in Review	Coal Type	Controls
NSW	3	Black	Fabric Filters (bag houses), low NO_x burners
VIC	1	Brown	ESP
QLD	8	Black	Fabric Filters, ESP, low NO_x burners
WA	2	Black	ESP

5.2 Information Collection

ERM has prepared a table with a list of questions to collect information from the 17 power stations. All information was based on the latest FY21 NPI reporting period. As shown in Table 5-2, in addition to general information about the power station emission sources, fuel and control methods, a series of questions relevant to each EET method was provided.

Table 5-2 Information Collected from Power Stations

Category	Question
General information (for ERM use only)	*Power station name*
	Operator name
	Power station location
	Type of fuel
	Number of stacks
	Stack control methods
EET 1 Mass Balance	Variable for mass balance
	Source of variable values
	Frequency of variable measurement
	Standard of variable measurements
EET 2 Fuel Analysis or Engineering Calculation	Description of calculation equation
	Variables used in equation
	Source of variable values
	Frequency of variable measurement
	Standard of variable measurements
	Any assumptions made for the input variables

EET 3 Sampling or Direct Measurement	Sampling method
	Standards followed for measurements
	Status of standards being met (i.e. maintenance and calibrations)
	Frequency of measurements
	Methods to screen out invalid data
	Calculations used to determine annual emissions
	Assumptions made for the calculations
EET 4 Emission Factor	Source of emission factor
	Variables used in the equations
	Source of variable values
	Standard of variable measurements
	Frequency of variable measurement
EET 5 Approved Alternative	Description of calculation method
	Description of calculation equation
	Variables used in equation
	Source of variable values
	Frequency of variable measurement
	Standard of variable measurements
	Assumptions made for the calculations
	Approximate date of approval from NPI regulator
Data	Amount of coal combusted during the reporting year
	Emission factors used for the five substances for each boiler
	Annual emissions of the five substances from each boiler

5.3 Summary of Information Received

Table 5-3 provides a summary of the information received for this review.

Table 5-3: Summary of information received

Substance	Method	Number of Stations	Notes
NO_x	CEMS	9	Hourly or annual emission factors based on NO_x concentrations and burn rates or energy production.
	Stack Tests	4	Quarterly or annual emission factors based on NO_x concentrations and burn rates or energy production.
	EF	1	EF from historical direct measurement
TSP	CEMS	7	Hourly or annual emission factors based on TSP concentrations and burn rates or energy production.
	Stack Tests	4	Quarterly or annual emission factors based on TSP concentrations and burn rates or energy production. Some facilities use historical data for checks.
PM_{10}	CEMS	7	Hourly or annual emission factors based on PM_{10} concentrations and burn rates or energy production.
	Stack Tests	6	Quarterly or annual emission factors based on PM_{10} concentrations and burn rates or energy production. Some facilities use historical data for checks, one uses 3-year rolling average.
	Stack Tests	1	PM_{10}/TSP size fractions assumed for the stack test data.
	Engineering Calculations	1	Uses historical data to provide site-specific EF, assuming ash content, control efficiency and particulate fraction
$PM_{2.5}$	CEMS	7	$PM_{2.5}$/TSP size fractions assumed for the CEMS data.
	Stack Tests	6	$PM_{2.5}$/TSP size fractions assumed for the stack test data. One facilities uses 3-year rolling average.
	Engineering Calculations	1	Uses historical data to provide site-specific EF, assuming ash content, control efficiency and particulate fraction
SO_2	CEMS	6	Hourly or annual emission factors based on SO_2 concentrations and burn rates or energy production.
	Stack Tests	2	Quarterly or annual emission factors based on SO_2 concentrations and burn rates or energy production.
	Mass Balance	6	Uses default emission factor with the site specific monthly, 6 monthly or historical coal sulfur content.
Mercury	Emission Factor	12	Uses default emission factor with site specific monthly, 6 monthly or historical coal mercury content sampling. One facility uses site-specific EF in NPI manual.
	Stack Tests	2	Emission factor estimated based on 6 monthly stack testing.

Figure 5.1 provides a visual representation of the emission estimation methods used by the survey respondents. It is noted that the number of responses used to generate this data ranged from 11 responses (TSP) to 14 responses (PM_{10}). Information regarding TSP emissions was not provided for all power stations, as this is not reported directly to the NPI.

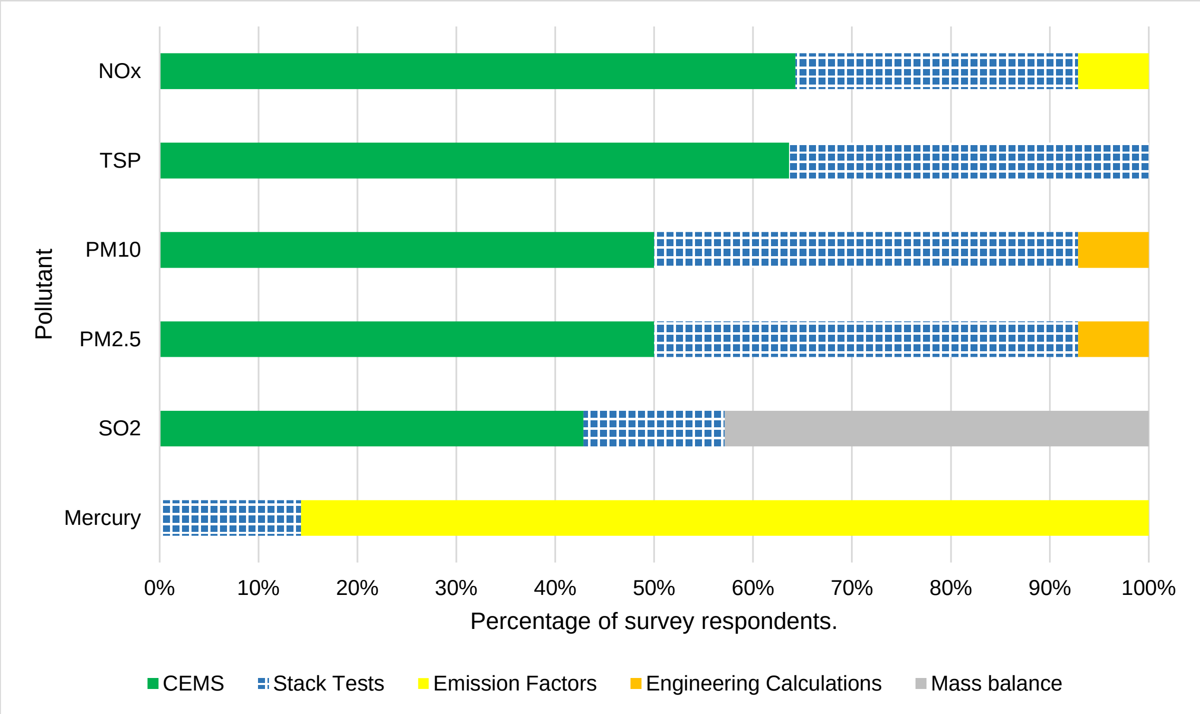

Figure 5.1 Summary of Adopted NPI Emission Estimation Method by Pollutant

5.4 Comparison of Emission Intensities

In order to understand the differences of the site specific and default emission factors provided in the NPI EETM, the emission intensities in kg/MWh for PM_{10}, $PM_{2.5}$, NO_x, SO_2 and mercury were plotted. These emission intensities represent the amount of a specific pollutant (kg) that is emitted per unit of electrical output (MWh), and are provided in the form of kg/MWh. Emission intensities for black and brown coal are presented separately.

The site specific emission intensities were calculated by taking the NPI reported emissions and dividing it by the electricity production provided in National Greenhouse and Energy Reporting (NGER) report. The default emission intensities were calculated from the default emission factor with an assumption of the net calorific value of black coal and the electricity generation thermal efficiency. Based on a review of typical coals used within Australia, an assumption of 20 MJ/kg was assumed for the net calorific value with a power station thermal efficiency of 33%.

