

Position Statement on WSP Report

Australian coal-fired power stations have a range of air emission control technologies in place. These technologies were designed in line with regulatory expectations at the time of their installation. Abatement technology has since evolved and some advocacy groups have argued that Australia's coal-fired power stations should be retrofitted with the new technology to protect the public's health. The European Union is often cited as the gold standard for Australia to follow to abate three air pollutants: particulate matter (PM₁₀ and PM_{2.5}), sulphur oxides (SO_x) and nitrogen oxides (NO_x). The AEC commissioned WSP to evaluate the viability of Australian coal-fired power stations being retrofitted to meet EU standards for the three air pollutants.

The WSP Report revealed that coal-fired power stations will incur exorbitant costs if they were required to retrofit. While costs vary depending on the size and type of a unit, for a single 720 MW black coal unit, the costs could reach as high as \$432 million in capital expenditure and \$27 million in annual operating costs.¹ If a station has more than one unit, which is standard, these costs would then need to be multiplied. In NSW alone, there are 16 black coal units around this size. These cost estimates are conservative because they do not take into account whether power stations have the physical space to install additional abatement technology or the costs of having a power unit out of service while being retrofitted.

The WSP Report also considered the environmental benefits of making these retrofits. In the case of particulate matter, where abatement technology is already installed, WSP found the viability of installing an additional retrofit on top of current technology 'is unlikely to be reasonable' as many plants already meet EU standards.² For sulphur oxides and nitrogen oxides, the Commonwealth Government's Department of Environment and Energy has found that these emissions are already at a level so low that they are unlikely to have a negative health impact.³ The benefit then of reducing these emissions must be balanced against the high costs as well as any impact in other environmental areas. The technology used to reduce sulphur oxides needs up to an extra 878,000,000 litres of water per year to operate, while nitrogen oxide abatement technology creates additional greenhouse waste streams, namely ammonia slip and nitrous oxide emissions.⁴ Nitrous oxide is 'another greenhouse gas that is approximately 300 times more harmful to the environment than CO₂ [carbon dioxide] in terms of contributing to global warming'.⁵ Thus, retrofitting such equipment seems likely to create more environmental problems than it will solve.

Outside of these affordability and sustainability issues, the impact of retrofitting on the reliability of existing plant would need to be assessed. The installation of further technologies will reduce plant efficiency and may inhibit the financial viability of flexible or two-shift operation. This is significant because flexible generation is important in supporting a grid transitioning to more variable renewable generation. The respective age of a power plant needs to be considered and for older generators, the

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¹ These figures represent the accumulative cost of installing fabric filters to abate particulate matter, wet flue gas desulphurisation to abate sulphur oxides, and selective catalytic reduction to abate nitrogen oxides. See page 4 of the WSP Report for a full breakdown of the costs.

² WSP, Considerations for Retrofitting Emissions Control Systems in Australian Coal Power Plants (October 2019), p1.

³ Australian Government, Sulfur Dioxide: Air Quality Fact Sheet (2005), Department of the Environment and Energy, <https://www.environment.gov.au/protection/publications/factsheet-sulfur-dioxide-so2>.

Australian Government, Nitrogen Dioxide: Air Quality Fact Sheet (2005), Department of the Environment and Energy, <https://www.environment.gov.au/protection/publications/factsheet-nitrogen-dioxide-no2>.

⁴ This is assuming the plant operates for 8,000 hours per year at full load. WSP Report, p35.

⁵ WSP, Considerations for Retrofitting Emissions Control Systems in Australian Coal Power Plants (October 2019), p39.

costs of retrofitting combined with the need to have units taken out of service while retrofitting occurs may render continued operation uneconomic. This would then have adverse consequences for the orderly transition of the power system.

The full report is below.

**Design
for a better
*future /***

AUSTRALIAN ENERGY
COUNCIL

**CONSIDERATIONS FOR
RETROFITTING
EMISSIONS CONTROL
SYSTEMS IN
AUSTRALIAN COAL
POWER PLANTS**

wsp

OCTOBER

Question today *Imagine tomorrow* Create for the future

Considerations for Retrofitting Emissions Control Systems in Australian Coal Power Plants

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GLOSSARY

Available Techniques	As defined in the EU Large Combustion Plant Directive 2010/75/EU: “Techniques developed on a scale which allows implementation in the relevant industrial sector, under economically and technically viable conditions, taking into consideration the costs and advantages and whether it is used or produced inside the Member State in question, provided they are reasonably accessible to the operator.”
Baseload	Refers to a power station which typically operates at a constant load.
BAT-associated emissions level	As defined in the EU Large Combustion Plant Directive 2010/75/EU: “The range of emission levels obtained under normal operating conditions using a BAT, or a combination of BATs.”
Best	As defined in the EU Large Combustion Plant Directive 2010/75/EU: “The most effective in achieving a high general level of protection of the environment as a whole.”
Best Available Technique (BAT)	As defined in the EU Large Combustion Plant Directive 2010/75/EU: “The most effective and advanced stage in development of activities and their methods of operation which indicates the practical suitability for particular techniques for providing the basis for emission limit values and other permit conditions designed to prevent and, where that is not practicable, to reduce emissions and the impact on the environment as a whole.”
Best available technology	As used in this report, refers to emissions abatement technology systems generally regarded as best practice internationally.
Cross-Media Effect	Impacts other than the reduction of the targeted emission (e.g. additional resource consumption, secondary emissions, changes in the level of emissions of other pollutants).
Electric Utility Steam Generating Unit	As defined in the US EPA MATS and per the Clean Air Act Section 112(a)(8): “Any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale.”
Electrical Capacity	The maximum electrical generation of the plant, typically expressed in MW.
Electrical Output	The electricity produced at the high-voltage side of the main transformer exported from the site.
kWe	Kilowatts electric.
Low Load	The load below which dictates the onset of limitations (e.g. most black coal plants are designed to operate over a load range of 40-100%).
MWh _e	Megawatt hours electric.
MW _{th}	Megawatts thermal. In this report, typically refers to energy input in the fuel to the power station boiler.
Nitrogen Oxides	The name given to the group of oxides of nitrogen that are produced during combustion and includes Nitrogen Oxide (NO) and Nitrogen Dioxide (NO ₂).

Off-gas	The gas leaving a process that is subsequently treated for recovery and/or emissions abatement. For coal power stations, off-gas is analogous to the flue gas produced from combustion of the fuel.
Sulfur Oxides	The name given to the group of oxides of sulfur that are produced during combustion and includes Sulfur Dioxide (SO ₂) and Sulfur Trioxide (SO ₃).
Two-shifting	The process whereby the power plant is started up and shutdown on a daily basis.
Techniques	As defined in the EU LCP Directive 2010/75/EU: “A technique includes both the technology itself and how the installation is designed, built, maintained, operated and decommissioned.”

ABBREVIATIONS

AEC	Australian Energy Council
BAT	Best Available Technique. In this report, BAT is used specifically in reference to: the <i>Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control)</i> .
BAT-AEELs	BAT-associated energy efficiency levels
BAT-AELs	BAT-associated emissions levels
BREF	Best Available Techniques (BAT) Reference Document for Large Combustion Plants
EGU	Electric utility steam generating unit
ELV	Emission Limit Value
ESP	Electrostatic Precipitators
EU	European Union
EWG	Environmental Working Group
FGC	Flue Gas Conditioning
FGD	Flue Gas Desulphurisation
LHV	Lower Heating Value
LNB	Low NO _x Burner
MATS	Mercury and Air Toxics Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NEPC	National Environment Protection Council
NEPM	National Environment Protection Measure
NO _x	Nitrogen Oxides
N ₂ O	Nitrous Oxide
PM _{2.5}	Particulate Matter 2.5 micrometres or less in diameter
PM ₁₀	Particulate Matter 10 micrometres or less in diameter
RFI	Request for Information
RO	Reverse Osmosis
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO _x	Sulfur Oxides

EXECUTIVE SUMMARY

Australian coal fired power plants are built with equipment that reflects the type of fuel they burn, their location and the regulatory requirements at the time they were constructed. These power plants typically contain one to four combustion units. Since their construction, the air pollution control requirements for these power stations have changed, and public attention has been drawn to the fact that these plants may no longer utilise the latest technologies, which may give rise to sub-optimal impacts on the community. The Environmental Working Group members (EWG), as a part of the Australian Energy Council (AEC), engaged WSP for advice on the estimated costs and other non-financial considerations to retrofitting Australia's coal fired fleet with best available technologies for emissions control.

APPROACH

Combustion plants emit particulate matter (PM_{2.5} and PM₁₀), sulfur oxides (SO_x) and nitrogen oxides (NO_x) in addition to other emissions such as CO₂ and mercury (in some instances) from the combustion of fossil fuels. Currently, the most effective way to reduce these emissions is to use as much of the heat produced by the combustion process as possible (Lecomte, et al., 2017). This may be done by optimising the steam cycle, or extracting and utilising additional energy from the flue gas. This maximises the efficiency of the conversion of the energy in the fuel to usable electricity, and minimises the amount of emissions per unit of electricity produced. However, extracting additional energy may not be technically feasible or viable for some plants, and as such, these plants may need to utilise abatement techniques that are targeted at reducing certain types of emissions. Per the agreed Scope of Works between WSP and the AEC, the focus of this report was to investigate the impacts of the best available technologies listed below:

- Fabric Filters for particulate (PM_{2.5} and PM₁₀) abatement
- Wet Flue Gas Desulphurisation (FGD) for SO_x abatement
- Selective Catalytic Reduction (SCR) for NO_x abatement

The *Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), 2017* (the BREF) was used as a reference to define best available technologies. This document was selected following a comparison of legislative policy between the European Union (EU), USA and Japan, which showed that only the EU jurisdiction actively describes best available technology. The USA and Japan mandate emission levels, but do not define technologies for emissions control. The emission levels mandated in USA and Japan are also generally below emission levels required in the EU. WSP notes that key differences arise between the Australian context and these other jurisdictions, such as population density and environmental climate. However, a full assessment of the differences and applicability of other jurisdiction emission levels is outside the scope of this investigation (the Study).

A proportion of this report summarises the conclusions of the BREF, which describes the Best Available Techniques (BATs) at the time of publication, for the abatement of the above elements and the level of emissions reduction that may be able to be achieved by implementing these best available technologies in the European contexts.

The level of abatement these techniques could achieve when installed in typical Australian black and brown coal plants was estimated using Thermoflow by modelling current emissions levels and assuming emissions removal efficiencies for the techniques as defined in the BREF.

WSP understands that the baseload Australian coal fired power plants investigated within this Study currently use a form of particulate control (i.e. electrostatic precipitator (ESP) or fabric filter). As such, the modelling undertaken by WSP for particulate control was the addition of another particulate control system on top of the existing installed particulate control equipment. WSP notes that the viability of implementing such a retrofit is unlikely to be reasonable, however, the intent of the modelling is to show the impacts of such a retrofit in terms of both emissions abatement and financial and non-financial considerations.

For SO_x and NO_x abatement, it was assumed that the typical reference Australian plant does not currently contain abatement systems for SO_x control or secondary control systems for NO_x abatement. As such, the modelling was for the retrofit (addition) of a new system for SO_x and NO_x abatement.

The modelling also tested the effects of different input fuel types by considering coal properties likely to cause low, typical and high emissions. The level of emissions after the installation of best available technologies was compared with the BAT-associated emission levels (BAT-AELs) in the table below as prescribed by the BREF (see Table ES.1).

Table ES.1 BAT-associated Emissions Levels

EMISSIONS PARAMETER	BAT-AELS – YEARLY AVERAGE FOR EXISTING PLANTS ⁽¹⁾		TYPICAL AUSTRALIAN PLANT ⁽²⁾
Rated Thermal Input (MW _{th}) per unit	300-1000	>1,000	Typically >1,000 with the notable exception of units with 350 MW output or less.
Particulate Matter (mg/Nm ³ @ 6% O ₂)	2-10	2-8	< 10 for black coal plants with fabric filters currently installed < 320 for black coal plants with ESP currently installed < approx. 200 for brown coal plants with ESP currently installed
SO _x (mg/Nm ³ @ 6% O ₂)	10-130		250 – 1,100
NO _x (mg/Nm ³ @ 6% O ₂)	65-150		250 – 860

⁽¹⁾ Other BAT-AELs apply for plants with smaller rated capacities but these were not applicable for the plants under consideration in this Study.

⁽²⁾ Typical Australian plant emissions are based on responses from committee members. WSP did not investigate all coal fired plants in Australia and hence the values stated may not be indicative for all Australian coal fleet plants.

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

Based on the input from committee members, some Australian coal fired plants currently have particulate emissions within the range indicated in the BREF. However, this does not apply to all Australian plants or for SO_x and NO_x emissions.

STUDY RESULTS

WSP understands that the Australian baseload coal fired power plants investigated within this Study are currently fitted with particulate emissions abatement technology. Therefore, the Thermoflow models of the typical reference Australian power plants were fitted with either an existing fabric filter or electrostatic precipitator to reflect this. For the purposes of this report, the following best available technologies were added individually to the typical reference models of the Australian coal fleet plants:

- An additional fabric filter system with a particulate removal efficiency of 99%
- Wet FGD with a SO_x removal efficiency of 95%
- SCR with a NO_x removal efficiency of 85%

After adding the best available technologies to the reference models, the estimated emissions from Thermoflow showed that these plant models achieved the BAT-AELs (see Table ES.2). Refer to Section 5 for the assumptions used for the modelling. It is noted that current emission values stated in Table ES.2 are adapted from committee member responses.

However, due to the broad categories of typical plant included in this study and assumptions within the modelling, the emission values will not necessarily be representative of all plants or necessarily any specific plant. The values should be treated as a generalisation of potential typical emissions from the different plant types.

WSP has undertaken an estimation of the potential costs associated with retrofitting these best available technologies. An incremental CAPEX was estimated representing the capital cost for the purchase, delivery and installation of the retrofitted best available technology systems, using the Thermoflow software add-on package PEACE. An incremental OPEX was estimated representing the additional operating cost to operate and maintain the best available technology systems. The incremental OPEX was estimated from consumable flow rates estimated by Thermoflow and allowances / factors for maintenance, and consumable unit prices from public literature and WSP in house data (see Table ES.3).

Costs shown in Table ES.3 are per unit. It is noted that most power plants in the Australian coal fleet have multiple units. Retrofitting to multiple units will incur additional costs, however, the increase is unlikely to be linear (i.e. there will be some savings from retrofitting multiple units such as common engineering costs, reduction for bulk material purchase and fixed maintenance costs). An estimation of potential cost savings from retrofitting multiple units was outside the scope of this Study.

Table ES.2 Current emissions and emissions after retrofitting best available technology

PLANT	PARTICULATE EMISSIONS		SO _x EMISSIONS		NO _x EMISSIONS	
	CURRENT (MG/NM ³ @ 6% O ₂) ^{(1) (2)}	AFTER RETROFIT (MG/NM ³ @ 6% O ₂)	CURRENT (MG/NM ³ @ 6% O ₂)	AFTER RETROFIT (MG/NM ³ @ 6% O ₂)	CURRENT (MG/NM ³ @ 6% O ₂)	AFTER RETROFIT (MG/NM ³ @ 6% O ₂)
350 MW Black Coal	120 – 268	< 3	892 – 1088	Particulates: 28 – 62 SO _x : 78 – 105	800	121
450 MW Black Coal	17	≤ 1	892	Particulates: 4 SO _x : 78	530	79.5
720 MW Black Coal	9 – 15	≤ 1	686 – 1065	Particulates: 2 – 3 SO _x : 60 – 115	640	106
500 MW Brown Coal	37 – 327	≤ 3	623 – 1700	Particulates: 9 – 76 SO _x : 46 – 196	290	43

⁽¹⁾ Current PM values are based on responses from AEC Committee Members post existing particulate control systems. That is, the current emissions stated factor in existing installed particulate control systems.

⁽²⁾ WSP has assumed a standard particulate control removal efficiency for the existing plant models as a generalisation of current PM emissions within the Australia coal fleet for different plant sizes and coal types. It is noted that the efficiencies of particulate control systems installed at individual plants will differ from each other based on the design, age and level of fouling. For instance, removal efficiencies will be higher for new systems or recently cleaned systems compared to heavily fouled systems. Better designs may also be utilised and as such, higher removal efficiencies may be possible compared to as modelled by WSP. Although based on committee member responses, current emission values as stated in this report should not be taken as necessarily reflecting what is currently being emitted at specific plants.

Table ES.3 Estimated incremental CAPEX and OPEX for retrofit of best available technology

PLANT	FABRIC FILTER		WET FLUE GAS DESULPHURISATION		SELECTIVE CATALYTIC REDUCTION	
	INCREMENTAL CAPEX	INCREMENTAL OPEX	INCREMENTAL CAPEX	INCREMENTAL OPEX	INCREMENTAL CAPEX	INCREMENTAL OPEX
350 MW Black Coal	\$36.7m	\$2.8m	\$187.5m	Reagent & water: \$4.6m–\$5.5m Maintenance: \$2.1m	\$51.2m	Reagent: \$3.2m Catalyst: \$372k-\$867k Maintenance: \$768k
450 MW Black Coal	\$42.4m	\$3.3m	\$212.5m	Reagent & water: \$6.0m Maintenance: \$2.4m	\$58.6 m	Reagent: \$2.6m Catalyst: \$440k-\$1.0m Maintenance: \$878k
720 MW Black Coal	\$67.8m	\$5.2m	\$277.9m	Reagent & water: \$8.0m–\$11.5m Maintenance: \$3.1m	\$88.8 mil	Reagent: \$5.2m Catalyst: \$728k-\$1.7 m Maintenance: \$1.3m
500 MW Brown Coal	\$91.4m	\$7.0m	\$308.7m	Reagent & water: \$8.8m–\$16.0m Maintenance: \$3.4m	\$102.1m	Reagent: \$2m Catalyst: \$906k-\$2.1m Maintenance: \$1.5m

The costs above have been estimated using proprietary cost estimation software. In the body of the report, WSP notes the assumptions, limitations and inherent level of accuracy of these costs. These costs are not appropriate for investment decision making purposes and require further detailed assessment to improve their level of accuracy. These costs are provided for the purposes of this report to inform and are for high level comparative and assessment purposes only.

