

# Challenges for the coal-using energy sector in South Africa and neighbouring nations – efficiency and emissions control options

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## Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

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## **1 Introduction – coal use for power generation in Southern Africa – a brief outline**

The accompanying report outlines the emissions reduction challenges faced by the African coal sector and suggests possible high level strategies and legislative approaches for combatting them in the context of a fast rising electricity demand. This report looks at the technologies that could be used to realise the needed emissions improvements and assesses which would be most applicable.

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## 2 Emission limits

The South African Government's new emission limits for particulates, SO<sub>2</sub> and NO<sub>x</sub> for coal units of 50 MWth and larger, published in 2010, are shown in Table 1 (Government Gazette, 2010). [These are all at 10% O<sub>2</sub> reference concentration in the flue gas; to convert to 6% O<sub>2</sub> reference, multiply by 1.36]. Identical limits apply to biomass fuelled units in the same size range. The existing plant category applied from five years after the publication of the order, i.e. 2015, the new plant category from 2020. However, derogations were sought and granted till dates up to 2020 for a number of coal-fired power plants. Note that existing units are expected to meet the new plant limits by 2020. Principal emission control technologies are reviewed later with a view to their potential for installation in the country and other parts of Southern Africa.

Of particular relevance to today's objective of reducing mercury emissions from the coal combustion sector, SO<sub>2</sub> and NO<sub>x</sub> control systems can have a major co-benefit in that respect, and this adds importance to considerations regarding the most apposite acid gas abatement technologies to adopt.

| <b>Table 1</b>                     |  |   |   |
|------------------------------------|--|---|---|
| <b>Description</b>                 |  | <b>Solid fuels installations for electricity generation</b> |   |
| <b>Application</b>                 |  | <b>All units with capacity &gt;50 MW heat input (LHV)</b>   |   |
| Substance or mixture of substances |  | Plant status  | mg/m <sup>3</sup> under normal conditions of 10% O <sub>2</sub> , 273 K and 101.3 kPa |
| Common name                        | Chemical symbol                              |   |   |
| Particulate matter                 | N/A  | New   | 50  |
|                                    |  | Existing  | 100   |
| Sulphur dioxide                    | SO <sub>2</sub>                              | New   | 500   |
|                                    |  | Existing  | 3500  |
| Oxides of nitrogen                 | NO <sub>x</sub> expressed as NO <sub>2</sub> | New   | 750   |
|                                    |  | Existing  | 1100  |

### 3 Current technologies used

Most current coal-fired plants in South Africa and worldwide use pulverised coal combustion (PCC) technology. In PCC, powdered coal is burned to raise steam for turning a steam turbine generator. The grinding mills are fed with hot air to dry and transport the coal dust to the boiler. The steam is recondensed into water for return to the boiler. For emissions control, South African units have particulate separation systems fitted, some using fabric filters, others electrostatic precipitators (ESPs), but no other post boiler flue gas cleaning is currently used. Combustion measures to limit NO<sub>x</sub> are however in the process of being installed, and, over the next few years, desulphurisation systems will be fitted to the supercritical units currently being installed at Medupi and Kusile.

Either water cooling or air cooling is used for condensing the steam at Eskom's plants. Thermal efficiency is higher for water cooling, as the steam can be expanded further in the turbine, but air cooling is necessary at some sites, and it is now required for future plants in South Africa because of limitations on water supplies.

Detailed descriptions of PCC plants are contained in a report on a series of case studies prepared by the present author for the IEA (IEA, 2007). This report is cited because it actually contains a valuable case study of Eskom's Majuba plant, which uses both types of cooling. The reduction in thermal efficiency from using air cooled condensers could therefore be quantified in this study of the six essentially identical boiler-turbine units, three of which differed from the other three only in the cooling system adopted. Steam conditions at the boilers are 17.2 MPa/540°C/540°C. The dry cooled systems (units 1–3) use direct air cooling of the steam from the turbine in large 'A'-frame-shaped condensers containing externally finned tubes. Air is blown over the condenser tubing. The condensing capability of these systems is very dependent on the ambient temperature, so unit output and efficiency vary with season. Ambient temperature range is –8°C to 34°C, and gross power varies typically between 620 MWe and a design 657 MWe. Units 4–6 of Majuba utilise conventional wet-cooling technology with natural draught cooling towers. Output and efficiency of these vary far less (output between 704 MWe and 713 MWe, gross). The higher turbine exhaust pressure was the main factor resulting in efficiency being around two percentage points lower for the dry systems.

Many flue gas desulphurising systems consume a considerable quantity of water, and this may limit the options available at some locations. Desulphurising technologies are described later.



## 4 High efficiency – its importance and how to achieve it

The thermal efficiency of a coal-fired power plant is one of the factors affecting its emissions intensity (mass of pollutants or CO<sub>2</sub> emitted per kWh sent out). There is therefore a powerful incentive to maximise it. Many factors determine the outturn efficiency, for example the configuration of the water/steam cycle, the turbine design, the degree of coal burnout, the extent of heat capture in the boiler, and the plant's own power consumption. The nature, and therefore temperature, of the cooling medium for the steam condenser, has a big influence, but, as pointed out above, there may be no choice in this.

The universally recognised way to maximise efficiency is to use steam temperatures and pressures in the supercritical range (pressures above 22.1 MPa), which of course is why Eskom has moved to such technology for Medupi and Kusile. The steam conditions for these units are 24.1 MPa/560°C/570°C and the efficiency is likely to be around 40% LHV basis, net, based on previous work (Henderson and Baruya, 2012). In hot countries, the efficiency of any coal-fired unit will be penalised by the use of air cooling in comparison with water cooling, but the advantage over the performance of subcritical systems will remain. State-of-the-art conditions, known as ultra-supercritical (USC), operate at steam parameters of 25-30 MPa/600°/620°C, and could be offered by suppliers for future units in South Africa for still better performance (around two percentage points higher efficiency).