The emission intensities for the pollutants assessment for the past four NPI reporting years (FY17 to FY20) are compared in Figure 5.2 to Figure 5.11. These figures show that whilst there is a wide range of values, the emission intensities overall are comparable to the emission intensity calculated from the default NPI EETM emission factor with fabric filter control. The figures also show that the emission intensities are generally lower than the emission intensity calculated from the default NPI EETM with ESP control.

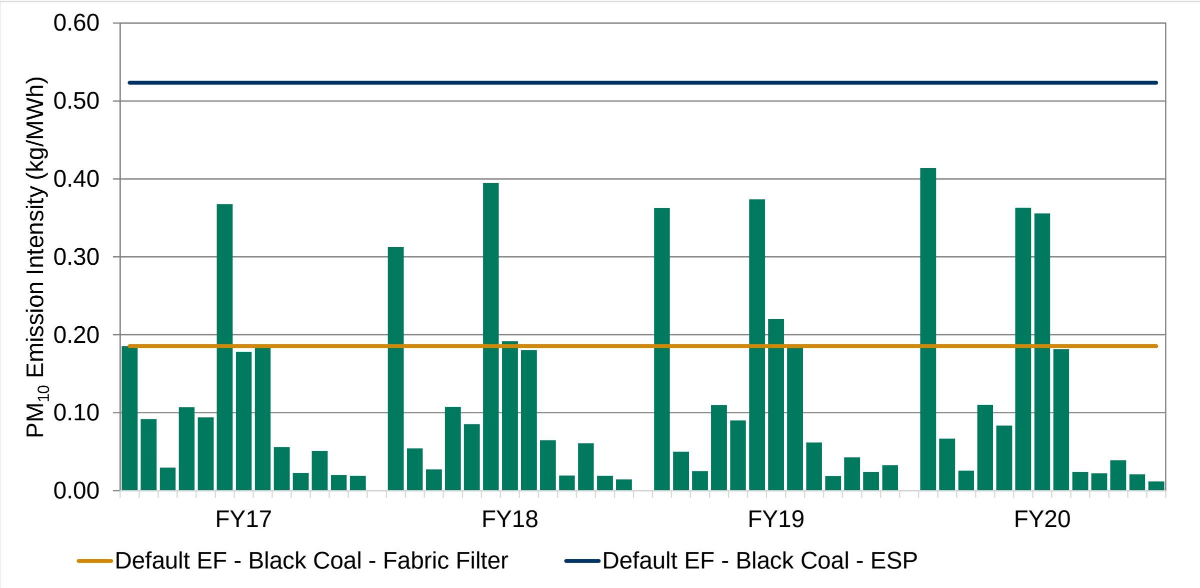

Figure 5.2: Black Coal: PM_{10} emission intensities – FY17 to FY20 NPI reporting year

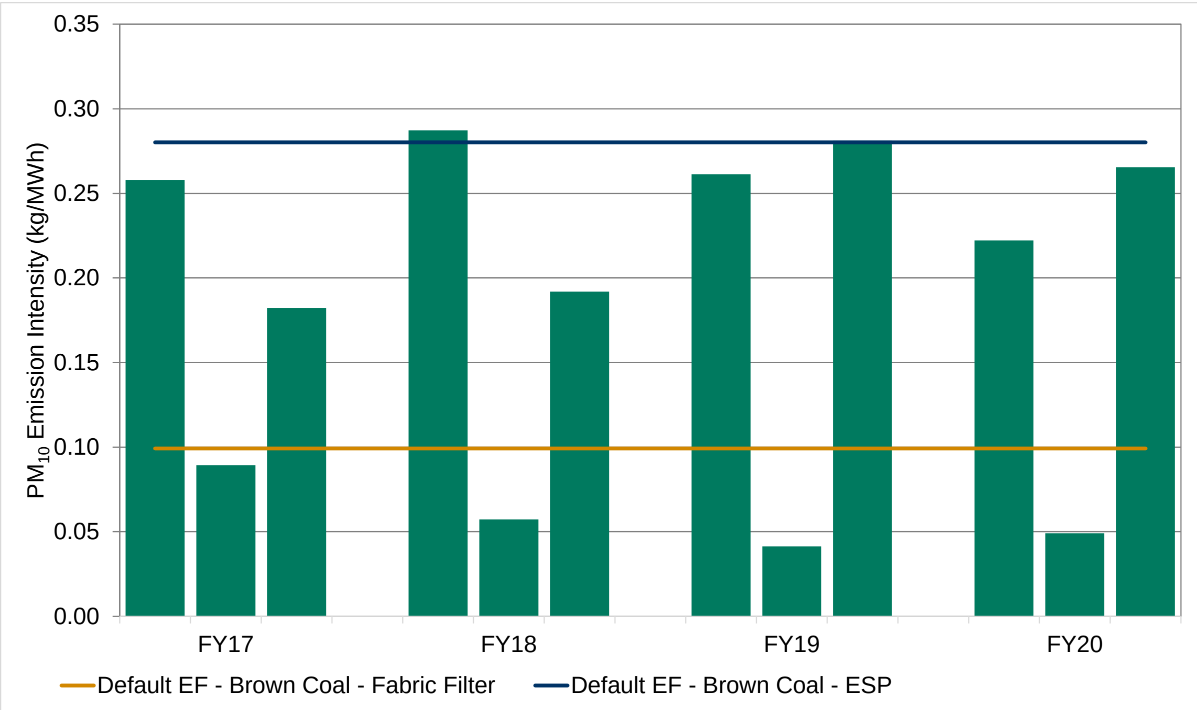

Figure 5.3: Brown Coal: PM_{10} emission intensities – FY17 to FY20 NPI reporting year

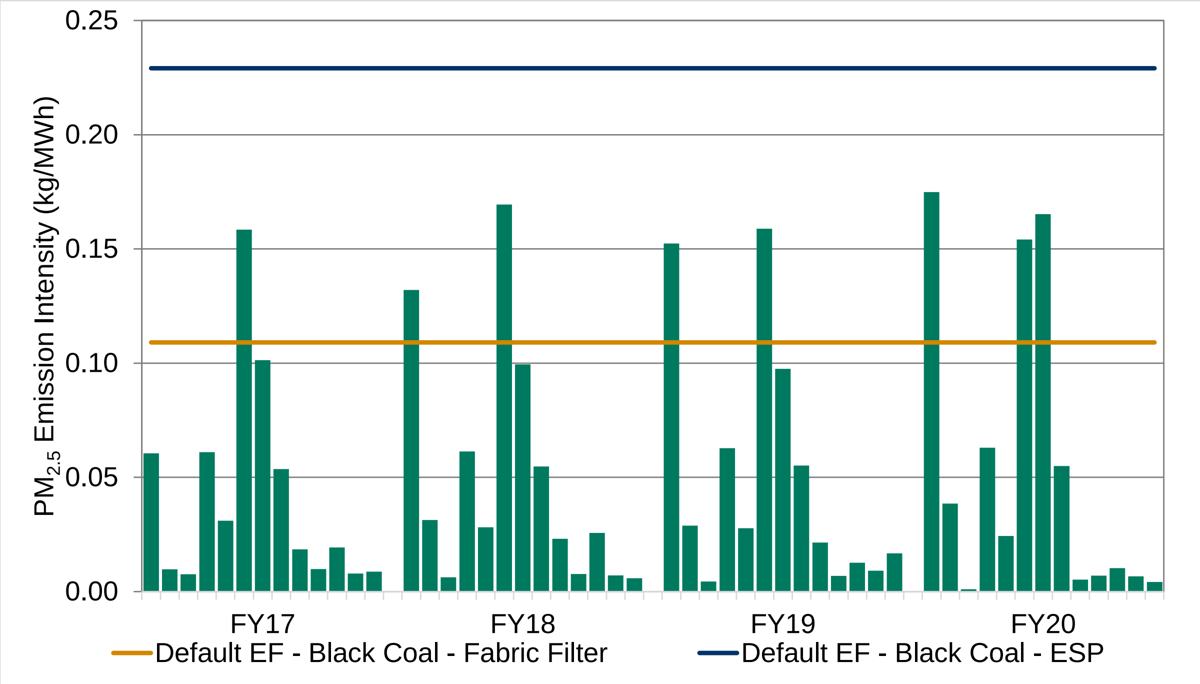

Figure 5.4: Black Coal: $PM_{2.5}$ emission intensities – FY17 to FY20 NPI reporting year