Table ES.4 shows the approximate footprints of the best available technologies as developed in ThermoFlow. This considered the equipment directly required for the best available technology itself (e.g. the space required for the fabric filters, the size of the SCR catalyst or the Wet FGD absorber). The footprints in Table ES.4 does not include other equipment which may be required, such as additional ducting or materials handling conveyors and storage tanks / facilities for water or reagents. The additional equipment required will be site specific (for example the additional ducting required will be dependent on the current configuration of the plant). The dimensions shown in Table ES.4 are a representation of the minimum footprint which may be required to retrofit these best available technology systems.

Table ES.4 Estimated footprints for the best available technologies

PLANT	FABRIC FILTER			WET FLUE GAS DESULPHURISATION		SELECTIVE CATALYTIC REDUCTION			
	LENGT H (M)	WIDTH (M)	HEIGH T (M)	ABSORBER DIAMETER (M)	HEIGHT (M)	LENGT H (M)	WIDTH (M)	HEIGHT (M)	NUMBER OF MODULES
350 MW Black Coal	22	25	20	13	24	9	9	19	2
450 MW Black Coal	24	28	21	15	25	10	10	17	2
720 MW Black Coal	57	21	22	19	25	10	10	17	3
500 MW Brown Coal	50	27	21	21	28	11	11	19	3

The indicative footprints shown above have been estimated using proprietary software. The footprint estimates are high level only and are not appropriate for plant layout planning or investment decisions and require further detailed design to improve level of accuracy.

ADDITIONAL IMPLICATIONS

Additional implications with / to installing best available technology systems within the Australian coal power plant fleet include:

- Increase in the auxiliary power consumption at the plant, which will lower its overall net electrical generation efficiency. This will increase the quantity of emissions for other contaminants not being directly addressed by the abatement technology, for example CO₂, on a per MWh electrical output basis.
- Potential for limitations / restrictions to low load operation or two-shift operation. At minimum, additional operational, maintenance or capital investment is required to manage operation at low load or two-shifting. These present additional costs to retrofitting which have not been quantified in this report.
- The potential risk of emitting a visible plume as a result of additional SO₃ if not monitored, or water vapour if flue gas temperature is too low. This will require additional operational or capital investment to manage which has not been quantified in this report.
- Creating new or additional waste streams at the plant that require handling and disposal. Key examples include:
  - Filter bags that need to be periodically replaced and properly treated and/or disposed of.
  - The creation of gypsum from a Wet FGD system. If the gypsum cannot be treated and on-sold for beneficial reuse, the most typical pathway would be to landfill.
  - Wastewater from a Wet FGD system. This water will require treatment before disposal.
- Altering the composition of the waste streams from the power plant affecting any potential re-use. The prime example is the retrofit of dry or semi-dry scrubbers which alters the composition of the fly ash collected by the particulate control system. By its nature, the scrubber system is intended to react with acid gases to form solid salts and also precipitate more heavy metals from the flue gas. The increased concentration of salts and heavy metals in

the flyash may inhibit the beneficial reuse of the flyash. Ammonia slip from SNCR and SCR systems may also cause ammonia accumulation in the flyash which may also inhibit reuse and handling.

- Increased water usage and consumption of other raw materials. Key examples include:
  - Lime / limestone, sodium hydroxide or calcium oxide for scrubber systems
  - Water for Wet FGD systems
  - Ammonia or urea for SNCR and SCR systems
- Space constraints / restrictions within plants may require complex arrangements or large / excessive plant work to retrofit best available technology systems. While an assessment of the viability of physically retrofitting best available technology systems within the existing Australian coal fleet is outside the scope of this study, it should not be assumed that retrofitting any of the best available technology systems referred to in this study is physically feasible or viable. This report offers no opinion on the physical feasibility or viability of retrofitting any best available technology system within the Australian coal fleet with WSP recommending that individual committee members undertake specific studies to determine feasibility for their individual and respective plant(s).
- Potential for generation of other emissions to air from the abatement technique. Prime example is the potential for ammonia slip with an SNCR or SCR system. The minimisation / control of ammonia slip may require additional operational and capital investment to manage which have not been quantified in this Study.
- Retrofitting best available technology systems within existing plants may not provide the highest removal efficiencies compared to a new plant with best available technology systems designed from the outset. The reactions required for the scrubber, SNCR and SCR systems perform optimally within a temperature range. It may not be viable to retrofit best available technology systems such that the system is at the most optimal conditions. This will be dependent on the individual plants and their individual designs. An assessment of the likely efficiency of installing best available technologies within the Australian coal fleet is outside the scope of this Study and WSP recommends that individual committee members undertake specific assessment for their individual and respective plant(s).
- Potential requirement to upgrade / augment existing plant equipment such as ID fans, compressed air, water supply, water treatment, water disposal, ash handling, electrical system or control system. A full assessment of implications to upgrade / augment existing plant systems is outside the scope of this study and will be dependent on individual site conditions.
- When properly installed, operated and maintained, the best available technology systems referred to in this study are not expected to alter the availability or reliability of the plants. Any additional equipment installed though presents additional risk of breakdown. It is also noted that although the best available technology systems referred to in this study are mature and commercial in status, some systems (such as Wet FGD) are not commonplace in Australia and experience in operating and maintaining these systems is limited.
- Substantial time is required to implement any best available technology retrofit project at any of the Australian coal plants. This includes time to assess, plan, seek approvals, negotiate, design, procure, construct, install and commission the system. Projects will typically require two years of planning, design, approvals and prefabrication prior to site works. In addition, during construction and installation, the unit being retrofitted will need to be out of service for an extended duration while the new system is connected to the existing plant. The duration of the outage will depend on the best available technology system and the individual plant however the downtime will not be short (likely to require many months).

Further commentary on the above elements are provided in section 5. It is noted however that a detailed assessment of these elements is outside the scope of this Study and implications and viability will vary, depending on the characteristics of individual plants.

CONCLUSIONS

There are many different considerations in regards to the suitability of retrofitting best available technology systems in the Australian context. Although the best available technology systems referred to in this study are mature and commercial internationally, many of the systems are not commonplace in Australia and there are minimal numbers of installations in any Australian industry, let alone utility generation. Given these considerations, the viability of retrofitting best available technology systems to the Australian coal fleet is not without issues and challenges. Similarly, viability should not be dismissed out of hand as witnessed by plants new to the European Union having to retrofit to meet the EU regulations. The purpose of this study then was not to assess the viability of retrofitting best available technology emissions control systems to the Australian coal fleet but discuss considerations and potential implications to retrofitting. Key considerations identified include:

- Based on the costs above, capital and operating costs are not insignificant to retrofit the best available technology systems.
- Based on the footprints above, the footprint of the best available technology systems are not insignificant and the physical viability of retrofitting needs to be assessed.
- Increased auxiliary power consumption with retrofit of best available technology systems. Without any further upgrade to the plant efficiency, this will likely result in a reduction in the plant net electrical efficiency. This would correspond to an increase in emissions of contaminants other than the contaminant being controlled by the best available technology system per MWh of electricity exported to the grid.
- Requirement for consumption of additional resources. Water in particular is a scarce resource in Australia and may inhibit viability of utilising certain best available technology systems, such as Wet FGD.

These considerations would require assessment on a case-by-case basis and would need to be evaluated against any environmental benefits achieved through the plant's remaining life.

1 INTRODUCTION

1.1 PROJECT BACKGROUND

Australian coal fired power stations are equipped with environmental abatement technologies that reflect the nature of the fuel, the immediate locational context of the plants and the requirements of regulatory bodies at the time that they were constructed. Since their deployment, technologies for emissions control has been more readily adopted globally and public attention has been drawn to the fact that emissions control technologies installed on Australian coal fired plants are, in some cases, at a lower performance level or not installed at all, compared to current international best available technologies. The public's concern therefore is that this shortfall has an impact on the health of the wider community.

The Environmental Working Group (EWG) members, as part of the Australian Energy Council (AEC), has engaged WSP to provide advice on the cost of retrofitting Australia's coal fired fleet with the best available technologies and provide comment on pertinent considerations for retrofitting of these systems within the existing fleet.

1.2 PURPOSE OF STUDY

The purpose of WSP's investigation (the Study) was to consider the environmental benefits of installing best available technologies to the Australian coal fired power plants. This consideration was to provide insight in terms of the indicative levels of pollutant reduction possible and also estimate indicative capital and operating costs to retrofitting these systems. In doing so, the technologies that are defined as the best available by other international jurisdictions was identified. The reduction in particulate matter (PM₁₀ and PM_{2.5}), sulfur oxides (SO_x) and nitrogen oxides (NO_x) were the focus of the Study. The Study focused on the abatement of these emissions using fabric filter, Wet Flue Gas Desulphurisation (FGD) and Selective Catalytic Reduction (SCR) systems respectively. These technologies were selected because they are capable of the highest removal efficiencies for the pollutants under consideration. Other cross-media effects and environmental impacts resulting from the installation of these techniques and considerations for the technical viability of retrofitting were also commented on.

1.3 SCOPE OF WORKS

The scope of the Study was to assess world's best available technologies for emissions control and abatement by reviewing the legislation for other developed countries and assessing them in the Australian context. WSP has also investigated the emissions abatement that can be achieved by installing the best available technologies and estimated the incremental costs for their installation and operation. The best available technologies considered for this Study as per the agreed Scope of Works were:

- Fabric Filters for particulate control
- Wet FGD for SO_x control
- SCR for NO_x control

Other factors that also need to be considered for the retrofit of these best available technologies to Australian coal fired plants were also discussed.

1.4 STUDY METHODOLOGY

In undertaking this Study, the regulations of other countries with developed standards were compared to determine the emissions abatement that can be achieved by what is considered to be best available technology. The emissions limits in Japan, the USA and Europe were compared.

The findings of the *Best Available Techniques (BAT) Reference Document (BREF) for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control)*, 2017 for the European Union were summarised and used as a guide for modelling purposes.

A Basis of Design was subsequently developed and issued to the EWG for feedback. Upon confirming the input parameters for models of indicative plants in the Australian coal fleet, the approach described below was followed:

- Base case models for 350 MW, 450 MW and 720 MW Black coal fired plants and a 500 MW Brown coal fired plant were used to estimate performance and emissions without additional best available technologies installed.
- Best available technology systems for particulates, SO_x and NO_x emissions were added to the base case models and the emissions after installing the best available technology was estimated.
- The incremental CAPEX corresponding to the capital cost for the purchase, delivery and retrofit installation of best available technology equipment was estimated via the cost estimation software PEACE.

PEACE is a proprietary cost estimation software within the Thermoflow suite of packages. PEACE develops reference costs for a plant constructed in the USA based on a database of equipment costs. The database is periodically updated to reflect the most up to date industry costs. PEACE also provides an estimation of erection and installation works based on likely labour hours and rates. To convert costs to the local context, multipliers (for equipment and labour) are applied to the reference USA cost and foreign exchange applied. PEACE has been shown to provide estimates which may be accurate to $\pm 30\%$ for a turn-key entire works project. However, it is noted that PEACE is intended for greenfield projects that typically have different procedures, labour hour requirements, and other implications when compared to a brownfield installation. As such, the cost estimates from PEACE when assumed for a brownfield installations may have greater inaccuracy. WSP has taken the incremental cost as the difference between a PEACE generated cost for a reference plant without additional best available technology installed and a cost for a plant with additional best available technology installed. WSP's general view is that PEACE may be conservative in regards to labour hours which is multiplied by the relatively higher labour rates in Australia. However as PEACE does not include an estimate for additional retrofit works (e.g. cutting in and reconnecting into existing ducting), the offset between the two may offset each other.

WSP notes that there are also additional costs that have not been assessed in this Study because they are site and project specific. This includes elements such as: lost revenue due to plant downtime, decrease in net export capacity which may impact on generation revenue or reserve capacity revenue, consultancy costs to undertake studies and assessments, and specific retrofit costs such as replacement of and upgrading of foundations, or upgrade costs of electrical supply / transformers to cater for additional auxiliary loads.

- For each best available technology installed, the incremental OPEX corresponding to the additional operating cost to operate and maintain the best available technology equipment was estimated based on the consumption rates of consumables required for the best available technologies (e.g. ammonia consumed by the SCR, limestone consumed by the Wet FGD) and an allowance made for yearly maintenance.
- The cross-media effects and other impacts on the plant as a result of installing the best available technology were highlighted.
- Additional implications of retrofitting the best available technologies that were not included in the overall costing were discussed. These included:
  - An estimate of incremental parasitic loads
  - The requirement for ID fan uprating
  - Impacts on flue plume
  - Impacts on residue generated, both new and on existing streams
  - Indicative sizing / footprint of best available technology systems

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1.5 LIMITATIONS AND DISCLAIMERS

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with the market. WSP does not warrant or guarantee the accuracy of any opinion expressed concerning predictions of the costs related to retrofitting best available technology systems to an existing power plant in the Australian coal fired fleet. The costs indicated in this report are not appropriate for investment decision making purposes and require further detailed assessment to improve their level of accuracy. They are provided for the purposes of this report to inform and are for high level comparative and assessment purposes only.

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2 OVERVIEW OF INTERNATIONAL EMISSIONS POLICIES

The combustion of fossil fuels to generate electricity utilises large quantities of combustible fuels and other raw materials, such as water and air, to produce energy. These installations also generate residues, wastes and emissions. Many of Australia's coal fired power plants were commissioned during the 1980s to the 1990s and since their deployment, technology has continued to develop. Relatively newer coal fired plants have higher energy efficiencies and may be installed with current emissions reduction technology. However, future increases in the efficiency of these plants will ultimately be limited by:

- Thermodynamic laws
- Diminishing returns from increasing development costs
- Increasing capital costs, leading to higher generation costs
- Plants not operating at their full capacity

These elements impact the amount of useful work that can be extracted from the combustion of fossil fuels, and therefore will ultimately impose a minimum level of emissions, since every unit of energy consumed at these plants represents additional cumulative emissions. Currently, the most effective way to reduce the emissions per unit of energy generated is to use as much of the heat produced as possible, so that less fuel is consumed and less emissions are produced (Lecomte, et al., 2017). This may be achieved by optimising the steam cycle, or recovering waste heat from the flue gas. However, improving the amount of heat extracted from the process may still not be enough to meet increasingly stringent emission reductions targets, and as such, abatement technology is the alternative to reduce emissions. These techniques are designed to target certain emissions produced by large combustion plants, most notably particulate matter, SO_x and NO_x, but may have other side effects such as reducing or increasing other emissions, generating additional residues or consuming additional inputs. Therefore, a balance must be achieved between the reduction in the targeted emission, and the additional environmental burden that these techniques may impose.

To provide a perspective of how best available technologies are defined internationally, WSP summarised the legislation from the European Union (EU), USA and Japan. Of the three assessed, the European BREF was found to be the most prescriptive in terms of defining best available technology and provides a typical removal efficiency for the relevant technologies, which was used as the basis of assumptions in this Study. In comparison, the policies in the US and Japan do not provide a definition of best available technology. Hence, for a comparative assessment, the BREF has been detailed in this report. The focus on the European BREF does not imply that WSP recommends the adoption of these technologies in the Australian context, but that they may serve as a reference to how best available technologies are defined from international practice.

While a full assessment of the Australian environmental parameters compared to other jurisdictions is outside the scope of this Study, some general observations can be made. Specifically, Australia has relatively less dense population centres, there are differences in the general natural environment such as water availability and general atmospheric conditions, and when compared to Europe, limited proximity to neighbouring countries or emissions from other jurisdictions.

2.1 EMISSIONS POLICIES IN THE EUROPEAN UNION

Fossil fuelled power generators in the EU operate with emissions permits where the conditions are based on what is achievable using best available technologies. The BAT conclusions developed under the Directive 2010/75/EU for large combustion plants are used as a reference for setting these permit conditions. Further information regarding the techniques that qualify as best available technology and emission limits that are expected to be achieved from implementing these best available technologies are detailed in Section 5.1.3 of the BREF and Section 5 of this Study.

2.2 EMISSIONS POLICIES IN THE USA

From WSP's investigation, the USA does not currently appear to have standardised best available technology reference documents that apply across programmes. Instead, there are other technology-based performance standards implemented, generally in the form of quantified emission limit values (ELVs). Under the Clean Air Act, the USA EPA is the regulatory body that controls the allowable ELVs for stationary sources of air pollution, such as coal fired boilers.

In 2011, the US EPA introduced the Mercury and Air Toxics Standards (MATS) to reduce mercury, heavy metal and acid gas emissions from new and existing plants over 25MW. The MATS finalises the performance standards for coal and oil fired power plants under sections 111 and 112 of the 1990 Clean Air Act amendments (United States Environmental Protection Agency, 2017). These standards generally apply to the coal and oil fired electric generating utility steam generating units (EGUs) with a capacity of at least 25MW. Specific emissions limits are provided based on the date on which the plant commenced construction, reconstruction or modifications. The MATS final rule amends the New Source Performance Standards (NSPS) emissions limits for SO₂, NO_{P2} and PM in 40 CFR part 60 Subpart Da such that it effects plants that began construction, modification or reconstruction after September 18, 1978¹.

The MATS final rule also amends the National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR part 63, which allows total filterable particulate matter to be used as a surrogate for the total emissions of non-mercury toxics, whilst mercury was measured separately (IEA Clean Coal Centre, 2015). These standards are also known as the Maximum Achievable Control Technology standards, which are derived from the Code of Federal Regulations (CFR). The following sections provide summaries of subparts from the Code of Federal Regulations Citation developed by the USA EPA, which addresses particulate emissions, SO_x and NO_x.

Electric utility steam generating units (EGUs) that are regulated by the MATS must meet the emissions standards by the date that their initial performance test is conducted, or required to be conducted. The EGUs have at least 3 years to carry out modifications in order to comply with the MATS as provided under the Clean Air Act. An additional year may be granted for installation works to be completed as needed. EGUs that are unable to comply with the MATS are addressed by the EPA on a case-by-case basis (United State Environmental Protection Agency, 2019).

