SELECTION OF AIR POLLUTION CONTROL TECHNOLOGIES FOR POWER PLANTS, GASIFICATION AND REFINING PROCESSES

By

Larey-Marié van Greunen

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Submitted in partial fulfilment of the requirements for the degree

MASTER OF ENGINEERING
(Environmental Engineering)

in the
Faculty of Engineering, Built Environment and Information Technology

University of Pretoria

December 2005

Declaration by Student

I, LAREY-MARIÉ VAN GREUNEN, hereby declare that the work as contained in this document was compiled and set out by myself and it has not been submitted to any other university.

SIGNED ON THE ____________ DAY OF DECEMBER 2005.

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LAREY-MARIÉ VAN GREUNEN

To Anna-Mart

Thank you for inspiring me

ACKNOWLEDGEMENTS

I would like to thank God, my heavenly Father, without Him I probably would have given up long ago. Thank you for the privilege to learn and work in a field that gives me great joy and for opening up my eyes to the greatness of your creation.

Thank you Mom and Dad, for your continuous support, encouragement and love over the past six years. I would not be the person I am today or achieved what I have achieved without your continuous input in my life.

Thank you Julian and Jacques, for always being there, and for your patience when I did not always understand when you were trying to explain.

To all my friends, thank you for just being there and for the unknowing support that you provided.

Lastly I would like to thank Francois for making this thesis possible and for always reminding me that life is easy.

Selection of air pollution control technologies for power plants, gasification and refining processes

Author: L van Greunen
Supervisor: JFC Friend
Department: Chemical Engineering
Degree: MEng (Environmental Engineering)

SYNOPSIS

Air quality legislation in South Africa is entering a transformation phase, shifting the concept of atmospheric emission control towards pollution prevention and emission minimisation through a more integrated approach. This transformation, along with public pressure and increased foreign trade, is providing industries with incentives to consider their effect on the environment and to take action where required. To assist South African industries in determining what air pollution control technologies are best suited to power plants, gasification and refining processes in South Africa; an assessment of air pollution control technologies used in other countries was carried out. This assessment concluded that the best available technologies for power plants to control air emissions are electrostatic precipitators, low-NO_x burners, selective catalytic reduction systems and wet flue gas desulphurisation (limestone) systems. For gasification processes it was found that the main air pollution contributor is the gas handling and treatment process. Releases from this process are controlled through dust collection, wet scrubbing, conversion of sulphide compounds, sulphur recovery and the incineration of final vent gases before release to the atmosphere. For refining processes the catalytic cracking unit is normally the largest single air emission source and controlling emissions from this unit avoids controlling multiple minor sources. Emissions from this unit are controlled via wet scrubbing, selective catalytic reduction systems and carbon monoxide boilers. An assessment of the financial effects associated with air pollution control at power plants was conducted by completing a cost analysis. This analysis demonstrated that by increasing capital expenditure on control technologies by R 1,7 billion, the external costs associated with producing electricity can be reduced by almost R 3,4 billion. Formulation of external cost factors for South African conditions, and the development of a software database for the information obtained from the different countries, will promote future technology selections.

KEYWORDS: air pollution control technology, power plant, gasification process, refining process, cost analysis, external costs

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ABBREVIATIONS

APPA	Atmospheric Pollution Prevention Act
AQA	Air Quality Act
EU	European Union
BAT	Best Available Techniques
IPPC	Integrated Pollution Prevention and Control
BREF	Best Available Technique Reference
IPC	Integrated Pollution Control
EA	Environmental Agency
BATNEEC	Best Available Techniques Not Entailing Excessive Cost
UK	United Kingdom
PPC	Pollution Prevention and Control
USA	United States of America
CAA	Clean Air Act
USEPA	United States Environmental Protection Agency
CAAA	Clean Air Act Amendments
NSR	New Source Review
RACT	Reasonable Available Control Technology
BACT	Best Available Control Technology
LAER	Lowest Achievable Emission Rate
RBLC	RACT/BACT/LAER/ Clearinghouse
ESP(s)	Electrostatic precipitator(s)
FGD	Flue gas desulphurisation
LSFO	Limestone forced oxidation
LEA	Low-excess-air firing
FGT	Flue gas treatment
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
FCC	Fluidised catalytic cracker
LDAR	Leak detection and repair programme
EEGECOST	Environmental Engineering Group environmental costing model
LCA	Life cycle assessment
TCA	Total cost assessment
DEC	Delivered equipment cost
TIC	Total installed cost

NOMENCLATURE

PM	particulate matter
SO_x	sulphur oxides
SO_2	sulphur dioxide
SO_3	sulphur trioxide
NO_x	nitrogen oxides
N_2	nitrogen
O_2	oxygen
NO	nitrogen oxide
NO_2	nitrogen dioxide
VOC(s)	volatile organic compound(s)
CO_x	carbon oxides
CO	carbon monoxide
NH_3	ammonia
H_2SO_4	sulphuric acid
HCl	hydrogen chloride
HF	hydrogen fluoride
H_2	hydrogen
H_2O	water
COS	carbonyl sulphide
CS_2	carbon disulphide
NaOH	sodium hydroxide
KOH	potassium hydroxide
A	nett plate area [m^2 or ft^2]
Q	volumetric gas flow rate [m^3/min or ft^3/min]
η	collection efficiency
w_e	drift velocity [m/min or ft/min]
P	purchase cost
a,b	constants used calculations
DEC	delivered equipment cost
TIC	total installed cost
CI	cost index
C	capacity of equipment
V	maximum filtering velocity [m/min or ft/min]
GCA	gross cloth area [m^2 or ft^2]
BBP	basic baghouse price
SSA	stainless-steel add-on
BP	bag price

CHAPTER 1

Introduction

Since 1965 air pollution in South Africa was controlled according to the Atmospheric Pollution Prevention Act (No 45 of 1965). This legislation had a source-based approach to emission control that did not take into account the receiving environment and did not sufficiently manage air quality; resulting in the development of air pollution hot spots, amongst others. In order to address these shortcomings the new Air Quality Act (or National Environment Management Act: Air Quality) was promulgated in 2005, thereby effectively replacing the old Air Pollution Prevention Act. The new Air Quality Act will present new challenges to South African companies, as the approach to air pollution control is completely different from the previous Air Pollution Prevention Act, focusing on ambient air quality rather than emission controls. Companies will therefore have to consider how this new approach affects their planning for air pollution control on new projects, as well as existing ones; as the new act will impose far stricter regulations on companies and far heftier fines for noncompliance than have ever been in place before.

One problem faced in South Africa, when compared to developed countries where similar air quality regulations have been imposed, is the lack of resources available to the Government and Agencies responsible for air quality issues. However, even though local government has done little in the way of monitoring air pollution or enforcing legislation, South African industries are acquiring more foreign shareholders and are trading more often on foreign markets. Since these markets require certain environmental standards, it provides incentives for South African industries to consider their effect on the environment and to take action where required.

For South Africa to successfully implement the new act, it is important that knowledge is gained from other countries on what practices have proven most successful and require the least resources to implement, so that these can be adopted by South African industries.

The objectives of this investigation are to:

- assess current literature available on Reasonable Available Control Technology (RACT), Best Available Technique (BAT) and control technologies used by industries in other counties;
- identify the best available practices for power plants, gasification and refining processes; and
- conduct a cost benefit analysis for a power plant to assess the impact of implementing selected air pollution control technologies on external costs associated with power plants.

A literature study in Chapter 2 will critically evaluate RACT, BAT and control technologies used by industries in the United States, the United Kingdom and other European countries. The best practices that are related to power plants, gasification and refining processes will be sourced out in Chapter 3, with a cost benefit analysis on the identified practices for a power plant completed in Chapter 4. Final conclusions and recommendations based on this investigation will be presented in Chapter 5.

CHAPTER 2

Literature Survey

2.1 AIR POLLUTION LEGISLATION IN SOUTH AFRICA

The Atmospheric Pollution Prevention Act (Act No. 45 of 1965), also known as APPA, has been used to control air pollution in South Africa since the mid 1960's. APPA was based on the 1915 British legislation (Groenewald, 2005) and used a source-based approach to emission control (Mabalane, 2005). It exercised source control mainly on industrial sources and was confined to the 72 scheduled processes listed in Schedule 2 of the act. No formal ambient air emission limits or standards were established (Kornelius, 2005) and there was a lack of compliance, enforcement mechanisms and transparency during decision-making. APPA has also long been outdated in terms of the roles of provincial and local government (Joubert, 2005).

With the publishing of a notice on 11 September 2005 in the Government Gazette, most sections of the new National Environmental Management: Air Quality Act (AQA) are brought into effect – exactly four years after its first draft was conceived (DEAT, 2005). However, the most important sections have not yet been brought into effect.

AQA defines a new approach to air quality management in South Africa, shifting the concept of atmospheric emission control towards pollution prevention, emission minimisation, cross-media integration, vertical and horisontal integration in institutions and spheres of Government, and the involvement of all sectors of society in air quality management (Mabalane, 2005). The AQA will impose far stricter regulations on companies and far heftier fines for non-compliance than have ever been in place before (Kornelius, 2005).

AQA will present new challenges to South African companies, as the approach is completely different from APPA. Companies will thus have to consider how this new approach affects their planning for air pollution control on new projects, as well as existing plants. (Kornelius, 2005)

2.2 INDUSTRIAL AIR POLLUTION CONTROL IN THE EUROPEAN UNION

In the European Union (EU) control of industrial air pollution is accomplished through the use of Best Available Techniques (BAT), as recommended by the Integrated Pollution Prevention and Control (IPPC) directive EC/96/61 (Hafker, Poot and Quedeville, 2003).

The IPPC directive (EC/96/61) requires member states of the EU to issue operating permits to certain installations carrying on industrial activities. The purpose of the directive is to introduce a more integrated approach to pollution control from industries. The directive promotes the use of BAT for reducing emissions of specified pollutants and is already in force for new installations, as well as for significant modifications or upgrades. However it does not apply to existing installations until October 2007. (Hafker *et al.*, 2003)

The directive states that to achieve the required level of protection of the environment, Best Available Techniques (BAT) is to be used. BAT is not a fixed concept and in any particular case, BAT has to be determined taking into account a number of factors, including cost and benefit. (Hafker *et al.*, 2003)

The directive requires that a process of information exchange takes place between the main stakeholders. The outcome of this exchange is the production of a Best Available Technique Reference (BREF) document for each major industrial sector. These documents are intended to give guidance to regulators on each sector and its emissions, the levels of pollution abatement achievable, the cross-media implications, energy use, costs, etc. (Hafker *et al.*, 2003)

Best Available Technique Reference documents for, *inter alia,* large power plants, large volume organic chemical industries and mineral oil refineries are available from the European IPPC Bureau (European IPPC Bureau, 2005b).

2.3 INDUSTRIAL AIR POLLUTION CONTROL IN THE UNITED KINGDOM

The Environmental Protection Act of 1990 established the Integrated Pollution Control (IPC) regulations, which resulted in the formation of the United Kingdom's Environmental Agency (EA). The EA controlled industrial air pollution by using Best Available Techniques Not Entailing Excessive Cost (BATNEEC), as described in the Chief Inspectorate's guidance notes (Kornelius and Munn, 2002). Currently the system in the United Kingdom is undergoing considerable changes as a result of the directives being issued by the EU that have to be adopted by member states.

At present an authorisation is required before an industrial plant can be operated. When considering an application for authorisation, an EA inspector will take local conditions into account before deciding on the applicable BATNEEC, whereafter the EA is obliged to issue a permit/license if all of its technical requirements are met. (Kornelius and Munn, 2002)

The Chief Inspector's guidance notes are issued by the Chief Inspector of Her Majesty's Inspectorate of Pollution (HMIP) for processes prescribed by the IPC regulations. The notes serve as a guide to inspectors on standards and techniques during their assessment of an application for, or variation of, an authorisation. The notes provide guidance on the best available techniques and standards without any consideration of the site-specific issues. Guidance is given on the achievable release levels for new processes, applying the best combination of techniques to limit environmental impacts. (HMIP, 1995a)

In order to comply with the EU directive EC/96/61, the UK government passed the Pollution Prevention and Control (PPC) regulations during 2000 (effective from 1 August 2000). These regulations are superseding the provisions of IPC sector-by-sector, using a transitional timetable concluding in 2007. The PPC regulations relate to installations in England and Wales and create a coherent new framework to prevent and control pollution from certain industrial activities and introducing the concept of BAT to environmental regulations. As a consequence the Chief Inspector's guidance notes are being gradually superseded by PPC guidance produced by the EA. (DEFRA, 2005)

Chief Inspector’s guidance notes are available from the United Kingdom’s Environmental Agency for, *inter alia,* power plants, gasification and refining processes. However, at present there is no final PPC guidance available for refineries or other similar sectors. These PPC guidance documents are currently in a consultation phase. Therefore, Chief Inspector’s guidance notes, based on the IPC regulations in these sectors, are still in use. (Demain, 2005)

2.4 INDUSTRIAL AIR POLLUTION CONTROL IN THE USA

Industrial air pollution is controlled in the United States of America (USA) through the Clean Air Act (CAA) of 1977 and its 1990 Amendments. The act is enacted through the work of the United States’ Environmental Protection Agency (USEPA).

The 1990 Clean Air Act Amendments (CAAA), the first major revision of the 1977 CAA, was signed in November 1990. One of the major breakthroughs of the 1990 CAA is a permit programme for larger sources that release pollutants into the air. Permits are issued by states or, when a state fails to carry out the CAA satisfactorily, by USEPA. The permit includes information on which pollutants are being released, how much may be released, and what kinds of steps the source's owner or operator is taking to reduce pollution, including plans to monitor the pollution. Businesses seeking permits have to pay permit fees, the money from the fees help pay for state air pollution control activities. (USEPA, 1993a)

In passing the CAA in 1977, the USA congress included a "grandfathering" loophole that allowed older power plants to avoid meeting the modern pollution control standards that new facilities had to adopt. Such a loophole was permitted with the expectation that these "grandfathered" facilities would soon retire and be replaced by cleaner, newer plants. However, the majority of these older plants are still in operation today. In an effort to limit the abuse of the "grandfathering" loophole congress created a key provision in the CAA known as "New Source Review" (NSR). This provision treats "grandfathered" power plants as "new sources" when they expand or significantly modify their facilities. It requires them to either prevent additional pollution by offsetting any increases with reductions in other sources at the same plant site, or obtain a clean air permit demonstrating that the best available pollution control technology has been installed. The NSR is triggered only when plants expand capacity or significantly modify their facilities. (Sierra Club, 2005)

The RBLC database, also known as the RACT/BACT/LAER clearinghouse database, was established by the USEPA to provide a central database of air pollution control technology information. The terms RACT, BACT and LAER are acronyms for different programme requirements under the NSR provision and are defined as (USEPA, 2005a):

- Reasonably Available Control Technology (RACT) is required on existing sources in areas that are not meeting National Ambient Air Quality Standards (NAAQS) (non-attainment areas).
- Best Available Control Technology (BACT) is required on major new or modified sources in clean areas (attainment areas).
- Lowest Achievable Emission Rate (LAER) is required on major new or modified sources in non-attainment areas.

The RBLC database includes past RACT, BACT and LAER decisions contained in NSR permits. The RBLC database promotes sharing of information between permitting agencies and assists in future permit determinations. The RBLC permit database contains over 5 000 determinations that assist in identifying technologies to mitigate most air pollutant emission streams. (van der Walt, 2005; USEPA, 2005a)

Information available from the RBLC database is not as comprehensive as the information from the EU and the UK, since the information in the database is not a complete set of guidelines. However, the information might be considered more valuable as the database supplies actual records of identified air pollution control technologies already used.

2.5 AIR POLLUTANTS

There is a vast number of air pollutants associated with industries, each having certain pollutants in higher concentration than others. Air pollutants from industries vary depending on the product, the process and even the geography of the particular industry. The following air pollutants are discussed regardless of product or process, as most major industries emit high amounts of these pollutants.

2.5.1 Particulate matter

Particulate matter (PM) are very-small-diameter solids or liquids, it includes dust, dirt, soot, smoke and liquid droplets. PM-10 refers specifically to particulate matter less than 10 µm in diameter. PM are caused by either materials-handling processes, combustion processes or through gas conversion reactions between other pollutants. Sources of PM include industrial processes, power plants (oil-, gas- and coal combustion), motor vehicles, unpaved roads and other smaller forms of fuel combustion. (Cooper and Alley, 2002; USEPA, 2005b)

PM can affect visibility (smog and haze), can cause damage to buildings and other materials through erosion and corrosion, and can also lead to alterations in local weather patterns. Scientific studies have also shown that PM could be responsible for a wide variety of health problems, ranging from aggravated asthma, chronic bronchitis, decreased lung function and premature death. (Cooper and Alley, 2002; USEPA, 2005b)

2.5.2 Sulphur oxides

Sulphur oxides (SO_x) are formed when sulphur or any material containing sulphur is combusted. Sources of SO_x include fossil-fuel power plants, petroleum refining and nonferrous metal smelting, with the greatest contributor being fossil-fuel combustion. (Cooper and Alley, 2002; USEPA, 2005b)

Sulphur dioxide (SO_2) makes up the most part of SO_x emissions but sulphur trioxide (SO_3) is also formed. Both SO_2 and SO_3 dissolve readily in water, and form acids when hydrolysed with water. These acids can have serious effects on the environment such as corrosion, damaged crops and forests, changes in soil makeup, and acidity of lakes and rivers. Other effects include reduced visibility due to the formation of smog and haze. SO_2 is also associated with human health problems. Children, the elderly and people with existing respiratory and heart disorders are more at risk from the effects of SO_2. The effects of SO_2 are intensified in the presence of other pollutants like PM by forming tiny sulphate particles - these particles are associated with increased respiratory symptoms and disease, difficulty in breathing and premature death. (Cooper and Alley, 2002; USEPA, 2005b)

2.5.3 Nitrogen oxides

Nitrogen oxides (NO_x) are a group of gases containing nitrogen and oxygen in varying amounts. NO_x are formed at high temperatures when nitrogen (N_2) and oxygen (O_2), both present in air, combine to form nitrogen oxide (NO) and nitrogen dioxide (NO_2) during the combustion of fuel in the presence of air. Organically bound nitrogen present in fuels also contributes to total NO_x emissions. Main sources of NO_x include motor vehicles, power plants, and other industrial, commercial and residential sources that burn fuels. Bacterial processes present in soil can also contribute to total NO_x. (Cooper and Alley, 2002; USEPA, 2005b)

NO_x emissions lead to smog formation and can damage crops and forests. Increased NO_x loading to water bodies can lead to chemical imbalances of nutrients present in water, and the additional nitrogen also accelerates eutrophication. As with SO_x, NO_x dissolve readily in water in the atmosphere to form acids, which fall to earth as rain, fog, snow or dry particles. NO_x also acts as a greenhouse gas. Human health effects associated with NO_x include problems associated with the respiratory system, damage to lung tissue and premature death. Small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory diseases such as emphysema and bronchitis, and aggravate existing heart disease. (Cooper and Alley, 2002; USEPA, 2005b)

2.5.4 Volatile organic compounds

Volatile organic compounds (VOCs) are organic compounds with appreciable vapour pressures, they are emitted as gasses from certain solids and liquids. VOCs make up a large part of emitted air pollutants, it includes pure hydrocarbons, partially oxidised hydrocarbons (organic acids, aldehydes, ketones), as well as organics containing chlorine, sulphur, and nitrogen. VOCs therefore represent a class of pollutants consisting of hundreds of compounds. Sources of VOCs include combustion processes, solvent evaporation, refining and handling of petroleum, surface coating operations and the paint and coating industry. (Cooper and Alley, 2002; USEPA, 2004)

Health effects will depend on the specific VOC compound exposure. Symptoms experienced shortly after exposure include headaches, dizziness, visual impairment and eye and respiratory tract irritation. Long-term exposure could result in cancer, liver, kidney and central nervous system damage. VOCs also play an important part in the formation of photochemical oxidants such as ozone (O_3). Photochemical oxidants are formed in the ambient atmosphere by a complex series of reactions that involve NO_x and VOCs. Oxidants like O_3 can lead to severe eye and respiratory tract irritation, and the deterioration of paints, rubbers and other materials. Leaf discolouration and cell collapse in plants are also associated with oxidant exposure. (Cooper and Alley, 2002; USEPA, 2004)

2.5.5 Carbon monoxide

Carbon monoxide (CO) is a colourless, odourless, tasteless gas that is caused by the incomplete combustion of any carbonaceous fuel. With power plants and other large furnaces usually designed and operated to ensure near complete combustion, the major source of CO is from the transportation sector. However, residential heating accounts for a significant fraction of total CO emissions, as do certain industrial processes. (Cooper and Alley, 2002)

CO is essentially inert to plants or materials but can have significant effects on human health. CO reacts with the haemoglobin in blood to prevent oxygen transfer.

Depending on the concentration of CO and the time of exposure, effects on humans range from slight headaches to nausea to death. (Cooper and Alley, 2002)

2.6 AIR POLLUTION CONTROL TECHNOLOGIES

2.6.1 Fuel switching

PM, SO_x and NO_x emissions can be reduced by switching to cleaner fuels. Sulphur emissions are proportional to the sulphur content of the fuel and fuels containing organically bound nitrogen can contribute over 50% of the NO_x total emissions.

Natural gas used as fuel can emit 60% less NO_x than coal and virtually no PM or SO_x. Burning either low-sulphur oil, or low-sulphur coal, can also effectively reduce SO_x emissions. Oil-based processes and low-ash fossil fuels emit significantly less PM than coal-fired combustion processes with high ash content coal. Also, lighter distillate oil-based combustion results in lower levels of PM emissions than heavier residual oils. (World Bank, 1999)

2.6.2 Fuel cleaning

The most significant option for reducing the sulphur content of fuel is called beneficiation. Up to 70% of the sulphur in high-sulphur coal is in pyretic or mineral sulphate form, not chemically bonded to the coal. Coal beneficiation can remove 50% of pyretic sulphur and 20-30% of total sulphur (it is not effective in removing organic sulphur). Beneficiation also removes ash responsible for particulate emissions. This approach may in some cases be cost-effective in controlling emissions of SO_x, but it may generate large quantities of solid waste and acid wastewaters that must be properly treated and disposed off. (World Bank, 1999)

2.6.3 Cyclones

Cyclone separators are one of the most widely used of all industrial gas-cleaning devices. The main reasons for the widespread use of cyclones are that they are inexpensive to purchase, they have no moving parts, and they can be constructed to withstand harsh operating conditions. Typically, a particulate-laden gas enters tangentially near the top of the cyclone as shown schematically in Figure 2.1. Cyclones operate by creating a double vortex inside the cyclone body. The gas flow is forced into downward spiral simply because of the cyclone’s shape and the tangential entry. Centrifugal force and inertia cause the particles to move outward, collide with the outer wall, and then slide downward to the bottom of the device. Near the bottom of the cyclone, the gas reverses its downward spiral and moves upward in a smaller, inner spiral. The cleaned gas exists from the top and the particles exit from the bottom of the cyclone. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

Cyclones by themselves are generally not adequate to meet stringent air pollution regulations, they are however, ideal for use as precleaners for more expensive final control devices such as baghouses or electrostatic precipitators. Efficiency varies greatly with particle size and with cyclone design. Some manufacturers have advertised cyclones that routinely achieve 90% or greater efficiency for particles larger than 10 microns. The fine-dust-removal efficiency of cyclones is typically below 70%. Generally as efficiencies increase, capital and operating costs increase. Cyclone collectors can be designed for many applications, and they are typically categorised as either high efficiency, conventional, or high throughput. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

Advantages of using cyclones include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- low capital cost,
- ability to operate at high temperatures, and
- low maintenance requirements because there are no moving parts.

Disadvantages of using cyclones include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- low efficiencies especially for very small particles, and
- high operating costs due to pressure drop.

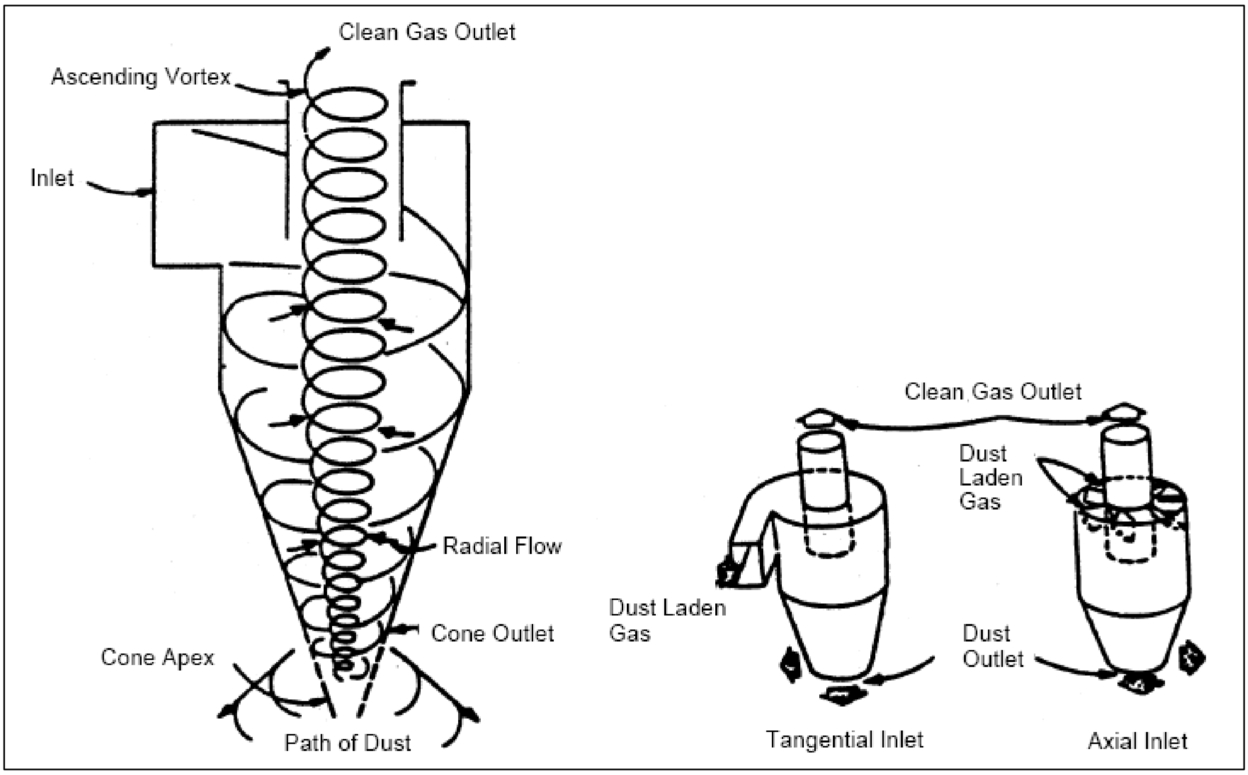

Figure 2.1 Schematic diagram of a typical cyclone.