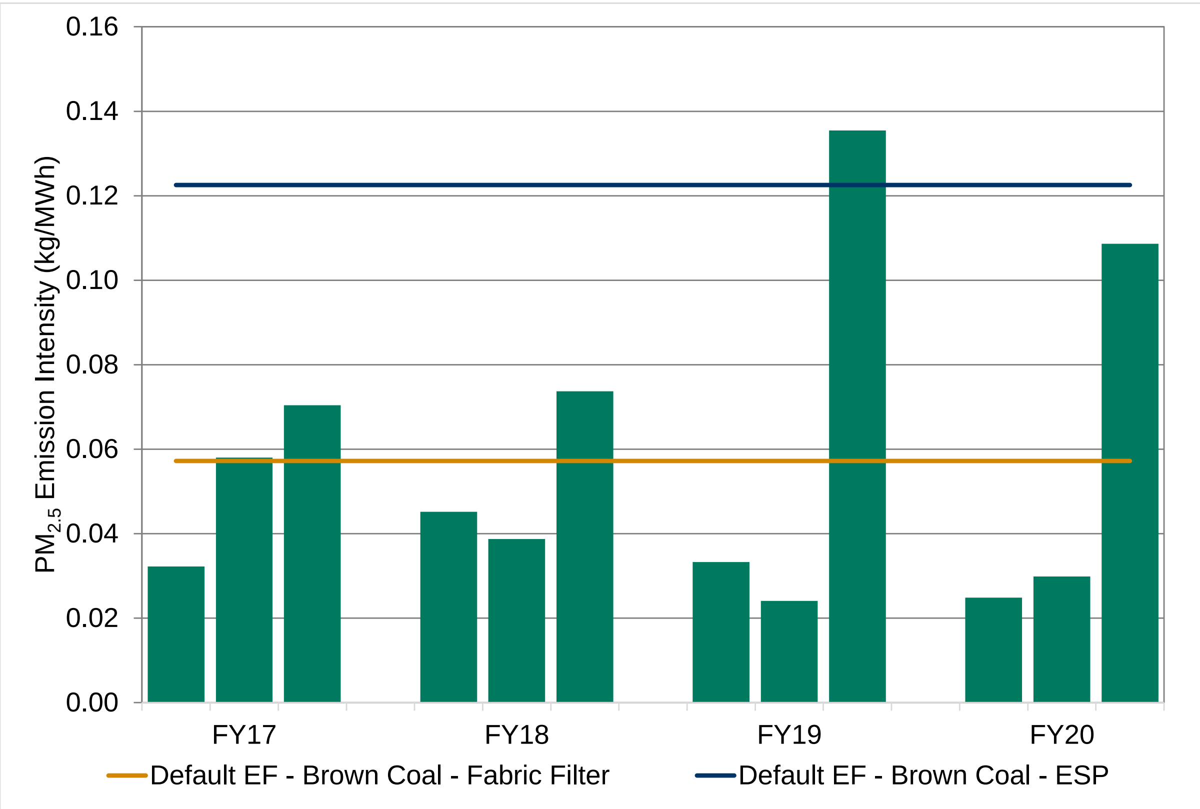

Figure 5.5: Brown Coal: $PM_{2.5}$ emission intensities – FY17 to FY20 NPI reporting year

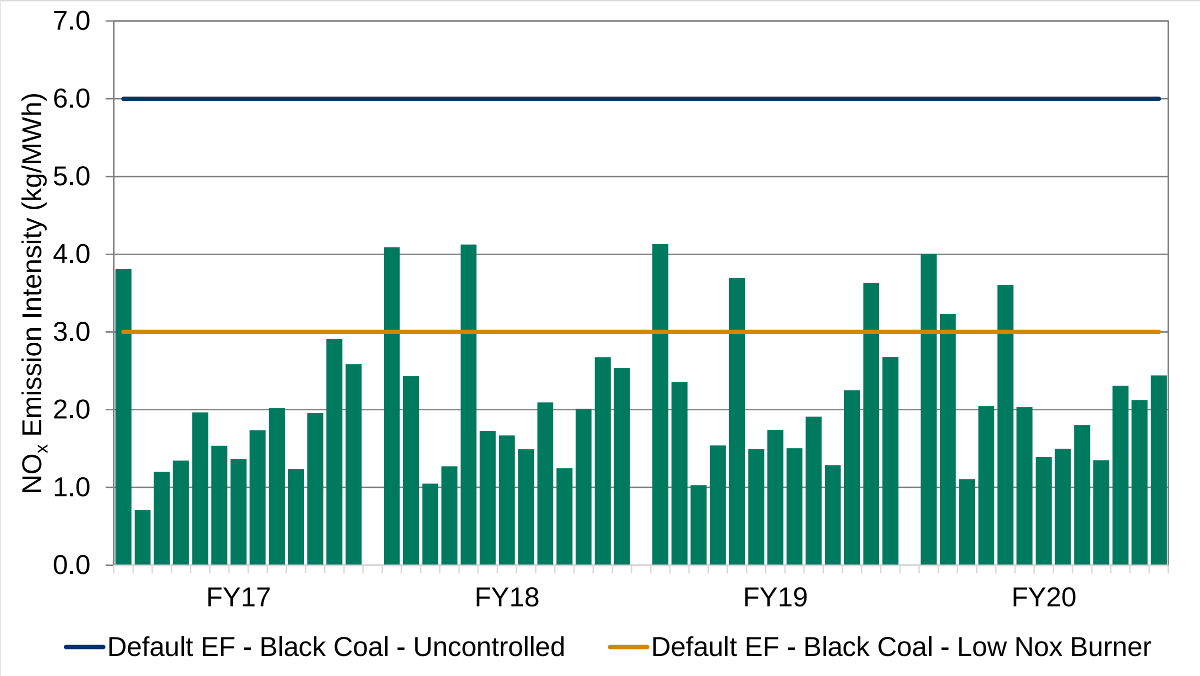

Figure 5.6: Black Coal: NO_x emission intensities – FY17 to FY20 NPI reporting year