The USA legislation is not comparable to the EU legislation due to the fact that the EU legislation provides emission values within bands of rated thermal input of the plant, whereas the USA limits are calculated predominantly on specific fuel input or energy output. However, a review of emission levels that would be applicable for the size of plants of the Australian coal fleet indicates that permitted emission values per the USA legislation is comparable, albeit on the higher end of the EU emission bands for NO_x and SO₂. Permitted particulate emissions per the USA legislation is higher than the EU legislation.

2.2.1 USA EPA REGULATIONS ON PARTICULATE MATTER

Under the NSPS and excluding certain exceptions, on and after the date on which the initial performance test is completed or required to be completed under §60.8 of the Code of Federal Regulations Citation², whichever date occurs first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction or reconstruction after 3 May 2011 particulates in excess of:

- 11 ng/J gross output
- 12 ng/J net output

Plants that are modified after May 3, 2011 shall not emit in excess of 13 ng/J heat input.

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¹ The NSPS provides different emissions limits based on the date by which construction, reconstruction or modification commenced. Plants that commenced construction, reconstruction or modification after September 1978 are the earliest plants that may be affected by this standard.

² EPA (2015), *Code of Federal Regulations Citation: 40 CFR Part 60 Subpart Da*, Environmental Protection Agency

The emission limits set under the NESHAP are shown in Table 2.1. The MATS allows EGU operators to use filterable PM as a surrogate for non-mercury hazardous air pollutant metals. This implies that operators can measure their filterable PM for compliance with the performance standards, or they may monitor the individual non-mercury emissions.

Table 2.1. NESHAP Filterable Emissions Limits

PLANT	FILTERABLE PM LIMIT
Existing coal fired unit, not low rank virgin coal	0.3 lb/MWh gross electric output
Existing coal fired unit, low rank virgin coal	
New or reconstructed coal fired unit, not low rank virgin coal	0.007 lb/MWh gross electric output
New or reconstructed coal fired unit, low rank virgin coal	

Given the size and age of the coal fired power units under consideration for this Study, it is likely that they would be regulated under the NSPS and NESHAP limits and would be required to meet the lower filterable PM limit of the two.

Compared to the BREF, the method of measuring pollutants in the US EPA's MATS allows more particulate matter per MWh_e and would indicatively also permit larger plants to emit more PM per normal cubic metre of flue gas. This is contrary to the BREF which typically requires larger plants to emit less PM per normal cubic metre of flue gas compared to smaller plants.

2.2.2 USA EPA REGULATIONS ON SO_x

Under the NSPS and excluding certain exceptions, on and after the date on which the initial performance test is completed or required to be completed, whichever date comes first, no owner or operator subject to the provisions of the Code of Federal Regulations Citation shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction or reconstruction commenced after or on May 3, 2011, any gases that contain SO₂ more than:

- 130 ng/J gross energy output, or
- 140 ng/J net energy output, or
- 3% of the potential combustion concentration (i.e. should achieve 97% reduction).

Plants that are modified after 3 May, 2011 shall not emit in excess of 180 ng/J gross output, or must achieve 90% reduction.

On and after the date on which the initial performance test is completed or required to be completed, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases that contain SO₂ in excess of 520 ng/J heat input and 15% of the potential combustion concentration (85% reduction), with exceptions. Compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

Sulphur dioxide emissions are limited to 520 ng/J heat input from any affected facility which:

- Combusts 100% anthracite;
- Is classified as a resource recovery unit; or
- Is in a non-continental area and combusts solid fuel or solid-derived fuel.

EGUs that are regulated by the NESHAP must limit their SO_x emissions according to the values in Table 2.2, which shows that new or reconstructed EGUs are permitted to emit less SO₂ or HCl than existing EGUs. EGUs affected by the

MATS are permitted to use SO₂ as a surrogate measurement for HCl compliance if they have a wet or dry FGD system installed and in operation in conjunction with a SO₂ continuous emissions monitoring system.

Table 2.2. SO_x and HCl emission limits under the NESHAP

EGU SUBCATEGORY	SO ₂	HCL
Existing coal fired unit, not low rank virgin coal	1.5 lb/MWh gross electric output	0.02 lb/MWh gross electric output
Existing coal fired unit, low rank virgin coal		
New or reconstructed coal fired unit, not low rank virgin coal	0.4 lb/MWh gross electric output	0.0004 lb/MWh gross electric output
New or reconstructed coal fired unit, low rank virgin coal		

Given the age and gross electric output of the coal fired units under consideration in this Study, it is likely that they would be regulated by both the NSPS and NESHAP for acid gas limits and would be required to meet the lower limit of the two.

Compared to the BREF, the pollutant measurement method in the US EPA's MATS allows larger plants to emit more SO_x whereas the BREF requires larger plants to achieve lower SO_x emissions per cubic metre of flue gas.

2.2.3 USA EPA REGULATIONS ON NO_x

Under the NSPS and excluding certain exceptions, plant owners or operators that commenced construction or reconstruction after May 3, 2011 cannot emit NO_x in excess of the limits listed below:

- 88 ng/J gross output
- 95 ng/J net output

Plants that were modified after May 3, 2011 cannot emit NO_x in excess of 140 ng/J gross output.

2.3 EMISSIONS POLICIES IN JAPAN

The Ministry of the Environment of the Japanese Government is the regulating body that develops the emissions standards for soot or dust and NO_x emissions. Under the general standards, power plants with coal boilers are subject to the dust and soot emissions limits in Table 2.3 and the NO_x emissions limits in Table 2.4.

Table 2.3. Emissions standards for Soot and Dust for plants with a heating area of 10m² or more

CAPACITY (NM ³ /H)	PARTICULATE EMISSIONS UNDER THE GENERAL STANDARD (MG/NM ³) ³
≥ 200,000	100
≥ 40,000 and < 200,000	200
< 40,000	300

³ Government of Japan (1998), *Regulatory Measures against Air Pollutants Emitted from Factories and Business Sites and the Outline of Regulation – Emission Standards for Soot and Dust, and NO_x*, Ministry of Environment, Government of Japan, https://www.env.go.jp/en/air/aq/air/air4_table.html

Table 2.4. Emissions standard for NO_x for plants with a heating area of 10m² or more

CAPACITY (NM ³ /H)	NO _x EMISSIONS UNDER THE GENERAL STANDARD (PPM)
≥ 700,000	200
≥ 40,000 and < 700,000	250
< 40,000	300

The Ministry of Environment uses the formula below to determine the permissible SO_x emissions in terms of Nm³/h, where q is the permissible SO_x emission, K is a specified constant between 3.0 to 17.5, and He is the effective stack height in metres⁴.

$$q = K \times 10^{-3} \times He^2$$

The K constant varies between regions in Japan based on the total emission reduction plant. For example, Tokyo has a K value of 3.0, whereas Kagoshima has a K value of 14.5, implying that plants in Tokyo would be permitted to emit less SO_x emissions compared to a similarly sized plant in Kagoshima.

The permitted emission levels in Japan are considerably higher than the EU. WSP notes that the emissions calculations for Japan are different to the EU for SO_x. One benefit of this calculation is that it considers local air sheds and the allowable pollution concentration specific to a region, whereas the EU BREF does not. However, the licensing bodies in the EU can impose more stringent emissions limits on plants at their discretion.

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⁴ The effective stack height is defined as the actual stack height plus the height of the smoke ascent.

3 INFO / DATA PROVIDED TO THE CONSULTANT

3.1 DATA PROVIDED TO THE CONSULTANT

Committee members responded to a Request for Information (RFI) issued by WSP, requesting information relating to properties of Australian coal utilised in the Australian coal fired power plant fleet including:

- Lower Heating Value (LHV)
- Fuel composition as a percentage of weight
- Ash characteristics

This information was used to construct the typical, high ash, low ash, high sulfur and low sulfur black and brown coal input fuels for the Thermoflow models. This information was important for analysing the emissions reductions using best available technologies in the Australian context.

Committee members also confirmed that plant models' critical operating parameters including those listed below as assumed by WSP were reasonable representations of the Australian coal fleet.

- Condenser pressure
- Cooling system configuration
- Steam turbine configuration and operating pressures and temperatures
- Quantity of feedwater heaters
- Total auxiliary load
- Boiler efficiency
- Removal efficiency of any existing particulate abatement technology
- Current emission values for PM, SO_x and NO_x

This information was used to develop the operating parameters for the plant models constructed in Thermoflow.

3.2 LITERATURE

Information on the BAT for particulate, SO_x and NO_x abatement was obtained from the *Best Available Techniques Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control)*, 2017.

The criteria for determining the techniques that were classified as BAT were documented in the *Industrial Emissions Directive 2010/75/EU*.

Further information on the BAT for particulate, SO_x and NO_x abatement was gathered from the *Commission Implementing Decision (EU) 2017/1442*.

4 POWER PLANT MODELS

4.1 BLACK COAL REFERENCE CASES

To estimate the emissions of a typical Australian black coal fired plant without installing best available technologies, the black coal reference plant models were constructed in Thermoflow with the following capacities and configurations:

- 350 MW Capacity, Subcritical Single Reheat steam cycle with primary NO_x control and ESP installed
- 450 MW Capacity, Supercritical Single Reheat steam cycle with primary NO_x control and fabric filter installed
- 720 MW Capacity, Subcritical Single Reheat steam cycle with primary NO_x control and fabric filter installed

4.1.1 350 MW BLACK COAL REFERENCE CASE

The 350 MW reference black coal plant model was constructed with a 99.2% efficient ESP and low NO_x burners (LNBs). Representative coal profiles for a typical black coal and a low ash black coal were developed with input from committee members and used as fuel input for the Thermoflow models (see Appendix A).

4.1.2 450 MW BLACK COAL REFERENCE CASE

The 450 MW reference black coal plant model was constructed with a 99.95% efficient fabric filter and LNBs. Representative coal profile for a typical black coal was developed with input from a committee member and used as fuel input for the Thermoflow models (see Appendix A).

4.1.3 720 MW BLACK COAL REFERENCE CASE

The 720 MW reference black coal plant was constructed with a 99.95% efficient fabric filter and LNBs. Representative coal profiles for the fuel types listed below were developed with input from committee members and used as fuel input for the Thermoflow models (see Appendix A).

- Typical black coal
- High sulfur black coal
- High ash black coal
- Low sulfur and low ash black coal

Each fuel type was used as an input in a separate model to provide the level of emissions without additional best available technologies for the range of possible fuels that the power plants may receive.

4.2 BROWN COAL REFERENCE CASE

The brown coal reference plant model was based on a 500 MW Subcritical Single Reheat unit with a 96.5% efficient ESP installed. The efficiency of the ESP was selected to match the typical PM emission concentration as stated by Committee Members assuming this is applicable for the typical brown coal property provided (see Appendix A). The following brown coal input fuels were constructed in Thermoflow with the input from committee members:

- Typical brown coal
- High sulfur brown coal
- Low sulfur brown coal
- High ash brown coal

— Low ash brown coal

Each fuel type was used as an input in a separate model to provide the level of emissions without additional best available technologies for the range of possible fuels that the power plants may receive.

5 BEST AVAILABLE TECHNIQUES

5.1 DEFINITION

Thermal power plants emit several pollutants as a result of the combustion process. Three of the most notable are particulate matter, SO_x and NO_x. The best available technologies for abatement of these three emissions are discussed in the following sections.

5.1.1 EUROPEAN DIRECTIVE BAT CRITERIA

Under the European Directive 2010/75/EU, 12 criteria for determining technologies that are considered to be the best available are listed as;

- 1 using low-waste technology;
- 2 using less hazardous substances;
- 3 furthering the recovery and recycling of substances generated and used, and where appropriate;
- 4 comparable processes, facilities or methods have been tried with success on an industrial scale;
- 5 technological advances and changes in knowledge and understanding;
- 6 the nature, effects and volume of the emissions concerned;
- 7 the commissioning dates for new and existing installations;
- 8 the length of time needed to introduce the BAT;
- 9 the consumption and nature of raw materials used in the process and energy efficiency;
- 10 the need to prevent or reduce to a minimum, the overall impact of the emission to the environment and the risks to it;
- 11 the need to prevent accidents and to minimise the environmental consequences;
- 12 information published by public international organisations

These criteria were used to develop the recommendations of the BREF. The technologies discussed in Section 5.4 onwards are examples of BAT as defined in the BREF.

5.1.2 BEST AVAILABLE TECHNOLOGY IN THE AUSTRALIAN CONTEXT

The public's concern of a short fall in the emissions abatement technology of Australia's coal fired plants arises from the fact that many of these plants were built in the 1980s and 1990s, before the technology that is considered as the best available today was more readily adopted or mandated by regulation. As such, an opportunity to reduce their emissions is by retrofitting these stations with best available technologies. Installing these technologies therefore depends on whether it is compatible with the existing equipment in terms of overall foot print, operating parameters and interfacing or connection points.

Noting that the most effective way to reduce emissions per unit of energy produced is to increase the efficiency of the plant to use as much of the heat produced as possible, the method of doing so is to design the plants for ultra high efficiency (i.e. supercritical or ultra supercritical steam cycle). It is noted however that the majority of the Australian coal fleet are subcritical designs, and retrofitting to supercritical is not viable.

The legislative emission abatement requirements should also be considered in conjunction with the geographical location of the emitting source and the air shed the plant exists within. The level of abatement that the power plant is required to achieve may (and often does) vary depending on whether there are other emitting sources in the air shed (such as other

power plants or industrial operations); whether the area is highly developed with emissions from transport sources; and the density of sensitive receptors within the air shed.

The National Environment Protection Council (NEPC) is the regulatory body established under the *National Environmental Protection Council Act 1994* that develops and reports on the effectiveness of the National Environment Protection Measures (NEPMs). Amongst the NEPMs developed by the NEPC is the Ambient Air Quality NEPM. WSP understands that the NEPM is currently being reviewed and may be revised. The scope of this study does not include analysis of the Australian Coal Fleet emissions compared to current or future NEPM values and it will be the responsibility of individual committee members to correlate the levels of performance of the best available technology to current or potential future NEPM levels.

5.2 BAT-ASSOCIATED ENERGY EFFICIENCY LEVELS

BAT-associated energy efficiency levels (BAT-AEELs) for new and existing coal power plants are listed in Table 5.1. These efficiency levels are considered as the highest achievable using the best currently available technology.

Table 5.1. BAT-AEELs for New and Existing Coal Plants⁵

TYPE OF COMBUSTION UNIT	NET ELECTRICAL EFFICIENCY (%) ⁽¹⁾	
	New Unit	Existing Unit
Coal fired, $\geq 1,000 \text{ MW}_{\text{th}}$	45-46	33.5-44
Coal fired, $< 1,000 \text{ MW}_{\text{th}}$	36.5-41.5	32.5-41.5
Lignite-fired $\geq 1,000 \text{ MW}_{\text{th}}$	42-44	33.5-42.5
Lignite-fired $< 1,000 \text{ MW}_{\text{th}}$	36.5-40	31.5-39.5
⁽¹⁾ BAT-AEELs are on a LHV basis. The lower end of the BAT-AEELs are achieved if the plant is situated in a location that experiences unfavourable climatic conditions. The higher end of the BAT-AEELs are achieved when the plant operates with high steam parameters such as pressure and temperature.		

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

The efficiency of a thermal power plant is dependent on the local climate conditions amongst other elements such as the equipment selected and the fuel choice. The climate, expressed in terms of the wet and dry bulb temperature influences the selection of the cooling system type and equipment, and the condenser pressure. Maintaining the cooling requirements of the plant can become difficult in areas where high air and water temperatures are met with low water availability, leading a plant to achieve the lower end of the BAT-AEELs. These climatic conditions often coincide with areas in Australia, which will impact the plant's ability to perform at the high BAT-AEELs.

5.3 BAT-ASSOCIATED EMISSIONS LEVELS

The best practice according to the European BREF indicates that the BAT is to use one, or a combination of the techniques discussed in sections 5.4 to 5.6 of this report for emissions abatement. In doing so, the plants under consideration should achieve yearly averages of emissions within the ranges shown in Table 5.2.

⁵ BAT-AEELs do not apply for units operating for less than 1,500 hr/yr

Table 5.2. BAT-AELs for emissions to air for existing coal and/or lignite combustion

EMISSION	YEARLY AVERAGE FOR EXISTING PLANT (MG/NM ³) ⁽¹⁾	
Rated Thermal Input (MW _{th}) per unit	300-1000	>1,000
Particulate Matter	2-10 ⁽²⁾	2-8
SO _x	10-130	
NO _x	65-150	

⁽¹⁾ Other BAT-AELs apply for plants with smaller rated capacities but these were not applicable for the plants under consideration in this Study.

⁽²⁾ The higher end of the BAT-AEL range is 12mg/Nm³ for plants put into operation no later than 7 January 2014.

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

5.4 PARTICULATE ABATEMENT

5.4.1 OVERVIEW

One of the primary pollutants from combustion plants is particulate matter (dust). These emissions arise predominantly from the mineral fraction of the fuel. The main abatement techniques that aim to reduce particulate air emissions from thermal power plants are:

- Electrostatic Precipitators (ESPs)
- Fabric filters (baghouses)
- Cyclone dust collectors
- Wet scrubbers

These techniques are discussed in the following sections.

The analysis in this section investigates the impact of adding a second stage of particulate control equipment to existing ESP or fabric filter systems currently installed. For example, a new fabric filter was added to the 350 MW black coal plant where an ESP is already installed. In this arrangement, the flue gas would exit the boiler, flow through the existing ESP and then through a new fabric filter before being emitted to the atmosphere via the stack.

Although the Australian baseload coal fired power plants investigated within this Study are already fitted with a form of particulate abatement system (i.e. fabric filter or ESPs), the particulate removal efficiency of some plants is insufficient to meet BAT-AEL emission values as prescribed in the EU BREF. The EU BREF is among the most stringent (if not the most stringent) standard in the world for atmospheric emissions and therefore there may be a benefit in retrofitting these plants with better technology. For plants that currently meet BAT-AEL emission values, the benefits with installing an additional best available technology system may not be sufficient to justify the costs and corresponding non-cost implications. Nonetheless, for the purposes of this Study, the additional abatement levels and incremental costs associated with installing an additional best available technology system has been investigated and presented in this report.