(*Source:* USEPA, 1998b.)

2.6.4 Fabric filters

Fabric filtration is a well-known and accepted method for separating dry particles from a gas stream. In fabric filtration, the dusty gas flows into and through a number of filter bags placed in parallel, leaving the dust retained by the fabric. The fabric itself does some filtering of the particles, however, the fabric is more important in its role as a support medium for the layer of dust that quickly accumulates on it. The dust layer is responsible for the highly efficient filtering of small particles for which baghouses are known. Fabric filters are efficient (99,9% removal) for both high and low concentrations of particles; but are suitable only for dry and free-flowing particles. Their efficiency in removing toxic metals such as arsenic, cadmium, chromium, lead, and nickel is greater than 99%. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

The various types of filter media include woven fabric, needled felt, plastic, ceramic and metal. The operating temperature of the baghouse gas influences the choice of fabric. There are different ways of weaving them into various sizes of bags, different ways of configuring bags in a baghouse, and different ways of flowing the air through the bags. Extended operation of a baghouse requires that the dust be periodically cleaned of the cloth surface and removed from the baghouse. The three common types of baghouses, classified by the method used for cleaning the dust from the bags, are reverse-air (Figure 2.2.), shaker (Figure 2.3), and pulse-jet (Figure 2.4) baghouses. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

Advantages of using fabric filters include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- very high collection efficiencies even for small particles,
- operate on a wide variety of dust types,
- modular in design, and modules can be pre-assembled at the factory,
- operate over an extremely wide range of volumetric flow rates, and
- require reasonably low-pressure drops.

Disadvantages of using fabric filters include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- require large floor areas,
- fabrics can be harmed by high temperature or corrosive chemicals,
- cannot operate in moist environments, fabric can become “blinded”, and
- have potential for fire or explosion.

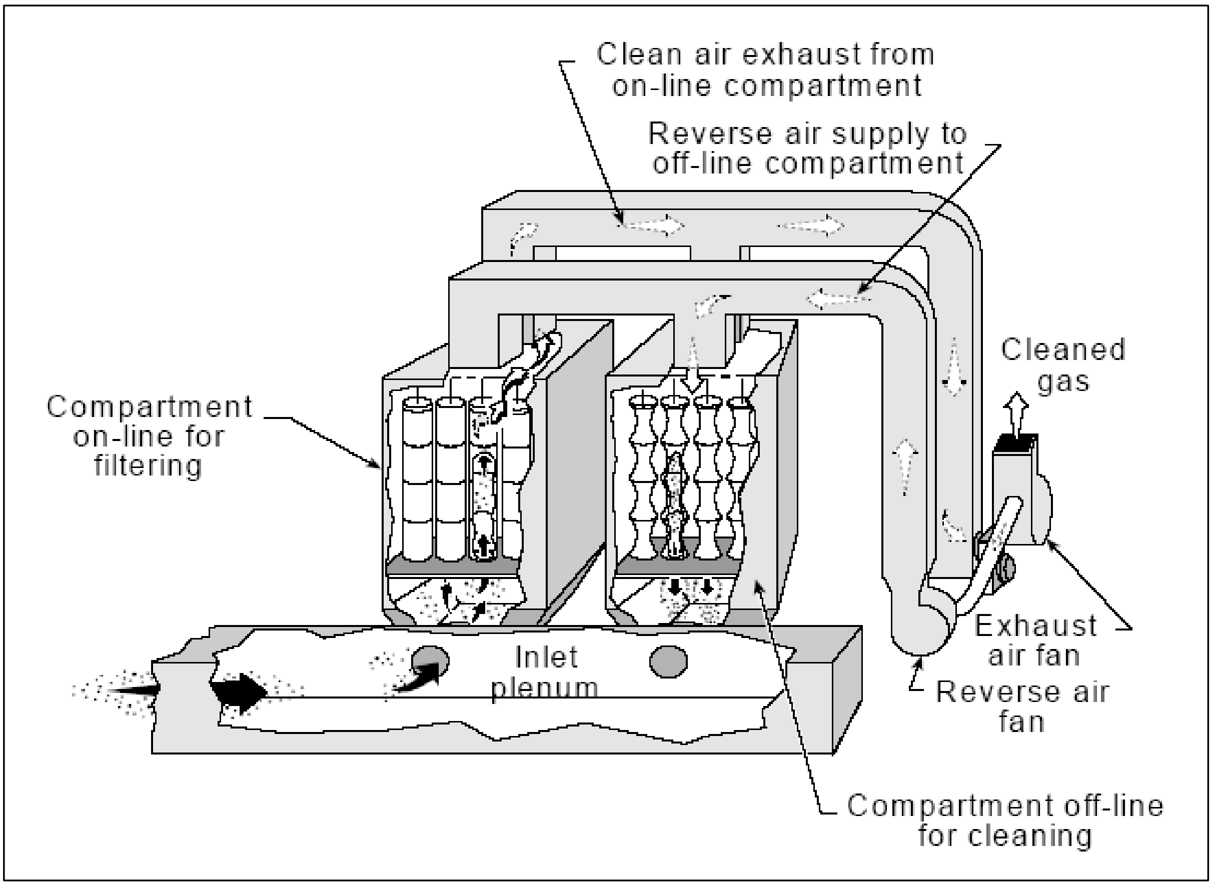

Figure 2.2 Typical reverse-air baghouse.

(*Source:* USEPA, 2002.)

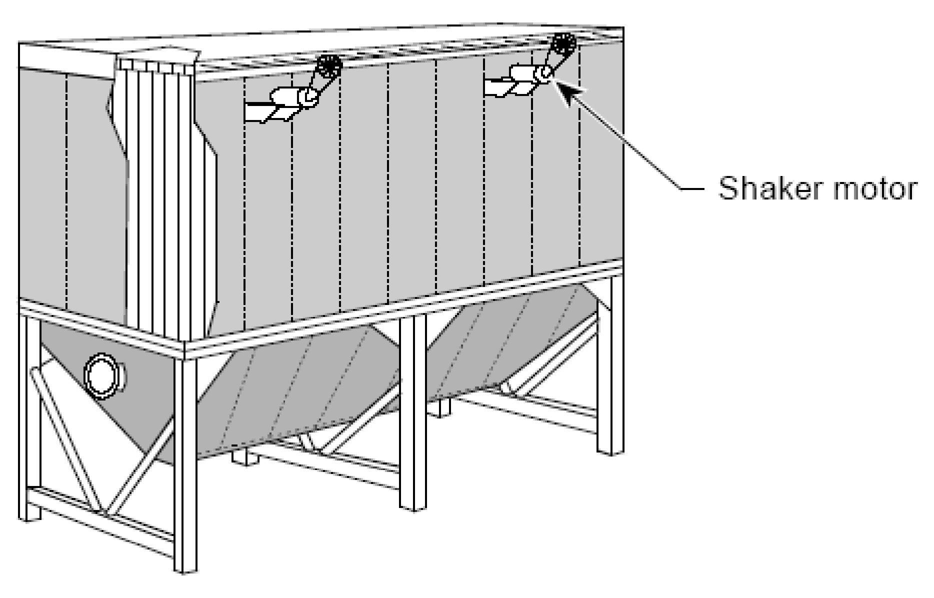

Figure 2.3 Typical shaker baghouse.

(*Source:* USEPA, 2002.)

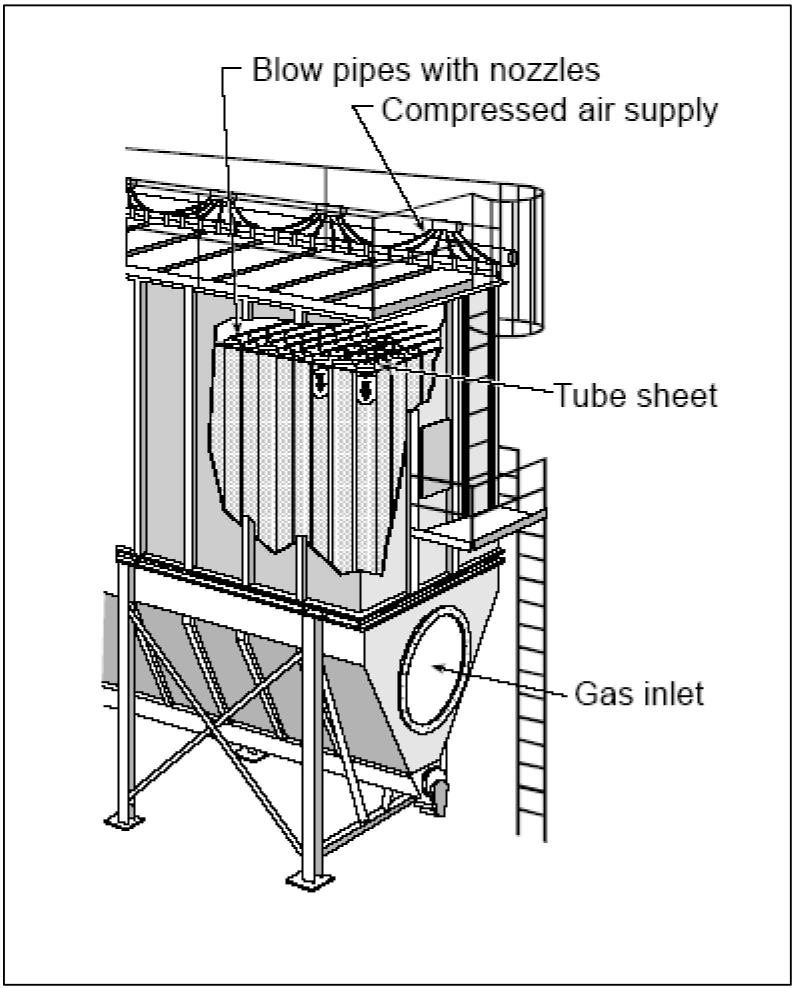

Figure 2.4 Typical pulse-jet baghouse.

(*Source:* USEPA, 2002.)

2.6.5 Electrostatic precipitators

The process of electrostatic precipitation involves the ionisation of contaminated air flowing between electrodes, the charging, migration, and collection of the contaminants (particles) on oppositely charged plates, and the removal of the particles from the plates. The particles can either be dry dust or liquid droplets. In an electrostatic precipitator (ESP), air flows through the unit and the particles are left behind on the plates (Figure 2.5). The particles are knocked off (rapped) or washed off the plates, and collected at the bottom of an ESP. Electrostatic precipitators are unique among air pollution control devices in that the forces of collection act only on the particles and not on the entire air stream. This phenomenon typically results in high collection efficiency with a very low air pressure drop. Modern ESPs have been designed for efficiencies greater than 99,9%. ESPs are especially efficient in collecting fine particulates and can also capture trace emissions of some toxic metals with an efficiency of 99%. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

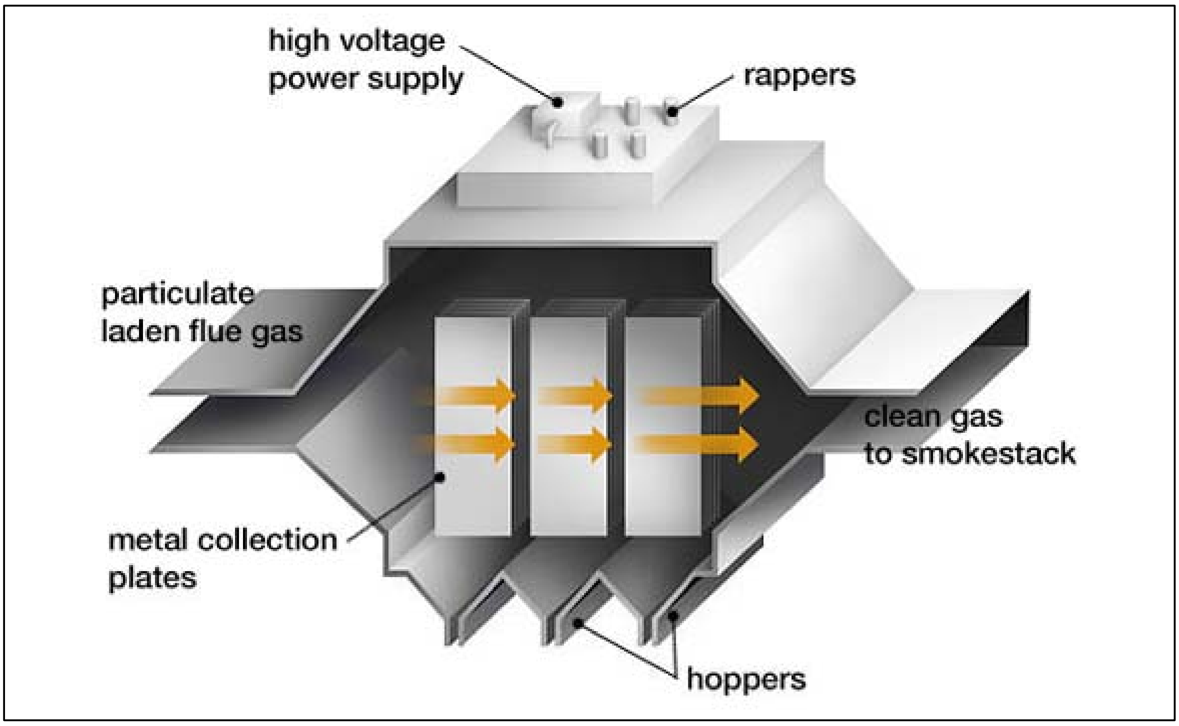

Figure 2.5 Schematic diagram of the side view of an electrostatic precipitator.

(*Source*: Dayley and Holbert, 2003.)

Electrostatic precipitators are generally divided into two broad groups, dry ESPs and wet ESPs. The distinction is based on what method is used to remove particulates from the collecting electrodes. In addition to wet and dry options, there are variations of internal ESP designs available. The two most common designs are wire-plate and wire-pipe collectors. Electrostatic precipitators are often designed with several compartments, to facilitate cleaning and maintenance. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

Lower sulphur concentrations in the flue gas can lead to a decrease in collection efficiency since it produces a high resistivity fly ash that is difficult to collect in an ESP. Under these circumstances flue gas conditioning can be applied when ESPs are not operating at design efficiencies. Flue gas conditioning can influence the electric field strength, ion density, adhesive and cohesive properties of the fly ash, particle size and particle size distribution; all of which affects the collection efficiency of an ESP. Common conditioning agents include sulphur trioxide (SO_3), ammonia (NH_3), ammonium compounds, organic amines and dry alkalis. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

Advantages of using ESPs include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- very high efficiencies, even for very small particles,
- can handle very large gas volumes with low pressure drop,
- dry collection of valuable materials, or wet collection of fumes and mists,
- can be designed for a wide range of gas temperatures, and
- low operating costs, except at very high efficiencies.

Disadvantages of using ESPs include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- high capital cost,
- will not control gaseous emissions,
- not very flexible, once installed, to changes in operating conditions,
- large space requirements, and
- might not work on particulates with very high electrical resistivity.

2.6.6 Wet scrubbers

Wet scrubbers are used in the control of particulates (see also Section 2.6.7) and rely on direct and irreversible contact of a liquid (droplets, foam, or bubbles) with the particulates. Scrubbers can be very specialised and designed in many different configurations. Wet scrubbers are generally classified by the method that is used to induce contact between the liquid and the particulates, for example, spray, packed-bed and plate scrubbers. Scrubbers are also often described as low-, medium-, or high-energy, where energy is often expressed as the pressure drop across a scrubber. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

The most common scrubber design is the introduction of liquid droplets into a spray chamber (Figure 2.6), where the liquid is mixed with the gas stream to promote contact with the particulates. In a packed-bed scrubber, layers of liquid are used to coat various shapes of packing material that become impaction surfaces for the particle-laden gas. Scrubber collection can also be achieved by forcing the gas at high velocities though a liquid to form jet streams. Liquids are also used to supersaturate the gas stream, leading to particle scrubbing by condensation. (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999)

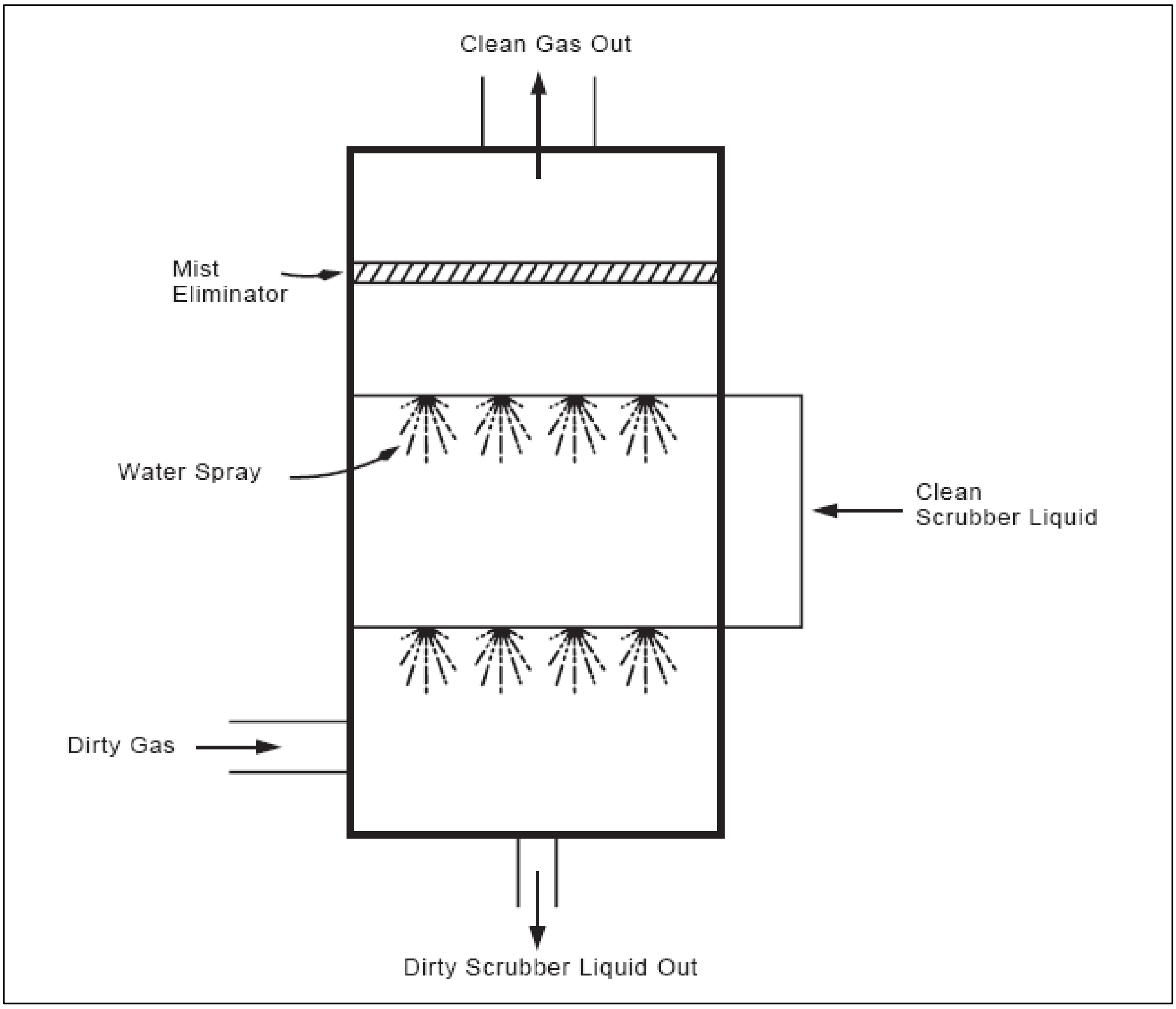

Figure 2.6 Schematic diagram of a spray chamber/tower.

(*Source:* USEPA, 2002.)

The various wet scrubbers that can be used include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- spray chambers/towers,
- packed-bed scrubbers,
- impingement plate scrubbers,
- mechanically-aided scrubbers,
- venturi scrubbers,
- orifice scrubbers,
- condensation scrubbers,
- charged scrubbers, and
- fibre-bed scrubbers.

Advantages of using wet scrubbers include (Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999):

- can handle flammable and explosive dusts with little risk,
- provides gas absorption and dust collection in a single unit,
- can handle mists,
- provide cooling of hot gases,
- collection efficiency can be varied, and
- corrosive gases and dusts can be neutralised.

Disadvantages of using wet scrubbers include(Cooper and Alley, 2002; USEPA, 1998a; World Bank, 1999).:

- high potential for corrosion problems;
- effluent liquid can create water pollution problems;
- protection against freezing required, off gas might require reheating to avoid visible plume;
- collected particulates may be contaminated and may not be recyclable; and
- disposal of waste sludge may be very expensive.

2.6.7 Flue gas desulphurisation

The flue gas desulphurisation (FGD) or SO_2 scrubbing process typically uses a calcium or sodium based alkaline reagent. The reagent is injected in the flue gas in a spray tower or directly into the duct. The SO_2 is absorbed, neutralised and/or oxidised by the alkaline reagent into a solid compound, either calcium or sodium sulphate. The solid is removed from the waste gas stream using downstream equipment. (USEPA, 2003a)

Scrubbers are classified as “once-through” or “regenerable”, based on how the solids generated by the process are handled. Once-through systems either dispose of the spent sorbent as a waste or utilise it as a by-product. Regenerable systems recycle the sorbent back into the system. At present, regenerable processes have higher costs than once-through processes, however, regenerable processes might be chosen if space or disposal options are limited and markets for by-products (for example, gypsum) are available. In 1998, approximately 3% of FGD systems installed in the USA were regenerable. Both types of systems, once-through and regenerable, can be further categorised as wet, dry, or semi-dry (USEPA, 2003a).

2.6.7.1 Wet systems

In a wet scrubber system, flue gas is ducted to a spray tower/chamber where an aqueous slurry of sorbent is injected into the flue gas (Figure 2.7). To provide good contact between the waste gas and sorbent, the nozzles and injection locations are designed to optimise the size and density of slurry droplets formed by the system. A portion of the water in the slurry is evaporated and the waste gas stream becomes saturated with water vapour. Sulphur dioxide dissolves into the slurry droplets where it reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator to remove any entrained slurry droplets, before exiting the absorber. The absorber effluent is sent to a reaction tank where the SO_2-alkali reaction is completed forming a neutral salt. In a regenerable system, the spent slurry is recycled back to the absorber. Once-through systems dewater the spent slurry for disposal or use as a by-product. (USEPA, 2003a)

Typical sorbent material is either limestone or lime. Limestone is very inexpensive but control efficiencies for limestone systems are approximately 90%. Lime is easier to manage on-site and has control efficiencies of up to 95%, but is significantly more costly. (USEPA, 2003a)

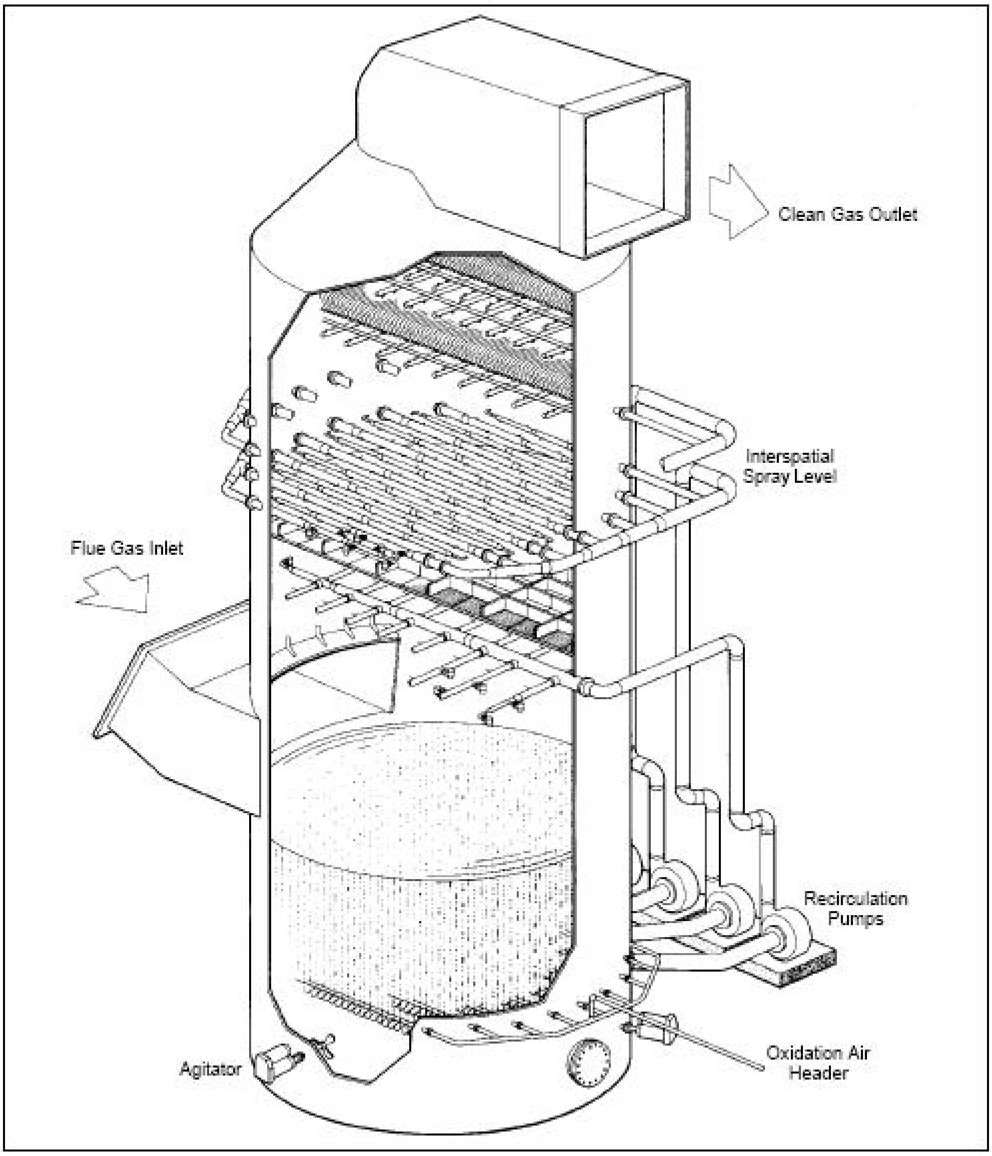

Figure 2.7 Wet flue gas desulphurisation absorber tower.

(*Source*: Nolan, 2000.)

