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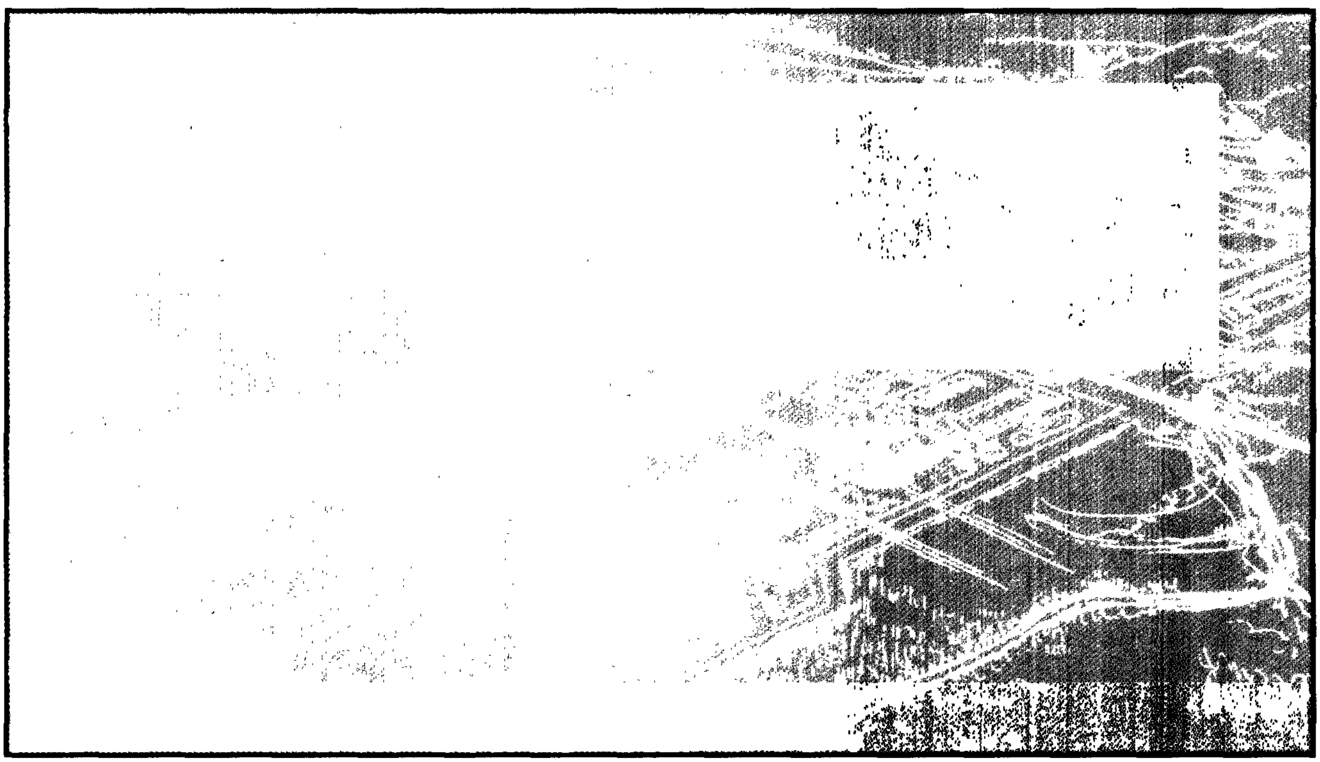
A Planner's Guide for Selecting Clean-Coal Technologies for Power Plants



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FOREWORD

As East and South Asia continue to develop economically, production of electrical energy must keep pace with demands of growing industries and burgeoning populations. Roughly three-fourths of the energy in Asian cities will come from thermal power plants burning indigenous coals. Some of these plants will be modern, state-of-the-art units, owned and operated by private interests, but most will be state owned and operated under less than optimal conditions. Resulting air pollution, creation of greenhouse gases and solid residuals will have ever greater environmental impact. In order to keep emissions at an absolute minimum, new power plants will have to include air pollution control devices. Older plants may have to be shuttered or retrofitted accordingly. Eventually, all new and retrofitted plants must meet the highest efficiency standards so that coal burning can be kept to a minimum.

Unfortunately, for many Asian countries, the costs of high efficiency, state-of-the-art pollution control systems are prohibitive. More often, less costly control systems will have to be employed. Typical decisions to be made by planners and engineers are whether to implement 95 percent sulfur removal at a prohibitive cost, 70 percent sulfur removal at modest cost or no control at all. Important factors in this equation include coal quality, power plant and mine location, local air quality standards, ambient air quality conditions, and waste transport and disposal. Few analytical tools exist to assist power sector planners and engineers in such a complex exercise. To add to the configuration of options, the commercial availability of several new combustion technologies, such as fluidized beds, have made the choice of technology even more challenging.

The World Bank has been involved in the power sector and with the institutional, financial and regulatory issues that affect its environmental performance. The Asia Environment and Natural Resources Division (ASTEN) seeks to assure that investments meet environmental guidelines set out by the Bank's Board of Directors. In this effort, ASTEN initiated the preparation of *A Planner's Guide for Selecting Clean-Coal Technologies for Power Plants*. We hope it will assist planners choosing among competing combustion and pollution control technologies. Several existing reports provide detailed descriptions of these technologies; few incorporate an organized analytical approach to examining the options from the standpoint of cost and performance. The particular value of this guide is to provide a synthesis of available combustion and pollution control technology information developed to date.

This report offers a step-by-step model for selecting the appropriate technology based on the resources and objectives. It is the hope of the authors that it will be widely circulated among power sector planners, engineer and environmental specialists and encourage further work along these lines. The importance of this topic cannot be overstressed since electrical generation will continue to grow rapidly in conjunction with overall economic development in the two regions of Asia.

Maritta Koch-Weser
Chief, Asia Environment and Natural Resources Division
World Bank

ABSTRACT

- Coal will continue to play a role in future energy supply in China and India, where today from 70 to 75 percent of electric power is coal based.

- The negative effects of coal on global environment, eco-systems and public health are well documented; its use must be balanced between the development needs of a country and the welfare of its people and land.

- The most widely used combustion technology in China and India are the subcritical pulverized coal boilers with low efficiencies resulting in the combustion of extra quantities of coal.

- Greater efficiencies will reduce emissions and prevent waste generation, and must be implemented in the short term. Planning should strive for increased utilization of by-products and waste. And if disposal is the only alternative, protection of waterways must be enforced.

- Washed-coal use in power production is the most cost-effective mean to reduce environmental impact. Coal cleaning reduces the ash content of coal and of substances such as inorganic sulfur and sodium associated with corrosion and deposition in boilers. Besides the use of washed coal offers several other advantages to the plant owner, such as increase efficiency and availability, less wear and lower maintenance cost, and reduced waste generation at the plant.

- Switching to coals with low sulfur content is the simplest method for reducing SO_2 emissions. However, ultra-low sulfur coals may not be readily available. Nevertheless, low- to medium-sulfur coals are available in both China and India. However, with the large quantities of coal burned for power, industry and at the household level, particulate and SO_2 emissions remain high, especially in industrial and urban areas.

- The procedure outlined in the report for selecting environmentally friendly technologies requires evaluation and optimization of several technical, environmental and economic factors, including quality of coal, requirements on waste product, yearly operating time and operating lifetime of the plant.

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ABBREVIATIONS, ACRONYMS, AND DATA NOTE

ACFB	atmospheric circulating fluidized bed
BOT	build-operate-transfer
CaO	lime
Ca/S	sorbent to sulfur ratio
CO_2	carbon dioxide
ESP	electrostatic precipitators
FGD	flue gas desulfurization
FOB	free-on-board
GJ	gigajoule
GT	gigaton
I&C	instrumentation and controls
IGCC	integrated gasification combined cycle
IPP	independent power producer
kg	kilogram
LHV	lower heating value
LNB	low NO_x burners
MJ	megajoule
Mt	megaton
MW	megawatt
NDG	normal dry gas
NO_x	nitrogen oxides
NSPS	new source performance standard
O&M	operation and maintenance
OFA	over fire air
PC	pulverized coal
PLF	plant load factor
PFBC	pressurized fluidized bed combustion
SCR	selective catalytic reduction
SNCR	selective non catalytic reduction
SO_2	sulfur dioxide
TWh	terawatt

Data Note: Unless noted, all tables and figures were originated by the authors.

EXECUTIVE SUMMARY

In 1994, 374 TWh of electric power were generated in India and 886 TWh in China. Electricity demand is growing rapidly in both countries and the annual growth rate from now until 2010 amounts to approximately 7% in India and 6% in China. Both countries rely heavily on coal for power production, industrial energy, and household heating and cooking. Approximately 70-75% of the electric power is coal-based. Coal is expected to continue to play a major role in future energy supply scenarios in these countries.

The use of coal negatively affects the global environment, local eco-systems and public health with emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulates. In addition to these emissions, the ash residue and the wastewater from coal combustion raise significant environmental issues. The very important task for both India and China is to balance the conflicting demands of economic growth and increased demand for power with environmental impact that can be considered reasonable for sustainable development.

This report has been prepared as a technology selection guide for the use of power system planners and engineers to facilitate the selection of cost-effective, environmentally friendly technologies for coal-based power generation in countries grappling with impending power and capital shortages in the face of stricter environmental regulations. The report focuses on plants greater than 100 MW_e in India and China.

COAL QUALITY AND COAL CLEANING

Starting with the coal itself, the use of washed coal is the most basic cost-effective and appropriate means of reducing the environmental impact of coal-based power production. Coal washing reduces the ash content in the coal. In India and China, coal washing is not widely used. This suggests that there is considerable potential for cost-effective environmental improvements.
Following are some of the properties of washed-coal use:

- increases the efficiency of power generation, mainly due to a reduction in the energy loss associated with the attempted combustion of inert material;
- increases plant availability;
- reduces investment costs, less cost for fuel and ash handling equipment;
- reduces operation and maintenance costs as a result of reduced plant wear and tear and reduced costs for fuel and ash handling;
- energy savings in the transportation sector and lower transport costs;
- reduces impurities and results in more even coal quality;
- reduces the load on the particulate removal equipment in existing plants; and
- reduces the amount of solid waste that has to be taken care of at the plant.

For the power plant owner, there is a substantial economic incentive for firing washed coal. This has been proven by earlier calculations made for specific Indian power stations. In these stations, a premium of US$0.40-$0.55/metric ton (ton) coal could be paid for each percentage point reduction in ash content of the purchased coal. Although sulfur removal is not the primary aim, coal washing is also the cheapest way to remove inorganic sulfur from the coal. Coal washing can be used as the primary cost-effective way to reduce emissions of SO_2 by 10 to 40%.

COMBUSTION TECHNOLOGIES

A new coal-fired power plant aims for high efficiency, high availability, low emissions and the production of a by-product that can be utilized, avoiding the need for disposal. By far the most used combustion technology in India and China is subcritical pulverized coal (PC) boilers with plant efficiencies in the range of 33-36%. By striving for higher efficiencies, the emissions and the waste per MWh_e produced is reduced. The coal consumption per MWh_e produced is also reduced. Higher efficiency is also the only way to reduce CO_2 emissions from a coal-fired power plant. Large supercritical boilers with high efficiencies have proven competitive on the international market. However, there are still no supercritical boilers in operation in India and just a few in China. Introducing this technology requires a transfer of technology know-how to domestic manufacturers and utilities from international manufacturers.

Atmospheric circulating fluidized bed boilers (ACFB) represent a newer technology, with improved environmental performance compared to PC boilers. In addition to the low emissions of SO_2 and NO_x, the fuel flexibility of ACFB boilers is extremely wide. Subcritical ACFB boilers with moderate efficiencies are commercial in sizes up to approximately 100 MWe. There are a few plants greater than 100 MW_e in operation in the world and some are under construction. In India and China, only small-scale fluidized bed boilers are in operation. The major drawback is that today there are only limited means of utilizing the waste, which means disposal is still necessary.

Other technologies like pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC) which offer high efficiencies and low emissions should be chosen only when the requirements on commercial readiness are not so high.

SO_2 EMISSION CONTROL TECHNOLOGIES

The simplest way to reduce SO_2 emissions is to switch to a coal with a lower sulfur content. When coal switching is not possible or not sufficient to reach acceptable emission levels, physical coal cleaning is still the most cost-effective route to reduction of SO_2 emissions. When further sulfur reduction is required, some SO_2 removal technology must be introduced. The choice of technology is affected by the sulfur content in the coal, required emission level, requirement on waste product, yearly operating time of the plant and plant lifetime. When selecting sulfur removal technology, it is vital to make correct assumptions regarding these factors in order to select the best technology.

Generally, the investment cost for technologies with low sulfur removal efficiencies, such as sorbent injection processes, are low; the investment for high efficiency technologies, such as wet scrubbers, is high. Spray dry scrubbers fall somewhere between these technologies with regard to both investment and efficiency. Today, sorbent injection processes and spray dry scubbers are used mainly in relatively small-scale units burning low sulfur coal, in peak load plants and in retrofit applications where the remaining operating time is short. Wet scrubbers are by far the most used technology worldwide.

In India and China, where there is a need for immediate reduction of SO_2 emissions and economic means are limited, a step-by-step approach can be considered. A low-cost sorbent injection process can be installed rapidly, followed by further upgrading to a hybrid sorbent injection process or a wet scrubbing system. Neither China nor India has significant experience with sulfur removal technologies and only a few plants in each country have some kind of sulfur removal equipment installed. The fact that the sulfur content in the coals burned in India is low does not mean that SO_2 emissions are not a problem since the total amount of SO_2 emitted from Indian plants is considerable.

NO_X EMISSION CONTROL TECHNOLOGIES

Operation with low excess air, fine tuning of the boiler and staged combustion are very inexpensive ways to reduce NO_x emissions. NO_x emissions should always be reduced, in the first instance, by optimizing the combustion process. Optimization needs to be related specifically to coal and plant. A reliable system for O_2 and NO_x monitoring is required. Up-grading or replacement of coal pulverizers can also be considered to minimize NO_x emissions in existing boilers. These measures can be combined with other low NO_x technologies.

Combustion modifications that can be made to reduce NO_x emissions further include the installation of low NO_x burners, over fire air (OFA), flue gas recirculation and coal reburning. Post-combustion measures include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Combustion modifications show a lower increase in electricity production cost than post-combustion technologies, but they can only achieve a reduction of NO_x emissions up to 60%. SCR is the most efficient and most expensive technology and should only be chosen when very low emission levels are essential. After optimizing the combustion process, combustion modification measures should be made to reduce NO_x emissions.

Typically in India, burners are designed for emissions of 600 ppm NO_x. Recently burners with NO_x emissions less than 400 ppm have been developed. In China, more than 20% of the power plants use some kind of low NO_x combustion, most are low NO_x burners. SCR and SNCR technologies for low NO_x emissions are not in use in either country.

PARTICULATE EMISSION CONTROL TECHNOLOGIES

Particulates can be removed with a great degree of efficiency either in electrostatic precipitators (ESP) or in baghouse filters. ESPs are used in all large plants in India and in most Chinese plants, while fabric filters (baghouse) are extremely rare. ESP is by far the most commonly used technology worldwide for particulate removal. ESPs are competitive for medium and high sulfur coals with low to medium ash resistivity when an efficiency up to and above 99.5% is required. They are also competitive for low sulfur coals and coals with high fly ash resistivity when lower efficiencies are accepted. Due to their robust design, ESPs can also handle erosive high ash coals. Baghouse filters are suitable in combination with some sulfur removal technologies, such as sorbent injection and spray dry scrubbers.

BY-PRODUCTS AND WASTE

Utilization of residues is an essential part of a successful environmental management strategy which embraces the concept of sustainable development. Prevention should be the priority for a waste management scheme followed by utilization, with safe disposal as a final resort. Residues from coal-use in India and China are limited to fly ash and slag since flue gas desulfurization is hardly used. Only a small portion of the fly ash and slag residue is utilized, thus, leaving the major part for disposal. Increased utilization as building material, for mine reclamation and for civil engineering purposes is promoted both in India and China.

Protection of water sources is the most important concern associated with the disposal of coal-use residues. Wet disposal in disposal ponds is the technology used in most plants in India and it is also the predominant technology in the southern part of China. Its main advantage is the ease by which residues can be transported and placed. However, the disadvantages are obvious; the need for additional water, increased generation of leachate and greater land requirements compared with dry disposal in landfills. There are also risks of overflow of the pond, during heavy rainfalls for example. Internationally, utilities tend to favor dry disposal in landfills, since problems like water pollution and consumption are minimized.

Analysis of the characteristics of the residue, including leachate tests to determine the potential for leaching, is essential before deciding on utilization or disposal. Waste from coal-based power production is not restricted to solid waste. A large amount of waste water is produced which needs suitable handling.

LOW-COST REFURBISHMENT

Refurbishment of existing power plants can be carried out to reduce operating and maintenance costs, increase plant efficiency, increase availability, reduce environmental impact, increase plant lifetime or increase plant load. There are several low-cost measures available for achieving the above, some of which are summarized in this report. These include the installation of O_2 measuring equipment for optimization of the combustion process and installation of mechanical condenser cleaning systems for increased efficiency.

TECHNOLOGY SELECTION MODEL AND CASE STUDIES

Successful selection of technology requires that all project specific environmental, economic and technical aspects are considered. A structured working procedure is necessary. Therefore, this report includes a technology selection model which is intended to be used as a guideline to perform a technology selection during the prefeasibility phase of a project. By using the model, suitable power plant concepts can be developed with clear data on:

- investment costs,
- electricity production costs,
- flue gas cleaning costs, and
- costs per ton emission removed.

The model is applied in two realistic case studies; *a greenfield plant* and *a boiler retrofit*. In these case studies the step-by-step approach to technology selection is demonstrated.

ENVIRONMENTAL GUIDELINES AND REQUIREMENTS

Emerging environmental problems are rapidly changing the way the authorities look upon environmental questions. It is important when selecting suitable power plant technologies to consider not only today's environmental requirements, but to plan for future more stringent requirements and standards. Today's environmental requirements for coal-fired power plants in India and China are not very stringent compared with those operating in the United States, Western Europe and Japan. Neither India nor China stipulates reduction of NO_x emissions and they both, to a great extent, rely on stack height and dispersion effects for emission of particulates and SO_2. There are, as yet, no legislative instruments to reduce the emissions in either country.

The World Bank has developed environmental guidelines to be applied to the planning of coal-fired power plants greater than 50 MW_e, restricting emissions of SO_X, NO_X and particulates. Water pollution is governed by Indian, Chinese and World Bank requirements and guidelines. Regulations cover, among other factors, suspended solids, oil and grease, heavy metals, pH and temperature increase.

SUSTAINABLE DEVELOPMENT AND SOCIO-ECONOMIC PLANNING

In the strive for a sustainable development with minimized environmental impact of power production, an integrated pollution management approach should be adopted that does not involve switching one form of pollution to another. For example, wet flue gas desulfurization (FGD) wastes could lead to contamination of the water supply and sorbent injection processes could lead to greater emissions of particulate matter. These factors have to be avoided.

The socio-economic aspects of planning also have to be considered. Pollution control technologies with an apparently greater capital cost may produce a by-product that can be utilized in the building industry or the infrastructure construction sector, thus avoiding the need for disposal, and resulting in a net financial gain.

1. INTRODUCTION

COAL DEMAND AND THE ASIAN ENVIRONMENT

Today, approximately 70% of the installed electricity generation capacity in the developing countries of Asia is concentrated in India and China. In 1994, 374 TWh of electric power were generated in India and 886 TWh in China. Electricity demand is growing rapidly in the region and planners forecast an annual growth of around 7% in India and 6% in China from 1995 until 2010 to keep pace with regional development objectives. India and China rely heavily on coal for power production; between 70% and 75% of the generated power is coal based. Both countries have large indigenous coal supplies, and coal continues to play a major role in all future energy supply scenarios. In China, hard coal production amounts to more than 1,100 megatons (Mt) per year; while in India, annual coal production exceeds 225 Mt.[1] Coal production will increase to satisfy growing domestic demand.

An enormous amount of capital investment will be required to reach the development goals for new electricity capacity in the developing countries of Asia, i.e. China, Taiwan, Malaysia, South Korea, Indonesia, Philippines, Thailand and India. It is estimated that capital investment of $1,500 billion will need to be made in the region between 1994 and 2010. These expenditures will be concentrated in China and India. Obtaining the required capital will be a major problem, and adding the increasingly essential pollution control equipment to a planned plant will increase the amount of capital that needs to be raised still further.

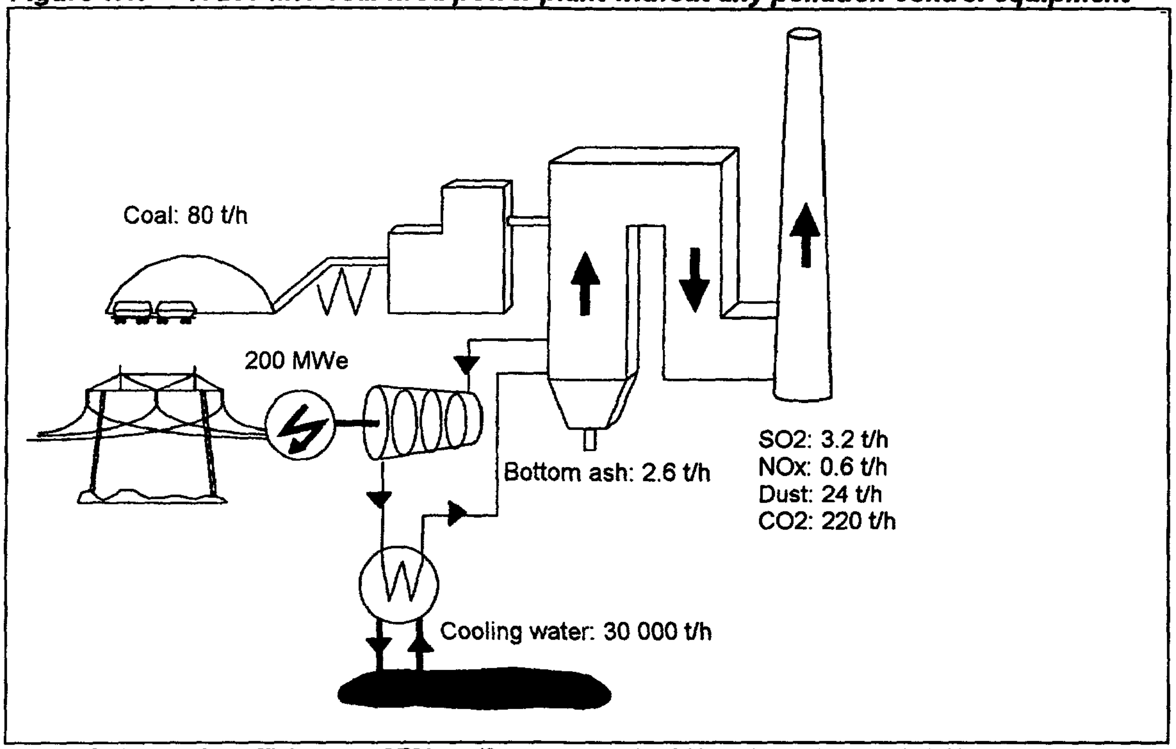
The need for capital comes at a time when principal issues facing power sector planners include brownouts, high transmission and distribution losses, and a stock of plants which are not well maintained and generally without pollution control. In addition, alternative approaches such as energy conservation and demand-side management have only been partially successful in reducing demand for new generation capacity. Another drawback is revealed when it is understood that current low electricity tariffs result in financial shortfalls in the utilities with a consequent lack of capital for new investment. Even government funding of the power sector is becoming more difficult since there is intense competition for funds between different industry sectors. As a result, private participation in power projects is emerging introducing IPP (independent power producer) and BOT (build-operate-transfer) projects into the market.

The use of coal in the electricity generation sector negatively affects the global environment, local ecosystems and public health. Mining is associated with problems of subsidence, aqueous discharges requiring treatment and emissions of methane. The coal-firing process causes emissions of CO_2, SO_2, NO_X and particulates. Furthermore, it produces wastewater and considerable amounts of ash and other solid waste. Picturing the amount of emissions and waste from a coal-fired power plant is best done by looking at a flow diagram. Figure 1.1 shows a 200-MW plant without any pollution control equipment with its different flows of fuel, emissions, cooling water and waste. As can be seen from the flow diagram, a single plant produces several tons per hour of

[1] Ton refers to *metric ton* throughout this report.

SO_2, NO_X, solid waste and dust. Plants with once-through cooling water systems as in Figure 1.1 also need considerable amounts of fresh water for the condenser. In the past, environmental issues were given little consideration in selecting coal technology in both India and China, but emerging environmental problems are changing this attitude. Technologies selected today and over the next several years will prevail for 20 to 30 years and so will their associated emissions of SO_2, NO_x, particulates and greenhouse gases.

Figure 1.1: A 200-MW coal-fired power plant without any pollution control equipment



***Note:** Data used -- efficiency = 37%, sulfur content, S= 2%, ash content= 32.8 %.*

In the short term, the challenge comes from having to balance the conflicting demands of economic growth and increasing demand for power with the requirement for an acceptable level of environmental impact. Clean coal technologies with enhanced power plant efficiency, fuel switching, use of washed coal, the introduction of pollution control equipment and emission monitoring instruments, and proper by-product and waste handling, are all ways to a cleaner future. Choosing the most cost-effective way to reduce the environmental impact of coal firing is the first vital step.

THE WORLD BANK'S ROLE

The World Bank has been involved in power sector projects for many years with investment totaling some $40 billion through fiscal year 1991 or some 15 percent of total lending. A large portion was obligated in the period 1985 through 1993. In addition, new projects continue to be developed in anticipation of future energy requirements. Investment in the sector will continue in spite of resistance from environmental groups because of the need for additional capacity.

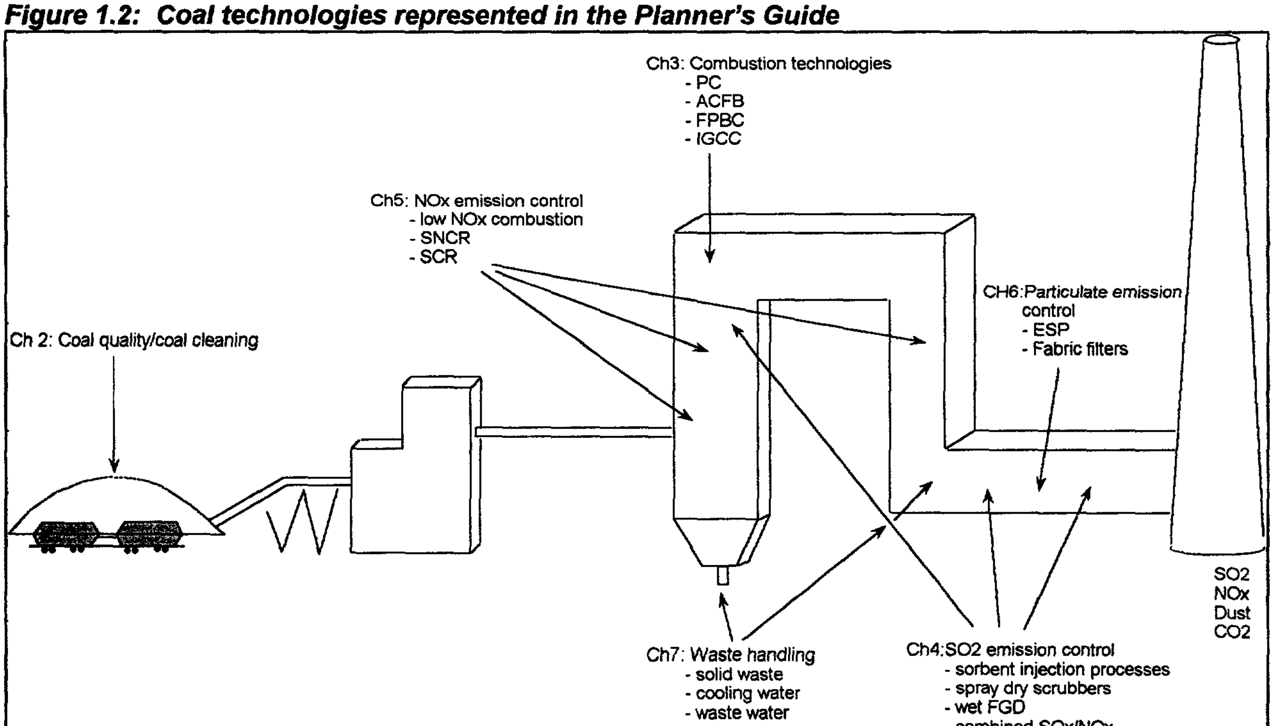
As the World Bank begins to grapple with institutional, financial and regulatory issues in the hope of improving the sector's performance, the issue of regional environmental impact needs to be examined as well. Efforts such as the RAINS-Asia will provide an overview of sulfur dioxide impacts based on source definition. However, the issue of technology choice and its impact on cost and environment have not been addressed, especially from the standpoint of the power system planner.

USE OF THE PLANNER'S GUIDE

This report is a technology and strategy guide for power system planners grappling with impending power and capital shortages in the face of stricter environmental regulations. It is intended to facilitate the selection of cost-effective, environmentally friendly technologies for coal-based power generation. The focus is on coal-fired plants greater than 100 MW_e in India and China. In addition, as privately owned and operated power plants are being introduced, there is a need for planners to have an understanding of what is being offered. This guide aims to help understanding power and associated pollution control technologies, their cost and performance.

In separate chapters, technical, environmental and some economic criteria for the technology areas shown in Figure 1.2 are provided. Information is intended to be used during a prefeasibility phase of a project.

Figure 1.2: Coal technologies represented in the Planner's Guide



Note: *Technical, economic, and environmental information is provided in separate chapters for technology areas and technologies shown in this figure.*

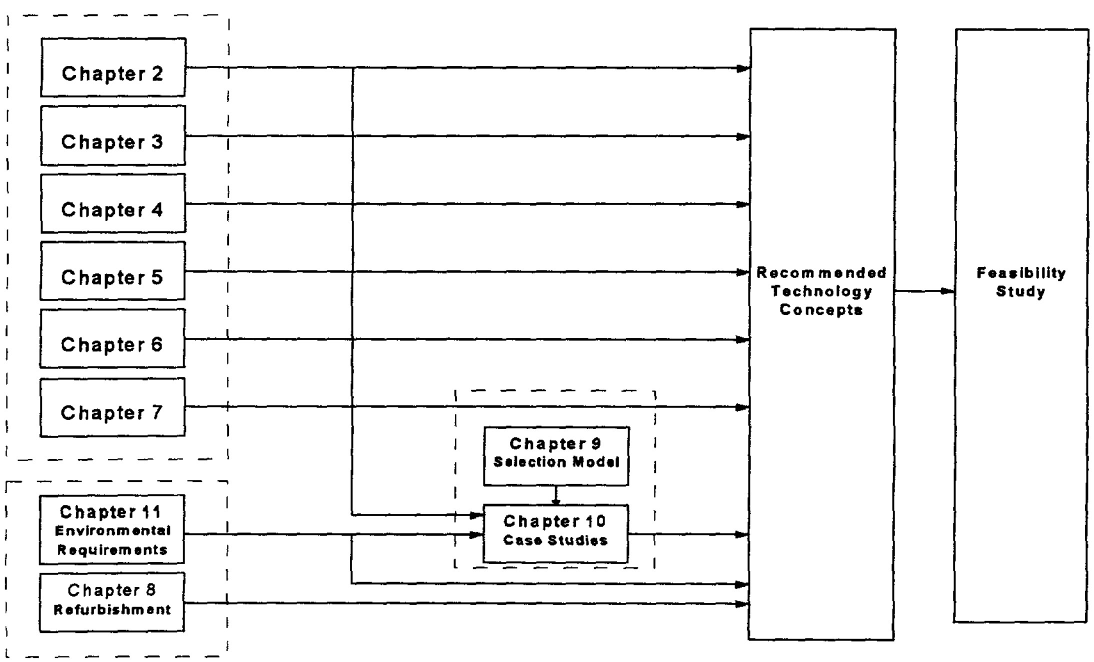
Also, to get a first quick impression of the performance of the different technologies described in this strategy guide, simplified flow diagrams like the one in Figure 1.1 have been developed. Such flow diagrams are included in the introduction to the coal cleaning chapter and at the end of each combustion, SO_2, NO_x and particulate emission control sub-chapter. By looking at these figures, the reader can get an impression of the impact of each technology as far as emissions, coal consumption and waste production are concerned.

The guide also contains a technology selection model, the Fast Track Model, and two realistic case studies. The model gives a working procedure for the technology selection phase of a prefeasibility study. By using information in this report and from suppliers, etc., the following important data can be established at a prefeasibility level:

- suitable power plant concepts,
- investment cost,
- electricity production cost,
- flue gas cleaning costs, and
- emissions of SO_2, NO_x and particulates.

Also included in the strategy guide are descriptions of low cost refurbishment options that can be carried out to increase efficiency, increase availability, reduce operating and maintenance costs etc. in an existing power plant. References marked throughout the text are listed at the end of respective chapters. Figure 1.3 shows the structure of the report and the linkage of the chapters to each other.

Figure 1.3. Structure of the report and linkage of chapters to each other



2. COAL QUALITY AND COAL CLEANING TECHNOLOGIES

This chapter focuses on the advantages of using washed coals and the effect coal quality has on the overall cost of power production. *How much more is it worth paying for a high quality coal than for a low quality coal?* Basic information regarding quality of Indian and Chinese coals, coal cleaning technologies and their suitability for use is also discussed.

Coal cleaning reduces the ash content of coal and of substances such as sodium associated with corrosion and deposition in boilers. The selection of coal cleaning equipment is often not considered in the design of coal-fired power plants, since the most common location of the cleaning plant is at the coal mine. However, coal quality is a major influencing factor in the design of the power plant, especially if high ash coals have to be used.

An additional benefit of coal cleaning is the removal of inorganic sulfur. As shown in Figures 4.2 and 4.3 in Chapter 4, coal cleaning is the cheapest way to reduce the sulfur emissions. A 10-40% reduction of sulfur content can be achieved by coal cleaning. The larger the percentage of inorganically bound sulfur in the coal, the higher the percentage of sulfur that can be removed. Hence, the use of washed coal is a primary cost-effective way to reduce the environmental impact of coal-based power production. Currently, coal cleaning is not widely used in India or China; therefore, there is a significant opportunity for introducing coal cleaning.

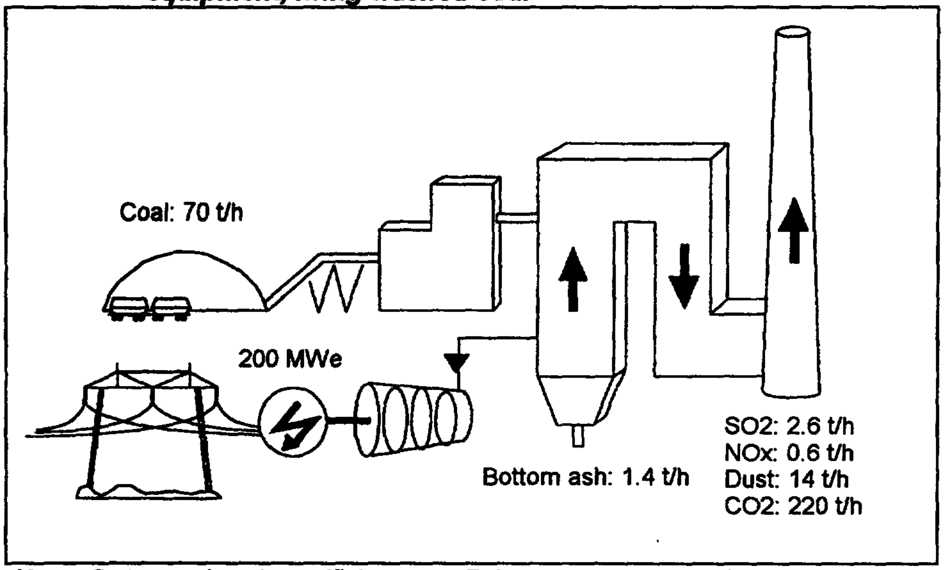
Following are some of the benefits of using washed coal:

- increased generation efficiency, mainly due to the reduction in energy loss as less inert material passes through the combustion process;
- increased plant availability;
- reduced investment costs due, as an example, to reduced costs for fuel and ash handling equipment;
- reduced operation and maintenance (O&M) costs due to less wear and reduced costs for fuel and ash handling;
- energy conservation in the transportation sector and lower transportation costs;
- less impurities and a more even coal quality;
- reduced load on the particulate removal equipment in existing plants; and
- reduction in the amount of solid waste that has to be taken care of at the plant.

When very low grade coals are used, coal cleaning may not be technically and economically justified. In such cases, a mine mouth power plant is the best solution.

Figure 2.1 shows a 200-MW subcritical pulverized coal-fired (PC) plant, without any flue gas cleaning equipment, firing washed coal. The reduction in coal quantity and waste production

Figure 2.1: A 200-MW$_e$ subcritical PC plant, with no flue gas cleaning equipment, firing washed coal



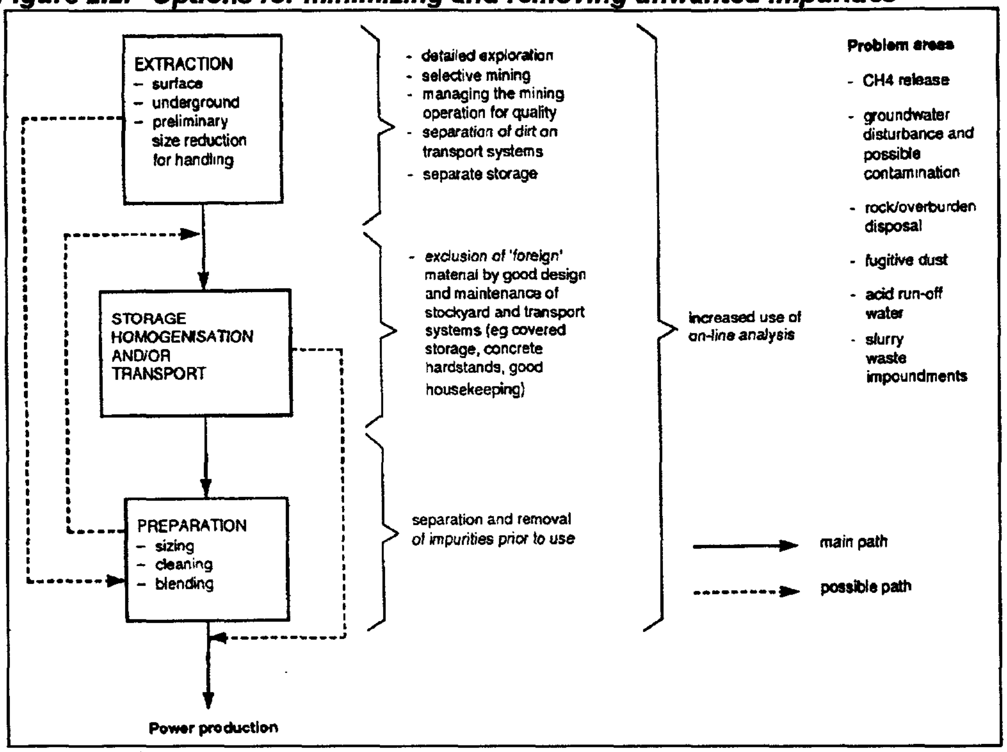
***Note:** Data used – plant efficiency = 37%, ash content= 20%.*

achieved can be seen by comparison with Figure 1.1. which shows the same plant firing a high ash coal.

When producing a high quality coal, the first objective is to minimize the impurities in the run-of-mine coal. The second is to try to avoid contamination during handling and the third is to select the most appropriate place to remove the various unwanted components from the system. Some mechanized mining methods mix more dirt in with the run-of-mine coal than others. Some dirt addition and high ash coal can be avoided by careful exploration and selective mining. These options for removing the impurities are shown in Figure 2.2.

Different coal cleaning technologies are used in a series of unit operations in a cleaning plant. These could include classifying (by size), other separation processes, size reduction (milling/grinding), and dewatering after separation. The cleaning costs generally increase as the particle size decreases. The assessment of any coal cleaning process is essentially empirical in nature. The separation achievable depends on the coal, the equipment and the conditions.

Figure 2.2: Options for minimizing and removing unwanted impurities



Source: *Singer (1991).*

COAL QUALITY

Coal in India

Coal has been produced in India for over 200 years. Output has been accelerating since independence, particularly since the formation of the nationalized coal company in the early 1970s. Annual production is over 225 Mt from coal fields that are located mainly in the east of the country in the states of Assam, Bihar, Uttar Pradesh, Madhya Pradesh, Andhra Pradesh, Orissa and West Bengal. India's total coal reserve base is estimated to be near 160 Gt (gigaton). Coal ranks range from lignites to bituminous coals with most being in the bituminous category. There are no anthracite or peat reserves. India has little good quality coal. Some 60% of the reserves have an in situ ash content of 25-45%. As most of this ash is embedded dirt, coal cleaning is often difficult. As a result calorific values of the coal are low; for saleable coal averaging is under 20 GJ (gigajoule) per ton, or about two thirds that of a good quality internationally traded coal. Sulfur contents are comparatively low by international standards, typically under 1%, but are not so good when expressed per unit of energy. Inherent moisture contents are unexceptional: typically 8-15%. The coal, which is hard, generally has a low swelling index and low volatile content. Much of the coal has a crushing strength of 200-300 kg/cm^3. Compared to other countries only a small part of Indian coal is screened or washed for impurities.

An unenforced Indian government policy states that coal should be washed whenever the distance between the mine and the end-user is greater than 1,000 kilometers. An attainable and reasonable goal for the washing of Indian raw coal is to reduce the ash content from as high as 50% to at least 30%-40% ash or even down to 25%. Table 2.1 presents examples of typical coals from several areas in India.

Table 2.1: Analyses of typical Indian coals from several regions

	Jharia	Jharia	Uttar Pradesh	Renusagar	Singrauli	Neyveli
Rank	**Medium volatile bituminous**	**High volatile bituminous**	**High volatile bituminous**	**Sub-bituminous**	**Sub-bituminous**	**Lignite**
As received						
Ash, %	38.9	31.6	28.0	28.6	31.5	4.5
Moisture, %	1.1	6.9	10.0	14.9	7.9	53.1
Moisture & ash free						
Volatile, %	25.3	37.2	41.0	45.1	47.4	57.1
Carbon, %	83.6			74.1	71.9	70.3
Hydrogen, %	4.5			4.8	5.0	5.2
Oxygen, %	9.9			18.6	20.3	23.1
Nitrogen, %	1.3			1.4	2.0	0.5
Sulphur, %	0.7	1.8	0.8	1.1	0.8	0.9
Lower heating value, *MJ/kg*	33.0	30.4	30.7	28.4	27.3	26.4
Hardgrove grindability, *°H*	63	60	50	56	50	95+

Source: *Singer (1981).*

Coal in China

China is the world's largest hard coal producer with an annual production over 1,100 Mt. Chinese coal resources are vast. Official Chinese figures suggest a total geological resource of over 770,000 Mt. The coals range from hard anthracite to lignite with ash contents between 10 and 40%. The bituminous coals are of medium and high volatile rank; the medium volatile being rather high in ash. The sulfur content is low in many coals, less than 1%, but there are also areas with over 2% sulfur. Compared to other countries, a small proportion of Chinese coal is screened or washed for impurities. Table 2.2 presents examples of some typical Chinese coals.