5.4.1.1 ELECTROSTATIC PRECIPITATORS (ESPS)

ESPs work by electrically charging the particles and separating them under the influence of an electric field and are installed to reduce PM₁₀, PM_{2.5} and mercury emissions. These techniques can operate over a wide range of temperature, pressure and dust burden conditions. ESPs are classified as either wet or dry, with the dry ESPs being further subdivided according to whether they are hot or cold side ESPs. Hot ESPs are located before the air preheater and as such, operate between 300-450 °C, whereas cold ESPs are located after the air preheater and will therefore operate at 80-220 °C. Wet ESPs can achieve higher removal efficiencies and collect more condensables. ESP techniques are generally applicable to coal plants however, Flue Gas Conditioning (FGC) may be more suitable in plants where the flue gas has low conductivity and can be used for very low sulfur fuels.

5.4.1.2 FABRIC FILTERS

Fabric filters are comprised of isolated compartments containing rows of filter bags constructed of porous, woven or felted fabric. These bags catch the dust particles including PM₁₀ and PM_{2.5} particles as the flue gas flows through the bags. The material selection for the bags should therefore reflect the characteristics of the flue gas and the maximum operating temperature. The operating temperature for this technique is 150 °C for polyester bags, and 260 °C for fibreglass bags, and the off-gas flow rate must be less than 1,100,000 m³/h. Other than replacing the filter bags, fabric filters require minimal maintenance and have little, if any, impact on boiler availability (Cushing, Merritt, & Chang, 1990). Bag filters are generally applicable to coal power plants.

5.4.1.3 CYCLONE DUST COLLECTORS

Cyclone dust collectors use centrifugal force to separate the particles from the carrier gas. This technique is best suited to capturing dust from dry flue gas. They consist primarily of an upper cylindrical section and a lower conical section. The contaminated flue gas flows into the cyclone tangentially via an opening in the upper cylindrical section and creates a vortex. The centrifugal force acting on the relatively heavy particles separates them from the flue gas stream. When the flue gas reaches the bottom of the conical section, it begins to flow inward radially and exits the cyclone through the exit vent in the top of the cylindrical section and deposits the dust in a collection bin. The removal efficiency of this technique is limited because it cannot collect dust particles that are smaller than 5-10 µm. Therefore, cyclone collectors are usually used in conjunction with another abatement option.

5.4.1.4 WET SCRUBBERS

Wet scrubbers are a group of particulate control techniques that use a liquid to collect flue gas particulate matter. Within this group, the venturi scrubbers and moving-bed scrubbers are the most common. Venturi scrubbers introduce the liquid uniformly at the top of the converging section of the venturi. The contaminated flue gas and scrubbing liquid flow into the venturi throat where the velocity of the flue gas causes the atomisation of the scrubbing liquid. Wetting the flue gas causes small particles to become heavier as they are trapped in droplets of the scrubbing liquid and are easier to capture in a separator.

Moving-bed scrubbers are filled with low-density plastic spheres that are free to move within the packing retainers. The flue gas enters from the bottom of the unit, flows up through the packing and fluidizes it. Liquid is then distributed on the top of the bed from spray nozzles. The motion of the packing material creates turbulent mixing and aids the formation of liquid droplets that become impaction targets for the dust in the flue gas. The capture rate of this technique can be enhanced by adding several moving-bed stages in series.

5.4.2 PARTICULATE REMOVAL EFFICIENCY AND CROSS-MEDIA EFFECTS

All techniques are likely to have cross-media effects in that although they reduce PM emissions, they may create other environmental burdens such as emissions to water or an increase in energy, water or raw material consumption. A comparison of the removal efficiency for the techniques and any cross-media impacts they may have are shown in Table 5.3 below. The removal efficiencies in the table are based on the particle size distribution from <1 and >10 micrometres.

Table 5.3. Removal Efficiency & Cross-media Effects of Particulate Control and Abatement Techniques

CROSS-MEDIA IMPACT	ESP	FABRIC FILTERS	CYCLONES	WET SCRUBBING
Removal Efficiency	96.5-99.95%	99.6-99.95%	30-90%	98.5-99.9%.
Energy Use	0.32% energy consumption as percentage of gross electrical output	0.2-3% energy consumption as a percentage of electric capacity.	No details.	Up to 3% consumption as a percentage of electric capacity (5-15kWh / 1,000m ³).
Residue Generation	Fly ash.	Fly ash.	Fly ash.	Fly ash sludge / wet slurry.
Water Consumption	Wet ESPs require water.	None.	None.	Wet scrubber systems utilise water.
Effluent Production	Effluent generated in Wet ESPs.	None.	None.	Wet scrubber systems generate effluent.

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

5.4.3 TYPICAL CAPEX AND OPEX

The typical operating cost mainly depends on the water and electricity consumed, maintenance and any by-product disposal costs. A summary of the capital costs (CAPEX) and operating costs (OPEX) for each technique as presented in the BREF is reproduced in Table 5.4.

Table 5.4. Particulate Control and Abatement CAPEX and OPEX

CROSS-MEDIA EFFECT	ESP	FABRIC FILTER	CYCLONE	WET SCRUBBER
Capital Costs	Initial investment costs may be higher or lower than for other techniques such as bag filters, depending on the applied fuel (e.g. coal, biomass, municipal waste). UK indicative costs (1999) are GBP 25/kWe.	UK indicative costs (1999) are GBP 10/kWe.	Lowest investment cost of all dust abatement techniques, but must work in conjunction with another technique.	Capital costs are generally lower than for ESPs or fabric filters, though this may be offset by the relatively high pressure drop and operating costs.
Operational Costs	Operational costs are smaller than the corresponding costs for other techniques. Using modern control systems can further reduce these costs. Maintenance costs are normally reasonable when processing ordinary fly ash. These devices	Maintenance costs are high as the filter material must be changed every two to five years. The minimum expense for a filter change is	Low maintenance costs due to the sturdiness of the equipment.	This technique involves cooling the flue gas, which requires reheating prior to emissions to the atmosphere. This incurs higher energy costs.

CROSS-MEDIA EFFECT	ESP	FABRIC FILTER	CYCLONE	WET SCRUBBER
	are competitive for power plants that have a wide range of power equipment and a variety of boiler processes.	approximately 10% of the initial investment cost.		

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

5.4.4 INCREMENTAL PARTICULATE ABATEMENT AND COSTS

It is understood that all Australian baseload utility coal fired power plants are currently fitted with a form of particulate control technology and consequently, the Thermoflow models for the reference cases were also fitted with existing particulate control techniques. WSP investigated the benefit of adding a new fabric filter downstream to the existing particulate control technique.

To demonstrate the emission level reductions and incremental CAPEX and OPEX from utilising an additional particulate control system, WSP modelled the installation of a fabric filter with an assumed removal efficiency of 99% on top of the existing particulate control system. To provide an indication of the likely CAPEX associated with achieving BAT levels of efficiency and emissions, WSP used PEACE. The OPEX was estimated from the BREF, which indicates the operating cost for fabric filters is approximately 10% of the installation cost (assuming exclusive of soft costs). Modelling results are shown in Table 5.5 for a single unit.

Table 5.5. Estimated Annual Incremental Particulate Abatement

PLANT CAPACITY	CURRENT PARTICULATE EMISSIONS (MG/NM ³ @ 6% O ₂) ⁽¹⁾	PARTICULATE EMISSIONS AFTER ADDITIONAL FABRIC FILTER INSTALLED (MG/NM ³ @ 6% O ₂) ⁽²⁾	INCREMENTAL CAPEX ⁽³⁾	INCREMENTAL OPEX
350 MW Black Coal	120 – 268	< 3	\$36.7 mil	\$2.8 mil
450 MW Black Coal	17	≤ 1	\$42.4 mil	\$3.3 mil
720 MW Black Coal	9 – 15	≤ 1	\$67.8 mil	\$5.2 mil
500 MW Brown Coal	37 – 327	≤ 3	\$91.4 mil	\$7.0 mil

⁽¹⁾ Current PM values are based on responses from AEC Committee Members post existing particulate control systems. That is, the current emissions stated in Table 5.5 factor in existing installed particulate control systems.

⁽²⁾ Emissions after installation of an additional fabric filter are based on the assumption that the new system removal efficiency is 99%. This value is assumed based on a conservative application of the values indicated in the BREF. WSP notes that confirmation of this value is outside the current scope of the study and actual removal performance will depend on the design of the system and the particular plant being retrofitted. In addition, although not explicitly stated, it may be inferred that the removal values stated in the BREF are based on plants where only a single particulate control system is installed. For the Australian coal fleet, all of the reviewed plants already have existing particulate control systems installed. The installation of a second system may not achieve as high of a removal efficiency given the reduced particulate emissions quantity exiting the first particulate control system.

PLANT CAPACITY	CURRENT PARTICULATE EMISSIONS (MG/NM ³ @ 6% O ₂) ⁽¹⁾	PARTICULATE EMISSIONS AFTER ADDITIONAL FABRIC FILTER INSTALLED (MG/NM ³ @ 6% O ₂) ⁽²⁾	INCREMENTAL CAPEX ⁽³⁾	INCREMENTAL OPEX

⁽³⁾ Capital costs are derived from Thermoflow modelling and estimated using PEACE. The cost shown includes an additional 30% for Contractor's soft costs for contingency, profit and fees.

⁽⁴⁾ As stated in section 4, WSP has assumed a standard particulate control removal efficiency for the existing plant models as a generalisation of current PM emissions within the Australia coal fleet for different plant sizes and coal types. It is noted that the efficiencies of particulate control systems installed at individual plants will differ from each other based on the design, age and level of fouling. For instance, removal efficiencies will be higher for new systems or recently cleaned systems compared to heavily fouled systems. Better designs may also be utilised and as such, higher removal efficiencies may be possible compared to as modelled by WSP. Although based on committee member responses, current emission values as stated in this report should not be taken as necessarily reflecting what is currently being emitted at specific plants.

Table 5.5 indicates that retrofitting another best available technology particulate control system in addition to the existing particulate control system for the Australian coal fired power plants will achieve BAT-AELs at the lower end or even below the BAT-AEL range for PM. That is, PM emissions may be close to or below 2 mg/Nm³ for PM emissions with additional best available technology installed at the existing plants. It is observed that some Australian plants are already achieving PM emissions within the BAT-AELs for existing plant (2 – 8 mg/Nm³) with their existing particulate control systems (i.e. without the need for additional fabric filters to be retrofitted).

Additional commentary on the implications of retrofitting additional particulate control systems to plants in the Australian coal fleet is provided in the following sections.

5.4.5 IMPACTS OF LOW LOADING AND TWO SHIFTING ON FABRIC FILTERS

The flue gas temperature inside the fabric filter is the main concern when operating at part loads, fluctuating loads, or with daily start-ups and shutdowns (two shifting). Fabric filters perform optimally when the flue gas temperature is relatively constant, and within their operating range. If the flue gas temperature falls below the dew point, the ash can become moist, causing it to stick to the filter fabric. This can lead to an increase in the pressure drop over the component. If the flue gas temperature falls below the condensation point of sulphuric acid, the flue gas can become corrosive and may reduce the service life of the filter bags.

To reduce the risk of damaging the bags during fluctuating loads, the filter bags should be kept dirty, whereby a layer of dust is kept on the fabric to protect the fibres from the dew point transition. In addition, the fabric filters should be installed with high quality insulation to mitigate the risk of the flue gas temperature falling outside of the operating temperature range of the fabric filter. The start-up and shut down procedure can also be modified to include a pre-heating unit to monitor the flue gas temperature and prevent moisture condensation.

5.4.6 INCREMENTAL PARASITIC LOAD FOR FABRIC FILTERS

Retrofitting a fabric filter to a power plant impacts the auxiliary load because the bags introduce an additional pressure drop that must be compensated for by the system's fans, which consume electricity. An increase in the amount of auxiliary load implies the net power output for the plant is less, thereby reducing the plant's overall net electrical efficiency. Table 5.6 shows the incremental parasitic load required to operate the plant with an additional fabric filter installed on top of any existing particulate control systems.

Table 5.6. Estimated incremental parasitic load for operating additional fabric filters

PLANT	FABRIC FILTER (MW)
350 MW Black Coal	3.0 – 3.2

PLANT	FABRIC FILTER (MW)
450 MW Black Coal	4.4
720 MW Black Coal	6.0 – 6.8
500 MW Brown Coal	6.7 – 7.1

As a result of the increased parasitic load, the plant's overall net electrical efficiency is reduced by the installation of an additional fabric filter (see Table 5.7).

Table 5.7 Change in overall plant net efficiency with additional fabric filter installed

PLANT	DECREASE IN NET PLANT EFFICIENCY (LHV)	INCREASE IN CO ₂ EMITTED (KG CO ₂ E / MWH)	% INCREASE IN CO ₂ EMITTED
350 MW Black Coal	0.34 percentage points	8.3	0.9
450 MW Black Coal	0.41 percentage points	10.0	1.1
720 MW Black Coal	0.39 percentage points	7.2	1.0
500 MW Brown Coal	0.55 percentage points	17.1	1.6
Decrease in net plant efficiency is provided as a range to reflect indicative values when operating on different coal types. Increase in CO ₂ is based on operation on the typical coal type only.			

5.4.7 ID FAN UPGRATING

The retrofit of an additional fabric filter will induce an additional pressure drop in the system. To compensate for this, the ID fan may potentially require uprating. Table 5.8 below shows the CAPEX estimated by Thermoflow for uprating the ID fans. This assumes that the current ID fan will be replaced.

Table 5.8. Estimated installed CAPEX for ID fan uprating

PLANT MODEL	UPDATED ID FAN CAPEX	MAXIMUM PRESSURE RISE (MILLIBAR)
350 MW Black Coal	\$4.7 mil	50
450 MW Black Coal	\$7.9 mil	67
720 MW Black Coal	\$17.3 mil	63
500 MW Brown Coal	\$18.6 mil	39

In order to accommodate and operate the uprated ID fans, additional considerations may also need to be made. For example, the larger fans may consume more power than the current fan. This increase may require the cabling, switchgears, power supply and other electrical equipment to be uprated accordingly. Furthermore, if the pressure rise of the uprated fans is higher than the existing ID fan, the pressure of the uprated fan may require the encasing to be reinforced to ensure it can withstand the suction pressure created in the event of a failure in the control system.

5.4.8 IMPACTS ON AUXILIARY SERVICES

Both ESPs and fabric filters can potentially require compressed air. In some ESPs, compressed air is used to operate the rappers, which ensure that the electrode contacts are relatively clean and effective. Similarly, some fabric filters are cleaned by pulsing compressed air through them to clean most of the particles from the fabric.

5.4.9 COMPATIBILITY WITH OTHER BEST AVAILABLE TECHNOLOGY SYSTEMS

Although primarily designed for SO_x abatement, wet lime/limestone scrubbers may also remove approximately 50% or more of the particulate matter in the flue gas, depending on the particle size. However, it should be noted that high particulate concentrations into the absorber may potentially cause the gypsum to be contaminated.

5.4.10 FABRIC FILTER FOOTPRINTS

Table 5.9 shows the approximate footprints for the fabric filters as generated by Thermoflow for the plant models. Figure 5.1 provides a general diagram of the fabric filters as indicated by the plant models.

Table 5.9. Estimated Fabric Filter Footprints

PLANT	LENGTH (M)	WIDTH (M)	HEIGHT (M)
350 MW Black Coal	22	25	20
450 MW Black Coal	24	28	21
720 MW Black Coal	57	21	22
500 MW Brown Coal	50	27	21

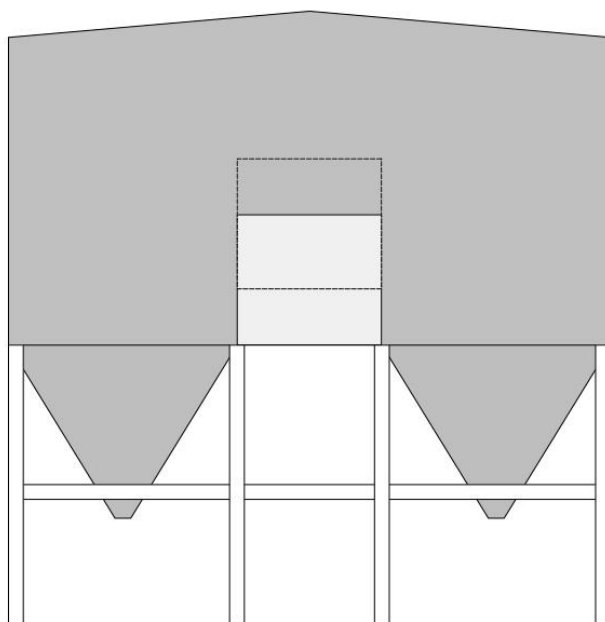


Figure 5.1. General Fabric Filter Diagram

The retrofit of a fabric filter system could have the spatial requirements as shown in Table 5.9, which may not be insignificant given space availability at respective plants. It will also require additional retrofit works whereby the ducting between the existing particulate control system and ID fan are cut and reconnected via the new fabric filter before reconnecting into the existing or new ID fan. While a full assessment of the feasibility of this work is outside the scope of

this Study, it could be envisaged that within the existing Australian coal fleet for plants of compact design, there may be insufficient space to implement this or more complicated arrangements will need to be utilised.

5.5 SO_x ABATEMENT

5.5.1 OVERVIEW

Sulfur oxides represent another group of primary air emissions that result from the combustion of fossil fuels and are mainly borne from the sulfur content of the input fuel. The majority of sulfur oxides produced from the combustion process take the form of sulfur dioxide (SO₂) with minor quantities of sulfur trioxide (SO₃). The main abatement techniques for reducing SO_x air emissions from thermal power plants are:

- Dry abatement techniques
- Semi-dry abatement techniques
- Wet abatement techniques

5.5.1.1 DRY ABATEMENT TECHNIQUES

The dry abatement techniques include furnace sorbent injection, duct sorbent injection and hybrids of both systems. In duct sorbent injection techniques, calcium or sodium based sorbents are injected into the flue gas. Common types of duct sorbent injection techniques include:

- Dry hydrated lime injection, which requires humidification
- Dry sodium injection, which does not require humidification but may require on-site milling for an improved capture
- Lime slurry injection or modified dry FGD, which does not require a separate humidification step

These systems require a downstream particulate matter collection system to collect the reformed reaction products such as a fabric filter.