Oxidation of the slurry sorbent causes calcium sulphate (gypsum) scale to form in the absorber. Limestone forced oxidation (LSFO) is a newer process based on wet limestone scrubbing that reduces scale. In LSFO, air is added to the reaction tank, which oxidises the spent slurry to gypsum. The gypsum is removed from the reaction tank prior to the slurry being recycled to the absorber. The recycled slurry has a lower concentration of gypsum and thus scale formation in the absorber is significantly reduced. Gypsum can be commercially sold, eliminating the need for land filling of the waste product. In addition to scale control, the larger size gypsum crystals formed in LSFO settle and dewater more efficiently, reducing the size of the by-product handling equipment. However, LSFO requires additional blowers, thereby increasing the capital and operating costs of the system. (USEPA, 2003a)

Wet limestone/lime scrubbing has high capital and operating cost due to the handling of liquid reagent and waste. Nonetheless, it is the preferred process for coal-fired power plants burning coal due to the low cost of limestone and SO_2 control efficiencies from 90% up to 98%. (USEPA, 2003a)

2.6.7.2 Semi-dry systems

Semi-dry systems, or spray dryers, inject an aqueous sorbent slurry similar to a wet system, however, the slurry has a higher sorbent concentration. As the hot flue gas mixes with the slurry solution, water from the slurry is evaporated. The water that remains on the solid sorbent enhances the reaction with SO_2. The process forms a dry waste product that is collected with a standard particulate collection device, such as a baghouse or electrostatic precipitator (ESP). The waste product can be disposed, sold as a by-product or recycled to the slurry. (USEPA, 2003a)

Various calcium and sodium based reagents can be utilised as sorbent. Spray dry chambers typically inject lime since it is more reactive than limestone and less expensive than sodium based reagents. The reagent slurry is injected through either rotary atomisers or dual-fluid nozzles, to create a finer droplet spray than wet scrubber systems. (USEPA, 2003a)

The performance of a lime spray dry scrubber is more sensitive to operating conditions. SO_2 control efficiencies for spray dry scrubbers are slightly lower than wet systems, between 80% and 90%. (USEPA, 2003a)

2.6.7.3 Dry systems

Dry sorbent injection systems pneumatically inject powdered sorbent directly into either the furnace, the economiser, downstream ductwork, or in a reaction chamber (Figure 2.8). The dry waste product is removed using particulate control equipment such as a baghouse or ESP. The flue gas is generally cooled prior to the entering the particulate control device. Water can be injected upstream of the absorber to enhance SO_2 removal (USEPA, 2003a).

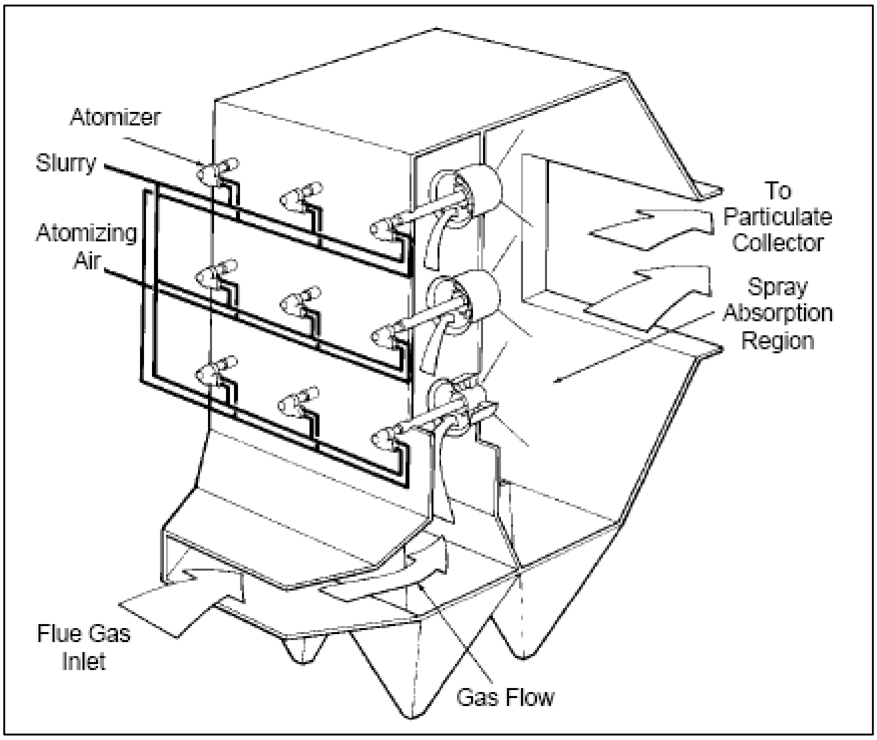

Figure 2.8 Dry scrubber module.

(*Source*: Nolan, 2000.)

Dry sorbent injection systems typically use calcium and sodium based alkaline reagents. A number of proprietary reagents are also available. A typical injection system uses several injection lances protruding from the furnace or duct walls. (USEPA, 2003a)

Dry scrubbers have significantly lower capital and operating costs than wet systems, because they are simpler, demand less water and waste disposal is less complex. Dry injection systems install easily and use less space, therefore, they are good candidates for retrofit applications. SO_2 removal efficiencies are significantly lower than wet systems, between 50% and 60% for calcium based sorbents. Sodium based dry sorbent injection into the duct can achieve up to 80% control efficiencies (USEPA, 2003a).

2.6.8 Combustion modifications

Combustion controls reduce NO_x formation by one or more of the following strategies (Cooper and Alley, 2002; World Bank, 1999):

- reduced peak temperatures of the flame zone,
- reduced gas residence time in the flame zone, and/or
- reduced oxygen concentration in the flame zone.

The preceding changes to the combustion process can be achieved by either modification of operating conditions on existing furnaces, or purchase and installation of newly designed (low-NO_x) burners and/or furnaces (Cooper and Alley, 2002; World Bank, 1999).

2.6.8.1 Modification of operating conditions

- *Low-excess-air firing* (LEA) is a very simple yet very effective technique. Owing to less-than-perfect mixing of air and fuel, there must be some excess air present at all times to ensure good fuel use and to prevent smoke formation. Currently, it is possible to achieve full combustion for coal-fired units with less than 15-30% excess air. (Cooper and Alley, 2002; World Bank, 1999)

- *Staged combustion* (off-stoichiometric combustion) burns the fuel in two or more steps. Staged combustion can be accomplished by firing some of the burners fuel-rich and the rest fuel-lean, by taking some of the burners out of service and allowing them only to admit air to the furnace, or by firing all the burners fuel-rich in the primary combustion zone and admitting the remaining air over the top of the flame.

Staged combustion techniques can reduce NO_x emissions by 20-50%. (Cooper and Alley, 2002; World Bank, 1999)

- *Flue gas recirculation* is simply the rerouting of some of the flue gas back to the furnace. Usually, flue gas from the economiser outlet is used, and so the furnace air temperature and the furnace oxygen concentration are reduced simultaneously. (Cooper and Alley, 2002; World Bank, 1999)

- *Gas reburning* or reburning is when 75-80% of the furnace fuel input is burned in the furnace with minimum excess air. The remaining fuel (gas, oil or coal) is added to the furnace above the primary combustion zone. The secondary combustion zone is operated substoichiometrically to generate hydrocarbon radicals that reduce the NO_x to N_2. The combustion process is then completed by adding the balance of the combustion air through an overfire air-port in a final burnout zone at the top of the furnace. (Cooper and Alley, 2002; World Bank, 1999).

- *Reduced air preheat and reduced firing rates* lower peak temperatures in the combustion zone, thus reducing thermal NO_x. This strategy, however, carries a substantial energy penalty. Emissions of smoke and CO need to be controlled, which reduces operational flexibility. (Cooper and Alley, 2002; World Bank, 1999)

- *Water injection* (or steam injection) can be an effective means of reducing flame temperatures, thus reducing thermal NO_x. (Cooper and Alley, 2002; World Bank, 1999)

2.6.8.2 Low-NOx burners

New low-NO_x burners (Figure 2.9) represent the most common equipment design change for reducing NO_x formation. Low-NO_x burners are not only effective on new power plants, but also can be readily applied to older facilities as retrofit projects. Low-NO_x burners limit the formation of NO_x by controlling the mixing of fuel and air, in effect automating low-excess-air firing or staged combustion. Compared with older conventional burners, low-NO_x burners reduce emissions of NO_x by 40-60%. (Cooper and Alley, 2002; World Bank, 1999)

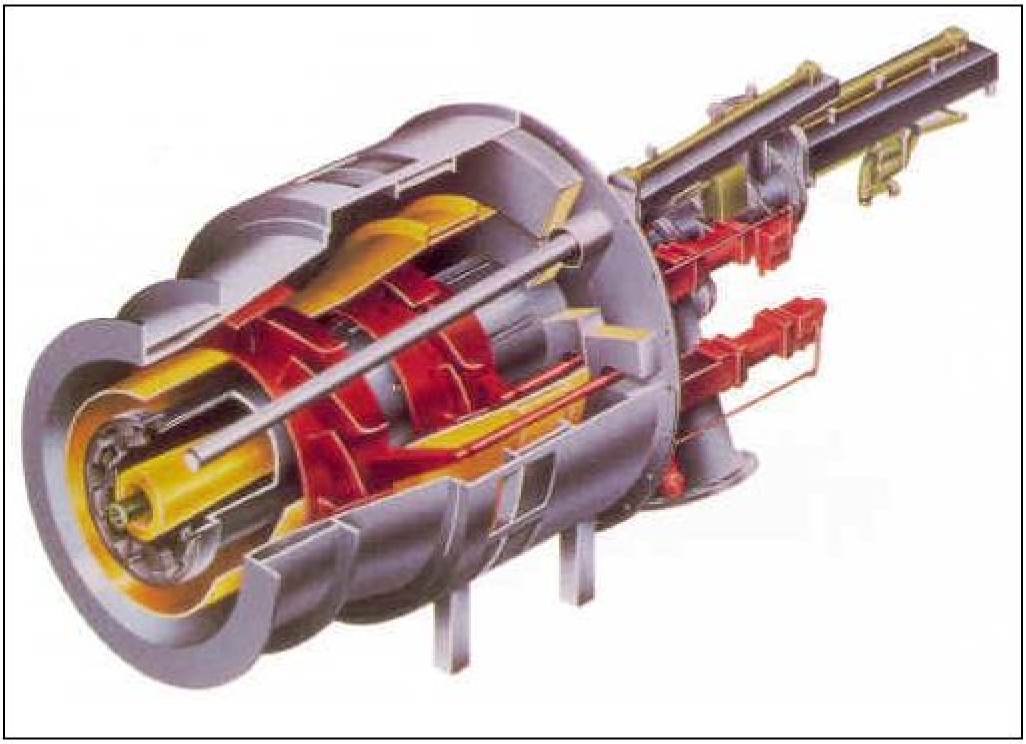

Figure 2.9 Schematic diagram of a low-NO_x burner.

(*Source:* NETL, 2004.)

2.6.9 Flue gas treatment techniques

Flue gas treatment (FGT) is more effective in reducing NO_x emissions than are combustion controls, although at a higher cost. FGT is also useful where combustion controls are not appropriate. FGT techniques are broadly classified as dry or wet techniques, the dry techniques include catalytic reduction, non-catalytic reduction, and adsorption, while the wet process is through absorption in a caustic scrubbing solution. (Cooper and Alley, 2002; World Bank, 1999)

2.6.9.1 Selective catalytic reduction

Selective catalytic reduction (SCR) is currently the most developed and widely used applied FGT technology. In the SCR process (Figure 2.10), ammonia (NH_3) is used as reducing agent to convert NO_x to nitrogen in the presence of a catalyst in a converter upstream of the air heater. The catalyst is usually a mixture of titanium dioxide, vanadium pentoxide and tungsten trioxide. SCR can remove 60-90% of NO_x from flue gases. Unfortunately, the process is very expensive, and the associated ammonia injection results in an ammonia (NH_3) slipstream in the exhaust. (Cooper and Alley, 2002; World Bank, 1999)

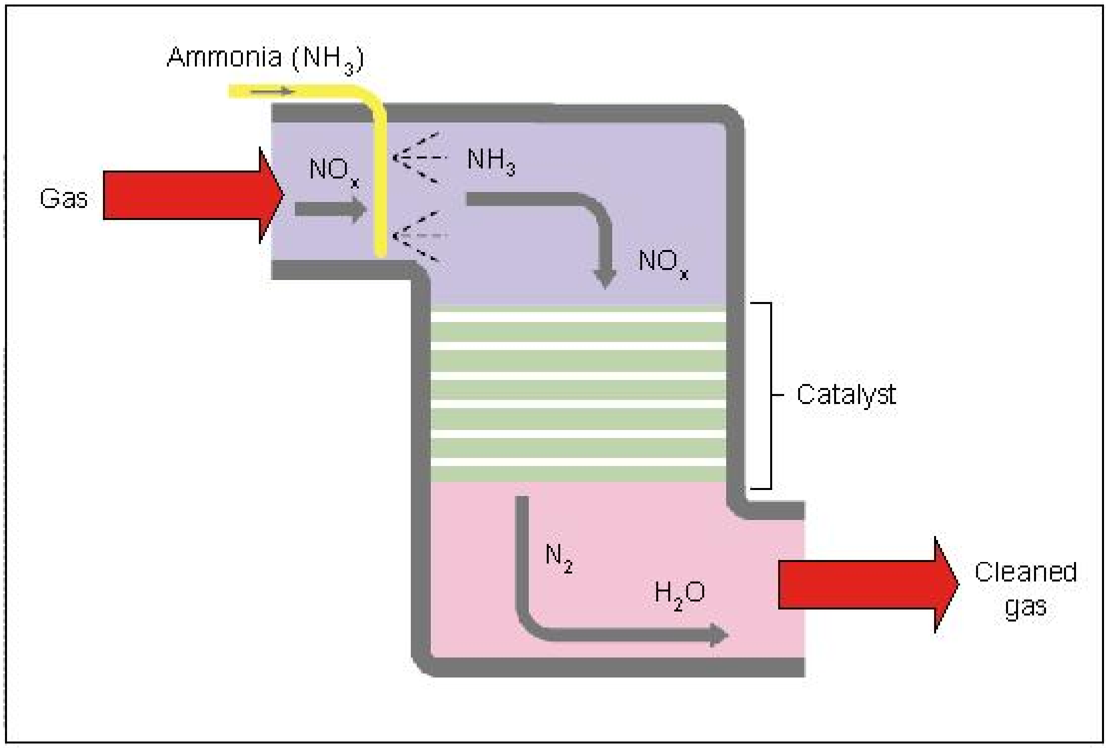

Figure 2.10 Schematic flow diagram of a selective catalytic reduction system.

(Adapted from Friend, 1995 and EPDC, 2004.)

2.6.9.2 Selective non-catalytic reduction

At temperatures of 900-1000ºC, NH_3 will reduce NO_x to N_2 without a catalyst. At NH_3:NO_x molar ratios of 1:1 to 2:1, about 40-60% NO_x reduction can be achieved. Potential problems with selective non-catalytic reduction (SNCR) include incomplete mixing of NH_3 with the hot flue gas and improper temperature control. If the temperature is too low, unreacted ammonia will be emitted, if the temperature is too high, NH_3 will be oxidised to NO. (Cooper and Alley, 2002; World Bank, 1999)

2.6.9.3 Adsorption

Several dry adsorption techniques have been proposed and demonstrated for simultaneous control of NO_x and SO_x. One type of system uses activated carbon with NH_3 injection, simultaneously reducing the NO_x to N_2 and oxidising the SO_2 to sulphuric acid (H_2SO_4). The activated carbon bed must be operated in the temperature range of 220-230ºC and must be regenerated to remove the H_2SO_4. (Cooper and Alley, 2002; World Bank, 1999)

Another adsorption system uses a copper oxide catalyst. The copper oxide adsorbs SO_2 to form copper sulphate. Both copper oxide and copper sulphate are reasonably good catalysts for the selective reduction of NO_x with NH_3. (Cooper and Alley, 2002; World Bank, 1999)

2.6.9.4 Wet absorption

Wet absorption or wet scrubbing processes usually remove SO_x as well as NO_x. The main disadvantage of wet absorption of NO_x is the low solubility of NO. Often the NO must be oxidised to NO_2 in the flue gas before a reasonable degree of absorption can occur in water. (Cooper and Alley, 2002)

2.6.10 Flares

Flaring is a VOC combustion control process in which the VOC are piped to a remote, usually elevated, location and burned in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for VOC destruction (>98%). Completeness of combustion in a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the gas stream components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all VOC are converted to carbon dioxide and water. Incomplete combustion results in some of the VOC being unaltered or converted to other organic compounds such as aldehydes or acids. (USEPA, 2003b)

Flares are generally categorised in two ways: (1) by the height of the flare tip (that is ground or elevated), and (2) by the method of enhancing mixing at the flare tip (for example, either steam-assisted, air-assisted, pressure-assisted, or non-assisted). Elevating the flare can prevent potentially dangerous conditions at ground level where, for example, the open flame (an ignition source) is located near a process unit. Elevating the flare also allows the products of combustion to be dispersed above working areas to reduce the effects of noise, heat, smoke and objectionable odours. In all combustion processes, good mixing and an adequate air supply are required to complete combustion and minimise smoke. The various flare designs differ primarily in their accomplishment of mixing. (USEPA, 2003b)

Steam-assisted flares are single burner tips, elevated above ground level for safety reasons (Figure 2.11). They account for the majority of the flares installed for industrial applications and are the predominant flare type found in refineries and chemical plants (USEPA, 2003b). To ensure good mixing and an adequate air supply, this type of flare injects steam into the combustion zone to promote turbulence for mixing and to introduce air into the flame. (USEPA, 2003b)

Advantages of using flares include (USEPA, 2003b):

- can be an economical way to dispose of sudden releases of large amounts of gas,
- in many cases do not require auxiliary fuel to support combustion, and
- can be used to control intermittent or fluctuating waste streams.

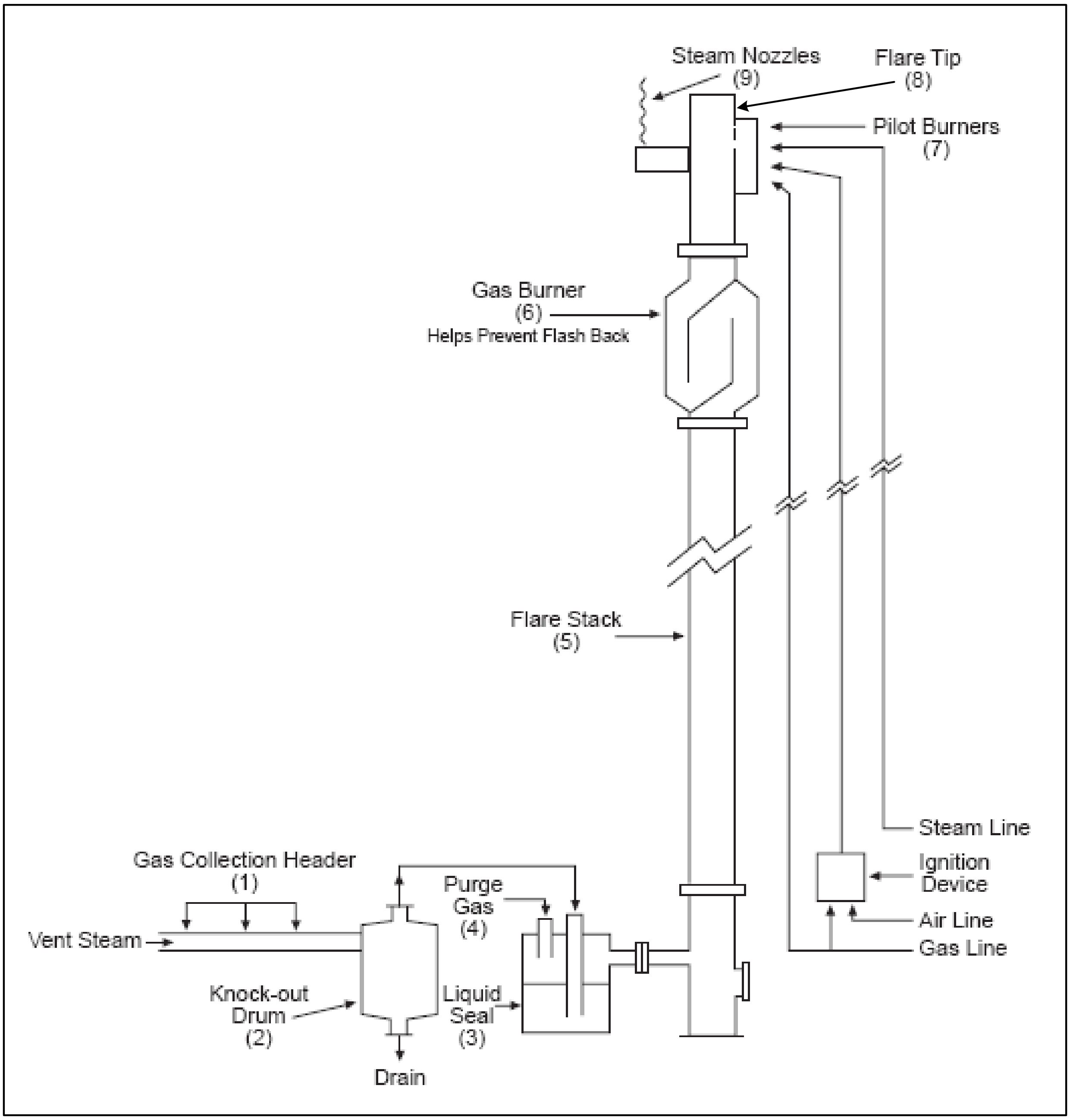

Figure 2.11 Steam-assisted elevated flare system.

(*Source:* USEPA, 2002.)

Disadvantages of using flares include (USEPA, 2003b):

- can produce noise, smoke, heat radiation and fugitive light (at night),
- can be a source of SO_x, NO_x and CO,
- cannot be used to treat waste streams with halogenated compounds, and
- released heat from combustion is lost.

2.6.11 Thermal incinerators

Incineration, or thermal oxidation, is the process of oxidising combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence, and the availability of oxygen all affect the rate and the efficiency of the combustion process. (USEPA, 2003c)

Thermal incinerators (also referred to as direct flame incinerators, thermal oxidisers, or afterburners) operate through a nozzle-stabilised flame that is maintained by a combination of auxiliary fuel, waste gas compounds and supplementary air, added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. The ignition temperature varies for different compounds and is usually determined empirically. (USEPA, 2003c)

The required level of VOC control of the waste gas that must be achieved, within the time that it spends in the thermal combustion chamber, dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. Studies based on actual field test data show that commercial incinerators should generally be run at 870ºC, with a nominal residence time of 0,75 seconds, to ensure a 98% destruction of non-halogenated organics. (USEPA, 2003c)

Advantages of using thermal incinerators include (USEPA, 2003c):

- incinerators are one of the best proven methods for destroying VOCs, with efficiencies up to 99,9999% possible, and
- thermal incinerators are often the best choice when high efficiencies are needed.

Disadvantages of using thermal incinerators include (USEPA, 2003c):

- thermal incinerator operating costs are relatively high due to supplemental fuel costs,
- they are not well suited to streams with highly variable flow (for example, increased flow conditions result in reduced residence time and poor mixing; which decreases

the completeness of combustion, causing the combustion chamber temperature to fall and thus decreasing the destruction efficiency), and

- incinerators are generally not recommended for controlling gases containing halogen- or sulphur-containing compounds, because of the formation of highly corrosive gases.

2.6.12 Catalytic oxidisers

Catalytic oxidisers (also referred to as catalytic incinerators or catalytic reactors) operate very similar to thermal incinerators, with the primary difference that the gas, after passing through the flame area, passes through a catalyst bed. The catalyst has the effect of increasing the oxidation reaction rate, enabling conversion at lower reaction temperatures than in thermal incinerator units. Catalysts, therefore, also allow for smaller incinerator size. Catalysts typically used for VOC incineration include platinum and palladium. Other formulations include metal oxides, which are used for gas streams containing chlorinated compounds. (USEPA, 2003d)

Advantages of using catalytic oxidisers include (USEPA, 2003d):

- lower fuel requirements,
- lower operating requirements,
- little or no insulation requirements,
- reduced fire hazard,
- reduced flashback problems, and
- less volume/size required.

Disadvantages of using catalytic oxidisers include (USEPA, 2003d):

- high initial cost,
- catalyst poisoning possible,
- particulates must often first be removed, and
- spent catalysts that cannot be regenerated may need to be disposed off.

2.6.13 Regenerative thermal oxidisers

Regenerative thermal oxidisers (also referred to as regenerative incinerators) use high density media, such as a ceramic-packed bed still hot from a previous cycle, to preheat an incoming VOC-laden waste gas stream. The preheated, partially oxidised gases then enter a combustion chamber where they are heated by auxiliary fuel combustion to a final oxidation temperature, typically between 760ºC and 820ºC. This temperature is maintained in order to achieve maximum VOC destruction. However, temperatures of up to 1 100ºC may be achieved, if required, for very high control efficiencies of certain toxic VOCs. The purified, hot gases exit this chamber and are directed to one or more different ceramic-packed beds cooled by an earlier cycle. Heat from the purified gases is absorbed by these beds before the gases are exhausted to the atmosphere. The reheated packed bed then begins a new cycle by heating a new incoming waste gas stream. Typical regenerative incinerator design efficiencies range from 95% to 99%. (USEPA, 2003f)

Regenerative incinerators offer many advantages for the appropriate application. High flow, low concentration waste streams that are consistent over long time periods can be treated economically. Pre-treatment to remove particulate matter may be necessary to prevent the packed bed from clogging. (USEPA, 2003f)

Advantages of using regenerative thermal oxidisers include (USEPA, 2003f):

- lower fuel requirements because of high energy recovery,
- high temperature capability provides better destruction,
- less susceptible to problems with chlorinated compounds, and
- generally lower NO_x emissions than thermal oxidation.

Disadvantages of using regenerative thermal oxidisers include (USEPA, 2003f):

- high initial costs,
- difficult and expensive installation,
- large size and weight, and
- high maintenance demand for moving parts.

Table 2.1 is a summary of all the major air pollution control technologies, showing efficiencies and availability/usage in South Africa.

Table 2.1 Summary of major air pollution control technologies.

Air pollution control technology	**Removal efficiency of applicable pollutant**	**Available in South Africa**
Cyclone	10μm 90% Fine dust 70%	Yes
Fabric filters	99,9% toxic metals 90%	Yes
Electrostatic precipitator	99,9% toxic metals 99%	Yes
Wet scrubbers	Depends on design or type used	Yes
	FGD - Wet System	
Limestone	90%-98%	Yes
Lime	95%	Yes
	FGD - Semi-Dry Systems	
Lime spray dryer	80%-90%	Yes
	FGD - Dry Systems	
Calcium based sorbent injection	50%-60%	Yes
Sodium based sorbent injection	80%	Yes
	Combustion Modifications	
Modifications of operating conditions	Depends on technique used	Yes
Low-NOx burners	40%-60%	Yes
	Flue Gas Treatment	
SCR	60%-90%	No
SNCR	40%-60%	No
Activated carbon adsorption	-	Yes
Copper oxide adsorption	-	Yes
Wet absorption	-	Yes
	Incineration	
Flares	>98%	Yes
Thermal incinerators	98%	Yes
Catalytic oxidisers	-	Yes
Regenerative thermal oxidisers	95%-99%	Yes
Data adapted from Howden Energy Systems (2004) and Burger (2005).		