Table 2.2: Analysis of Chinese coals

Rank	Sub-bituminous	High volatile bituminous	Medium volatile bituminous	Low volatile bituminous
As received				
Ash, %	32.8	37.0	29.7	27.7
Moisture, %	22.6	3.3	10.3	9.6
Moisture and ash free				
Volatile, %	46.8	39.3	22.7	17.0
Carbon, %	74.7	79.6	80.8	83.9
Hydrogen, %	4.8	5.4	6.0	4.5
Oxygen, %	18.6	12.4	10.7	5.1
Nitrogen, %	1.3	1.7	1.4	1.4
Sulphur, %	0.6	0.9	1.1	5.1
Lower heating value, *MJ/kg*	24.2	29.2	30.8	31.6
Hardgrove grindability, *°H*	52	45	50	48

Source: *Singer (1981).*

COSTS

Cost of coal cleaning

Coal cleaning plants are commonly located close to the mine and the cost of cleaning is included in the coal price. The costs for coal cleaning vary from case to case, as does the impact on coal quality. Therefore there are hardly any published costs specific to different cleaning methods, however some are shown in Table 2.3.

Table 2.3 Examples of published costs for coal cleaning

Cleaning method	Cleaning costs *US$/ton*
Conventional cleaning	
• coarse fraction	2-3
• fine fraction	3-10
• jig, dense-medium or froth (for the US)	4-8
Advanced physical separation	15-30

Source: *Couch (1995a) and Sachdev (1992).*

Coal quality impact on power generation cost

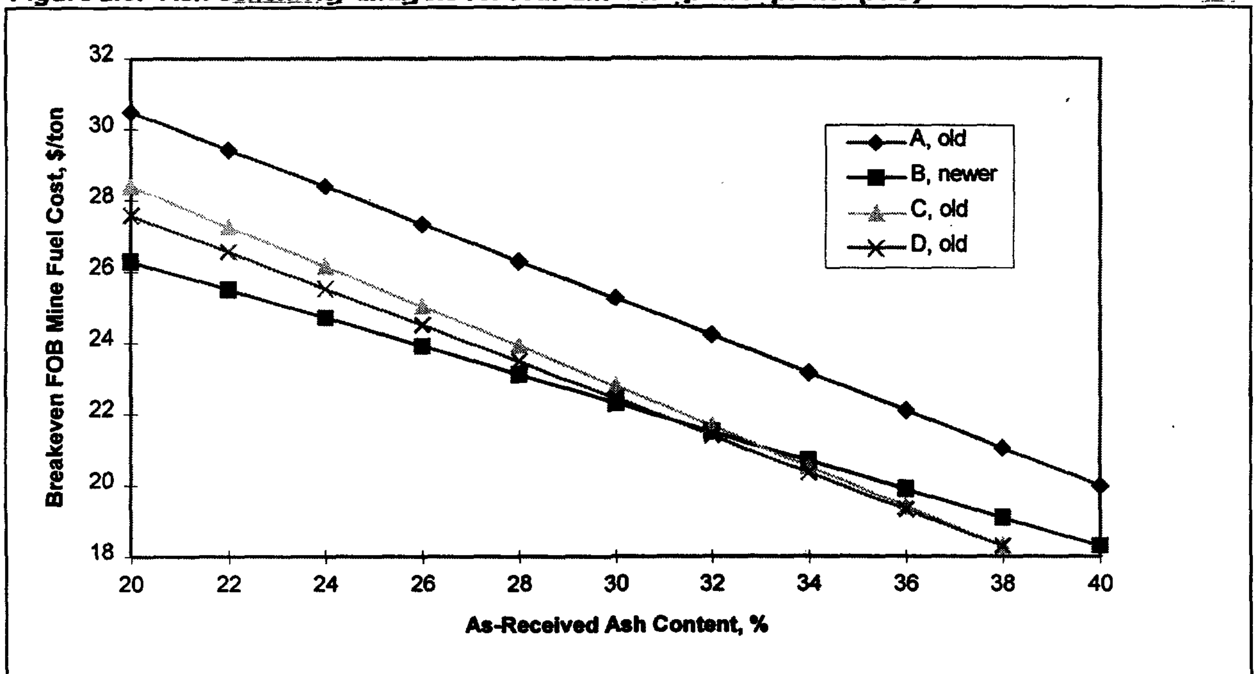
The degree of coal cleaning (e.g. ash content) has an impact on power plant economics. The investment cost and the O&M costs are affected by the coal quality. In India and China, there would be an economic advantage in many existing plants for firing washed coal. This has been proven by calculations made for specific Indian power stations using two American state-of-the-art computer models (Ref. 9). Using data from four representative Indian units in three power stations and typical coal data, a substantial economic incentive for firing washed coals in these power plants was identified. A break-even cost analysis established the following:

- premium of about $0.55/ton could be paid for each percentage point reduction in the ash content of the typical high ash bituminous coals fired in older, existing power plants (Ref. 9).

- Cleaning high ash coals for use in newer plants that were designed for high ash coals was projected to be somewhat less attractive. A premium of about $0.40/ton for each percentage point reduction in a coal's ash content could be paid (Ref. 9).

Projected savings derive mainly, from reduced maintenance costswithin the power plant, increased plant availability, and reduced fuel transportation costs. Figure 2.3 shows the results of the ash sensitivity analysis for the four different power plants in India on the break-even free on board mine fuel cost. When the coal is purchased at a price following the slopes in Figure 2.3, the electricity production cost is constant. If the coal can be obtained at a lower cost than its break-even cost, then the power plant's electricity production cost can be reduced.

Figure 2.3: Ash sensitivity analysis for four different power plants (A-D)



Note: The figure shows the coal price that can be paid as a function of ash content in the coal in order to reach the same cost for electricity production. The figure is based on model calculations made for four Indian power plants.
Source: *Sachev (1992).*

Production cost savings when reducing the ash content are illustrated by the break-even fuel costs in Figure 2.3. Savings are split into different parts; fuel-related costs (e.g. more fuel needed), transportation costs, operation costs, maintenance costs, derate (e.g. high ash content may result in restricted mill throughput and higher energy consumption in mills) and increase in overall plant availability. Table 2.4 presents the savings due to reduced ash content split into these areas for the different plants presented in Figure 2.3.

Table 2.4: Savings due to reduced ash content split into different power plants

	A, old %	B, newer %	C, old %	D, old %
Fuel (free on board)	2	6	2	4
Transportation	49	27	19	68
Operation	0	0	11	0
Maintenance	39	27	14	23
Derate	0	22	34	0
Availability	10	18	20	5
Total	100	100	100	100

Note: *Based on Figure 2.3.*
Source: *Sachdev (1992).*

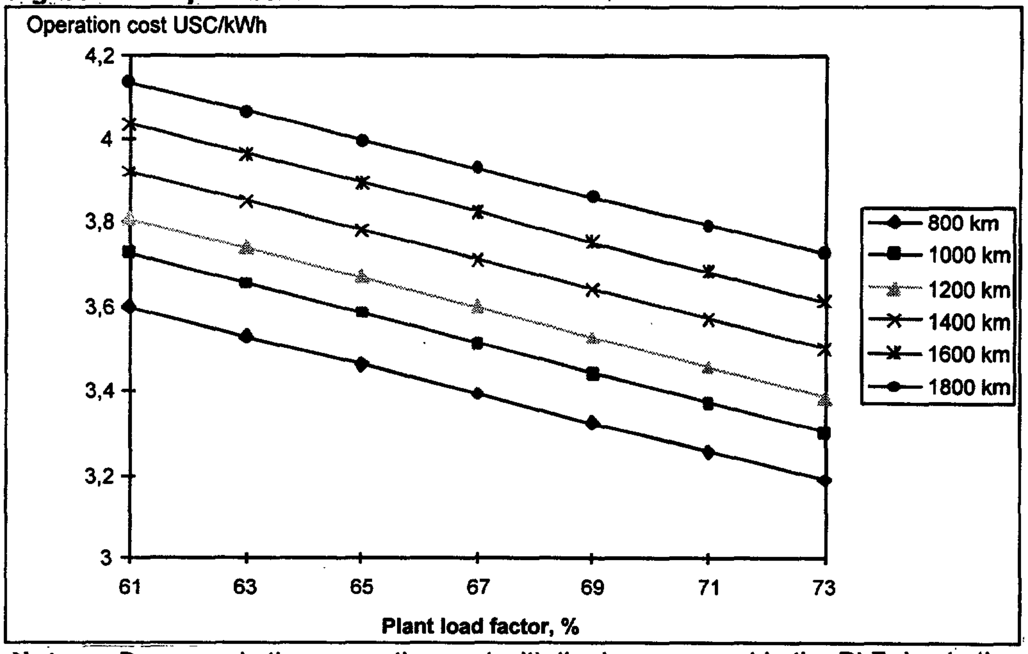
As shown in Table 2.4, the ash content of the coal has an effect on:

- fuel costs,
- fuel transportation costs,
- operational costs (e.g. ash handling, operation of pulverisers),
- maintenance costs,
- generation capacity, and
- availability and forced outage rate.

When deciding which coal quality to purchase, all the savings should be added and calculated per ton coal. The savings should be compared to the costs for cleaned or cleaner coal. This was done in Figure 2.3 and Table 2.4.

An example from an Indian mine with an annual capacity run-of-mine of 6.5 million tons shows the following: the specific investment cost for coal cleaning was \$24/ton, the ash content in washed coal was 34% and the moisture content was 8% (Ref 8). The effect of using washed coal (with a reduction in ash content from about 40 to 34 %), compared to run-of-mine coal, was evaluated. The plant load factor was anticipated to increase in the order of 5-10% when the ash content was reduced from 40 to 34%. Data relating to the improvement in plant performance, distance from the mine and the cost of generation was analyzed. Figure 2.4 shows the decrease in operation costs with the increase in the plant load factor (PLF), due to the use of washed coal, for a given transportation distance from the mine. This is another proof of the importance coal quality has on operating costs.

Figure 2.4: Operational cost decrease with PLF increase



Note: *Decrease in the generation cost with the improvement in the PLF due to the use of washed coal. Operational cost data are calculated for different distances between power plant and mine, $1=Rs35.*
Source: *Quingru et al (1991).*

Significant investment cost savings can also be realized for new plants if they are designed for firing washed coal. The equipment affected by the ash content includes:

- coal receiving, preparation, handling and storage equipment;
- steam generation;
- combustion air and flue gas systems;
- particulate removal system;
- flue gas desulfurization system;
- bottom ash system; and
- waste disposal system including transportation system and disposal area requirements.

When designing a plant for lower ash content or for washed coal, the reliability of the coal washing plant has to be close to 100%. For as long as coal cleaning technology is not widespread in India and China, and in cases where 100% coal cleaning cannot be guaranteed, it is recommended that power plant is designed in anticipation of there being no positive influence from coal cleaning. It is also important to strive for a correlation between the contracted coal price and the quality of the coal.

COAL CLEANING METHODS

Conventional preparation/cleaning involves the separation of coal-rich from mineral-matter rich particles in different size ranges. A simple plant will only separate the coarse sizes, while more complex operations undertake separations of coarse, intermediate and fine. Different levels of cleaning involve progressively separating finer size ranges.

The physical methods are based on the differences in either density or surface properties between the organic matter and the minerals it contains. A few separation methods which are under development depend on differences between the magnetic or electrostatic properties of the materials. Chemical and biological methods have been tested on a small scale, but are not seen as having economic potential over the next 5-10 years in connection with power generation and they are not covered by this guide.

Physical coal cleaning may consist of the following stages:

- size reducing (crushing, <50 mm),
- sizing (coarse, 10-150 mm; intermediate, 0.5-10 mm; fine < 0.5 mm),
- cleaning,
- dewatering, and
- drying.

Most methods are water-based, either by gravity or by surface property. The water-based processes may increase the moisture content in the treated coal, the rate depending on the dewatering and drying processes used. All cleaning processes produce a reject consisting of the inert material but also a certain content of carbon. The cleaning methods will cause some losses in carbon and may increase the water content of the coal. The environmental problems connected with coal cleaning are briefly described in Appendix 1. Proven, simple technologies for coal cleaning are recommended to be used. The following methods for coal cleaning are considered as commercial and are further discussed in this technical guide. The methods themselves are described in Appendix 1:

Gravity based:

- Jigs,
- Dense-medium separators,
- Hydrocyclone,
- Flowing film, and
- Concentration table.

Surface property based:

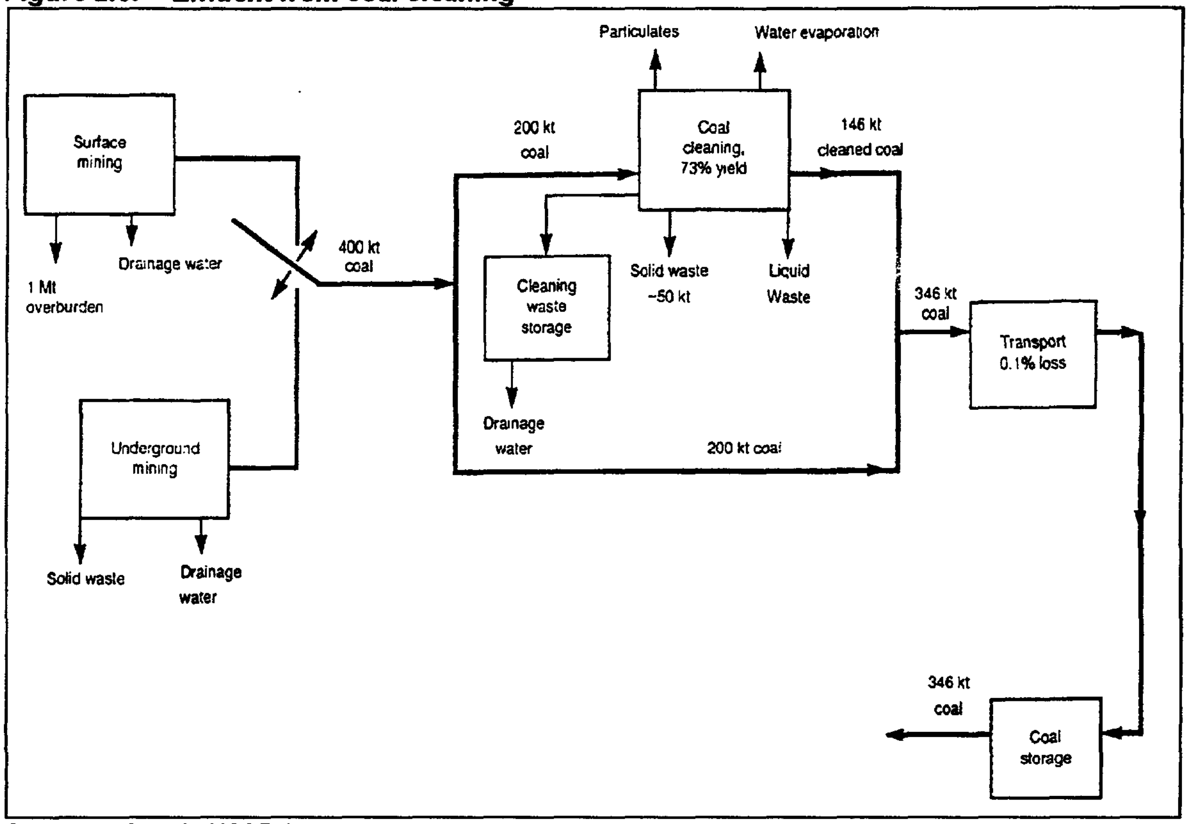
- Froth flotation.

Dry methods:

- Cleaning coarse coal with a fluidized air dense-medium.

Cleaning processes produce effluents such as wastewater and solid residues. Figure 2.5 gives an example of how quantities and concentrations of effluents vary for different methods.

Figure 2.5: Effluent from coal cleaning



Source: *Couch (1995a).*

Different coal cleaning methods (described in the Appendix) are compared regarding the state of technology, performance, advantages and disadvantages, costs and suitability in Tables 2.4 and 2.5.

Table 2.4: Comparison of different coal cleaning method

Methods	Jigs	Dense-medium separators	Hydrocyclones
State of technology	• Commercial	• Commercial	• Commercial
Advantages	• Large capacity • Inexpensive • Most common type world wide	• Good separation • Second most common method	
Disadvantages	• Lower separation than dense-medium	• Small capacities	• Water consumption
Costs	• Inexpensive	• Expensive	
Suitability	• Intermediate efficiency device. For moderately difficult to clean coal • Specific gravity >1.5-1.6 • Size: 0.5-150 mm	• For difficult or most difficult to clean coal. • Specific gravity >1.3-1.9 • Size: 0.5-150 mm	• For coarse to intermediate particles. • Size: 0.5-150 mm

Table 2.5: Comparison of different coal cleaning methods

Methods	Concentration tables	Froth flotation	Dry cleaning
State of technology	• Commercial	• Commercial	• Close to commercial
Advantages	• Inexpensive • Good pyrite separation	• Good results on fines	• No water required
Disadvantages	• Quite small capacities of 10-15 tons/hr;	• Complex • Poor pyrite separation • Poor dewatering characteristics	• Not for difficult to clean coal
Costs	• Inexpensive	• Expensive	• Lower than wet processes
Suitability	• Used for fine coal containing a great deal of pyrite. • Specific gravity >1.5 • Size: 0.0-15 mm	• Used for fines. Mainly used for metallurgical coals • Size: <0.5 mm	• Requires easy coal.; size >10 mm • Rough separation • For coal tending to form slimes in wet processes

ALTERNATIVE LOCATIONS FOR CLEANING

Coal cleaning can either be located near the mine, at the stockyard or at the power plant. The predominant choice is cleaning near the mine. Disposal costs at the mine site will almost certainly be much lower than those near a power plant, possibly by a factor as large as 10:1.
Transport costs are proportionately reduced and the process results in a more consistent product.

Coal cleaning at the power plant is not a traditional location. Most commonly the utilities have preferred to let the coal producers prepare/clean the coal. On-site cleaning would not be possible at some existing sites due to lack of space. A major disadvantage is that the coal cleaning plant would need to be used most of the time. In addition to capital investment, an infrastructure and a team of skilled management and operators are required.

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3. COMBUSTION TECHNOLOGIES

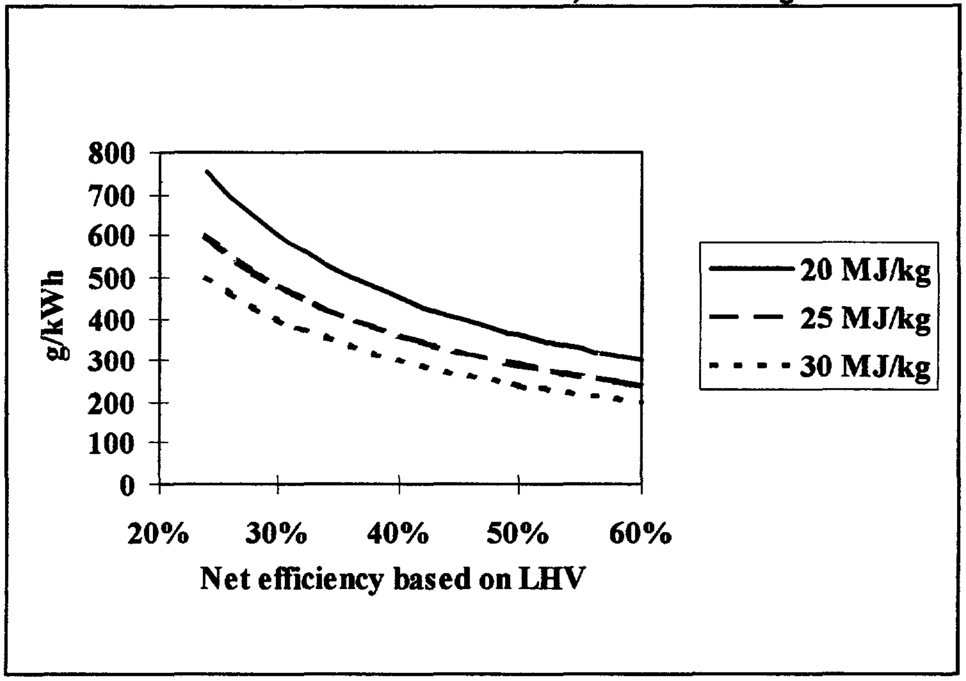
The rapid growth of electric power consumption in India and China calls for planning and building of cost-efficient power plants. Available combustion technologies include conventional PC-fired units, with subcritical steam data and, hence, moderate efficiencies and supercritical PC units with higher efficiencies. Pulverized coal-fired technology is the most widely used coal combustion technology for boiler sizes up to 1000 MW_e. Atmospheric circulating fluidized bed combustion (ACFB) is a relatively mature technology which will likely contribute to new coal-fired units. There are also several new coal combustion technologies i.e. pressurized fluidized bed combustion (PFBC) and integrated gasification combined cycle (IGCC).

In order to be cost-effective, new plants should have high efficiencies, high availability, low emissions, and produce a by-product that can be utilized, avoiding the need for disposal. As discussed in Chapter 2, the use of washed coal is a first cost-efficient step towards increased plant efficiency and availability, reduced investment and O&M costs. The use of washed coal with low ash content also reduces the amount of solid waste disposal at the plant. This is further discussed in Chapter 7.

A major concern in both India and China is the inefficient use of coal in the power industry due to low plant efficiencies (33 to 36%). Older power plants might have efficiencies as low as 25%. Higher plant efficiencies will reduce the emissions of SO_x, NO_x and particulates and the waste production per MWh_e. In addition to these advantages, coal consumption is reduced per MWh_e produced. This is illustrated in Figure 3.1 where the hard coal consumption per kWh of electricity produced is shown as a function of unit efficiency. For example, the figure shows that when the efficiency of a hard coal-fired power plant is increased from 34-42%, coal consumption is decreased from 0.42-0.34 kg/kWh of electricity produced, or around 20%, if the hard coal has a lower heating value (LHV) of 25 MJ/kg. Not only the coal consumption is decreased, but emissions and waste are also reduced by 20%. Another consequence of reduced consuption is the lessened amount of coal being transported on the already overloaded railways.

Internationally the current trend in base load PC-fired power plants is to build large, supercritical plants with efficiencies around 42%, which could be the high efficiency technology alternative for India and China. This calls for transfer of technology know-how to manufacturers and utilities in India and China. As mentioned above, supercritical boilers with increased steam parameters are very competitive on the international market for large PC plants. Most large PC boilers built in Western Europe are supercritical. Although the investment cost is higher for a supercritical boiler, the gains in reduced power generation costs and decreased emissions are obvious. Until recently, steam temperatures have been limited to 540°C since high temperature steels, normally used in boilers and turbines, do not allow for higher temperatures. Today, there are materials available at acceptable costs which permit higher steam temperatures. In the future, efficiencies of around 50% will be possible with ultra supercritical steam parameters.

Figure 3.1 Hard coal consumption per kWh of electricity produced for three different coals with LHV 20, 25 and 30 MJ/kg



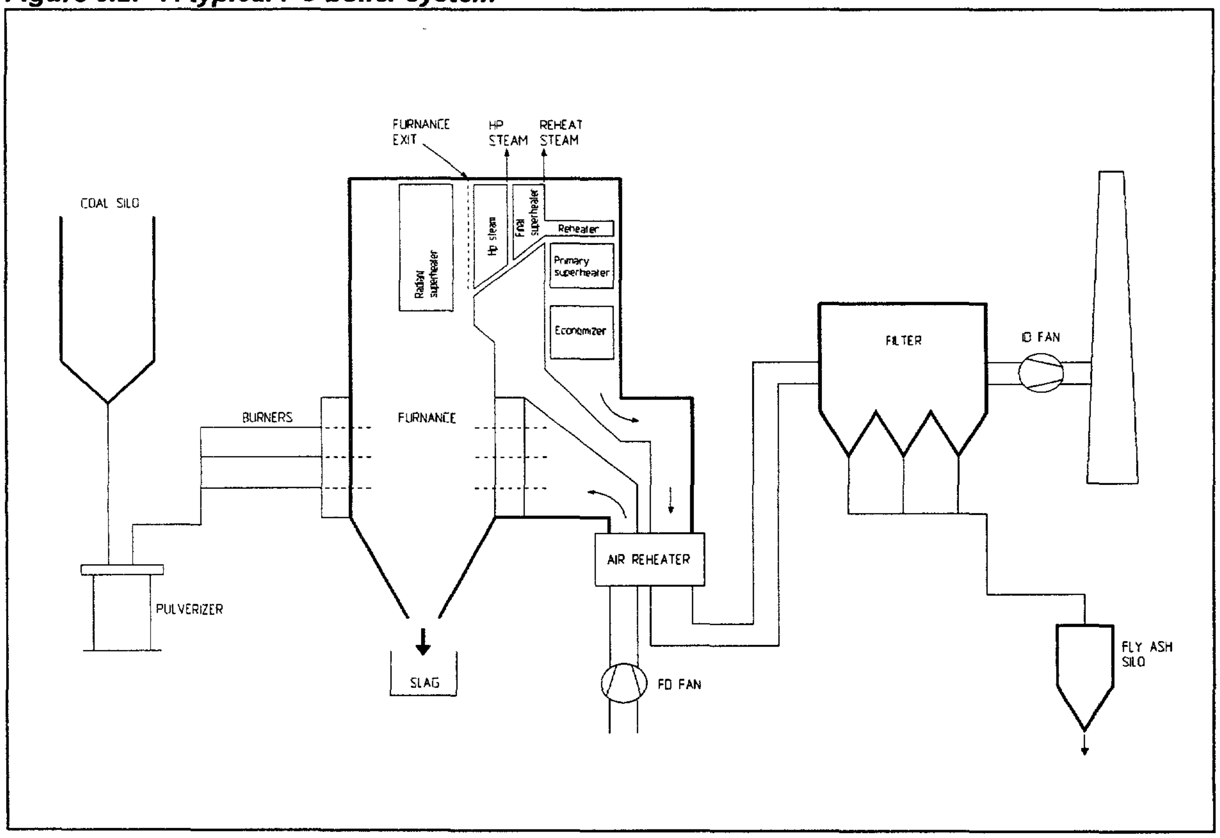
Pulverized coal-fired units cannot meet moderate emission standards without pollution control equipment. Since reducing emissions from a PC unit is not without cost, other technologies have been developed. The ACFB technology has a low-cost advantage of a wide fuel flexibility and low emissions of both NO_x and SO_2. Sulfur is captured directly in the boiler bed and NO_x formation is low due to the low combustion temperature. The drawbacks of today's ACFB technology is that its waste of mixed ash and desulfurization products is difficult to utilize. An ACFB plant also emits significant amounts of N_2O which has a potential for global warming. The efficiency is relatively low due to the use of subcritical steam parameters. Currently subcritical ACFB boilers are commercial in sizes up to approximately 100 MW_e. Developmental work is underway on larger size units, with possibilities for waste utilization and even increasing steam parameters. Market prices are difficult to predict, but a cost comparison between a PC plant equipped with wet FGD and an ACFB plant usually shows a lower investment cost for the ACFB plant.

Offering high efficiencies and low emissions, PFBC and IGCC are technologies under development with few or no commercial plants in the world. Further demonstration is needed before they reach commercial status. Improving efficiency in existing power plants must be considered as an important, achievable first step to increased, cost-effective power generation. Since plants in India and China currently operate mainly at low efficiencies, there is substantial potential for improvement. Some of these efficiency improving measures are discussed in Chapter 8 on Low Cost Refurbishment.

PULVERIZED COAL COMBUSTION

Pulverized coal technology is the oldest and most commonly used technology for thermal power generation worldwide. It can be used for boiler sizes up to and above 1,000 MW_e. Pulverized coal technology requires flue gas cleaning in order to be environmentally friendly, since the emissions of SO_2 and NO_x become unacceptably high. Fly ash and bottom ash from PC firing can be used in the building industry. Pulverized coal boilers can be divided into two groups based on steam data: subcritical PC boilers, where the live steam pressure and temperature are below the critical values 221.2 bar absolute pressure and 374.15°C; and supercritical PC boilers with steam data above the critical values. The current trend is to increase the steam data in order to increase plant efficiency.

Figure 3.2: A typical PC boiler system



Suitability

Both sub- and supercritical PC boilers can be used for all boiler sizes up to 1,000 MW_e. They can be designed for any coal from lignite to anthracite, but a given boiler must be designed for one type of coal (lignite, bituminous or anthracite). This means that once designed for a specific coal, PC units are somewhat more sensitive to changes in fuel quality than fluidized bed combustion technology. Uncontrolled emissions from PC firing are high compared to other technologies, which means that emission reduction equipment is necessary and can be rather expensive.

Subcritical PC boilers
The moderate steam data used in subcritical PC boilers results in rather low plant efficiencies. The advantage of subcritical boilers is that they are fairly simple to operate and maintain, relative to other combustion technologies. The availability of subcritical PC-boiler plants is very high as a result of the simple design and long time experience.

Supercritical PC boilers
Supercritical technology is newer than subcritical. In the industrialized world, there are now many supercritical PC plants in operation, and most plants that are under construction will also be supercritical. There are no supercritical boilers in operation in India and just a few in China, so there is limited practical experience in supercritical PC firing in both countries. Currently, no supercritical boilers are manufactured in either India or China. The efficiencies of supercritical PC plants are higher than those of subcritical ones and of ACFB plants. When plants with high efficiency are wanted, supercritical boilers should be selected. The higher efficiency has major advantages such as reduced coal consumption and reduced emissions of NO_x, SO_2, particulates and waste per MWh_e produced.

In boilers operating at high steam temperatures (above 540°C), corrosion becomes more of an issue. When high steam temperatures are used, coals with a high corrosion potential are less suited and should be avoided. Due to the more complex design of supercritical boilers, the requirements on O&M routines are higher than those for a subcritical boiler. Also the demands on water quality and instrumentation and controls (I&C) equipment are high.

State of technology

Subcritical boilers
Subcritical PC boilers have been used for more than 50 years. Unit sizes vary from less than 100 to above 1,000 MW_e. The technology is well proven and hundreds of units are in operation in India and China.

Supercritical boilers
The technology is well-proven in the industrialized world with more than 200 units in operation. There are no supercritical boilers in operation in India today (Ref. 1). In China there are only a small number of supercritical plants; they include Shanghai (2x600 MW_e); Liaoning (2x500 MW_e), and Hebei (2x500 MW_e), all built in the 1990s (Ref. 2).

Future development
The major future technical development will be to increase efficiencies and improve the environmental performance of PC boilers. Improvement in efficiency is achieved by increasing steam conditions and potentially by the introduction of double reheat. To date, the use of ferritic materials has limited steam temperatures to 540°C. Higher steam temperatures used to require austenitic materials. Development of new ferritic material now allows steam conditions up to 248 bar and 593°C. Plants with steam data of 300 bar and 580-600°C are currently planned.

Plant size

Unit sizes over 1,000 MW_e are possible. Normal sizes for new units are 250-600 MW_e. Currently, all units being installed in India are either of 210-250 MW_e or 500 MW_e capacity. In China, large boilers of 300 MW_e and 600 MW_e are projected.

Fuel flexibility

Pulverized coal-firing technology can handle a wide range of coals, from anthracite to lignite. However, combustion stability problems might occur if high ash and moisture coals are fired. Anthracite firing requires special boiler design due to the very low volatile compound content. For a particular plant, the boiler and auxiliary equipment must be optimized for its design-specific coal. The flexibility for each PC boiler to handle a range of coal qualities is limited. Table 3.1 below shows the limits for some coal parameters for a normal PC boiler.

Table 3.1: Limits for coal parameters for PC boiler designed for normal bituminous coal

Coal parameter	Limit (approximate values)
Lower Heating Value	>20 MJ/kg
Ash content	<10%
Initial Deformation Temperature (IDT)	>1,100 °C
Moisture	<10%
Chlorides	<0.3%
Volatile Matters (VM)	>25 %
Sodium+Potassium (Na+K)	<2.5%

A PC boiler can be designed for wider variations in coal parameters than indicated in Table 3.1, but this generally results in increased capital cost and lower efficiency during off-design operation. Operational flexibility, such as turn down, can also be compromised if the plant is designed for too wide a range of coal qualities.

Performance

Efficiency

Table 3.2 summarizes steam parameters and efficiency data for typical PC plants.

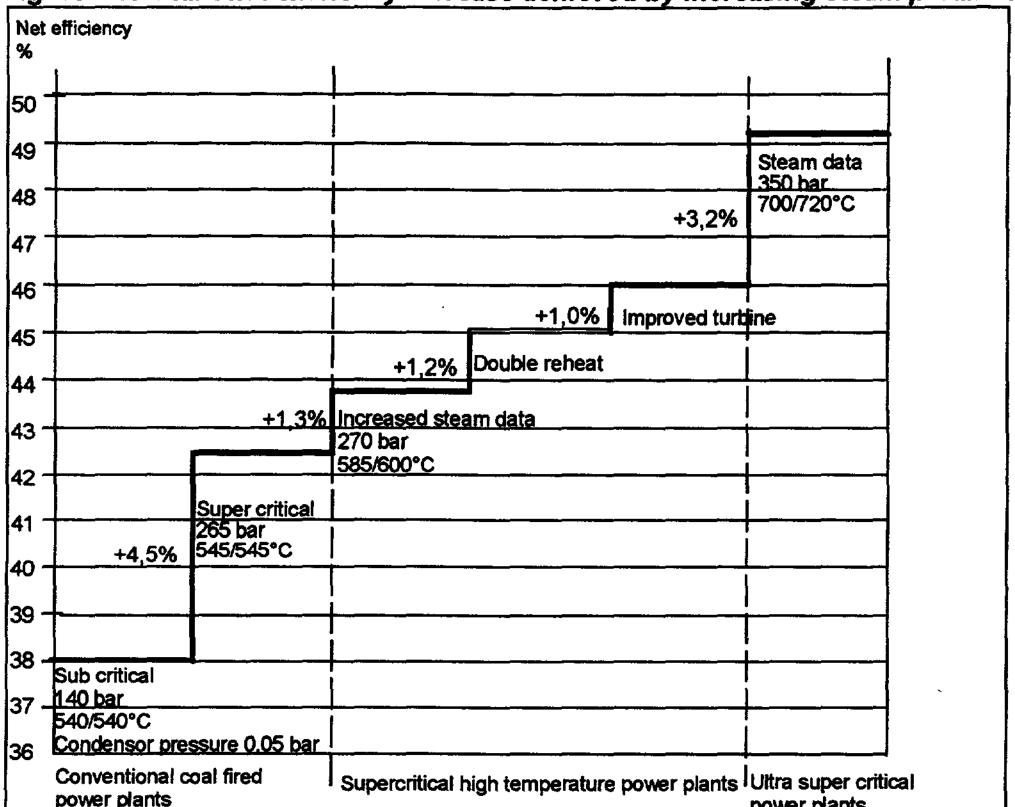
Table 3.2 Efficiency data for PC boilers

	Subcritical boilers	Supercritical boilers	Supercritical high temperature boilers	Ultra supercritical boilers- future potential
Steam pressure *(bar)*	140	240	300	350
Steam temperature *(°C)*	540/540	540/540	590	650
Unit net efficiency *(%)*	36-38	40-42	45	close to 50

***Note:** Unit net efficiency based on LHV of coal, includes wet FGD with condenser pressure.*

The increase in plant net efficiency achieved by increasing steam parameters is shown in Figure 3.3 (Ref. 6). Conventional subcritical PC plants are shown to the left, followed by supercritical plants with efficiencies above 42%, and slightly higher steam parameters than shown in Table 3.2. Increasing steam data and the introduction of double reheat can increase efficiency still further. The future potential for an ultra supercritical boiler is shown to the right.

Figure 3.3: Plant net efficiency increase achieved by increasing steam parameters



Note: *This diagram shows normal net efficiencies in conventional power plants (left), the efficiencies in supercritical high temperature plants (middle) and future efficiencies of ultra supercritical power plants (right).*
Source: *VGB Kraftwerkstecknik (1996).*

Load range

The minimum load is in the range of 25-40% of maximum continuous rating. However, oil or gas might be required as a support fuel in this low load range. The practical limit for commercial part load operation is usually at a load determined by the need to introduce oil or gas firing to maintain PC combustion stability. This boundary is determined by the fuel composition and boiler island design, but normally occurs between 40 and 60% of maximum continuous rating.

Load change rate

Changes of load (ramping) can be extremely rapid at up to 8% per minute. However, a normal load change rate required by the grid for coal-fired plants is circa 4% per minute within the whole load range.

Start- up time

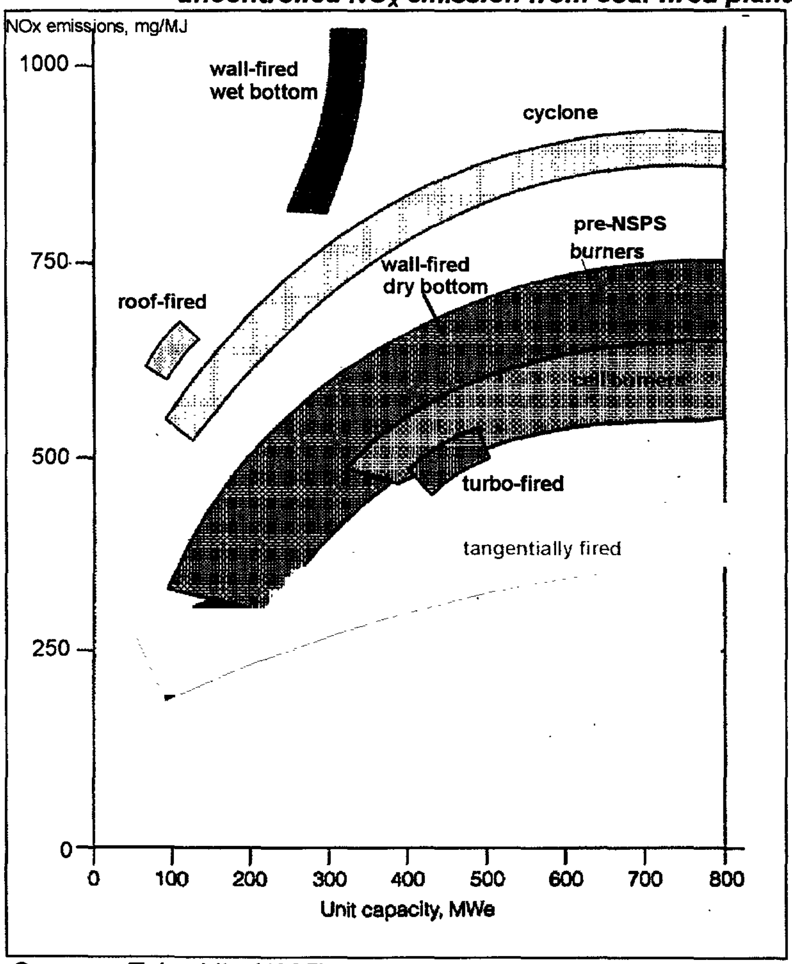
Cold start: 4-8 hours depending on type of circulation; once through is the fastest; natural circulation requires the longest time.
Restart of a hot unit: 1-1.5 hours.

Environmental performance

Sulfur:	Corresponds to the sulfur content of the coal.
Particulates:	10-25 mg/Nm^3 using ESP or bag filter.
NO_x :	New bituminous coal-fired boilers can be designed for NO_x emissions from 150-250 mg/MJ_{fuel} if the boiler is equipped with low NO_X burners; anthracite-fired boilers may produce emissions around 500 mg/MJ_{fuel}.

Fig 3.4 below shows the *uncontrolled* NO_X emission from coal combustion depending on firing technique and boiler size. Note that burners with new source performance standards (NSPS) for wall-fired boilers, using staged combustion which produces lower NO_x emissions than pre- NSPS burners, have been developed.

Figure 3.4: Effect of boiler firing types and unit size on uncontrolled NO_X emission from coal-fired plants



Source: *Takeshita (1995).*

Waste production

PC-firing produces fly ash (80-95% of the total ash flow) and bottom ash (5-20%). The ash is producable without further treatment and can be used in the building or cement industry.

However, it is important that the content of unburnt carbon in the ash is low (normally less than 5%). Ash utilization is further developed in Chapter 7.

Availability

Availability figures are high both for subcritical and supercritical plants. The availability is in the range of 86-92%, including planned outages of 4 weeks per year.

Construction issues

Construction time

The normal construction time is 36 months from contract award to commercial operation. Because of the large boiler sizes, most of the plant has to be erected on site.

Possibilities for domestic manufacturing/ licensing agreements for subcritical boilers

Both India and China have very experienced manufacturers of subcritical PC boilers. There are also some licensing agreements between large boiler manufacturers in industrialized countries and domestic manufacturers in China and India (Ref. 1 and 2).

Possibilities for domestic manufacturing/ licensing agreements for supercritical boilers.

Chinese boiler manufacturers do not currently have the capability to design and manufacture supercritical boilers. Cooperation activities between international and Chinese manufacturers are underway and local manufacturing will be possible in the near future (Ref. 2). Supercritical boilers cannot be manufactured currently in India, but international companies are investing in local manufacturing (Ref. 1). Already, part of a PC plant with a supercritical boiler can be manufactured locally if the design is carried out by an international manufacturer.

Maintenance

Normally, a yearly overhaul period of four to five weeks is required. Equipment that needs more frequent maintenance due to excessive wear and tear, such as coal pulverizers, must be made redundant. Units with drum boilers can be maintained by ordinary maintenance personnel. Some parts in supercritical once through boilers require maintenance by specially trained staff.

Complexity of technology

The design of a power plant with PC boilers has a low degree of complexity. A unit consists of boiler, turbine, fuel and ash handling equipment and flue gas cleaning equipment. A subcritical PC unit with a drum boiler is fairly simple to operate because the drum serves as a water magazine and compensates for deviations between the firing rate and the feedwater supply. This makes load changes fairly easy to control.

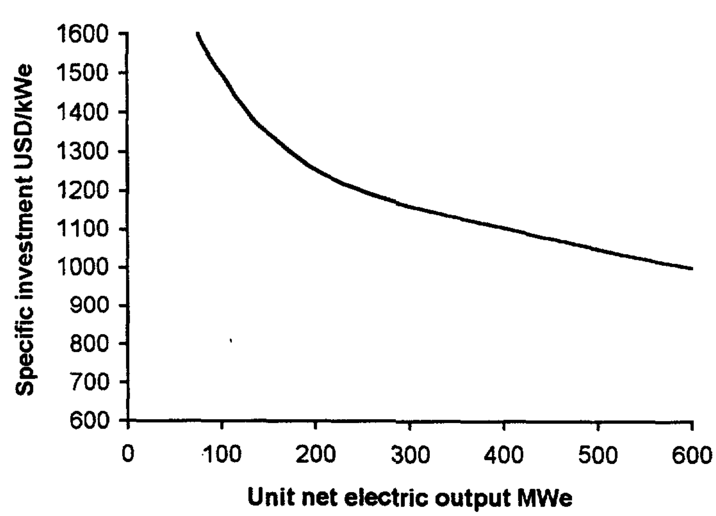
In a once-through supercritical boiler, the firing rate must always be in balance with the feedwater supply. Evaporation surfaces and superheaters might otherwise become dry with no water or steam in them. This kind of drying damages the surfaces. That makes the operation of once-through boilers more complex than that of drum boilers.