5.5.1.2 SEMI DRY ABATEMENT TECHNIQUES

Spray dry scrubber systems are an example of a semi-dry abatement technique because they involve the use of a lime slurry. This technique introduces a suspension/solution or alkaline reagent into the flue gas stream and operates at approximately 120-200 °C at the flue gas inlet, and 65-80 °C at the flue gas outlet. The mixture reacts with the gaseous sulfur compounds and forms a solid reaction product, which must be removed in a PM collection system such as a fabric filter or ESP downstream of the scrubber system. These systems have reliabilities in the order of 95% - 99%.

5.5.1.3 WET ABATEMENT TECHNIQUES

Wet lime/limestone scrubbers remove the sulfur in the flue gas by injecting a slurry of lime/limestone sorbent for capturing the SO₂ in an absorber and transforming it into gypsum. In these processes, the gaseous compounds dissolve into a liquid form (water or alkaline solution). These techniques will typically operate at 45-60 °C. Solid and gaseous compounds are removed simultaneously by saturating the flue gases with the lime/water slurry. The slurry is collected in an absorber sump from where some of the liquid is removed and sent for treatment in a waste water process with any insoluble matter collected by filtration or sedimentation. Gypsum is separately removed from the sump and dewatered for further treatment and reuse or disposal. These systems can typically achieve a reliability of 95% - 99% of operating time, depending on the oxidation process, and can achieve 98 - 99% availability (Hamon, n.d.; Adrian & Housley, 1999).

Seawater scrubbers are also classed as a wet abatement technique and utilise the seawater's inherent properties to absorb and neutralise the SO₂ in the flue gases. This technique has an operating temperature of 145 °C at the flue gas inlet, and 30-40 °C at the seawater outlet temperature. These techniques can achieve reliabilities of 98% - 99%.

Unlike the dry and semi dry techniques, wet scrubbers do not require a downstream PM control system.

5.5.2 SO_x REMOVAL EFFICIENCY AND CROSS-MEDIA EFFECTS

Any technique employed is likely to have cross-media impacts in that, whilst the process reduces SO_x, HF and HCl emissions, it increases emissions to water or air, energy usage, water consumption and raw material use. The additional transportation required for delivering additional material (e.g. trucking) would also produce secondary emissions. Table 5.10 below shows a comparison of the removal efficiency for each of the techniques and any cross-media impacts as stated in the BREF.

Table 5.10. Removal efficiency and cross-media effects of SO_x control and abatement techniques

CROSS-MEDIA EFFECT	DRY	SEMI-DRY	WET
Removal Efficiency	Furnace sorbent injection SO ₂ 30-50%, 70-80% by recycling the reaction product. Duct sorbent injection SO ₂ 50-80%	HCL > 99% SO ₂ 85-92% SO ₃ >99% Sulfur contents exceeding 3%, the removal efficiency decrease slightly.	Wet limestone scrubber HCl 90-99% HF 90-99% SO ₂ 92-99.5% SO ₃ aerosol 50% Seawater Scrubber HCl 95-99% HF 95-99% SO ₂ 85-98%
Energy Use	0.01-0.2% energy consumption as a percentage of electrical capacity.	0.5-1% energy consumption as a percentage of electrical capacity.	1-3% energy consumption as a percentage of electrical capacity.
Reagent Use		7-15 (lime) kg/t fuel input.	2-3 (NaOH), ~ 10 (CaO), 5-10 (lime/limestone) kg/t fuel input.
Residue Generation	7-25 kg/t fuel input.	12-25kg/t fuel input.	10-15 (wet) kg/t fuel input. 3-5 (dry) kg/t fuel input.
Water Consumption	Not required.	20-40 litres per 1,000m ³ of flue gas.	220-250 litres/MWh _e
Effluent Production	None.	None.	250-500 litres/t fuel input.

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

A Wet FGD system would likely achieve the highest removal efficiency and therefore, represents the best technology that is currently available in regards to SO_x removal efficiency. However, water consumption is an important consideration and potential impediment to utilisation of Wet FGD systems in Australia and thus, additional assessment of feasibility would be required in the Australian context on a case by case basis.

A potential solution to minimise water consumption and maximise removal efficiency is to utilize a seawater scrubber. However this is only viable for plants located with access to seawater. Seawater scrubbers do not consume water or reagents (e.g. lime / limestone) and do not produce a solid by-product, however will require an intake and discharge to the sea. The seawater discharged must be conditioned (e.g. aeration basins to modify pH) to ensure it meets

environmental requirements. As seawater scrubbers are not viable at all Australian coal plants, it was not included for further assessment in this Study.

5.5.3 TYPICAL CAPEX AND OPEX

The typical operating costs mainly depend on the amount and type of reagent, water, and electricity consumption, maintenance, and end product residue disposal costs. Table 5.11 provides a summary of the CAPEX and OPEX for the SO_x abatement techniques as stated in the BREF.

Table 5.11. SO_x Control and Abatement CAPEX and OPEX

AREA	DRY	SEMI-DRY	WET
Capital Expenditure	Furnace Sorbent Injection A 350 MW _{th} unit with one reactor has a CAPEX approximately 25% of the capital cost of a wet limestone process. Low capital cost due to simplicity and adaptability in retrofitting but lower SO ₂ removal efficiency.	Spray Dry EUR 7-45 /kW _{th} for a boiler. Generally lower capital costs, but higher operating costs than wet scrubbers.	Wet Limestone Scrubber Approx. EUR 35-50/kW _e for new plants. EUR 60-300 /kW _e for retrofits. Operation and maintenance costs between EUR 0.4-0.7/MWh (energy input).
Operating Expenditure ⁶		EUR 0.5-0.7 /MWh operating and maintenance costs.	Typical SO ₂ removal costs are EUR 750-1,150/t SO ₂ removed and the effect on the price of electricity is EUR 3-6/MWh (electricity produced).
Energy Use			Energy loss due to reheating flue gas is large compared to dry FGD, which typically do not require heating.
Reagent Use	Cost of limestone accounts for roughly half of the process operating cost.	Four to five times higher cost of lime sorbent used in spray dry scrubbers compared to limestone for wet scrubbers.	Lime commonly used in early plants for its better reactivity with SO ₂ . Lime has since been replaced with limestone to reduce the risk of lime calcination, which is energy intensive, costly and time consuming to repair.
Residue Generation		Residue by-product contains unreacted lime and cannot be disposed of without treatment because it produces dust and there may be a risk of uncontrolled leaching of	Gypsum is produced and may either be sold to third parties, or landfilled.

⁶ Data is extracted from the BREF. Where the BREF does not specify the operating expenditure, this has been left blank.

AREA	DRY	SEMI-DRY	WET
		hazardous components. Therefore, it is specially conditioned by mixing with water and fly ash to produce a disposable product.	

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

The CAPEX for wet lime/limestone scrubber processes are mainly influenced by the flue gas flow rate. FGD retrofit installations are more expensive than green field installations.

In relation to the cost of reagent use, the cost of the lime sorbent used in spray dry scrubbers compared to limestone for wet scrubbers is one of the key disadvantages of spray dry scrubbers.

5.5.4 INCREMENTAL SO_x ABATEMENT AND COSTS

To demonstrate the potential emission level reductions and incremental CAPEX and OPEX with installing a Wet FGD system in the Australian coal fleet, WSP modelled the installation of a retrofit Wet FGD system to the reference cases with a SO₂ removal efficiency of 95%. This reflects the mid-level performance of a Wet FGD system installed in a typical power plant as stated in the BREF. The operating principle of a Wet FGD also allows it to remove some particulate matter depending on the size of the particles.

The incremental CAPEX costs were estimated with the PEACE software. The incremental OPEX was developed using the limestone consumption rate estimated from Thermoflow and an assumption of 8,000 plant operational hours at full capacity per year. The unit prices for reagent and water are from WSP's in house data. A high level estimate of the maintenance costs was assumed as 1.5% of capital costs. Modelling results are shown in Table 5.12 for a single unit.

Table 5.12. Estimated annual incremental SO_x abatement

PLANT CAPACITY	CURRENT SO _x EMISSIONS (MG/NM ³ @ 6% O ₂)	EMISSIONS AFTER WET FGD INSTALLED (MG/NM ³ @ 6% O ₂)	INCREMENTAL CAPEX	INCREMENTAL OPEX
350 MW Black Coal	892 – 1088	Particulates: 28 – 62 SO _x : 78 – 105	\$187.5 mil	Reagent & water: \$4.6 mil – \$5.5 mil Maintenance: \$2.1 mil
450 MW Black Coal	892	Particulates: 4 SO _x : 78	\$212.5 mil	Reagent & water: \$6.0 mil Maintenance: \$2.4 mil
720 MW Black Coal	686 – 1065	Particulates: 2 – 3 SO _x : 60 – 115	\$277.9 mil	Reagent & water: \$8.0 mil – \$11.5 mil Maintenance: \$3.1 mil
500 MW Brown Coal	623 – 1700	Particulates: 9 – 76 SO _x : 46 – 196	\$308.7 mil	Reagent & water: \$8.8 mil – \$16.0 mil Maintenance: \$3.4 mil

Table 5.12 indicates that if a Wet FGD was installed in the black coal reference plants and achieved the 95% removal rate, the SO_x emissions of the plants with a Wet FGD installed would fall within the 10-130 mg/Nm³ (at 6% reference O₂) BAT-AEL range indicated by the BREF (see Table 5.2). The brown coal reference plant however, may continue to emit SO_x in excess of the BAT-AELs indicated in the BREF, albeit marginally and only for the high sulfur fuels.

Some particulate matter would also be removed from the flue gas as a result of installing a Wet FGD system.

Capital costs shown in Table 5.12 include costs for equipment, labour, materials, engineering and soft costs and are estimated with the PEACE software. The cost multipliers and soft costs used in the model are per values shown in Appendix A except for Labour Contingency (i.e. the contingency applied to estimated labour costs). The default PEACE value for labour contingency is 75% which is believed to be high and so was revised to 40% which WSP believes may be more representative of Australian contractor allowances for labour contingencies.

The capital costs estimated by PEACE are within the BREF indicative range, albeit close to the upper range of EUR 300 /kW_e for retrofits.

Additional commentary on implications of retrofitting FGD best available technology to plants in the Australian coal fleet are provided in the following sections.

5.5.5 IMPACTS OF LOW LOADING AND TWO SHIFTING ON WET FGD SYSTEMS

The performance of a Wet FGD system depends on the reaction conditions, which stem from other plant operating conditions such as the flue gas temperature. The number of start-ups and shutdowns for a plant with a Wet FGD installed should be minimised because the system needs to be purged to avoid slurry solidification and the accumulation of start-up fuel oil residues in the absorber. Furthermore, at low loads, it can become difficult to achieve optimal performance from the Wet FGD system if the reagent flow is fixed.

Maintaining the performance of the Wet FGD system with fluctuating loads may require an upgrade of the control systems to monitor the reagent flow. To achieve the desired SO_x abatement, the liquid/gas ratio may need to be increased.

5.5.6 INCREMENTAL PARASITIC LOAD FOR WET FGD SYSTEMS

Retrofitting a Wet FGD system to the power plant impacts the auxiliary load because of the additional materials handling and transporting equipment. An increase in the auxiliary load reduces the net power output of the plant, thereby reducing the plant's overall net electrical efficiency. Table 5.13 shows the incremental parasitic load required to operate the plants with a Wet FGD system installed.

Table 5.13. Incremental parasitic load for operating the Wet FGD system

PLANT	WET FGD (MW)
350 MW Black Coal	2.7
450 MW Black Coal	3.5
720 MW Black Coal	5.6 – 6.4
500 MW Brown Coal	6.2 – 6.6

The parasitic load of a wet flue gas system can be minimised with sophisticated control systems and by switching off some of the circulation pumps whilst operating at part loads.

As a result of the increased parasitic load, the plant's overall net electrical efficiency is reduced as shown in Table 5.14.

Table 5.14 Change in overall plant efficiency with the Wet FGD system installed

PLANT	DECREASE IN NET PLANT EFFICIENCY (LHV)	INCREASE IN CO ₂ EMITTED (KG CO ₂ E / MWH)	% INCREASE IN CO ₂ EMITTED
350 MW Black Coal	0.32 percentage point	7.7	0.9
450 MW Black Coal	0.33 percentage point	7.8	0.9

PLANT	DECREASE IN NET PLANT EFFICIENCY (LHV)	INCREASE IN CO ₂ EMITTED (KG CO ₂ E / MWH)	% INCREASE IN CO ₂ EMITTED
720 MW Black Coal	0.32 – 0.36 percentage point	5.8	0.8
500 MW Brown Coal	0.39 – 0.61 percentage point	15.6	1.4
Decrease in net plant efficiency is provided as a range to reflect indicative values when operating on different coal types. Increase in CO ₂ is based on operation on the typical coal type only.			

5.5.7 WET FGD PERFORMANCE WITH LOW SULFUR COALS

The inlet SO_x concentration is a factor that impacts the efficiency of a Wet FGD system and is impacted by the sulfur content of the coal (Devitt, Gerstle, Gibbs, Hartman, & Klier, 1978). When the scrubbing mixture contacts relatively high concentrations of SO_x in the flue gas, it reacts with the SO_x and decreases the mixture's ability to absorb additional SO_x. Since the dissolution rate of the scrubbing mixture is slower than the reaction rate between the mixture and the SO_x, there is a resistance to further absorption that can inhibit the system's efficiency. Therefore, the higher end of removal efficiencies is more easily achieved at lower inlet SO_x concentrations because the amount of SO_x that the scrubbing mixture needs to absorb to achieve the desired removal efficiency is smaller (Devitt, Gerstle, Gibbs, Hartman, & Klier, 1978; Zahiri & Roozbehani, 2018). Achieving the same removal efficiency while burning a coal that has a higher sulfur content is possible, but may be more energy intensive (Rubin & Nguyen, 1978).

5.5.8 IMPACTS ON FLUE PLUME VISIBILITY AND FALLOUT

The flue gas temperature will be reduced to approximately 45-80 °C through the Wet FGD. At these temperatures, reheating the flue gas may be required in order to improve the dispersion of the cleaned flue gas and to ensure that the plume is not visible. Flue gas reheating for this purpose is typically achieved using a regenerative gas-gas heat exchanger. The cost for the flue gas reheater was included in the incremental capital cost in the Wet FGD model.

An alternative to flue gas reheating is to disperse the flue at a lower temperature. This may however require a retrofit of the stack with material that is more resistant to corrosion, due to the potential formation of acid gases at lower temperatures (i.e. below the acid dew point temperature). Other considerations will also need to be assessed if this alternative is to be used including plume visibility from the stack, density and buoyancy for flue gas dispersion and the impacts on the ID fan if greater acid gases are formed.

5.5.9 CONSUMABLES, TRANSPORTATION AND HANDLING

The operating mechanism of a Wet FGD system requires water and lime or limestone to create the slurry that is injected to control the SO_x emissions. The use of water represents an additional burden on the environment, as well as a cost to the plant operator. Additional piping and conveyor systems for the wastewater, limestone and gypsum may be required. Storage of the limestone on site and a milling plant to prepare the limestone before it is used in the system should be considered in the plant foot print when implementing a Wet FGD system that utilises limestone.

Table 5.15 shows an estimated yearly limestone and water consumption rate with the retrofit of a Wet FGD system to the reference plants modelled to represent plants within the Australian coal fleet. Assumptions used for the estimation are:

- The plants operate for 8000 hours per year at full load
- Maximum and minimum bounds were determined assuming the same quality fuel was used throughout the year

Table 5.15. Annual water and limestone consumption

PLANT	LIMESTONE CONSUMED (TONNES / YEAR)	WATER CONSUMED (MEGALITRES / YEAR)
350 MW Black Coal	11,700 – 14,400	370 – 372
450 MW Black Coal	15,000	489
720 MW Black Coal	18,800 – 29,900	799– 878
500 MW Brown Coal	15,000 – 39,100	1,427– 1,486

As an example, the water consumption for a 720 MW black coal plant operating on a typical coal for 8,000 hours per year could consume 799 megalitres of water per year. If the same plant used a higher sulfur fuel for 8,000 hours per year, it could consume 878 megalitres per year. It is noted that water consumption of the Wet FGD system is dependent on the flue gas flow rate and the sulfur content of the fuel.

5.5.10 WASTE STREAM HANDLING

The addition of a Wet FGD process will produce an additional stream of waste water from the process, as well as gypsum, which can be landfilled or sold to third parties. The end use of the gypsum should be considered when determining suitable storage requirements. The gypsum that is produced by a Wet FGD can contain higher amounts of fluorine, chlorine and heavy metals which may be hazardous if they leach out of the gypsum (Córdoba, 2019). However, it can be treated so that it is safe to be used as a building material or for soil restoration (Chen, et al., 2015; Romanik, 2016).

The waste water produced by a Wet FGD system may be high in chloride depending on the properties of the coal, which can cause corrosion. Recirculating or mixing it in a system with steel parts is therefore not practical. Treating the waste water generated by the Wet FGD system can be carried out using a reverse osmosis (RO) plant or dedicated ponds. Using a tank based system is generally preferred because higher performances can be achieved.

5.5.11 WET FGD FOOTPRINTS

Table 5.16 below shows the estimated footprints for the Wet FGD absorber module as estimated by the plant models. The footprint estimate does not include sizing of any required limestone milling plant, gypsum processing plant or water treatment plant. The estimated footprint does not include any additional dams or water storage. The wastewater from this technique is likely to be suitable for storage in the existing onsite dams after treatment, however this requires an investigation into the capacity of the existing dams and whether additional environmental approvals are required. This may show that an additional dam, or upgrades to the current dams may be needed.

Figure 5.2 provides a general diagram of the Wet FGD absorber module installed from the plant models.

In addition to the absorber module itself, space is required for the ducting of the flue gas both into and out of the absorber module. For retrofit plants, space may be constrained between the ID fan and the stack, which may prohibit the installation of Wet FGD units. Although a full assessment of the feasibility of this work is outside the scope of this Study, it could be envisaged that modifications to the existing ductwork may not be insignificant (see Figure 5.3).