2.7 GENERIC POLLUTANT CONTROL TECHNOLOGY

The selection of control technologies for a specific case requires consideration of many different parameters, but generic pollutant control looks at non-specific air pollution control. No consideration is given to industry type, process or product. The following lists of technologies were sourced from literature to facilitate in the selection of appropriate control measures according to the polluting species. The lists are in no way exhaustive, but the technologies are well known, well used and well supported by existing documentation.

2.7.1 Particulate matter control

The following air pollution control technologies, representing the most widely used and referenced technologies, are available for the prevention and control of particulate matter (World Bank, 1999; USEPA, 2002; Cooper and Alley, 2002; USEPA, 1998a; European IPPC Bureau, 2003):

- fuel switching,
- fuel cleaning,
- settling chambers,
- cyclones,
- fabric filters,
- electrostatic precipitators, and
- wet scrubbers.

Wet scrubbers can be further subdivided into the following types (World Bank, 1999; USEPA, 2002; Cooper and Alley, 2002; USEPA, 1998a; European IPPC Bureau, 2003):

- spray chambers/towers,
- packed-bed scrubbers,
- impingement plate scrubbers,
- mechanically-aided scrubbers,
- venturi scrubbers,
- orifice scrubbers,

- condensation scrubbers,
- charged scrubbers, and
- fibre-bed scrubbers.

During equipment selection consideration should be given to all the different parameters that may affect the device, but generally for industrial applications the use of ESPs or baghouses is recommended for the effective removal of particulates (or PM-10). Cyclones and mechanical separators should be used only as precleaning devices upstream of a baghouse or an electrostatic precipitator. (World Bank, 1999; USEPA, 2002; USEPA, 1998a)

2.7.2 Sulphur oxides control

There are two approaches to controlling sulphur oxides (SO_x) emissions, either by removing sulphur from the fuel before combustion (through fuel switching or cleaning), or by removing SO_x from the flue gasses. Different types of flue gas desulphurisation (FGD) processes, also know as SO_2 scrubbing, are presented in Table 2.2 (World Bank, 1999; Cooper and Alley, 2002; European IPPC Bureau, 2003). Although there are a vast number of these processes available, only those that are well known, well researched and well referenced are shown in Table 2.2.

2.7.3 Nitrogen oxides control

The following air pollution control technologies are available for the prevention and control of nitrogen oxides (World Bank, 1999; USEPA, 2002; Cooper and Alley, 2002; USEPA, 1993b; European IPPC Bureau, 2003):

- fuel switching,
- fuel cleaning,
- combustion modifications, and
- flue gas treatment.

Table 2.2 Once-through and regenerable FGD processes.

Once-through processes			**Regenerable processes**	
Wet systems/scrubbing	**Semi-dry systems**	**Dry systems**	**Wet systems**	**Dry systems (for SO_x and NO_x)**
Lime	Lime spray drying	Lime (calcium based sorbent) injection	Limestone forced oxidation	Activated carbon adsorption
Limestone	Limestone spray drying	Sodium based sorbent injection	Wellman-Lord	Copper oxide adsorption
Dual alkali		Trona	Magnesium oxide	
Magnesium enhanced lime		Nahcolite	Citrate carbonate	
Seawater		Circulating fluidised bed	Sulphite	

Combustion modifications are further subdivided into either low-NO_x burners or some form of modification of operating conditions. Modification of operating conditions include (World Bank, 1999; USEPA, 2002; Cooper and Alley, 2002; USEPA, 1993b; European IPPC Bureau, 2003):

- low-excess-air firing (LEA),
- off-stoichiometric combustion/staged combustion,
- flue gas recirculation (FGR),
- gas reburning,
- reduced air preheat/or reduced firing rates, and
- water/steam injection.

Flue gas treatment for control of NO_x are divided into either wet or dry techniques. Wet techniques consist of absorption processes and dry techniques include the following (World Bank, 1999; USEPA, 2002; Cooper and Alley, 2002; USEPA, 1993b; European IPPC Bureau, 2003):

- selective catalytic reduction (SCR),
- selective non-catalytic reduction (SNCR), and
- adsorption (using either activated carbon or copper oxide).

2.7.4 Volatile organic compounds control

There is a wide variety of techniques available to control the emissions of volatile organic compounds (VOCs), with the techniques focusing either on destruction or recovery. Only techniques or methods that are well researched and referenced are presented below, but the list is in no way exhaustive. Destructive techniques include (USEPA, 2002; USEPA, 1995; European IPPC Bureau, 2003):

- incineration,
    - catalytic incineration,
    - thermal oxidisers,
    - regenerative thermal incineration,
- flares,
    - elevated flares,
    - grounded flares,
- biofiltration, and
- ultra D-tox system.

Recovery techniques can be divided into the following (USEPA, 2002; USEPA, 1995; European IPPC Bureau, 2003):

- selective membrane separation,
- refrigerated condensation,
- absorption,
- adsorption (enhanced carbon adsorption), and
- scrubbers.

2.8 INDUSTRY SECTOR AIR POLLUTION CONTROL

The industries discussed within this section are considered high air pollution contributors that require specific attention. In each case a short overview is given of the industry, followed by the recommended technologies from each country/union to reduce air pollution from the relevant industry.

2.8.1 Coal-fired power plant

In most large industrial facilities combustion plants (power plants) are applied according to the owner's demands or requirements as either large utility plants or industrial combustion plants; providing electricity, steam or heat to industrial production processes. For the purpose of this investigation the focus was on large utility plants (power stations) that use coal in conventional steam-producing thermal power plants for the generation of electricity. An overview of all the different mass streams are presented in the generalised flow diagram of a power plant and its associated operations in Figure 2.12.

Power plants generate a number of residues, wastes and large amounts of emissions to all environmental media. The most important emissions to air from the combustion of coal are SO_x, NO_x, CO, particulates and greenhouse gases such as carbon dioxide (CO_2). Other substances such as heavy metals, hydrogen fluoride (HF), hydrogen chloride (HCl), halide compounds, unburned hydrocarbons, non-methane volatile organic compounds and dioxins are emitted in smaller quantities. (HMIP, 1995a; European IPPC Bureau, 2005a; USEPA, 2005a)

Table 2.3 to Table 2.8 show the possible technologies recommended by the United Kingdom, European Union and the United States to reduce, prevent or abate particulates, SO_x, NO_x, CO, heavy metals, HCl and HF. The technologies were sourced from various references and the database discussed in Section 2.2 to Section 2.4.

Good combustion practices and good combustion control will aid in the prevention and control of air pollution emissions, regardless of the type of fuel used, the combustion method followed and the size of a facility (HMIP, 1995a; European IPPC Bureau, 2005a; USEPA, 2005a). It should also be noted that the type of flue gas desulphurisation (FGD) technique used for the prevention and control of SO_x depends on the type of combustion method, the output, and whether the plant is new or existing. Similarly for the prevention and control of NO_x a combination of combustion modifications and flue gas treatment (FGT) can be used; depending on the output, the fuel used and whether the plant is new or existing. (European IPPC Bureau, 2005a)

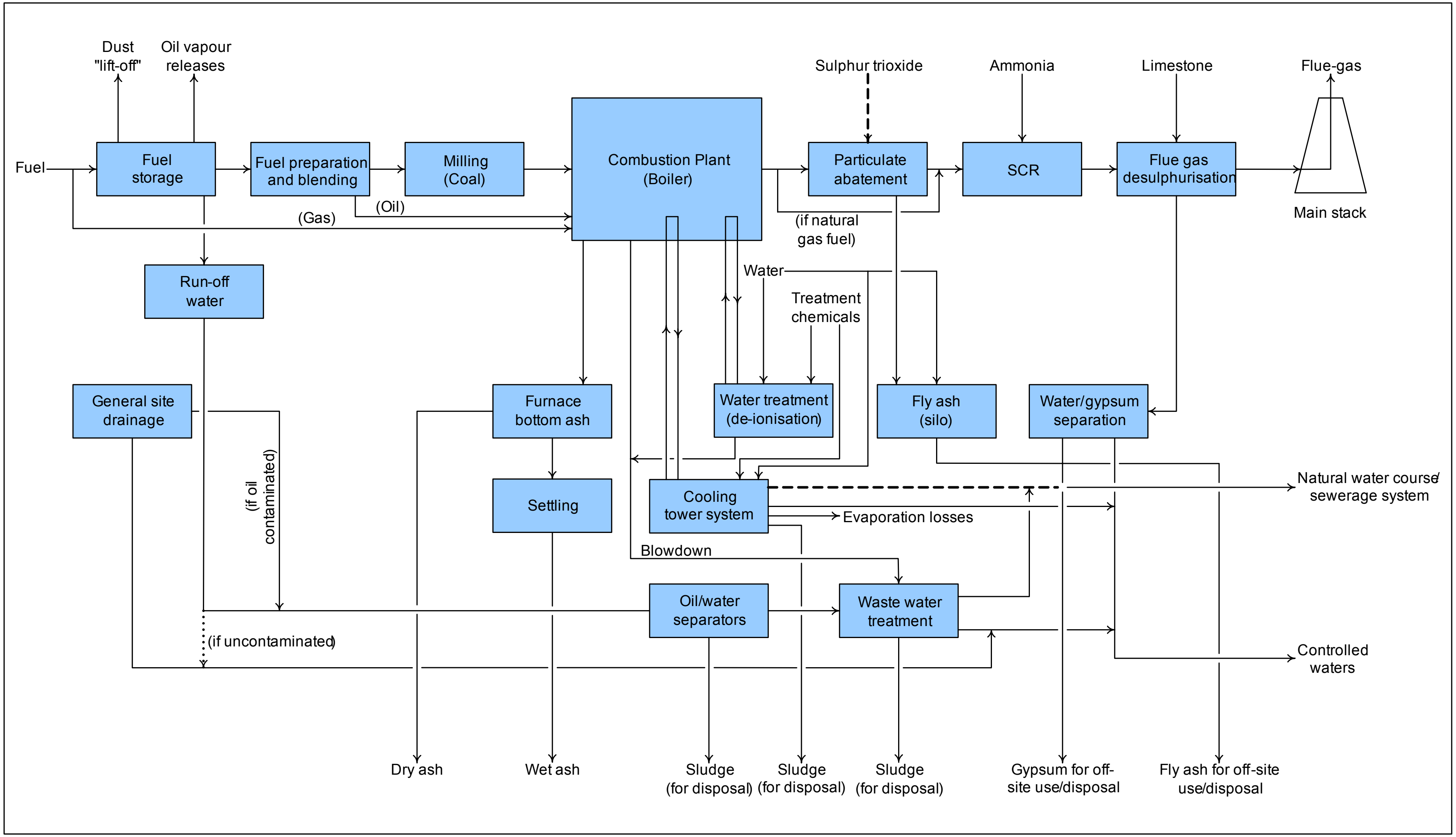

Figure 2.12 Generalised flow diagram of a power plant and its associated processes.

(Adapted from HMIP, 1995a.)

Table 2.3 Air pollution control technologies for the prevention and control of PM from coal-fired power plants.

Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK[*]	Recommended BAT for the EU[§]	Recommended through the RBLC database by the following permits[¥]
Switch fuel	Yes	-	VA-0268
Cyclones (pre-cleaners only)	Yes	Yes	MT-0027
Fabric filter (baghouse)	Yes	Yes	PA-0249, PA-0248, ND-0021, PA-0247, PA-0182, AR-0074, OH-0231, IA-0067, KS-0026, WY-0057, PA-0183
ESP (wet and dry)	Yes	Yes	GA-0114, SC-0104, KY-0084, PR-0007, KY-0084
Wet flue gas desulphurisation (wet scrubber)	-	Yes	MT-0027
Semi-dry flue gas desulphurisation - spray dryer	-	Yes	-
Flue gas desulphurisation - sorbent injection	-	Yes	-

∗ Data adapted from HMIP (1995a).
§ Data adapted from European IPPC Bureau (2005a).
¥ Data from the RBLC database (USEPA, 2005a), searched for coal-fired fuel combustion processes.

Table 2.4 Air pollution control technologies for the prevention and control of SO_x from coal-fired power plants.

Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK[*]	Recommended BAT for the EU[§]	Recommended through the RBLC database by the following permits[¥]
Fuel switching	Yes	Yes	TX-0298, TX-0358, PR-0007, VA-0268
Fuel cleaning	Yes	-	-
Wet flue gas desulphurisation (specifically limestone)	Yes	Yes	SC-0104, KY-0084
Semi-dry flue gas desulphurisation - spray dryer (specifically limestone)	Yes	Yes	ND-0021, IA-0067, WY-0057, KY-0086
Dry flue gas desulphurisation - sorbent injection (specifically limestone)	Yes	Yes	PA-0249, AR-0074, MT-0022, KS-0026, PR-007, OH-0231¸PA-0247, PR-007
Wet scrubbing (specifically seawater)	Yes	Yes	SC-0104, MT-0027

∗ Data adapted from HMIP (1995a).
§ Data adapted from European IPPC Bureau (2005a).
¥ Data from the RBLC database (USEPA, 2005a), searched for coal-fired fuel combustion processes.

Table 2.5 Air pollution control technologies for the prevention and control of NO_x from coal-fired power plants.

Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK[*]	Recommended BAT for the EU[§]	Recommended through the RBLC database by the following permits[¥]
Fuel switching	Yes	-	-
Combustion Modifications			
Low-excess-air firing	Yes	-	-
Staged combustion	Yes	Yes	-
Flue gas circulation	Yes	-	-
Over-fire air	Yes	-	MT-0022, IA-0067, KS-0026
Gas reburning	Yes	Yes	-
Low NO_x burners	Yes	Yes	SC-0104, AR-0074, MT-0022, IA-0067, KY-0084, KS-0026, WY-0057
Flue Gas Treatment			
SCR	Yes	Yes	SC-0104, MT-0022, IA-0067, KY-0084, KS-0026, WY-0057, MT-0027
SNCR	Yes	Yes	PA-0248, PA-0247, PA-0182, KY-0086, PA-0183, PR-0007, ND-0021

∗ Data adapted from HMIP (1995a).
§ Data adapted from European IPPC Bureau (2005a).
¥ Data from the RBLC database (USEPA, 2005a), searched for coal-fired fuel combustion processes.

Table 2.6 Air pollution control technologies for the prevention and control of CO from coal-fired power plants.

Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK[*]	Recommended BAT for the EU[§]	Recommended through the RBLC database by the following permits[¥]
Complete combustion	-	Yes	PA-0248, ND-0021, PA-0247, GA-0114, SC-0104, TX-0298, PA-0182, AR-0074, OH-0231, IA-0067, TX-0358, KY-0084, KS-0026, WY-0057, KY-0086, VA-0268, PA-0183, PR-0007
Good combustion practices/control	-	Yes	

∗ In some cases information could not be obtained from all three countries/unions for each industry.
§ Data adapted from European IPPC Bureau (2005a).
¥ Data from the RBLC database (USEPA, 2005a), searched for coal-fired fuel combustion processes.

Table 2.7 Air pollution control technologies for the prevention and control of heavy metals from coal-fired power plants.

Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
ESP (wet and dry)	Yes	Yes	SC-0104, KY-0084
Fabric filter (baghouse)	Yes	Yes	KY-0086
Wet scrubber	Yes	-	SC-0104, KY-0084
SCR	-	-	SC-0104
Low NOx burners	-	-	SC-0104
Activated carbon	-	-	IA-0067

∗ Data adapted from HMIP (1995a).
§ Data adapted from European IPPC Bureau (2005a).
¥ Data from the RBLC database (USEPA, 2005a), searched for coal-fired fuel combustion processes.

Table 2.8 Air pollution control technologies for the prevention and control of hydrogen chloride and hydrogen fluoride from coal-fired power plants.

Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
Wet scrubber	-	Yes	SC-0104, PR-007
Spray dryer	-	Yes	PA-0249, ND-0021, IA-0067

∗ In some cases information could not be obtained from all three countries/unions for each industry.
§ Data adapted from European IPPC Bureau (2005a).
¥ Data from the RBLC database (USEPA, 2005a), searched for coal-fired fuel combustion processes.

2.8.2 Coal gasification

Gasification involves the reaction of a source of carbon (coal or biomass) with a source of hydrogen and/or oxygen to yield a gas containing carbon monoxide, hydrogen, carbon dioxide and methane in proportions dependent on the ratio of the reactants utilised and on the reaction conditions. The carbonaceous feedstocks would normally be coal, lignite or liquid hydrocarbons. Products from the gasification process can be used in power generation, the chemical industry and in the production of synthetic fuels. (HMIP, 1995b)

Gasification takes place through a complex set of reactions. In the simplest terms gasification can be regarded as the reaction of carbon with the gasifying agent. Sulphur and nitrogen in the feedstock react to produce hydrogen sulphide (H_2S), carbonyl sulphide, smaller amounts of other sulphur compounds, ammonia (NH_3), hydrogen cyanide and other nitrogen compounds; which can be removed in subsequent purifying stages. (HMIP, 1995b)

The main gasification processes available are catalytic gasification with steam, thermal hydrogenation, and gasification with either oxygen and/or steam, or with air and steam (HMIP, 1995b). Coal gasification with air and steam will be discussed in more detail as part of this investigation.

Gasifiers generally operate at high temperatures, but some processes do operate at lower temperatures. During gasification hydrocarbon feedstocks are reduced to low molecular weight substances such as carbon monoxide and molecular hydrogen. Numerous reactions take place within the gasifiers but essentially in an oxygen and steam fed gasifier the reactions may be summarised as (HMIP, 1995b):

$C+H_2O \rightarrow CO+H_2$ steam/carbon reaction, and

$C+\frac{1}{2}O_2 \rightarrow CO$ partial oxidation.

The composition of the synthetic gas, which is produced by a gasifier, will depend on the feedstock, the steam to oxygen ratio and the temperature and pressure at which a gasifier is operated. Although oxygen is fed into gasifiers, a reducing atmosphere exists and as a result sulphur present in the relevant feedstock is converted to H_2S, with smaller amounts of carbonyl sulphide (COS), methyl mercaptan and carbon disulphide being produced. Fuel-bound nitrogen will be converted mainly to molecular nitrogen, but in the presence of hydrogen, some small quantities of ammonia and hydrogen cyanide will be produced.

Table 2.9 shows various activities associated with the gasification process and the air pollutants from these air emission sources.

An example of how gasification forms part of a synthetic fuel refining and/or chemical manufacturing facility is illustrated in Figure 2.13. Table 2.10 to Table 2.12 show the possible technologies or methods recommended by the United Kingdom to reduce, prevent or abate air pollutants from a gasification process (see Section 2.3).

Table 2.9 Air emissions associated with gasification processes.

Source	Pollutant
Raw materials, storage and handling	particulate matter (PM)
	volatile organic compounds (VOCs)
Gas handling and treatment	particulate matter (PM)
	sulphur oxides (SO_x)
	nitrogen oxides (NO_x)
	oxides of carbon (CO_x)
	organic compounds
	volatile organic compounds (VOCs)
	hydrogen sulphide (H_2S)
	ammonia (NH_3)
Data adapted from HMIP (1995b).	

Table 2.10 Air pollution control technologies for the prevention and control of air pollutants - raw materials, storage and handling (including slag/ash handling).

Air Pollutant	Air Pollution Control Technology	Recommend BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits§
General	Unloading into enclosed hoppers	Yes	-	-
	Enclosed conveyors	Yes	-	-
	Enclosed discharge towers	Yes	-	-
	Removal from stockpile via bottom off-take	Yes	-	-
	Use fixed conveyor system	Yes	-	-
	Use enclosed system when working with dusty materials	Yes	-	-
	Bag or ceramic filters for dust handling	Yes	-	-
	Liquid feedstocks stored in appropriate roof tanks	Yes	-	-
	Scrub or incinerate vented gas	Yes	-	-

∗ Data adapted from HMIP (1995b).
§ In some cases information could not be obtained from all three countries/unions for each industry.

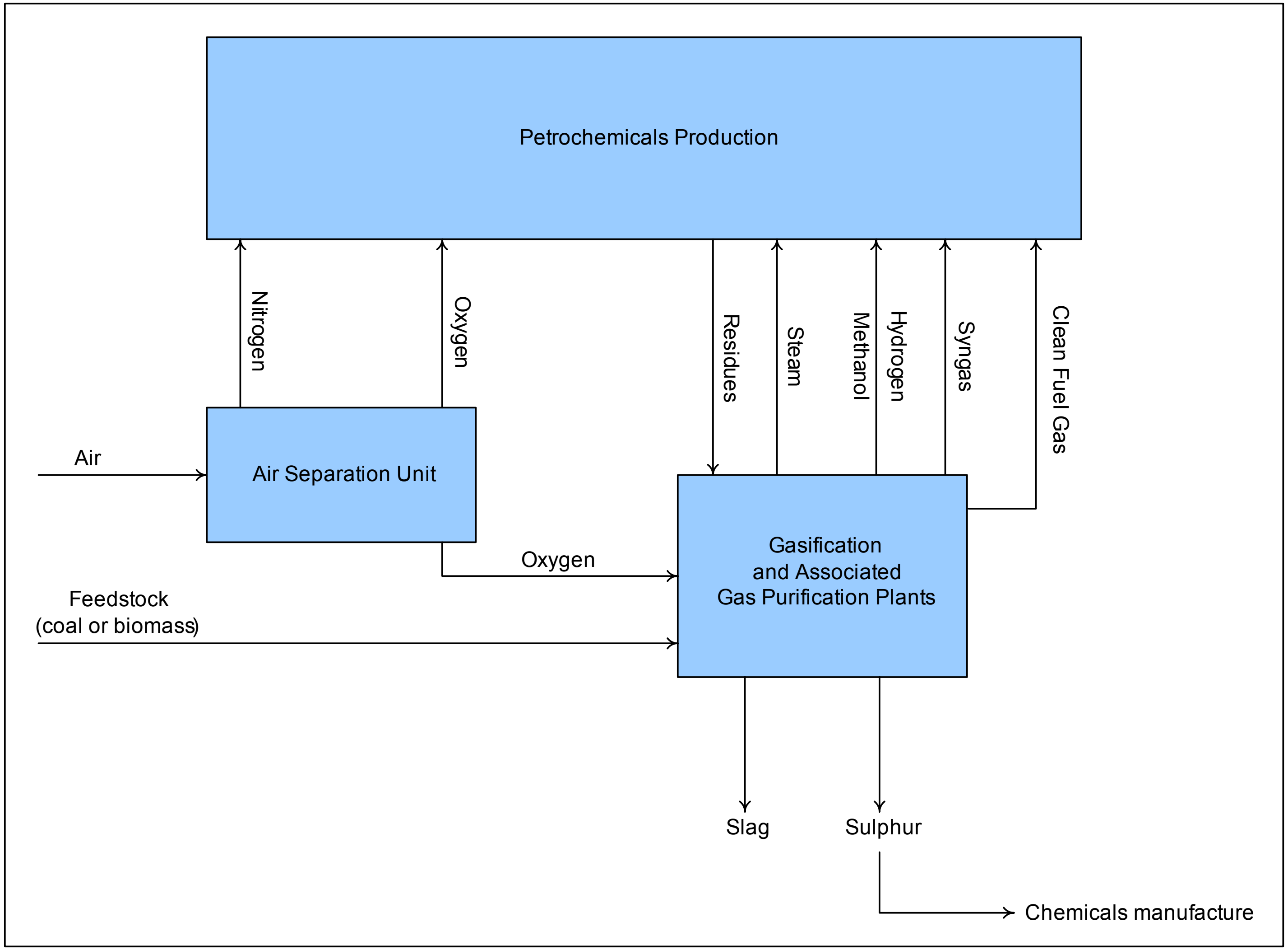

Figure 2.13 An example of the gasification process during synthetic fuel refining and/or chemical manufacturing.

(Adapted from HMIP, 1995b.)

Table 2-11 Air pollution control technologies or methods for the prevention and control of air pollutants from a gasification unit.

Air Pollutant	Air Pollution Control Technology	Recommend BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits§
General	Proper design, operation and control	Yes	-	-
	Coal charging via double lock system	Yes	-	-
	Gases released during charging, should be re-injected or vented to treatment system	Yes	-	-
	Alternatively use wet feed (slurry)	Yes	-	-
	All process vents to flare system	Yes	-	-
	All pressure reliefs to flare system	Yes	-	-
	Proper design, operation and control of flare	Yes	-	-

∗ Data adapted from HMIP (1995b).
§ In some cases information could not be obtained from all three countries/unions for each industry.

2.8.3 Petroleum refining

The petroleum refining industry converts crude oil into multiple refined products, including liquefied petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, fuel oil, lubricating oil and petrochemical industry feedstock. Petroleum refining activities start with receipt of the crude oil at the refinery, followed by multiple petroleum handling and refining operations and terminate with the storage of the refined products prior to transport. Figure 2.14 illustrates a schematic diagram for an oil refinery process, largely determined by the composition of the crude oil feedstock and the petroleum products it chooses to manufacture. (MIC, 2004; Rucker and Strieter, 2000)

In Table 2.13 the five categories of general refinery processes and associated operations are shown (MIC, 2004; Rucker and Strieter, 2000):

Table 2.12 Air pollution control technologies for the prevention and control of air pollutants from a gas purification and conversion unit.

Air Pollutant	Air Pollution Control Technology	Recommend BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits§
Liquid Quenching				
General	Any gas/flash stream arising on pressure let down, routed to treatment system or combined with acid gas stream and routed to SRU	Yes	-	-
Particulate Matter Removal				
General	Collected material should be collected via a lock hopper	Yes	-	-
Acid Gas Removal				
General	Amine scrubbing to remove H_2S	Yes	-	-
	Concentrated acid gas treated in sulphur recovery process eg Claus kiln	Yes	-	-
	Tail gases from Claus kiln to thermal incinerator or catalytic oxidiser	Yes	-	-
	Final vent gas should be incinerated	Yes	-	-
	Carbonyl sulphide, methyl mercaptan and other sulphur containing constituents removed by conversion and forwarding to Claus process	Yes	-	-
	HCN and NH_3 removed by water scrubbing	Yes	-	-
	CO_2 released vie appropriate chimney if concentration is adequately low	Yes	-	-
	CO_2 combustion only if odour problem exists	Yes	-	-
	Process vents to incinerator/flare	Yes	-	-
	Pressure reliefs to incinerator/flare	Yes	-	-

∗ Data adapted from HMIP (1995b).
§ In some cases information could not be obtained from all three countries/unions for each industry.