Costs

Investment costs

The investment cost ranges from 1,000-1,600 USD/kW_e for subcritical boiler plants for unit sizes between 75 and 600 MW_e. In Figure 3.5, the cost is given for a complete one-unit plant that includes everything from fuel storage to waste handling. No emission reduction equipment is included with the exception of low NO_x burners. The investment cost for a boiler only amounts to approximately 30% of the investment cost for a complete plant. Supercritical boiler plants are only slightly more expensive (around 5%) than subcritical, if steam temperatures are kept at ordinary levels. The cost is highly dependent on the state of the market, the size of the plant, number of units, the extent to which manufacturing can be carried out in low wage rate areas etc.

Figure 3.5: Investment costs for PC-boiler plants



Note: *Investment costs for PC boiler plants including everything from coal storage and handling to waste handling except emission reduction equipment.*
Source: *US Dept. of Energy (1994).*

Operation and maintenance costs

In Table 3.3, O&M costs for various sizes of PC boiler units are listed (Ref 5). The costs include the boiler system, steam turbine system and auxiliary systems.

Table 3.3 O&M costs for PC boiler units including steam turbine system and balance of plant

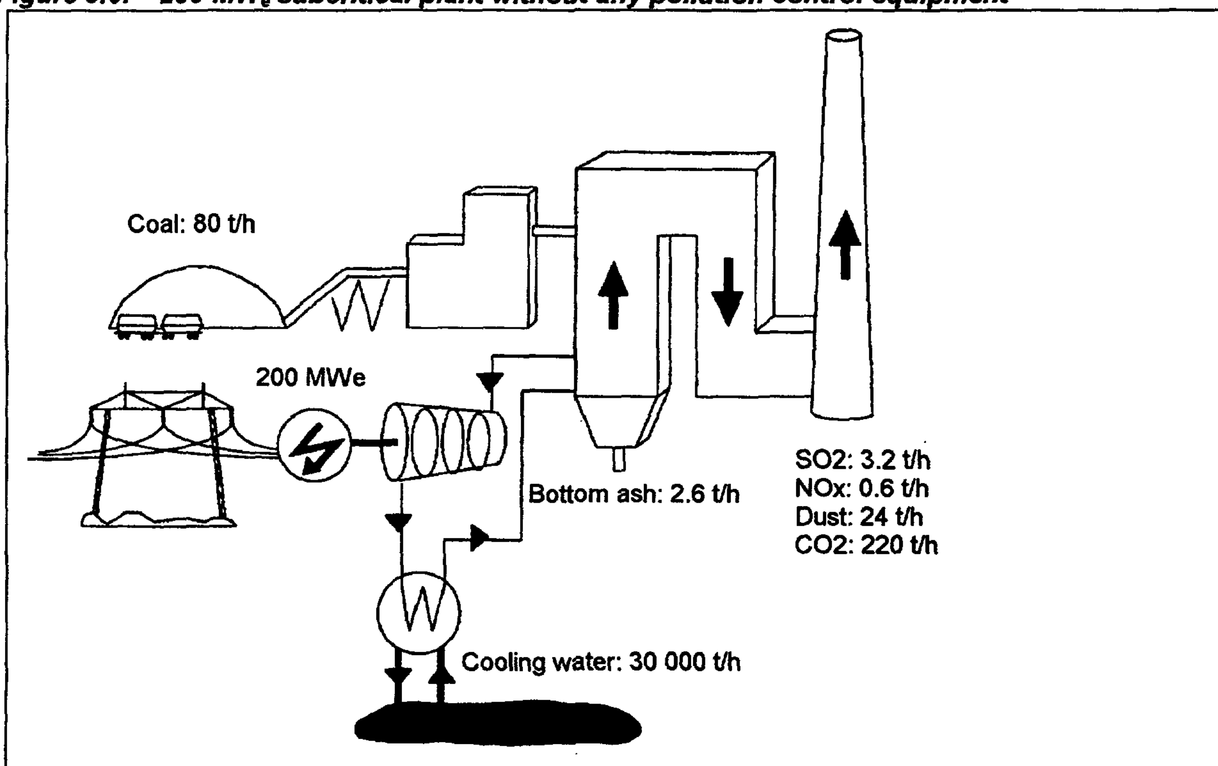
Unit size MW_e	Fixed O&M costs USD/kW/yr	Variable O&M costs UScents/kWh
500	27	0.2
150	36	0.5
75	53	0.6

Source: *US Dept of Energy (1994).*

A 200-MW$_e$ PC plant

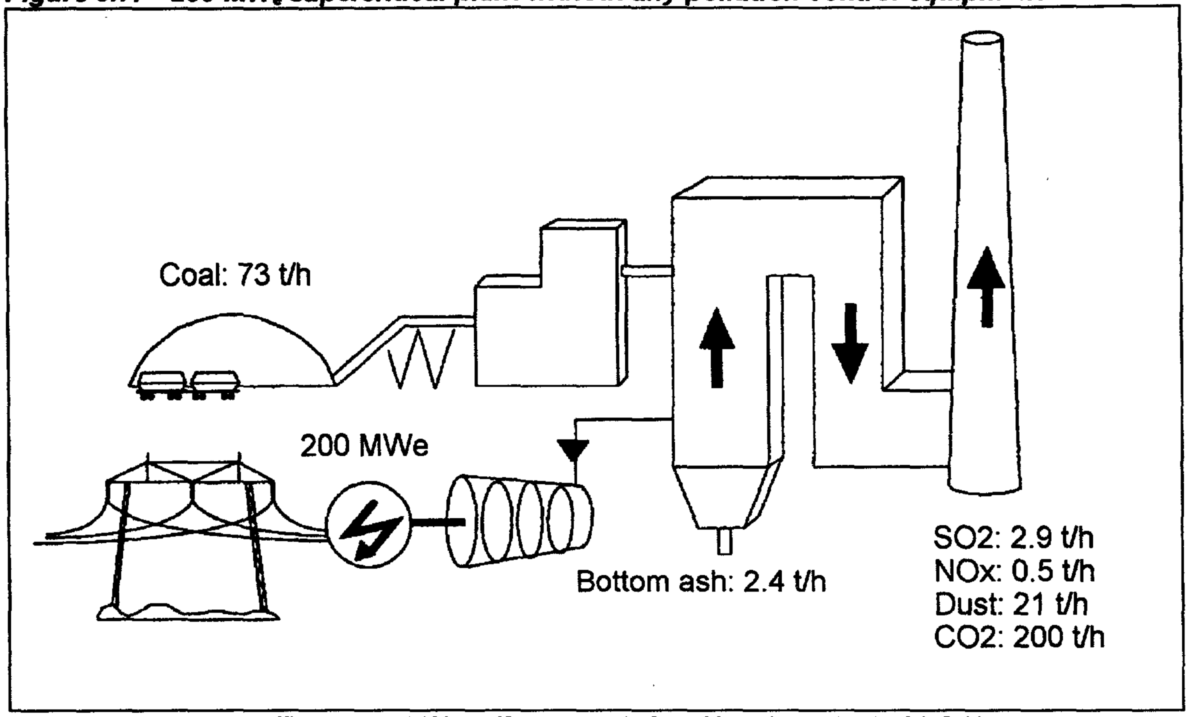
Figure 3.6 shows a 200-MW subcritical power plant without any flue gas cleaning equipment and Figure 3.7 shows a supercritical PC plant. The reduction in waste production, emissions and coal consumption that are achieved by increasing plant efficiency are shown by comparing Figure 3.6 and Figure 3.7.

Figure 3.6: 200-MW$_e$ subcritical plant without any pollution control equipment



Note: *Data used -- efficiency = 37%; sulfur content, S= 2%; ash content= 32.8%.*

Figure 3.7: 200-MW$_e$ supercritical plant without any pollution control equipment



Note: *Data used -- efficiency = 41%; sulfur content, S= 2%; ash content= 32.8 %.*

Screening criteria

Tables 3.4 and 3.5 are used for the technology screening in Chapter 9.

Table 3.4: Screening criteria for subcritical boiler units

Maturity of technology	• More than 100 units in operation in India and China, respectively
Max unit size	• Over 1,000-MW$_e$ net
Waste product	• Possible to use without processing

Table 3.5: Screening criteria for supercrtical boiler units

Maturity of technology	• More than 100 units in operation in the world; none in India and less than 5 in China.
Max unit size	• Over 1,000- MW$_e$ net
Waste product	• Possible to use without processing

ATMOSPHERIC CIRCULATING FLUIDIZED BED COMBUSTION

Atmospheric circulating fluidized bed combustion is a relatively new combustion technology which has been used most commonly in small-scale plants of less than 100 MW_e. The technology has some major advantages including low emissions of SO_x and NO_x. Sulfur can be captured cost-effectively and directly in the furnace by limestone injection.

Suitability

ACFB boilers have an extremely high fuel flexibility and will accept a very wide range of different fuels including low grade fuels. SO_x emissions are low since sulfur can be captured directly in the furnace by limestone injection. Because of the low combustion temperatures (circa 850°C) the NO_x emissions are comparatively low. However, significant amounts of N_2O emissions have been detected from ACFB boilers. Currently, all ACFB plants use subcritical steam data which means that plant net efficiencies are relatively low compared to those of supercritical PC boiler plants. The amount of waste is larger than for PC boiler units and a major drawback is that with current standards, there are only limited means to utilize the waste produced. Normally the investment cost for a ACFB plant is lower than that of a PC boiler plant equipped with wet scrubber for flue gas desulfurization.

There are only a few companies in the world supplying large ACFB boilers today. The technology is commercially viable for boiler sizes up to 100 MW_e.

State of technology

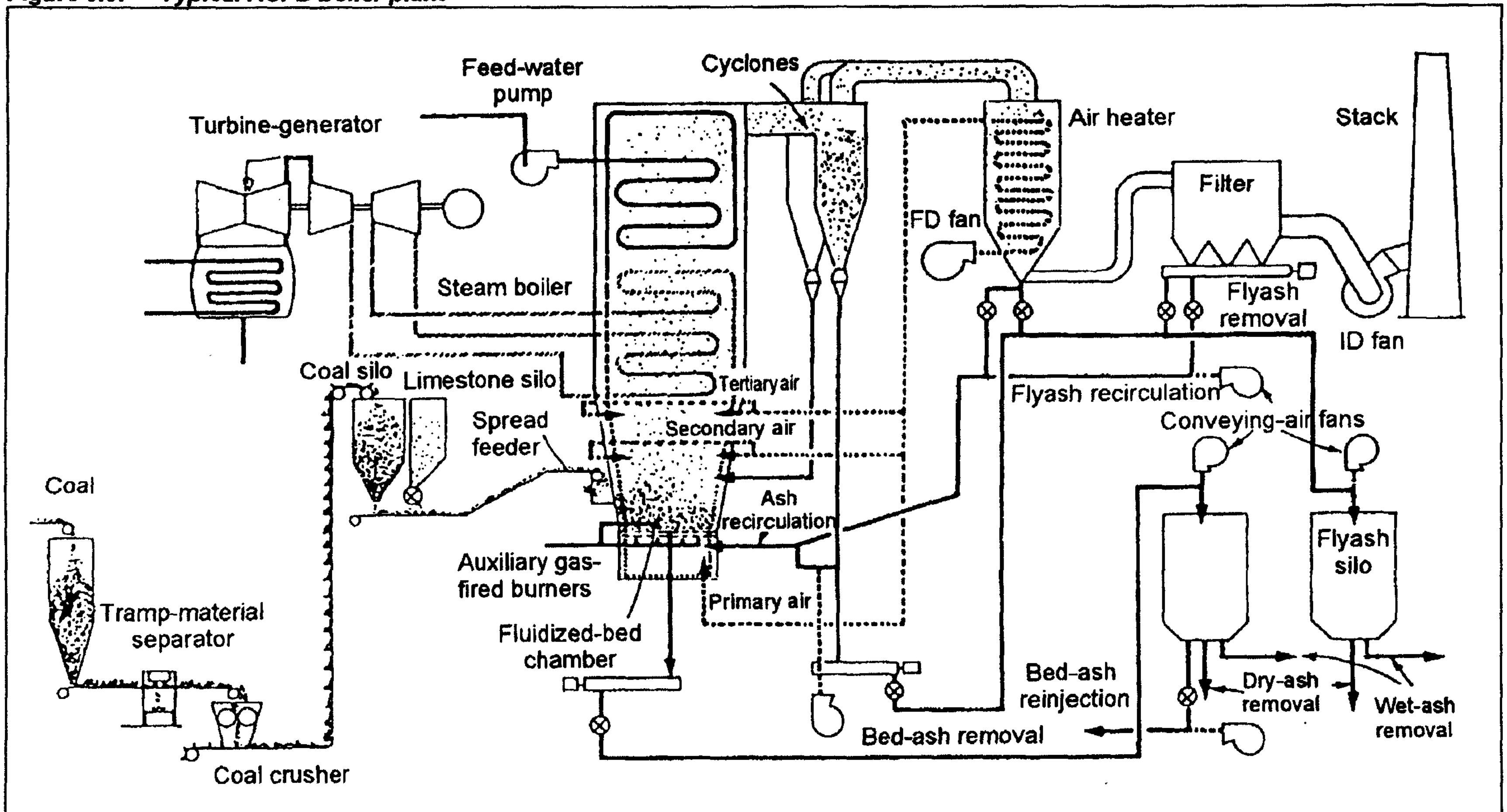
During the past ten years, fluidized bed technology has been extensively used for burning low-grade fuels in small plants. ACFB plants are commercially viable in sizes up to 100 MW_e. Its use at a utility scale to date is limited. Currently, the largest plant in operation is rated at 250 MW_e, although plants in sizes up to 350 MW_e are under construction. There are less than 10 ACFB boilers with an output of 100 MW_e or more in operation in the world.

There are numerous small-scale fluidized bed boilers in operation in India today, but no large ACFBs (Ref 1). In China, there are numerous small-scale fluidized bed boilers, but almost no large-scale units. In Neijang Power Station, Sichuan Province, a ACFB boiler with a capacity of 100 MW_e supplied by an international supplier was commissioned in 1996 (Ref. 2). There are also a number of ongoing projects in China for 50-MW_e ACFBs. Today's ACFB boilers use subcritical steam data and, hence, plant efficiencies are moderate.

Future development

A major future development of ACFB technology is scaling up to larger unit sizes in order to provide utilities with a complete range of unit sizes. Sizes up to 650 MW_e are currently planned. By-product utilization and N_2O emissions are other issues that are being investigated. The use of higher steam data to compete with PC plant efficiencies lies in the future.

Figure 3.8: Typical ACFB boiler plant



Source: *Coal Industry Advisory Board (1995).*

Plant size

Today, ACFB boilers are common in sizes below 100 MW_e. Unit sizes up to 250 MW_e are in operation. However, the major international ACFB supplier will offer commercial guarantees for units up to 400 MW_e. In the future, unit sizes up to 650 MW_e will be available.

Fuel flexibility

The fuel flexibility of ACFB boilers is extremely wide, probably the widest of any power generation technology. One single boiler can be designed for a wide range of fuels. Various types of fuels such as biomass, peat, lignite, and hard coal can be burned in the same ACFB boiler together or separately. Even coal cleaning wastes can be fired in a ACFB boiler. Table 3.6 shows the possible variations in some chosen coal parameters for a normal ACFB boiler equipped with fluegas recirculation.

Table 3.6 Acceptable values for some coal parameters for normal ACFB boiler with flue gas recirculation

Coal parameter	**Limit** (approximate values)
Lower Heating Value	>5 *MJ/Kg*
Ash content	<60%
Initial Deformation Temperature (IDT)	>900°C
Moisture	<55%
Chlorides	<0.5%
Volatile Matters (VM)	>10%
Sodium+Potassium (Na+K)	<3.5%

Performance

Efficiency

Today, ACFB efficiency is more or less the same as for subcritical PC fired plants, as shown in Table 3.7. In the future, if supercritical ACFB boilers are built, the efficiency will increase.

Table 3.7 Performance data ACFB boiler plants

Parameter	**Today**	**Future Potential**
Steam pressure *(bar)*	140	240
Steam temperature *(°C)*	540/540	540/540
Unit net efficiency *(%)*	36-38	40-41

Note: Unit efficiency data based on condenser pressure 50 mbar and LHV of the fuels.
Source: *Takeshita (1995).*

Load range and load change rate

Minimum load is in the range of 30-40% of maximum continuous rating. Changes of load (ramping) can be 5-7% per minute. A normal load change rate required by the grid for coal-fired plants is usually 4% per minute.

Start-up time

Cold start:	8 - 12 hours depending on type of circulation.
Restart of a hot unit:	1 - 1.5 hours.
Restart after a weekend shut-down:	2 - 3 hours.

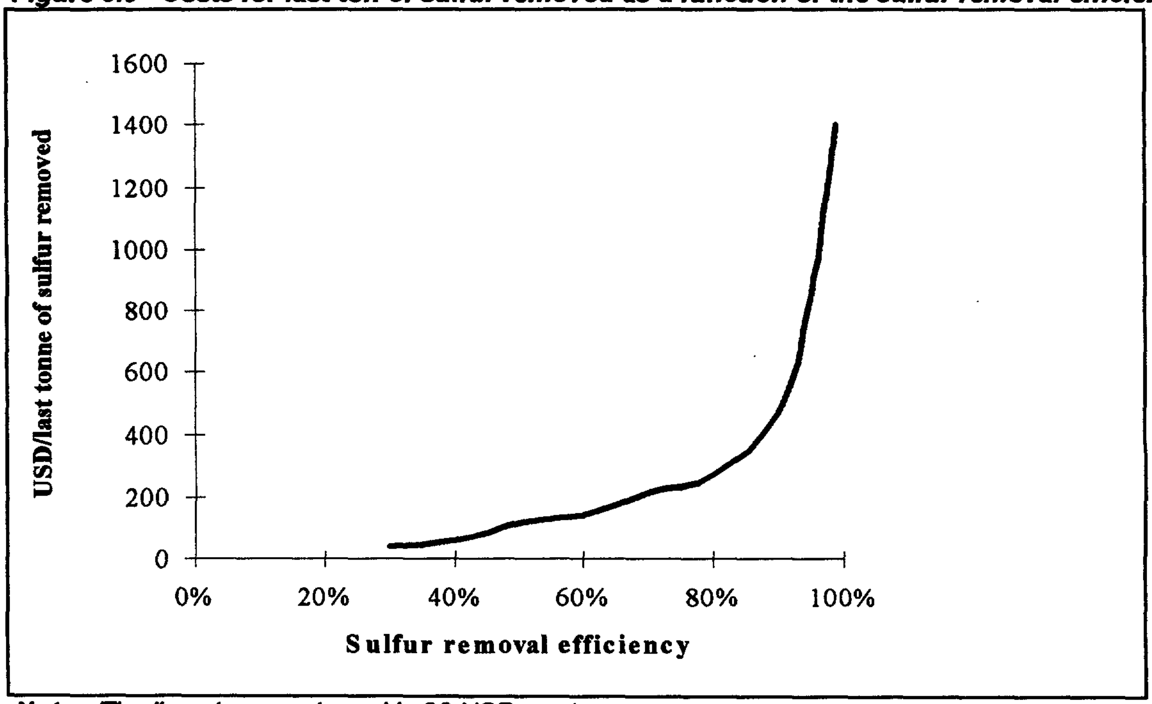
Environmental performance

NO_x:	80-150 mg/MJfuel for bituminous coal without NO_x reduction equipment.
N_2O:	significant emissions of N_2O have been observed.
Particulates:	10-25 mg/Nm^3 with ESP or bag filter.
Sulfur:	90-95% removal of sulfur.

Sulfur is captured in the bed by the injection of limestone. The sulfur removal rate is highly dependent on the sorbent to sulfur ratio (Ca/S). Increased sorbent to sulfur ratio improves the SO_2-removal. At a Ca/S ratio of 2, a 90% sulfur removal is possible. At a slightly higher Ca/S ratio, 95% sulfur removal is feasible. However, at higher sorbent ratios the sorbent utilization decreases, resulting in increased sorbent consumption and higher operating costs.

Figure 3.9 shows the cost for the last ton of sulfur removed in a ACFB boiler. The molar ratio between calcium and sulfur increases drastically with increasing sulfur removal efficiency.

Figure 3.9 Costs for last ton of sulfur removed as a function of the sulfur removal efficiency



Note: *The limestone cost used is 20 USD per ton.*

Waste production

Solid residues from ACFB combustion using limestone injection for SO_2 control consist of a mixture of coal ash oxides, calcium sulfate, high levels of lime (CaO) and low levels of carbonates. Of the residues, 80-90% are removed as fly ash and the rest as bottom ash. Today, ACFB wastes normally are landfilled. Development work on the use of ACFB wastes is ongoing.

Availability

Availability data is limited, but a sample of five fluidized bed boilers in the size range 80-160 MW_e including both bubbling and circulating beds, all less than six years old, shows an average availability between 87-88% with planned outages of 4 weeks per year.

Construction issues

Construction time

The construction time for a ACFB plant is 36 months from contract award to commercial operation. Because of the large boiler sizes, most of the plant has to be erected on site.

The possibilities for domestic manufacturing

Today, BHEL in India manufactures ACFB boilers with an output of 30 MW_e. Some Chinese boiler manufacturers cooperate with foreign companies in order to implement the ACFB technology in China.

Complexity of technology

The complexity of the design of a power plant with ACFB boilers is low compared to that of, for example, an IGCC plant. A unit consists of a boiler, a turbine, fuel and ash handling equipment and flue gas cleaning. The operation of a ACFB boiler plant is more complex than that of a PC boiler plant. The temperature in the furnace must be kept within a narrow span in order to ensure as efficient sulfur reduction. The distribution of air to the furnace must be well controlled.

Maintenance

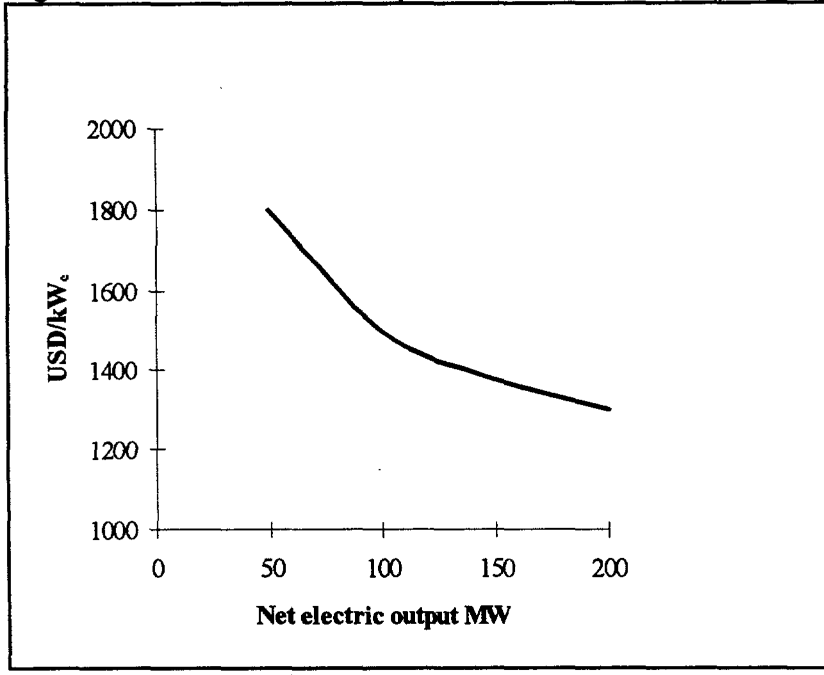
Normally, a yearly overhaul period of four to five weeks is required. The manufacturing companies provide regular inspection and maintenance services to their clients.

Costs

Investment cost

The investment cost for a ACFB boiler plant lies in the range of 1,300-1,800 USD/kW_e for unit sizes 50-200 MW_e. Figure 3.10 shows the estimated investment costs depending on the unit sizes for plants firing medium sulfur (2.1%) bituminous coal. The cost is given for a complete plant with one unit and includes everything except dust cleaning (ESP or bag filter) from fuel storage to waste handling. The cost for a boiler only amounts to approximately 30% of the investment cost for a complete plant. The cost is highly dependent on the state of the market, the size of the plant, number of units, the extent of manufacture in low-wage rate areas, etc.

Figure 3.10: Investment cost per kWe for ACFB boiler plants



Source: Forsberg (1996).

Operation and maintenance costs

The O&M costs are shown in Table 3.8. Fuel costs are not included.

Table 3.8: Operation and maintenance costs for a ACFB plant

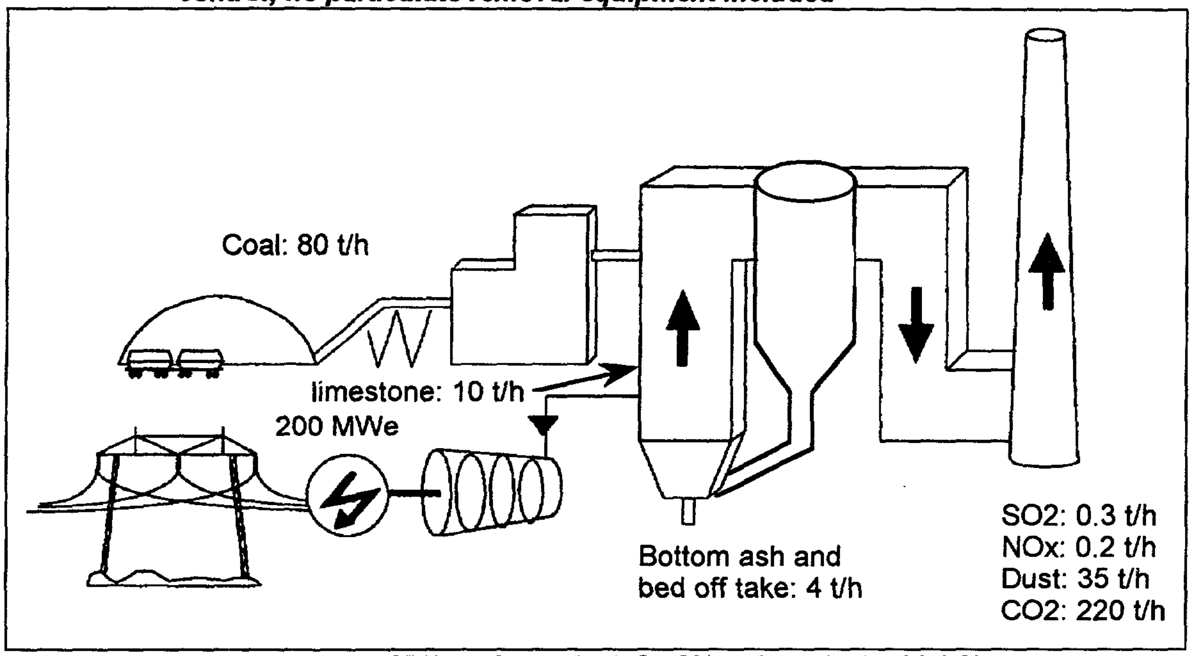
Unit size *MW$_e$*	Fixed O&M costs *USD/kW/yr*	Variable O&M costs *UScents/kWh*
150	44	0.85
75	64	1.04

Source: US Dept. of Energy (1994).

A 200-MW_e ACFB plant

Figure 3.11 shows a 200-MW_e ACFB plant using limestone injection for SO_2 control.

Figure 3.11 200-MW_e ACFB plant using limestone injection for SO_2 control; no particulate removal equipment included



Note: *Data used -- efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*

Screening criteria

The table below is used for technology screening in Chapter 9.

Table 3.9: Screening criteria for ACFB plants

Maturity of technology	• Commercial in industrialized countries for sizes <100 MW_e. There are less than 10 units with an electric output above 100 MW_e in operation in the world today. No units with an output above 100 MW_e are in operation in India and one 100 MW_e unit is under construction in China.
Maximum unit size	• Up to 250-MW_e net
Waste products	• Not possible to use today.

PRESSURIZED FLUIDIZED BED COMBUSTION

Pressurized fluidized bed combustion is an even newer technology than ACFB with only a few plants in operation worldwide. In a PFBC plant as illustrated in Figure 3.12, power is generated in an integrated combined cycle with the hot gas from the combustor driving the gas turbine. Steam generated mostly in the combustor powers a steam turbine. The main advantages of the PFBC technology are the low emissions and the high efficiency.

Suitability

The technology is new with limited operational experience. There is only one commercial plant in operation today and only one company in the world supplying PFBC plants. The efficiency is high and the environmental performance is good with low emissions of SO_X and NO_X. Sulfur can be captured directly in the combustor by limestone or dolomite injection. Because of the low combustion temperatures ,~850 °C, the NO_X emissions are low. PFBC units can be designed for a wide range of fuels including low grade. The drawbacks are high investment costs, shortage of experience of the technology and the waste product which as of today is still difficult to use.

State of technology

The PFBC technology is new with only one commercial plant in operation in the world (P200 in Värtan, Stockholm, Sweden) and a few others under construction. There are plans to build one PFBC plant in Dalean in China.

Plant size

Currently only two sizes of PFBC plants are available, the P200 and the P800. The P200 produces approximately 80 MWe with a fuel input of 200 MW, and P800 produces approximately 340 MW_e with a fuel input of 800 MW. No P800 plant is in operation, but one unit is under construction in Japan.

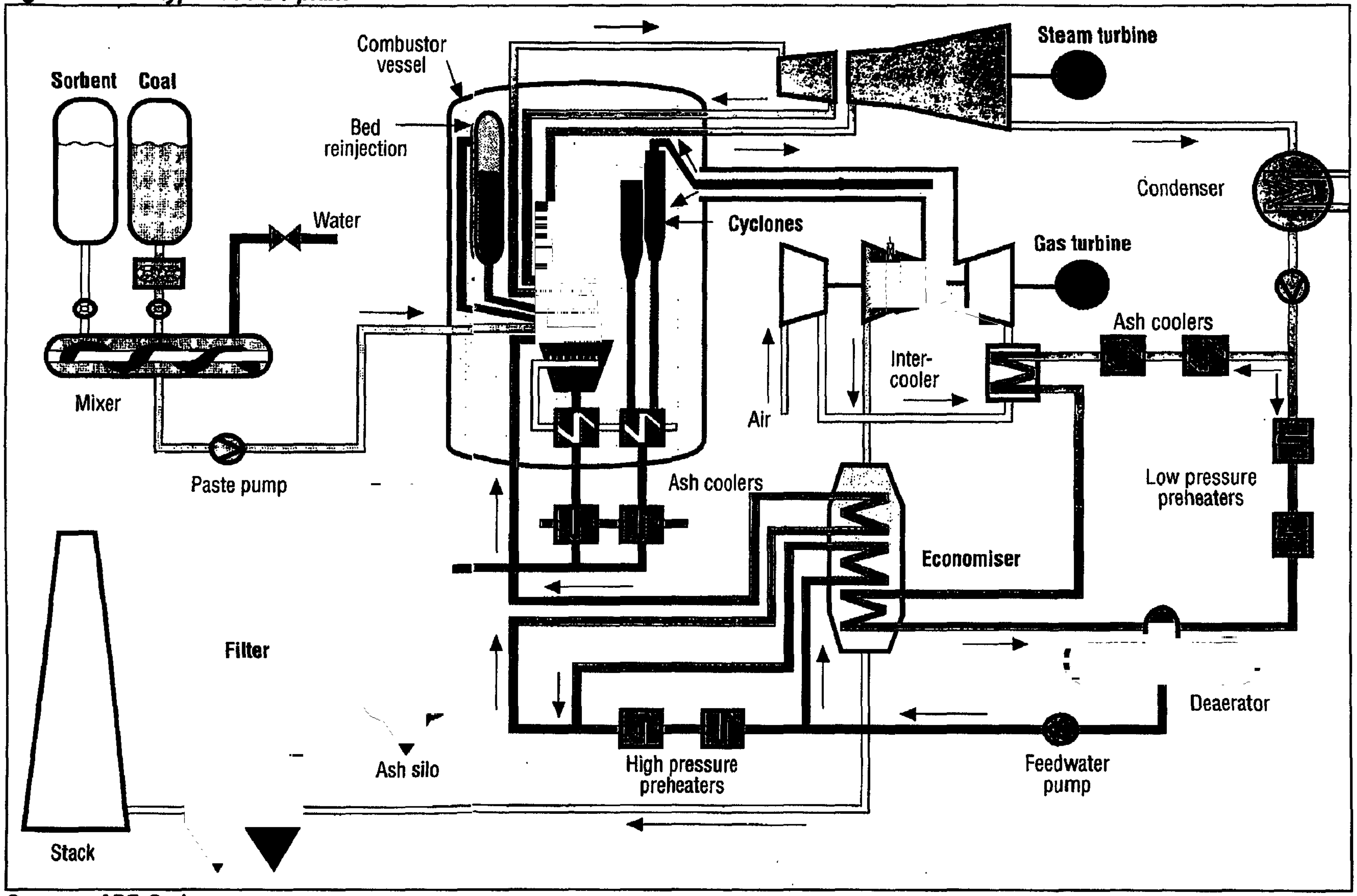
Fuel flexibility

The fuel flexibility of PFBC technology is extremely wide. However, for a specific plant the combustor and auxiliary equipment must be optimized for its design coal. The flexibility is therefore limited for each PFBC unit to handle a range of coal qualities.

Performance

Table 3.10 below summarizes the performance of PFBC plants. The efficiencies are higher than those of ACFB boiler plants.

Figure 3.12: A typical PFBC plant



***Source:* ABB Carbon.**

Table 3.10: PFBC performance

Efficiency P200 [a]	Efficiency P800 [b]	Load range	Start-up time hot	Start-up time cold
42%	45%	40-100% of MCR	3 hours	15 hours

[a] condensing mode, subcritical steam parameters condenser pressure of 50 mbar.
[b] condensing mode, supercritical steam parameters condenser pressure of 50 mbar.
Source: *Takeshita (1995).*

Environmental performance
Sulfur is removed by limestone or dolomite injection. At a Ca/S ratio of 2, a 90% sulfur removal is reached. Environmental performance is shown in Table 3.11.

Table 3.11: *PFBC environmental performance*

NO_x *mg/MJ*	Sulfur removal %	Particulates *mg/Nm*^{3}
70 - 110	90-99	10-25 with ESP or bag filter

Source: *Coal Industry Advisory Board (1995).*

Waste production

Solid residues from PFBC combustion consist of a mixture of coal ash oxides, calcium sulfate and carbonates. The content of lime is low (Ref. 8). Due to the low lime content, the PFBC waste is expected to have a higher potential for utilization than ACFB waste. However, today no area of utilization exists, but the wastes are disposed.

Construction issues

The possibilities for domestic manufacturing
With only one supplier in the world for PFBC plants today, the possibilities for manufacturing in India and China are limited. However, if the design and the critical parts, such as the gas turbine and combustion equipment are manufactured abroad, the rest of a plant can be made domestically. The construction time for PFBC is approximately 42 months.

Complexity of technology

Since this is a combined cycle consisting of a gas turbine operating together with a steam turbine and the combustion process is pressurized, the complexity of the design is high. Operation of a PFBC plant is complex and requires skilled personnel.

Maintenance

Normally a yearly overhaul period of four to five weeks is required.

Costs

The investment ranges from 1,100-1,500 USD/kW.

Screening criteria

The table below is used for technology screening in Chapter 9.

Table 3.12: Screening criteria PFBC plants

Maturity of technology	• With only one plant in the world in commercial operation the technology is new with limited operational experience
Unit sizes	• P200: 80 MW_e, P800: 340 MW_e
Waste products	• Disposal

INTEGRATED GASIFICATION COMBINED CYCLE

Integrated gasification combined cycle is a technology under development with only one commercial plant in operation; Buggenum in The Netherlands. A few plants are presently under construction. In Madras, India, work is under way to build a 60-MW IGCC plant fueled with lignite. The operating principle of an IGCC plant is illustrated in Figure 3.13.

In a gasification process, electricity is produced in a gas turbine fueled by a synthetic gas produced by the partial oxidation of coal in a gasifier. Steam, produced by synthetic gas cooling, drives a steam turbine. Sulfur is removed from the syngas before combustion. Removed sulfur is converted to elemental sulfur which can be sold. Coal ash is removed as slag from the gasifier. The main advantages of the gasification process are the very low emissions and the high plant efficiency, as shown in Table 3.13.

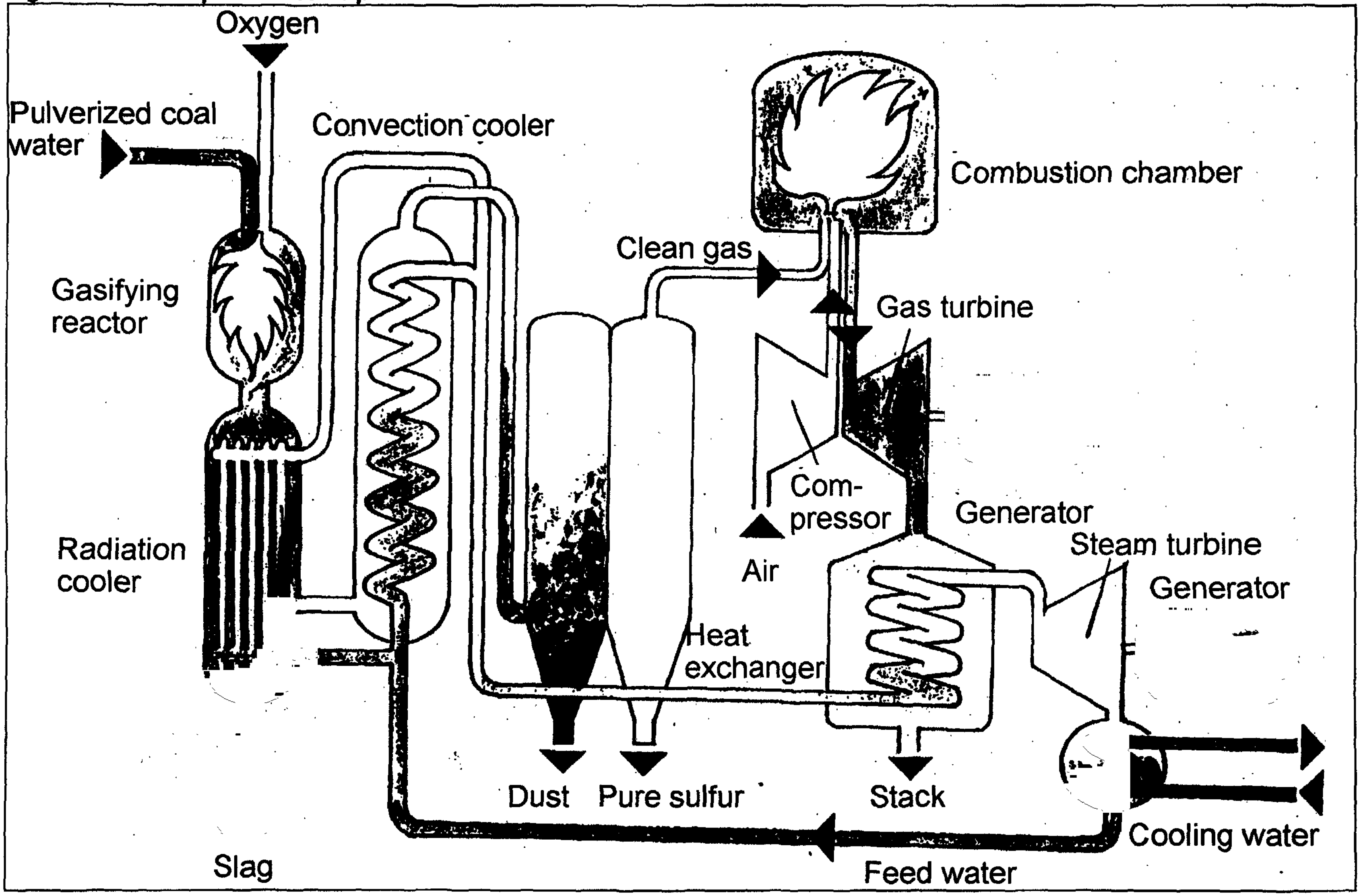
The major drawbacks are that the process is very complex, it requires a large surface area and there is very little commercial experience of operation. The investment cost is high, approximately 1,500-1,600 USD/kW_e. The construction time is expected to be four years. Performance data available for IGCC plants presented below are relatively uncertain since there are only a few IGCC plants in operation in the world today.

Table 3.13: Performance data IGCC

Unit size ***MW_e***	**Net efficiency** *Based on LHV of the fuel* *%*	**NOx emission** ***mg/MJ***	**SOx removal rate, %**	**Particulate emission, *mg/Nm³***
100-350	42-45	35-50	98	10

Source: *Takeshita (1995).*

Figure 3.13: Principle of an IGCC plant



Screening criteria

Screening criteria to be used in Chapter 9 are presented in Table 3.14.

Table 3.14: Screening criteria IGCC

Maturity of technology	• With only one commercial plant in operation in the world, the technology is in the development phase.
Unit sizes	• 100-350 MW_e
Waste products	• Ash and bottom slag. Elemental sulfur that can be sold.