There is similar value in increasing the efficiency of existing plants where possible, and it can often also be possible to increase output. An example of where this has been carried out here is at Eskom's 6 x 350 MWe Arnot power station (Figure 1). The project covered the boiler, HP, IP and LP turbines, condenser and various balance of plant components as well as new 400 MW generators. This was a particularly good site for the retrofit, because the boiler was actually originally over-sized, and so amenable to being uprated considerably (Henderson, 2013).



Figure 1 Arnot Power station, South Africa (Davies and others [Alstom], 2012)

### Coal quality

Whilst they are bituminous, coals supplied to the power plants in South Africa are usually generally lower in quality than those sent for export, in that they have fairly high ash contents (reaching to over 30%). This has not generally presented a major problem, however, and pulverised coal combustion systems, including modern supercritical and ultrasupercritical plants, are able to use such coals, with some energy penalty. The sulphur content of the prepared coals is typically at a medium level, i.e. around 1–1.5%, and commercial desulphurisation systems could easily ensure that SO<sub>2</sub> emissions satisfied the new daily average limit, as shown later.

## 5 Biomass cofiring

Biomass holds considerable potential as a fuel for the future, as around 18 Mt of agricultural waste is produced each year in South Africa. While co-firing this with coal in existing units would not increase capacity, it would reduce emissions of all pollutants, including mercury and CO<sub>2</sub>. Eskom is reported to be considering trials. Cofiring has proven successful at many plants abroad, especially in Europe. In some, this has been the preface to a 100% conversion to biomass firing.

Introduction of biomass can reduce NO<sub>x</sub> through its lower nitrogen content and higher volatiles release in the fuel rich zone of the flame. Biomass also gives a lower flame temperature, reducing thermal NO<sub>x</sub>. Less important here is that incorporating it in the fuel mix may affect the catalysts used in SCR units – larger quantities of alkalis, such as K, Na, Ca, and also phosphorus may blind or poison catalysts. SCR is discussed later, but is not likely to be applied yet as the NO<sub>x</sub> limits can be met without using it.

Coal blend properties principally affecting SO<sub>2</sub> emissions are the total sulphur content and the ash composition (since typically 5–10% of the SO<sub>2</sub> can be captured by alkalis in the coal ash). Biomass generally has much lower contents of sulphur, as well as higher concentrations of alkalis in its ash, and so SO<sub>2</sub> emissions are generally considerably reduced when cofiring.

The chemical and physical properties of fly ash particulates from biomass combustion are different from those of coal. Adding biomass can give higher release of trace metals and reduced fly ash loadings. It may also increase the overall collection efficiency of ESPs due to larger particulates and ease of agglomeration. The one uncertainty can be that it may instead reduce collection efficiency due to high resistivity of the fly ash. Biomass can also increase PM<sub>2.5</sub> emissions.

It is vital to ensure and prove the environmental sustainability of biomass sources. Many utilities abroad have joined together in developing sustainability criteria, including standard contracts, common criteria and verification or certification. Safety in storing and transferring biomass is taken very seriously by generators as the material is readily flammable. It is important that airborne dust be eliminated at every opportunity. Bulk storage needs very careful management, with monitoring of temperatures and gases and exclusion of air. Fire systems have to incorporate innovative solutions. Gas inerting has been found to be better than water deluge to manage fires.

## 6 Technologies for SO<sub>2</sub> reduction

There are many desulphurisation systems that could be used at the power plants to meet the SO<sub>2</sub> limits. Principal types that have been considered are outlined below. These are potentially able to contribute to capture of mercury as a co-benefit. All are commercially available and proven.

### 6.1 Limestone/gypsum process

This wet scrubbing process (Figure 2) is the most widely applied form of SO<sub>2</sub> abatement. The flue gas is contacted with a slurry of limestone in water in a spray tower through which the raw flue gas is passed upwards. The slurry is extensively recirculated to achieve efficient limestone utilisation (a Ca: S ratio of 1.05 is usually adequate). The cleaned gas is demisted, then, typically, reheated before discharge to the stack. It is most energy efficient to use heat exchange between the raw and cleaned gas streams for this purpose. The limestone is converted to gypsum for disposal or, if there is a convenient market outlet, the gypsum may be purified for use in wallboard manufacture. A blowdown stream of water is withdrawn to maintain a water balance and suitable gypsum purity. Variants of the process employing, for example, co-current flow of gas and slurry in packed or jet bubbling reactors are available. The process employs a considerable quantity of electric power for pumping the recirculating fluid and to power a booster fan to push the gases through the system.