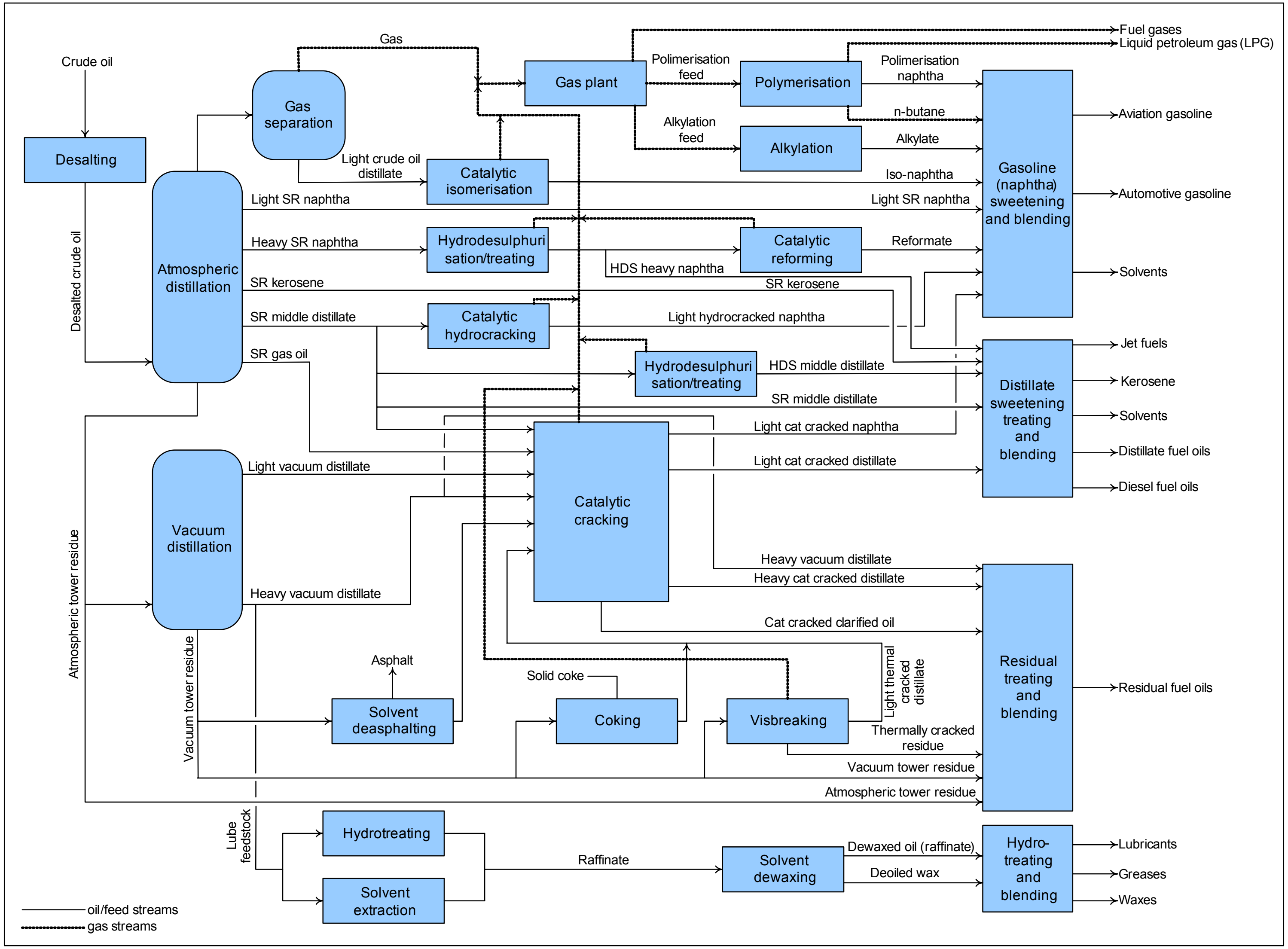

Figure 2.14 Schematic flow diagram of an oil refinery process.

(Adapted from MIC, 2004.)

Table 2.13 Five categories of general refinery processes and associated operations.

Separation processes	Petroleum conversion processes	Petroleum treating processes	Feedstock and product handling	Auxiliary facilities
Desalting	Catalytic cracking	Hydrotreating	Storage	Steam boilers
Atmospheric distillation	Thermal cracking (visbreaking)	Chemical sweetening	Blending	Waste water and solid waste treatment
Vacuum distillation	Alkylation	Acid gas removal	Loading	Hydrogen production
Light ends recovery/gas processing	Polymerisation	Deasphalting	Unloading	Sulphur recovery plant
	Isomerisation	Asphalt blowing		Cooling towers
	Reforming	Dewaxing		Blowdown system
	Coking			Compressor systems

Separation processes

Crude oil is a complex mixture of hydrocarbon compounds, including paraffinic, naphthenic and aromatic hydrocarbons plus small amounts of some impurities including salt, sulphur, nitrogen, oxygen and metals. The first phase in petroleum refining operations is the separation of crude oil into its major constituents using four consecutive petroleum separation processes; namely desalting, atmospheric distillation, vacuum distillation and light ends recovery - also known as gas processing). (MIC, 2004; Rucker and Strieter, 2000)

Desalting separates the salt from the crude oil by water addition to dissolve the salt, followed by physical separation of the crude oil and water phases prior to distillation of the crude oil. Atmospheric distillation involves the heating, vaporisation, fractionation and condensation of different boiling point fractions of the crude oil at normal pressure. Vacuum distillation repeats the process at reduced pressures in order to separate higher boiling point fractions of the crude oil not accomplished by atmospheric distillation. Finally light ends recovery is the separation of non-condensable gases (refinery fuel gas) from condensable hydrocarbons so that the fuel gas can be used as a refinery energy source. (MIC, 2004; Rucker and Strieter, 2000)

Conversion processes

Various crude oil components are converted to gasoline and other light hydrocarbon fractions to meet the demands for high-octane gasoline, jet fuel and diesel fuel. Processes such as catalytic cracking, thermal cracking (visbreaking – so called because it reduces viscosity) and coking are used to break down large petroleum molecules into smaller petroleum molecules. Catalytic cracking uses a catalyst and high temperature in order to break apart long chain hydrocarbons to yield lower boiling point hydrocarbons suitable for the production of gasoline or fuel oil. A fluidised catalytic cracker (FCC) is normally used and during the process coke (carbon) is deposited on the catalyst, which is then burnt off in the regenerator. The exhaust gases of the regenerator are sent to atmosphere, being the source of SO_2 and NO_x emissions from the FCC process. Visbreaking, which is less commonly used, accomplishes the same result using heat and high pressure, but without a catalyst. (MIC, 2004; Rucker and Strieter, 2000)

Coking produces valuable volatile hydrocarbons from low volatility petroleum fractions that are not valuable. Distillation residues, for example, are heated to high temperatures with limited oxygen being present to form solid coke and liquid hydrocarbons. Polymerisation and alkylation processes are then used to combine small petroleum molecules into larger molecules more suitable for use in gasoline production. Polymerisation or alkylation requires a catalyst (phosphoric, hydrofluoric or sulphuric acid) with pressure and/or heat to accomplish this. Finally, isomerisation and reforming processes rearrange the structure of petroleum molecules in order to produce molecules of similar molecular size to the original molecule but of higher value in the final refined product. A catalyst and heat are required in both isomerisation and reforming processes. (MIC, 2004; Rucker and Strieter, 2000)

Treating processes

Petroleum treating processes stabilise and upgrade the petroleum products by separating them from less desirable products and by removing objectionable elements. Treating processes that are used in oil refineries include hydrotreating, chemical sweetening, acid gas removal, deasphalting, asphalt blowing and dewaxing. (MIC, 2004; Rucker and Strieter, 2000)

Hydrotreating employs a catalyst to react hydrogen, at high pressure and temperature, with either the sulphur, nitrogen or oxygen in the crude oil to form hydrogen sulphide, ammonia and water, respectively. Chemical sweetening employs caustic and air to convert odorous mercaptans in the petroleum to less odorous disulphides. Acid gas removal absorbs sulphur compounds into a solution in order to separate them from the refinery fuel gas. (MIC, 2004; Rucker and Strieter, 2000)

Deasphalting is primarily used for the separation of asphaltenes and resins from vacuum distillation residues by extraction with a solvent such as refinery propane. Asphalt blowing is used primarily for polymerising and stabilising asphalt in order to improve its weathering characteristics. This is accomplished by heating the asphalt in the presence of a flowing air stream. Dewaxing is used to remove any waxy hydrocarbon components from lubricating oil base stocks. Dewaxing is done by either selective hydrocracking over a zeolite catalyst or by solvent extraction. (MIC, 2004; Rucker and Strieter, 2000)

Feedstock and product handling

The major refinery feedstock and product handling operations consist of unloading, storage, blending and loading activities. Each of these is a critical step in the successful operation of a petroleum refinery. (MIC, 2004; Rucker and Strieter, 2000)

Auxiliary facilities

A wide assortment of processes not always directly involved in the refining of crude oil are used in functions vital to the operation of the refinery. Examples of these are steam boilers, wastewater treatment or solid waste treatment units, hydrogen plants, sulphur recovery plants, cooling towers, blowdown systems and compressor systems. (MIC, 2004; Rucker and Strieter, 2000)

Refinery process air emissions

The most significant air emission sources in oil refineries are catalytic or thermal cracking units, catalytic reformer units, sulphur recovery plants, storage vessels, coking units, equipment leaks, blowdown systems, vacuum distillation units, steam boilers, process furnaces, process heaters, vessel loading and gasoline loading racks -

specifically located at petroleum refineries. Table 2.14 identifies the air pollutants from these air emission sources. (MIC, 2004; Rucker and Strieter, 2000)

Table 2.14 Significant refinery air emission sources and their associated air pollutants.

Refinery Process	Air Pollutant
Equipment leaks	volatile organic compounds (VOCs)
Catalytic cracking (fluid bed)	particulate matter (PM)
	sulphur oxides (SO_x)
	nitrogen oxides (NO_x)
	carbon monoxide (CO)
	volatile organic compounds (VOCs)
Coke production	particulate matter (PM)
	sulphur oxides (SO_x)
	volatile organic compounds (VOCs)
Bitumen production	particulate matter (PM)
	sulphur oxides (SO_x)
	nitrogen oxides (NO_x)
	carbon oxides (CO_x)
	volatile organic compounds (VOCs)
	hydrogen sulphide (H_2S)
Visbreaking	particulate matter (PM)
	sulphur oxides (SO_x)
	nitrogen oxides (NO_x)
	carbon oxides (CO_x)
	volatile organic compounds (VOCs)
	hydrogen sulphide (H_2S) and mercaptans
HF alkylation	particulate matter (PM)
	sulphur oxides (SO_x)
	carbon oxides (CO_x)
	volatile organic compounds (VOCs)
Sulphur recovery unit (SRU)	sulphur oxides (SO_x)
	reduced sulphur (H_2S, CS_2, COS)
	volatile organic compounds (VOCs)
Vacuum distillation	volatile organic compounds (VOCs)
Loading, handling and storage of feedstocks and products	volatile organic compounds (VOCs)
Data adapted from MIC (2004), Rucker and Strieter (2000), van der Rest *et al.* (1999) and HMIP (1995c).	

Table 2.15 shows the possible technologies recommended by the United Kingdom, European Union and the United States to reduce, prevent or abate VOC emissions from various units within an oil refinery. (This table is discussed separately since these control technologies apply all over an oil refinery. If the information within this table applies to a specific unit, mentioned will be made of General VOC controls).

Table 2.15 Air pollution control technologies for the prevention and control of VOC emissions (General VOC controls).

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
VOC	Leak detection and repair programme (LDAR)	Yes	Yes	CA-0735, OK-0092, OK-0095, TX-0269, TX-0268, TX-0320, TX-0340, TX-0361, TX-0379, TX-0418
	Low emission valve stem packing on critical valves	Yes	Yes	CA-0735
	Low release valves where gate valves are not essential	Yes	Yes	CA-0735, CA-0744, CA-0745
	Balanced bellows type relief valves	Yes	Yes	CA-0735
	Minimise the number of flanged connections	Yes	Yes	-
	Canned pumps or double mechanical seals on conventional pumps	Yes	Yes	CA-0735
	End caps/plugs on open ended lines	Yes	Yes	-
	Relief valves emissions vented to incineration system	Yes	Yes	CA-0735, CA-0744
	Optimise sampling volume and frequency	Yes	-	-
	Inspection and maintenance programme	-	-	CA-0711, CA-0712, MT-0013

∗ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ Data from the RBLC database (USEPA, 2005a), searched for fugitive and equipment leaks.

Table 2.16 to Table 2.23 show the possible technologies recommended by the United Kingdom, European Union and the United States to reduce, prevent or abate air pollutants from various units within an oil refinery. The information was sourced from the various sources and the database discussed in Section 2.2 to Section 2.4. The

RBLC database generally only had permit information for the major polluting units at an oil refinery.

Table 2.16a Air pollution control technologies for the prevention and control of air pollutants from a catalytic cracking.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
PM	Fuel cleaning	-	Yes	-
	Cyclones	Yes	Yes	OK-0089, OK-0092
	Fabric filters	-	Yes	-
	ESP	Yes	Yes	-
	Wet gas scrubber	Yes	-	AR-0061, IL-0079, LA-0090, LA-0166, NJ-0057, OK-0089, OK-0092, TN-0153
	Control and reuse of catalyst fines	-	Yes	-
SO_x	Fuel cleaning	Yes	Yes	OK-0089, OK-0092
	DeSOx catalyst additive	Yes	Yes	-
	Flue gas desulphurisation			
	Wet scrubbing	Yes	Yes	AR-0061, IL-0079, LA-0166, NJ-0057, NM-0045, OK-0089, OK-0092, TX-0290, LA-0090
	Dry and semi dry scrubbing	Yes	Yes	-
	Wet gas sulphuric acid processes	Yes	Yes	-

∗ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ Data from the RBLC database (USEPA, 2005a), searched for petroleum refining conversion processes and fugitive and equipment leaks.

Table 2.16b Air pollution control technologies for the prevention and control of air pollutants from a catalytic cracking.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK[*]	Recommended BAT for the EU[§]	Recommended through the RBLC database by the following permits[¥]
NO_x	Fuel cleaning	-	Yes	OK-0089, OK-0092
	Low NOx burners in CO boilers	-	-	OK-0089, OK-0092, TX-0341
	Proper CO Boiler operation to avoid hot spots	Yes	Yes	LA-0090, LA-0171, WA-0294
	SNCR on regenerator flue gas	-	Yes	TX-0346, WA-0294, WA-0317
	SCR on regenerator flue gas	-	Yes	CA-0887, CA-0999, IN-0101, TX-0290
	LoTox technology	-	-	AR-0061, TX-0289
CO	Proper operation and control of full combustion type regenerators	Yes	Yes	AR-0061
	CO Boiler	Yes	Yes	LA-0090, OK-0089, OK-0092, TX-0346, TX-0429, WA-0294, WA-0317
	High temperature combustion	-	-	OK-0089, OK-0092
VOC	General VOC controls (Table 2.15)			

[*] Data adapted from HMIP (1995c).
[§] Data adapted from European IPPC Bureau (2001).
[¥] Data from the RBLC database (USEPA, 2005a), searched for petroleum refining conversion processes and fugitive and equipment leaks.

Table 2.17 Air pollution control technologies for the prevention and control of air pollutants from a coke production unit.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
PM	Cyclones	Yes	Yes	-
	Fabric filters	Yes	Yes	TX-0319, TX-0286
	ESP	-	Yes	-
	Partial and full enclosures	Yes	Yes	TX-0319
	Covered conveyers	-	Yes	TX-0319
	Collect and recycle coke fines	-	Yes	-
SO_x	Fuel switching	Yes	Yes	OK-0089, OK-0092
	Flue gas desulphurisation			
	Wet scrubbing	-	Yes	AR-0061, IL-0079, LA-0166, NJ-0057, NM-0045, OK-0089, OK-0092, TX-0290, LA-0090
	Dry and semi dry scrubbing	-	Yes	-
	Wet gas sulphuric acid processes	-	Yes	-
VOC	General VOC controls (Table 2.15)			

∗ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ Data from the RBLC database (USEPA, 2005a), searched for petroleum refining conversion processes and fugitive and equipment leaks.

Table 2.18 Air pollution control technologies for the prevention and control of air pollutants from a bitumen production unit.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
General	Oxidiser overheads routed to scrubber prior to incineration	Yes	Yes	-
	Gases vented from storage should be vented to incinerator and wet ESP to destroy VOCs and odours	Yes	Yes	-
	Incineration temperature of at least 800°C and residence time of 0,5 seconds	Yes	Yes	-
VOC	General VOC controls (Table 2.15)			

∗ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ In some cases information could not be obtained from all three countries/unions for each industry.

Table 2.19 Air pollution control technologies for the prevention and control of air pollutants from a visbreaking unit.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
General	Sour gas treated by amine scrubbing	Yes	Yes	-
	Treated gas should be recovered in products or vented to RFG	Yes	Yes	-
VOC	General VOC controls (Table 2.15)			

∗ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ In some cases information could not be obtained from all three countries/unions for each industry.

Table 2.20 Air pollution control technologies for the prevention and control of air pollutants from an HF alkylation unit.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
General	Alkaline scrubber to remove HF from incondensable gas stream	-	Yes	-
	Operate acid relief neutraliser to reduce HF in incondensable gas stream	Yes	Yes	-
	Flare vent gas	Yes	Yes	-
VOC	General VOC controls (Table 2.15)			

⁎ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ In some cases information could not be obtained from all three countries/unions for each industry.

Table 2.21 Air pollution control technologies for the prevention and control of air pollutants from a sulphur recovery unit (SRU).

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
General	Amine scrubbing for H_2S capture	Yes	Yes	LA-0149
	Furnace designed to destroy NH_3	Yes	Yes	-
	Proper tail gas treatment unit (thermal incinerator, catalytic oxidiser)	Yes	Yes	LA-0149, LA-0166
VOC	General VOC controls (Table 2.15)			

⁎ Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ Data from the RBLC database (USEPA, 2005a), searched for petroleum refining treating processes and fugitive and equipment leaks.

Table 2.22 Air pollution control technologies for the prevention and control of air pollutants from vacuum distillation units.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
General	Vacuum distillation condensers vented to heater or incinerator	Yes	Yes	-
	Vacuum gaseous streams vented to amine scrubber, before incineration	Yes	Yes	-
	NH_3 injection, where applied, should be in an enclosed system	Yes	Yes	-
	De-coking vents need suitable knock-out and dust suppression facilities	Yes	Yes	-
	Pressure reliefs vented to flare	-	Yes	MS-0032
VOC	General VOC controls			

* Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ Data from the RBLC database (USEPA, 2005a), searched for petroleum refining separation processes and fugitive and equipment leaks.

Table 2.23 Air pollution control technologies for the prevention and control of air pollutants from the loading, handling and storage of feedstocks and products.

Air Pollutant	Air Pollution Control Technology	Recommended BATNEEC/BAT for the UK*	Recommended BAT for the EU§	Recommended through the RBLC database by the following permits¥
PM	Bottom loading of container	Yes	-	CA-0641
	Sprinkle stockpiles	-	-	TX-0322
	Contain catalyst losses to atmosphere	-	Yes	-
SO_x	Use proper tank based on vapour pressure at storage temperature	Yes	Yes	LA-0166
	Bottom loading of container	Yes	-	-
	Vapour recovery/incineration	Yes	Yes	-
	Closed-loop system	Yes	-	-
NO_x	Use proper tank based on vapour pressure at storage temperature	Yes	Yes	-
	Bottom loading of container	-	-	CA-0641
	Vapour recovery/incineration	-	Yes	CA-0641
VOC	Use proper tank based on vapour pressure at storage temperature	Yes	Yes	-
	Bottom loading of container	Yes	-	CA-0641
	Vapour recovery/incineration	Yes	Yes	CA-0641, LA-0166
	Closed-loop system	Yes	-	LA-0166, OK-0102

* Data adapted from HMIP (1995c).
§ Data adapted from European IPPC Bureau (2001).
¥ Data from the RBLC database (USEPA, 2005a), searched for petroleum refining feedstock blending, loading, unloading and storage.

CHAPTER 3

Technology Selection

3.1 SELECTION PROCESS

The various tables in Chapter 2 were compiled from information obtained from the European union (EU), United States of America (USA) and the United Kingdom (UK). The lists of technologies and techniques mentioned in the tables are not exhaustive, but aim to represent the technologies and techniques most often used or recommended by the various countries for preventing, abating and controlling air emissions from certain industrial installations. The lists were used to source out the best technologies or techniques for the following industrial installations:

- coal-fired power plant,
- coal gasification, and
- petroleum refining.

Technology selection was done by considering the frequency of use of a specific technology or technique and the advantages and disadvantages of its use. The selection process weighed heavily on the experience gained in practise from other countries. Little or no consideration was given to cross media implications of certain technologies and to other limitations, such as floor space requirements and power requirements.

3.2 COAL-FIRED POWER PLANT

The most important air emissions that have to be controlled from a coal-fired power plant are particulate matter (PM), sulphur oxides (SO_x), nitrogen oxides (NO_x) and to a lesser extent carbon monoxide (CO), certain heavy metals, hydrogen chloride (HCl) and hydrogen fluoride (HF) (HMIP, 1995a).

For the control of particulates from coal-fired power plants, electrostatic precipitators (ESP) and/or fabric filters can be selected. Both of these control technologies provide a removal efficiency of 99,9% for particulates, and removal efficiencies of 90% for heavy metals such as arsenic, cadmium, chromium, lead and nickel (Cooper and Alley, 2002; World Bank, 1999). Both ESPs and fabric filters are recommended technologies for particulates and heavy metals removal by the UK and the EU and are in use in more than 7 (ESPs) and 12 (fabric filters) records from the RBLC database (Table 2.3 and Table 2.7). For final selection the electrostatic precipitator was chosen as the control technology for particulates and heavy metals removal since the device is not as sensitive to high temperatures as fabric filters, and since ESPs have been proven to work effectively in South African power plants (Eskom Holdings Limited, 2002). (Cyclones are also recommended for PM removal by the UK, EU and by records from the RBLC database, but should only be used as pre-cleaners upstream of the primary collection device; for example, an electrostatic precipitator, where dust loading is high).

Controlling SO_x emissions from coal-fired power plants should, where possible and economically feasible, be controlled first and foremost by switching or changing fuel. This is recommended by the UK, EU and various RBLC records (Table 2.4). Flue gas desulphurisation (wet, semi-dry and dry) is the most highly recommended control technology for the control of SO_2, being recommended by the UK and the EU and is in use in more than 14 RBLC records (Table 2.4). Flue gas desulphurisation technologies, such as spray dryers, can also effectively remove HCl and HF (Table 2.8). For final selection wet flue gas desulphurisation with limestone was chosen as the control technology for SO_2 and possibly HCl and HF emissions from coal-fired power plants. This control technology offers the highest removal efficiency (90-98%) (Cooper and Alley, 2002) and is the preferred technology for coal-fired electric utility power plants (USEPA, 2003a).

For the prevention and control of NO_x a combination of combustion modifications and flue gas treatment (FGT) can be used (European IPPC Bureau, 2005). Low-NO_x burners were selected as the combustion modification to be used. Low-NO_x burners are recommended by the UK and the EU and are in use in more than 7 RBLC records (Table 2.5). Low-NO_x burners can reduce NO_x emissions by 40-60% and can be used on both new and existing facilities (Cooper and Alley, 2002; World Bank, 1999). The flue gas treatment that was selected is selective catalytic reduction (SCR). A SCR system is the recommended control technology for the UK and the EU and is in use in more than 7 RBLC records (Table 2.5). SCR systems are the most developed and widely spread FGT technology and can remove 60-90% of NO_x from flue gases (Cooper and Alley, 2002; World Bank, 1999). Selective non-catalytic reduction (SNCR) systems are also recommended to a great extent (Table 2.5) but the removal efficiency is lower (40-60%), the operating temperature is higher (900ºC – 1 000ºC), and the technology is not as well developed and wide spread as the SCR (Cooper and Alley, 2002; World Bank, 1999).

Good combustion practises and control is the only way to reduce carbon monoxide (CO) emissions from coal-fired power plants. Proper practises and control will ensure complete or near complete combustion, which consequently reduces CO emissions (Table 2.6).

Figure 3.1 shows the final technology selection that was made for control of air pollution from a coal-fired power plant.

3.3 COAL GASIFICATION

During the gasification process various air pollutants are emitted, including PM, SO_x, NO_x, VOCs, hydrogen sulphide (H_2S) and ammonia (NH_3). The majority of these pollutants are emitted during gas handling and treatment (Table 2.9). The techniques or technologies used to control releases to air from a gasification process are discussed according to the various processes associated with gasification, namely:

- materials handling,
- gasification, and
- gas purification and conversion.

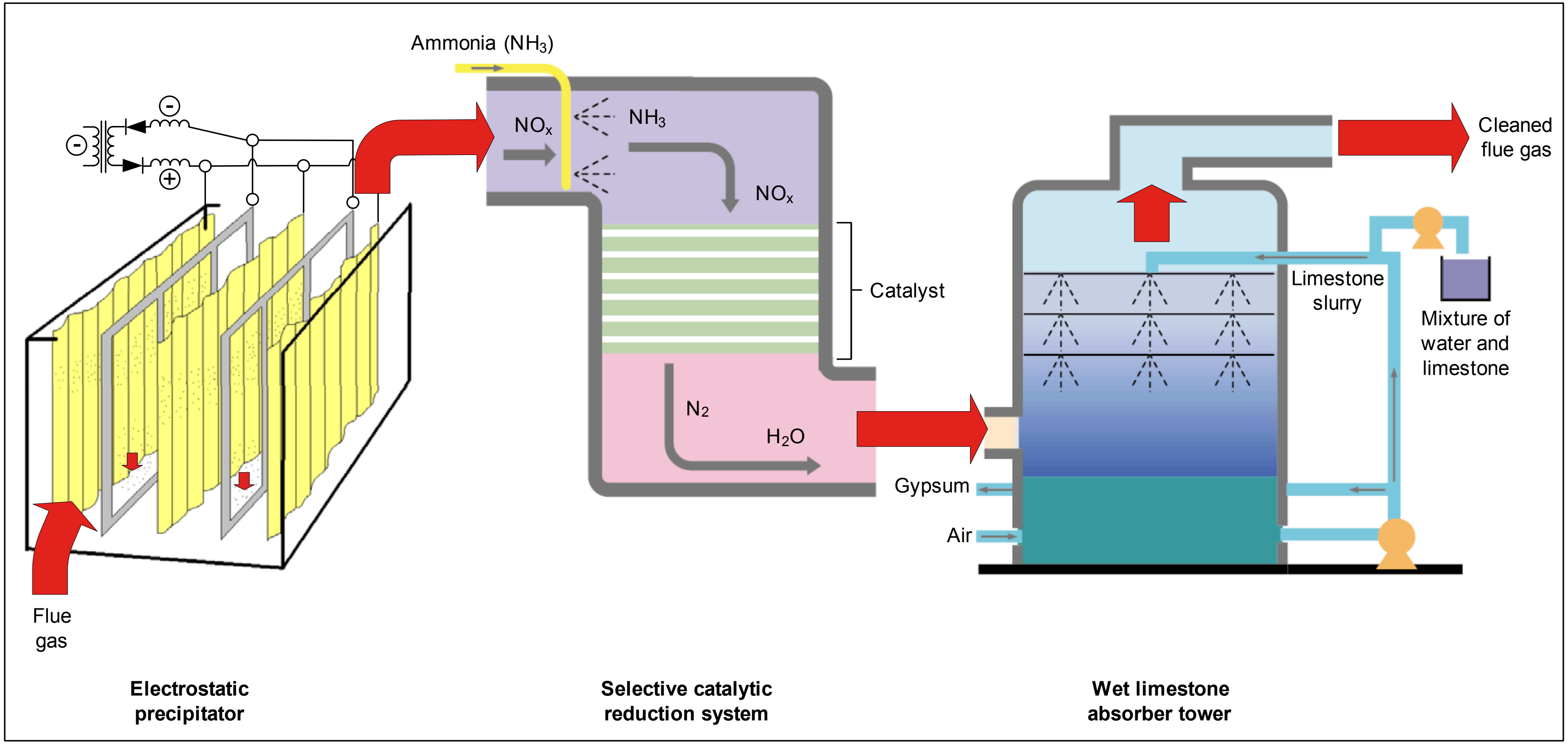

Figure 3.1 Schematic diagram of the selected control technologies for the control of air pollution from a coal-fired power plant.