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4. SO_2 EMISSION CONTROL TECHNOLOGIES

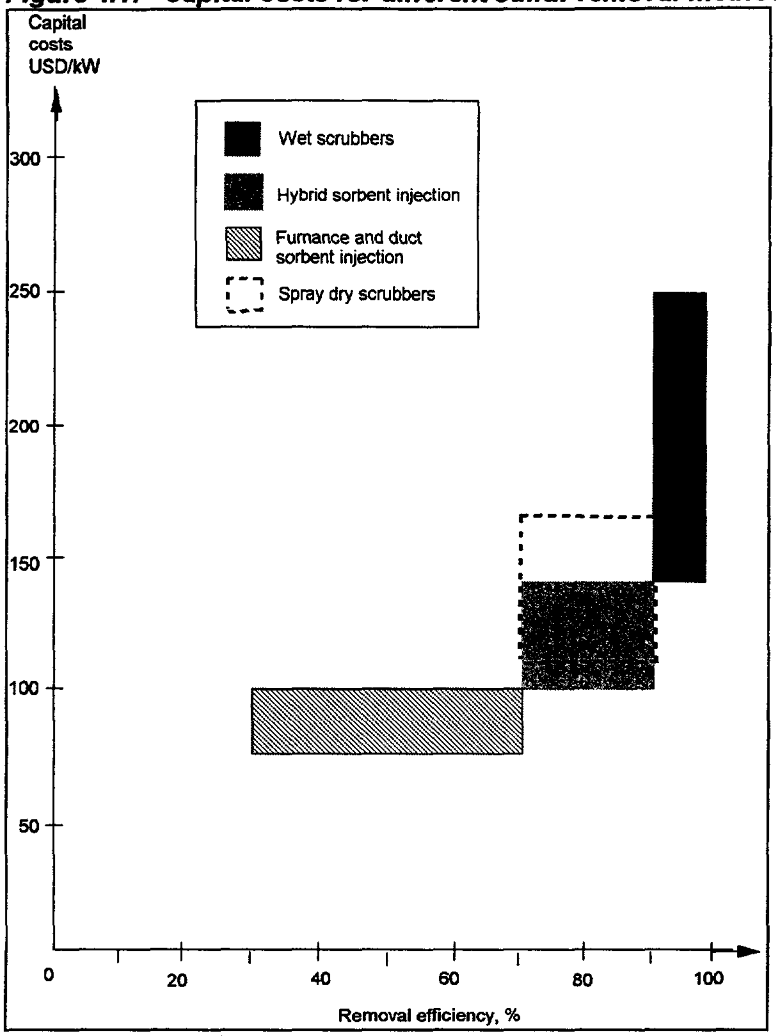
Since the sulfur content of coal can vary considerably, the simplest way to reduce SO_2 emissions in industrializing countries is to switch to a coal with a lower sulfur content. The benefits are obvious: it requires no change in operating procedures, and no additional by-products are generated. The capital investment can range from none to considerable. In some cases, modification to coal-handling equipment is necessary. Switching to low sulfur coal alone is rarely sufficient to meet regulatory requirements, but it can be a first step in an emission reduction program, reducing the cost of following control technologies.

For large power plants tied to local suppliers for political or economic reasons, fuel switching may be difficult. In such cases an alternative is coal cleaning by physical separation, described in detail in Chapter 3. Although sulfur removal is not the primary aim, physical coal cleaning techniques remove inorganic sulfur compounds in the coal, resulting in a SO_2 removal of 10 - 40%. Obvious benefits come from reduced ash content and improved heat value of the coal. Coal cleaning at the mine site also reduces the cost of transportation and has the advantage of reducing the amount of by-products generated at the power plant; less sorbent is needed for SO_2 removal, hence reducing the cost of waste disposal. The major drawback is that with a lower sulfur content, the fly ash resistivity may increase. This affects the ESP performance. ESP modifications may be necessary. Nonetheless, coal cleaning remains the most cost-effective route to reduce SO_2 emissions.

When fuel switching and coal cleaning are not possible or not sufficient to meet desired emission levels, an SO_2 removal technology must be introduced. The choice of SO_2 removal technology depends on a number of factors: emission requirements, plant size and operating conditions, sulfur content in the fuel(s), and the cost of various technology options, all of which are unique to each site. This chapter presents basic technical and economical information important for selection between different SO_2 removal technologies. The technologies discussed in this section include sorbent injection processes, wet scrubbers, and spray dry scrubbers. Advanced combined SO_x/NO_x-removal is discussed briefly in the section, *Combined SO_x/NO_x Control* (page 62.) Wet scrubbing has become the most commonly used technology for large base load, coal-fired power plants. It has a market share of 85% of the installed capacity.

The capital cost and the rate of SO_2 removal varies considerably between different technologies. Figure 4.1 illustrates the capital cost for three different sulfur removal methods in USD/kW$_e$ as a function of the sulfur removal efficiency. The figures in the diagram give an indication of the cost level, but the absolute levels of the costs should be considered with care. The diagram shows that wet scrubbing is the most efficient method, but it is also the most expensive one. Sorbent injection requires a lower investment, but gives a lower removal. Generally, the capital cost for SO_2 removal per kW is higher for a specific technology for smaller boilers than for larger plants.

Figure 4.1: Capital costs for different sulfur removal methods



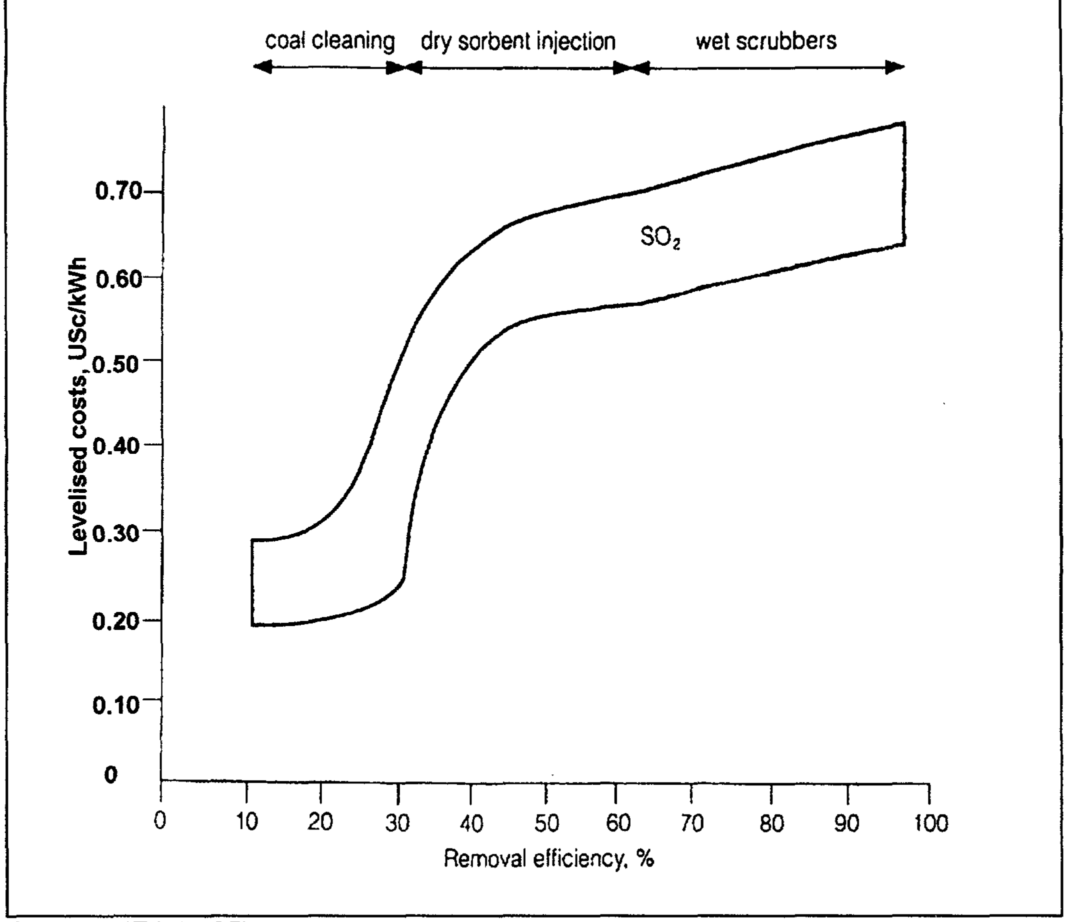
Source: *IEA (1995), Holme and Darnell (1996), and Smith (1996).*

In commercial applications, technologies with lower capital costs, such as sorbent injection processes and spray dry scrubbers, are used mainly in relatively small plants burning low sulfur coal and in plants at peak load operation. They are also installed in retrofit application in plants with a short remaining lifetime.

Capital costs for FGD have come down in the last few years due to improved design and simplified processes and they can be expected to decrease further in the next decade as a result of a greater demand in the emerging markets of Asia and Eastern Europe.

The increase in electricity production costs for different methods is illustrated in Figure 4.2. It shows the estimated levelized costs per kWh of electricity produced as a function of sulfur removal efficiency. Coal cleaning followed by sorbent injection gives the lowest increase in production costs, but the sulfur removal capability is limited. Wet scrubbing gives the highest increase in electricity production cost.

Figure 4.2 ***Levelized costs in UScents/kWh of electricity produced for different SO_x removal technologies***

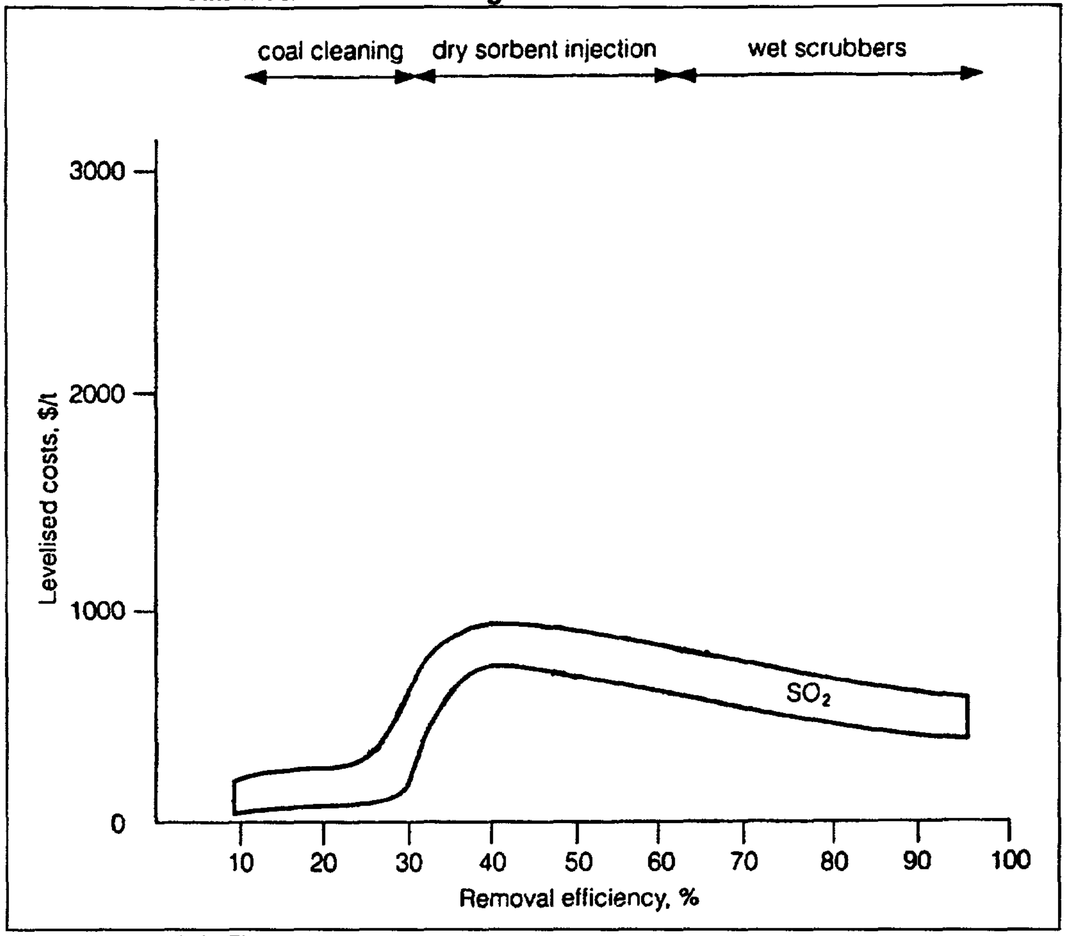


Source: IEA (1995).

High capital costs result in high overall costs for smaller boilers and boilers with few operating hours due to peak load operation. The most economical choice for these boilers is either fuel switching, coal cleaning or a sorbent injection method with low capital requirements. This is also true for boilers with short residual lifetime. Therefore, when choosing a sulfur removal system, it is important to have realistic assumptions about annual operating hours and the lifetime of the plant. Assumptions which are too optimistic may result in incorrect conclusions.

Despite the considerable variations in capital cost and increased electricity production cost, the actual dollar costs per ton of SO_2 removed do not vary much for different methods. This can be seen in Figure 4.3. Coal cleaning is the most cost-efficient route to reduce SO_2 emissions. Sorbent injection processes, which have lower capital costs than wet scrubbers, require larger quantities of sorbent resulting in higher overall costs. The relatively low operating costs of wet scrubbers, combined with high sulfur removal efficiency, makes the overall sulfur removal cost lower than for sorbent injection processes despite the higher investment.

Figure 4.3: Levelized costs in USD/ton of SO_2 separated for different sulfur removal technologies

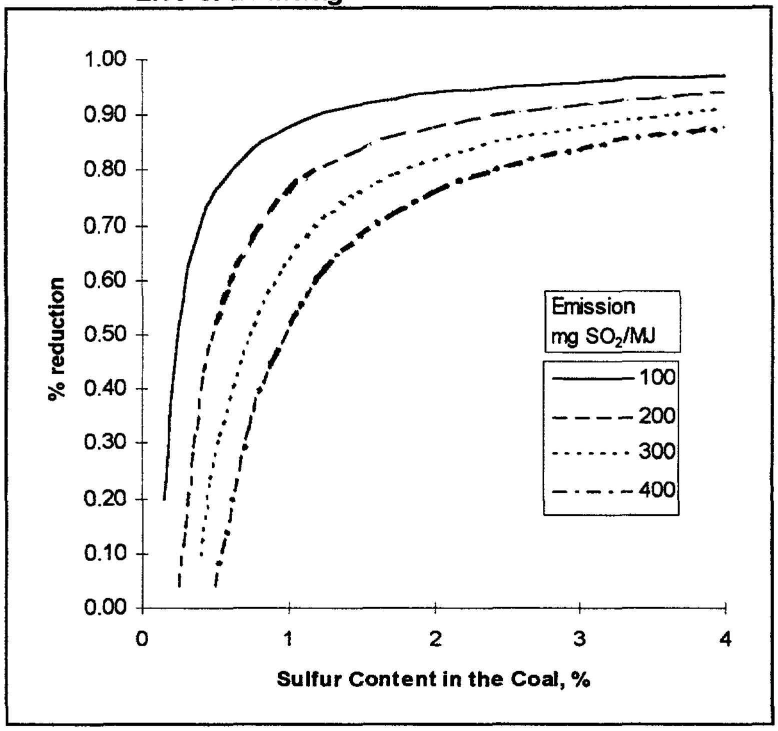


Source: IEA (1995).

In countries with a need for immediate removal of SO_2 emissions under tight economical constraints, a stepwise approach can be considered. Low-cost sorbent injection is an appropriate first step that can be implemented rapidly. It can be followed later by further upgrading to a hybrid system with higher removal efficiencies. Another option is to upgrade by adding a conventional wet scrubber, with the sorbent injection process and the scrubber sharing the same limestone storage and transport system.

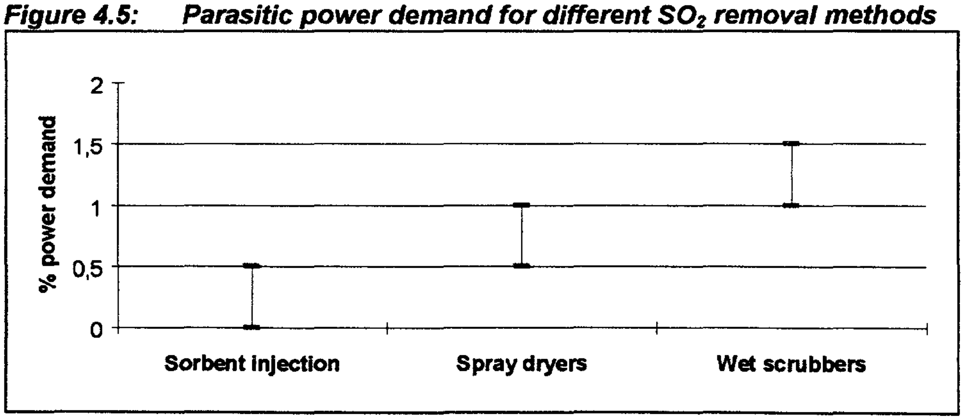
When evaluating sulfur removal methods, it is important to use the actual average sulfur content of the coal for the estimation of the required SO_2-removal. If the maximum sulfur content is used in the evaluation, the result may be totally misleading. Figure 4.4 shows the SO_x removal efficiency which is required in order to obtain specific SO_2 emissions when the sulfur content varies between 0.5 and 4.0% in the coal as fired. It can be used as assistance when an appropriate sulfur removal method is chosen.

Figure 4.4: Required SO_2 removal efficiency for coals with a LHV of 24 MJ/kg



One important aspect to be considered, particularly in the case of countries with a shortfall in power capacity, is the parasitic power consumption required by the SO_2-removal process. As shown in Figure 4.5, sorbent injection systems have the lowest parasitic power demand (up to 0.5% of the electricity production). Spray dry scrubbers have a higher power demand, but only about half of that of wet scrubbers.

Figure 4.5: Parasitic power demand for different SO_2 removal methods

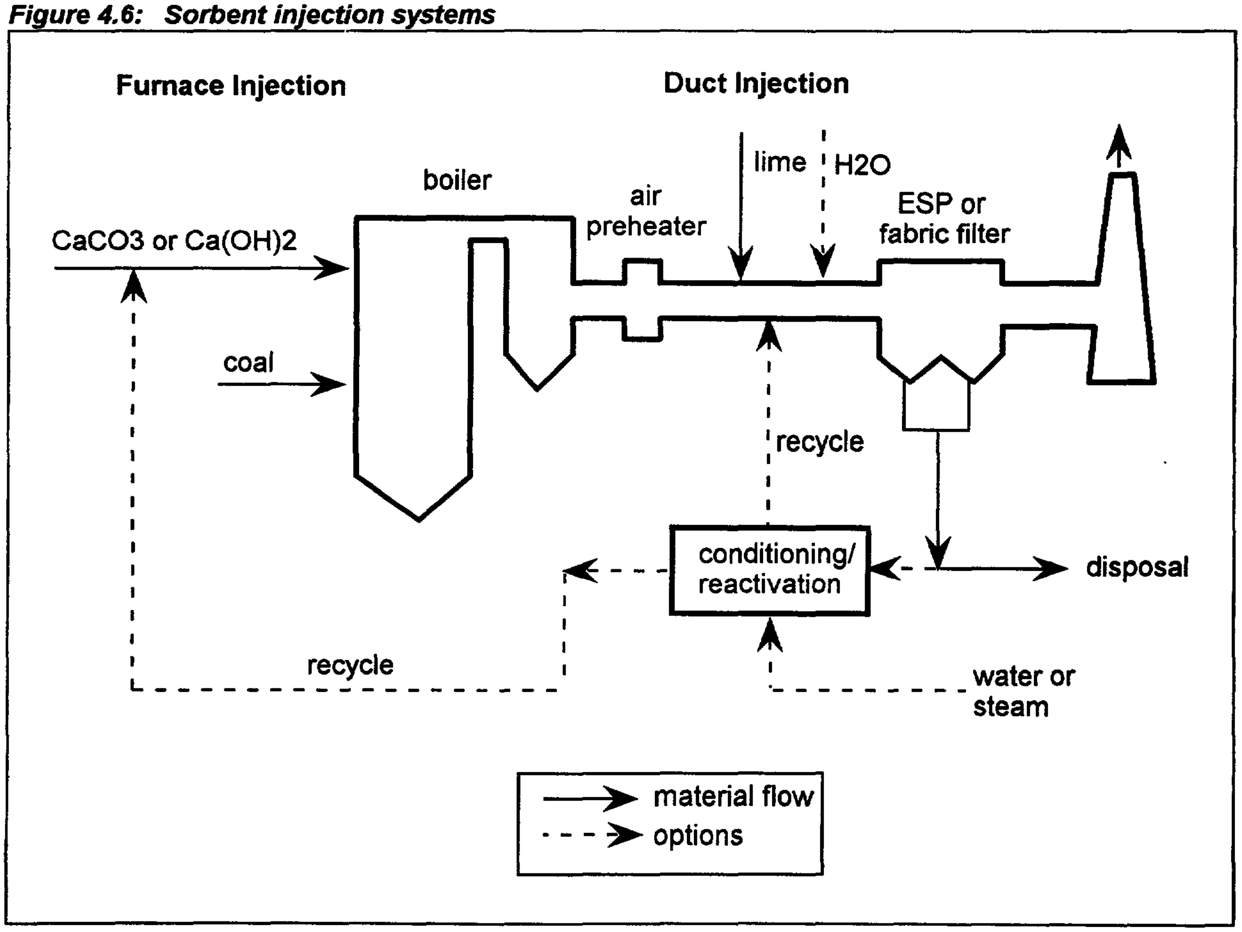


SORBENT INJECTION PROCESSES

For PC boilers, injection of a sorbent is a simple technology for SO_2 removal. This chapter deals with three categories of sorbent injection processes: furnace sorbent injection, duct sorbent injection, and hybrid sorbent injection. The processes are illustrated in figure 4.6. In the first two processes, the sorbent is injected directly into the boiler furnace or duct. Hybrid sorbent injection is a combination of furnace and duct sorbent injection, as injection of sorbent into the furnace is followed by either:

- downstream sorbent injection into the duct,
- reactivation of the sorbent by humidification in a reactor, or
- separation of unreacted sorbent removed along with ash from the ESP followed by reactivation and recycling of the unreacted sorbent.

Figure 4.6: Sorbent injection systems



Suitability

Sorbent injection is a simple process with low capital and maintenance costs and low power consumption (<0.5% of electricity produced) compared to a wet FGD process. It is suitable when a moderate (30-70%) SO_2 removal efficiency is acceptable. Due to their low capital cost, but relatively high operational costs, sorbent injection processes are especially suitable for old boilers with limited remaining lifetime, and for peak load boilers with short annual operating time. For the same reasons, they are also suitable for small boilers. The system is easy to install, operate and maintain, and no wastewater is generated. It is particularly suitable for retrofit applications as it has very low space requirements. It is suitable for low sulfur coals, due to the moderate sulfur removal rate.

Furnace sorbent injection, representing the simplest, lowest-cost process for SO_2 removal, is suitable in industrializing countries as a first step towards an immediate reduction in SO_2 emissions. It can be followed by further upgrading to a hybrid system with higher removal efficiencies. For example, a humidification step could be added. Hybrid systems can, depending upon technology, reach removal efficiencies up to 80-95% at relatively low operating costs. One important aspect of sorbent injection is that the waste production increases considerably. The effect on precipitator performance and ash handling cannot be neglected. In retrofit installations, modifications to the existing ESP or installation of baghouse filter may be required.

State of technology

Since it has been in use for several years, furnace sorbent injection can be considered commercially proven for small plants. For large plants, several demonstration projects have been completed in the United States and some are under construction. In China, furnace limestone injection is being tested in a 1-MW pilot plant. The system is developed by the Thermal Power Research Institute (TPRI) and it has reached an efficiency of 80-85%.

Duct sorbent injection is in the demonstration and early commercialization phase. Two large scale pre-ESP sorbent injection plants are in operation in the United States: Pennsylvania Electric's 140-MWe plant, Seward; and Ohio Edison's 104-MWe plant, Edgewater (Ref. 7). Approximately 40 plants worldwide have duct injection of some type installed today, most of them are small units retrofitted with sorbent injection. Further demonstration on larger units is needed.

Hybrid sorbent injection includes several different processes, some of which are commercial and some of which are in the demonstration phase. The Tampella LIFAC process can be considered commercial with eight reference plants in the world. The process will be installed in two new 125-MWe units which are under construction in the Xiaguan power plant in the Nanjing province in China (Ref. 2). Presently, there are no large power plants in operation in China equipped with sorbent injection systems for sulfur removal. In India, there are no sorbent injection installations.

Plant size

Sorbent injection processes are mostly used in smaller units and in retrofit applications, but they can be installed on any unit. The largest new installation today is 600 MW_e. Retrofit installations up to 300 MW_e exist.

Fuel flexibility

Because of a low sulfur removal efficiency, furnace or duct sorbent injection processes are most suitable for low sulfur coals or where the emission requirements are less strict. Hybrid processes, with higher sulfur removal, are suitable for coals with higher sulfur content.

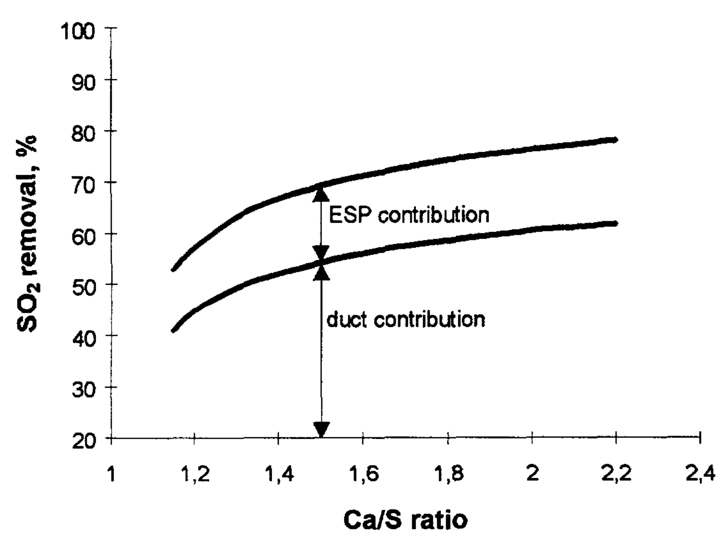
Performance

Efficiency
The sulfur removal efficiency is normally 30-60% for furnace sorbent injection and somewhat higher, 50-70%, for duct sorbent injection. Hybrid sorbent injection processes using additives, sorbent recirculation etc., normally reach higher desulfurization efficiencies in the 80-90% range. With some processes, even higher efficiencies up to 95% can be achieved. The SO_2 removal efficiency is highly dependent on the sorbent to sulfur ratio (Ca/S molar ratio). The relationship between the removal efficiency and the sorbent ratio for a duct sorbent injection process is shown schematically in Figure 4.7. An increased sorbent to sulfur ratio improves the SO_2 removal. However, at higher sorbent ratios the sorbent utilization, i.e. the fraction of reacted sorbent, decreases. This leads to increased sorbent consumption and higher operating costs. In some cases, it may not be economically justifiable with a large increase in sorbent consumption, to achieve only a small improvement in SO_2-removal.

After the Ca/S ratio, the single most important factor affecting sorbent injection efficiency is the approach-to-adiabatic-saturation temperature. The SO_2 removal increases with decreased approach temperature. The efficiency can also be raised by reactivating excess sorbent through humidification of the flue gas, by recycling unreacted sorbent, and by the use of additives. Pilot tests indicate that these methods can raise the removal efficiency to 90-95%. Humidification also serves another purpose as it improves the ESP performance.

Power consumption
The power consumption is low; 0.5% of the unit's generating capacity is consumed by the sorbent injection.

Figure 4.7: The effect of increased sorbent ratio on the SO_2 removal



Source: *IEA (1993).*

Sorbent

Furnace sorbent injection typically uses sorbents which include pulverized limestone ($CaCO_3$), hydrated lime [$Ca(OH)_2$], and dolomite ($MgCO_3$ x $CaCO_3$). In duct sorbent injection processes, $Ca(OH)_2$, sodium bicarbonate [$Na(CO_3)_2$] or lime slurry are used as sorbents. A Ca/S ratio of 2 is common.

Waste production

Waste production increases considerably when using sorbent injection processes and the increase depends on the sulfur content in the coal and the Ca/S ratio. A Ca/S ratio of 2 can triple the ash production rate for a high sulfur coal. The waste, normally consisting of a mixture of calcium or sodium sulfates, unreacted sorbent and fly ash is non-usable and must be disposed of. In post-ESP duct sorbent injection, the fly ash is separated before the injection of sorbents and can therefore be used in the usual way.

Availability

Since the process is relatively simple, the availability will most probably be close to 100%; but, since up to this date the technology is relatively unproved, the availability value is still relatively uncertain.

Construction issues

Construction time
If space is available for the installation of sorbent injection equipment, the downtime required for retrofit of an existing unit is 3 to 6 weeks.

Area requirements
The installation has very small space requirements. This is an advantage in retrofit installations. For post-ESP sorbent injection processes an extra filter is required. The area required for post-ESP sorbent injection will therefore be larger than for pre-ESP sorbent injection.

The possibilities for domestic manufacturing, licensing agreements
Currently, there are no Chinese manufacturers of sorbent injection systems for sulfur removal for large power plants. The technologies are still in the small-scale research and testing phase. Consequently, there are no license agreements between Chinese and international manufacturers for sorbent injection processes (Ref. 2). However, since the manufacturing for the technology is fairly simple, Chinese manufacturers will be able to supply sorbent injection systems as soon as the market requires. In India, there are no power plants equipped with sorbent injection systems. Since the sulfur content in Indian coals is normally very low, less than 1% (see Section 2), the interest in sulfur removal is low.

Complexity of the technology

The design of this type of system is relatively simple and has a low complexity.

Costs

Investment

Furnace and duct sorbent injection:	75- 00 USD/kW (developed from Ref. 5)
Hybrid systems:	100-140 USD/kW (Ref. 3 and 9)

New installations will fall in the lower range whereas retrofit installations can be expected to fall in the upper range.

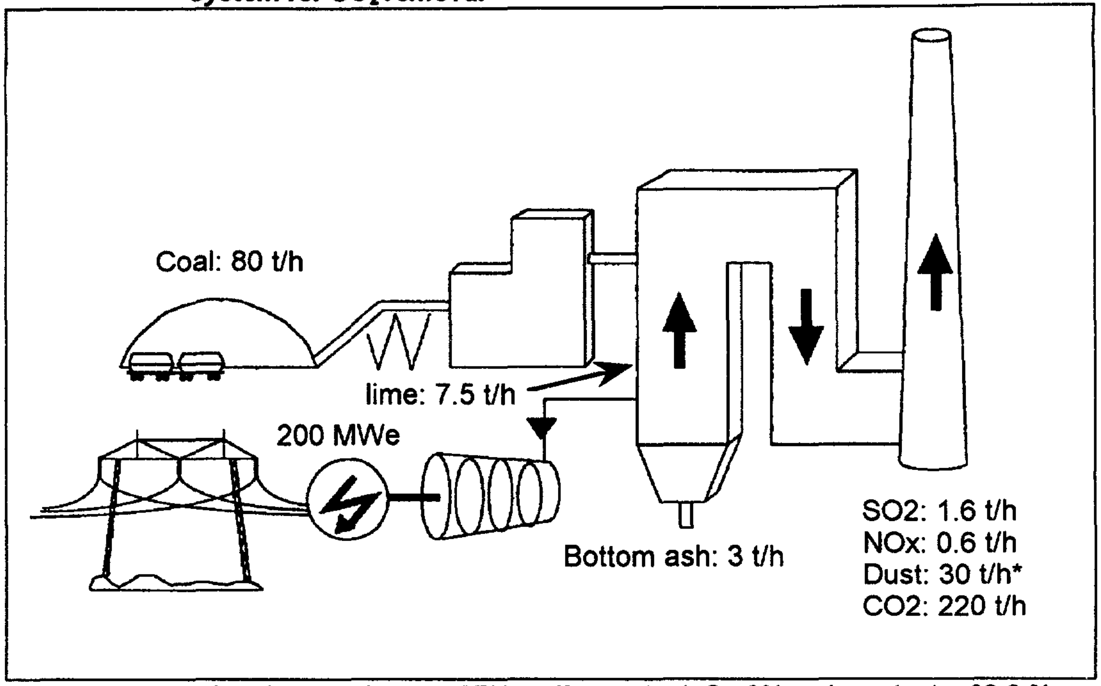
Operation and maintenance
fixed = 6.0 USD/kW/year
variable = 0.3 UScent/kWh (Ref. 3)

Total levelized costs typically range from 0.2-0.75 UScent/kWh or 500-750 USD/ton of SO_2 removed (Ref. 3 and 9).

200-MW$_e$ PC plant equipped with sorbent injection

Figure 4.8 shows a 200-MW subcritical PC plant equipped with a sorbent injection system for SO_2 removal. The reduction in SO_2 emission achieved can be compared with Figure 3.6.

Figure 4.8 200-MW$_e$ subcritical PC plant equipped with sorbent injection system for SO_2 removal



Note: Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.
** No dust removal equipment.*

Screening criteria

Table 4.1 is used for technology screening in Chapter 9.

Table 4.1: Screening criteria sorbent injection processes

Maturity of technology	• Furnace sorbent injection is commercial for small plants. It is being demonstrated for large plants. Duct sorbent injection is in the early commercialization stage. More than 10 reference plants exist worldwide, however few are commercial. Hybrid sorbent injection includes several different processes, some of which are commercial and some are in the demonstration phase. There are no plants using sorbent injection in India or China.
Maximum unit size	• Mostly used for smaller units or retrofit of existing boilers. The largest new plant is 600 MW$_e$, the largest retrofit 300 MW$_e$.
Waste product	• Not possible to use. No wastewater.

SPRAY DRY SCRUBBERS

Spray dry scrubbers were developed as a cheaper alternative to wet scrubbers in the early to mid-1970s. Presently, they have a market share of about 10 %, but the demand has fallen recently due to difficulties with utilization of the by-product. The by-product, which consists of a mixture of unreacted lime, fly ash, and calcium sulfite/sulfate, must be disposed of.

Suitability

Dry scrubbers have lower capital costs than wet scrubbers because there is no need for waste sludge handling and processing, and because cheaper material can be used in the absorber etc. The spray dryer absorber, which operates at 10-20°C above dew point of the flue gas, can be constructed of carbon steel; whereas wet scrubbers operate below the dew point and therefore require rubber lining or stainless steel. But the drawback of spray dry scrubbers is the four to five times higher cost for lime sorbent compared to the limestone used in wet scrubbers. This is why spray dry scrubbers are used mostly in small boilers burning low to medium sulfur coals, i.e. less than 2.5% sulfur, and for large plants in peak load operation. For the same reasons, the system is suitable for retrofit on plants with a limited remaining lifetime.

Due to their low capital requirements, spray dryers are suitable for developing countries. However, a significant percentage of the capital requirements (at least during the first 3 to 7 years of technology deployment) will be in foreign exchange. Demonstration may be needed for high ash Indian coals and high sulfur coals generally. An important feature of spray dry scrubbers compared with wet scrubbers is that no waste water is produced. Therefore, they are suitable for sites where there is no space for waste water handling. Because they normally are more compact than wet systems, they are also advantageous in retrofit applications where there are often space constraints. The process has a high efficiency for SO_3 and HCl removal, which makes it suitable for plants with such requirements.

A critical aspect of spray dry scrubbers is the increase in waste production. The effect on precipitator performance and ash handling cannot be neglected. In retrofit installations, modifications to the existing ESP may be required.

State of technology

Dry scrubbers are used commercially with low sulfur coals in Europe, Japan and the United States. In China, a spray dryer absorption system developed by the Southwest Electric Power Design Institute, in cooperation with other institutions, is in commercial operation in the Sichuan province. The system operates with an efficiency in the 80-90% range (Ref. 7).

Two demonstration projects for dry FGD are currently operating on in China. In the Huangdao 2×210-MW plant in the Shangdong province, a simplified dry FGD device is being tested. The equipment, which was supplied by Japan, has been in operation since 1995. The other project is a half-dry FGD method which is tested in the Taiyuan power plant in the Shanxi province. The goal is to find a method with lower investment cost -- at least half that of wet FGD. The equipment was supplied by Mitsubishi and was sponsored by the Chinese Ministry of Electric Power (Ref. 2).

The effective performance of spray dryers with high sulfur coals needs to be proven. Specific issues that require further demonstration include impact of chloride contained in the coal on spray dryer performance, and ability of existing ESPs, if downstream from the spray dryer, to handle the increased particulate loading and achieve the required efficiency.

Plant size

One scrubber can treat flue gas from boilers up to 200 MWe. For larger boilers, several scrubbers are installed in parallel.

Fuel flexibility

Spray dry scrubbers are most suitable for low to medium sulfur coals, i.e. less than 2.5% sulfur, because there is limit to the amount of lime slurry that can be injected into the reactor without causing condensation problems, which constrains the achievable level of SO_2 removal. For plants burning higher sulfur coal, spray dry scrubbers can be used if a lower sulfur removal efficiency can be accepted. Just as in wet scrubber systems, the presence of chlorine in the coal enhances the SO_2 removal or reduces the sorbent need at constant removal level.

Performance

Efficiency
Spray dry scrubbers can be designed for up to 99% SO_2 removal, but normally they are designed for 70-95% efficiency. In practice, the design efficiency depends on emission limits and sulfur content in the coal. For low sulfur coal, a lower efficiency can be sufficient to meet regulations. The efficiency increases with increasing lime to SO_2 ratio, increasing flue gas inlet temperature and decreasing approach-to-saturation temperature. Recirculation of the reaction product containing unreacted lime is used to enhance SO_2 removal and improve lime utilization. The efficiency is improved by the presence of chloride either from the coal or from additives such as $CaCl_2$ or sea water. Preliminary laboratory and large scale testing indicate that similar efficiency of SO_2 removal can be achieved with high sulfur coals (up to 4.5 percent by weight).

Power consumption
The power consumption is low. It ranges from 0.5-1.0% of the unit's generating capacity.

Sorbent

Lime is used as sorbent. The lime to SO_2 ratio is typically between 1.1 and 1.6.

Waste production

Non-productable solid waste consisting of a mixture of fly ash, calcium sulfite ($CaSO_3$), calcium sulfate ($CaSO_4$) and unreacted sorbent is produced. The content of unreacted lime and calcium sulfite and calcium sulfate may cause leaching of hazardous components. The waste needs conditioning with water to avoid problems with dust and leaching before disposal. The problems of disposing of the waste product at a reasonable cost is one of the major drawbacks with the technology. Various utilization options are being investigated. No waste water is produced.

Availability

Most existing plants achieve a reliability above 97%, many reach 99-100% availability.

Construction issues

Construction time
Retrofit: 3 to 6 weeks is needed to connect a spray dryer in an existing power plant

Area requirements
Typical absorber size is 15 meters diameter by 12 meters height of cylindrical form for a boiler of 100 - 150 MWe capacity.

The possibilities for local manufacturing, licensing agreements
At present, there are no Chinese manufacturers of spray dry scrubbers and there are no licensing agreements between Chinese and international manufacturers (Ref. 2). The situation in India is similar (Ref. 1).

Complexity of the technology

Spray dryer systems have fewer components than a wet FGD process and the design of the process is therefore less complex than that of a wet FGD process. The construction of the absorber is easier as the absorber operates above the dew point of the flue gas which means that cheaper material can be used. There is no need for rubber lining, stainless steel or nickel alloys required by a wet scrubber.

Costs

Investment and operation and maintenance
Table 4.2 shows estimates of capital and O&M costs for spray dryers. The capital requirement for installation of a spray dryer plant depends on many site specific conditions, which explains the wide range on the figures in table 4.2. For example, in some plants a pre-collector is installed between the air heater and the absorber. The pre-collector removes most of the fly ash before the absorber. This prevents erosion, decreases the amount of waste that has to be disposed of, and separates the salable fly ash. Installation of a pre-collector will, of course, increase the capital cost. A requirement to reheat the cleaned flue gas before it enters the stack also increases the capital cost. Capital costs for plants that do not require these additional installations will fall in the lower range of the numbers in Table 4.2. If there are requirements for a pre-collector, a spare absorber and reheat devise, the capital cost will end up in the upper range. The operating cost depends on coal sulfur content and desired removal levels.

Table 4.2: Capital and O&M costs for spray dryers

	Cost factor
Capital costs	110 - 170 USD/kW
Variable O&M	0.25 - 0.3 UScents/kWh:
Fixed O&M	8.5 - 9.5 USD/kW per year

Source: IEA (1995).

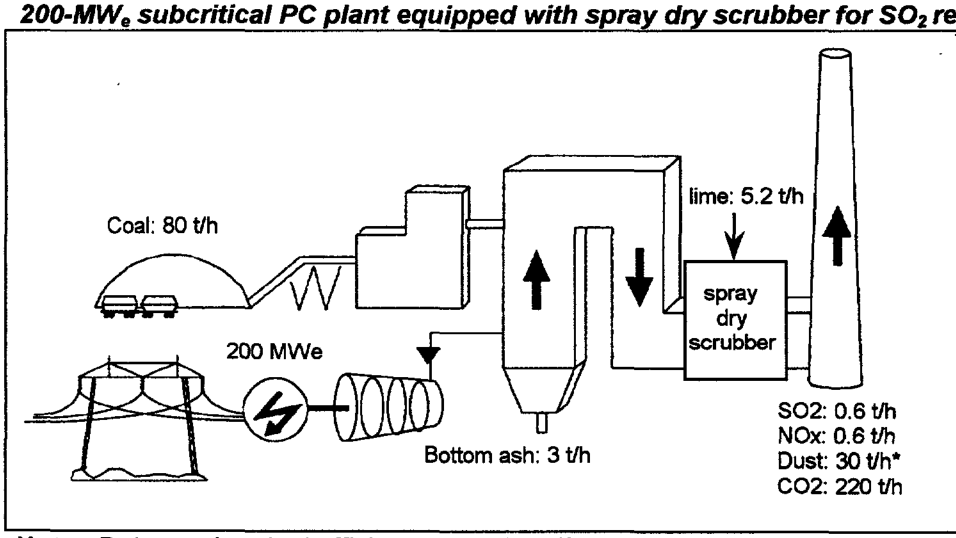
For retrofit installations, several site specific factors affect the capital cost. Such factors include ease of access and ducting distance.

The capital cost requirements for spray dryers are lower than those for wet scrubbers mainly because there is no need for waste sludge handling and processing. Cheaper material can be used in the scrubber. The dry scrubber can be constructed of carbon steel since it operates at 10-20°C above the flue gas dew point, whereas a wet scrubber operates below the dew point and therefore requires rubber lining or stainless steel. However, the operating costs of a dry scrubber are higher, because of the four to five times higher cost for lime reagent compared to limestone. Spray dryer systems are simpler and easier to operate and maintain than wet scrubbers.

A 200-MW$_e$ PC plant equipped with spray dry scrubber

Figure 4.9 shows a 200-MW subcritical PC plant equipped with a spray dry scrubber for SO_2 removal. The reduction in SO_2 emission achieved can be seen by comparison with Figure 3.6.

Figure 4.9: 200-MW$_e$ subcritical PC plant equipped with spray dry scrubber for SO_2 removal



***Note:** Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8%.*
**No dust removal equipment.*

Screening criteria

Table 4.3 is used for technology screening in Chapter 9.

Table 4.3: Screening criteria for spray dry scrubbers

Maturity of technology	• Commercial for low sulfur coals in Europe, Japan and the United states. One reference plant in the Sichuan province in China. No reference plant in India.
Maximum unit size	• One scrubber can be used for boilers up to 200-MWe. For greater boiler, several scrubbers are installed in parallel.
Waste product	• Not possible to use.

WET SCRUBBERS/WET FLUE GAS DESULFURIZATION

Wet scrubbers or wet flue gas desulfurization (FGD) have 85% of the market for processes capable of removing SO_2 from flue gases in thermal power plants. Wet scrubbers include a large number of processes based on gas/liquid reactions which occur when the sorbent is sprayed over the flue gas in an absorber. The sulfur oxides in the flue gas react with the sorbent and form a wet by-product. The wet lime/limestone process is the single most popular wet scrubber process having a market share of 70%. In most industrialized countries wet scrubbing is a well-established process for removing SO_2.