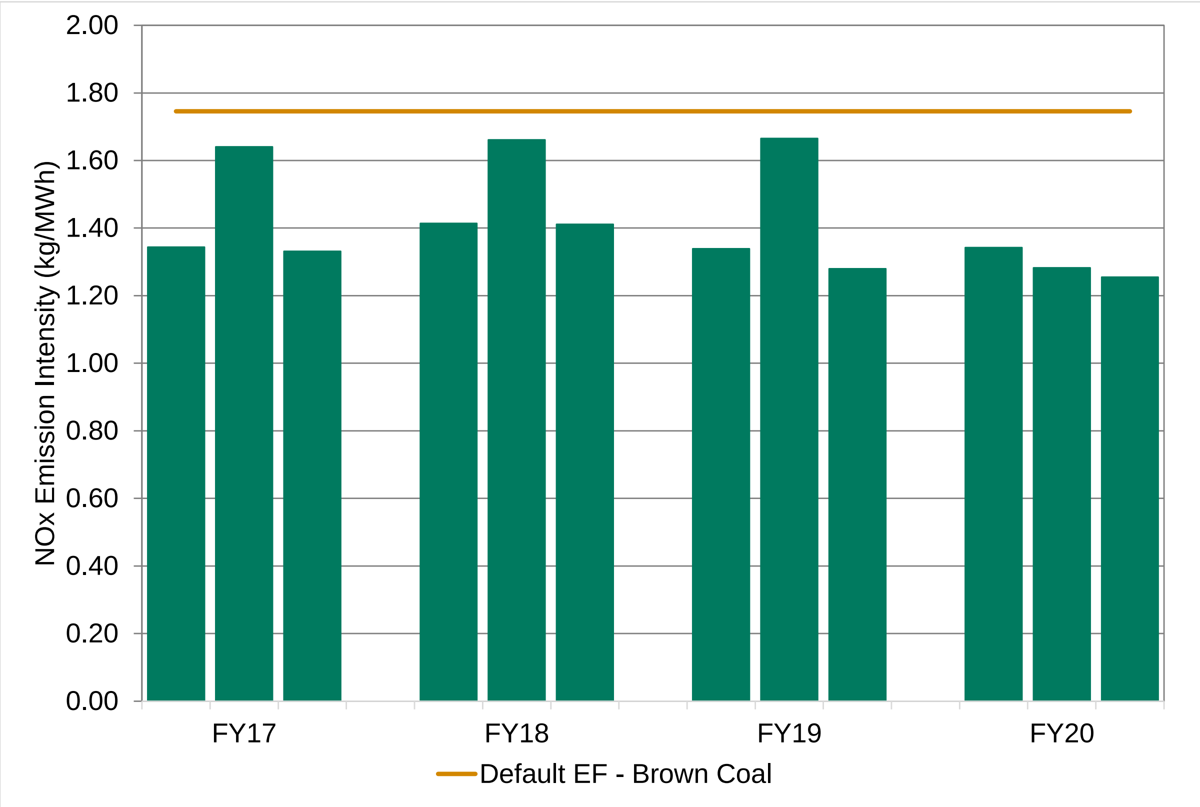

Figure 5.7: Brown Coal: NO_x emission intensities – FY17 to FY20 NPI reporting year

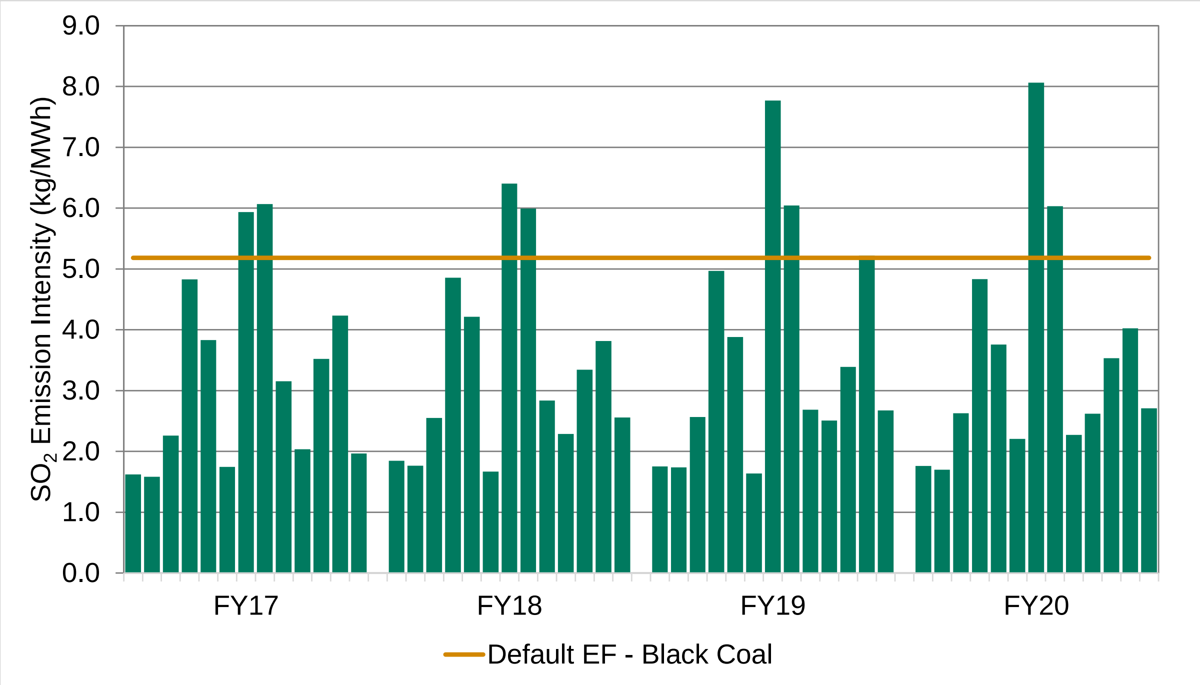

Figure 5.8: Black Coal: SO_2 emission intensities – FY17 to FY20 NPI reporting year

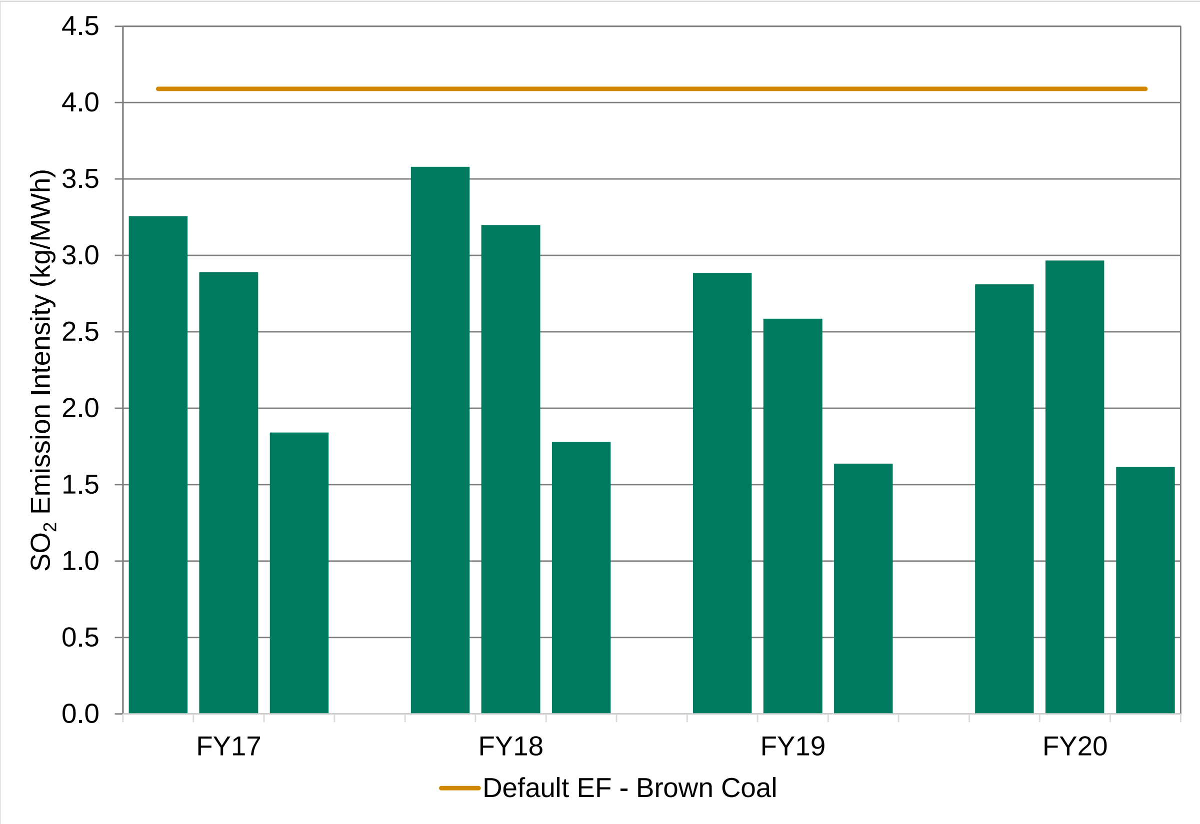

Figure 5.9: Brown Coal: SO_2 emission intensities – FY17 to FY20 NPI reporting year