(Adapted from Friend, 1995 and EPDC, 2004.)

3.3.1 Materials handling

Coal and other solid raw materials may create a dust problem during receipt and subsequent handling and operations. During unloading discharge should be into purpose built enclosed hoppers, any transfers should take place, if possible, via enclosed conveyors (Table 2.10). Where open stockpiles are used, transfer to these from conveyors should be via enclosed discharge towers, this minimises freefall and reduces wind whipping of fines (Table 2.10). Raw materials removal from stockpiles should be by bottom off-take and use should be made of enclosed systems with extraction and arrestment equipment when working with dusty materials (Table 2.10). Bag or ceramic filters should be used for dust handling. Liquid feedstocks should be stored in appropriate roofed tanks. Any vented gas should either be scrubbed or incinerated (Table 2.10).

3.3.2 Gasification

Gasification will normally take place at high pressures and the toxic, offensive and flammable nature of the gases contained in the gasifier requires high standards of containment. Coal charging should be via a double lock system, whereby the gases released from the reactor during charging are contained within the lock hopper. After closure of the charge valve they are routed either to recompression for re-injection into the crude gas stream or to a vent treatment system (Table 2.11). Alternatively, a wet feed (slurry) system may be used with comparable features. All process vents and pressure reliefs should be routed to a flare system. Flares should be designed to ensure destruction of combustible gases and impurities at all flow rates, including pressure relief at full operating pressure (Table 2.11). Handling and disposal systems for ash and slag should be designed and operated to prevent the emission of fine particulate matter to atmosphere to the standards specified for materials handling (Section 3.3.1).

3.3.3 Gas purification and conversion

The diversity of crude gas purification and conversion options available prevents the selection of detailed procedures for these processes, but the following general procedures should be observed. They are by no means a full representation of the options available and each case should be considered individually on its merits.

3.3.3.1 Liquid quenching

If a side stream of the aqueous liquor is removed to maintain process conditions, any flash steam/gas arising on pressure let down should be totally contained and routed to an appropriate treatment system or combined with the acid gas stream from later treatment stages and routed to the sulphur recovery unit (Table 2.12).

3.3.3.2 Particulate matter removal

Where dry removal of particulate matter is carried out prior to purification or conversion, the collected material should be removed from the system via a lock hopper arrangement - designed to prevent the loss of process gases to atmosphere (Table 2.12).

3.3.3.3 Acid gas streams

Gas treating or sweetening is a term used to describe the various processes for removal of certain contaminants, primarily H_2S and carbon dioxide (CO_2) from natural gas or hydrocarbon liquids. CO_2 and H_2S are also termed “acid gases” because when absorbed in water, they form an acidic solution. In addition to H_2S and CO_2, the sulphur acids, carbonyl sulphide (COS), carbon disulphide (CS_2), and mercaptans, when present in sufficient quantities, are also candidates for removal with specific amines.

A number of proprietary regenerative absorption processes, commonly based on amines (for example, sulfinol), are available and should be used to scrub H_2S out of the fuel gas. The acid gases are recovered in a concentrated gas stream and this stream should be treated by a sulphur recovery process (for example, a Claus kiln), in which the gases are partially oxidised and elemental sulphur recovered by catalytic treatment (Table 2.12). The final vent gas from the relevant sulphur recovery process should be incinerated (Table 2.12). Carbonyl sulphide (COS), methyl mercaptan and other sulphur containing minor constituents of the gas stream may be removed by conversion and forwarding to the sulphur recovery process. Hydrogen cyanide and NH_3 should be removed from the gas stream by water scrubbing and can be routed to the sulphur recovery process (Table 2.12). CO_2 should be released via an appropriate stack, provided the concentration of the CO_2 is adequately low (Table 2.12). All process vents and pressure reliefs should be contained and routed to the incinerator or flare system (Table 2.12).

Figure 3.2 gives an example of the gas treating units.

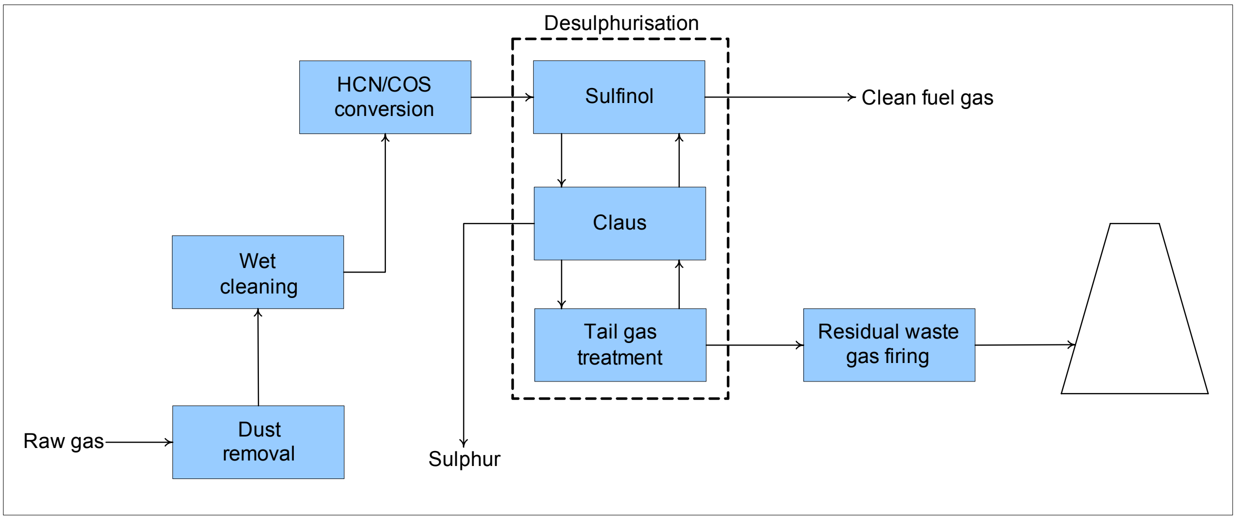

Figure 3.2 Gas treating units for coal gasification.

(Adapted from HMIP, 1995b.)

3.4 PETROLEUM REFINING

Petroleum refining employs a variety of processes to manufacture multiple products. A refinery's processing flow scheme is largely determined by the composition of the crude feedstock and the petroleum products it chooses to manufacture. The various processes emit different air pollutants at varying amounts (Table 2.14).

For many refineries, the catalytic cracking unit's regenerator is the single largest air emission source, contributing particulates, SO_x, NO_x and other hazardous air pollutants. Because of the large gas volume involved, and the subsequent tons/year of pollutants generated, controlling emissions from the catalytic cracking unit may allow the plant to avoid having to control multiple minor sources (Confuorto, Weaver and Eagleson, 2000).

The other major contributor to air pollution from a refining facility is the process furnaces or process heaters that are used for power generation. The same technologies that were mentioned in Section 2.8.1 and selected in Section 3.2 can be used to control air pollution from these units.

Although the abovementioned units are the major contributors to air pollution from a refining facility, technologies or techniques to control air pollution from smaller units will also be selected in order to follow an holistic approach.

3.4.1 General volatile organic compounds control

Volatile organic compounds (VOCs) are of concern over an entire refining facility, therefore technologies and techniques for the prevention and control of VOCs were discussed in Section 2.8.3 in a generic way, meaning applying to a refinery as a whole. The following selected technologies or techniques should therefore be applied on the entire refining facility. The most highly recommended technology is the implementation of a leak detection and repair programme (LDAR), recommended by both the UK and the EU and in use in more than 10 RBLC records (Table 2.15). There are various other technologies or techniques that are also recommended by all three information sources, namely (Table 2.15):

- use of low release valves where gate valves are not essential,
- use of balanced bellows type relief valves,
- use of canned pumps or double mechanical seals on conventional pumps, and
- venting of relief valve emissions to incineration systems.

These technologies or techniques will essentially form part of or will result from a proper LDAR. The final selection of a control technology to control VOCs emissions from a refining facility was thus the implementation of a leak detection and repair programme.

3.4.2 Catalytic cracking unit

Particulate matter (PM) emissions in the catalytic cracking unit result from catalyst escaping the catalytic cracking unit's regenerator in the flue gas. Cyclones are recommended for the control of particulates by al three information sources (Table 2.16), but cyclones still allow a significant amount of fine catalyst to escape. Typically uncontrolled catalyst emissions exiting cyclones range from 5 – 10 kg per 1 000 kg of regenerator coke burn-off (Confuorto *et al.,* 2000).

Electrostatic precipitators (ESPs) and wet scrubbers are the other technologies that are in widespread use in catalytic cracking units for the control of particulates (Table 2.16). Adding an ESP or wet scrubbing system to control particulates for environmental compliance represents a significant investment in capital. By only adding particulate control, the costs for installation and operation are not offset by increase in profits (Confuorto *et al.,* 2000). It should be noted that the incremental cost of adding SO_x control while adding particulate control is low. With the ability to control SO_x, feed sulphur content and unit capacity can possibly be increased (Confuorto *et al.,* 2000). Therefore, along with the information in Table 2.16 for final technology selection, a wet scrubbing system was chosen for the control of PM and SO_x emissions.

Controlling NO_x emissions from a catalytic cracking unit can once again be obtained through a combination of flue gas treatment and combustion controls (Table 2.16).

Regenerator flue gas can be treated by either a SNCR or SCR system, according to the recommendations by the EU and by more than 7 RBLC records (Table 2.16). For the same reasons given in Section 3.2 the SCR was chosen during final technology selection.

For the control of CO emissions from a catalytic cracking unit's regenerator, the UK, EU and more than 8 RBLC records (Table 2.16) recommend to either install a downstream CO boiler, or to ensure proper operation of full combustion type regenerators. Table 2.16 gives the impression that downstream CO boilers are more often utilised, and was therefore chosen during final technology selection. If a downstream CO boiler is installed it must be operated to the correct standards in order to avoid the formation of hot spots, which could lead to the formation of NO_x (HMIP, 1995c).

3.4.3 Coke production unit

During coke production PM may be released from the kiln gas cleaning system, rotary cooler gas cleaning system, coke handling, and storage and loading operations. Fabric filters are the recommended technology for the UK, the EU and is used by more than 2 RBLC records for the control of PM releases during coke production. A combination of an appropriate cyclone with a fabric filter can be used to achieve suitable release levels (HMIP, 1995c). The principal option, according to the UK, to reduce SO_x releases is through fuel switching. Although this is also recommended by the EU and by more than 2 RBLC records (Table 2.17), the technology or technique that seems to have the highest frequency of use is wet scrubbing (Table 2.17). Therefore since selection is based on the frequency of use, wet scrubbing was chosen during final technology selection. Fuel switching should be considered as a supplementary technique.

3.4.4 Bitumen production unit

The major potential releases from bitumen production occur as releases to air from a number of sources containing H_2S, which can cause odour problems. Potential releases into air also include SO_x, NO_x, oxides of carbon (CO_x), smoke and particulates.

Hydrocarbons and sulphur compounds may emanate from leakages, particularly on overhead systems. Therefore overheads from the oxidiser should be treated or scrubbed to remove air pollutants, specifically sulphur compounds prior to incineration. Gases vented during storage should be vented to an incinerator or other equivalent arrestment equipment. This may include the use of a wet ESP, which has proven capable of successfully removing the liquid element of the aerosol that is recovered from storage vents. Incineration should take place in a purposely-designed incinerator or a process heater at a temperature of at least 800ºC, and a residence time in the combustion chamber of at least 0,5 seconds (Table 2.18).

3.4.5 Visbreaking unit

During visbreaking oil is heated to above its decomposition temperature. The hydrocarbon molecules break up by thermal cracking to give mixed products, typically fuel gas, visbreaker naphtha and visbroken gas and fuel oils.

The gas form the visbreaking unit is usually sour, and should be sweetened, typically amine scrubbing should be applied for the sweetening operation. The treated gas should be recovered, either into products or used as refinery fuel gas (Table 2.19). The above-mentioned operations are not specific control technologies or techniques, nevertheless they were still chosen during final technology selection to prevent or control releases to air from a visbreaking unit.

3.4.6 Hydrogen fluoride alkylation unit

This process uses anhydrous, liquid hydrogen fluoride (HF) to catalyse the addition of iso-butane to a butylene or propylene molecule. The reaction proceeds at moderate temperatures and pressures and an alkylate is formed having a high octane number, which is valuable in petrol blending.

It is recommended by the EU that a scrubber using an alkaline solution (NaOH or KOH) should be used to remove HF from the incondensable gas. Both the EU and the UK recommend that an acid relief neutraliser should be operated to reduce HF in the incondensable gas stream (Table 2.20). They both also recommend that the vented gas should be passed to flare and not be used as refinery fuel gas, and that a dedicated flare or stack is retained for this (Table 2.20). While the above are not specific control technologies or techniques, they were still chosen during final technology selection to prevent or control releases to air from an HF alkylation unit.

3.4.7 Sulphur recovery unit

Sulphur recovery systems are used on all major refineries as the means by which sulphur is separated from products streams, captured and converted to a saleable by-product; instead of being released into the environment.

Sulphur should be recovered from sour gasses by the application of appropriate techniques to convert it to H_2S. Amine scrubbing remains the best available technique according to the UK and the EU and is in use in more than 1 RBLC record (Table 2.21). A combination of common and individual scrubbers may be required for H_2S removal. After sulphur has been recovered in its elemental form via, for example a Claus kiln, tail gases should be treated to remove any residual H_2S. Tail gas treatment can be achieved through thermal or catalytic incinerators, as recommended by the UK and the EU and more than 2 RBLC records (Table 2.21). Thermal incinerators should be operated at temperature of at least 800ºC with a residence time in the combustion chamber of at least 0,5 seconds. Catalytic incinerators should be operated at a temperature in accordance with the catalyst used (HMIP, 1995c). Therefore for final technology selection amine scrubbing with an appropriate tail gas incinerator was chosen to prevent or control releases from a sulphur recovery unit.

3.4.8 Distillation units

The initial process in refineries is one of the most important and consists of distilling the crude oil into fractions, or cuts, of various boiling ranges that then go forward as either products to finishing processes, intermediates for conversion processes, or residual materials as fuels. Light and heavy cuts receive atmospheric pressure distillation alone while bottoms, that is residues, are vacuum distilled as a prelude to conversion or cracking.

Both the EU and the UK recommend that incondensables from vacuum distillation column condensers should be vented to a process heater or incinerator (Table 2.22). Further pollution reduction can be achieved if vacuum gaseous streams (vent gases) are routed to an appropriate amine scrubbing unit prior to incineration. Furthermore, both the EU and the UK recommend that where ammonia (NH_3) injection is applied it should be done in an enclosed system and de-coking vents must be provided with proper knock-out and dust suppression facilities (Table 2.22). While these are not specific control technologies or techniques, they were still chosen during final technology selection to prevent or control releases to air from distillation units.

3.4.9 Handling and storage of feedstock and products

Crude oil is normally shipped into refineries through marine terminals but can also arrive via pipeline, rail or road. Unless properly handled, crude oil can easily give rise to hydrocarbon releases to air. Similarly, to avoid such releases, intermediates and final products should be handled and stored in appropriate equipment.

During handling and storage the most highly recommended technology or technique to reduce or prevent particulate matter (PM) is bottom loading of containers (Table 2.23). The use of proper tanks, based on the vapour pressure at storage temperature, is recommended by the UK and the EU and by more than 1 RBLC record to prevent or control SO_x, NO_x and VOC emissions during storage and handling operations (Table 2.23). Vapour recovery and incineration is further also recommended by the UK and the EU and by more than 3 RBLC records to prevent or control NO_x and VOC emissions (Table 2.23).

Figure 3.3 summarises all the air pollution control technologies or techniques that were selected for petroleum refining.

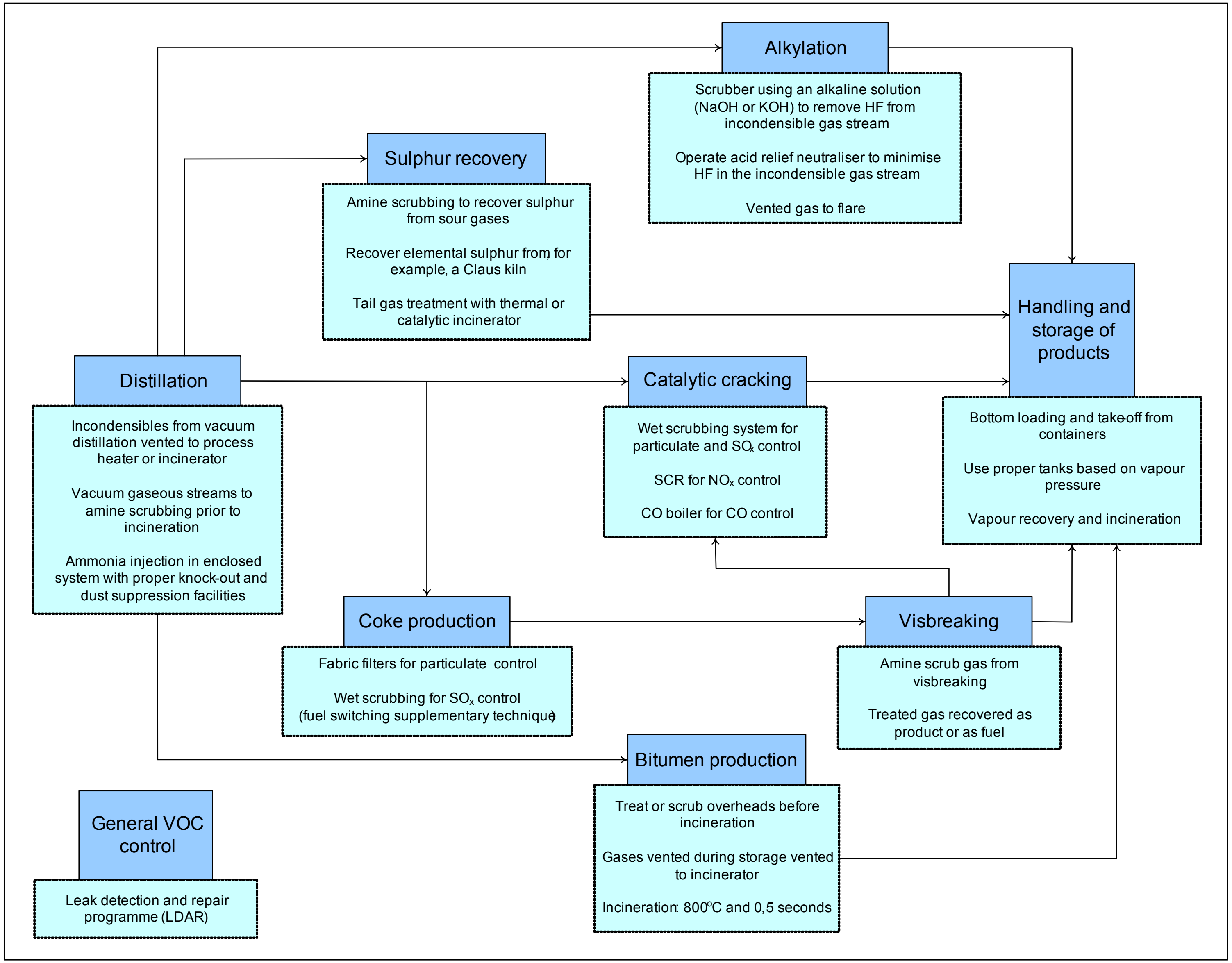

Figure 3.3 Schematic diagram summarising the selected air pollution control technologies for petroleum refining.

CHAPTER 4

Cost Analysis

4.1 BACKGROUND

With South African industries trading more often on foreign markets and acquiring more and more foreign shareholders; they are now being provided with incentives to consider their effect on the environment as these markets and shareholders require certain environmental standards. Consequently, industries are becoming progressively more aware of the environmental and social liabilities pertaining to their operations and products, and the associated financial effects (USEPA, 2000).

The financial effects associated with applying the air pollution control technologies selected in Chapter 3 can be assessed by using an environmental costing model. For the cost analysis conducted in this chapter the EEGECOST environmental accounting model (De Beer and Friend, 2005) was used to assist in expressing environmental and social liabilities as environmental costs. Environmental costs are those costs that have a direct financial impact on a company (internal costs), and costs to individuals, society and the environment for which the company is not accountable (external costs) (USEPA, 1996).

The cost analysis completed was for a coal-fired power plant only, since the final technology selection for a power plant is clearly defined for the entire facility and since information on this process is more readily available than for the other processes. Similar cost analyses can be conducted for coal gasification and petroleum refining should more information on these industries and their associated control technologies become available.

4.2 THE EEGECOST MODEL

The EEGECOST model was developed to promote environmental accounting in South Africa. The EEGECOST model (Environmental Engineering Group environmental costing model) is based on the principles of the total cost assessment (TCA) environmental accounting system. The objective of the model is to fully understand the cost significance of environmental and human health related decisions, activities and consequences over the whole life cycle of a product or process. The structure of the model is given in Figure 4.1 and consists of five steps for analysis (De Beer and Friend, 2005):

- objective statement and scope of analysis,
- life cycle assessment,
- cost inventory,
- impact assessment, and
- document results and assumptions.

The model is a spreadsheet-based program and consists of pathways that the user must follow in specific analysis. These different pathways depend on the objective statement and scope of analysis, and the amount of data the user needs to acquire (De Beer and Friend, 2005).

Compiling an objective is the first step of the EEGECOST model. This entails a background of the company and provides some informative value to the product or process being considered. The scope of analysis determines the time frame that is desired for the analysis and the type of cost comparison (De Beer and Friend, 2005).

The next step of the EEGECOST model is the life cycle assessment (LCA) of the process or product being considered. The LCA is a procedure that is determined by a company’s own specific guidelines. Therefore, the model does not support an LCA procedure in itself, but only the output of a relevant LCA is used as input to the model (De Beer and Friend, 2005). The LCA for environmental accounting systems entails coupling a quantitative value to environmental impacts associated with a project by (Little, 2000):

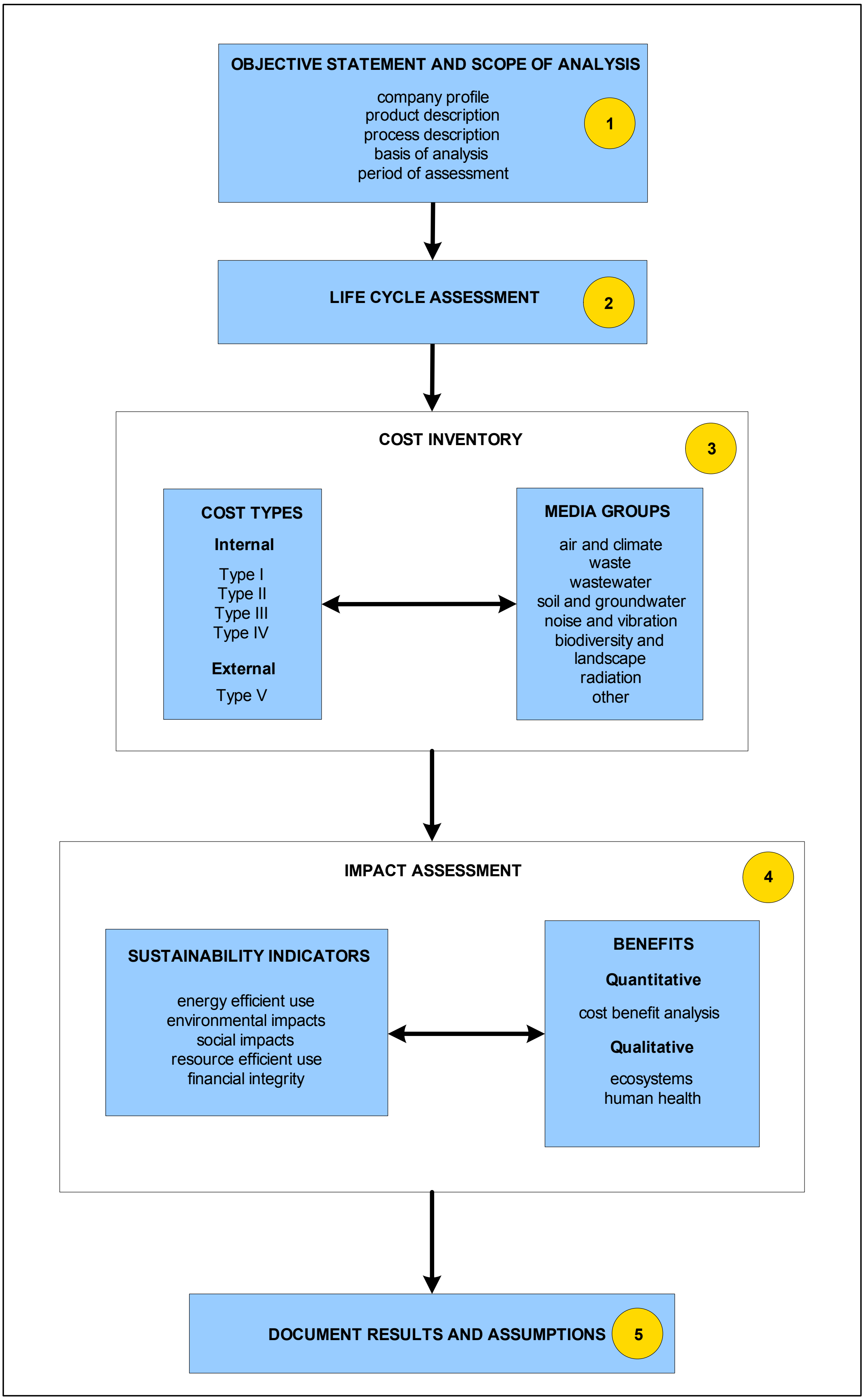

Figure 4.1 Structure of the EEGECOST model.