Suitability

Wet scrubbing is the technology of choice for new and retrofit applications that require more than 80-90% SO_2 removal. The investment is higher than for sorbent injection systems and spray dry scrubbers, but due to the lower sorbent demand they are more cost-effective than sorbent injection systems and spray dry scrubbers for coals with high sulfur content and for large boilers. The drawback relative to sorbent injection is that wet FGD systems require a larger surface area.

There is a lot of chemistry involved in a wet scrubbing process. Chemical engineers, chemical laboratories and revised O&M procedures will be needed in order to achieve a properly functioning plant with both minimal emissions and material corrosion. Since there are only a few installations in China and India, demonstration and adaptation may be required for Indian and Chinese coals. As the wet scrubbing process is sensitive to high fly ash inlet concentrations, high efficiency, reliable precipitators, well adapted to Indian and Chinese coals, will be needed for successful wet scrubbing operation (Ref 5).

State of technology

Wet scrubbing is by far the most proven and commercially established SO_2 removal process. In 1994, there were 136 GW of installed electrical capacity worldwide (Ref 6). Eighty percent of installed FGD systems are wet scrubbers. The wet lime/limestone scrubber process alone has a market share of 70%.

China has only one large-scale wet scrubber in commercial operation. In the Luohuang power plant (2×360 MW) in Sichuan province, the Huaneng International Power Development Corporation (HIPDC) has installed two limestone/lime-gypsum wet scrubbers. The equipment was manufactured by Mitsubishi Heavy Industries (Ref 2). The fuel is 3.5-5% sulfur coal, and the efficiency of the FGD is 95% (Ref 7).

India has one wet scrubber in the Trombay plant, operated by the Tata Electric Company (TEC) in Bombay. This uses sea water to scrub the flue gas (Ref 1). In this process, the natural alkalinity of sea water is used to absorb SO_2 from the flue gas under formation of sulfate ions, which is a natural constituent of sea water. After neutralization with sea water from the cooling water heat exchanger, the effluent is discharged into the sea. The unit is installed in a 500-MWe boiler which can operate on coal, oil or gas. The coal sulfur content is 0.35%. The name of the process is Fläkt Hydro and the technology was supplied by ABB Environmental, Norsk Viftefabrikk. The engineering and manufacturing was carried out in India, largely with domestic components. Less than 20% of the components were imported. Operation started in 1988. Two thirds of the flue gas flow from the boiler is treated in the scrubber. The plant operates with a removal efficiency of 85-87%, and its availability has been higher than that of the boiler.

The sea water scrubbing process has the advantage of design simplicity. No sorbent is needed. There is no waste disposal cost and it has low capital and operating costs. A disadvantage is that the pollution is transferred to the sea which in the long run will lead to contamination. However, monitoring to date indicates that no harm has been caused to marine life (Ref 8).

Plant size

Wet FGD installations are available for all boiler sizes. In large plants two lines can be used.

Fuel flexibility

The fuel flexibility is high. The technology has a high sulfur removal efficiency and is suitable for both high and low sulfur coal qualities. The presence of chlorine in the coal enhances the SO_2 removal or reduces the sorbent need at constant removal level. The choice of coal affects the quality of the gypsum by-product. Changes in coal quality in an existing plant can affect the gypsum quality. Installation of a prescrubber upstream from the absorber improves the gypsum quality and makes the system less sensitive to changes in ash characteristics.

Performance

Efficiency

The sulfur removal efficiency is very high. The removal efficiency can be improved still further by the use of additives. These performance levels have been proven for both high and low sulfur coals in many commercial applications:

- Efficiency without additives: 80-90% SO_2 removal.
- Efficiency with additives: 95-99% SO_2 removal.

Power consumption

Approximately 1.0-1.5% of a unit's total generating capacity is consumed by the scrubber.

Sorbent

Both lime and limestone can be used, but limestone is the most popular sorbent mainly because it is cheaper than lime. Additives such as magnesium or adipic acid are sometimes used to improve removal efficiency or to reduce sorbent to sulfur ratio for a given efficiency. In a new installation, a reduced sorbent need significantly reduces the size of the scrubber and the sorbent handling system. This decreases the investment cost.

Waste production

Wet lime/limestone scrubber systems produce either commercial grade gypsum, gypsum slurry or stabilizate as by-product. The favored wet limestone scrubbing process is the one producing commercial grade gypsum. Calcium sulfite produced during flue gas scrubbing is oxidized to calcium sulfate bihydrate, gypsum, either in the scrubber or in a separate vessel. The gypsum slurry is washed and dewatered to produce commercial grade gypsum containing less than 10% water. A bleed stream from the process is required to ensure a high quality gypsum. The bleed stream is led to a wastewater treatment plant. Coal quality and ESP performance have a large impact on gypsum quality. In some applications, a prescrubber is installed upstream from the absorber to improve gypsum quality and ensure a constant quality.

When gypsum slurry or stabilizate are chosen as final by-products from wet scrubbers, the need for dewatering and washing of the by-products is reduced. The water content in the gypsum slurry from the scrubber is approximately 50%. When a gypsum slurry is the final by-product, the slurry is pounded. After settling in the gypsum slurry pond, water should be recycled to the scrubber system. Fixation of the slurry can be done by adding fly ash and/or lime. The resulting by-product is a stabilizate with a low permeability coefficient. When stabilizate is produced, no wastewater is produced. Utilization of the by-products is further described in Chapter 7.

Availability

The wet FGD process can be designed for availability up to 99.9%, but the availability depends not only on design but also on the sulfur content of the coal and the availability of spare parts. The availability for existing installations has increased considerably over the years with increased experience and knowledge about operation and maintenance of the FGD process. New scrubber installations normally have an availability between 98 and 100%.

Construction issues

Construction time

- Retrofit: 3 to 6 weeks of outage to connect the FGD with the boiler piping.
- New plant: Scrubbers don't affect the construction time of a new coal fired plant.

Area requirements

A wet FGD plant requires a relatively large area which may be a problem in retrofit applications. For example, a wet FGD plant with a flue gas volume flow of approximately 1,050 Nm^3/h has an area requirement of approximately 2,000 m^2 (sulfur content 2.5%, requirement on SO_2 max. 350 mg/Nm^3, dry 6% O_2).

Possibilities for local manufacturing, licensing agreements

Chinese manufacturers have not yet manufactured wet scrubbers for coal-fired power plant applications and there are no licensing agreements between Chinese and international manufacturers (Ref 2). However, if the market so requires, technology will be transferred and it will be possible to manufacture wet FGD systems in China in the future.

Since the sulfur content in Indian coals is very low (<1%), the demand for wet scrubbers is low. With an increasing demand for wet scrubbers, license agreements between international suppliers and Indian manufacturers can be developed, so that local manufacturing can take place. Even now parts of the wet FGD equipment can be manufactured locally if the design is undertaken by an international supplier.

Complexity of technology and design

If the equipment exposed to corrosive media is rubber lined, additional skills are required for maintenance and construction of the rubber lining: alternatively, stainless steel can be used. Since complex chemistry is involved, wet scrubbers require revised O&M routines and skilled personnel in chemical engineering.

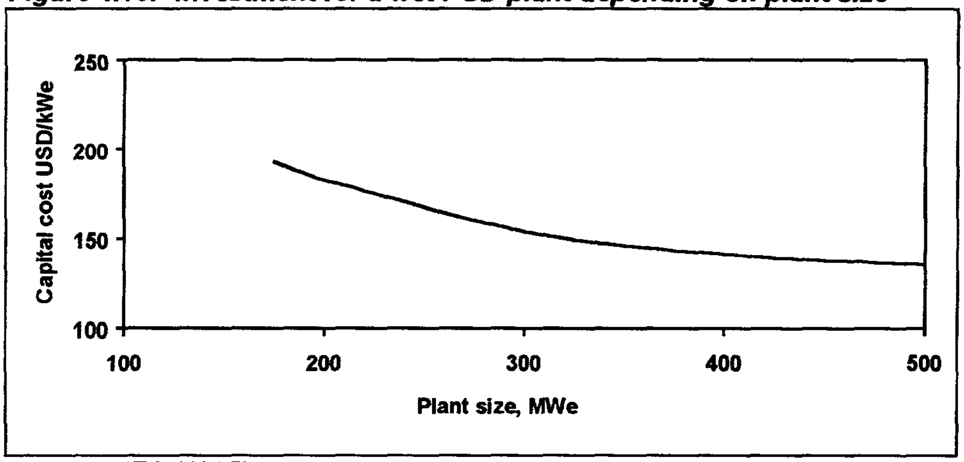
Costs

The investment cost and the total cost for SO_2 removal depends on a number of site-specific technical conditions such as plant size, sulfur content of the coal, residual lifetime of the plant, etc. and on certain economic criteria chosen for the project, such as discount rate and estimated annual inflation. Other factors which influence the cost are the choice of FGD process and the type of by-product.

Investment
Generally, investment costs have gone down over the years due to simplification of the design and improvements in the FGD process. Therefore, advanced wet limestone FGD processes can often be more cost-effective than conventional wet scrubbers. The capital cost for a 300-MW_e unit typically ranges from 160 to 240 USD/kW_e for 90-95% SO_2 removal, depending on the type of process.

The influence of plant size on the investment cost is shown in Figure 4.10. The capital cost per kW_e installed decreases with increased plant size up to around 300-400 MW where the curve flattens. The retrofit cost is approximately 30% higher than the cost of installing a scrubber on a new plant.

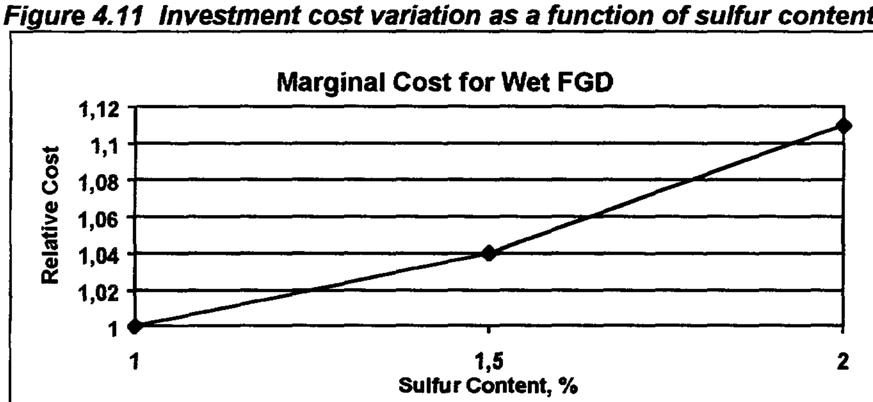
Figure 4.10: Investment for a wet FGD plant depending on plant size



Source: IEA (1995).

The investment cost for the FGD plant does not depend as much on the sulfur content of the coal as on boiler size. The boiler size and the flue gas flow determine the scrubber size. The only parts of the total process that depend on the sulfur content are the sorbent and waste product handling equipment. To maintain the same emission level when the sulfur amount in the coal increases from 1 to 2%, the investment cost increases approximately 10% as shown in Figure 4.11.

Figure 4.11 Investment cost variation as a function of sulfur content in the coal



Source: Holme and Darnell (1996).

Operation and maintenance costs

The variable O&M cost is highly dependent on the sulfur content. The amount of sorbent needed to reach a specific emission level is always proportional to the sulfur content. This means that if the sulfur content is doubled, the amount of sorbent required to reach the desired emission level is approximately doubled. Table 4.4 shows typical O&M costs for wet FGD installations.

Table 4.4 O&M costs for wet FGD plants

Variable O&M	Fixed O&M
0.15-0.20 UScents/kWh	12 - 13 USD/kW per year

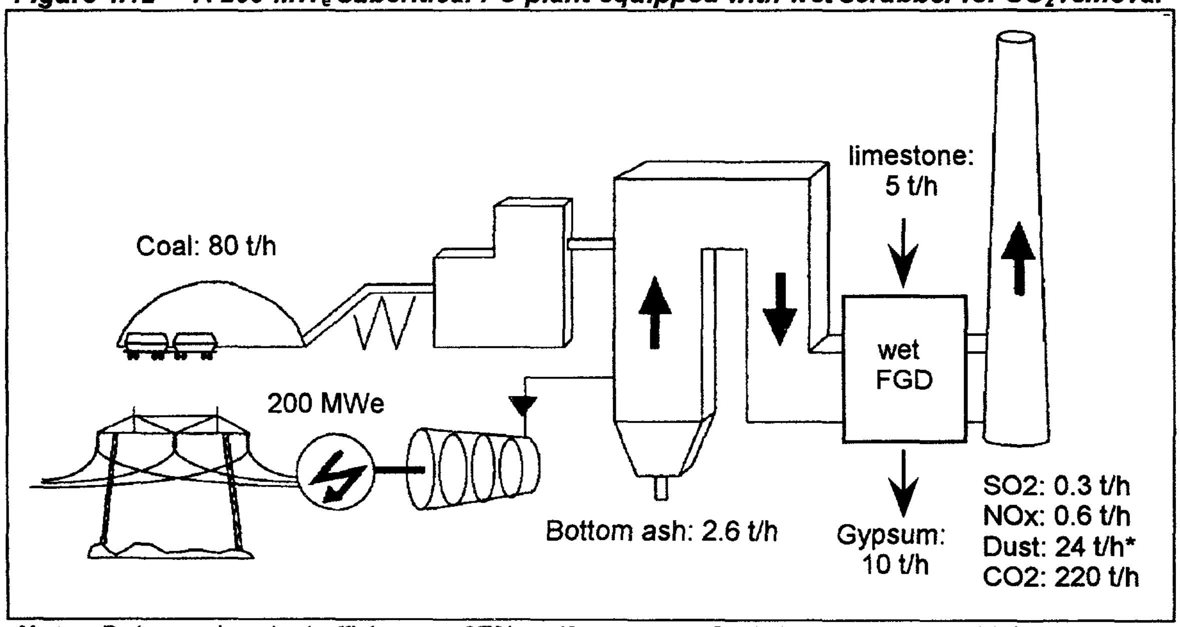
Source: *IEA (1995).*

Levelized costs in USD per ton of SO_2 removed typically range from 280 USD/ton for a 600-MW_e plant firing high (4.5%) sulfur coal to around 500-630 USD/ton for a 300-MW_e plant firing a medium (2.6%) sulfur coal. If there is a market for the by-product, income from by-product sales can reduce the levelized cost considerably.

A 200-MW_e PC plant equipped with wet scrubber

Figure 4.12 shows a 200-MW_e subcritical PC plant equipped with a wet scrubber for SO_2 removal. The reduction in SO_2 emission achieved can be seen by comparison with Figure 3.6.

Figure 4.12 A 200-MW_e subcritical PC plant equipped with wet scrubber for SO_2 removal



Note: *Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*
**No dust removal equipment*

Screening criteria

Table 4.5 is used for technology screening in Chapter 9.

Table 4.5: Screening criteria for wet FGD

Maturity of technology	• Commercial in Europe, USA, Japan. One wet limestone/lime reference plant in China and one sea water scrubber plant in India.
Maximum unit size	• Suitable for any boiler size.
Waste product	• Possible to use without processing.

COMBINED SO_2 / NO_X CONTROL

There are a number of processes for combined SO_2/NO_x removal which have the potential to reduce SO_2 and NO_x emissions simultaneously at a lower cost than the total cost for conventional FGD and SCR. The processes can be divided into the following categories:

- solid adsorption/regeneration,
- gas/solid catalytic operation,
- electron beam irradiation,
- duct alkali injection, and
- wet scrubbing.

At present, combined SO_2/NO_x removal processes are generally considered to be too complex and expensive to be used in developing countries. They will need to be demonstrated and commercialized before they are suitable. This could take some 5 to 10 years. However, looking at emission removal from the point of view of the positive perspective of the production of useable by-products, an advanced SO_2/NO_x removal plant can be seen as a chemical factory producing useful goods such as gypsum, sulfuric acid, elemental sulfur or fertilizer, all goods that may be in short supply in developing countries. Therefore, despite the high capital costs and in many cases unproven technology, advanced combined SO_2/NO_x removal can, under some circumstances, be considered suitable in developing countries for large power stations burning high sulfur coal.

These new processes aim at achieving higher efficiencies compared with conventional FGD and SCR. The reported efficiencies are 95-99% SO_2 removal and more than 90% NO_x removal. Most combined SO_2/NO_x processes are still only at laboratory scale or in the developmental stage. Only a few processes for low sulfur coals are in commercial operation. These include activated carbon, WSA-SNOX, DESONOX, and duct sorbent injection. The main features of these four processes are listed in Table 4.6.

As a result of the limited commercial experience, there is still little information available on the costs of the processes. It is believed that they require higher capital and levelized costs than conventional or advanced FGD in combination with SCR. Reported actual and estimated capital costs range from 190 to 625 USD/kW. Levelized costs range 0.35-2.0 UScents/kWh (Ref. 6).

Table 4.6: Comparison of commercial combined SO_2/NO_x control processes

Process/ Process Type	**Features**	**Removal rates SO_2/NO_x %**
Activated carbon/ solid adsorption/ regeneration	Activated carbon adsorbs SO_2, and sulfuric acid or elemental sulfur is produced. Simultaneous NO_x removal by addition of ammonia. Commercial operation in 1 power plant in Japan and 2 in Germany. Largest unit 350 MW_e, total 664 MW_e. High removal of SO_3, hydrocarbons, heavy metals and other toxic material. No wastewater is produced.	98/80
WSA-SNOX/ gas/solid catalytic operation	Two catalysts are used to remove NO_x by SCR and to oxidize SO_2 to SO_3. The latter is condensed to sulfuric acid. One commercial installation in a 300-MW_e plant in Denmark and one 30-MW unit in Italy. No wastewater or waste products are produced, and no chemical other than ammonia is consumed. Very low energy consumption. No NH_3 slip.	>95/95
DESONOX/ gas/solid catalytic operation	Similar to WSA-SNOX in that two sequential catalysts are used to reduce NO_x and to oxidize SO_2 to SO_3. 2 units in commercial operation: 98 + 31 MW_e at Hafen, Munster in Germany. High removal of HCl and HF	90/90
Duct sorbent injection/ alkali injection	Pulverized sodium bicarbonate is injected into the duct after the economizer but before the ESP. Sodium sulfate is produced and collected with the fly ash. 8 commercial installations on coal fired plants, all in the USA. The largest is Monticello 575 MW_e.	<90/<40

Source: *Holme and Darnell (1996).*

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5. NO_X EMISSION CONTROL TECHNOLOGIES

The first step in any NO_x emission reduction strategy is to optimize plant operation. Operational changes should be made prior to implementation of any NO_x reduction technology or installation of additional equipment. For example, low excess air and boiler fine tuning can be regarded as methods of reducing NO_x formation significantly at little or no extra cost. Both methods are easy to implement and require no boiler modifications. Minimizing excess air may also lead to increased boiler efficiency. This is discussed further in Chapter 8, Instrumentation and Control Systems (page 110). As every boiler is more or less unique, each must be tested to find the optimum level of excess air at which the boiler can be operated without risking corrosion or high rates of unburned coal.

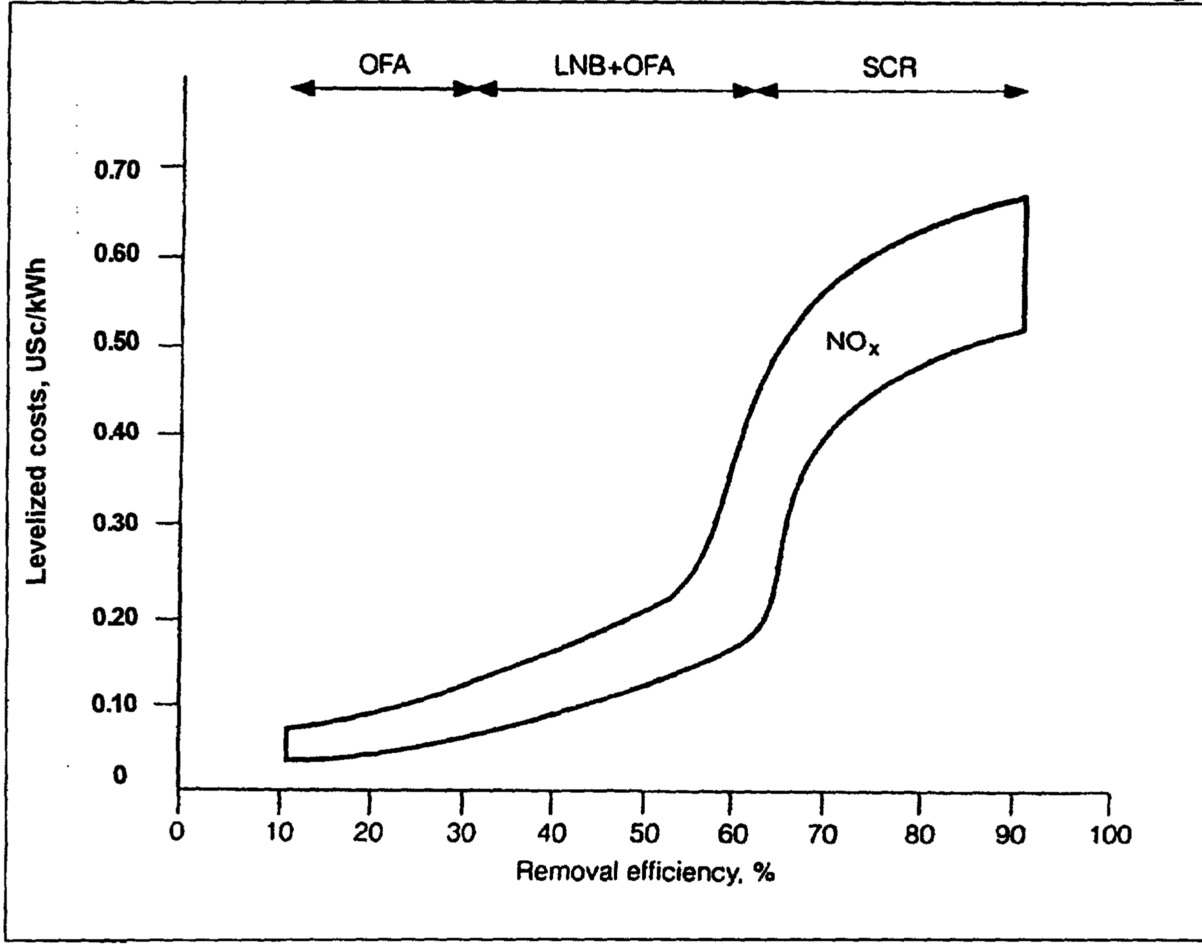
Upgrading or replacing coal pulverizers to maintain coal fineness, and balancing fuel and air flows to the various burners to create a staged combustion are other low cost routes to the reduction of NO_x emissions. The staged combustion is accomplished by withdrawing a portion of the total air required to achieve complete combustion from the early stage of combustion in order to create a combustion zone with lack of oxygen, which oppresses the NO_x formation. The air is added-in at a later burner stage to ensure complete combustion. The NO_x emission reductions which can be achieved by these methods may not be sufficient to reach the required emission level, but they are extremely cost-effective. These methods can also be combined with other low-cost modifications.

Optimizing operational performance should not only involve individual component elements. The entire fuel preparation and furnace system must be optimized if NO_x formation is to be effectively minimized. A reliable system for continuous monitoring of O_2 and NO_x concentrations in the flue gas can assist in defining the optimum operational parameters. After optimizing plant operation, in-furnace NO_x reducing equipment should be applied on PC boilers. In-furnace NO_x reducing equipment involves modification of the combustion process, e.g. low NO_x burners (LNB), OFA, flue gas recirculation and gas or coal reburning.

After this type of in-furnace NO_x control has been implemented, post-combustion measures must be installed to reduce NO_x emissions further. Post-combustion NO_x removal equipment includes: selective non catalytic NO_x reduction, selective catalytic reduction, and combined SO_2/NO_x removal. Such methods are the only available options for reduction of NO_x emissions from fluidized bed boilers, however, uncontrolled NO_x emissions tend to be quite low from fluidized bed boilers.

This chapter presents basic information to enable selection between different NO_x reduction technologies. Figure 5.1 shows estimated levelized costs per kWh of electricity produced for various removal efficiencies (Ref. 3). The figure shows that combustion modifications such as LNB and OFA give the lowest increase in production cost but they can only reduce the emissions up to 60%. SCR is the most efficient way to reduce NO_x emissions, but it is also the most expensive technology. Combustion modifications require a lower capital cost than SCR, and they have very low, if any, O&M costs. The variable O&M cost for SCR represents up to 50% of the total levelized cost.

Figure 5.1. Levelized costs in UScents/kWh electricity for different NO_x reduction technologies



Source: *Takeshita (1955).*

LOW NOx COMBUSTION TECHNOLOGIES

Low NO_x combustion modifications include LNB, OFA, flue gas recirculation and gas or coal reburning. These measures can be implemented on PC-boilers to reduce NO_x emissions. In low NO_x burners, air staging is achieved within the flame to prevent NO_x formation. Today, almost all boiler and burner manufacturers supply low NO_x burners, and they are routinely installed in new boilers. OFA is a type of air staging in which a portion, typically 10-30%, of the combustion air is withdrawn from the combustion zone. This stream of air is added through special OFA ports situated higher up in the furnace to complete combustion. Reburning is another name for fuel staging. A portion of fuel is injected in a second combustion zone, the reburning zone, situated over the primary combustion zone in the furnace. The reburning fuel can be a portion of the primary coal fuel or another type of fuel such as natural gas or oil.

Suitability

Low NO_x burner technologies are very suitable for developing countries due to their low investment cost compared to other more efficient techniques. Minor adaptations may be required for Chinese and Indian coals. New boilers should be equipped with low NO_x burners and OFA. The use of low NO_x burners and the installation of OFA will hardly affect the cost of new boilers. If a new boiler is not equipped with OFA, the boiler should still be designed for future installation of OFA. Different low NO_x combustion measures can be used in combination to reduce NO_x emissions. LNB, for example, are commonly used in combination with OFA. These methods are also suitable to use in combination with other NO_x control technologies.

Reburning is an attractive option where natural gas is available at the power plant site and required NO_x emissions are below 800 mg/Nm^3. Reburning gives a NO_x reduction in the same range as SNCR but gives no ammonia slip. LNB are not easily used on wet bottom boilers because the temperature in the furnace changes, which may cause problems with slag drainage. For such boilers, natural gas reburning may be the only available NO_x control technology.

Due to their low capital cost, low NO_x combustion measures are suitable for retrofit of old boilers with a limited remaining lifetime. However, in retrofit applications these techniques may lead to unwanted changes in the boiler operation. Combustion efficiency can decrease due to a higher level of unburned carbon in the fly ash, and due to change in temperature profile in heat exchanging parts. Also, LNB with a higher pressure drop and flue gas recirculation consume more power for the flue gas fans, which reduces the plant efficiency. Operating with low excess air, LNB and OFA create zones with reducing atmosphere, which may cause corrosion on the boiler tubes. Furthermore, there are often physical limitations for installation of low NO_x combustion measures on existing boilers, e.g. limited space around the furnace and duct, and limited area in the furnace for installation of OFA ports or burners for the reburning fuel.

State of technology

LNB and LNB plus OFA are being used commercially in Europe, Japan, and the United States. New PC boilers in industrialized countries all use low NO_x burners, and retrofits of old boilers are common. Reburning using a separate reburning fuel on coal-fired boilers is only in commercial operation in the USA. The technique is in the large-scale test and demonstration stage. Reburning using fine pulverized coal as reburning fuel is in commercial operation in the Federal Republic of Germany.

In India typical burners for coal-fired power plants are designed for NO_x emissions of 600 ppm. However, burners with NO_x emissions less than 400 ppm have been introduced recently (Ref. 1). In China, more than 20% of the power plants use some type of low NO_x combustion technology; low NO_x burners are the most common. Some plants have a simplified form of OFA installation, in which the exhaust air from the coal pulverizing system is injected into the furnace above the primary air. A technology similar to SGR burners is used for retrofitting boilers in old power plants. This technology has lower NO_x emissions than conventional burners (Ref. 2).

Fuel flexibility

The content of nitrogen and volatiles in the coal is highly significant when choosing low NO_x combustion technology. As most combustion modifications aim at suppressing thermal NO_x formation, it is difficult to achieve low NO_x emissions through combustion measures with coals with a high nitrogen content. For low volatile coals and anthracite, special low NO_x burners have been developed. As reducing conditions are created in the combustion zone with low NO_x technologies, coals with high sulfur or chlorine content may cause problems with corrosion. A high iron content can also cause problems in low NO_x combustion applications.

Plant size

Combustion modifications are suitable for all plant sizes, but the most suitable choice of modification depends on boiler type and size. The total investment cost for installation of low NO_x burners, for example, depends largely on boiler size, whereas the investment cost for installation of OFA can be considered independently from boiler size.

Performance

Efficiency

Reduction efficiencies typically achieved by different combustion modifications are listed in Table 5.1. The efficiency achieved when retrofitting an existing plant is generally lower than that of a new plant because of plant specific limitations.

Table 5.1 NO_x reduction efficiency for various technologies

Measure	NO_x reduction %
low excess air	15 - 25
flue gas recirculation	15 - 20
OFA	12 - 250
LNB	30 - 55
LNB + OFA	30 - 55
Natural gas reburning	45 - 60

***Source:** Takeshita (1995).*

Low excess air and flue gas recirculation achieve NO_x reduction levels only up to around 20% as stand alone measures, but the techniques are often used in combination with other primary measures such as OFA or reburning to achieve higher removal efficiencies.

Effect on load regulation

When introducing combustion modifications in an existing boiler, it is important to avoid negative impact on the operational safety. Calculations must be made before to ensure that stable ignition can be secured over the whole load range.

The use of low NO_x burners can cause decreased flame stability at reduced loads, which may limit the boiler minimum load. On the other hand, new Mitsubishi SGR burners or similar local technologies which are installed in many old power plant boilers in China in order to stabilize the low load flame have lower NO_x emissions than conventional burners (Ref. 2). The NO_x emissions are more independent of the load in a boiler with combustion modifications than is the case in a conventional boiler.

Reagent

None

Availability

Very high availability (98-99%). Low NO_x combustion measures do not affect the availability of the boiler and they do not require any extra overhaul time.

Construction issues

Construction time

Low NO_x combustion measures do not require any extra construction time for a new plant. The estimated outage times for retrofit of LNB, OFA and natural gas reburning are in Table 5.2.

Table 5.2. *Outage time for retrofit for various NO_X reduction technologies*

Measure	Outage time for retrofit (weeks)
LNB	3 - 5
LNB + OFA	4 - 9
Natural gas reburning	5 - 10

Source: *Tavoulareas (1995).*

The possibilities for local manufacturing, licensing agreements

In India, one manufacturer, BHEL, offers burners with NO_x emissions less than 400 ppm. These burners are developed by BHEL; and there are no international license agreements (Ref. 1). Low NO_x burners and the simplified form of OFA installation mentioned in section 5.2.1 can be manufactured in China. There is no license agreement between any Chinese manufacturer and international manufacturers, but one Chinese boiler manufacturer, the Dongfang boiler plant, cooperates with Foster Wheeler and imports their low NO_x burners (Ref. 2).

Area requirements

For new plants, combustion measures for low NO_x operation require no additional space. Installation of low NO_x burners on an existing boiler requires no extra space. Introduction of OFA and reburning on an existing boiler requires available area over the burners in the furnace for installation of OFA ports and additional burners for the reburning fuel. It also requires appropriate space around the boiler and duct for OFA air tubes.

Costs

The investment cost for combustion modifications depends on technology, boiler size and type and space available for retrofit. An overview of capital costs for retrofit installations is presented in Table 5.3. For OFA installation, the total capital cost is relatively independent of boiler size. Therefore, small boilers require a much higher capital cost per kW_e for OFA installation than large boilers. For low NO_x burners the total capital cost is highly dependent on boiler size, but the lowest specific capital costs occur in large sized plants due to the economies of scale. Capital costs for reburning are somewhat higher than those of low NO_x burners combined with OFA. Reburning with natural gas is less costly to install than reburning with pulverized coal.

Table 5.3 *Investment costs for retrofit installation of NO_x reduction technologies*

Technology	**Capital Costs** ***(USD/kW)***	
Boiler size, *MW*$_e$	**>300**	**<300**
OFA	7-9	30-40
LNB	10-40	20-45
LNB + OFA	8-30	30-40
Natural gas reburning	14-30	35-45

Source: *Takeshita (1995).*

Capital costs for equipping new boilers with LNB or OFA are very low, around 1-3 USD/kW. The capital cost for natural gas reburning on new boilers are in the 10-30 USD/kW range. The O&M costs for OFA and low NO_x burners are very low and are the same as for boilers with conventional burners. The operating cost for natural gas reburning is higher due to the higher cost of the natural gas fuel compared to coal. Reburning with pulverized coal instead of natural gas has significantly lower operating cost and a lower levelized cost in UScents/kWh despite the higher capital cost (Ref. 3).

The cost effectiveness of the different combustion modifications depends largely on the type of boiler and its uncontrolled NO_x emissions. Modifications to boilers with high uncontrolled emissions, e.g. wall-fired wet bottom boilers or cyclone boilers, are more cost-effective than modifications to boilers with lower NO_x emissions such as tangentially fired boilers. This is illustrated in Table 5.3, which lists typical ranges of cost effectiveness in USD/ton of NO_x removed of combustion modifications on wall fired and tangentially fired boilers (Ref. 3).

Table 5.3: Cost efficiency for NO_x reduction technologies

Type of boiler modification	**Wall fired** ***USD/t NO_x***	**Tangential fired** ***USD/t NO_x***
OFA		440
LNB	175 - 250	540 - 700
LNB + OFA	300 - 450	460 - 900
Natural gas reburning	780 - 960	1,200 - 1,800

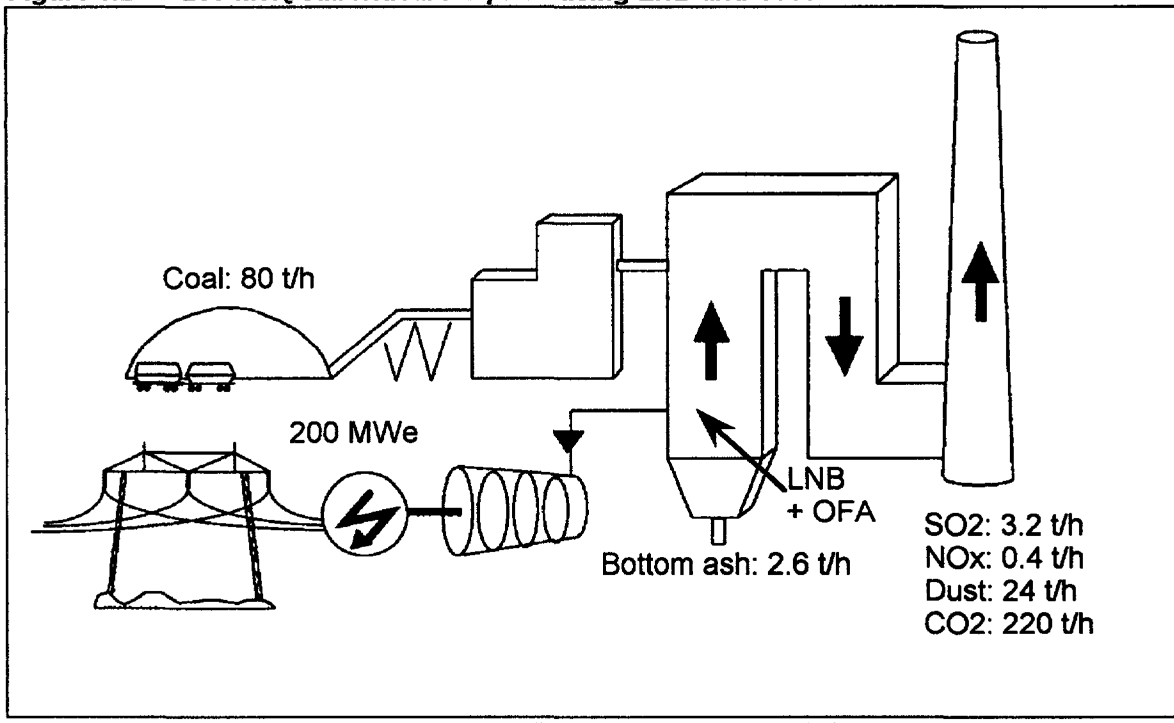
Source: *Takeshita (1995).*

The coal-to-natural gas price difference has a major impact on the cost-effectiveness of natural gas reburning. An increase in price difference by 50%, increases the NO_x removal cost by nearly 50%.

The use of LNB and OFA in a 200-MW$_e$ PC plant

Figure 5.2 shows a 200-MW$_e$ subcritical PC plant using LNB and OFA. The reduction in NO_x emission achieved can be seen by comparison with Figure 3.6.

Figure 5.2 200-MW$_e$ subcritical PC plant using LNB and OFA



Note:: *Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*

Screening criteria

Table 5.4 is to be used for technology screening as in Chapter 9.

Table 5.4: Screening criteria for low NO_X combustion technologies

Maturity of technology	• Low NO_X burners are commercial in India and PR China. OFA installations are commercial in Europe, Japan and the US. Reburning is in commercial operation in
Unit size	• all plant sizes
Waste product	• none

SELECTIVE NON-CATALYTIC REDUCTION

In a selective non-catalytic reduction system, ammonia or urea is injected into the high-temperature zones of the boiler to reduce formed NO_x to nitrogen and water without the use of a downstream catalyst. The temperature window for efficient operation occurs between 900 and 1,100°C. At higher temperatures, ammonia decomposes to N_2, and at lower temperatures, the rate of the reaction between ammonia and NO_x is slow and a high ammonia slip occurs, (i.e. the release of unreacted ammonia).

Suitability

SNCR is suitable when reduction rates up to 50% is sufficient, for example, when NO_x reduction above what is achieved by low NO_x burners and other combustion modifications is required. The process is also suitable for use in combination with combustion modifications to reach higher NO_x removal levels. SNCR is also suitable for fluidized bed boilers, where the combustion conditions already result in low NO_x emissions and the need for further NO_x reduction is limited. The higher ammonia slip from SNCR, that results in ammonia contamination of the fly ash, can be acceptable in the case of fluidized bed boilers since the by-products are generally disposed of.

The performance depends, to a high degree, on boiler-specific conditions such as the mixing conditions of the reagent and the flue gas temperature and residence time. Because of the low NO_x reduction and the difficulty of maintaining the NO_x reduction over the whole range of boiler load, SNCR is not often used in large coal-fired boilers.

State of technology

The technology has been demonstrated in 15 utility-scale boilers in the United States and Europe. Commercial operation has started during the past few years in several countries, but most SNCR installations in commercial operation are in small boilers and in fluidized bed boilers. Experience of SNCR in large coal-fired plants is limited. In Europe, four large coal-fired plants have been equipped with SNCR. Today there are no SNCR installations in India or China. SNCR is under research in some combustion research institutes in China.

A number of technical issues remain to be solved, the major concern being the ammonia slip which is much higher for SNCR than for SCR. A high ammonia slip leads to ammonia contamination of the ash which reduces the possibility of selling the fly ash. There is also a risk of the formation of ammonium bisulfate from unreacted ammonia and SO_3 in the flue gas, and deposition and plugging of ammonium bisulfate on the air heater baskets. A further issue is the increased generation of N_2O, which is an ozone depleting greenhouse gas.

Fuel flexibility

For high sulfur coals, there is a potential risk of reaction between the unreacted ammonia and SO_3 in the flue gas to form ammonium bisulfate. The ammonium bisulfate can precipitate onto and cause plugging of the air heater.

Plant size

Most SNCR installations in commercial operation are in small boilers and fluidized bed boilers. Experience with SNCR in large plants is limited, although commercial SNCR installations in coal-fired plants up to 500 MW_e do exist.

Performance

Efficiency

The reduction efficiency depends on many site-specific conditions. NO_x reduction efficiencies normally range from 30 to 70%, but reduction levels up to and over 80% have been reported. If SNCR is used in combination with low NO_x combustion modifications, NO_x emissions reduction levels, comparable to those of SCR as a stand alone measure, can be achieved.

Effect on load regulation

The physical position of the suitable temperature window in the furnace for reagent injection shifts with the boiler load. Therefore, it can be difficult to find reagent entry areas where the No_x reduction efficiency is maintained over the whole boiler load without increasing the ammonia slip.

Reagent

Urea or ammonia, concentrated or in a 25% water solution, is used as the reagent, normally in a stoichiometric ratio of around 2. In some plants, the use of urea as the reagent has resulted in increased N_2O emissions.

Construction issues

Construction time

For a new plant, the installation of an SNCR system does not affect the construction time. In retrofit installation, an outage of two to five weeks can be expected.

The possibilities for local manufacturing, licensing agreements

There is no SNCR manufacturer in China or India today. There are no license agreements between Chinese or Indian manufacturers and international manufacturers.

Area requirements

The process itself has no area requirement, but some space is required for storage of reagent.

Costs

Investment

Capital costs for SNCR are generally much lower than those of SCR as no catalyst is used. For boiler sizes of 100-500 MW, capital costs fall in the range of 10-25 USD/kW (Ref. 3). The specific capital cost per kW depends highly on boiler size. For larger boiler sizes the capital cost decreases rapidly due to economies of scale and fall in the lower cost range. However, today there is still only limited experience of SNCR installations in large plants. For small boilers the costs fall in the upper range. The cost also depends on whether it is a new plant or a retrofit. The cost for retrofit installation is higher and will fall in the upper cost range.