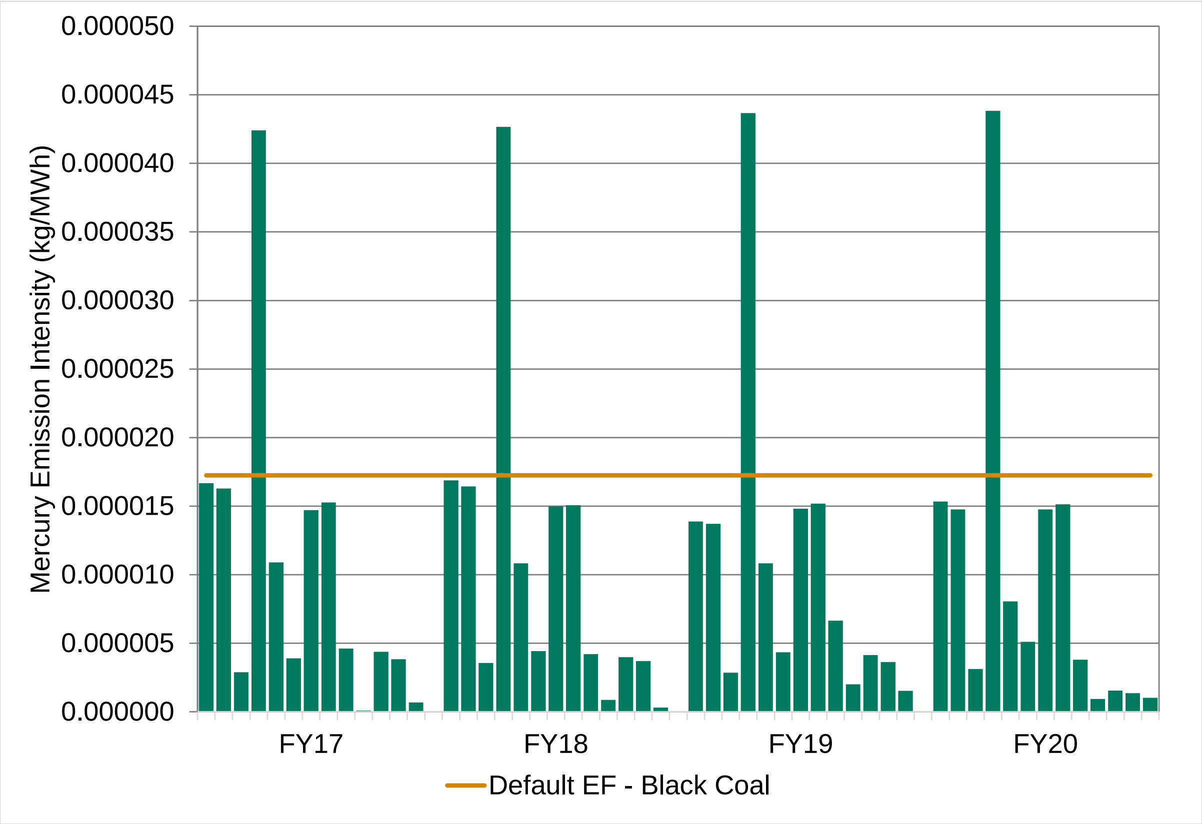

Figure 5.10: Black Coal: Mercury emission intensities – FY17 to FY20 NPI reporting year

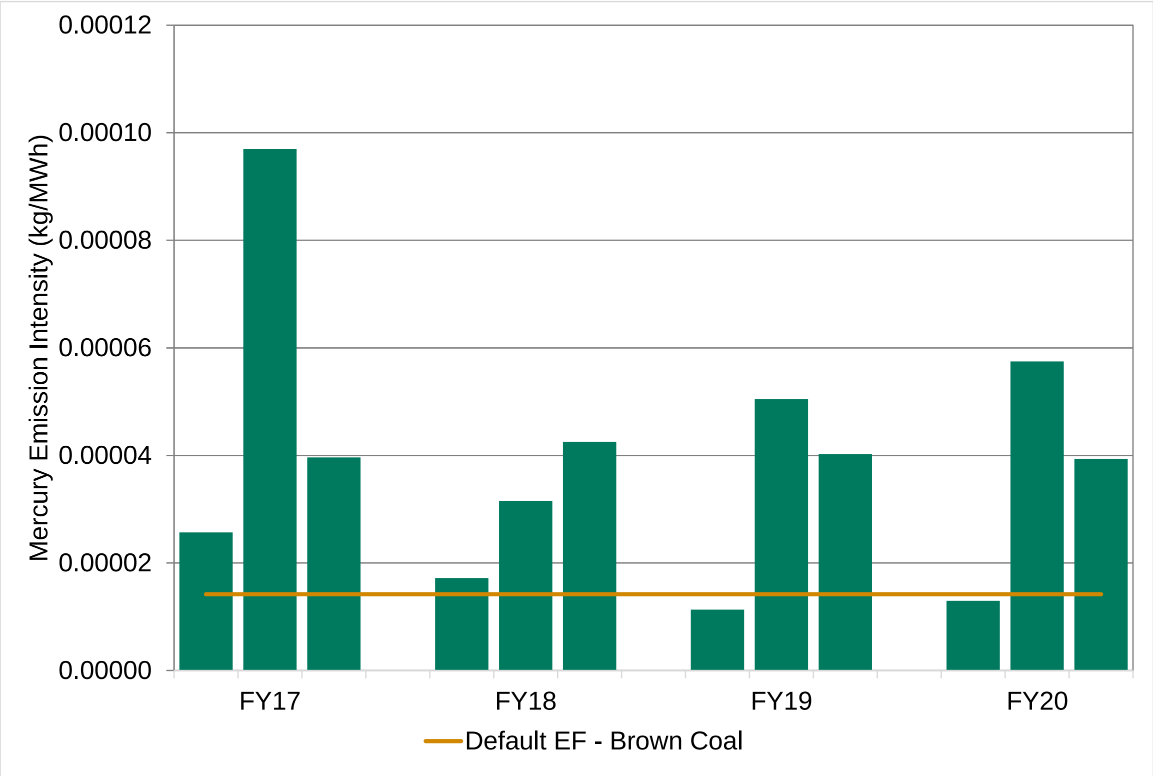

Figure 5.11: Brown Coal: Mercury emission intensities – FY17 to FY20 NPI reporting year

5.5 Comparison of Particulate Matter Control Factors

A comparison of the estimated particulate matter control factors was also completed based on the default control factors provided in the NPI EETM.

The site specific control factors were estimated using the following process:

- Uncontrolled TSP emission factors were calculated using the site specific coal ash content and the emission factor from the NPI EETM
- A site specific emission factor was calculated by dividing the emissions reported to the NPI by the tonnes of coal consumed
- The site specific control factor was estimated by dividing the site specific emission factor by the uncontrolled emission factor.

In addition to 10 facilities, data was extracted from the NSW EPA Review Coal Fired Power Stations Air Emissions and Monitoring (NSW EPA, 2018). This review found all the power stations had a theoretical control efficiency greater than 99.9%. The comparison of the particulate matter control factors is provided in Figure 5.12 and includes the available data from the NSW review.