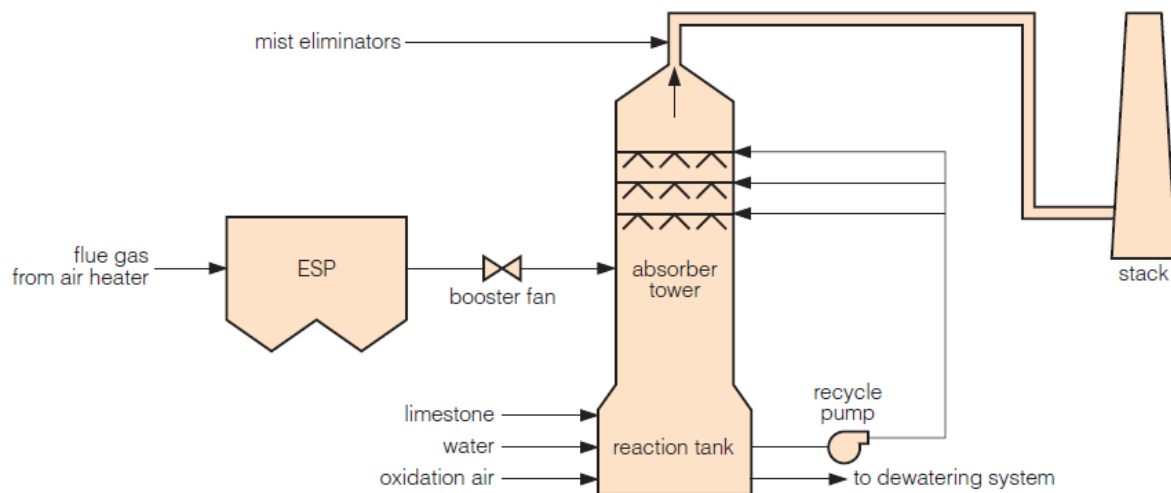


Figure 2 Limestone/gypsum wet scrubber (Carpenter, 2013)

The limestone/gypsum process is capable of reducing SO<sub>2</sub> levels down to below 100 mg/m<sup>3</sup> at 6% O<sub>2</sub>, but this depth of removal will not be necessary to reach the South African 500 mg/m<sup>3</sup> at 10% O<sub>2</sub> limit. Typically, around 50% of the particulates escaping the particulates removal systems are captured as a co-benefit. Oxidised mercury is water-soluble and can be absorbed in the aqueous slurry as a co-benefit. The amount of mercury captured is dependent on the type of coal and other plant systems, such as if SCR is fitted and what type of particulate control is employed. The familiar cold-side ESP arrangement (as used in South Africa) is generally quite favourable, while fabric filters, which are also installed here, can allow even

greater mercury capture, from continuing reactions in the filter cake. Maximising the proportion of mercury in the oxidised form (e.g. by upstream bromide injection) will increase its capture by the FGD.

Unfortunately, wet scrubbers consume considerable quantities of water, and this may limit selection of these systems in parts of South Africa. Cooling the flue gas before it enters the scrubber reduces the evaporative losses (and is readily achieved by the heat exchange with the cleaned gas referred to above). Where the process is designed to produce marketable gypsum, the mining of natural gypsum may be avoided.

The process is well proven and investment costs have decreased over the years but they are still comparatively high. Despite the efficient sorbent utilisation, the high water requirement and need for a relatively complex water treatment plant mean that operating costs are quite high, so the system is generally selected for new or recently built plants.

## 6.2 Lime spray scrubbers

Also known as semi-dry scrubbers or spray-dryers, these are also installed in large numbers, mostly in the USA (Carpenter, 2013). In these, the flue gas emerging from the combustion air preheater, at around 120-150°C, is contacted with an atomised slurry of calcium hydroxide (Figure 3). The contacting takes place in a reaction chamber into which the reagent feed rate is carefully controlled such that all of the moisture injected evaporates but such that the emerging gas/solid stream is only around 15°C hotter than saturation temperature, to allow maximum uptake of SO<sub>2</sub> and utilisation of sorbent. The emerging gas/solid stream is then sent on to the particulate control system. Use of bag filters rather than electrostatic precipitators increases the degree of SO<sub>2</sub> removal as the absorption reactions continue within the baghouse. Lime spray-driers are well established commercially and have been applied even on units up to around 500 MWe gross capacity.

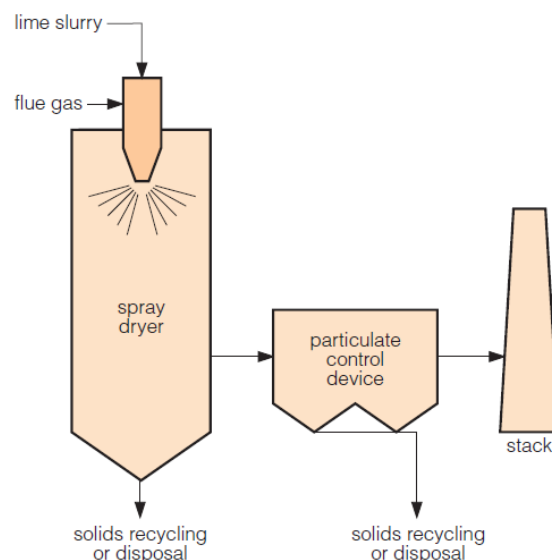


Figure 3 Spray dry scrubber system (Carpenter, 2013)

As with wet FGD, spray dry scrubbers also remove some mercury, other heavy metals and particulates as a co-benefit. The mercury removal efficiency is dependent on many factors, including coal composition, the level of unburnt carbon in the ash, and the flue gas temperature. The mercury capture efficiency is higher with fabric filters than with ESPs due to continuing reactions in the filter cake. In installations in Europe, the spray dry system is placed after the fly ash collectors so that the fly ash can be sold. This arrangement does, however, reduce the mercury capture co-benefit as well as increase costs. Injecting a mercury sorbent into the dry scrubber may then be necessary to improve mercury capture efficiency, at a cost (Carpenter, 2013).

Energy consumption is lower than for wet scrubbers as there is no recycling of slurry. SO<sub>2</sub> residual concentrations as low as 200 mg/m<sup>3</sup> at 6% O<sub>2</sub> have been reported. Water consumption is around 40–50% of that of wet scrubbers. The solid waste is normally disposed of dry after conditioning. It can be used in mine reclamation.

Capital costs are lower than those of wet scrubbers. The sorbent is more expensive than the limestone used in the latter and utilisation is lower (Ca:S ratios of around 1.4 are typically needed), so reagent costs are higher. The cost of waste disposal is also higher. These extra costs are partly compensated by the lower water requirement. Overall, these systems look good candidates for the South African situation.