Operation & maintenance

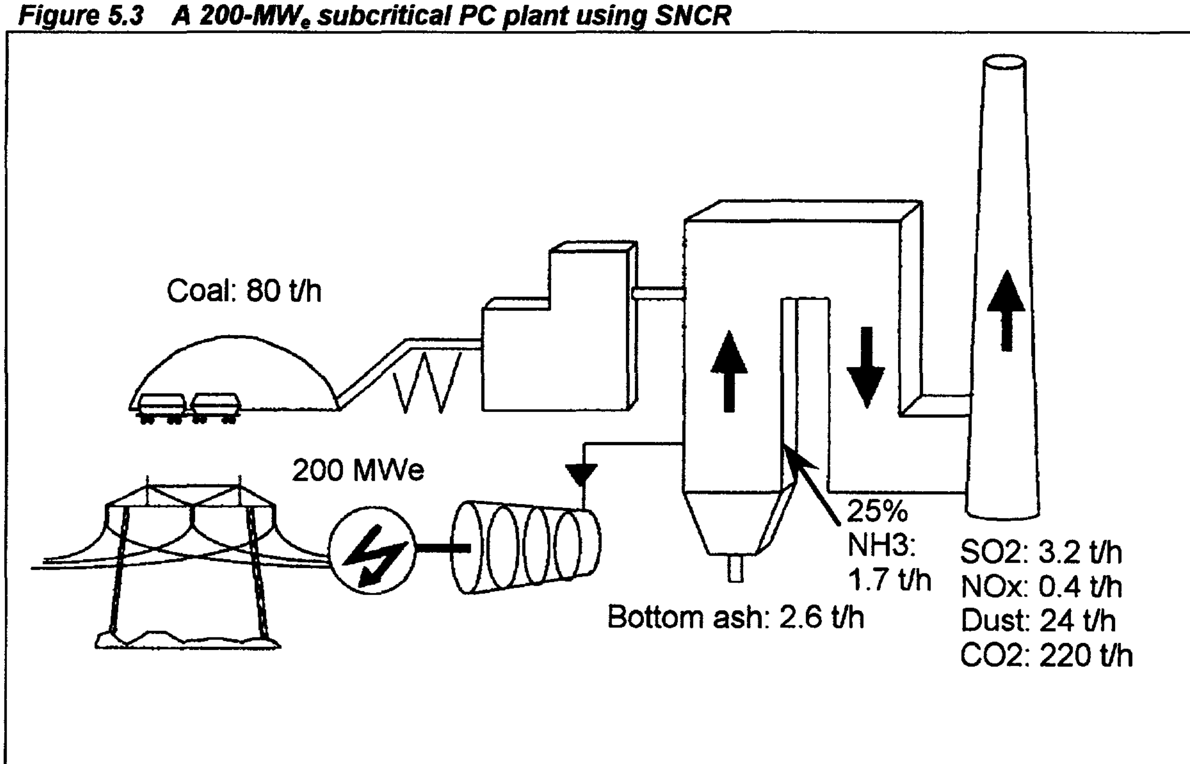
O&M costs are highly dependent on the cost of the reagent due to the high rate of consumption. Normally they range from 0.1-0.2 UScent/kWh (Ref. 5). Contamination of the fly ash by ammonia can reduce the possibility of selling the fly ash; instead there will be a cost for fly ash landfill. Also, a high ammonia slip can cause plugging and corrosion problems on the air heater, resulting in lower boiler availability which has a negative effect on the O&M costs.

Levelized costs for 50% reduction at a urea price of 300 USD/ton have been estimated to range from 0.2 UScents/kWh or 1,100 USD/ton NO_x removed for a 100-MW unit to 0.15 UScents/kWh or 900 USD/ton NO_x removed for a 500-MW unit (Ref. 3). At higher reagent costs the levelized cost increases. If a lower reduction is sufficient, the levelized cost decreases as a result of lower reagent consumption.

The use of SNCR in a 200-MW$_e$ PC plant

Figure 5.3 shows a 200-MW subcritical PC plant using SNCR. The reduction in NO_x emission achieved can be seen by comparison with Figure 3.6.

Figure 5.3 A 200-MW$_e$ subcritical PC plant using SNCR



Note: *Data are used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*

Screening criteria

Table 5.5 is to be used for technology screening according to Chapter 9.

Table 5.5: Screening criteria for SNCR

Maturity of technology	• SNCR is used commercially in coal fired plants in Western Europe and in the USA. There are no SNCR installations in India or China. In China SNCR is being researched.
Unit size	• all plant sizes
Waste product	• none

SELECTIVE CATALYTIC REDUCTION

In the SCR process, the NO_x in the flue gas is reduced by the addition of ammonia in the presence of a catalyst. The SCR reactor can be placed in three different locations:

- high dust - at the outlet of the economizer before the ESP,
- low dust - after the ESP before the air preheater, or
- tail end - after the particulate filter and the FGD system.

Suitability

SCR is suitable for use in developing countries when combustion modifications are not sufficient to meet the emission limits. It is suitable for coal-fired power plants when the required NO_x emission limits are less than 100 ppm, and 80 to 90% NO_x reduction is required, for example in power plants located in heavily populated areas.

Technology demonstration and some adaptation may be required in the case of possible use with high sulfur and high ash coal types. Installation of a high dust SCR system in an existing boiler requires extensive modification of the boiler backpass. Lack of available space for retrofitting is often a constraint.

State of technology

Since the mid-1960s more than 200 SCR units have been installed and are operating in coal-fired power stations with a total capacity of more than 65 GW_e (Ref. 3). SCR is mainly used in Austria, Germany and Japan when combustion modifications are not sufficient to meet stringent NO_x requirements. The technology is not yet demonstrated in India or China. In China, research and small-scale tests are being carried out in combustion research institutes (Ref. 2). SCR is commercially available for low to medium sulfur coals (<1.5%), and the method has also been demonstrated for most types of coals on the free market.

The high dust location type is the most widespread worldwide. The low dust location variant is used in some plants in Japan as it gives a greater fuel flexibility, but it requires expensive high-temperature ESP. The tail-end location type is used mainly in Germany and in retrofit cases where space is restricted, and for wet bottom boilers. The tail-end location requires a gas-reheater in order to reheat the flue gas after the FGD to the SCR operating temperature of 300-400°C.

Fuel flexibility

The SCR technology works best with low and medium sulfur coals with a low ash content. There is not much experience of SCR with high sulfur coals. The catalyst can be deactivated by high levels of arsenic. A high ash content can lead to erosion of the catalyst, but on the other hand, SCR may not be necessary for high ash coals as they tend to give lower NO_x levels due to a lower flame temperature (Ref. 4). A tail-end catalyst is more flexible when using different types of coals than is a high dust catalyst.

Plant size

SCR technology can be applied to a wide range of boiler sizes. In retrofit applications, however, space constraints may limit the physical size and capacity of the system.

Performance

Efficiency

The NO_x reduction efficiency of an SCR system depends on the NH_3/NO_x molar ratio and the catalyst volume. The efficiency for low to medium sulfur coals is usually 70-90% at a NH_3/NO_x molar ratio of 0.7-0.9 (Ref. 3). Similar NO_x reduction is expected with high sulfur coals, but such performance has not been demonstrated in utility-scale boilers. The pressure drop over the catalyst is not negligible, which means that the overall plant efficiency decreases somewhat.

Load regulation effects

The SCR process can be operated in a wide-load range and at fluctuating load.

Reagent

Ammonia, concentrated or in aqueous solution, is used as the reagent. A 150-MW plant will consume approximately 250 lb/h (115 kg/h) of concentrated ammonia.

Availability

The availability of the catalyst is normally high due to its modular design. The SCR unit will not affect the yearly overhaul time for a plant.

Construction issues

Construction time

The SCR unit will not affect the construction time for a new plant. For retrofit applications the estimated outage times are (Ref. 5):

- high dust SCR retrofits: 2 to 3 months outage.
- tail-end SCR retrofits: 3 to 6 weeks outage.

The possibilities for local manufacturing, licensing agreements

It is not possible to manufacture the SCR catalyst in India or China today (Refs. 1 and 2), and there is no license agreement between Chinese or Indian manufacturers and international manufacturers. Other parts of the SCR unit, other than the catalyst can be manufactured locally.

Area requirements

The area requirement is higher for SCR than for SNCR or low NO_x combustion measures. In retrofit applications, space constraints may limit the physical size and capacity of the system. A tail-end catalyst location is used when available space in the boiler duct system is restricted.

Costs

Investment

The cost for installation of SCR on a new plant is around 50-90 USD/kWe, and the cost for retrofit is 90-150 USD/kW$_e$ (Ref. 3). Installing SCR on a new plant costs less than retrofitting an existing plant, because in existing plants, space is limited and retrofitting requires considerable modification of existing equipment such as air heater and fans. The investment cost depends on the required catalyst volume. Minimizing the catalyst volume is important in order to keep down investment as well as maintenance costs.

The location of the SCR affects the capital cost considerably. A low dust location requires a high temperature ESP. A tail-end location requires a smaller catalyst than a hot side location since the dust load on the catalyst is lower in the tail-end position; but, in addition, it requires a gas-gas reheater with supplementary gas- or oil-firing in order to reheat the flue gas to SCR reaction temperature.

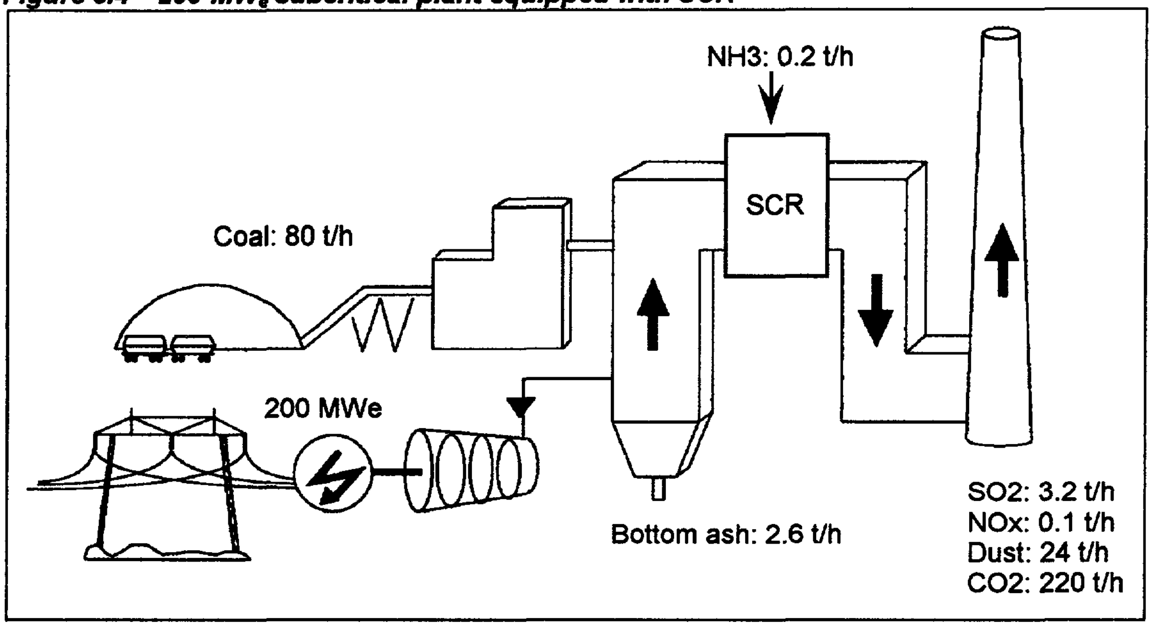
Operation and maintenance

O&M costs for SCR are expected to add 0.2 to 0.4 UScents/kWh, depending on the catalyst life (typically 5-7 years) and the catalyst cost, typically 16,000-20,000 USD/m^3 (Ref. 3).

A 200-MW_e PC plant equipped with SCR

Figure 5.4 shows a 200-MW_e subcritical power plant using SCR. The reduction in NO_x emission achieved can be seen by comparison with Figure 3.6.

Figure 5.4 200-MW_e subcritical plant equipped with SCR



Note: *Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*

Screening criteria

In Table 5.6 screening criteria will be used for technology screening in Section 9.

Table 5.6: Screening criteria for the SCR technology

Maturity of technology	• Commercial in Europe and Japan but not in India or China. No reference plant in India or China.
Unit size	• Suitable for any boiler size.
Waste product	• none

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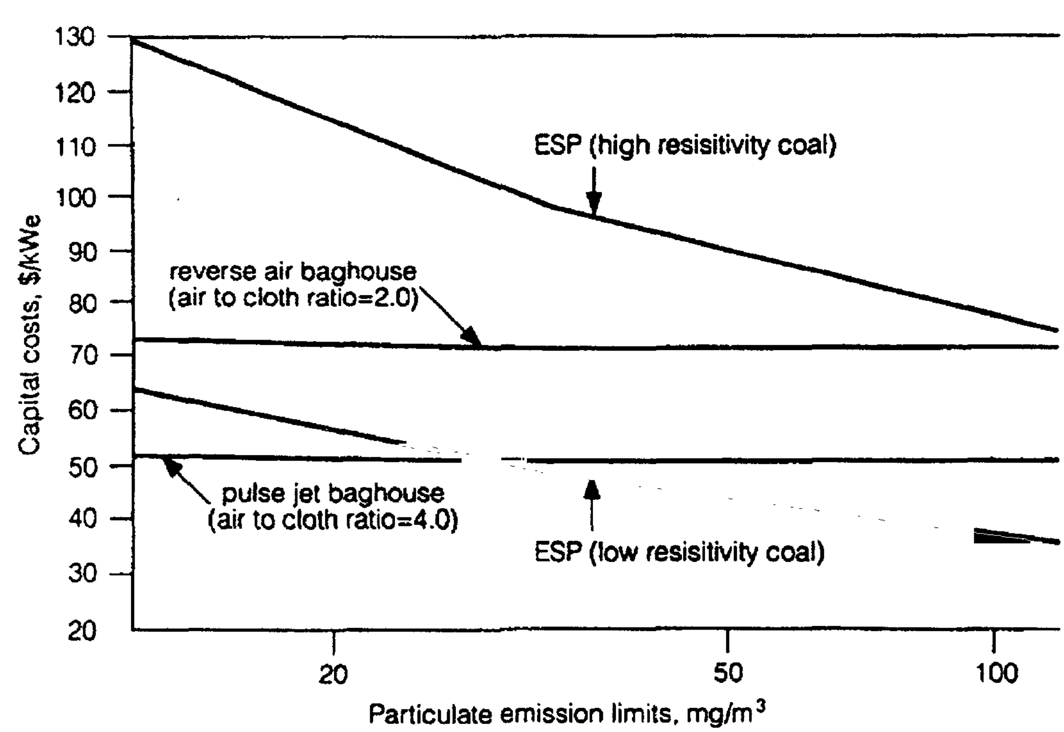
6. PARTICULATE EMISSION CONTROL TECHNOLOGIES

There are two main types of particulate emission control technology: fabric filters (baghouse filters) and ESPs. Fabric filter technology is the most widely used particulate control device in industry, but ESPs is by far the most commonly used technology in power plants worldwide. Both technologies are capable of meeting very low emission limits.

The choice of particulate control technology depends upon several site-specific conditions such as ash and fuel characteristics, environmental requirements and operational factors. The influence of an outlet emission limit and fly ash resistivity on the choice of particulate collector is illustrated in Figure 6.1. The figure shows the capital cost for different types filters per kW of electricity installed as a function of the particulate emission limit.

The figure shows that ESPs require a lower capital cost than baghouse filters for particulate emission limits higher than 30 mg/m^3 when firing coals with low fly ash resistivity (Ref. 3). For coals with high fly ash resistivity, baghouse filters are more economical. Pulse jet baghouse filters have lower capital cost when stringent emission limits are required.

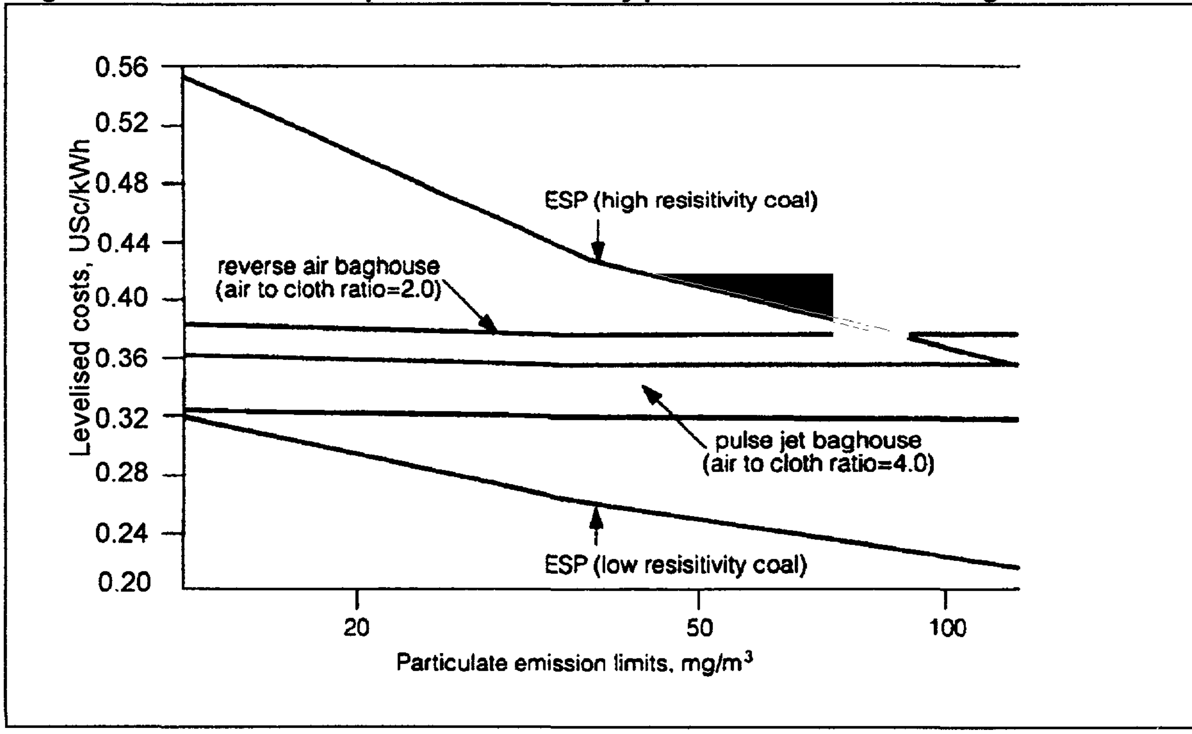
Figure 6.1 Capital cost per kW electricity installed for ESPs and baghouse filters



Source: *Sloat et al (1993).*

Looking at the levelized cost gives a somewhat different picture. ESPs have a lower O&M cost than fabric filters because they have a lower pressure drop over the filter, and because fabric filters require an annual cost for bag replacement. The pulse-jet baghouse filters have the highest O&M cost of the three filter types. Figure 6.2 shows the levelized cost for the three filter types per kWh of electricity produced depending on the particulate emission limit (Ref. 3). The figure shows that ESPs are competitive for low resistivity coals at the whole range of emission limits. They are also competitive for coals with medium to high fly ash resistivity at less stringent emission limits. When firing coals with high fly ash resistivity, baghouse filters gives a smaller increase in production cost.

Figure 6.2: Levelized cost per kWh of electricity produced for ESPs and baghouse filters



***Source:** Sloat et al (1993).*

Another important aspect in the selection of particulate control equipment is the power consumption of the process. Despite the power consumption required by the ESPs in order to create the electric field, ESPs normally have a significantly lower total power consumption than fabric filters. This is because ESPs have a lower pressure drop than fabric filters, approximately 0.2-0.3 kPa versus 1-2 kPa, resulting in lower power consumption by the flue gas fans. The total power consumption of ESPs is approximately 60-70% of that of baghouses (Ref. 6).

Electrostatic Precipitator Technology

The electrostatic precipitator is the single most used emission control equipment in thermal power plants. The principle of operation is based on the creation of an electrostatic field. Emitted particulates are charged when they pass through the electrostatic field and are attracted to the electrodes, where they are collected. ESPs have a lower pressure drop than fabric filters and can operate at higher temperatures. They are relatively insensitive to disturbance.

Suitability

Electrostatic precipitators are competitive for medium and high sulfur coals with low to medium ash resistivity (<1,012 Ohm-cm). For these coals, they are suitable for particulate removal efficiencies up to above 99.5%. They have lower capital and levelized costs in this area than baghouse filters. They are also cost-effective for low sulfur coals and coals with a high fly ash resistivity when lower emissions are required. Due to their robust design, ESPs can normally endure tough conditions. This is an attractive characteristic when firing coals with a high ash content and with an erosive ash such as Indian coals (Ref. 4). In cases where more than 99.5% collection efficiency is required, especially for low sulfur, high resistivity coals, reverse air or pulse-jet fabric filters are normally more cost-effective than ESPs.

A number of options exist to enhance the performance of ESPs, especially suitable in developing countries. In India, the high volume, high ash resistivity coals place large demands on ESPs. Replacing existing ESP systems with new ones when environmental regulations become stricter will require a considerable capital investment. Therefore, improvements of existing ESPs may present a cost-effective option. When some clean coal technologies are used (specifically spray dryers, sorbent injection, and fluidized bed combustion) improvements of ESPs may be needed. If a market develops for such improved ESP features, supply should not be a problem.

State of technology

Electrostatic precipitators are commercially available worldwide and are installed in most coal fired power plants in China (Ref. 2). In India, all power plants greater than 100 MW are equipped with ESPs. The major Indian manufacturer of ESPs, BHEL, has developed an ESP technology that can achieve the required collection efficiency for the high resistivity, high volume ash of Indian coals. In several plants, ammonia injection systems have been installed upstream of the ESP to enhance conductivity and ESP clean-up efficiency (Ref. 1).

Plant size

Electrostatic precipitators have been operating for many years on coal-fired units with sizes up to and above 1,000-MW_e output.

Fuel flexibility

The quality of the coal has a great impact on the size and the cost of a new ESP. The most important parameter regarding coal quality is the fly ash electrical resistivity. A high content of alumina and silica (>95% of the ash) increases the precipitator area significantly as alumina and silica in the ash form an electrical insulator. A high sodium content has a positive effect as an electrical leader, resulting in a reduced precipitating area.

Switching from high to low sulfur coal may have a negative impact on the ESP performance. As low sulfur coals normally have higher fly ash resistivity, the existing ESPs may operate at reduced removal efficiency.

Performance

Efficiency

Normally, ESP efficiency is above 99.5% for hard coal and higher for lignite. However, ESPs can be sized for extremely high efficiencies up to 99.99% with dust emissions as low as 5 mg/m^3(n) guaranteed (Ref. 7). In India, ESPs in large plants typically have efficiencies greater than 99.7%. ESPs installed in smaller plants with boilers with a capacity of less than 200 MW located in rural areas have lower efficiencies, typically around 99.1%. Approximately 140 ESPs have an efficiency in the 99.5-99.8% range and the rest have efficiencies in the 99.0-99.2% range. At several units in India, an ammonia injection system has been added upstream of the ESP in order to enhance ESP conductivity and clean-up efficiency (Ref. 1).

Many flue gas and ash characteristics have an impact on the ESP cleaning efficiency. Such flue gas characteristics include flue gas flow, temperature, concentration of unburned material and particulate content. Ash characteristics of special importance are electrical resistivity and sulfur content. The prediction of the impact of these characteristics is based more on experience than on theory. ESP manufacturers differ in their opinion regarding the influence of different parameters.

There are several options for improving the performance of an existing ESP, if it is required by stricter environmental laws. Efficiency can be enhanced by increasing the size of the ESP and by wider plate spacing. Conditioning of the flue gas with moisture, SO_3 or NH_3 can have a positive impact on collection efficiency. Finally, increased efficiency can be achieved by replacing conventional DC-generators with high pulse-generators (Ref. 7). The quality and status of the ash removal system has a major impact on the flue gas cleaning efficiency of an installed ESP. An ESP can never reach a high efficiency if the ash removal system is not functioning (Ref. 4).

Availability

If the instructions of the manufacturers for operation and maintenance are followed, the availability for this type of well-proven technology should be high, approximately 99% or more.

Construction issues

Time

- Installing a new ESP: 2 to 3 month outage
- Increasing the size of existing ESP: 2 to 3 month outage
- Retrofitting of ESP: 2 to 6 weeks of unit outage (Ref. 5)

The possibilities for domestic manufacturing, licensing agreements

In China, there are at least three ESP manufacturers for plants up to 600-MW electric output (Ref. 2). In India, there is one manufacturer, BHEL, which has the major part of the ESP market (Ref. 1). BHEL previously had a license agreement with ABB Fläkt and adapted their technology to Indian coal types with high ash content and high ash resistivity. Currently, there is no agreement and ABB Fläkt has a subsidiary in India called ABB India (Ref. 4).

Costs

Investment

The investment cost for an ESP is determined by its specific collection area (SCA), which in turn depends on fly ash resistivity, flue gas temperature and outlet emission limit. Low sulfur, high fly ash resistivity coals require a higher SCA than do high sulfur coals and coals with low fly ash resistivity to reach the same reduction, so consequently the ESP cost becomes higher. The influence of outlet particulate emission limit and fly ash resistivity on the investment cost is shown in Figure 6.1.

The investment cost for a new ESP ranges from 30 USD/kW$_e$ for a coal with a fly ash resistivity of 10^{10} Ohm-cm, to 80 USD/kW$_e$ for a coal with a fly ash resistivity of 10^{13} Ohm-cm (Ref. 7). This includes also costs for fans, ductwork and fly ash handling. ESPs with very high collection efficiencies (>99.7%) may cost up to 100 USD/kWe (Ref. 5). Costs for ESP improvements range from 1-20 USD/kW$_e$ (Ref. 5).

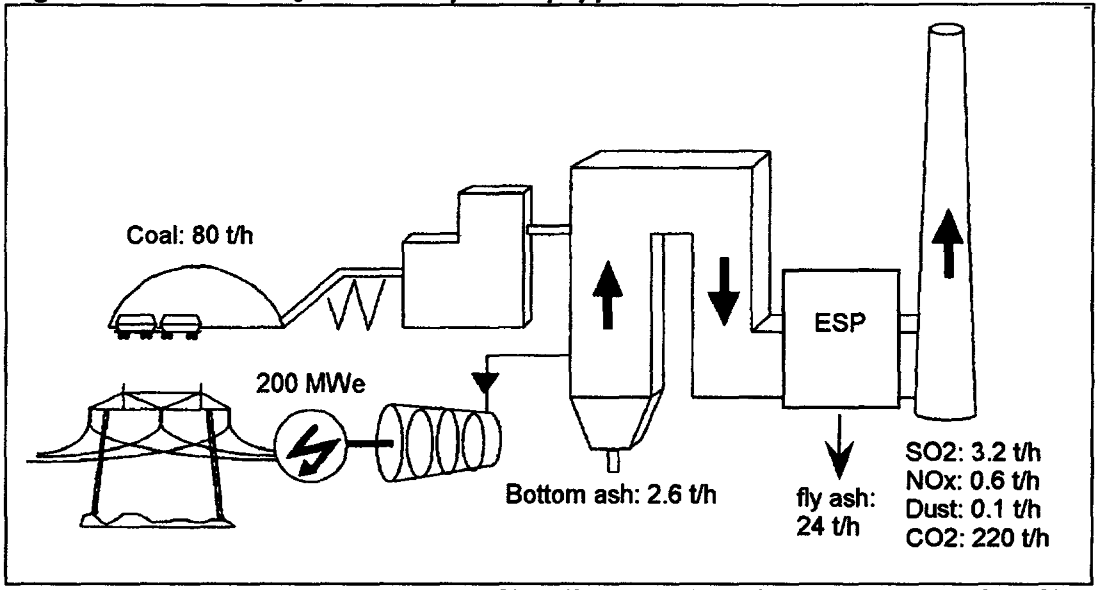
Operation and maintenance

The pressure drop over the ESP is normally very low, approximately 15-30 mmWC, resulting in low power consumption and thereby, a low operation cost (Ref. 7). ESPs normally require very little maintenance. Total O&M costs of conventional ESPs range from 0.15-0.4 USc/kWh (Ref. 5 and 6) or around 5 USD/kW per year (Ref. 3).

A 200-MW$_e$ PC plant equipped with ESP

Figure 6.3 shows a 200-MW subcritical PC plant equipped with ESP. The reduction in dust emission achieved can be seen by comparison with Figure 3.6.

Figure 6.3 A 200-MW$_e$ subcritical plant equipped with ESP



Note: *Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*

Screening criteria

Table 6.1 lists criteria to be used for technology screening as described in Chapter 9.

Table 6.1: Screening criteria for ESPs

Maturity of technology	• ESPs are commercially available world wide and are installed in most coal fired power plants in India and China.
Unit size	• all plant sizes
Waste product	• none

FABRIC FILTER (BAGHOUSE)

For a long time fabric or baghouse filters have been the most widely used particulate control device in industry. Their application potential has been increased by the introduction of new materials capable of withstanding higher temperatures. They are popularly used in thermal power plants, especially in the United States. A feature of baghouses is their relative insensitivity to gas stream fluctuations and to changes in inlet dust loading. In fact, outlet emission becomes almost independent of inlet particulate concentration. Another advantage is that they can enhance SO_2 capture in combination with upstream sorbent injection and dry scrubbing systems.

Suitability

Baghouse filters are normally more cost effective than ESPs when firing low-sulfur or high fly ash resistivity coals, and when more than 99.5 % collection efficiency is required. Pulse-jet fabric filters are a newer type of baghouse filter which has a lower capital and levelized cost than the more widely used reverse air fabric filters.

Baghouse technologies can be used in combination with sulfur removal technologies such as sorbent injection and dry scrubbing systems. In installations downstream spray dryers or sorbent injection systems, fabric filters can enhance SO_2 capture because chemical reactions between particulates and gases can also occur in the filter system. The filters collect unused reagent from the process and absorb more SO_2. Pulse-jet fabric filters are being applied with increasing frequency at utilities equipped with spray dryer systems. SO_2 removal performance may be enhanced by 25% with a baghouse in combination with the spray dryer.

Baghouse filters are not commonly used in developing countries as the current emission limits favor ESPs. With the advance of more stringent emission limits, baghouse filters may be further introduced in the power sector.

State of technology

Baghouse technologies are commercially available throughout the world. However, they are not used widely in power plants in developing countries. Baghouse filters are used for air treatment in industry in China, but there are only a few coal plants operating with baghouse filters. In India, there is only one power plant using baghouse filters.

Plant size

The filter type is used in units up to and above 300-MW electric output.

Fuel flexibility

Baghouse filters can be designed for any type of coal from lignite to anthracite. Their efficiency is independent on the sulfur content. Flue gases with presence of acid or alkaline will reduce the fabric lifetime. Hygroscopic material, tarry adhesive components, moisture condensate can all produce problems such as filter plugging.

Performance

Very high collection efficiencies, above 99.5%, can be achieved, even with very small particles in the 0.5-1.0 micron range. The performance does not deteriorate with low SO_2 content in the flue gas as it does in an ESP. The performance of the fabric filter is determined by the filter material.

Traditional materials are semi-permeable and woven, often fiber glass, capable of withstanding maximum 260°C. New materials have recently been developed to withstand much higher temperatures, in the range of 480°C, for use in hot side units and with fluidized beds. These materials are made of ceramic fibers and achieve collection efficiencies of 99.99%, but they are very costly.

Availability

If the instructions of the manufacturers for O&M are followed, the availability for this type of well-proven technology should be high, 99% or more.

Construction issues

The possibilities for local manufacturing, licensing agreements

There are manufacturers of baghouse filters in China, but the normal use is for air treatment. Baghouse filters for power plants will probably need to be imported. In India, there is currently no domestic manufacturing of baghouse filters, but it should be possible to manufacture more than 99% domestically.

Costs

In general, baghouses are more cost effective than ESPs in cases where high cleaning efficiencies (>99.5%) are required and when firing low-sulfur coals or coals with high fly ash resistivity.

Investment

The investment cost of baghouse filters does not depend as much on the coal quality or the emission limit as do ESPs. For baghouse filters, the filter cleaning method is important; fabric filters with pulse jet cleaning have normally a lower investment cost than fabric filters with reverse air cleaning. Other important parameters include the air-to-cloth ratio and the bag material. As was shown in Figure 6.1, typical capital costs for baghouses range from 50 USD/kW for pulse jet fabric filters to 70-75 USD/kW for reverse air fabric filters (Ref. 6). Levelized costs range from 0.32-0.4 UScents/kWh for pulse-jet and reverse air fabric filters, respectively (Ref. 3).

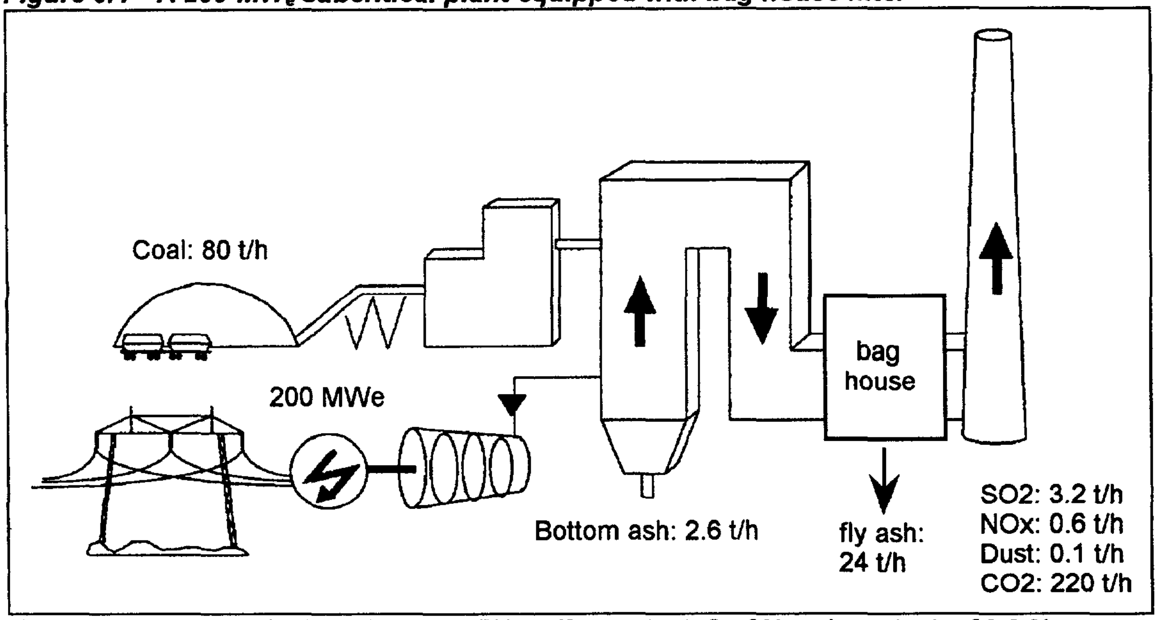
Operation and maintenance

Operating costs are normally 20-35% higher for baghouse filters than for ESPs due to a high pressure drop over the filter resulting in a significantly higher power consumption. The pressure drop is typically in the range of 100-250 mm water column. Also, maintenance costs are higher than for ESPs because the bags have to be replaced and the valves need to be controlled regularly. Total O&M cost is around 0.18-0.2 UScent/kWh or 6-7 USD/kW per year (Ref. 6).

A 200-MW_e PC plant equipped with baghouse filter

Figure 6.4 shows a 200-MW subcritical PC plant equipped with baghouse filter. The reduction in dust emission achieved can be seen by comparison with Figure 3.6.

Figure 6.4 A 200-MW_e subcritical plant equipped with bag house filter



Note: *Data used -- plant efficiency = 37%, sulfur content, S= 2%, ash content = 32.8 %.*

Screening criteria

Table 6.2 lists criteria to be used for technology screening as described in Chapter 9.

Table 6.2: Screening criteria for baghouse filters

Maturity of technology	• Baghouse filters are widely used in industries world wide and they are popular in thermal power plants in the United States. In China there are a few coal plants using baghouse filters and in India there is one plant.
Unit size	• all plant sizes
Waste product	• none

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7. BY- PRODUCTS AND WASTE HANDLING

Coal-use for power generation produces large quantities of wastewater and solid residues such as fly ash, bottom ash, FGD residues, ACFB residues etc. Currently, solid residues from coal-based power generation in India and China are limited to fly ash and bottom ash from PC boilers since FGD and large ACFB boilers are hardly used.

Management of coal-use residues concerns their handling, transport and utilization or disposal. A first step in a successful management strategy for coal-use residues is to minimize the quantity of by-products produced. Possible routes for achieving this are to increase the use of washed coal and to strive for higher plant efficiencies. The benefits of using washed coal, in addition to minimizing the amount of solid residues that need to be taken care of at the power plant, are described in Chapter 2. By increasing plant efficiency, the amount of solid residues produced per MWh_e is reduced. An increase in plant efficiency from 34% to 42% reduces the amount of waste produced per MWh_e by 20%, as shown in Chapter 3.

A second step in a successful environmental management strategy, which embraces the concept of sustainable development, is the maximum utilization of the residues. Utilization of residues has the advantage of making land available for other non-disposal purposes. Since both India and China are undergoing rapid industrialization, there is a great demand for large quantities of building and construction materials. This demand is expected to continue to increase over the decade. Some residues from coal-based power have properties already being asked for by the construction industry. Fly ash can be used for land and mine reclamations and as a substitute for Portland cement in concrete. Gypsum from a wet scrubbing system can be an adequate substitute for natural gypsum. Whether utilization of the residue is possible or not is dependent on the initial selection of combustion and flue gas cleaning technology. Not all types of residues can currently be utilized. Hence, residue use should remain a focus when selecting combustion and flue gas cleaning technology for a proposed power plant.

Before deciding on utilization or disposal, the characteristics of the residue should be examined to determine the suitability of either solution. If the by-product is of too low quality to be utilized; if utilization of the by-product is not economically feasible, or if the by-product generation is larger than the market demand, disposal of the by-product will be necessary. In such a case, it is important to assure safe, environmentally acceptable disposal. However, disposal should be looked on as the last resort in residue management. Waste from coal-based power production is not restricted to solid waste. A large amount of wastewater is produced which needs proper treatment. Treatment methods are summarized in this chapter.

UTILIZATION

Today only a small portion of the fly ash and slag residue produced in power plants in India and China is utilized leaving the major part for disposal. Internationally, utilization of residues is a well-established technology. These facts are illustrated in Table 7.1 where it can be seen that the ash utilization rates in India and China are very low compared to the ash utilization rate in Germany which is close to 100%. Not shown in the table is gypsum from FGD plants which also has a high rate of utilization internationally. The high utilization rate in Germany is achieved by a comprehensive program for the standardization of by-products and construction materials and active marketing of construction materials produced from by-products. Co-operation between the power industry and the construction materials industry in Germany also contributes to the high utilization rate.

Table 7.1 Coal ash production and use in India, China and Germany

Country	Fly and bottom ash *(kt/year)*	Utilization *(kt/year)*	Utilization %	Year
China	110,000	34,000	30	1995
India	40,000	8,000	2	1992
Germany	20,000	19,800	99	1992

Source: *Zhang et al (1996), Sloss et all (1996).*

With the huge quantity of ash being generated, as shown in Table 7.1, it is essential that the question of utilization be addressed. Increased utilization of residues, for example as building materials and for civil engineering purposes, is therefore to be promoted both in India and China. In China, a feasibility study for ash and slag utilization will be required as part of new power plant feasibility studies in the near future (Ref. 4). As per the latest stipulations by the Indian authorities, an ash utilization plan is required for new power plant projects (Ref. 2).

It should be concluded that utilization will be a high priority in the future. There will be demand for high utilization rates in new power plants and increased utilization at existing plants. Requirements on utilization affects the selection of combustion, ash handling and flue gas cleaning technologies, and thereby promotes technologies that produce solid residue that can be utilized easily, e.g. wet scrubbers producing gypsum, dry ash handling systems, etc.

A range of technical and economic considerations influence the feasibility of utilization. Residue should be utilized as close to the power plant as possible, avoiding long distance transportation. This could be achieved by reserving land for construction material production near the power plant. Other factors affecting the feasibility for utilization are land availability near the power station for a disposal site and regulations on solid waste disposal; availability of natural competing materials; existing commercial experience in using the by-product; promotion of cooperation between utilities and industries using the by-product, and the quality of the by-product.

There is an environmental concern related to utilization with the risk of the spread of potential contaminants widely in the environment without control. Hence, before deciding on utilization or not, the suitability to use the actual by-product has to be examined. Generally the suitability depends on:

- the physical and chemical properties of the by-product;
- the risk for leaching of trace elements; and
- the environment the by-product will be used in; depending on leaching characteristics, restrictions for by-product utilization may apply in ecologically sensitive areas, applications above ground water level and wetland areas etc.

Requirements for fly ash and bottom ash utilization

Fly ash characteristics vary considerably with parameters such as coal type and combustion conditions. Both the physical and chemical properties of the fly ash are important when determining the suitability for use in specific areas. Chemical properties are pozzolanicity, i.e. the ability to combine with CaO in the presence of water to form cementitious compounds, and reactivity. A physical property of fly ash is its fineness. Classification systems and specifications are used to ensure that the correct fly ash is used for a specific purpose. For example, both India and China have country specific specifications for coal fly ash for use in Portland cement (Ref. 3) where unburned content, SO_2 content, specific surface, etc. are specified. Evaluation of by-products for use includes leaching tests for different trace elements such as As, Cd, Cr, Cu, Hg, Ni, Pb, Zn, Cl, SO_4. Tests include initial and long-term leaching properties of material.

Requirements for FGD gypsum utilization

In order to be able to utilize the gypsum produced in a FGD plant, the quality of the gypsum has to be controlled. The most important parameters to control include:

- free moisture content,
- quantity of solid impurities,
- chemical composition,
- color, and
- crystal shape and particle size.

Internationally, commercial grade FGD gypsum is often required to have a purity greater than 95%, a free moisture content of maximum 10%, a chlorine content of less than 400 ppm and a whiteness of 80%.

Areas of utilization

Fly and bottom ash from PC firing and FGD gypsum can be used commercially in many applications. Fly ash can be used either as an active pozzolanic agent or simply as a cheap admixture to provide bulk in engineering materials and FGD gypsum can replace natural gypsum.

Currently, other solid residues are disposed of, since there are limited means of utilizing them commercially. Table 7.2 summarizes the areas of utilization for different solid residues.

Table 7.2: Areas of utilization for coal-use residues

By-product	Utilization areas/ disposal	State of utilization
Fly ash	• cement industry • concrete and construction materials • structural fill soil stabilization	• commercial • commercial • commercial • commercial
Bottom ash	• cement industry • concrete and construction materials • structural fill	• commercial • commercial commercial
Fluidized bed residues	• disposal • some utilization areas are studied; processing and mixing in one or another way is required	• R&D
Spray dry scrubber residues	• disposal • some utilization areas are studied; processing and mixing in one or another way is required	• R&D
Sorbent injection residues	• disposal • some utilization areas are studied; processing and mixing in one or another way is required	• R&D
Wet scrubbing: • gypsum • stabilizate • gypsum slurry	 • building materials; – wallboards – plasterboards – mortars – floor screeds – cement • civil engineering – mining applications – roadbase and structural fill • agriculture – conditioning alkaline soils • disposal • disposal	 • commercial • commercial • R&D
PFBC	• potential use as – structural fill – road base construction etc.	• R&D
IGCC		• R&D

DISPOSAL

Disposal methods can be divided into two categories: wet and dry disposal. Wet disposal involves the handling of the by-product as a slurry or in liquid form. The disposal site is usually referred to as a pond, impoundment or reservoir. In dry disposal systems, or landfills, the by-product is handled as a solid. Wet disposal ponds are used in most plants in India. Wet disposal is also the predominant technology in the southern part of China. Presently, dry disposal is becoming the most popular in new disposal facilities over the world.

The choice between dry or wet disposal must correspond to the waste collection method employed in the power plant. Otherwise, the disposal system must include means to convert the waste to either the wet or dry disposal method. The latter is actually common in many power plants. Many power plants with wet waste collection systems have a process to convert to dry disposal. Three such treatments include *dewatering processes* in which the water is physically separated from the solid; *stabilizing processes* which include addition of dry solids, and *fixating processes* which involve the addition of a compound that reacts chemically and binds the water into the product. FGD slurries often require more than one such process prior to disposal.