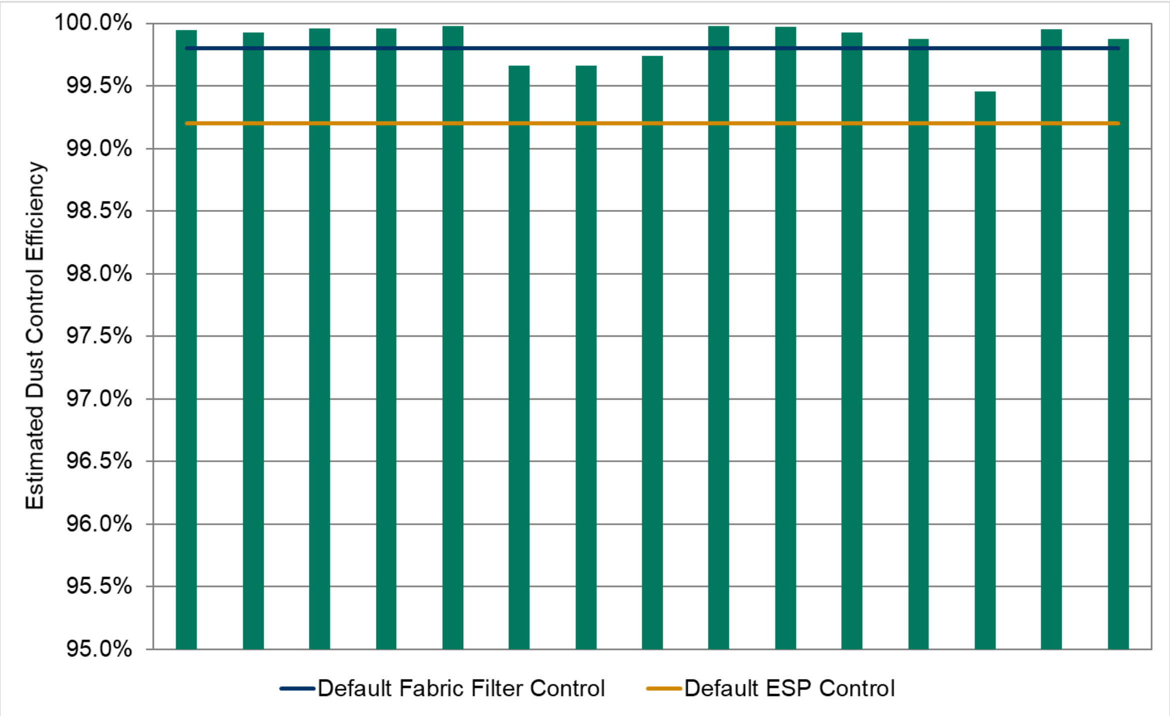

Figure 5.12: Comparison of estimated particulate matter control factors

6. SUMMARY OF DISCUSSIONS WITH AUSTRALIAN NPI REGULATORY BODIES

ERM contacted each of the state, territory and commonwealth contacts listed on the NPI website, and requested a discussion or email response to collect information about emission estimation methodology preferences for power stack emissions. NPI representatives provided responses via email or during virtual meetings. The questions asked and responses provided are summarised in Table 6-1. During virtual meetings, NPI representatives were also asked what resources were available in their jurisdictions for NPI reporting – this ranged from 0.33 to 2.0 full time equivalent employees.

Table 6-1 NPI Regulator Methodology Preferences

Western Australia	Northern Territory	Victoria	Queensland	New South Wales	South Australia*	Department of Agriculture, Water and the Environment
Do you have a preferred method for determination of air emissions from power station stack sources?						
1. Direct measurement (if representative). CEMs (including methods not explicitly listed in NPI manual) or stack testing data 2. Emission factors (NPI or AP-42 as relevant) 3. Any other method likely to provide an adequate representation of a facility's emission profile, preferably after discussion with NPI representative.	1. Direct measurement. 2. Emission factors (stack monitoring is conducted by a few facilities - air discharge licence requirement is not triggered by facilities such as power stations).	Whichever method is the most reliable and representative of annual emissions. Methods used currently include CEMS/stack testing required for compliance purposes, and other methods included in the NPI documentation.	For particulates: 1. Engineering calculations. 2. Default emission factors. For NOx, SO_2 and mercury, no preference. If direct measurement is used, the most appropriate technique for the process and substance being measured should be used.	No preference. It is noted that NSW licences often prescribe NSW Approved methods for direct measurement.	1. Stack test/direct measurement if available. 2. Emission factors (e.g. if stack testing is not required for some pollutants) It is noted that the option exists for other methods to be used if agreed on with the regulator.	No. State and territory regulators are responsible for this, and are encouraged to use methods that are practical, appropriate and reasonably representative of actual emissions.
Why is that your preference?						
Direct measurement may be more representative of actual operations than emission factors. However, it is recognised that this depends on the stack testing regime. The available data should be reviewed to select the most representative method for an individual facility with respect to the preferred methods above, and this method may vary year to year.	Stack test data considered to be more representative of an individual site than Emission factors.	To maintain reliability and representativeness of the NPI emissions inventory. Victoria power stations are strictly regulated and licence conditions include monitoring, conducted by NATA certified laboratories. Guidelines and established methods exist for this compliance monitoring. This data is therefore generally considered robust.	For particulates, it has been noted that stack test and CEMS data produce emission estimates significantly lower than those from the engineering calculation or default EF even when using site specific data e.g. ash content. Unless the discrepancy can be explained, direct measurement is not the preferred method.	n/a. It is noted that each jurisdiction may prescribe direct measurement methods that can be used for NPI reporting.	Stack test data is likely to be more representative of actual operations. However, the number of stack test results should be considered as a single stack test result may not be representative (several years could be considered instead).	As above.

Western Australia	Northern Territory	Victoria	Queensland	New South Wales	South Australia*	Department of Agriculture, Water and the Environment
Are there common errors or discrepancies that you have observed in submissions?						
Interpretation of stack test results into annual emissions profiles.	No, though stack test data is reviewed by licensing unit not NPI officer.	No. Majority of errors identified in site audits related to non-stack sources.	As above, the discrepancy between emission estimates of PM_{10} and $PM_{2.5}$ from direct measurement compared to engineering calculations or default emission factors.	A recent review (NSW EPA, 2018) identified minor errors were common, and were due to human error. Errors included transcription and rounding errors, inconsistencies in concentration or volume reference basis for direct measurement calculations, incorrect extrapolation of individual duct measurements to total emissions, incorrect particle size fractions, historical composition data.	Occasionally site audits have identified stack tests being conducted but not used for NPI reporting. NPI staff do not routinely check or have access to the detailed NPI emission calculations.	Particulate emissions have been observed to vary significantly from year to year for some power stations using direct measurement. Environmental health advocacy groups have previously drawn attention to these variances.
Are there common difficulties involved in checking/reviewing these emissions?						
No. For power stations, validation is readily done by cross checking against fuel combusted, and by reviewing licence conditions (if any) to assess if any data collected through that process has been used in estimates. Resourcing makes facility audits difficult, however some are done each year.	Level of detail of NPI reporting does not resolve individual emission source types (e.g. tanks vs power generation) and does not identify emission factors used. This information can be obtained from site audits.	None specified.	Can be difficult to source sufficient data from facilities (e.g. ash content) to perform ‘sanity checks’ on the emissions.	No.	None noted. There is collaboration between NPI and compliance staff as NPI data is used to determine load-based licensing fees.	n/a – state and territory regulators are responsible for this. DAWE assists by providing national statistical reports allowing outlying data to be identified

Western Australia	Northern Territory	Victoria	Queensland	New South Wales	South Australia*	Department of Agriculture, Water and the Environment
Are there any methods you do not think should be used? Why is that?						
No. WA NPI leaves assessment of stack testing methods to the Air Quality Services unit in DWER.	No.	None specified.	No, but accuracy and representativeness of the method is important to consider.	No. NPI was designed to permit facilities use different jurisdiction prescribed methods to minimise potential duplication and monitoring costs.	No, any may be suitable if they provide a representative emissions estimate. It is noted that the mercury EF may not be representative of SA coal.	n/a. State and territory regulators are responsible for this.
What key factors do you think should be considered in selecting a consistent method for power generators to report stack emissions?						
Facilities and data availability differ, therefore selecting a method to provide representative emission estimates is more important than consistency in selected method across sites. Consistency in how each of the various methods are applied is useful for facilitating comparisons between operations during data validation.	Representativeness of actual emissions from facility.	Reliability and representativeness of emissions inventory.	All facilities should consider the engineering calculation or default emission factors. Whilst there may be reasons to adopt another method, it would be preferable if data is provided to justify the deviation from the emissions produced by the preferred methods (e.g. through comments in the NPI ORS) to assist NPI staff to perform quality assurance checks.	n/a. Consistency in selected method and emission estimates may be an issue for power generators with facilities in different jurisdictions, however it is unlikely to impact the reliability of the reported NPI emissions.	Representativeness of site operations for the year.	1. State and territory regulator support for the method 2. Representativenes s of the method outputs 3. Practicality of the method 4. Acceptance of method by relevant industries.