(Adapted from De Beer and Friend, 2005.)

- compiling an inventory of relevant energy and material inputs and environmental releases,
- evaluating the potential environmental and social impacts associated with identified inputs and releases, and
- interpreting the results to make informed decisions.

Coupling a quantitative life cycle assessment to an environmental accounting system provides a comprehensive view of the environmental impacts of a project and a more accurate picture of the true environmental trade-offs, with associated financial effects (USEPA, 2001).

During the third step of the EEGECOST model, output from the LCA of the process or product is allocated to cost types to be used in the environmental cost inventory. The model allocates environmental costs to the following cost types (De Beer and Friend, 2005):

- Type I: site costs,
- Type II: corporate costs,
- Type III: impact costs,
- Type IV: internal intangible costs, and
- Type V: external costs.

Type I costs are further subdivided in Type I(a) non-recurring site costs and Type I(b) recurring site costs.

After allocation to cost types, the output from the LCA is translated to an economic value. Economic values are calculated by recording/entering all relevant present and future environmental costs and revenues in cost inventory forms. These forms are categorised into the following environmental media groups (De Beer and Friend, 2005):

- air and climate,
- waste,
- wastewater,
- soil and groundwater,
- noise and vibration,

- biodiversity and landscape
- radiation, and
- other costs.

Since only the financial effects associated with air pollution and air pollution control was being considered in this cost analysis, use was only made of the air and climate environmental media group.

The final report compiled by the EEGECOST model can be compiled according to a company's specific regulations, incorporating the reported values as given in the *costs incurred by type form*, the *cost types by year form* and the *cost report form* of the model (De Beer and Friend, 2005).

4.3 COST ANALYSIS PROCEDURE

The EEGECOST model was used to study the financial effects of controlling air pollution from a coal-fired power plant. The basis of the study was a hypothetical 3 600 MW (six 600 MW units) power plant (Figure 4.2), which is the average size of a power plant in South Africa (Eskom Holdings Limited, 2003b). The analysis was done over the time span of one production year, assuming 330 days of production, and it was assumed the power plant operates at 85% capacity on average. It was further assumed that the air pollution control technologies operated at their full design control efficiency (see Table 2.1).

Three different control regimes were analysed with the aid of the EEGECOST model:

- **Control regime 1**: Hypothetical power plant with only control of particulate matter via an electrostatic precipitator (ESP) with 90% operating efficiency. This was done in order to represent an older plant since older existing ESPs have operating efficiencies between 90% and 99%, and newer ESPs between 99% and 99,9% (USEPA, 2003e).
- **Control regime 2**: Hypothetical power plant with only particulate matter control in place in the form of a 99,9% efficient baghouse (fabric filter). This was done in order to represent a newer plant with a baghouse employed for air pollution control.

- **Control regime 3**: Hypothetical power plant with full pollutant control in place in the form of the final selected control technologies (see Section 3.2):
    - 99,9% efficient ESP,
    - 60% efficient low-NO_x burners,
    - 90% efficient selective catalytic reduction (SCR) system, and
    - 98% efficient wet flue gas desulphurisation (FGD) system with limestone.

Figure 4.2 Photo of a 3 600 MW coal-fired power plant consisting of six 600 MW units.

(*Source*: Eskom Holdings Limited, 2003a)

The purpose of the cost analysis was to show that the external costs or damage costs would be greatly reduced if proper air pollution control technologies were utilised. Only the financial effects associated with air pollution and air pollution control were considered in the cost analysis.

Since the costs that were obtained for the cost analysis were not all in Rand (R) value for the year 2005, the costs had to be adjusted to compensate for any price increases due to inflation and other factors. Cost adjustments were done using the Marshall and Swift equipment cost index (see Table 4.1) and the following equation (Cooper and Alley, 2002):

$$P_{2003} = P_x \times \frac{CI_{2003}}{CI_x} \qquad (4.1)$$

where P_{2003} = cost in 2003,

P_x = cost in relevant year x,

CI_{2003} = cost index for 2003, and

CI_x = cost index for relevant year x.

Table 4.1 Marshall and Swift equipment cost indices.

Year	Index*
1988	852
1992	943,10
1997	1056,80
1998	1061,90
1999	1068,30
2002	1104,20
2003	1123,60
* Data from Schweikart (2004) and Cooper and Alley (2002).	

Since the most recent cost index available is for the year 2003, the cost analysis was done by adjusting costs for 2003 and using the exchange rates for 3 November 2003 (see Table 4.2).

Table 4.2 Exchange rates on 3 November 2003.

Exchange Rate 3 November 2003*	
Rand/Dollar	6,91
Rand/Euro	7,91
* Data from TSC (2004).	

In some cases the capacity of a required piece of equipment differed in capacity of a known piece of equipment with a known price. The following equation was used to adjust costs where necessary (Cooper and Alley, 2002):

$$P_2 = P_1\left(\frac{C_2}{C_1}\right)^a \tag{4.2}$$

where P_1 = price of known equipment,

C_1 = capacity of known equipment,

P_2 = price of new equipment,

C_2 = capacity of new equipment, and

a = an exponent (average of 0,6 in the chemical industry).

The following costs were obtained from various literature sources and, where required, adjusted using Equation 4.1 and Equation 4.2. These costs were then inserted into the EEGECOST model, following the sequential steps of the program.

4.3.1 Equipment costs

Equipment costs were obtained by sizing literature costs based on a 3 600 MW power plant, using efficiencies as stated.

4.3.1.1 Electrostatic precipitator

For this cost analysis two different electrostatic precipitators (ESPs), an older ESP with 90% control efficiency and a new ESP with a control efficiency of 99,9%, were used.

The purchase cost of an ESP can be estimated as a function of the collection plate area as follows (Cooper and Alley, 2002):

$$P = aA^{b} \tag{4.3}$$

where P = purchase cost [$, 1998],

A = nett plate area [ft^2], and

a,b = constants, as follows:

for 10 000 $ft^2 < A <$ 50 000 ft^2, a = 962 and b = 0,628

for 50 000 $ft^2 < A <$ 100 000 ft^2, a = 90,6 and b = 0,843.

The nett plate area can be calculated by using Equation 4.4 (Cooper and Alley, 2002):

$$A = \frac{-Q}{w_e} \ln(1-\eta) \tag{4.4}$$

where Q = volumetric flow rate [ft^3/min or m^3/min],
w_e = drift velocity [ft/min or m/min], and
η = collection efficiency.

The delivered equipment cost (DEC) can be estimated with Equation 4.5 and the total installed cost (TIC) can be estimated with Equation 4.6 (Cooper and Alley, 2002):

$$\text{DEC} = P \times 1{,}18 \tag{4.5}$$

$$\text{TIC} = \text{DEC} \times 2{,}22 \tag{4.6}$$

From Appendix A a nett plate area of 13 769 ft^2 for a 90% efficient ESP and a nett plate area of 41 308 ft^2 for a 99,9% efficient ESP were calculated. Based on calculated purchase costs of \$ 382 307 and \$ 762 158 for the 90% and the 99,9% electrostatic precipitators respectively, the total installed costs for these units were (Appendix A):

- 90% efficient ESP = R 44 million, and
- 99,9% efficient ESP = R 100 million.

Based on the volume of flue gas treated the operating costs for both the 90% and the 99,9% ESP were calculated to be R 20 million (Appendix A).

4.3.1.2 Fabric filter

The purchase cost of a baghouse system (fabric filter) can be estimated as a function of gross cloth area. Equation 4.7 was used to calculate the gross cloth area of the baghouse system (Cooper and Alley, 2002):

$$\text{GCA} = \frac{Q}{V} \tag{4.7}$$

where GCA = gross cloth area [ft^2],

Q = volumetric gas flow rate [ft^3/min], and
V = maximum filtering velocity [ft/min].

From Appendix A a gross cloth area of 58 858 ft^2 for a 600 MW unit was calculated. Since the gross cloth area is greater than 30 000 ft^2 but smaller than 70 000 ft^2, a large shaker baghouse was selected and Equations 4.8 to 4.10 used to estimate the purchase cost of a baghouse (Cooper and Alley, 2002):

$$BBP = \$\ 96\ 230 + \$\ 3{,}33 \times GCA \tag{4.8}$$

where BBP = basic baghouse price [$ 1998], and

$$SSA = \$\ 51\ 280 + \$\ 1{,}43 \times GCA \tag{4.9}$$

where SSA = stainless-steel add-on [$ 1998].

$$INS = \$\ 26\ 330 + \$\ 0{,}57 \times GCA \tag{4.10}$$

where INS = insulation add-on [$ 1998].

The total purchase cost of the baghouse system is the baghouse price plus the cost of the bags. Shaker loop top bags were selected and the bag price was estimated with Equation 4.11 (Cooper and Alley, 2002):

$$BP = 0{,}63 \times GCA \tag{4.11}$$

where BP = bag price [$ 1998].

The delivered equipment cost (DEC) can be estimated with Equation 4.12 and the total installed cost (TIC) can be estimated with Equation 4.13 (Cooper and Alley, 2002):

$$DEC = P \times 1{,}18 \tag{4.12}$$

$$TIC = DEC \times 2{,}19 \tag{4.13}$$

Based on the calculated purchase cost of $ 542 632, the total installed cost in 2003 was R59 million (Appendix A).
Based on the estimates made for the ESPs operating costs the operating cost for the baghouse system was calculated to be R 20 million (Appendix A).

4.3.1.3 Low-NO$_x$ burners

Low-NO$_x$ burners appear to be very cost effective, yielding 40%-60% reductions at a capital cost of about 6-9 $/kW (STEP, 2005; Cooper and Alley, 2002).

Based on the calculated capital cost of $ 27 million, the capital cost in 2003 was R 198 million (Appendix A).

4.3.1.4 Selective catalytic reduction system

The capital costs for selective catalytic reduction (SCR) and selective non-catalytic reduction systems (SNCR) have significantly declined in the last 20 years, due to improved designs and more familiarity with the technology (Cooper and Alley, 2002). The capital cost of a SCR in 1997 was estimated at between 44-66 $/kW with a 70-80% control efficiency (STEP, 2005; Cooper and Alley, 2002), and the operating cost of a SCR system in 1997 was estimated between 1,60-3,25 $/MWh (STEP, 2005).

Based on the calculated capital cost of $ 198 million, the capital cost in 2003 was R 1,5 billion and with the operating cost calculated at $ 59 million, the operating cost in 2003 was R 433 million (Appendix A).

4.3.1.5 Wet flue gas desulphurisation with limestone

The technology of flue gas desulphurisation (FGD) systems is now more advanced than it was in the 1970s, and costs have decreased. Nevertheless, FGD systems still represent a huge investment, as much as 20% of the capital cost of a new coal-fired power plant (Cooper and Alley, 2002). The capital cost for a FGD system can be estimated at between 100-250 \$/kW and the operating cost at between 20-50 \$/kW (USEPA, 2003a).

Based on the calculated capital cost of \$ 630 million, the capital cost in 2003 was R 4,4 billion and with the operating cost calculated at \$ 126 million, the operating cost in 2003 was R 886 million (Appendix A).

4.3.2 Life cycle assessment

Life cycle assessment (LCA) data is specific to every plant and every situation. However, since this analysis is based on a hypothetical 3 600 MW plant, use was made of annual reported data representing a number of power plants. Typically life cycle data is more complete, but for the purpose of this analysis the annual reported data given in Table 4.3 was used to represent LCA data for the hypothetical plant. Other inputs to the process, for example coal and electricity, were not available as intrinsic values and the total cost spent on primary energy was used to determine these relevant costs (see Section 4.3.4.4).

Table 4.3 Annual reported data used in the cost analysis to represent LCA data.

Input	**Unit**	**Number of units**
Water	ℓ/kWh	1,29
Output	**Unit**	**Number of units**
PM	g/kWh	0,28
SO_2	g/kWh	8,22
NO_x	g/kWh	3,62
CO_2	g/kWh	0,9
Data from Eskom Holdings Limited (2003b).		

The data shown in Table 4.3 was converted to mass values for one production year (see Appendix A). In order to calculate the pollutants emitted for each control regime, the yearly mass values were reduced according to the applicable removal efficiency of the control technologies in place. For Control regime 1 no reductions were applied since it was assumed that the data in Table 4.3 applies to a power plant with a 90% efficient ESP already in place (see Appendix A).

4.3.3 External costs

External costs (also know as externalities) associated with coal-fired power generation are the costs imposed on society, individuals and the environment that are not accounted for by the producers and consumers of energy, that is, they are not included in the market price. These costs include, for instance, damage to the natural and built environment such as the effects of air pollution, occupational disease and accidents. A research project of the European Commission, known as the ExternE Project, attempted to use a consistent 'bottom-up' methodology to evaluate the external costs associated with, *inter alia,* a coal-fired power plant (European Commission, 2001). External costs were obtained from the ExternE project for the United Kingdom (UK), since this country's information was used throughout the investigation.

Although there is information available on the external cost per unit electricity, these costs depend heavily on the specific technology in place and the site of the facility. They are therefore hardly transferable between fuel sources, technologies and different locations and can therefore be very much misleading. Use was thus made of damage costs per unit pollutant emitted, since these costs can be used in a more general context, as it does not depend on the fuel source and the abatement technologies in place (Krewitt *et al.,* 1999). Table 4.4 shows the 1998 estimated damage costs per ton pollutant emitted in Euro's, and Table 4.5 the 2003 estimated damage costs per ton pollutant in Rands (see Appendix A).

Table 4.4 Estimated damage costs in 1998 per ton pollutant emitted.

Pollutant	**€/ton of pollutant [1998]***
SO_2	6 818
NO_x	5 736
PM	14 0623
CO_2	139

* Data from European Commission (2001).

Table 4.5 Estimated damage costs in 2003 per ton pollutant emitted.

Pollutant	R/ton of pollutant [2003]
SO_2	57 091,35
NO_x	48 029,68
PM	117 750,6
CO_2	1 163,90

As no externalities data is available for South Africa, data for the United Kingdom/Europe was used for the estimated damage costs shown in Table 4.5. However, as the majority of power stations in the United Kingdom (UK) and Europe are located much closer to towns and cities (even within cities) than in South Africa (Friend, 1995), it is anticipated that these values are much higher than can be expected for similar data for South Africa. For this reason some modification to the UK/European data is required to formulate data that is more applicable to South Africa (see Appendix A). Using an adjustment factor (k_{LF}) of 0,22 (Appendix A), the data from Table 4.5 was adjusted for South African conditions and is shown in Table 4.6.

Table 4.6 Estimated damage costs adjusted for South African conditions in Rand per ton pollutant emitted.

Pollutant	R/ton of pollutant [2003]
SO_2	12 560,10
NO_x	10 566,53
PM	25 905,13
CO_2	256,06

4.3.4 Other costs

4.3.4.1 Insurance for environmental liabilities

Insurance for environmental liability includes the annual contribution to insurance against traditional damage to persons, goods and biodiversity caused by dangerous and potentially dangerous activities and, insurance for transportation of hazardous materials (De Beer and Friend, 2005). An amount of R 12 million was allocated for pollution control costs, rehabilitation and any future closures (see Appendix A) based on a 3 600 MW power plant for one production year. The EEGECOST model automatically allocates insurance costs as Type II costs.

4.3.4.2 Provisions for environmental management

These costs include future expenses related to, for example, remedial activities, equipment repairs and governmental and public hearings that can result due to an accidental event; for example, air emission releases due to control equipment breakdown (De Beer and Friend, 2005). An amount of R 84 million was allocated for non-current liabilities (see Appendix A) like future pollution control costs and future rehabilitation costs. This cost is based on a 3 600 MW power plant for one production year. Any provisions are automatically allocated as Type III costs by the EEGECOST model.

4.3.4.3 Research and development

Research and development accounts for extra expenses related to internal environmental related research and development projects. Research and development costs can be allocated as either Type I or Type II costs, based on the company's own regulations (De Beer and Friend, 2005). For the purpose of this cost analysis 40% was allocated to Type I costs and 60% was allocated to Type II costs. An amount of R 2 million was allocated for research and development for a 3 600 MW power plant for one production year (see Appendix A).

4.3.4.4 General direct costs

Direct costs represent direct capital outlay and include raw materials like primary energy and water and any other auxiliary materials that become part of the product. Direct costs can be allocated as either Type I or Type II costs, based on the company's own regulations (De Beer and Friend, 2005). For the purpose of this cost analysis 40% was allocated to Type I costs and 60% was allocated to Type II costs.

An amount of R 94 million is paid annually for water and an amount of R 965 million is paid annually for primary energy, which includes coal and electricity (see Appendix A). A further amount of R 82 million is paid annually for other materials (Appendix A). These costs were all based on a 3 600 MW power plant for one production year.

4.4 COST ANALYSIS RESULTS

The purpose of this cost analysis was to show specifically the financial effects of controlling air pollution. This was done by inserting all aforementioned costs into the EEGECOST model and consequently comparing the external costs (Type V) of the different analyses. Special attention was paid to external costs since it was assumed that, apart from the extra expenditure on control equipment; all other costs would stay fairly constant for the different analyses. External costs are furthermore becoming more and more relevant since these costs are not taken into account when making decisions but are real to members of society (European Commission, 2001). Valuing external costs therefore allows these values to be included and considered during decision-making (European Commission, 2001).

For Control regime 1, a hypothetical 3 600 MW power plant was analysed for one production year. All the costs were inserted into the EEGECOST model and the model automatically assigned the costs to the different cost types. In all analyses a discount rate of 12% was used for Type I to IV costs, which are internal to the company, and a discount rate of 3% for Type V costs, which are external to the company. It is important to note that in the cost analysis attention was only on the financial effects of air pollution and air pollution control.

The percentage contribution by cost type for a 3 600 MW coal-fired power plant for one production year with Control regime 1 is shown in Figure 4.3. Type V costs (external costs) contribute 74%, and Type II cost, which is mostly the capital cost of the control equipment, contribute 14%. The external costs seem exaggerated since the only large capital expenditure in the analysis is that of the ESP.

For Control regime 2 the same hypothetical 3 600 MW power plant was analysed, but in this analysis the air pollution control device was a 99,9% efficient fabric filter (see Figure 4.4). There is little difference between Control regime 1 and 2; with an external cost reduction of only 1%. This can be contributed to the fact that the two control devices are fairly similar in efficiency and capital expenditure.

In the last analyses the hypothetical 3 600 MW power plant was analysed with Control regime 3 in place. All the major pollutants are being controlled to some extent, except for carbon dioxide (CO_2). Figure 4.5 shows the percentage contribution by cost type for a 3 600 MW coal-fired power plant for one production year with Control regime 3. The external costs are significantly reduced by 64% if all the major air pollutants are controlled. However, it is also important to note that Type **II** cost have now increased to 73%.

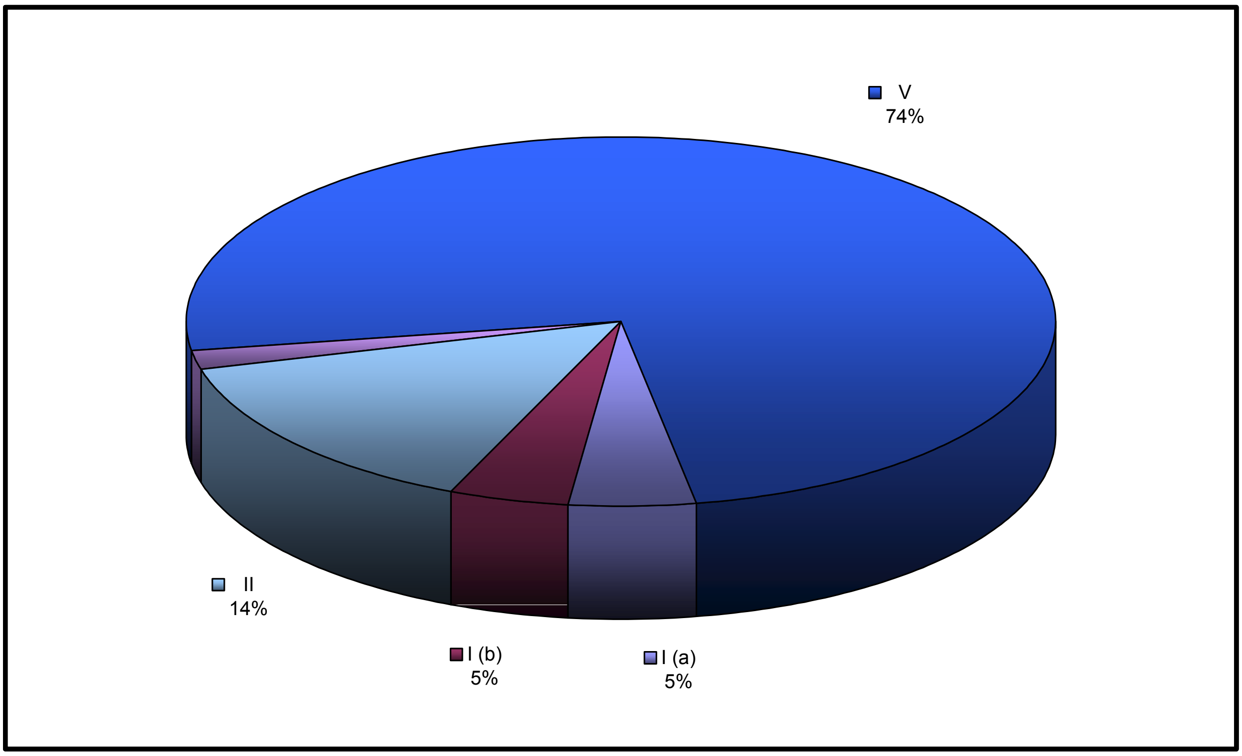

Figure 4.3 Percentage contribution of the various cost types associated with a coal-fired power plant controlling only particulate matter via an electrostatic precipitator.

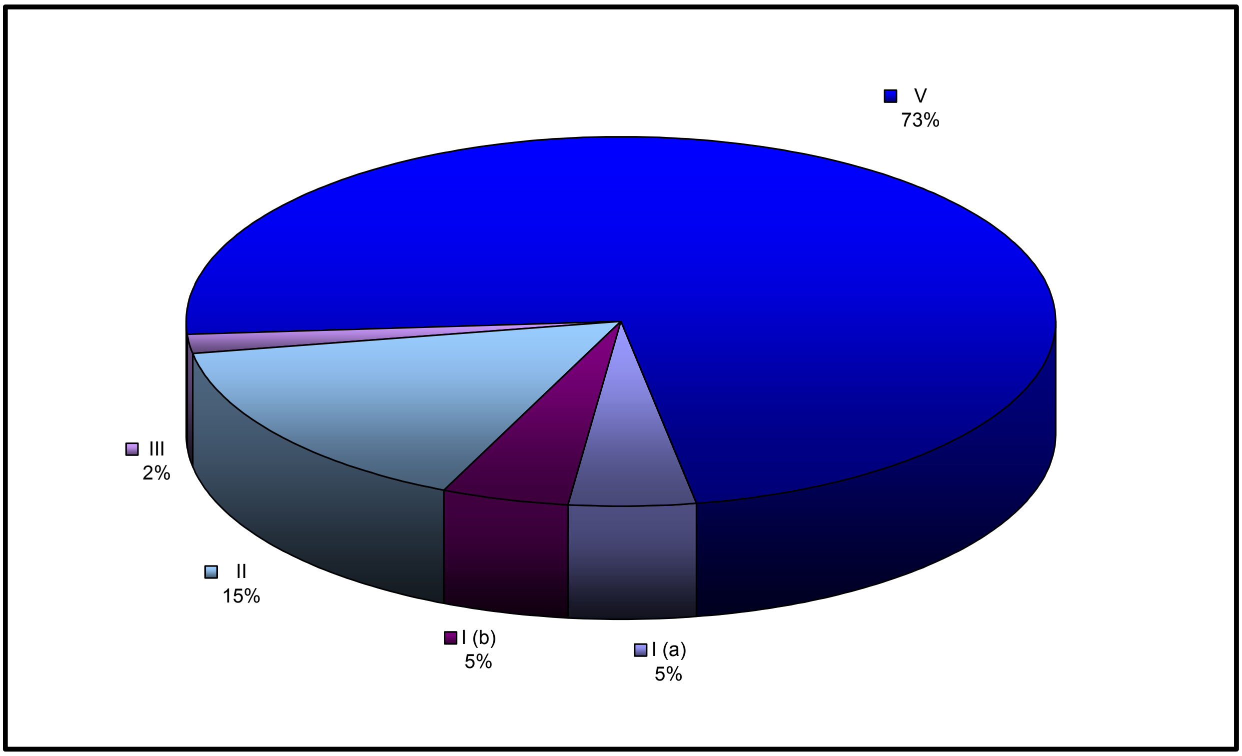

Figure 4.4 Percentage contribution of the various cost types associated with a coal-fired power plant controlling only particulate matter via a bag filter.

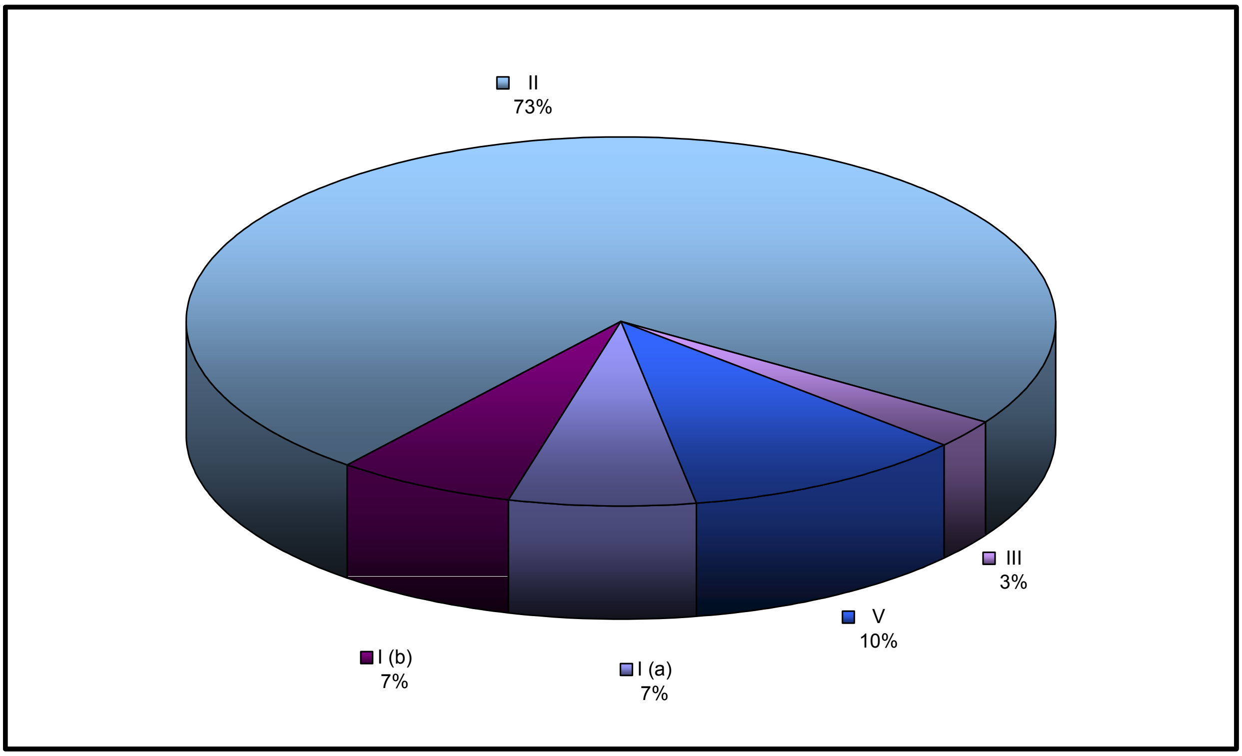

Figure 4.5 Percentage contribution of the various cost types associated with a coal-fired power plant controlling particulate matter, sulphur oxides and nitrogen oxides.