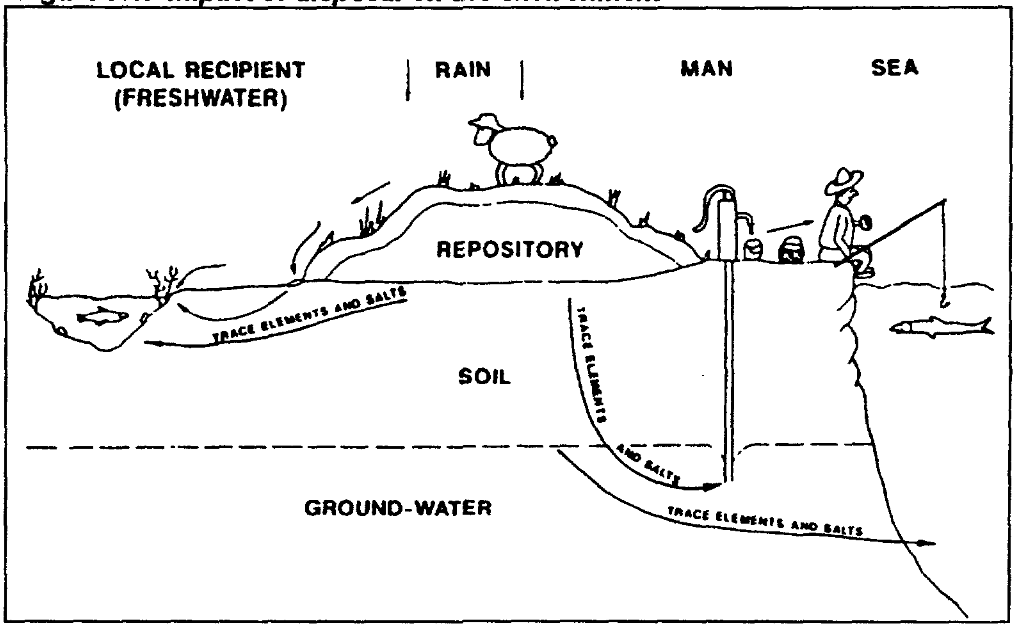
The major environmental concern connected to disposal is the potential short- or long- term risk of leaching of inorganic salts and trace element into surrounding water systems. The disposal strategy must assure that the concentrations at the site and its surroundings are not elevated to unacceptable levels. Possible routes for impact of disposal on the environment are illustrated in Figure 7.1. Leaching of material as well as surface run-off of material from the disposal site can lead to contamination of soil, ground water, fresh water systems, and sea. When designing a disposal system a major concern will be to prevent this contamination in order to protect the environment and human health. Other factors that can affect the choice of disposal strategy and method include the properties of the residues, applicable methods, costs and conditions at the disposal site.

Requirements for disposal

With prevention of water contamination becoming an increasingly important issue associated with residues from coal-fired plants, the environmental consequences must be found out before disposal. A method for determining the suitability of the waste material for disposal is to investigate the potential for leaching from the residue. Leachate tests can give information about which components in the material are readily released in water and the consequences for the water quality. Furthermore, they can give an indication of hazardous materials unsuitable for disposal. Basically, three types of leachate tests are employed:

- shake tests,
- column tests, and
- field tests.

Figure 7.1: Impact of disposal on the environment



Shake tests are made batchwise and are the most simple and inexpensive; however the drawback is that the batch situation does not a give an accurate simulation of the natural situation. *Column tests* provide representative conditions in nature while still at a laboratory scale; the material is placed in a column and a liquid flow percolates through it. The leaching media used in these laboratory tests can be distilled, de-ionized or demineralized water, acetic acid or a buffer. In a *field test,* a large sample of material is used and exposed to natural conditions, while leachate is collected and analyzed over a long period of time. Field tests give the most accurate reproduction of field conditions as they simultaneously account for chemical and microbiological reactions.

Once the potential for leaching to the environment has been tested and estimated, the suitability and the precautions disposal can be determined. The legislative and regulatory guidelines for disposal of coal-use residues vary from country to country. Generally the regulations include limit values for concentrations of trace elements, such as arsenic, cadmium, chromium, copper, mercury, lead, etc., in the leachate.

Dry disposal

The trend today is toward increasing use of dry disposal in landfills. Dry disposal has the advantage of requiring a smaller site area than wet disposal and is therefore an attractive option for plants with wet waste collection systems. In such cases, an intermediate wet pond can be used for sedimentation of the residues prior to disposal. Furthermore, problems like water pollution and consumption are minimized using dry disposal.

There are some important considerations for dry disposal in landfills. The landfill must be designed to be stable in all weather conditions during its entire lifecycle from construction through operation, to its final closure and after. Site selection and design should prevent influx of groundwater. In order to protect groundwater quality, a water management system must be included, filtration must be prevented and leachate must be collected and treated.

A vital element in landfill design is to estimate the potential for surface runoff. Both runoff from the area above and from the landfill itself should be considered. Runoff from above can be led around the landfill to avoid contamination. Runoff from the landfill itself should be collected and treated, as an example by sedimentation prior to release to the recipient (see Figure 7.2.) The system must be capable of handling runoff in all weather conditions, including heavy rainfall and storms.

A leachate collection system should be installed under the whole landfill to protect the groundwater system and preserve the landfill stability. Collection can consist of a network of perforated pipes or a blanket of granular material, e.g. sand, gravel, or bottom ash. A system for monitoring of all wastewater streams and the groundwater is necessary to ensure protection from groundwater contamination. Both pollutant concentrations and water flows should be monitored. With such a system in operation, any malfunctions of the leachate collection system will be discovered before severe damage has occurred.

Many landfill sites are isolated with liners in order to reduce permeability at the deposit boundaries. The liners are constructed so as to control the direction of the leachate and route it toward the drainage system. Figure 7.2 illustrates the principles of landfill disposal. When closing, the landfill should be sealed by a soil or clay cap in order to minimize infiltration of water. Leachate production can only be limited by reducing the amount of water entering a residue deposit. The cap design should be impermeable. Rain and water falling on it should not be captured but routed through collecting channels off the cap to a sedimentation pond before it is discharged to the recipient.

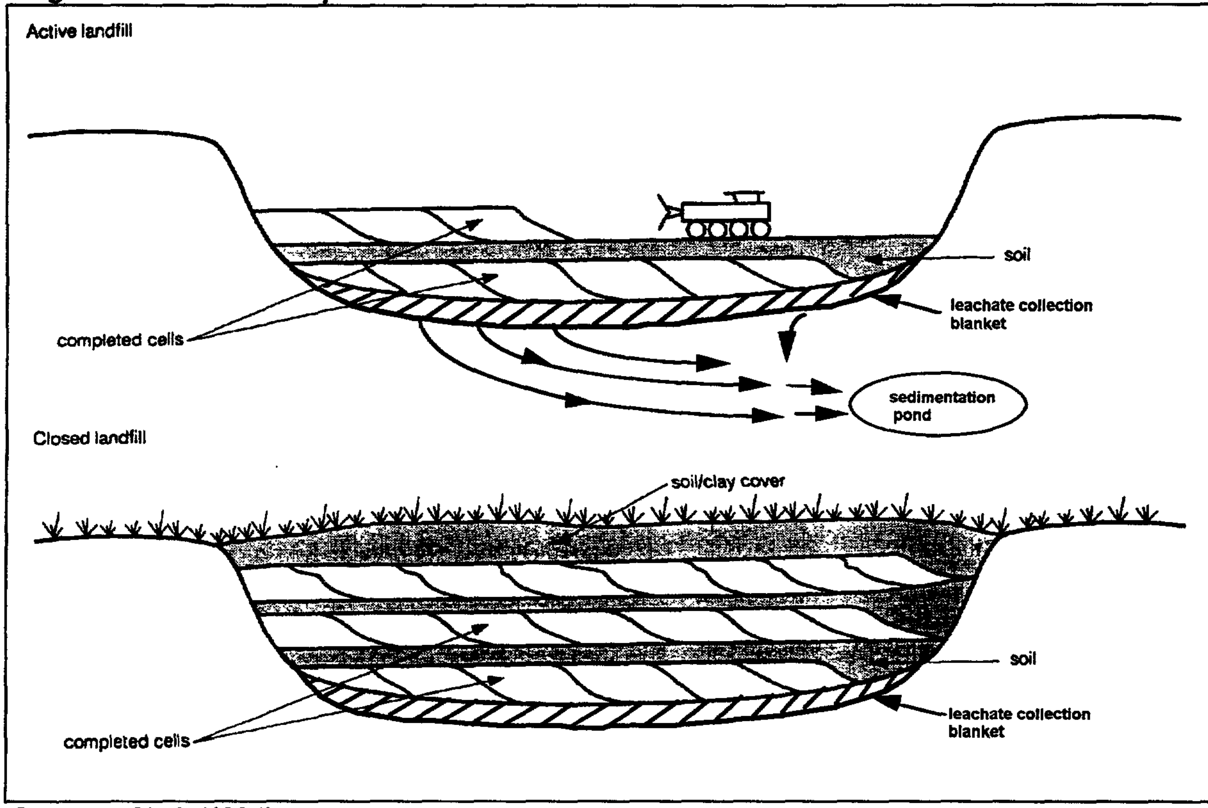
For power plants located close to the coal mine, backfilling the mine with coal ash is an attractive option from an environmental, as well as an economical point of view. For power plants located at a distance from the coal mine, ash disposal in the mine will require high transportation costs. For such plants, dry ash disposal must be made in natural low lands or in mounds. Disposal in mounds is a more efficient land use than disposal in low lands, but the costs are higher. Land reclamation, after the disposal site closes, is easier for a low land site. Estimated capital and O&M costs for dry disposal methods are listed in Table 7.3.

Table 7.3: Estimated capital and O&M costs for dry ash disposal methods

Method	Estimated Disposal Costs	
	Capital *(USD/m^3)*	**Annual O&M** *(USD/m^3)*
Mine backfilling	0.3	1.2
Low lands	0.3	1.0
Mounds	1.4	3.1

Source: *WESA (1996).*

Figure 7.2 Landfill disposal site for coal-use residues



Source: *Clark (1994).*

Wet disposal

Wet disposal is used for residues in the form of slurries or sludges. Internationally it is not as popular today as dry disposal due to:

- greater land requirement for the same amount of waste,
- more complicated process management,
- more problems with leachate, and
- high capital costs.

The advantage is the ease by which residues can be transported and placed by using pipelines from the plant to the pond. But this requires additional water which can easily lead to an increased generation of leachate.

In order to reduce the need for fresh water, clear process water from the pond should be recycled and reused. Pipelines for the return of the clear process water remaining after the sedimentation must be included, which increases the capital cost. When designing the discharge and return pipeline systems, efforts must be made to minimize short-circuiting of slurry water directly from the outlet to the return water inlet. To reduce water consumption in existing power plants using wet disposal, pipelines to recirculate process water from the pond back to the plant can be installed.

Wet disposal is suitable for residues from wet FGD. They can be removed and disposed of in the form of slurry thus reducing the need to dewater it. In such cases, dry ash can be used for construction of the impondment dam. This will not only reduce capital cost but will also reduce the cost for dry ash handling.

The design of a wet disposal site is similar to that of a landfill, but for a pond it is even more important to take maximum advantage of the terrain. The terrain in combination with the geology and hydrology of the chosen site are essential for the pond configuration. Safe containment of the full volume of waste slurry in all weather conditions is provided by impermeable barriers. An allowance in volume should be made for unexpected water streams such as storms. Heavy rainfall and flooding may have serious impacts on wet disposal ponds. In some cases evaporation may cause a partial drying of the pond with dust problems as a consequence. All wet disposal sites eventually become dry when the site is completed, the solids have settled and the excess water has been recycled or released.

All ponds leak; the question is only the rate of leakage. Therefore, when designing a pond for wet disposal it is very important not only to perform stability calculations, but also to make correct estimations of seepage and pore pressure. A functioning drainage management system is essential. All water streams to and from the pond must be considered including excess process water, rainfall on the pond, surface runoff reaching it and evaporation. The demand of returnwater at the power plant must also be considered. As with landfills, a system for monitoring of wastewater streams and groundwater should be used to check that the material fulfills specified leachate requirements in order to assure that the leaching is kept within acceptable levels.

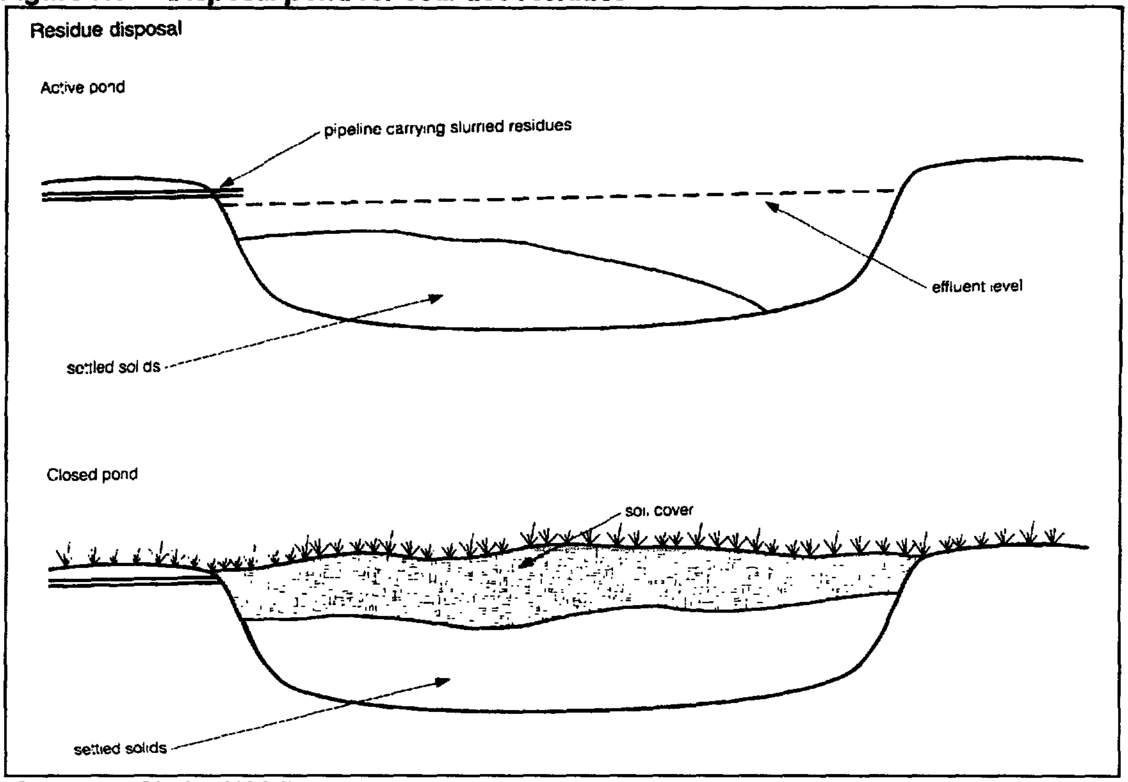
The principle of wet disposal is described in Figure 7.3. When the pond is completed and the suspended solids have settled, excess water is recycled or discharged, the remaining dry waste should be covered by a soil or clay cap to avoid dusting. Estimated capital costs for wet disposal vary 0.3-0.4 USD/m^3, and annual O&M costs vary 0.5-0.6 USD/m^3 (Ref. 7).

Site selection

Disposal site selection involves the balancing of costs versus environmental aspects. The major issue is to protect water and other natural resources. The first step in a site selection process is to define site selection criteria. Some criteria are of an exclusionary nature, which means that a site that does not fulfill these criteria will be eliminated from the selection process. When defining such exclusionary criteria, the following features should be considered:

- national and local regulations;
- distance from the power plant;
- size ability to contain the required volume,;

Figure 7.3 Disposal pond for coal-use residues



Source: *Clarke (1994).*

- risk of affecting major water bodies such as wetlands, rivers, and lakes, or water supply reservoirs or wells;
- proximity to nature reserves such as parks, forests, recreation areas and lakes; and
- urban areas.

After eliminating unsuitable areas with the exclusionary criteria, a list of criteria for ranking the remaining possible sites should be developed. Such ranking criteria include engineering criteria as well as environmental criteria. The engineering criteria include aspects such as:

- site characteristics (existing or a new site);
- new road construction requirements;
- sedimentation ponds, channels etc.;
- soil characteristics;
- depth to groundwater;
- upstream drainage area;
- topography (estimation of stability);
- transportation possibilities, and
- distance from the power plant.

The environmental criteria to consider relate to aspects such as:

- proximity to aquatic and terrestrial resources;
- the potential for accidents caused by the waste disposal, and
- noise, dust and visible impact on neighbors etc.

Potential sites are found by working from maps; eliminating areas that violate any of the exclusionary criteria. The work results in a list of possible candidates. As much information as possible should be gathered about these sites before they are scored using the list of ranking criteria. This procedure aims to produce a short-list of the most suitable candidates. The two or three best sites are then investigated in more detail before a final selection is made. The investigation program should include:

- environmental inventory covering the existing land use, surface conditions, vegetation and wildlife observations;
- sampling and analysis of surface water bodies;
- investigation of the subsurface, and
- groundwater studies.

Transportation

The selection of transportation method depends upon type and volume of the waste, distance between the power plant and the disposal site, and the terrain. Available options include continuos systems such as pneumatic systems, pipelines, and conveyors, and discontinuous systems such as trucks and other types of vehicles and railway.

For short distances within the plant, continuous systems are most suitable. Pipelines are the only suitable option for handling slurries and can be used in difficult terrains, even for long distances. Pneumatic systems are used for short to medium distance transportation of dry granular materials. Conveyors are widely used for transporting large volumes of both dry material and fixed or stabilized sludges. They can be used both for long and short distances. This well-proven technology has high reliability and can be used in all types of terrain. Apart from the visual impact, the environmental impact is low. The aerial tram is a system similar to conveyors, which is used only rarely for transportation of small volumes in difficult terrains. Pipelines and pneumatic systems have the advantage of low environmental impact. Pipelines, pneumatic systems, conveyors and arial trams all have relatively high capital costs but low variable operating costs.

When the disposal site is a long distance from the power plant, transportation by truck is most common. However, the environmental impact is significant and the operating costs are high. The high volume flexibility and low capital costs make them suitable for transportation of waste from peak load plants. There are a number of other vehicle types for transportation of waste on roads where the use of trucks is restricted. Railway transportation is a feasible option when the waste can be returned to the coal mine. As the capital costs and the fixed operating costs are high, railroad is only used at very large plants for handling of large waste volumes. Finally, for very long distances, transportation by barge may be an option.

Estimated capital and O&M costs for various transportation methods are listed in table 7.4.

Table 7.4 Estimated capital and O&M costs for ash transportation methods

Method	Estimated Costs	
	Capital *(MUSD/km)*	**Annual O&M *(USD/m³/km)***
Pipelines	0.7	0.1
Pneumatic systems	2.5 - 3	0.23
Conveyors	2	0.17
Truck	5	0.1
Railway	3	0.03 - 0.1
Barge	3	0.03 - 0.1

Source: *WESA (1996).*

Cooling Water

When selecting cooling water systems for a plant (once-through systems or cooling towers), consideration should be given to the quality and quantity of available fresh water, the distance to the fresh water source and the acceptable temperature increase in recipient due to cooling water discharge. The aim should be the minimization of the environmental impact of the cooling water system and the limitation of freshwater consumption by closing the system.

Once-through cooling water systems

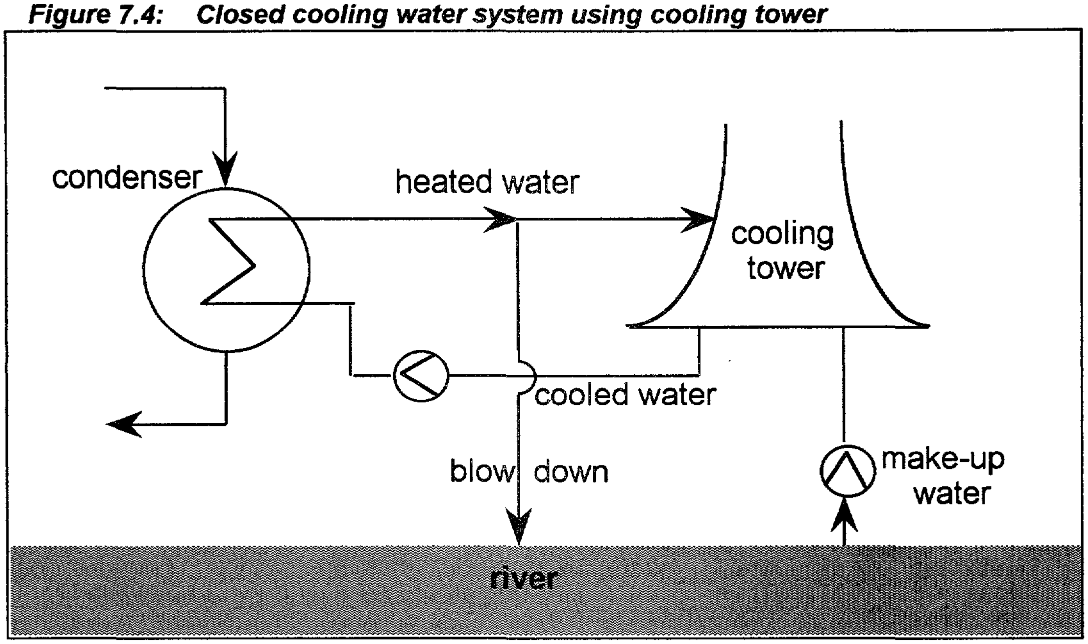
In a once-through system, cooling water is pumped from the fresh water intake through the condenser and back to the recipient. These systems are commonly used when there is enough fresh water available. The cooling water temperature effects the efficiency of the plant. Heat transfer in the condenser takes place at a temperature approximately 15°C above cooling water temperature. By careful selection of the cooling water intake and discharge points, the amount of cooling water needed and the impact of its discharge can be minimized. Discharge of cooling water results in increased water temperature of the recipient. Acceptable temperature increase is stated in the environmental guidelines and requirements in Chapter 11. To minimize the environmental impact the use of biocides and corrosion inhibitors should be avoided. Instead of using chemicals to prevent biological growth and corrosion, the use of a mechanical condenser cleaning system and corrosion resistant material should be promoted.

As shown in Figure 1.1 in Chapter 1, the freshwater consumption in a 600-MW_e plant just for condenser cooling purposes is 90,000 tons per hour in a once-through cooling water system.

Cooling towers

In a closed system using cooling towers, the heated water from the condenser is cooled by air in a cooling tower. The cooled water is recirculated to the condenser as shown in Figure 7.4. Some make-up water is needed to compensate for water losses to the cooling air. To avoid increased concentration of salts etc. there is a need for a blow down. Heat transfer in the condenser takes place at a temperature approximately 40°C above ambient air temperature. This means that when the ambient air temperature is high, the efficiency of the plant becomes low.

Figure 7.4: Closed cooling water system using cooling tower



The investment cost is higher for a closed cooling water system, but the amount of cooling water needed can be reduced to approximately 5% of the amount needed in a once-through system, making it ideal for water scarce areas.

WASTEWATER

The water consumption, wastewater production, the sources for waste water production and a flow diagram of the fundamentals of a waste water treatment plant are described below.

Water consumption and wastewater production

The total process water consumption in a coal-fired power plant and the distribution between different consumers varies significantly from one plant to another. In a typical power plant with a wet FGD system, 50% of the process water is used in the FGD system and 50% in other parts of the process. Table 7.5 shows the overall and specific water consumption and wastewater production in four different coal-fired co-generation plants (Ref. 5). The table shows an average specific water consumption between 60-230 l/MWh_e and a specific wastewater production between 20-50 l/MWh_e.

Table 7.5: Water consumption and wastewater production in coal fired co-generation plants

	Plant #1	Plant #2	Plant #3	Plant #4
Plant size *(MW_e + MW_{heat})*	744 + 99	794 + 859	907 + 1038	392 + 315
Electricity production *(GWh_e/year)*	4,280	3,510	3,820	1,520
Cooling water consumption *(m^3/year)*	570,000,000	473,000,000	685,000,000	376,000,000
Process water consumption *(m^3/year)*	260,000	800,000	800,000	180,000
Wastewater production *(m^3/year)*	74,000	160,000	120,000	30,000
Specific process water consumption *(l/MWh_e)*	60	230	210	120
Specific wastewater production *(l/MWh_e)*	20	50	30	20

***Note**: Plants 2 and 3 are equipped with FGD. Examples from Scandinavian power plants.*
***Source**: ELSAM (1995).*

Pollutant sources

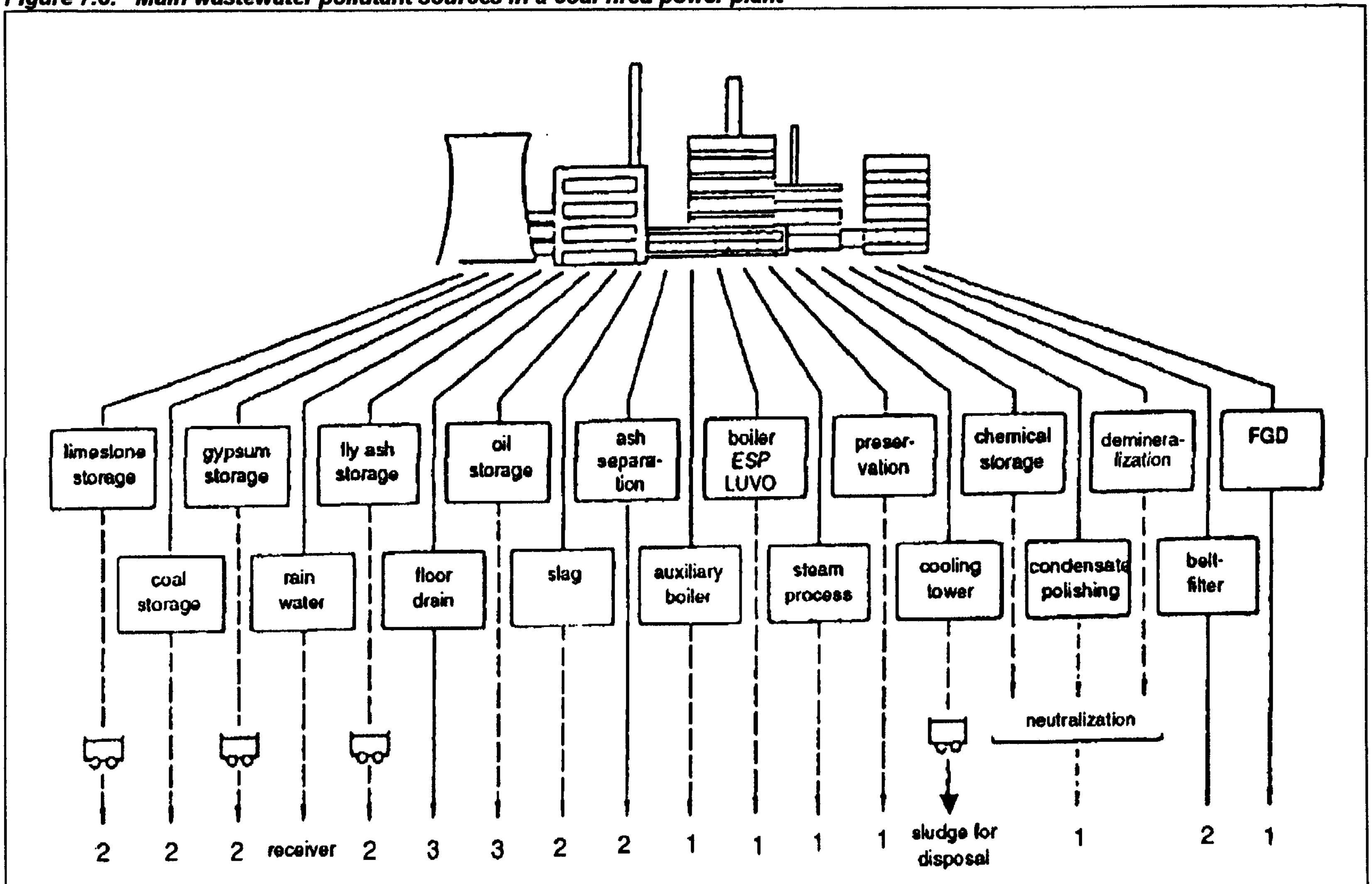
Wastewater pollutants originate from different parts of the process. The concentration of each pollutant, the wastewater flow rate and thus the mass flow of each pollutant depends on the wastewater source. Other factors affecting the waste water composition are the composition of the coal, the type of cooling water system used, the fly ash transportation system and the FGD-system. A summary of the main water pollutant sources in a coal fired power plant are shown in Figure 7.5.

Wastewater treatment

The wastewater from different sources in a coal-fired power plant have to be treated to reduce the environmental impact and meet the local standards for integrated wastewater discharges. World Bank guidelines and Indian and Chinese requirements regarding waste water quality are summarized in Chapter 11.

Wastewater treatment includes neutralization of pH by addition of acid or base, gravity settling of particles in sedimentation basins, oil separation from wastewater by the use of oil traps, flocculation and precipitation of metal ions and detoxification of process streams that, as an example, contain toxic additives for biofouling control. The produced excess sludge from the water treatment is normally transported, after thickening and dewatering, to landfill for disposal and the treated wastewater is returned to recipient.

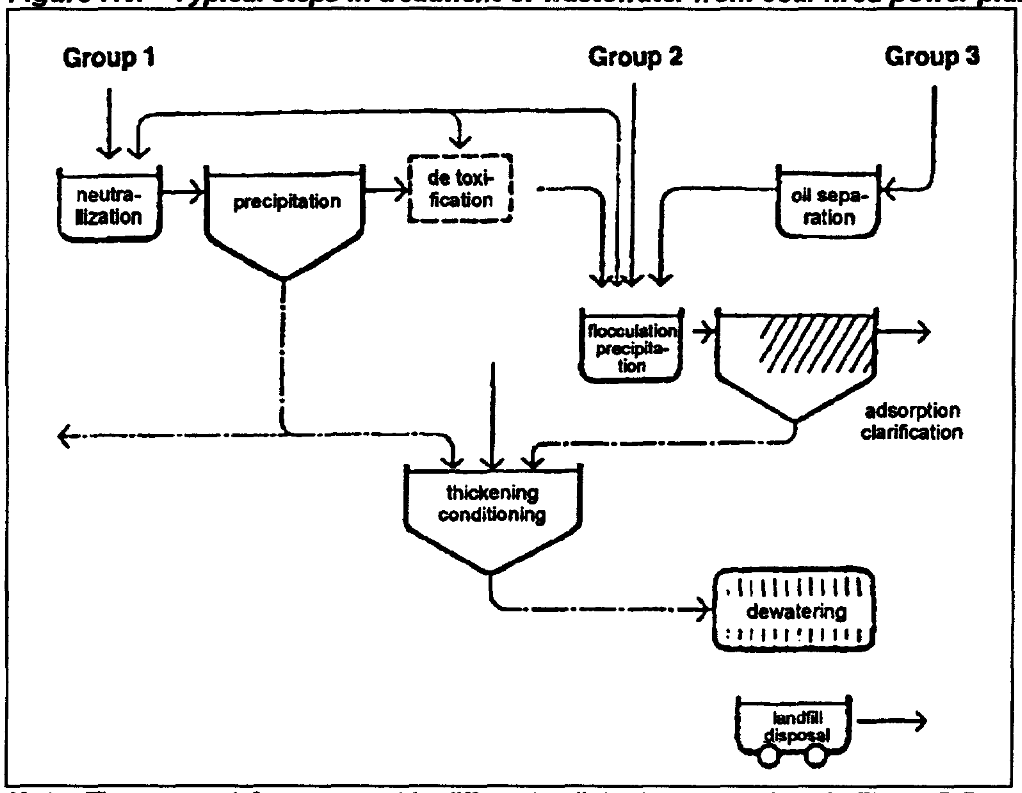
Figure 7.5: Main wastewater pollutant sources in a coal-fired power plant



Note: *The numbered streams 1-3 can be found in Figure 7.6 where different treatment steps necessary for different pollutant sources are shown.*
Source: *Steinmuller (1990).*

An example of the most common steps of treatment applied in coal fired power plants is presented in Figure 7.6. The numbered groups correspond to the numbered streams in Figure 7.5. Wastewater in Group 1 includes, for example, water from the boiler, ESP, air preheater, steam cycle, chemical storage, condensate polishing plant and FGD system. Group 2 includes wastewater from storage areas for fuel, limestone and fly ash, ash separation processes and reject water from dewatering processes. Group 3 includes water from oil storage and floor drains.

Figure 7.6: Typical steps in treatment of wastewater from coal-fired power plants



Note: *The groups 1-3 correspond to different pollutant sources given in Figure 7.5.*
Source: *Steinmuller (1990).*

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8. LOW-COST REFURBISHMENT INCLUDING O&M IMPROVEMENTS

Why refurbish an old power station? There are many different reasons for refurbishment and/or O&M improvements in an old power station:

- to reduce operation and maintenance cost,
- to increase plant efficiency,
- to increase unit availability,
- to reduce environmental impact,
- to increase unit lifetime, and
- to increase plant load.

When should an old plant be refurbished? Before investing money in refurbishment, consideration should be given to the remaining operating time of the plant. This depends on the age, condition and performance of the plant and what other alternative production plants exist. If sufficient operational life remains to justify renewed investment then consideration should be given to whether the power station currently fulfills or, after refurbishment, could fulfill the environmental requirements.

Selection of refurbishment action is governed by the reason for refurbishment. Major refurbishment measures, such as fuel switching to washed coal, boiler retrofit, installation of pollution control equipment and proper waste handling are described in Chapters 2-7. Refurbishment actions discussed in Chapter 8 and their principal effects are summarized in Table 8.1 below. Note that all actions that increase efficiency also result in reduced emissions thus adding value to the investment decision.

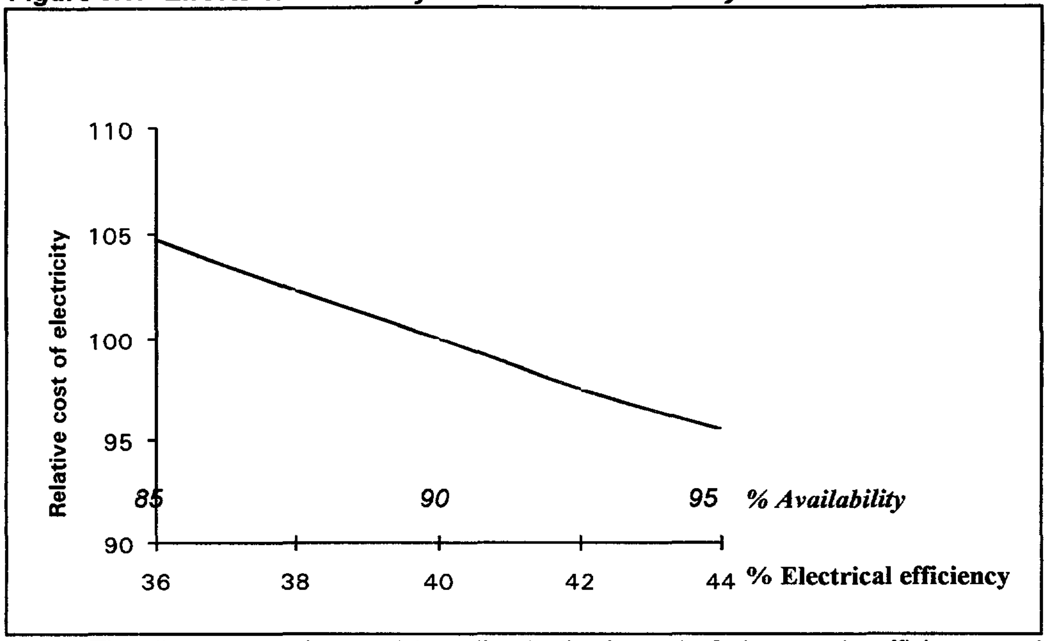
Table 8.1: Summary of low-cost refurbishment measures

Reduce operating costs	Increase efficiency	Increase availability	Reduce emissions	Increase unit lifetime	Increase plant load
• feedwater pump speed control • fan control • computerized maintenance system • steam air preheater • reduce air preheater leakage	• combustion (O_2) control • steam temperature control • reduce air preheater leakage • cleaning of convective heating surfaces • condenser cleaning system	• computerized maintenance system	• all actions that increase efficiency • excess air control	• steam temperature control • water chemistry control	• reduce air preheater leakage

Note: *Only the major effect of each action is shown.*

Table 8.1 shows measures to increase plant efficiency and availability. Such an increase in efficiency or availability has a direct impact on the electricity production costs. Figure 8.1 can be

Figure 8.1: Effects of availability and electrical efficiency on relative cost of electricity



Note: The diagram can be used to estimate the impact of changes in efficiency and availability on relative cost of electricity.

used to quickly translate changes in availability and efficiency given in this chapter into impact on electricity production cost. It shows the relative cost of electricity as a function of availability and as a function of plant efficiency. The effects of changes in efficiency are of roughly the same magnitude as changes in availability. For example, increasing plant availability from 90 to 91% reduces the production cost by about 1%, as does increasing the efficiency from 40% to about 41%.

Finally, the improvement achieved by refurbishment does not just depend on the actual refurbishment concept, but also on the existing plant and its built-in possibilities and limitations. Therefore, the performance improvements are unique for each concept. The data given in this chapter is intended to give an indication of possible improvement rates. It is, of course, necessary to make an economic evaluation for each individual concept.

INSTRUMENTATION AND CONTROL SYSTEMS

Combustion control by O_2 measurement

A reliable system for O_2 control and monitoring is important for obtaining maximum plant efficiency. With such equipment, the combustion process can be controlled properly and optimum parameters of operation can be determined. The result is more efficient combustion, which not only gives higher plant efficiency, but also controlled CO and NO_x emissions, as well as minimized content of unburned fuel in the ash.

Excess air is the most important parameter for control of the combustion process and the largest factor affecting boiler efficiency. Excess air can be expressed in percentage of theoretical need for air or as O_2 content in flue gas at economizer outlet. For an efficient combustion process the O_2 content in the flue gas must be high enough to maintain the desired steam temperature and to assure complete combustion and a minimum of losses of unburned fuel in the ash. However, there are several reasons to control and minimize the excess air. Large amounts of excess air leads to unwanted extra heat losses when the flue gas leaves the stack and higher flue gas exit temperature, both of which result in decreased boiler efficiency. Minimizing excess air also decreases the parasitic power demand for the air fans.

Another reason to control excess air is that a high amount of excess air and a resulting high firing temperature are the two most important parameters for formation of NO_x. Over the load range, the need for excess air varies. Higher amounts are necessary at lower loads. The optimum O_2 content in flue gases depends on the coal and the combustion system. For a given coal and boiler the optimum curve of O_2 content in the flue gases versus boiler load can be defined. In order to maintain operation close to the optimum O_2 curve, a reliable control system, including O_2 measurement instruments, is necessary. Normal values of O_2 content in flue gases when firing coal are 4.3 % by volume dry gas at full load and 5% by volume dry gas at half load.

Steam temperature control to increase plant lifetime and efficiency

By controlling steam temperatures in a plant, the lifetime and the efficiency of the plant are increased. The use of boiler and turbine in an optimal manner means that the live and reheat steam temperatures should be close to the actual maximum allowed values. For a plant in good condition, that corresponds to the nominal contract values. If the plant is in bad condition, relevant reduced steam temperatures should be determined and used as modified set values. The main reason for a reduction in the steam temperature levels is poor condition material in the superheater surfaces and in the turbine. Instead of reducing steam temperatures, a check should be made as to whether a more optimal solution would be to replace a superheater surface section, reconstruct the turbine etc. and operate with normal temperatures.

If the steam temperature control system is out of order or performing badly this could result in consciously reduced set values for the steam temperatures. Such reduction in set values creates safety margins during static operation, and thus prevents exceeding the critical temperature levels for the plant during load variations and when fuels with non-homogenous heat values are fired.

Every lost degree Centigrade in steam temperature corresponds to a reduction of 0.02% in electrical efficiency. The corresponding impact on the relative electricity production cost can be estimated by the use of Figure 8.1.

Pump and fan control to reduce operating costs

Auxiliary power consumption amounts to 7-12% of the electric output in a normal coal-fired power plant. Pumps and fans represent a major part of this consumption. Worn equipment, poor maintenance and outdated equipment can result in high auxiliary power consumption figures. New technologies and equipment provide for improvements in reduced auxiliary power consumption and hence reduced operating costs. The potential for the reduction of auxiliary power consumption by fans and pumps depends on:

- the status of the plant (simple existing equipment and bad maintenance indicate a high potential for improvement);
- the load profile of the plant (the potential is better in plants with a significant operating time on part load); improvements mostly affect part-load characteristics, with reduced auxiliary power consumption at part load; and
- the configuration of the fans/pumps (1 x 100%, 2 x 50%, etc.); when fans and pumps are installed in parallel (2 x 50%), the potential for improvement is lower.

The profitability has to be analyzed for each individual plant. Capital costs have to be balanced against reductions in operating costs. A summary of possibilities for fans and pumps is given below.

Fans

Normally there are flue gas fans and primary and secondary air fans in a plant. Air and flue gas fans use between 25-35% of the total auxiliary power consumed in a plant. Where possible, modern plants are equipped with axial fans. Radial fans are only used when high pressure drops have to be overcome, such as within primary air fans. However, in older plants radial fans are still common.

If plants are already equipped with axial air and flue gas fans using adjustable control vanes then the potential for improvement is low. Theoretically, variable speed control can be introduced, but this change is not common. If the plant is equipped with radial fans then the potential for improvement is higher. Depending on conditions at the actual plant, the following can be done to improve part load characteristics:

- improve existing guide vane control;
- change from guide vane control to variable speed control; and
- change fan - install axial fan.

Boiler-feed water pump

Feedwater pumps use 40-50% of the total auxiliary power consumed in a plant, depending on feedwater pressure. There is potential for reducing the maintenance costs and auxiliary power consumption at part load by changing the control method. Feedwater pump controls exist at *constant speed* where excess head is reduced by throttling in a control valve, and at *variable speed* where pump speed governs flow and head.

The type of feedwater pump drive used effects the O&M costs of the pump system. Compared with a constant speed drive, a variable speed drive has lower operating costs, especially at part load. The savings in operating costs depend on the cost of auxiliary power and the operating time on part load. Variable speed drive also has lower maintenance costs. High pressure drop control valves necessary in constant speed systems are frequently high maintenance components.

In new installations, the investment is higher for variable speed drive than for constant speed drive.

BOILER SYSTEMS

Reduction of air preheater leakage

Plants with an electric output above 50 MW are often designed with recuperative air preheaters of the rotating type, such as the Ljungstrom. In such air preheaters there is an inevitable leakage from the combustion air side to the flue gas side. This air leakage must be kept carefully under control since the leakage air has the following effects:

- increased power consumption in the combustion air and flue gas fans;
- load reduction due to mechanical or electrical overload of the fan systems, in particular when the preheater is in a poor condition; and
- extra cooling when mixed into the flue gases which can result either in low temperature corrosion, or in increased "true" flue gas temperature at preheater outlet, i.e. lowered boiler efficiency.