### **6.3 Post combustion circulating dry scrubbers**

These are another semi-dry SO<sub>2</sub> removal technology that is placed before the particulate removal system. Calcium hydroxide is normally used as the reagent and the flue gas is used as the fluidising medium. Circulating fluidised beds are most commonly used (Figure 4), but entrained systems also exist. Water is injected to maximise sorbent utilisation. The reaction products, particulate-bound mercury, spent and unreacted sorbent, along with the fly ash, are removed by the particulate control device and continuously recycled to the scrubber to maximise sorbent utilisation. Circulating dry scrubbers can provide SO<sub>2</sub> removal efficiencies up to approximately 98% because of their effective contacting. Mercury capture at up to 95% is possible with high chlorine coals (Carpenter, 2013).

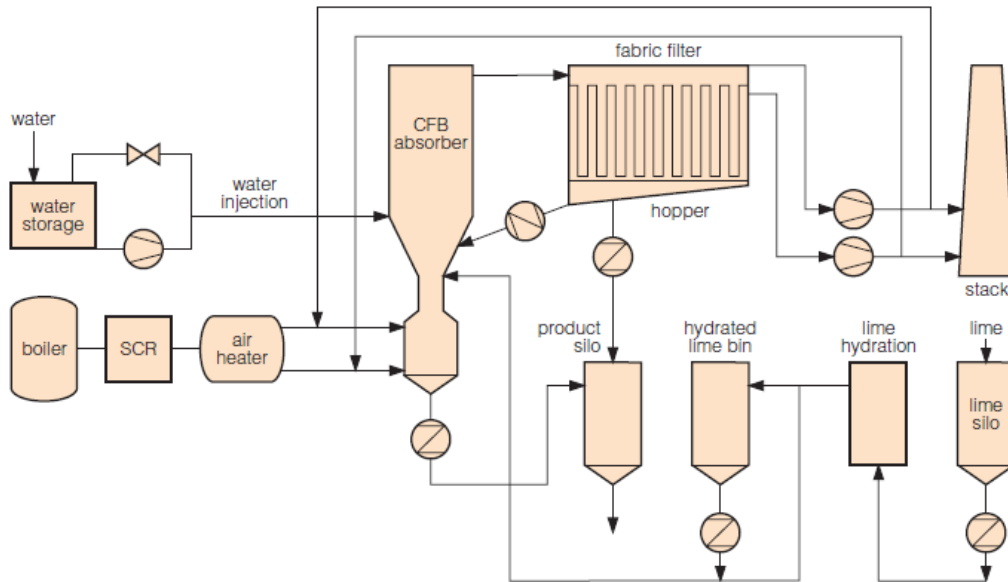


Figure 4 CFB scrubber flowsheet for Dry Fork, USA (Carpenter, 2013)

Capital costs are lower than for wet scrubbers and comparable with those of spray dryers. Circulating dry scrubbers do not require a wastewater treatment facility. Their water requirements, at about 40% of that of wet scrubbers, are comparable with those of spray dry scrubbers. Their sorbent requirements are however about 20% higher.

#### 6.4 Dry sorbent injection

There are two main types of dry sorbent injection: furnace injection and duct (post-furnace) injection. For furnace injection, limestone may be used, but calcium hydroxide is a more commonly used reagent. Calcium hydroxide, Trona and sodium bicarbonate are used in duct injection systems. Downstream humidification of the treated gases is often employed to improve performance. Sulphur capture is around 50% without humidification, but may be 70–80% if it is applied. Furnace injection can give rise to increased fouling of boiler convection passes, but the deposits are usually easy to remove by increasing sootblowing frequency. Dry sorbent injection systems are much lower in capital costs than wet scrubbers or spray-dryers. However, achieving the 500 mg/m<sup>3</sup> level at 10% O<sub>2</sub> will be difficult with these systems unless low sulphur coals are available.

#### 6.5 Dry regenerable systems

Desulphurisation systems that require virtually no water have an obvious attraction for application in areas of water shortage, and these can act as multi-pollutant control systems also, including high degrees of mercury capture. These also have the benefit of being regenerable technologies, and so requiring relatively small quantities of input raw materials as reagents. The ReACT™ system is proven on a large power generation site in Japan and is discussed below.

## ReACT™

J-POWER's ReACT™ process operates in three stages: adsorption, regeneration and by-product recovery (Figure 5). The system is installed after the particulate control device. In the adsorption stage, ammonia is injected into the flue gas which then passes horizontally through the adsorber that contains a moving bed of activated coke. SO<sub>2</sub>, SO<sub>3</sub>, NO<sub>x</sub> and mercury are removed through adsorption, chemisorption and catalytic reactions. The SO<sub>2</sub> and SO<sub>3</sub> are converted to sulphuric acid, NO<sub>x</sub> is catalytically reduced by the ammonia and mercury is retained on the activated coke. Over 99% of SO<sub>2</sub> and SO<sub>3</sub>, 20–80% NO<sub>x</sub>, >90% of mercury (elemental and oxidised) and ~50% of the particulates are removed with low to medium sulphur coals. The system has been installed on coal-fired power plants in Japan and the USA, and in Germany, on industrial plants (Carpenter, 2013).