Table note:

* Responses related to gas-fired power stations. Included or completeness, as some considerations around emissions determinations from these sources will be consistent.

7. SUMMARY OF INTERNATIONAL POWER GENERATION INVENTORY REPORTING METHODS

ERM has reviewed methodology information for several annual emission reporting inventories in the UK and US. Overall, these consider the same range of methods as the NPI. The guidance documentation reviewed was generally consistent in the use of methods in the following order of preference:

1. Direct measurement methods
2. Engineering or mass balance where appropriate
3. Emission factors when no other methods are suitable.

The documentation reviewed also included discussion or guidance on:

- PM_{10} and $PM_{2.5}$ fraction assumptions.
- The need to take care with calculations involving normalisation of concentrations and flow rates, making sure reference and actual conditions are correctly accounted for.
- Ensuring appropriate calibration of monitoring equipment and relevance of monitoring standards.
- Quality Assurance (QA) checks on monitoring data, and evaluation of representativeness of data.
- If emission factors are to be used, the use of industry-specific or industry standard emission factors, or site-specific.

7.2 United Kingdom

Emissions to air in the United Kingdom are compiled annually into the National Atmospheric Emissions Inventory (NAEI), which includes a set of maps providing spatial pollution distributions derived from emissions data from multiple sources and modelling techniques.

Data for point sources regulated under the Industrial Emissions Directive (IED) are provided for the NAEI by each member country's regulatory body in the form of the pollution inventories (Tsagatakis, et al., 2021):

- Environment Agency's Pollution Inventory (PI).
- Scottish Environment Protection Agency's Scottish Pollutant Release Inventory (SPRI).
- Natural Resources Wales' Welsh Emissions Inventory (WEI).
- Northern Ireland Pollution Inventory (NIPI).

7.2.1 England

Emissions to air from facilities that are regulated under the Environmental Permitting (England and Wales) Regulations 2010 (EPR) must submit data to the PI. Methods for estimation of these emissions is provided in the *Pollution inventory reporting – combustion activities guidance note* (Environment Agency, 2013) and include the following for solid, liquid and gas fuel generators:

- NO_x emissions – CEMS data, or if that is not available, fuel burn and NO_x emission factors agreed with the regulatory authority.
- PM – typically measured by CEMS.
- PM_{10} and $PM_{2.5}$ fractions are assumed to be 80% and 40% of TSP (others provided for different control technologies) for solid/liquid fuels. $PM_{2.5}$ is assumed to comprise 100% of diesel particulate.
- PM_{10} and $PM_{2.5}$ are assumed to be 100% TSP when burning natural gas.

- Assumptions are provided around typical exhaust flow by tonne of input fuel.
- Mercury emission factors are provided for gaseous fuel only.
- Fuel analysis is described that could be used for SO_2 and trace metals, with assumption that 5% of sulphur is retained in the ash at coal fired plants.
- Solid and liquid fuel analysis is also described, which requires fuel composition data and then uses provided factors to account for the quantity present in the ash.

Notes are included regarding taking care to ensure normalisation calculations are performed correctly, and equations are also provided to assist. No monitoring standards are referred to.

7.2.2 Scotland

Scottish Pollutant Release Inventory Reporting guidance (Scottish Environment Protection Agency, 2017a) includes the following methods:

- Stack sampling, with care taken regarding normalisation of concentrations and flows
- CEMS with appropriately calibrated instrumentation (e.g. ISO/national standards), and preferably calculation methods agreed with the regulator
- Emission factors – both general ones, and site-specific release factors (which should be verified periodically)
- Fuel analysis/mass balance.

It notes that when emission factors are used, any mandatory or industry emission factors should be considered to promote consistency in reporting.

The industry-specific guidance for sectors including combustion (Scottish Environment Protection Agency, 2017b) appears consistent with the PI combustion activities guidance note, referencing generic and ESI emission factors, and the use of CEMS data for NOx etc.

7.2.3 Wales

The Emissions Inventory Reporting: Guidance note (Natural Resources Wales, 2019) lists information sources for emissions determination, in priority order:

- NAEI
- Atmospheric Emission Inventory Guidebook
- IPCC
- USEPA
- Australia NPI EETs.

It includes links to best practice guidance for monitoring, if that is used to determine annual emissions, including referring to ISO and other standards institutes.

Additional guidance is provided:

- Sampling data – ensuring spot samples are representative of annual average operations
- CEMS – collection and averaging procedures preferably agreed with the regulator
- Site-specific emission factors can be generated where unit operations remain consistent.

7.2.4 Northern Ireland

The guidance published for the Northern Ireland Pollution Inventory (Northern Ireland Environment Agency, 2013) is consistent with the Welsh guidance, providing links to best practice guidance for monitoring, including reference to ISO and other standards organisations, the same prioritised list of information sources, and additional guidance notes.

7.3 United States

The US EPA maintains several emissions databases (the CAMD, TRI and NEI) that are relevant to this review.

7.3.1 Clean Air Markets Division Power Sector Emissions Data

Power section emissions are reported to EPA under the regulations in 40 CFR Part 75 (which requires continuous measurement of emissions and reporting to EPA for compliance assessment for a range of programs) and released publicly in the Power Sector Emissions Data.

Of relevant to this review, this includes hourly emissions of SO2, NOx and mercury, fuel types, control devices, emissions monitoring methods and QA test information. This does not include emissions of particulates.

The user guide (US EPA CAMD, 2021) states that the emissions data generally covers generators with >25 MW nameplate capacity.

Monitoring options include:

- Solid fuel: CEMS or mass emissions determined from concentration and flow measurements
- Liquid or gas: CEMS, and various non-CEMS methodologies e.g. continuous flow measurements and periodic fuel sampling, or development of site-specific NOx emission rates. For smaller units, fuel-specific default emission rates are allowed.

In addition to the generators being responsible for QA checks on monitoring e.g. calibrations, EPA conducts QA tests on the submitted data both automatic and by staff.

In its notes on interpreting the data, the user guide notes that missing data is required to be filled, and that methods for this have become increasingly conservative. In addition, a bias adjustment factor (BAF) is discussed that is used to adjust some emissions to account for possible low bias in the CEMS (both adjusted and unadjusted values can be reported).

7.3.2 National Emissions Inventory

The EPA also compiles a National Emissions Inventory (NEI) each three years, drawing on emissions submitted by state, local and tribal agencies. The 2020 NEI Plan (US EPA, 2020) notes that point source emissions should be based on stack test data, material balance, or other site-specific and reliable calculation methods, and if that is not possible, best available emission factors can be used.

7.3.3 Toxics Release Inventory Program

Section 4.2.2 of the reporting guidance for the Toxics Release Inventory (TRI) Program (US EPA, 2021b) assigns responsibility of selecting the best emission data to use to each facility. It notes that facility-specific monitoring data would be the best source if sufficient data was available, with emission factors being a practical alternative. AP-42 emission rates are suggested when other data are not available. However, the guidance notes “These factors are based on a limited number of samples and may not reflect more accurate information available to the facility for the particular type of coal combusted and pollution control devices used”.

Emissions of metal should be based on the best fuel composition data.

Mass balance is noted as a method for emission of some chemicals when no better data is available, with control devices accounted for using efficiency data from monitoring, manufacturer's specifications and air permit applications.

8. CONCLUSIONS

This report has documented a review of the methodologies used to report power station stack emissions to the National Pollutant Inventory (NPI).

The NPI allows electricity generators to apply a range of estimation methods inclusive of the following, listed in decreasing order of potential reliability:

- Direct measurement (CEMS or stack tests)
- Source-specific emission factors derived from sampling events
- Engineering calculations
- Mass balances
- Published emission factors.