TABLE 5.16. ESTIMATED WET FGD FOOTPRINTS

PLANT	DIAMETER (M)	HEIGHT (M)
350 MW Black Coal	13	24
450 MW Black Coal	15	25
720 MW Black Coal	19	25
500 MW Brown Coal	21	28

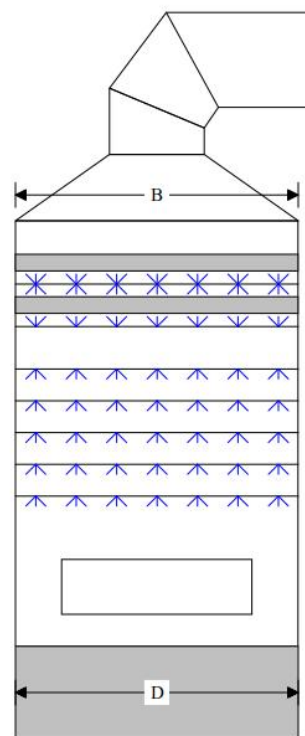


FIGURE 5.2. GENERAL WET FGD ABSORBER DIAGRAM



Figure 5.3 Wet FGD System installed at a power plant with one absorber per unit (Babcock & Wilcox, 2012)

5.6 NO_x ABATEMENT

5.6.1 OVERVIEW

Nitrogen oxides are a group of nitrogen compounds that form one of the primary emissions from the combustion of fossil fuels. Abatement techniques that aim to reduce NO_x emissions (predominantly NO₂) from combustion plants are classified according to the stage of the plant in which they operate. Primary techniques are those that control NO_x formation in the combustion chamber. Therefore, these methods involve modifying the combustion process with technologies such as:

- Air Staging
- Flue gas recirculation
- Fuel staging
- Low-NO_x burners (LNBs)

The operating principle of LNBs is the reduction of the peak flame temperatures by modifying how the fuel and air are injected to delay mixing. This reduces the availability of oxygen, which leads to a lower peak flame temperature. These techniques have been developed as air staged burners, flue gas recirculation burners and fuel-staged burners. Air staged LNBs operate on a fuel-rich, air-lean mixture, which limits NO_x, but creates a higher concentration of CO. Flue gas recirculation LNBs inject a portion of the flue gas into the combustion zone or air supply to lower the flame temperature and the oxygen concentration in the mixture of air and fuel. This technique is therefore feasible for burning solid and liquid fuels that have a nitrogen content between 0.3%wt – 0.6% wt. Over this range, the fuel NO_x dominates the thermal NO_x, giving rise to the need for reducing the oxygen content and peak flame temperature. Fuel staged LNBs involve injecting fuel in multiple stages and are most commonly used for gas applications. The NO_x removal efficiency of an LNB depends on the type of burner. Air staged LNBs can achieve a 25-35% removal efficiency, whereas flue gas recirculation LNBs achieve up to 20%. Higher rates of removal can be achieved when these techniques are combined with other NO_x abatement techniques. If the use of primary techniques alone is not sufficient to achieve the legislative emission targets, it may be necessary to implement secondary techniques to achieve lower abatement levels.

Secondary techniques are post combustion methods of controlling NO_x formation and include technologies such as:

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)
- A combination of SCR and SNCR⁷

These systems require the injection of ammonia, urea or other compounds that react with the NO_x in the flue gas, reducing it to molecular nitrogen. These techniques are further described in the following sections.

The scope of this study is limited to secondary techniques and in particular, SCR technology.

5.6.1.1 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

SNCR reduces NO_x by injecting ammonia, urea or other reagent into the boiler chamber without a catalyst. This technique is carried out at higher temperatures compared to SCR systems, and occurs optimally between approximately 800-1,000 °C. Implementing an SNCR system requires sound knowledge of the temperature distribution in the combustion chamber under the possible operating cases, and a good control of the quantity of injected products.

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⁷ Although these technologies are designed to abate NO_x emissions, they do not reduce N₂O but may potentially produce N₂O.

5.6.1.2 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR is the selective reduction of NO_x emissions using ammonia, urea or other reagent with a catalyst. The NO_x is reduced to molecular nitrogen by the reagent in a catalytic bed. The level of reduction can be enhanced by adding more catalyst layers. An SCR can also be fitted with an additional oxidation layer to reduce CO and NH₃ emissions. The optimal temperature for this reaction to occur is approximately between 300-450 °C. When the NO_x removal rate is within the range of 85-90%, the system can be controlled with a simple control system. Higher reduction rates require more advanced control systems because complex reagent premixing and injection systems are involved. This technique is generally not applicable to plants with capacities less than 100 MW_{th}, or plants with capacities less than 300 MW_{th} that also operate for less than 500 hours per year. Retrofitting this technology to plants that operate for 500-1,500 hours per year, and plants with capacities of 300MW or more that operate for less than 500 hours per year may face technical and financial barriers.

Combining SNCR and SCR in a hybrid SNCR/SCR system is a version of an SCR system where the catalyst is combined with SNCR to consume any remaining sorbent in the flue gas that was injected during the SNCR stage. This type of system requires less catalyst and can achieve higher removal efficiencies and low ammonia slip.

5.6.2 NO_x REMOVAL EFFICIENCY AND CROSS-MEDIA EFFECTS

Any technique employed is likely to have cross-media effects in that, whilst NO_x may be reduced by adding the system to the plant, it may increase other environmental impacts such as emissions to water and air, increased parasitic load or raw material consumption. A comparison of the removal efficiency for the techniques and any cross-media effects they may have are shown in Table 5.17 below per the BREF.

Table 5.17. Removal efficiency and cross-media effects of NO_x control and abatement techniques

CROSS-MEDIA EFFECT	SNCR	SCR
Removal Efficiency	30-50%	80-95%
Emissions to Air	NH ₃ : 5-30 mg/Nm ³ N ₂ O: 10-30mg/Nm ³	NH ₃ : < 10 mg/Nm ³ N ₂ O: N/A
Energy Usage	45-50 thermal kWh/t of fuel input due to cooling effect of in-furnace injection.	65-1000 thermal kWh/t of fuel input due to the need for reheating the flue gases (if required). 10-15 electrical kWh/t of fuel input relates to a pressure drop across the catalyst.
Reagent Use	8.5kg/t of fuel input.	3.2 kg/t of fuel input.
Residue Generation	No residue generated by SNCR system.	No residue generated by SCR system.
Water Consumption	Not significant.	Not significant.
Effluent Production	None.	None.

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

In addition to the potential ammonia emissions that these systems may release into the atmosphere, it should be noted that SNCR systems may also emit between 10 – 30 mg/Nm³ of nitrous oxide (N₂O), which is another greenhouse gas that

is approximately 300 times more harmful to the environment than CO₂ in terms of contributing to global warming. For example, releasing 1kg of N₂O into the atmosphere is equivalent to releasing nearly 300 kg of CO₂ (Brander, 2012).

5.6.3 TYPICAL CAPEX AND OPEX

A summary of the CAPEX and OPEX for SNCR and SCR techniques is presented in Table 5.18 below, as stated in the BREF.

Table 5.18. NO_x control and abatement CAPEX and OPEX

AREA	SNCR	SCR
Capital Expenditure	Approx. EUR 430/t NO _x reduced in a coal -fired 250 MW _{th} boiler operating for 4,000 h/yr assuming NO _x reduction 50%.	EUR 5,000 – 10,000 per m ³ . For a flue gas volume of 1 million m ³ /hr, approx. EUR 15 million (incl. raw dust arrangement with planning, erection and all surrounding equipment such as pipework, pumps, fans, excludes catalyst). System CAPEX for retrofit applications removing between 60 – 90% NO _x ranges between EUR 50/kW – 100/kW.
Operating Expenditure ⁸		EUR 1.17 – 1.34 million per year including costs for electricity, catalysts, reducing agents, maintenance and wear and tear.
Reagent Use	Approx. EUR 75/t NO _x for anhydrous ammonia. Approx. EUR 125/t NO _x for 40% urea solution.	Approx. EUR 75/t NO _x for anhydrous ammonia. Approx. EUR 125/t NO _x for 40% urea solution.

Source: Best Available Techniques (BAT) Reference Document for Large Combustion Plants, Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control), Thierry Lecomte, José Félix Ferrería de la Fuente, Frederik Neuwahl, Michele Canova, Antoine Pinasseau, Ivan Jankov, Thomas Brinkmann, Serge Roudier, Luis Delgado Sancho (2017)

5.6.4 INCREMENTAL NO_x ABATEMENT AND COSTS

To demonstrate potential emission level reductions and incremental CAPEX and OPEX from installation of a best available technology for NO_x reduction in the Australian coal fleet, WSP modelled the installation of an SCR system with a removal efficiency of 85% to the reference plant models in Thermoflow. This represents the mid-level performance of the BATs for NO_x abatement as stated in the BREF. The current NO_x emissions as shown in Table 5.19 are based on committee member responses and as such would include any current NO_x reductions achieved through use of primary control techniques. The after SCR installed values shown in the table consider emission levels after installation of an SCR as stated above.

The incremental CAPEX was estimated using the cost estimation package PEACE. The OPEX was calculated using the estimated consumption rate of reagent and the assumption that the plant would operate for 8,000 hours per year. The price of the reagent was gathered from WSP's in house data. The catalyst life time in a coal fired plant typically ranges from three to seven years, but can reach up to 20 years when using catalysts that benefit from regenerative techniques. The lifetime of the catalyst depends on several site-specific factors. For example, the type of equipment used, fuel characteristics, plant operating schedule and the desired performance of the SCR. The cost of replacing the catalyst was calculated by estimating the total cost of replacing the catalyst, and allocating this amount over the expected life of the

⁸ Data is from the BREF. Where the BREF does not specify an operating expenditure, this has been left blank.

catalyst, which was assumed to be three to seven years. High level maintenance cost allowance was assumed at 1.5% of capital costs. Modelling results are shown in Table 5.19 for a single unit.

Table 5.19. Estimated Annual Incremental NO_x Abatement

PLANT CAPACITY	CURRENT NO _x EMISSIONS (MG/NM ³ @ 6% O ₂)	AFTER SCR INSTALLED (MG/NM ³ @ 6% O ₂) ⁹	INCREMENTAL CAPEX	INCREMENTAL OPEX
350 MW Black Coal	800	121	\$51.2 mil	Reagent: \$3.2 mil Catalyst: \$372k - \$867k Maintenance: \$768k
450 MW Black Coal	530	79.5	\$58.6 mil	Reagent: \$2.6 mil Catalyst: \$440k – \$1.0 mil Maintenance: \$878k
720 MW Black Coal	640	106	\$88.8 mil	Reagent: \$5.2 mil Catalyst: \$728k - \$1.7 mil Maintenance: \$1.3 mil
500 MW Brown Coal	290	43	\$102.1 mil	Reagent: \$2 mil Catalyst: \$906k - \$2.1 mil Maintenance: \$1.5 mil

Table 5.19 indicates that the reference plant models fitted with an SCR that achieves an 85% removal rate would achieve emission values within the range of the BAT-AELs documented in the BREF for existing plants (i.e. less than 150 mg/Nm³).

Capital costs shown in Table 5.19 include cost for equipment, labour, materials, engineering and soft costs and are estimated with the cost estimation package PEACE with the option for “Retrofit” selected for the SCR. It is understood this automatically increases the capital cost compared to a greenfield site. The cost multipliers and soft costs used in the model are per values shown in Appendix A.

The capital costs estimated by PEACE are within the BREF indicative range albeit close to the upper range of EUR 50 /kW_e – 100 /kW_e for retrofits.

5.6.5 IMPACTS OF LOAD LOADING AND TWO SHIFTING

The chemical reactions that occur in an SCR system rely on precise control of the reaction conditions which depend on the reagent flow and flue gas temperature. Flexible load operations can therefore impact the performance and reliability of the abatement technique because the flue gas quantity and temperature may vary. Operating large coal fired combustion plants that have a SCR installed at low loads can force the SCR system to operate with lower flue gas temperatures. This can lead to the formation of a pasty liquid substance called ammonium bisulphate, which can accumulate in the catalyst pores, reducing the surface area available to react with the flue gas. The ammonium bisulphate may also reach the boiler ducts, which can influence the readings of the airflow instruments.

⁹ Emissions in this column assume retrofit of the additional best available technology system for NO_x abatement.

The conventional practice for new plants is to include a flue gas or water-side economiser bypass in the plant design. Using the bypass elevates the flue gas temperature, thus ensuring the flue gas is hot enough to avoid ammonium bisulphate formation. Plants that retrofit a SCR without this bypass capability can potentially mitigate the low load related issues by continuously monitoring the inlet NH_3 and SO_3 concentrations and comparing them with the concentrations at the design point or by improving the SCR inlet temperature distribution with a static mixer. Rapid load changes can generally be accommodated when implementing either method.

The maintenance requirements for the SCR system may impact the availability of the overall plant if ammonium bisulphate forms in the catalyst as this should be cleaned so that optimal performance can be achieved and avoid operational issues as aforementioned.

5.6.6 INCREMENTAL PARASITIC LOAD FOR SCR SYSTEMS

Retrofitting an SCR system to the power plant impacts the auxiliary load because of the pressure drop it introduces to the system requiring compensation by the plant's fans, consuming additional power and the additional load for the required corresponding material handling plant for the reagent. An increase in the auxiliary load reduces the net power output of the plant and thus reduces the plant's overall net electrical efficiency. Table 5.20 shows the incremental parasitic load required to operate the plant with the SCR system installed.

Table 5.20. Incremental parasitic load for operating the SCR system

PLANT	SCR (MW)
350 MW Black Coal	1.4
450 MW Black Coal	1.6
720 MW Black Coal	2.5
500 MW Brown Coal	3.2

As a result of the increased parasitic load, the plant's overall net electrical efficiency is reduced (see Table 5.21).

Table 5.21 Change in overall plant efficiency with SCR system installed

PLANT	CHANGE IN NET PLANT EFFICIENCY (LHV)	INCREASE IN CO_2 EMITTED (KG CO_2E / MWH)	% INCREASE IN CO_2 EMITTED
350 MW Black Coal	0.17 percentage point	3.9	0.4
450 MW Black Coal	0.15 percentage point	3.4	0.4
720 MW Black Coal	0.14 percentage point	2.6	0.4
500 MW Brown Coal	0.24 percentage point	7.6	0.7

5.6.7 IMPACTS ON OPERATING PARAMETERS

In SCR systems, the flue gas passes through the catalyst to reduce NO_x emissions. This stage of the process generally leads to a pressure drop varying from 5 mbar to 15 mbar. Depending on the other operating parameters of the plant, additional energy may need to be imparted on the flue gas if this pressure drop cannot be tolerated by the downstream components.

5.6.8 SCR PERFORMANCE WITH PRIMARY CONTROLS

The inlet NO_x concentration is a factor that impacts the removal efficiency of an SCR system. Generally, higher NO_x removal efficiencies are achieved with higher inlet NO_x concentrations up to approximately 150 ppm, due to reaction kinetics. Beyond approximately 150 ppm, the removal efficiency generally does not increase with the inlet NO_x concentration (Sorrels, 2016). Lower inlet NO_x concentrations below 150 ppm therefore result in lower removal efficiencies because the reaction rate is lower.

SCR systems can be operated when a primary NO_x control system such as an LNB is used. However, since the LNB reduces the amount of NO_x in the flue gas at the inlet of the SCR, the performance of the SCR system may be reduced (Sorrels, 2016). An exact reduction in performance will require further assessment outside the scope of this Study.

5.6.9 IMPACTS ON PLUME VISIBILITY

During the combustion process, both SO_2 and SO_3 are produced due to the sulfur content in the fuel itself. Installing an SCR system to control NO_x emissions can potentially have negative impacts on the SO_x concentrations in the flue gas at the air preheater and the stack. This occurs as the SO_2 reacts with oxygen molecules (O_2), forming SO_3 . The elevated levels of SO_3 can lead to operational issues relating to fouling in the air preheater and corrosion, which may lead to more visible emissions due to the sulfuric mist. To avoid these effects, catalyst manufacturers will generally formulate their catalysts to minimise this oxidation reaction. Ensuring that SO_3 stack emissions are below 5 vppm is sufficient to avoid visual emissions.

5.6.10 MINIMISATION OF OTHER EMISSIONS

Both SNCR and SCR techniques can potentially suffer from the effects of ammonia slip when ammonia is used as the reagent. This occurs when unreacted ammonia is released into the environment, and arises when there is an incomplete reaction of NH_3 with NO_x . This causes small amounts of NH_3 to leave the combustion chamber with the flue gas and causes it to be emitted. As a result, NH_3 can accumulate in the catalyst and other downstream components. Ammonia slip becomes more prominent if the NH_3 to NO_x ratio is increased. In SNCR systems in particular, ammonia slip is exacerbated with poor mixing of NH_3 with the flue gas. Ammonia slip that leads to ammonia emissions greater than $10\text{mg}/\text{Nm}^3$ can cause the flue gas to have a slight odour (Kamuk, 2009).

The reagent used in SNCR systems can potentially influence the formation of N_2O , which is another greenhouse gas. Using ammonia or caustic ammonia as a reagent induces negligible amounts of N_2O , but can give rise to ammonia slip. Injecting urea directly into the boiler can lead to relatively high amounts of N_2O . To control the generation of N_2O , urea can also be injected into the burnout air.

To extend the life of the catalyst in an SCR system, the catalyst can be washed periodically. However, this creates an effluent that may be unlike the typical waste water streams generated by the plant and may require the existing water treatment process to be upgraded or otherwise modified.

5.6.11 IMPACTS ON RESIDUE

When using ammonia as the reagent, both SNCR and SCR systems can potentially suffer from ammonia slip. This may cause higher amounts of ammonia content in fly ash, which may affect its disposal or sale. Ammonia emissions above approximately 2 ppm could impact the usability of the ash (Spliethoff, 2010). Excessively high amounts of ammonia in the fly ash as a result of ammonia slip can potentially make the residue unsafe to handle.

5.6.12 SCR SYSTEM FOOTPRINTS

Table 5.22 below shows the estimated footprints of the SCR catalyst systems per reactor module from the plant models.