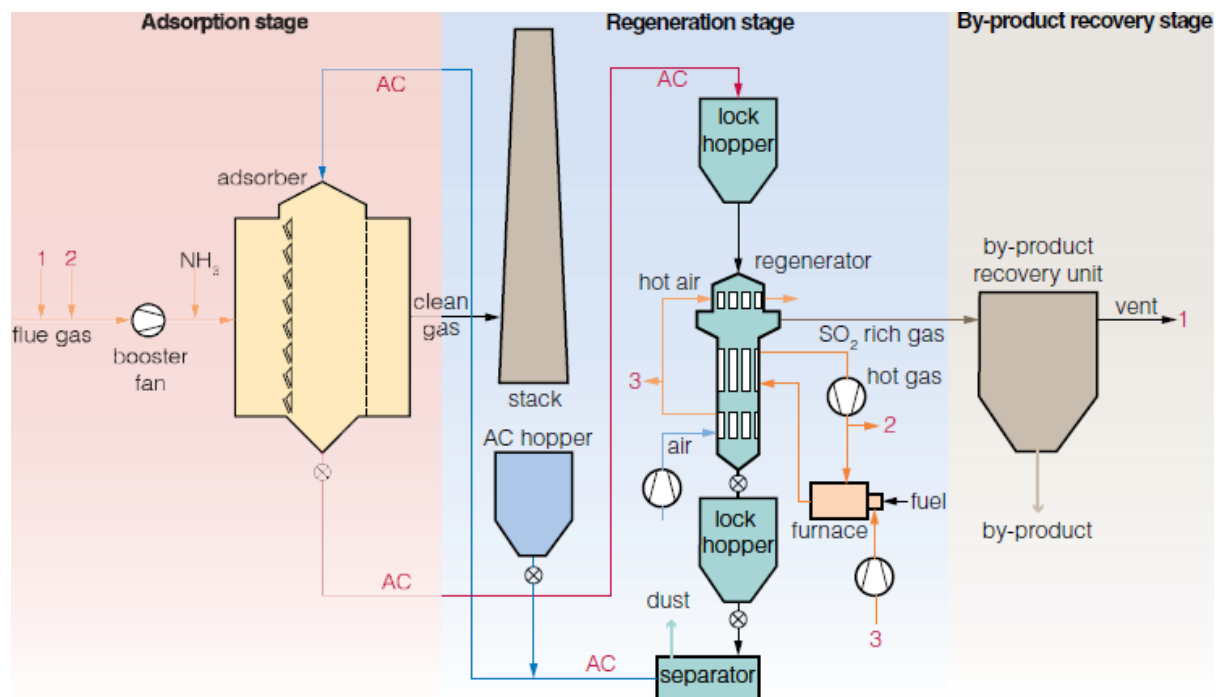


Figure 5 ReACT™ process (Peters, 2011)

Mercury is removed with the activated coke during planned outages every few years. After cooling, the regenerated activated coke is screened to remove fines and captured fly ash before it is returned to the adsorber. Activation of the coke increases with time because its surface area increases during the recycling process. Exceedingly low residual SO<sub>2</sub> emissions can be achieved, as shown by, for example, the 2 ppm (6 mg/m<sup>3</sup>) at 6% O<sub>2</sub> of SO<sub>x</sub> emissions reported at Isogo in Japan fired on a low sulphur coal (Carpenter, 2013). NO<sub>x</sub> levels are also very low (7 ppm, i.e. 14 mg/m<sup>3</sup>) when SCR is also used.

## 6.6 Desulphurisation systems - summary

Wet non-regenerable limestone scrubbers are by far the most widespread desulphurisation systems in commercial use. The limestone/gypsum process is most commonly chosen and is capable of high desulphurisation efficiency. It will also provide a significant co-benefit of mercury removal. It does have a fairly high capital cost and requires a lot of water. It will be best suited to the large new plants.



Spray-driers have become increasingly common in recent years for boilers up to 500 MWe. They offer reasonably high SO<sub>2</sub> removal at lower overall cost than wet scrubbing with lower water consumption. However, reagent costs are relatively high. The solid product may find a use in opencast mine reclamation.

Solid adsorption in fluidised beds may be valuable, having very high removal efficiency at a similar capital cost to spray dryer systems. Water use is comparable with that of spray dryers. Reagent costs can be high but there is a dry solid by-product. These systems should be considered for application at existing plants to meet the new regulations.

Dry injection of sorbent, whether into the furnace or into the ducting downstream of the boiler, can give medium degrees of SO<sub>2</sub> removal at low capital cost and are readily retrofitted. However, they are unlikely to allow the new limits on SO<sub>2</sub> emissions to be met and so have been excluded from further consideration.

Dry multi-pollutant control is probably the gold standard in flue gas cleaning systems. The ReACT™ process uses virtually no water, but is able to remove SO<sub>2</sub>, NO<sub>x</sub> and mercury, to leave very low residual concentrations in the exit gases. The main disadvantage is a high capital cost and small reference base in commercial installations, although performance has been good at the locations where it has been applied.

## 7 NOx control

During coal combustion, NO<sub>x</sub> is formed from oxidation of both fuel nitrogen and nitrogen from the air (thermal NO<sub>x</sub>). A minor contribution comes via a free radical mechanism (prompt). In the absence of NO<sub>x</sub> control, during pulverised coal combustion, the NO<sub>x</sub> produced is predominantly from the fuel nitrogen (typically 75% of the total). The contribution from thermal NO<sub>x</sub> is of the order of 20% but can be higher, depending on boiler design. It is produced in significant quantities above 1500°C and can be minimised by minimising the residence time at high temperature in an oxidising environment. Uncontrolled emissions of NO<sub>x</sub> from pulverised coal-fired boilers and furnaces range from around 650 mg/m<sup>3</sup> to over 2000 mg/m<sup>3</sup>, at 6% O<sub>2</sub>, depending on fuel, burner type and combustion arrangement.

Technologies available for abating NO<sub>x</sub> emissions are described in this section. All are commercially proven and available from several suppliers. Flue gas treatment processes, which involve the addition of a reagent to the combustion products, are included, although they are probably not necessary for meeting the South African limits on NO<sub>x</sub> emissions. NO<sub>x</sub> control technologies based on combustion measures are aimed at control of the fuel: air ratio and combustion temperature/residence time, in order to reduce its production from fuel nitrogen and nitrogen from the air.