From Figure 4.3 to Figure 4.5 the external costs were reduced by almost 64% by controlling all the major air pollutants through increasing the capital expenditure on control technologies with 58%. The percentage contribution of the external costs are so high since these costs have to be carried by individuals, the environment and society every year, while the capital expenditure on air pollution control technologies are depreciated over their depreciable life. Furthermore, only the effect of air pollution and controlling air pollution are included in the analyses.

Another way to illustrate the financial effects associated with applying air pollution control technologies selected in Chapter 3 is shown in Figure 4.6. There is little difference between Control regime 1 and 2, since the control technologies control the same pollutant to almost the same extent. However, the total cost of Control regime 3 is reduced by almost R 1,6 billion compared to the other two control regimes. The external costs for Control regime 3 was reduced by almost R 3,4 billion by applying the control technologies selected in Chapter 3. This reduction in external cost was brought about by increasing the capital expenditure on control technologies by R 1,7 billion.

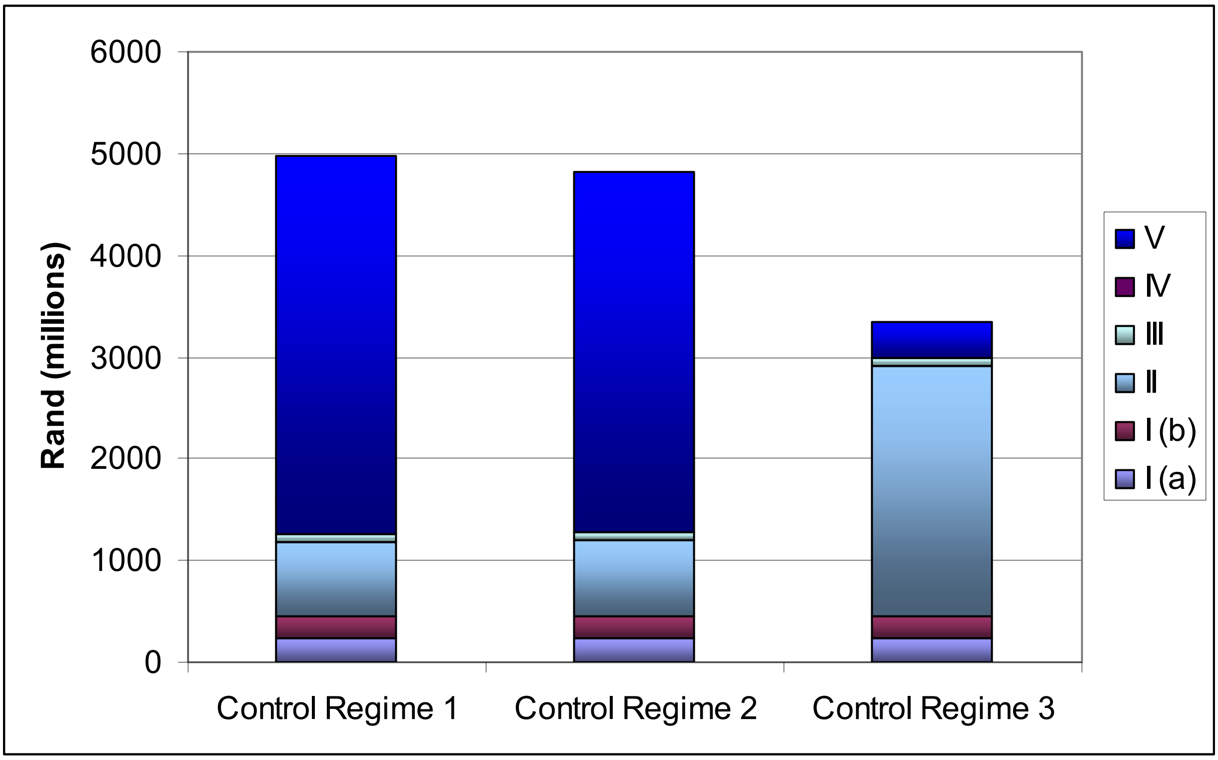

Figure 4.6 Cost incurred by type for the three different control regimes.

CHAPTER 5

Conclusions and Recommendations

The future of air quality legislation in South Africa is standing on the verge of a major transformation, shifting the concept of atmospheric emission control towards pollution prevention and emission minimisation through a more integrated approach. This transformation, along with increased foreign trade, is providing industries with incentives to consider their effect on the environment and to take action where required. The knowledge and experience gained from other countries in this regard is a valuable asset and was used to determine what technologies are best suited to power plants, gasification and refining processes in South Africa.

Therefore, with the information sourced from other countries the following conclusions were made regarding the best available technologies or techniques suited to power plants:

- an electrostatic precipitators for particulates and heavy metal control,
- low-NO_x burners for reducing nitrogen oxide formation in the boiler or furnace,
- selective catalytic reduction systems for NO_x control, and
- wet flue gas desulphurisation with limestone for SO_x control.

During the gasification process various air pollutants are emitted, including particulate matter, SO_x, NO_x, VOCs, hydrogen sulphide and ammonia. The following conclusions were made regarding the best available technologies or techniques used to control releases to air from gasification processes:

- the majority of pollutants are emitted during gas handling and treatment,
- any gas/flash stream, arising from pressure let down during liquid quenching, should be treated or combined with acid gas streams and routed to a sulphur recovery unit,
- any material collected during particulate matter removal should be collected via a lock hopper,
- acid gases should be scrubbed in an amine scrubber to remove hydrogen sulphide,

- concentrated gases should be treated in a sulphur recovery process, for example a Claus kiln,
- any other sulphur containing constituents should be removed by conversion and forwarded to the Claus process,
- hydrogen cyanide and ammonia should be removed via water scrubbing,
- carbon dioxide can be released via a stack if the concentration is adequately low, and
- all process vents, pressure reliefs and final vent gases should be routed to an incinerator or flare.

During petroleum refining a variety of processes are used to manufacture multiple products, determined largely by the composition of the crude feedstock and the petroleum products manufactured; resulting in various air pollutant emissions. The following conclusions were made regarding the best available technologies or techniques used to control releases to air from refining processes:

- the catalytic cracking unit's regenerator can be the largest single air emission source during the refining process,
- due to the large gas volume involved, controlling emissions from the catalytic cracking unit may allow the plant to avoid having to control multiple minor sources,
- a wet scrubbing system should be utilised to control particulates and SO_x emissions from the cracking unit, as it is not economically feasible to control the two pollutants separately,
- regenerator flue gases should be treated with a selective catalytic reduction system to control NO_x emissions, and
- a CO boiler should be installed downstream of the furnace or boiler to control carbon monoxide emissions.

It should be noted that the technologies and techniques that should be applied can vary on a case-by-case basis; depending on the specific industry, the raw materials used, the process and even the geography of the area. Technologies were selected based on how frequently a technology or technique was recommended or used by other countries.

A cost analysis conducted for a power plant with selected air pollution control technologies in place demonstrated that the selected technologies worked well to reduce the external cost associated with producing electricity by almost R 3,4 billion. This reduction in external cost was brought about by increasing the capital expenditure on control technologies by R 1,7 billion. Even though the cost of controlling air pollution is high, it resulted in a considerable reduction in external cost that normally has to be carried by the environment, society and individuals.

It is recommended that the same cost analysis procedure be applied to gasification and refining processes in order to show what the associated financial effects will be of applying the selected air pollution control technologies to these two industries.

It is further recommended that the k_{LF} adjustment factor, used to estimate external cost factors for South Africa, should be calculated more carefully by taking into account other factors that could contribute to the variance of external cost factors for different countries. It is also recommended that further research be conducted in order to estimate proper external cost factors for South Africa.

In order to aid in future selections, it is recommended that the information obtained from the various countries for power plants, gasification and refining processes be combined in a software based, user friendly database.

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APPENDIX A

Cost Calculations

EQUIPMENT COSTS

Electrostatic precipitator

From Equation 4.4 (Chapter 4) the nett plate areas for the two ESPs were calculated using a drift velocity of 6 m/min, and assuming the plant consisted of six 600 MW units, each treating 200 000 m^3/hr (3 333 m^3/min) flue gas (Eskom Holdings Limited, 2003a):

$$A = \frac{-Q}{w_e} \ln(1-\eta)$$

$A_{90\%} = \frac{-3\,333}{6} \ln(1-0{,}9)$ = 1 279,21 m^2 = 13 769 ft^2 per 600 MW unit, and

$A_{99.9\%} = \frac{-3\,333}{6} \ln(1-0{,}999)$ = 3 873 64 m^2 = 41 308 ft^2 per 600 MW unit.

Since both the 90% and the 99,9% ESP's nett plate areas are less than 50 000 ft^2; Equation 4.3, can be used to calculate the purchase costs with the relevant constants (see Chapter 4) as follows:

$$P = 962A^{0{,}628}$$

$P_{90\%}$ = \$ 382 307 per 600 MW unit (1998), and
$P_{99{,}9\%}$ = \$ 762 158 per 600 MW unit (1998).

Using Equations 4.5 and 4.6, the total installed cost (TIC) for a 600 MW unit was calculated:

$TIC_{90\%}$ = DEC × 2,22 = P × 1,18 × 2,22
= \$ 1 001 492 per 600 MW unit (1998), and
$TIC_{99,9\%}$ = \$ 1 996 548 per 600 MW unit (1998).

For a 3 600 MW power plant the total installed cost (TIC) is:
$TIC_{90\%}$ = \$ 1 001 492 × 6 = \$ 6 008 953 (1998), and
$TIC_{99,9\%}$ = \$ 1 996 548 × 6 = \$ 11 979 287 (1998).

Adjusting the 1998 costs to 2003 values, Equation 4.1 was used:

$$P_{2003} = P_x \times \frac{CI_{2003}}{CI_x}$$

$$TIC_{90\%,2003} = 6\,008\,953 \times \frac{1\ 123{,}60}{1\ 061{,}90}$$ = \$ 6 358 094, and

$$TIC_{99{,}9\%,2003} = 11\ 979\ 287 \times \frac{1\ 123{,}60}{1\ 061{,}90}$$ = \$ 12 675 325.

The corresponding costs in 2003 in Rands were:
$TIC_{90\%}$ = \$ 6 358 094 × R 6,91/\$ = **R 43 928 071,00** and
$TIC_{99,9\%}$ = \$ 12 675 325 × R 6,91/\$ = **R 100 307 068,00.**

Unfortunately estimates for operating costs for ESPs are not widely available. However, one reference stated that the annual operating cost of a unit treating 1 416 m^3/min gas was \$ 220 000 in 1988 (STEP, 2005.). This cost was adjusted to a unit treating 200 000 m^3/hr (3 333 m^3/min) flue gas with Equation 4.2:

$$P_2 = P_1 \left(\frac{C_2}{C_1} \right)^a$$

$$P_{operating} = 220\ 000 \left(\frac{3\ 333}{1\ 416} \right)^{0.6}$$ = \$ 367 740 per 600 MW unit in 1988.

Adjusting the 1988 operating cost to the 2003 value, Equation 4.1 was used:

$$P_{\text{operating,2003}} = 367\,740 \times \frac{1\,123{,}60}{852} = \$\ 484\,968 \text{ per 600 MW unit.}$$

The corresponding operating cost in 2003 in Rands were:

$P_{\text{operating}}$ = \$ 484 968 × R 6,91/\$ = R 3 350 644 per 600 MW unit.

Therefore for the 3 600 MW power plant the annual operating costs for both the 90% and the 99,9% ESP is:

$P_{\text{operating}}$ = \$ 3 350 644 × 6 = **R 20 103 866,00.**

Fabric filter

From Equation 4.7 (Chapter 4) the gross cloth area was calculated using a maximum filtering velocity of 2 ft/min (Cooper and Alley, 2002), and assuming the plant consisted of six 600 MW units, each treating 200 000 m^3/hr (117 716 ft^3/min) (Eskom Holdings Limited, 2003a):

$$GCA = \frac{Q}{V} = \frac{117\,716}{2} = 58\,858 \text{ ft}^2.$$

With the gross cloth area (GCA) available, the baghouse price was calculated with Equations 4.8 to 4.11:

BBP = \$ 96 230 + \$ 3,33 × 58 858 = \$ 292 226 per 600 MW unit in 1998,
SSA = \$ 51 280 + \$ 1,43 × 58 858 = \$ 135 447 per 600 MW unit in 1998,
INS = \$ 26 330 + \$ 0,57 × 58 858 = \$ 59 879 per 600 MW unit in 1998, and
BP = 0,63 × 58 858 = \$ 37 080 per 600 MW unit in 1998.

The total baghouse purchase cost is:

$P = BBP + SSA + INS + BP$ = \$ 524 632 per 600 MW unit in 1998.

Using Equations 4.12 and Equation 4.13, the total installed cost (TIC) for a 600 MW unit was calculated:

$$\text{TIC} = \text{DEC} \times 2{,}19 = \text{P} \times 1{,}18 \times 2{,}19$$
$$= \$\ 1\ 355\ 755$$

Adjusting the 1998 cost to the 2003 value, Equation 4.1 was used:

$$\text{TIC}_{2003} = 1\ 355\ 755 \times \frac{1\ 123{,}60}{1\ 061{,}90} = \$\ 1\ 434\ 528 \text{ per 600 MW unit}$$

The corresponding TIC in 2003 in Rands was:

$$\text{TIC} = \$\ 1\ 434\ 528 \times \text{R } 6{,}91/\$ = \text{R } 9\ 911\ 160 \text{ per 600 MW unit.}$$

Therefore for the 3 600 MW power plant the TIC for the baghouse system is:

$$\text{TIC} = \$\ 9\ 911\ 160 \times 6 = \textbf{R 59 466 961,00.}$$

Unfortunately estimates for operating cost for baghouse systems are not widely available. In order to include an operating cost in the analysis it was assumed that the operating cost for a baghouse system would be closely related to that of an ESP. The ESPs' operating costs were on average 33% of the TIC, and this was used to estimate the operating cost of the baghouse system:

$$\text{P}_{\text{operating}} = \text{TIC} \times 0{,}33 = \textbf{R 19 624 097,00.}$$

Low-NO$_x$ burners

Using the average of the referenced capital cost (see Chapter 4), the capital cost of installing low-NO$_x$ burners in 1997 = \$ 7,5 × 3 600 000 kW = \$ 27 000 000.

Adjusting the 1997 cost to the 2003 value, Equation 4.1 was used:

$$\text{P}_{2003} = 27\ 000\ 000 \times \frac{1\ 123{,}60}{1\ 056{,}80} = \$\ 28\ 706\ 662$$

Therefore the corresponding capital cost in 2003 in Rands was:

P_{2003} = \$ 26 792 884 × R 6,91/\$ = **R 198 334 325,00.**

Selective catalytic reduction system

Using the average of the referenced capital cost (see Chapter 4), the capital cost of a SCR system in 1997 = \$ 55 × 3 600 000 kW = \$ 198 000 000.

Adjusting the 1997 cost to the 2003 value, Equation 4.1 was used:

$$P_{2003} = 198\,000\,000 \times \frac{1\ 123{,}60}{1\ 056{,}80} = \$\ 210\ 515\ 519$$

Therefore the corresponding capital cost in 2003 in Rands was:

P_{2003} = \$ 210 515 519 × R 6,91/\$ = **R 1 454 451 718,00.**

Using the average of the referenced operating cost (see Chapter 4), the operating cost of a SCR system in 1997 = \$ 2,43 × 24 235 200 MWh = \$ 58 891 536.

Adjusting the 1997 cost to the 2003 value, Equation 4.1 was used:

$$P_{2003} = 58\,891\ 536 \times \frac{1\ 123{,}60}{1\ 056{,}80} = \$\ 62\ 614\ 051$$

Therefore the corresponding operating cost in 2003 in Rands was:

P_{2003} = \$ 66 479 117× R 6,91/\$ = **R 432 600 483,00.**

Wet flue gas desulphurisation with limestone

Using the average of the referenced capital cost (see Chapter 4), the capital cost of a wet FGD system with limestone in 2002 = \$ 175 × 3 600 00 kW = \$ 630 000 000

Adjusting the 2002 cost to the 2003 value, Equation 4.1 was used:

$$P_{2003} = 630\,000\,000 \times \frac{1\ 123{,}60}{1\ 104{,}20} = \$\ 641\ 068\ 647$$

Therefore the corresponding capital cost in 2003 in Rands was:

P_{2003} = \$ 641 068 647 × R 6,91/\$ = **R 4 429 143 282,00.**

Using the average of the referenced operating cost (see Chapter 4), the operating cost of a wet FGD system with limestone in 2002 = \$ 35 × 3 600 000 kW= \$ 126 000 000.

Adjusting the 2002 cost to the 2003 value, Equation 4.1 was used:

$$P_{2003} = 126\,000\,000 \times \frac{1\ 123{,}60}{1\ 104{,}20} = \$\ 128\ 213\ 729$$

Therefore the corresponding operating cost in 2003 in Rands was:

P_{2003} = \$ 128 213 729× R 6,91/\$ = **R 885 828 656,00.**

LIFE CYCLE ASSESSMENT

Table A.1 shows the operating statistics of the hypothetical 3 600 MW power plant for one production year.

Table A.1 Operating statistics for a 3 600 MW power plant.

Parameter	Value
Power plant output	3 600 MW
Production period	1 year
	330 days
	7 920 hours
Operating capacity	85%
Average output	= 3 600 MW × 0,85 = 3 060 MW
Yearly output	= 3 060 MW × 7 920 h = 24 235 200 MWh
	24 235 200 000 kWh

Using the values in Table A.1 and the annual reported data (Table 4.3, Chapter 4), yearly mass values were calculated for the hypothetical power plant. The yearly mass values below is for one production year of a 3 600 MW power plant with Control regime 1 in place.

- Input
  - Water = 1,29 ℓ/kWh (Eskom Holdings Limited, 2003b)
    1,29 ℓ/kWh × 24 235 200 000 kWh = 31 263 408 000 ℓ = **31 263 kℓ**

- Outputs
  - PM = 0,28 g/kWh (Eskom Holdings Limited, 2003b)
    0,28 g/kWh × 24 235 200 000 kWh = 6 785 856 000 g = **6 786 ton**
  - SO_2 = 8,22 g/kWh (Eskom Holdings Limited, 2003b)
    8,22 g/kWh × 24 235 200 000 kWh = 199 213 344 000 g = **199 213 ton**
  - NO_x = 3,62 g/kWh (Eskom Holdings Limited, 2003b)
    = 3,62 g/kWh × 24 235 200 000 kWh = 87 731 424 000 g = **87 731 ton**
  - CO_2 = 0,9 g/kWh (Eskom Holdings Limited, 2003b)
    0,9 g/kWh × 24 235 200 000 kWh = 21 811 680 000 g = **21 812 ton**

The yearly mass values below is for one production year of a 3 600 MW power plant with Control regime 2 in place.

- Input
  - Water = 1,29 ℓ/kWh
    1,29 ℓ/kWh × 24 235 200 000 kWh = 31 263 408 000 ℓ = **31 263 kℓ**

- Outputs
  - PM = 6 786 – (0,099 × 6 786) = **6 114 ton**
  - SO_2 = 199 213 – (0× 199 213) = **199 213 ton**
  - NO_x = 87 731 – (0× 87 731 ton) = **87 731 ton**
  - CO_2 = 21 812 – (0× 21 812 ton) = **21 812 ton**

The yearly mass values below is for one production year of a 3 600 MW power plant with Control regime 3 in place.

- Input
  - Water = 1,29 ℓ/kWh

    1,29 ℓℓ/kWh × 24 235 200 000 kWh = 31 263 408 000 ℓ = **31 263 kℓ**

- Outputs
  - PM = 6 786 – (0,099 × 6 786) = **6114 ton**
  - SO_2 = 199 213 – (0,98 × 199 213) = **3 984 ton**
  - NO_x = 87 731 – (0,6 × 87 731 ton) = 35 093 – (0,9 × 35 093) = **3 509 ton**
  - CO_2 = 21 812 – (0 × 21 812 ton) = **21 812 ton**

EXTERNAL COSTS

Adjustment of United Kingdom's estimated damage costs (Table 4.4, Chapter 4) using Equation 4.1 and exchange rates from Table 4.2 (see Chapter 4):

$$P_{SO_2,2003} = 6\ 818 \times \frac{1\ 123{,}60}{1\ 061{,}90} = €\ 7\ 214{,}00$$

$$P_{NO_x,2003} = 5\ 736 \times \frac{1\ 123{,}60}{1\ 061{,}90} = €\ 6\ 069{,}00$$

$$P_{PM,2003} = 14\ 063 \times \frac{1\ 123{,}60}{1\ 061{,}90} = €\ 14\ 880{,}00$$

$$P_{CO_2,2003} = 139 \times \frac{1\ 123{,}60}{1\ 061{,}90} = €\ 147{,}00$$

$$P_{SO_2,2003} = €\ 7\ 214 \times R\ 7{,}91/€ = R\ 57\ 091{,}00$$

$$P_{NO_x,2003} = €\ 6\ 069 \times R\ 7{,}91/€ = R\ 48\ 030{,}00$$

$$P_{PM,2003} = €\ 14\ 880 \times R\ 7{,}91/€ = R\ 117\ 751{,}00$$

$$P_{CO_2,2003} = €\ 147 \times R\ 7{,}91/€ = R\ 1\ 164{,}00.$$

In order to formulate data that is more applicable to South Africa, an adjustment factor (k_{LF}) was estimated by comparing the size of the affected population of a United Kingdom (UK) power plant to the affected population of a South African power plant, using the following postulation:

The external costs obtained for the UK was based on a power plant in West Burton (Nottinghamshire) with an output of 1 800 MW (Berry, 1998). Together with another power plant in Nottinghamshire, Cottam Power Station with an output of 2 000 MW (EDFE, 2005), these two power plants are comparable, based on output, to the Duvha Power Station (3 600 MW) located near Witbank, South Africa (Eskom Holdings Limited, 2003a). The population of Nottinghamshire is approximately 748 300 (NCC, 2002) and the population of Witbank is approximately 167 183 (Brinkhoff, 2005). It was assumed that the two power plants in Nottinghamshire will affect the entire population to some extent and it was also assumed that Duvha Power Station only affects the population of Witbank. An adjustment factor, k_{LF}, for the postulation above was thus calculated as follows:

$$k_{LF} = \frac{167\,183}{748\,300} = 0{,}22$$

This adjustment factor is a conservative estimate, as the population in Nottinghamshire is exposed to more than just the two power stations used for this postulation (NCC, 2001).

OTHER COSTS

Insurance for Environmental Liabilities

Insurance for environmental liability = R 95 000 000 (Eskom Holdings Limited, 2003b). This cost is based on a number of power plants, producing 196 980GWh in one production year. It was assumed that R 95 000 000 $\div$ $1{,}9698 \times 10^{11}$ kWh = 0,0048 R/kWh has been allocated for insurance. Therefore for a 3 600 MW plant operating at 85% capacity on average the cost allocated for insurance is:

0,0048 R/kWh × 24 235 200 000 kWh = **R 11 688 212,00.**

Provisions for Environmental Management

Provisions for environmental management = R 679 000 000 (Eskom Holdings Limited, 2003b). This cost is based on a number of power plants, producing 196 980 GWh in one production year. It was assumed that R 679 000 000 ÷ $1,9698 \times 10^{11}$ kWh = 0,0034 R/kWh has been allocated for provisions. Therefore for a 3 600 MW plant operating at 85% capacity on average the cost allocated for provisions is:

0,0034 R/kWh × 24 235 200 000 kWh = **R 83 539 957,00.**

Research and Development

An amount of R 16 020 000,00 (representing 9% of the entire R 178 000 000,00 budget for research and development) is set aside for research and development projects pertaining specifically to the environment (Eskom Holdings Limited, 2003b). This cost is based on a number of power plants, producing 196 980 GWh in one production year. It was assumed that R 16 020 000 ÷ $1,9698 \times 10^{11}$ kWh = $8,31 \times 10^{-5}$ R/kWh has been allocated for environmental research and development. Therefore for a 3 600 MW plant operating at 85% capacity on average the cost allocated for research and development is:

$8,31 \times 10^{-5}$ R/kWh × 24 235 200 000 kWh = **R 1 971 002,00.**

General Direct Costs

From the yearly mass values calculated from the annual reported data (Table 4.3, Chapter 4), the total water used for a 3 600 MW power plant, operating at 85% capacity on average, was 31 263 408 000 ℓ for one production year. The cost of water was taken as R 0,003/ℓ (Kruger, 2005). Therefore the cost of water for one production year is:

31 263 408 000 × R 0,003/ℓ = **R 93 790 224,00.**

An amount of R 7 847 000 000 has been allocated for primary energy, which includes both coal and electricity (Eskom Holdings Limited, 2003b). This cost is based on a number of power plants, producing 196 980 GWh in one production year. It was assumed that R 7 847 000 000 ÷ 1,9698 × 10^{11} kWh = 0,04 R/kWh has been allocated for primary energy. Therefore for a 3 600 MW plant operating at 85% capacity on average the cost allocated for primary energy is:

0,04 R/kWh × 24 235 200 000 kWh = **R 965 446 311,00.**

An amount of R 665 000 000 has been allocated for any other materials (Eskom Holdings Limited, 2003b). This cost is based on a number of power plants, producing 196 980 GWh in one production year. It was assumed that R 665 000 000 ÷ 1,9698 × 10^{11} kWh = 0,0034 R/kWh has been allocated for other material costs. Therefore for a 3 600 MW plant operating at 85% capacity on average the cost allocated for other material costs is:

0,0034 R/kWh × 24 235 200 000 kWh = **R 81 817 484,00.**