Table 5.22. Estimated SCR System Footprints

PLANT	LENGTH (M)	WIDTH (M)	HEIGHT (M)	NUMBER OF MODULES
350 MW Black Coal	9	9	19	2
450 MW Black Coal	10	10	17	2
720 MW Black Coal	10	10	17	3
500 MW Brown Coal	11	11	19	3

The SCR catalyst is typically installed after the boiler economiser and before the air preheater to meet required operating temperature requirements. As such, to retrofit a system into an existing plant, extensive ducting modifications may be required to accommodate the catalyst (see Figure 5.4 and Figure 5.5).

A general drawing of the catalyst within the system is shown in Figure 5.6.



Figure 5.4 SCR system installed at a power plant (Zhejiang Feida Environmental Science & Technology Co., Ltd., n.d.)



Figure 5.5. SCR systems at three 660MW steam generators (Steinmüller Babcock Environment, 2019)

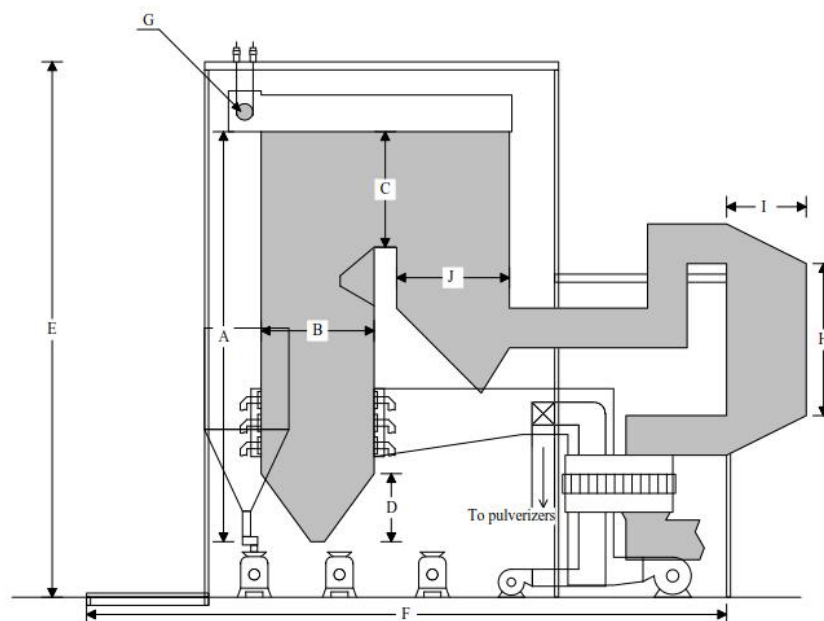


Figure 5.6. General Diagram of SCR Installed

An assessment of the feasibility of the works required to retrofit SCR systems within the Australian coal power plant fleet is outside the scope of this Study. However, it could be envisaged that modifications to the ductwork will not be insignificant especially if the air preheater is located close to the economiser. Further considerations may include: whether there is available space in the existing boiler house or if the ducting must be re-routed outside the boiler house and returned, or if the air preheater must also be removed and relocated to accommodate the SCR catalyst section.

5.7 BEST AVAILABLE TECHNOLOGY APPLICABILITY

The applicability of certain BATs as defined in the BREF is limited for small thermal plants and for plants that are operated for emergency use, or for relatively low operating hours. The tables below summarise the findings of the BAT

conclusions for techniques with limited applicability. Other techniques may be available for small thermal plants or those that generate for low operating hours.

Installing wet lime/limestone scrubbers to existing plants may be difficult due to the space requirements of the scrubbers and the size and complex modifications to the flue gas piping systems that the ancillary equipment may require.

Seawater FGD systems are only suitable for plants that use low sulfur fuels and have a source of seawater that is readily available for use. These techniques must be used in conjunction with an efficient particulate abatement technique to remove the particulates prior to transfer to the seawater scrubbing system.

Table 5.23. Applicability of BAT for SO_x Abatement

TECHNIQUE	APPLICABILITY
Wet FGD	Not applicable to combustion plants that are operated for <500 hours per year. Plants with less than 300 MW _{th} thermal capacity may encounter technical and financial restrictions when installing Wet FGD techniques.
Seawater FGD	Plants that operate for 500-1,500 hours per year may also face technical and economic barriers if retrofitting.

For NO_x abatement, the application of SNCR systems can be restricted by the operating temperature window or where it occurs in the boiler, and the residence time required to inject the reactant.

SCR systems may not be compatible with some plants because of their spatial requirements. Furthermore, frequent variations in the load can cause the flue gas temperature to become unstable and fall outside of the relatively narrow operating temperature window.

Table 5.24. Applicability of BAT for NO_x Abatement

TECHNIQUE	APPLICABILITY
SNCR	Potentially limited to the design of the plant's boiler and whether the boiler load is highly variable. Boilers with high cross-sectional areas may also prevent homogenous mixing of the reagent and NO _x , making SNCR unsuitable for these types of boilers. Implementing an SNCR system requires sound knowledge of the temperature distribution in the combustion chamber under the possible operating cases, and a good control of the quantity of injected products.
SCR	Generally not applicable to plants with capacities <100 MW _{th} , or plants with capacities less than 300 MW _{th} that also operate for less than 500 hours per year. Retrofitting this technology to plants that operate for 500-1500 hours per year, or plants with capacities of 300 MW or more that operate for less than 500 hours per year may face technical and financial barriers.

This Study has contained a high-level assessment of best available technologies for emissions abatement at Australian coal fired power plants. The commentary provided in this report are general only and viability of retrofitting best available technologies should be assessed at each plant on a case by case basis taking into consideration site-specific parameters of each plant. This should include a full suite of studies including options assessment and concept design development prior to a full feasibility study. Aspects which will need to be reviewed and assessed of feasibility include:

- Current plant parameters (e.g. current emission levels, plant performance, cycle conditions) and equipment operating parameters / conditions / constraints (e.g. for the ID fans, stack) and how these will impact / affect desired outcomes.
- Physical plant layout constraints.
- Tie-in points to plant services such as electrical connection, compressed air, water, ash handling, etc. to develop interface connection layout / drawings.
- Discuss and understand options with equipment suppliers.
- Undertaking of design optimisation and performance modelling to determine performance after retrofit.
- Undertake hazards and risks assessments.
- Develop cost estimates and undertake financial assessment to assess financial viability.
- Understand and liaise with relevant authorities development approvals, licences and permitting.
- Assess environmental impact and understand / develop mitigation strategies to manage impacts.

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APPENDIX A

MODEL PARAMETERS



1. BLACK COAL PLANT BASIS OF DESIGN

1.1 BLACK COAL PLANT PARAMETERS

	UNIT	VALUES			COMMENT
Site					
Plant Site	-	Reference Plant Black Coal (circa 350 MW)	Reference Plant Black Coal (circa 450 MW)	Reference Plant Black Coal (circa 720 MW)	
Altitude	m	100	100	100	
Ambient Temperature	°C	25	25	25	
Ambient Relative Humidity	%	60	60	60	
Ambient Wet Bulb Temperature	°C	19.45	19.45	19.45	
Site Cooling Water Temperature	°C	29.5	29.5	29.5	
General Plant					
Power Specification	MW	350	450	720	Gross power
Cooling System					
Condenser pressure	Bar	0.087	0.059	0.0825	
Cooling type	-	Natural draft cooling tower	Natural draft cooling tower	Natural draft cooling tower	
Steam Cycle					
Steam Turbine Configuration	-	Subcritical Single Reheat	Supercritical Single Reheat	Subcritical Single Reheat	
HP Turbine Pressure	Bar	166	250	159	
HP Turbine Inlet Temperature	°C	538	566	538	
IP Turbine Inlet Pressure	Bar	38	44	38	
IP Turbine Inlet Temperature	°C	538	566	538	

	UNIT	VALUES			COMMENT
LP Turbine Inlet Pressure	Bar	9.0	8.4	9.3	
Boiler feed pump drive	-	Condensing Steam Turbine	Electric Motor	Condensing Steam Turbine	
Steam Turbine Feedwater Heaters					
Number of feedwater heaters	-	6	7	7	
Steam Turbine					
Generator power factor	-	0.9	0.9	0.9	
Process Streams (Extractions and admissions for cogeneration): None					
Boiler Configuration					
Boiler efficiency	%	88.3 (HHV)	88.8 (HHV)	88.8 (HHV)	
		92.4 (LHV)	92.9 (LHV)	92.9 (LHV)	
NOx generated in the furnace	mg/Nm ³ @ 6% O ₂ dry	804	804	804	Committee members to provide
Current Emissions					
Existing ESP or fabric filter removal efficiency	%	99.2%	99.95%	99.95%	Committee members to provide.

1.2 BLACK COAL PROPERTIES

TYPE	UNIT	TYPICAL	LOW ASH, HIGH SULFUR	COMMENT
<i>350MW and 450MW Black coal plants</i>				
Fuel Supply Temperature	°C	25	25	
LHV (at 25C)	kJ/kg	19600	26260	
Moisture	wt. %	12	7.7	
Ash	wt. %	28	18.9	
Carbon	wt. %	48.4	65.5	
Hydrogen	wt. %	3.2	3.6	
Nitrogen	wt. %	0.9	1.5	
Chlorine	wt. %	0	0	
Sulfur	wt. %	0.3	0.5	
Volatile Matter	wt. %	24	2.2	
Specific Heat @ 25C, dry	kJ/kg-°C	1.13	1.13	
Specific Heat @ 300C, dry	kJ/kg-°C	1.926	1.926	
Inherent (as-mined) moisture as % of total moisture	%	100	100	
Coal Rank	-	High-Volatile C Bituminous	Medium-Volatile Bituminous	
Hardgrove Grindability Index (HGI)	-	52	83	
Mercury Content (dry basis)	ppmw	0	0.03	
SiO ₂	wt. %	72.3	53.42	
Al ₂ O ₃	wt. %	23.3	23.18	

TYPE	UNIT	TYPICAL	LOW ASH, HIGH SULFUR	COMMENT
Fe ₂ O ₃	wt. %	0.9	8.98	
CaO	wt. %	0.09	6.03	
MgO	wt. %	0.16	1.56	
Na ₂ O	wt. %	0.1	0.41	
K ₂ O	wt. %	0.27	1.16	
TiO ₂	wt. %	1.4	1.1	
P ₂ O ₅	wt. %	0.09	0.81	
SO ₃	wt. %	0.01	0.17	
Other	wt. %	1.38	3.18	
Fouling	-	Low/Medium	Low/Medium	
Initial Deform. Temp.	°C	1280	1220	
Softening/Deposition Temp.	°C	1232	1232	

TYPE	UNIT	TYPICAL	HIGH ASH	HIGH SULFUR	LOW ASH, LOW SULFUR	COMMENT
<i>720MW Plant</i>						
Fuel Supply Temperature	⁰ C	25	25	25	25	
LHV (at 25C)	kJ/kg	24500	21200	23400	24300	
Moisture	wt. %	7.5	7.5	9	6.7	
Ash	wt. %	19.5	28	22	20	
Carbon	wt. %	60.91	54.65	59.62	62.62	
Hydrogen	wt. %	3.7	3.52	3.83	3.82	
Nitrogen	wt. %	1.33	1.13	1.36	1.26	
Chlorine	wt. %	0	0.007	0.014	0.007	
Sulfur	wt. %	0.29	0.35	0.45	0.31	
Volatile Matter	wt. %	27.5	4.84	3.726	5.28	
Specific Heat @ 25C, dry	kJ/kg- ⁰ C	1.13	1.13	1.13	1.13	
Specific Heat @ 300C, dry	kJ/kg- ⁰ C	1.926	1.926	1.926	1.926	
Inherent (as-mined) moisture as % of total moisture	%	100	100	100	100	
Coal Rank	-	High-Volatile B Bituminous	High-Volatile B Bituminous	High-Volatile B Bituminous	High-Volatile B Bituminous	
Hardgrove Grindability Index (HGI)	-	96	96	96	96	
Mercury Content (dry basis)	ppmw	0	0	0	0	
SiO ₂	wt. %	65.4	62.05	78.9	60.6	
Al ₂ O ₃	wt. %	26	20.59	15.2	30.2	
Fe ₂ O ₃	wt. %	3.81	5.69	2.3	2.3	

TYPE	UNIT	TYPICAL	HIGH ASH	HIGH SULFUR	LOW ASH, LOW SULFUR	COMMENT
CaO	wt. %	0.62	3.06	0.2	2.5	
MgO	wt. %	0.4	0.8	0.3	0.5	
Na ₂ O	wt. %	0.1	1.05	0.3	0.6	
K ₂ O	wt. %	2	3.32	1.1	0.6	
TiO ₂	wt. %	0.76	0.78	0.6	1.1	
P ₂ O ₅	wt. %	0.24	0.07	0.1	0.3	
SO ₃	wt. %	0.23	1.18	0.1	0.5	
Other	wt. %	0.44	1.41	0.9	0.8	
Fouling	-	Low/Medium	Low/Medium	Low/Medium	Low/Medium	
Initial Deform. Temp.	⁰ C	1500	1188	1188	1188	
Softening/Deposition Temp.	⁰ C	1232	1232	1232	1232	

2. BROWN COAL PLANT BASIS OF DESIGN

2.1 BROWN COAL PLANT PARAMETERS

	UNIT	VALUE	COMMENT
Site			
Plant Site	-	Reference Plant Brown Coal (circa 500 MW)	
Altitude	m	100	
Ambient Temperature	°C	25	
Ambient Relative Humidity	%	60	
Ambient Wet Bulb Temperature	°C	19.45	
Site Cooling Water Temperature	°C	29.5	
General Plant			
Power Specification	MW	500	Gross power
Cooling System:			
Condenser pressure	Bar	0.095	
Cooling Water Type	-	Natural draft cooling Tower	
Steam Cycle			
Steam Turbine Configuration	-	Subcritical Single Reheat	
HP Turbine Inlet Pressure	Bar	160	
HP Turbine Inlet Temperature	°C	535	
IP Turbine Inlet Pressure	Bar	36	

	UNIT	VALUE	COMMENT
IP Turbine Inlet Temperature	⁰ C	535	
LP Turbine Inlet Pressure	Bar	8.6	
Boiler feed pump drive	-	Electric Motor	
Steam Turbine Feedwater Heater:			
Number of feedwater heaters	-	6	
Steam Turbine			
Generator power factor	-	0.9	
Process Streams (Extractions and admissions for cogeneration): None			
Boiler Configuration:			
Boiler efficiency	%	73.5% (HHV) 89.3% (LHV)	
NO _x Generated in the Furnace	mg/Nm ³ @ 6% O ₂ dry	286	Committee members to provide.
Emissions:			
Existing ESP Collection Efficiency	%	96.5	Committee members to provide.

2.2 BROWN COAL PROPERTIES

TYPE	UNIT	TYPICAL	HIGH ASH	LOW ASH	HIGH SULFUR	LOW SULFUR	COMMENT
Fuel Supply Temperature	°C	25	25	25	25	25	
LHV (at 25C)	kJ/kg	9000	8600	9200	9100	9600	
Moisture	wt. %	59.6	58.5	59.7	58.2	7.5	
Ash	wt. %	1.05	3.86	0.36	2.31	1.16	
Carbon	wt. %	27.19	25.77	28.17	27.42	28.84	
Hydrogen	wt. %	1.98	1.95	1.97	1.96	2.10	
Nitrogen	wt. %	0.22	0.20	0.18	0.22	0.18	
Chlorine	wt. %	0.03	0.03	0.03	0.03	0.03	
Sulfur	wt. %	0.16	0.17	0.15	0.31	0.12	
Volatile Matter	wt. %	19.96	19.96	19.96	19.96	19.96	
Specific Heat @ 25C, dry	kJ/kg-°C	1.13	1.13	1.13	1.13	1.13	
Specific Heat @ 300C, dry	kJ/kg-°C	1.926	1.926	1.926	1.926	1.926	
Inherent (as-mined) moisture as % of total moisture	%	100	100	100	100	100	
Coal Rank	-	Lignite B	Lignite B	Lignite B	Lignite B	Lignite B	
Hardgrove Grindability Index (HGI)	-	130	96	96	96	96	
Mercury Content (dry basis)	ppmw	1100	1000	10001	1500	1000	
SiO2	wt. %	60	60	60	60	60	
Al2O3	wt. %	10	10	10	10	10	
Fe2O3	wt. %	4.3	4.3	4.3	4.3	4.3	

TYPE	UNIT	TYPICAL	HIGH ASH	LOW ASH	HIGH SULFUR	LOW SULFUR	COMMENT
CaO	wt. %	2.12	2.12	2.12	2.12	2.12	
MgO	wt. %	4.51	4.51	4.51	4.51	4.51	
Na ₂ O	wt. %	4.45	4.45	4.45	4.45	4.45	
K ₂ O	wt. %	0.62	0.62	0.62	0.62	0.62	
TiO ₂	wt. %	1.61	1.61	1.61	1.61	1.61	
P ₂ O ₅	wt. %	0.03	0.03	0.03	0.03	0.03	
SO ₃	wt. %	8.04	8.04	8.04	8.04	8.04	
Other	wt. %	4.32	4.32	4.32	4.32	4.32	
Fouling	-	Severe	Severe	Severe	Severe	Severe	
Initial Deform. Temp.	⁰ C	1250	1188	1188	1188	1188	
Softening/Deposition Temp.	⁰ C	1232	1232	1232	1232	1232	

3. FINANCIAL MULTIPLIERS

3.1 REGIONAL COST MULTIPLIERS

COST MULTIPLIERS:			
Specialised Equipment	-	1.1	
Other Equipment	-	1.1	
Commodities	-	1.2	
Labour	-	2	
Exchange Rate	USD/AUD	0.75	Approximate long term average from 2015-2019

3.2 CONTRACTOR'S SOFT COSTS

COST ADDITIONS	UNITS	VALUE	COMMENT
Labour supervision, contingency, mobilisation, temporary housing etc	%	75	
Contingency for specialised equipment	%	2	
Contingency for other equipment	%	3	
Contingency for commodities	%	5	
Profit margin on labour	%	20	
Profit margin for specialised equipment	%	5	
Profit margin on other equipment	%	5	
Profit margin on commodities	%	5	
Permits, licenses, fees and miscellaneous	%	0	
Bonds and insurance	%	1	
Spare parts and materials	%	0	
Contractor's fee	%	3	