### 7.1 Low NOx burners

Low-NO<sub>x</sub> burners (Figure 6) operate by staging the introduction of the combustion air to the combustion zone. The coal is conveyed into the combustion system by a sub-stoichiometric quantity of primary air so that devolatilisation of the fuel occurs, encouraging the release of the fuel nitrogen as molecular nitrogen. In a subsequent air-rich stage, the combustion process is completed as the released volatiles are combusted. The secondary air is usually swirled. Tertiary air is then introduced to ensure that no reducing gases reach the furnace walls.

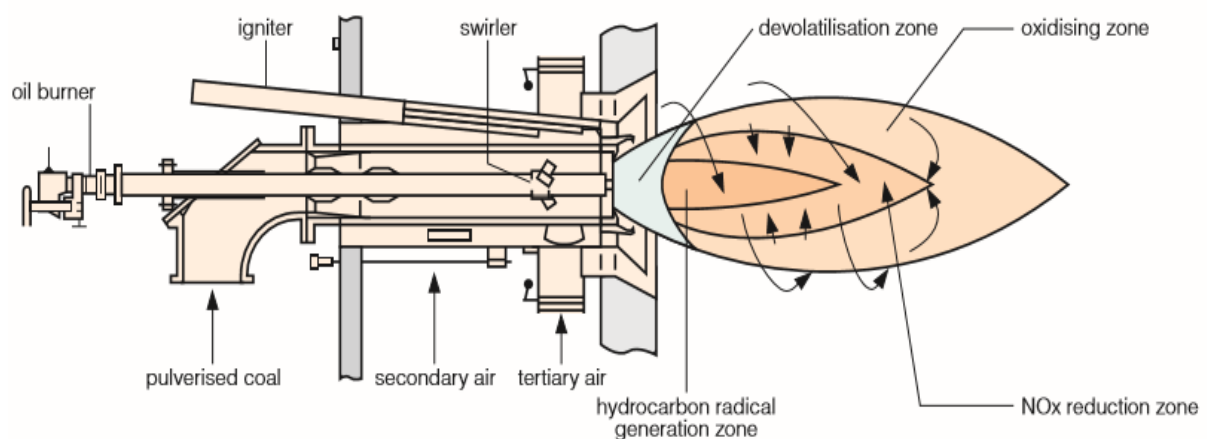


Figure 6 Schematic of a low-NO<sub>x</sub> burner (Nalbandian, 2009)

Low-NOx burners have been developed by most boiler manufacturers and are almost universally used in new boiler installations even if flue gas de-NOx is also installed. LNBs are generally combined with other primary measures such as overfire air (OFA), or, less commonly, reburning or flue gas recirculation. A great deal of commercial experience also exists in retrofitting low-NOx burners to existing boilers and furnaces and the technology is very well proven. As in any retrofitting situation, site-specific factors will limit options and influence optimum choices, but, provided that the boiler is able to accommodate an increased flame length (or if this can be avoided by increasing the number of individual burners within the boiler without undue cost), there is normally no difficulty.

A 30% or better reduction in NOx emissions, compared with uncontrolled releases, can be achieved using these systems. Ash carbon levels can be increased, and above 5% carbon needs to be avoided if the ash is being sold for use in cement production. Coal properties can have a considerable influence on NOx production but the technology is applicable to a wide range of coals. There can be a small increase in operating costs due to slightly lower combustion efficiencies.

## 7.2 Air staging

Low NOx burners constitute a form of air staging process. The air can also be staged external to the individual burners by operating them sub-stoichiometrically and then introducing further air (typically 10–20% of total required air). Introduction of such overfire air is often used in conjunction with low-NOx burners to give additional abatement. Hence the relatively low temperature secondary stage also limits the production of thermal NOx. The location of the injection ports and mixing of OFA system air are critical to maintain efficient combustion. Retrofitting OFA on an existing boiler involves water wall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and an extra windbox. Care is needed to avoid a reducing environment in the boiler that can damage the waterwall tubes.

A variant, boosted overfire air (BOFA), operates similarly except that the OFA air velocity is increased to enable a greater degree of mixing between the air and unburnt char in the flue gas for improved boiler efficiency.

## 7.3 Reburning

Reburning, known also as fuel staging, is another staged combustion process but reduces NOx by a different mechanism. Additional fuel (not necessary coal, more frequently oil or natural gas) is introduced into the furnace downstream of the main combustion zone. The added fuel (typically 15–20% of total fuel requirement) produces hydrocarbon radicals which ‘mop up’ NOx. Additional air is then added downstream of the reburning zone to complete combustion. There may be an energy penalty, depending on the reburning fuel chosen and system design. For instance, recirculation of some flue gas as carrier gas for reburning fuel will increase fan power.

The technology gives a reduction in NO<sub>x</sub> emissions of around 50%. Used in conjunction with low-NO<sub>x</sub> burners, the technology should give 70% abatement or more. The reburning fuel must have a high volatile matter content and low nitrogen content. If the main fuel does not have these characteristics, a different fuel must be available for use as the reburning fuel. If coal is the reburning fuel, it needs micronising more finely than the main pulverised coal feed. Most experience is with natural gas. Biomass has also been suggested as a suitable reburning fuel because of its low devolatilisation temperature, high volatiles content (75–80%) and low to medium nitrogen content (Nalbandian, 2009).