A survey of coal-fired power generators identified that all of these methods are used, with CEMS and stack tests being the most common. Direct measurement was least common for SO_2 and mercury emission estimates, and is understandable given the direct dependence of these emissions on the coal composition. Conversely, particulate matter and NO_x depend on a wider range of operating conditions and were more commonly estimated using direct measurement.

Currently, NPI regulators across Australia generally prefer direct measurement, though consider that the aim of selecting the method able to provide the most reliable and representative data should guide method selection. The use of direct measurement to obtain a representative emissions estimate requires calibrations, maintenance and associated standards to be adhered to, and plant conditions during testing to be considered.

These method preferences are also reflected in guidance documentation for preparing emissions estimates for national pollutant inventories published in the US and UK, i.e. prioritising direct measurement methods, followed by engineering or mass balance where appropriate, and using emission factors where no other methods are suitable. Direct measurement allows for the development of site-specific emissions estimates, which is preferable to emission factors that are generic and based on sampling from a potentially wide range of facilities.

Common errors and discrepancies noted by Australian NPI representatives were generally minor in nature. Examples included resolution of particulate size fractions, normalisation calculations, and translation of stack tests into annual profiles. In one jurisdiction (Queensland), discrepancies between particulate emissions derived from direct measurement when compared with emission factors or engineering calculations were noted, resulting in a preference from the Queensland regulator for engineering equations over direct measurement.

A review of the emission intensity was undertaken for each of the key pollutants, using the NPI reported emissions and NGER reported electricity output to establish the quantity of emissions per unit of electrical output (kg pollutant emission / MWh generated). Whilst there may be variations in the thermal efficiency of various plants, it is noted that overall, this analysis indicated:

- Variability between the emission intensity of plants. This is expected given variability in fuel types, operating loads, plant scale, and emission controls.
- A general consistency between average reported emission intensity, and the emission intensities derived from the default NPI emission factors.

9. REFERENCES

Acurex Corporation. (1985). *Inhalable Particulate Source Category Report For External Combustion Sources. EPA Contract No. 68-02-3156.* Mountain View.

California Air Resources Board. (2021). *California Air Toxcs Emission Factor*. Retrieved from https://ww2.arb.ca.gov/california-air-toxics-emission-factor

Commonwealth of Australia. (2011). NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation.

Commonwealth of Australia. (2015). *National Pollutant Inventory Guide Version 6.1.*

DE. (1997). *Air Quality Sampling Manual.* Brisbane: Department of Environment.

DEC NSW. (2007). *Approved Methods for the Sampling and Analysis of Air Pollutants in New South Wales.* Sydney: Department of Environment and Conservation.

DER Western Australia. (2016). *Continuous Emission Monitoring System (CEMS) Code for Stationary Source Air Emissions.* Perth: Department of Environment Regulation.

EEA. (2019). *EMEP/EEA air pollutant emission inventory guidebook 2019: Technical guidance to prepare national emission inventories.* European Environment Agency.

Ellson, A., & Johnston, D. (2005, December). Interpretive guide for the NPI - a guide to understanding South Australia's NPI data. Adelaide: South Australia Environment Protection Authority.

Environment Agency. (2013, January 4). Pollution inventory reporting - combustion activities guidance note, Version 4. *Environmental Permitting (England and Wales) Regulations 2010, Regulation 60(1)*. Environment Agency, Horizon House, Deanery Road, Bristol BS1 5AH.

EPA South Australia. (2012). *Emission Testing Methodology for Air Pollution, Version 2.* Envronment Protection Authority.

EPA Victoria. (2002). *A Guide to the Sampling and Analysis of Air Emissions and Air Quality, Publication 440.1.*

Natural Resources Wales. (2019, January). Reference number: GN 25. *National Inventory Reporting: Guidance note*.

Northern Ireland Environment Agency. (2013, November 29). Pollution Inventory Reporting - General Guidance Notes.

NSW EPA. (2018). *Review of Coal Fired Power Stations Air Emissions and Monitoring.*

NSW EPA. (2018). *Review of Coal Fired Power Stations Air Emissions and Monitoring.* Sydney: NSW Environment protection Authority.

Pacific Power. (2002). *Review of the NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation.* Pacific Power International Environmental Services. Undertaken for Electricity Supply Association of Australia. March 2002.

R. K. Srivastava, C. M. (2004). Emissions of Sulfur Trioxide from Coal-Filed Power Plants. *Journal of the Air & Waste Management Association*.

Ravi K. Srivastava, R. E. (2005). Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. *Journal of the Air & Waste Management Association*.

Scottish Environment Protection Agency. (2017a). Scotting Release Inventory (SPRI) Operator Guidance on Release Estimation Techniques (RET). *Scottish Pollutant Release Inventory Reporting*.

Scottish Environment Protection Agency. (2017b). Sector Guidance Note: Petroleum, Incineration, Paper and wood production and processing, Cement and lime, Production and processing of metals, Combustion and Chemicals. *Scotting Pollutant Release Inventory Reporting*.

SEWPaC. (2012). *NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation Version 3.0.*

Tsagatakis, I., Richardson, J., Evangelides, C., Pizzolato, M., Pearson, B., Passant, N., . . . Otto, A. (2021). *UK Spatial Emissions Methodology: A report of the National Atmospheric Emission Inventory 2019.* Retrieved from: https://naei.beis.gov.uk/reports/reports?report_id=1024.

US EPA. (1993). *Emission Factor Documentation for AP-42 Section 1.1 Bituminous and Subbituminous coal combustion.*

US EPA. (1998a). *AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, Introduction, page 4.*

US EPA. (1998b). *AP-42, Chapter 1.1 Bituminous and Subbituminous Coal Combustion.*

US EPA. (2001). *Emergency Planning and Community Right to Know Section 313 Guidance for Reporting Toxic Chemicals: Mercury and Mercury Compounds Category.* US EPA Office of Environmental Information. 2001.

US EPA. (2019). *Performance Specification 2—Specifications and Test Procedures for SO2 and NOx Continuous Emission Monitoring Systems in Stationary Sources.* US EPA. 14 January 2019. https://www.epa.gov/sites/default/files/2020-12/documents/procedure_1_1.pdf.

US EPA. (2020, August). *2020 NEI Plan*. North Carolina: Office of Air Quality Planning and Standards, Air Quality Assessment Division, Emissions Inventory and Analysis Group, Research Triangle Park.

US EPA. (2020). *Procedue 1. Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems used for Compliance Determination.* US EPA. 7 October 2020. https://www.epa.gov/sites/default/files/2020-12/documents/procedure_1_1.pdf.

US EPA. (2021a). *Compilation of Air Pollutant Emission Factors (AP-42)*. Retrieved from United States Environmental Protection Agency: https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors

US EPA. (2021b). *TRI Program*. Retrieved from Guidance: Calculating Release and Other Waste Management Estimates at Electricity Generating Facilities: https://ordspub.epa.gov/ords/guideme_ext/f?p=guideme:gd:::::gd:egf_4_2#egf_4_2_2

US EPA CAMD. (2021). *CAMD's Power Sector Emissions Data Guide*. Retrieved from https://www.epa.gov/sites/default/files/2020-02/documents/camds_power_sector_emissions_data_user_guide.pdf

ERM has over 160 offices across the following countries and territories worldwide

Argentina
Australia
Belgium
Brazil
Canada
Chile
China
Colombia
France
Germany
Ghana
Guyana
Hong Kong
India
Indonesia
Ireland
Italy
Japan
Kazakhstan
Kenya
Malaysia
Mexico
Mozambique
Myanmar
The Netherlands
New Zealand
Norway
Panama
Peru
Poland
Portugal
Puerto Rico
Romania
Russia
Senegal
Singapore
South Africa
South Korea
Spain
Sweden
Switzerland
Taiwan
Tanzania
Thailand
UAE
UK
US
Vietnam

ERM's Brisbane Office
Level 4, 201 Leichhardt St
Spring Hill, Brisbane 4000
QLD, Australia

T: +61 7 3839 8393
F: +61 7 3839 8381
www.erm.com

The business of sustainability