APPENDIX B

HEAT BALANCE DIAGRAMS

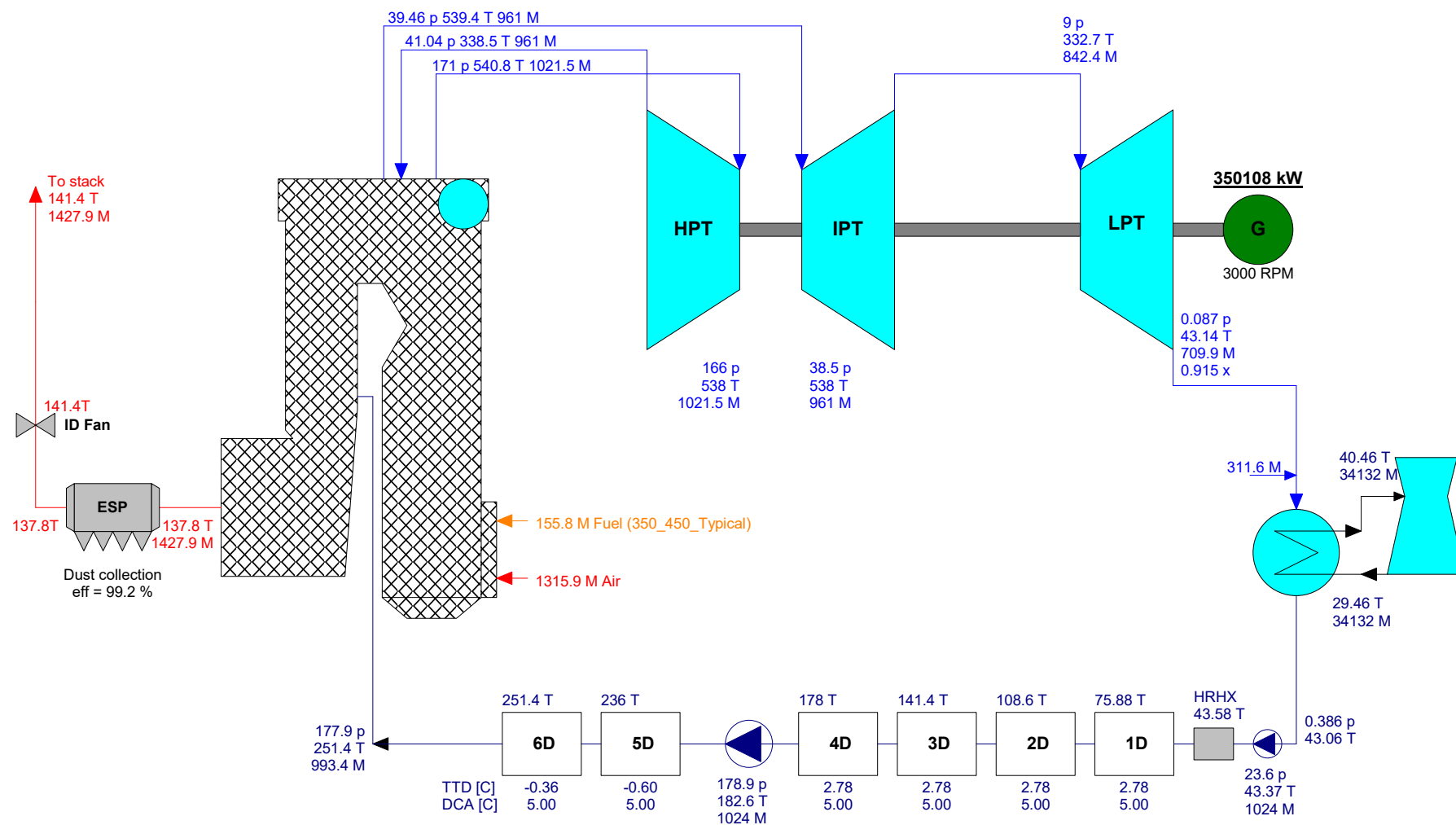


APPENDIX B-1

350 MW BLACK COAL PLANT WITH TYPICAL FUEL

Plant gross power	350108	kW
Plant net power	323484	kW
Number of units	1	
Plant net HR (HHV)	9920	kJ/kWh
Plant net HR (LHV)	9442	kJ/kWh
Plant net eff (HHV)	36.29	%
Plant net eff (LHV)	38.13	%
Aux. & losses	26624	kW
Fuel heat input (HHV)	3209	GJ/h
Fuel heat input (LHV)	3054	GJ/h
Fuel flow	3740	t/day

Ambient
1.001 p
25 T
60% RH
19.45 T wet bulb

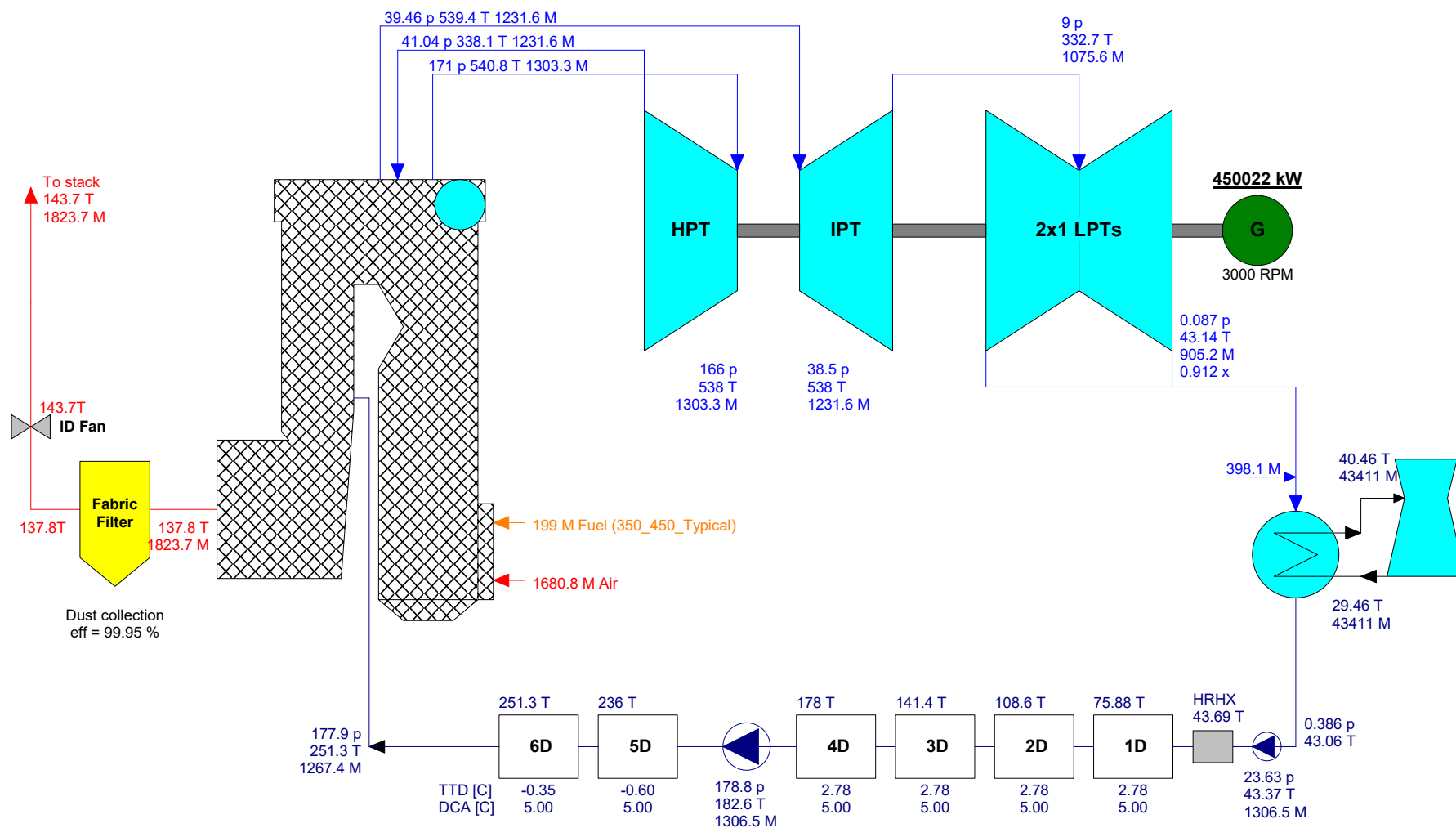


p [bar] T [C] M [t/h] x [-]

APPENDIX B-2
450 MW BLACK COAL PLANT WITH
TYPICAL COAL

Plant gross power	450022	kW
Plant net power	415242	kW
Number of units	1	
Plant net HR (HHV)	9871	kJ/kWh
Plant net HR (LHV)	9395	kJ/kWh
Plant net eff (HHV)	36.47	%
Plant net eff (LHV)	38.32	%
Aux. & losses	34780	kW
Fuel heat input (HHV)	4099	GJ/h
Fuel heat input (LHV)	3901	GJ/h
Fuel flow	4777	t/day

Ambient
1.001 p
25 T
60% RH
19.45 T wet bulb

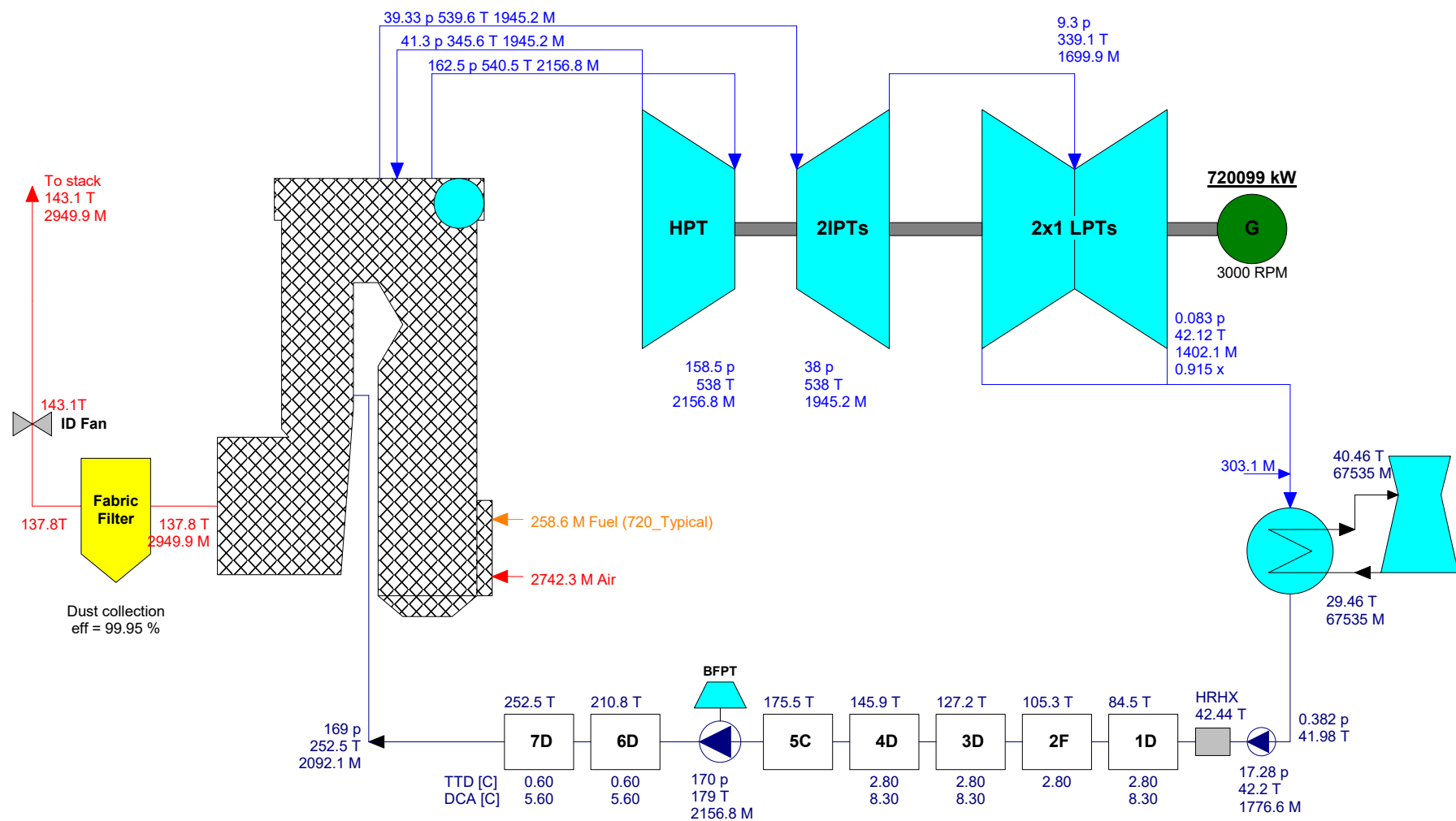


p [bar] T [C] M [t/h] x [-]

APPENDIX B-3
720 MW BLACK COAL PLANT WITH
TYPICAL COAL

Plant gross power	720099	kW
Plant net power	687657	kW
Number of units	1	
Plant net HR (HHV)	9587	kJ/kWh
Plant net HR (LHV)	9215	kJ/kWh
Plant net eff (HHV)	37.55	%
Plant net eff (LHV)	39.07	%
Aux. & losses	32442	kW
Fuel heat input (HHV)	6593	GJ/h
Fuel heat input (LHV)	6337	GJ/h
Fuel flow	6207	t/day

Ambient
1.001 p
25 T
60% RH
19.45 T wet bulb



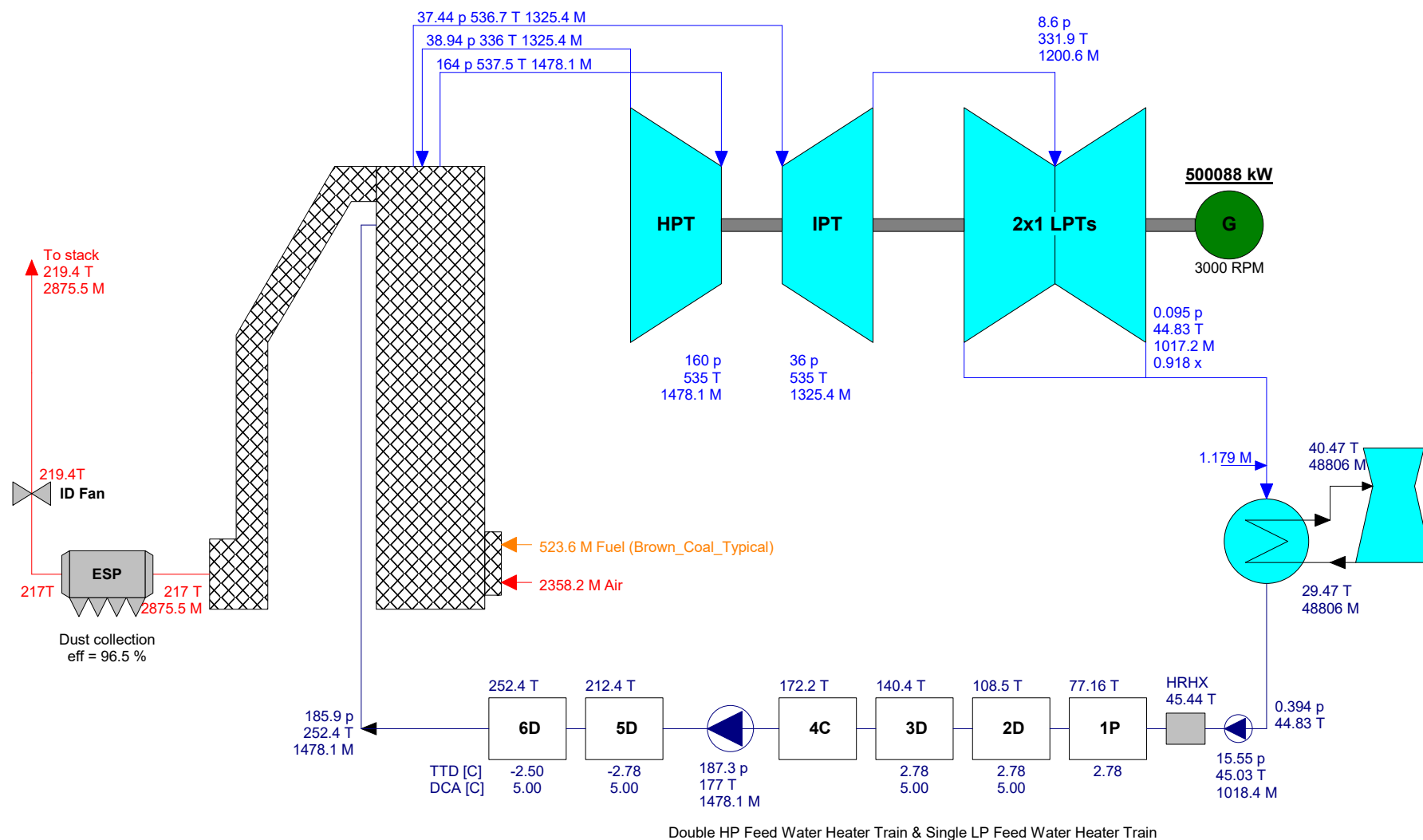
Double HP Feed Water Heater Train & Single LP Feed Water Heater Train

p [bar] T [C] M [t/h] x [-]

APPENDIX B-4
500 MW BROWN COAL PLANT WITH
TYPICAL COAL

Plant gross power	500087	kW
Plant net power	458639	kW
Number of units	1	
Plant net HR (HHV)	12429	kJ/kWh
Plant net HR (LHV)	10274	kJ/kWh
Plant net eff (HHV)	28.96	%
Plant net eff (LHV)	35.04	%
Aux. & losses	41449	kW
Fuel heat input (HHV)	5701	GJ/h
Fuel heat input (LHV)	4712	GJ/h
Fuel flow	12566	t/day

Ambient
1.001 p
25 T
60% RH
19.45 T wet bulb



p [bar] T [C] M [t/h] x [-]