## 7.4 Flue gas recirculation

Flue gas recirculation (FGR) is a technique that abates NO<sub>x</sub> by diluting the combustion air and reducing the flame temperature. In this technology up to 20% of the flue gas is recirculated and mixed with the combustion air. The resulting dilution in the flame decreases the temperature and availability of oxygen, thereby reducing thermal NO<sub>x</sub> formation (Nalbandian, 2009). The technology is not usually as effective as the measures outlined above and is expensive. Consequently, it is not widely applied, except on slagging boilers, for which abatement levels of 20–30% may however be achieved. It gives rise to increased fan power consumption.

## 7.5 Flue gas treatment

If combustion measures are not sufficient for conforming within emissions limits for NO<sub>x</sub>, downstream flue gas treatment, involving the addition of a reagent such as ammonia can be used. There are two approaches: non-catalytic and catalytic.

### 7.5.1 Selective non-catalytic reduction (SNCR)

SNCR requires reaction temperatures in the 900–1100°C range and the reagent (ammonia or urea being most commonly used) is consequently injected into the boiler furnace. The reactions convert the oxides of nitrogen to nitrogen and water so that there is no waste disposal problem. Efficient mixing of the reagent with the hot combustion gases is essential, not only to achieve effective NO<sub>x</sub> abatement, but also to minimise the release of ammonia to the stack. Additives are sometimes used to extend downwards the temperature range of optimum removal and to help maintain abatement performance during boiler load variations.

SNCR is generally capable of removing 30–50% of NO<sub>x</sub> although higher performance is sometimes possible. Injection must be within the correct window to prevent ammonia release (slip) or even increased NO<sub>x</sub> production. For variable load operation, different injection points may be needed. There are no solid residues for disposal, although ammonium salts may be produced and subsequently deposited on elements of plant downstream.

Investment requirements are considerably lower than for systems using catalysts (*see next section*). Operating costs are also lower, despite higher reagent requirements.

### 7.5.2 Selective catalytic reduction (SCR)

The use of a catalyst (titanium oxide is dominant, but zeolite, iron oxide or activated carbon are also used) allows lower reaction temperatures (generally 300–400°C) and more complete removal of NO<sub>x</sub> from the combustion gases at a lower reagent consumption. The reagent used is ammonia and the NO<sub>x</sub> is again reduced to water and nitrogen. The system is most frequently placed between the economiser and the air heater, where the temperature is correct for most catalyst types, but this may be difficult in retrofit situations. An alternative, but less favoured configuration, is just downstream of a hot particulate removal system. Another is immediately before the stack, after the desulphurisation system, but gas reheating is then needed. For retrofit installations, such an arrangement is usually easiest, because space is more readily available in this plant area. SCR is often used together with combustion modifications to reduce the capital and running costs of the SCR system. The technology is widely used worldwide.

SCR is capable of removing 80–90% of NO<sub>x</sub>, with residual concentrations in the clean gas as low as 20 mg/m<sup>3</sup> at 6% O<sub>2</sub> reported at some sites. Ammonia slip can occur if reagent feed rates are too high or when the catalyst requires replacement. In high dust configuration systems, catalyst erosion can occur with high ash coals, a point to consider if SCR is selected for South African plants. At reduced boiler load, careful temperature monitoring is needed to avoid ammonium bisulphate formation and deposition on the catalyst and the air heater. Solutions include adding a gas or water-side economiser bypass to enable the flue gas temperature to be kept at design value, adding a heating facility for hot gas carrying components or even simply adding static baffles.

SCR is more capital intensive than SNCR, and operating costs are also higher because of greater system complexity and the need for catalyst replacement every 3 to 5 years. However, as it gives a far greater abatement than is needed for compliance in South Africa, it is not likely to be preferred.

## 7.6 NO<sub>x</sub> control systems – summary

None of the measures for NO<sub>x</sub> control results in the production of waste streams for sale or disposal. Where NO<sub>x</sub> emissions legislation is not extremely tight, combustion measures alone should satisfy requirements and most of these have the advantage of needing no raw materials and entailing the lowest investment and operating costs.

## 8 Particulate control systems

The two particulate control system technologies that predominate worldwide and that are used in South Africa are electrostatic precipitators (ESPs) and fabric filters (also called bag filters). Dry ESPs and fabric filters have similar overall PM removal efficiencies, of more than 99.9%, but fabric filters are better at abating fine PM (PM<sub>2.5</sub>), and are less sensitive to particulate loading and fly ash characteristics. The systems are already familiar in South Africa on power plants, so only short descriptions are given here.

Wet electrostatic precipitators (WESPs) are increasingly being used, usually as a final stage after dry ESPs, in some other countries where very stringent emission limits exist for PM<sub>2.5</sub>. While particulate-bound mercury and some oxidised mercury are also removed as a co-benefit, the system is not discussed here as there is no stringent PM<sub>2.5</sub> limit. More information on particulate control systems can be found in the IEA Clean Coal Centre reports by Nicol (2013) and Zhang (2016).

### 8.1 Bag filters

Bag filters are fabric filtration systems. The dust-laden flue gas is passed through a woven or felted fabric, supported on a cage frame. The effective filtration medium is usually the accumulated filter cake that initially forms. A large number of individual bags is used within typical installations. The fabric is cleaned at intervals by a reverse pulse jet. A wide variety of fabrics is available, differing in their resistance to temperature and acid-induced degradation. A somewhat higher fan power consumption arises from the higher pressure drop than for ESPs.

### 8.2 Electrostatic precipitators (ESPs)

The principle of ESP operation is that the flue gas is passed through a corona discharge created between electrodes, the potential difference between which is 30–75 kV, so that the particulates become charged by attachment of negative ions. The particulates then migrate to the positive electrode, which usually takes the form of a number of parallel plates, between which are negative discharge wires. Removal of collected material from the collection plates is effected generally by mechanical rapping. Collection efficiency is adversely affected by high electrical resistivity of the particles, encountered on certain coals. Lower collection performance can occur for certain ashes. ESPs are higher in capital cost than bag filters, but pressure drop and direct power consumption are low so that operating costs are low.

### 8.3 Particulate control systems – summary

Bag filters and ESPs are the most effective systems technically and are the only acceptable options to conform with emissions limits for new plant in many parts of the world.

## 9 Coal in neighbouring Southern African nations

There are potentially large coal resources in Southern African countries such as Botswana, Mozambique, Zambia, Zimbabwe and Namibia (Baruya and Kessels, 2013). The governments in these regions are now recognising coal as a strategically important commodity, capable of adding value to the economy by generating much needed electricity to support economic growth and the welfare of communities.

In Mozambique, for example, electricity supply is based on hydroelectric power, and there are currently no coal-fired units. However, there are a number of plans for new coal-fired generation projects that could be built and commissioned before 2020 in the context of a very high electricity demand growth rate and plentiful coal resources. These are all associated with coal mines, at Benga, Moatize (Vale), Jindal (Jindal Steel & Power), and Ncondezi.

There are also huge coal resources in Botswana, some of which is exported to South Africa. Botswana's power capacity is limited to one 4 x 33 MWe coal-fired station. Being in an area where water shortage is a problem the units were designed with air-cooled condensers. A new 4 unit CFBC station (Morupule B) is due to increase coal capacity above 700 MWe.

Coal reserves in Zambia are uncertain, though much smaller. Production is around a million tonnes per year, but likely to rise as new coal-fired generation capacity is planned. Hydro is currently the main source of power, but a 300 MW minemouth coal project based on CFBC has been implemented.

Around 3 Mt of coal is mined in Zimbabwe per year. The 920 MWe Hwange Power Station is the most important coal-fired plant, supplying approximately 40% of the country's electricity supply. The plant was built in two stages and consists of four units of 120 MWe and two units of 220 MWe. New plants are planned, to use sub-critical technology.

Namibia has one 4x30 MWe coal-fired power plant that uses dry cooling. A planned plant will have two dry-cooled 150 MWe CFBC units and the potential to expand this to 800 MWe is also being considered (Baruya and Kessels, 2013).

## 10 Commentary and recommendations on appropriate technologies for Southern Africa

It was announced by the Science and Technology Minister last autumn that the latest power shortages that had been a feature for over a year had been eliminated, while, at the same time, additional households had been connected to the grid. The improvement in supplied power was attributed to an improved maintenance strategy by Eskom. The company's two new large supercritical coal-fired power plant projects, consisting of six units each of 800 MW, at Medupi and Kusile, although delayed, are also gradually commissioning. It was reported that Medupi unit 6 had reached commercial operation, and unit 5 had been synchronised, with commercial operation set for 2017 (Energycentral, 2016). Notwithstanding the above, there is a continuing need for extra generating capacity due to demand growth. For even higher efficiency, future plants with ultra-supercritical steam parameters could and should be ordered that would use the domestic coals currently used in the country.

The new NO<sub>x</sub> and particulates limits for South African plants are not excessively demanding. Combinations of combustion measures should be adequate for meeting the 2020 limit of 750 mg/m<sup>3</sup> at 10% O<sub>2</sub> (1020 mg/m<sup>3</sup> at 6% O<sub>2</sub>). For example, a study for the IEA by the author in 2006-07 showed the Majuba plant's NO<sub>x</sub> emissions at 600 mg/m<sup>3</sup> at 6% O<sub>2</sub> at that time, which was easily within the new 2020 limit while particulates were said to be already at 50 mg/m<sup>3</sup> (37 mg/m<sup>3</sup> at 10% O<sub>2</sub>) at that time, and so within the 50 mg/m<sup>3</sup> limit at 10% O<sub>2</sub> (IEA, 2007). Nevertheless, derogations till 2020 have been agreed for a large number of Eskom's plants under the existing plant requirements for NO<sub>x</sub> and particulates (News Channel Africa, 2015). The NO<sub>x</sub> postponements were granted to locations where installation of modern low NO<sub>x</sub> burners was still not complete.

Meeting the SO<sub>2</sub> limits will require some form of FGD. Keeping to typical design coal sulphur levels of around 1% would require about 70% removal, while worst coals, with approaching 2% sulphur contents, would need more than 85% removal. Wet FGD, spray dry scrubbers or post-combustion circulating dry scrubbers would meet these requirements, but not dry sorbent injection. The dry multi-control ReACT™ system would be very effective but is expensive and not necessary for the South African situation.

It has already been commented that wet FGD scrubbers are best suited economically to new or nearly new power units because of the high costs. The prepared coal from the Grootegeluk opencast mine that is supplied to Medupi is believed to have a sulphur content of around 0.95% ar (XMP, nd). It is reported that all the Medupi units will have wet FGD retrofitted and that the first FGD system will be retrofitted in 2021. To meet the extra water demand, a water augmentation project is being developed. Incorporating flue gas cooling at the FGD inlets has been suggested for consideration as a way to reduce water requirements there (Eng News, 2016).

The Kusile units will also have wet FGD (Daily Maverick, 2015; ABB, nd) to comply with the new emission limit. FGD is anyway required because the Kusile plant is in the Greater Witbank where, according to Eskom, existing atmospheric pollution is perceived to be a challenge (MPS, 2009). Mercury capture co-benefit



should ensue at these plants, and can be enhanced if necessary by adding systems such as bromide addition, which is inexpensive, effective, and readily installed.

Delay in adding acid gas removal systems at existing plants is delaying the co-benefit of reductions of trace emissions, such as mercury, which can be reduced significantly by any of the desulphurising systems that are likely to be used to meet the emission limits. Again, adding systems such as bromide addition could be readily done if necessary.

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