Keeping the leakage under control requires the sealing system to be included in the maintenance routine for regular control and adjustments. Information on the air leakage value is given by the O_2 content in the flue gas at the preheater outlet *and* inlet. Differences of around 1.5-percentage units O_2 (dry gas) corresponds to an air leakage of 10%. Correspondingly, a 3-percentage units O_2 difference corresponds to an air leakage of 20%, which gives a poor economy of operation. Seal adjustments should be made to keep the leakage value around 10% at full load.

Steam air preheater to reduce maintenance costs

To protect an air preheater of the recuperative type, like the Ljungstrom, its inlet air should be heated. Heating is done to increase the material temperatures on the "cold side" of the Ljungstrom air preheater. This way corrosion from low temperature operation and thereby high maintenance costs can be avoided. The most critical situations for low temperature corrosion are the start up and low load operation periods. Preheating is achieved by installing a steam air preheater upstream from the Ljungstrom air preheater. Temperatures on the "cold side" of the Ljungstrom preheater, above the acid dew point, will be reached with a steam air preheater.

Using a steam air preheater affects the design of the Ljungstrom preheater. A somewhat larger surface is needed to achieve the same flue gas outlet temperature since the air inlet temperature is slightly higher. Steam needed in the steam air preheater is often available from external sources, such as other boilers in the plant during a start up. If this is not the case a service boiler is needed. During normal operation steam is bled off from the process.

Cleaning of convective heating surfaces to increase efficiency

It is necessary to keep convective heating surfaces in the boiler clean in order to achieve steam temperature set values. In the boiler back pass, economizer and air preheater sections, deposition of coal ash will result in increased flue gas outlet temperature. Coal ash deposited on the surfaces can be removed by soot blowers. The amount of ash and its characteristics determines the number of soot blowers and the frequency of use needed to maintain effective heat transfer. The cleaning medium is usually normal steam, bled off from a superheater section which can achieve suitable steam data over the load range.

It is important to keep the soot blowing system in good condition and use it in accordance with operating manuals. If any of the soot blowers are out of order, a buildup of ash might result in surface damages. Super heater cleaning is important to achieve steam temperature set values. Every lost degree Centigrade in steam temperature corresponds to a reduction in plant efficiency of roughly 0.02 percentage units. Ash deposition in the economizer and air preheater section causes increased outlet flue gas temperatures. An increase of 20°C corresponds to a change in boiler efficiency from 90% to about 89%, or plant efficiency from 30% to 29.7%.

COOLING WATER SYSTEMS

Condenser cleaning system to increase efficiency

Depending on cooling water source; the cooling water system (once-through or closed circuit); the season; water level in rivers; and type, mesh size and performance of pre-screening, the cooling water will carry various quantities and kinds of floating and suspended substances, which may cause failures in heat exchangers and condensers. Fouling, scaling and clogging in tubes and tube sheets are typical examples of such failures.

Effects of microfouling and scaling on cooling surfaces include:

- reduced heat transfer coefficient;
- reduced turbine generator output;
- increase in heat consumption, and
- tube corrosion.

Effects of macrofouling in the cooling water circuit if caused by tube sheet and tube clogging include:

- reduction of cooling surfaces available and thus lower output;
- erosion corrosion due to destroyed protective film around a wedged particle in the tube, by turbulence and increased water velocity;
- increased corrosion by anaerobic decay of organic substances in clogged tubes yielding of sulfides and ammonia; and
- increased pressure drop in the condenser.

The installation of a tube cleaning system with recirculating cleaning balls is an effective way to minimize these problems. In the case of sea water cooling or cooling water with coarse debris, some kind of debris filter should also be installed upstream from the condenser and/or the heat exchangers. The goal should be to achieve the design value of the condenser pressure at a given cooling water temperature.

A loss in electric efficiency of about 0.35-2.4%, at a cooling water temperature level of 18°C, may occur due to fouling in the condenser and the resulting increase in back-pressure. The sensitivity of turbine efficiency to fouling impact varies between turbine types and therefore a general relationship cannot be given.

AUXILIARY SYSTEMS

Water chemistry control to increase plant lifetime

In order to extend the lifetime of boiler and turbine components, a proper water chemistry regime must be sustained. Guidelines from different countries and organizations are available. Widely used guidelines are the "Interim Consensus Guidelines for Fossil Plant Cycle Chemistry" from EPRI (USA) and "VGB-Richtlinie für Kesselspeisewasser..." VGB-R 450 L (Germany). The need for surveillance is related to the steam pressure and to boiler construction. Generally, the higher the pressure, the greater the concern about water chemistry. Water Chemistry Control can be divided into hardware (i.e. analyzers, instrumentation, computers etc.) and instructions.

Hardware
As the guidelines indicate, many of the parameters should be continuously monitored to ensure a good water quality. Commonly, the analyzers are connected to the main computer in the control room but the chemical analysis system can also run on a PC as a stand-alone chemistry system. Alarms, transient trends, etc. can be tracked easily with this arrangement. This will also simplify trouble-shooting and enhance the ability to see long-term changes in the cycle chemistry.

Instructions
As for all power plant operation tasks, water chemistry has to be organized in a well-defined fashion to maintain the overall goals. This includes well educated and motivated personnel. To achieve this goal the power company management has to set up a strategy. In this strategy instructions for chemistry control have to be formalized. The instructions have to be developed and anchored in consensus with the operators that will be responsible for the water chemistry. The implementation of the instructions includes formal training, so a profound understanding of cycle chemistry must be obtained. Great concern should be taken to establish good contact between chemical staff and the O&M personnel.

OPERATION AND MAINTENANCE

Computerized maintenance management system to increase availability

A computerized maintenance management system may be a useful tool to increase the availability of a power plant and to minimize cost. The maintenance management system should comprise:

- a planning system where all maintenance activities of the plant will be planned;
- a work order system which will be used for preparation, planning and time scheduling for each individual maintenance work;
- a preventive maintenance system which includes programs for regular inspection, testing, lubrication and inspection; and
- a spare parts storing system containing documentation of available spare parts.

The preventive maintenance should be based on real knowledge of every major object. This implies that important apparatus and components in the plant should be equipped with measuring points for continuous control.

9. TECHNOLOGY SELECTION MODEL

The selection of technology for a coal-fired power plant is a complex task. It involves the evaluation and optimization of a large number of technical, environmental and economic considerations. This chapter presents a model which can be used to help select environmentally friendly technologies for coal-fired power plants. It is simply called the *Fast Track Model.*

FAST TRACK MODEL

The Fast Track Model is built up by four logical steps. Each step has a clearly defined scope and result. An overview of the model is given in Figure 9.1 showing the results of each step. This step design provides a tool which will enable the user to handle the large amounts of information that have to be considered in power plant projects.

Step 1 handles project definition. To facilitate the forthcoming studies, a rough screening is done in Step 2 resulting in a description of applicable technologies within different technology areas. In Step 3, a number of power plant concepts are stated, corresponding to different environmental requirements; ranging from very stringent to less stringent. These concepts are then evaluated against the prerequisites given in Step 1. The result will be a list of possible useful power plant concepts. In Step 4, the cost calculations can be made for the possible power plant concepts. This will determine the possible investment cost, the electricity production cost and the cost of reducing emissions. Finally, on the basis of the cost calculations, a recommendation can be made as to which alternatives should be subjected to a more detailed feasibility study.

Figure 9.1: Steps and results in the Fast Track Model

Step 1 **Project definition**	**Step 2** **Technology screening**	**Step 3** **Possible alternatives**	**Step 4** **Cost calculation and recommendation**
Type of project. Prerequisites: • general, • economic, • environmental, • operational.	Technologies (combustion, SO_2, NO_X, & particulate emissions) that meet requirements regarding: • maturity of technology, • unit size, • waste product.	Technical and environmental evaluation of 3-5 power plant concepts. Evaluation against prerequisites.	Power plant concepts presented with: • investment cost, • electricity production cost, • cost/ton emission removed, • emissions of SO_X, NO_X and particulates, • utilization of by-products/ waste production.
Result: Project definition statement.	**Result:** Applicable technologies.	**Result:** Possible power plant concepts.	**Result:** Recommended alternatives for a feasibility study.

The purpose of the Fast Track Model is to enable the user to make a recommendation on the most suitable technology combination for a power plant, taking into account aspects such as environmental impact and costs. A planner gets answers to the following questions:

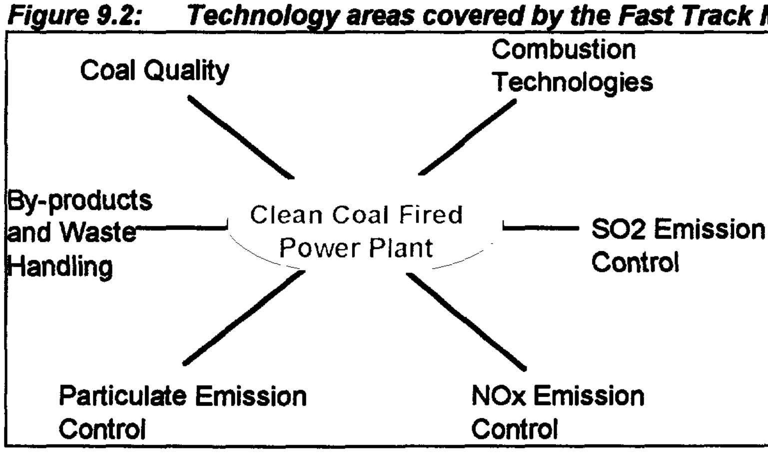
- possible power plant concepts?
- investment cost?
- electricity production cost?
- flue gas cleaning cost?
- cost/ton SO_x removed?
- cost/ton NO_x removed?

The Fast Track Model is meant to be used early in the project during the prefeasibility phase, when the first technology selections are made. During the prefeasibility phase, alternative power plant concepts are studied to find the most suitable concept for each specific project. In the feasibility phase, concepts that proved successful in the prefeasibility study are examined in more detail.

The Fast Track Model only deals with the technology selection part of the prefeasibility study based on technical, environmental and some economic requirements. However, there are a lot of other activities that have to be begun during the prefeasibility phase, besides selection of technology. These include, for example, power delivery and fuel supply agreements, governmental support, environmental requirements, financing and purchasing policy. Some of these also have an effect on technology selection.

Technology areas covered by the Fast Track Model are coal quality; combustion technologies; emission control technologies for SO_2, NO_x and particulates; and by-products and waste handling, as illustrated in Figure 9.2 below. Technical, environmental and economic data regarding these areas is given in Chapters 2-7. The World Bank guidelines and guidance on environmental requirements in India and China are found in Chapter 11.

Figure 9.2: Technology areas covered by the Fast Track Model



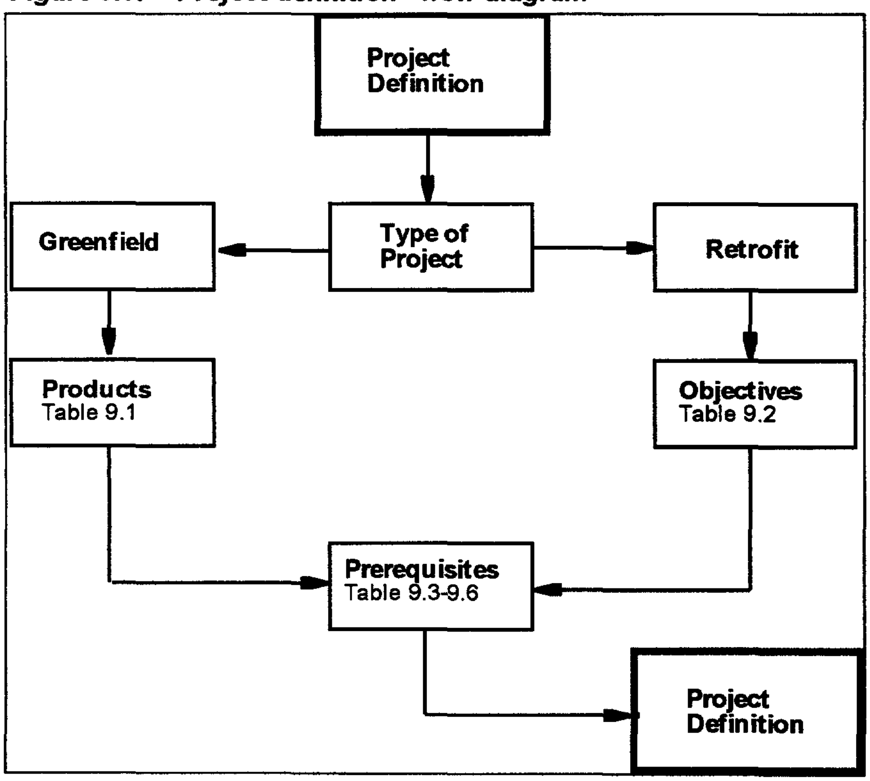
STEP 1. PROJECT DEFINITION

The aim of Step 1 is to document non-changeable project data. Use of the project definition data by all members of the project group is vital. It ensures that everyone in the project group uses the same input data and works towards the same goal. A well-defined project forms the basis for all related work and provides the foundation for progress. Project definition data that need to be settled are:

- type of project whether a greenfield power plant or retrofit of an existing power plant,
- type and amount of products produced at the plant,
- objectives of a retrofit, and
- prerequisites.

The work procedure for project definition is illustrated below in figure 9.3.

Figure 9.3: Project definition - flow diagram



The project definition starts by answering simple questions. Is it a greenfield plant or a retrofit? What are the main objectives and needs? For a greenfield power plant, you have to define what type of products are going to be produced, as shown in Table 9.1. For a retrofit project you have to define the objectives with the retrofit, as shown in Table 9.2.

Table 9.1: Products produced at the power plant

• electricity;
• steam;
• oxygen, nitrogen etc. generated, for example, in an IGCC plant;
• district heating;
• others.

Table 9.2: Objectives for the retrofit

• reduce operating and maintenance costs;
• increase plant efficiency;
• increase availability;
• reduce environmental impact, such as waste, emissions of SO_x, NO_x and particulates;
• increase unit lifetime;
• increase electricity production;
• other products, see table 9.1.

After defining the type of project, the prerequisites listed in Tables 9.3-9.6 should be considered to make the frames and objectives of the project more clear. Some of these prerequisites will then be used to evaluate different plant concepts technically, environmentally and economically. The prerequisites are divided into four categories: general, economic, environmental and operational.

Table 9.3: General prerequisites

• type of project
– commercial or development.
• power plant
– size,
– number of units,
– site,
– location,
– available space.
• coal
– domestic/ imported/ both domestic and imported,
– distance from domestic mine to power plant,
– coal type,
– value & range of main characteristics
* ash content,
* sulfur content,
* heating value.
• date of commissioning

Table 9.4: Economic prerequisites

- project economy
  - rate of return,
  - economic lifetime.
- financing policy
  - project financing,
  - equity,
  - World Bank loans.
- purchasing policy
  - turn key,
  - split procurement.
- demands on local manufacturing

Table 9.5 Environmental prerequisites

- SO_x
  - National/ local requirements,
  - World Bank requirements.
- NO_x
  - National/ local requirements,
  - World Bank requirements.
- particulates
  - National/ local requirements,
  - World Bank requirements.
- waste water
  - National/ local requirements,
  - World Bank requirements.
- other environmental policy
  - SO_x,
  - NO_x,
  - particulates,
  - waste water.
- requirements on solid by products/waste
  - utilization,
  - utilization after processing,
  - disposal.

Table 9.6: Operational prerequisites

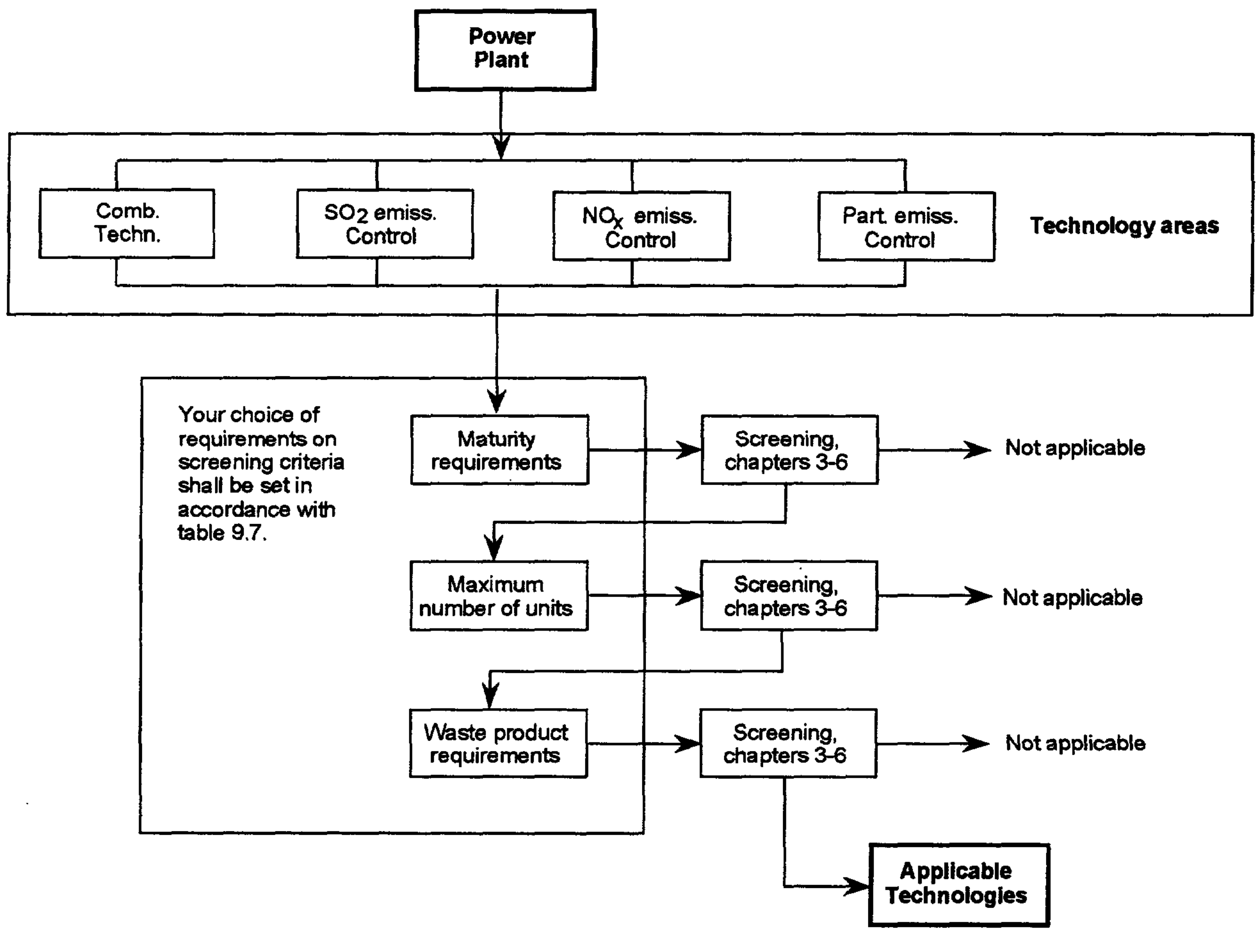
- operation time,
- base load or peak load,
- availability factor,
- efficiency,
- load change rate
- minimum load.

STEP 2. TECHNOLOGY SCREENING

The technology screening procedure is illustrated by a flow chart in Figure 9.4. Screening is done to quickly find which technologies do or do not meet overall requirements. Those that do not can be quickly eliminated. The applicable technologies which meet the overall project requirements will be used in Step 3, when the alternative power plant concepts are stated.

The screening should be carried out for four of the technology areas: combustion technologies, SO_2-emission control technologies, NO_x-emission control technologies and particulate emission control technologies. Screening is carried out against three criteria: required maturity of technology, maximum number of units accepted and by-product/waste-related requirements.

Figure 9.4: Technology screening



The screening criteria can be used for all projects, but the requirements on the criteria are project specific. Requirements are chosen from the ones given in Table 9.7. The required maturity of technology is set by the type of project. When the project is commercial and the requirements on availability are high, the requirements on maturity of technology can be high. In a development project, the requirements on maturity of technology can be lower. Other factors than just type of project affect the requirements on maturity of technology, such as financing policy.

Plant size and maximum number of units required were also determined in Step 1 and will be used when screening each technology area against number of units required. The final screening criterion is the requirement on solid by-product/waste. Technologies that do not meet the requirements on these criteria can be eliminated. Technologies that meet the requirements are applicable technologies and can be used in the next phase.

Different combustion and flue gas cleaning technologies produce different types of solid by-products/waste. Screening should be made against the requirements on the waste product defined in Step 1. Should it be possible to use the by-product, for example in the building industry, or should it just be disposed of?

Table 9.7: Screening criteria and choice of requirements

Screening criteria for each technology area	Choice of requirements	Choice of requirements	Choice of requirements
Maturity of technology	> 10 commercial reference plants in India/ China	< 10 commercial reference plants in India/ China and > 10 commercial reference plants worldwide	< 10 commercial reference plants worldwide
Required number of units	total plant size is 1- 2 units	total plant size is 3- 4 units	total plant size is >4 units
Waste product	possible to use without processing	possible to use after processing	disposal

The screening criteria can be applied for each technology and compared with the data and information given in the screening criteria tables from Chapters 3-6:

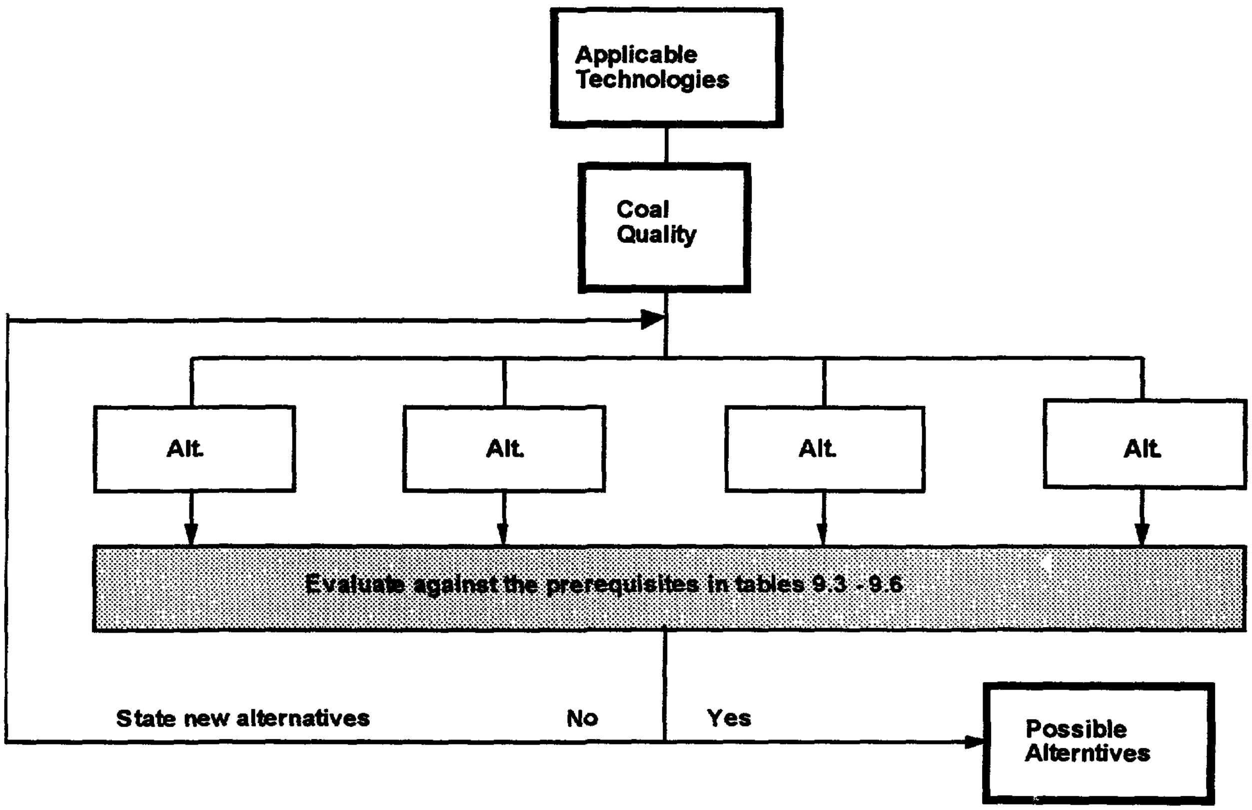
- Table 3.4 Subcritical PC
- Table 3.5 Supercritical PC
- Table 3.9 ACFB
- Table 3.12 PFBC
- Table 3.14 IGCC
- Table 4.1 Sorbent injection
- Table 4.3 Spray dry scrubbers
- Table 4.5 Wet FGD
- Table 5.4 Low-NO_x combustion technologies
- Table 5.5 SNCR
- Table 5.6 SCR
- Table 6.1 ESP
- Table 6.2 Baghouse filters

The screening results in Step 2 gives the applicable technologies which meet the overall requirements of the project, in terms of required maturity of technology, number of units accepted and the requirements for the by-product/waste. These technologies will be used for stating possible power plant concepts in Step 3.

STEP 3. POSSIBLE ALTERNATIVES

Now applicable technologies from Step 2 can be used to find possible power plant concepts. The alternatives represent technical solutions for the whole power plant. Figure 9.5 shows the different parts of Step 3.

Figure 9.5: Logical sequence in developing project specific power plant alternatives



Coal quality

As shown in Figure 9.5, the first question to deal with is which quality of coal should be purchased since coal quality has a major effect on the economics of power plant operation, as discussed in Chapter 2. The available coal qualities were defined in the general prerequisites (Table 9.3) and now it is time to ask: Which is the best coal to use considering both environmental and economic impacts? If it is a high ash, non-washed coal, it is important to find out whether it would be better to purchase coal with a lower ash content.

Use the section on *Costs* in Chapter 2 as a first point of reference to help to find out the impact coal quality has on the costs of electricity production. Consider the environmental issues: reduced transportation, minimized handling of residues, O&M impacts, etc. Information on how much it is worth paying for a coal with a lower ash content is given for some specific plants in Chapter 2. Locate available coals, their quality and price to find the coal which is the most economical for each project.

Stating the possible alternatives

After deciding which coal quality should be purchased, a number of alternatives regarding the power plant configuration can be stated.

- Use the result from the technology screening (Step 2) to eliminate unsuitable technologies.
- Use information in chapters 3-7, especially the paragraphs "Suitability" and "Fuel flexibility" to find which technologies are suitable for your choice of coal quality.
- State a number of alternatives that represent technical solutions for the whole power plant.
- Use cost data, performance diagrams and other technical information from Chapters 3-7 to find the technologies that are most likely to be successful for your project. Alternatives should always include at least one configuration which complies with each of the following:
  - national or local requirements (Chapter 11),
  - World Bank environmental guidelines (Chapter 11), and
  - more stringent environmental requirements.

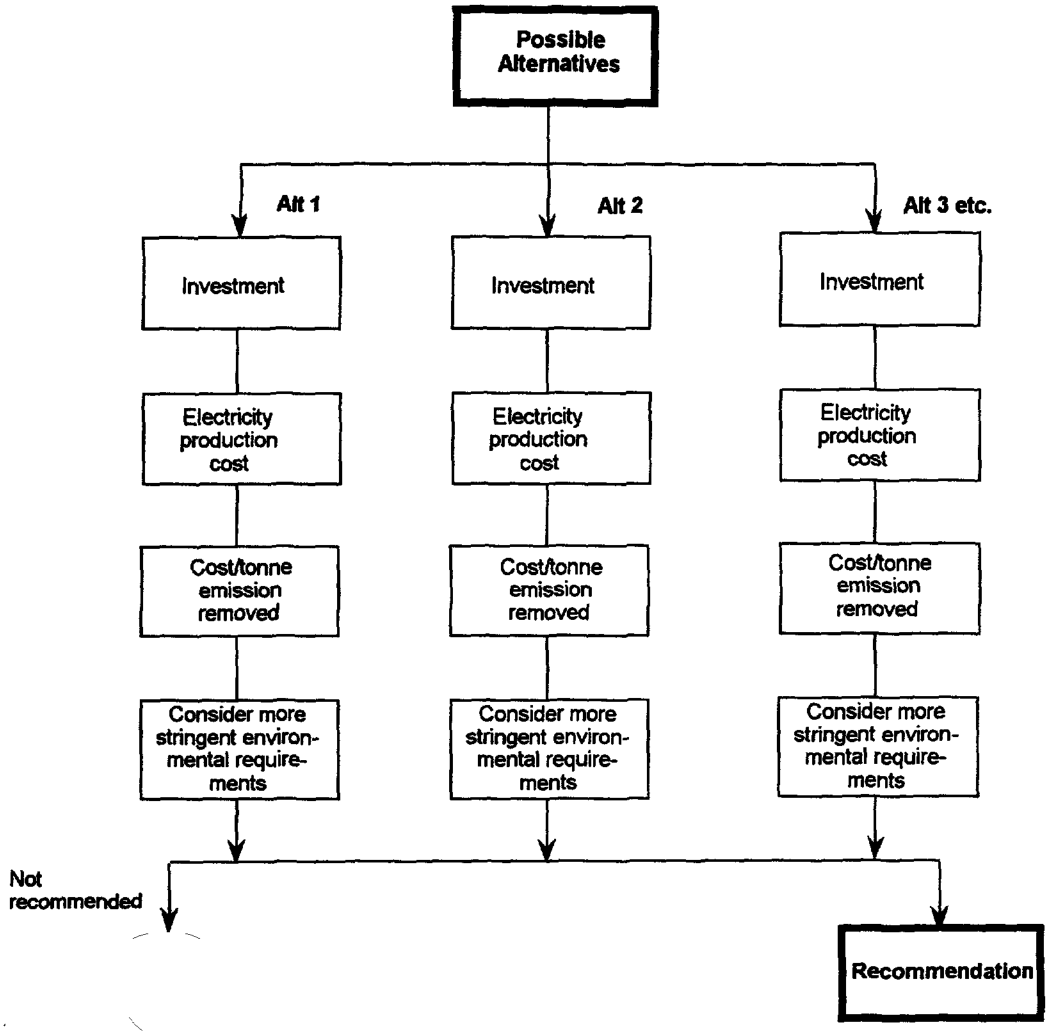
Evaluation of alternatives

Now the alternatives need to be evaluated. The results of the technical evaluation are alternatives that correspond with the prerequisites. Start by gathering facts, contact suppliers for current data regarding investment costs. Then check that the alternatives comply with the prerequisites in Table 9.3-9.6: general, environmental, operational and some economic prerequisites. Most of the economic evaluation is done in the final Step 4. Step 3 results in possible power plant alternatives that meet the main prerequisites. If there is no alternative which complies with the prerequisites, then state new alternatives, and loosen the requirements of the prerequisites. If the latter is necessary, the Fast Track Model steps must be reapplied from the beginning.

STEP 4. COST CALCULATION AND RECOMMENDATION

The aim of Step 4 is to make an economic evaluation of the alternatives that comply with the main prerequisites. In an economic evaluation, two parameters are usually important: investment (USD millions) and electricity production cost (USD/MWh_e). When evaluating different emission reduction technologies, a third parameter is equally important. This is the cost/ton emission removed: for example USD/ton sulfur removed and USD/ton NO_x removed. An overview of the cost calculation recommendation step is given in Figure 9.6.

Figure 9.6: Cost calculation recommendation - flow diagram



Investment

Data for estimating the investment for different alternatives is found in Chapters 2 to 6. The investment cost is a very important factor in the decision as to whether a project will be carried through. After filling in Table 9.8, the total investment for each alternative can be calculated.

Table 9.8: Sample table used for investment cost calculation

Technology area	Investment *(MUSD)*				
	Alt. 1	Alt. 2	Alt.3	Alt.4	Alt.5
Combustion technology *					
SO_x emission reduction					
NO_x emission reduction					
Particulate emission reduction					
Total investment					

** Costs for a complete power plant except flue gas cleaning equipment.*

Electricity production cost

The electricity production cost (USD/MWh_e) is the price of electricity that is needed to achieve the required profit and is the sum of capital costs + variable operating costs + fixed operating costs + fuel costs. The electricity production cost also depends on economic assumptions that have to be stated for each project. Economic assumptions include rate of return, estimated inflation and economic lifetime. The production cost is just as important as the investment when deciding which process alternative to choose. The lower the production cost the better. Low variable costs are important when the plant has been built, since a plant with low variable costs can have a longer yearly operating time than one with high variable costs. Country specific taxes can also have a great impact on the electricity production cost but are not considered in this report.

Operation and maintenance costs

Table 9.9 can be used to calculate the total O&M cost for the alternatives. O&M cost data for the different technologies is found in Chapters 3 to 7.

Table 9.9: Sample table used to calculate total O&M costs

Technology area	fixed *(MUSD/yr)* and variable *(USc/kWh)* O&M cost				
	Alt. 1	Alt. 2	Alt.3	Alt.4	Alt.5
Combustion technology*					
SO_x emission reduction					
NO_x emission reduction					
Particulate emission reduction					
Waste handling					
Total O&M: fixed variable					

** Costs for a complete power plant except flue gas cleaning equipment.*

Table 9.10 lists data required for the calculation of electricity production cost. Typical economic data used for the calculation of production costs can be found in the case studies in Chapter 10.

The availability factor for the combustion technology chosen (Chapter 3) can be used as the availability factor for the whole plant. Efficiency data for whole power plants can be found in Chapter 3 under each combustion technology.

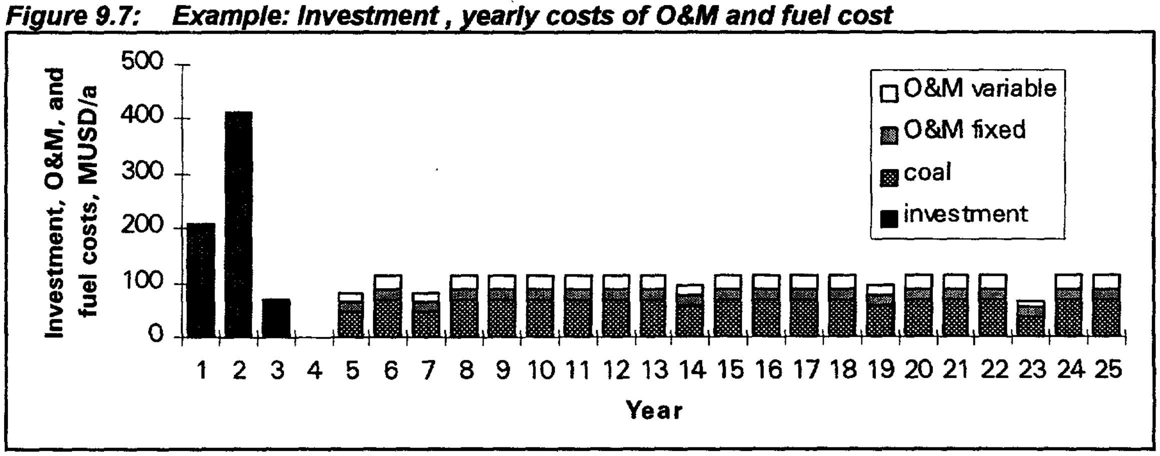
Table 9.10: Sample table used to calculate electricity production cost

Data needed to calculate the electricity production cost						
		Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**	**Alt. 5**
Construction period	*months*					
Operating time	*hours/ year*					
Availability factor*	%					
Coal price	*USD/ MWh*					
Electricity production	*MWe*					
Plant net efficiency*	%					
Investment	*MUSD*					
O&M costs						
fixed	*USD/ kWe*					
variable	*USD/ MWhe*					
Rate of return	%					
Economic lifetime	*years*					

* *Use data from Chapter 3 for whole plant.*

Calculate the yearly costs for fixed O&M, variable O&M and coal, and the investment. An example of the cost calculation is shown in Figure 9.7 below. In Figure 9.7, the calculation has been done in real terms, without inflation.

Figure 9.7: Example: Investment, yearly costs of O&M and fuel cost

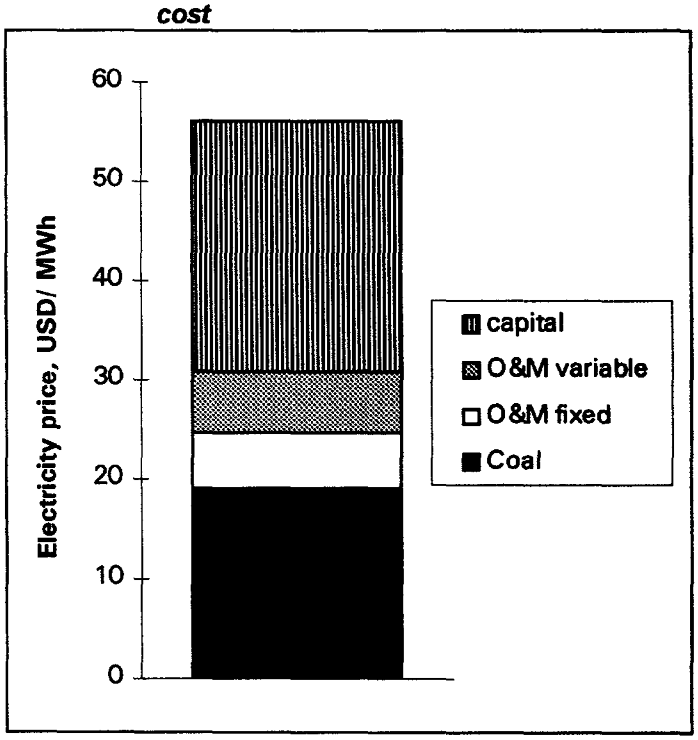


Next, estimate the average yearly electricity production volume considering annual operation time and the availability factor. Use the required rate of return and the economic lifetime defined in the project definition phase to:

A. calculate the sum of the net present values of the investment, O&M costs, and fuel costs in USD:
B. calculate the sum of the net present values of the amount of electricity produced during the economic lifetime of the plant in MWh; and
C. obtain required levelized electricity price by dividing **A** by **B**.

To find out how big portion of the electricity production cost that derives from fixed O&M, variable O&M, fuel and capital costs, respectively: calculate the sum of the net present value of each individual item (fixed O&M, variable O&M, fuel and capital cost) in USD. Divide each sum by B above. An example of how the total electricity production cost can be divided into these four types of costs is shown in Figure 9.8 below.

Figure 9.8 Example: Contribution from fuel, O&M and capital cost to the total production cost



Cost per ton emission removed

To compare the cost-effectiveness of different emission reduction technologies, calculate the cost for each emission reduction technology/ton emission removed. For example, the cost of sulfur removal equipment/ton sulfur removed is derived by:

A. calculating the sum of the net present values of the investment in SO_x removal equipment and O&M costs related to SO_x removal in USD;

B. calculating the sum of the net present values of the yearly removed amounts of SO_x from the plant in tons; and

C. divide **A** by **B** to get the cost/ton sulfur removed.

Recommendation

The Fast Track Model produces a range of alternatives, each presented with information on investment (USD millions); electricity production cost (UScents/kWh_e); flue gas cleaning cost (USD/ton SO_x and NO_x removed); emissions of SO_x, NO_x, and particulates, and by-products and waste. The two alternatives that are best from an economic and environmental standpoint should be recommended for further examination in a feasibility study.

Although the current state of the law in India and China does not require the installation of flue gas cleaning equipment or the utilization of by-products, the emergence of environmental problems is changing the opinion of the authorities regarding these questions. More stringent environmental requirements can be expected to be imposed in the near future. When selecting technologies, it is essential to plan to meet increasingly strict pollution control legislation. It has to be possible to add pollution control equipment to a plant, and to have strategies available for the utilization of by-product. For example, space should always be set aside for the installation of additional equipment, such as wet FGD and SCR.

10. CASE STUDIES USING FAST TRACK MODEL

This chapter presents two case studies: a *greenfield plant* and a *boiler retrofit*, where the Fast Track Model for technology selection is applied. Both cases focus on how the most suitable technologies are selected for the individual plant, depending on factors such as unit size, maturity of technology, requirements on waste product, annual operating hours, emissions, costs etc.

GREENFIELD PLANT

Step 1. Project definition

The project presented below was initiated as a result of an increased demand for power and because new clean coal-fired power plants have become necessary. To meet up with the demand for power, a new plant with an electric output of 600-700 MW_e will be built. The questions regarding which technologies to choose for this new plant are solved using the Fast Track Model.

This is a greenfield coal fired plant located in China that will produce electricity only. The plant will have a base load function and use domestic anthracite as fuel. It is a commercial project meaning that only mature technologies will be used and the demands on availability are high. Although the environmental requirements applicable for this project are not very stringent, solutions with low emissions should be achieved to minimize the environmental impact of such a large new power plant. Tables 10.1-10.3 summarize the prerequisites that are valid for this project.

Table 10.1: General prerequisites

Type of project:	commercial
Plant	
• size:	600 MW_e
• number of units:	1-2
Coal	
• type:	domestic anthracite
• distance from domestic mine to power plant:	approximately 1,200 km
• value & range of main characteristics	
– ash content:	19-20%
– sulfur content:	1%
– heating value:	22.9- 24.4 MJ/ kg
Date of commissioning:	January 1, 2000

Table 10.2: Economic prerequisites

Project economy • rate of return: • economic lifetime:	 7% 20 years
Financing policy :	project financed
Purchasing policy:	turn-key
Requirements on domestic manufacturing:	as much as possible should manufactured domestically

Table 10.3: Environmental prerequisites

SO_2:	2,500 mg SO_2/MJ_{fuel} stack height 240 m
NO_X:	no requirements
Particulate:	280 mg/Nm^3 stack height 240 m
Other environmental policy:	strive for low emissions
Solid by-products/waste:	solid waste will be disposed

Table 10.4: Operational prerequisites

Operation time:	6,000 hr/year
Availability factor:	80% including overhaul
Load change rate:	5% per minute
Minimum load:	50%

Step 2. Technology screening

Technology screening is done using the criteria requirements found in Table 9.7 in Chapter 9. Screening is done to find applicable combustion technologies, SO_2, NO_x, and particulate emission reduction technologies. Since this is a commercial project the requirements on maturity of technology are high. The size of the plant shall be such that the total plant size can be accommodated in one or two units. The waste products will be disposed.

Table 10.5: Screening criteria for a greenfield coal fired power plant in China

Technology area	Maturity of technology	Required number of units	Waste product
Combustion	>10 commercial reference plants in China	total plant size in 1-2 units	disposal
SO_2 emission control	<10 commercial reference plants in China & >10 reference plants worldwide	-	disposal
NO_X emission control	<10 commercial reference plants in China & >10 commercial reference plants worldwide	-	-
Particulate emission control	>10 commercial reference plants in China	-	-

Applicable technologies

The screening to find applicable technologies is done by comparing the requirements defined in Table 10.5 above with information in Chapters 3 to 6. This results in applicable technologies for this project according to Table 10.6. Note that sorbent injection, spray dry scrubbers and SNCR have mostly been used on smaller scale plants.

Table 10.6: Applicable technologies for a 600-MW greenfield power plant in China

Applicable combustion technologies	Applicable SO_2 emission control technologies	Applicable NO_x emission control technologies	Applicable particulate emission control technologies
• sub critical PC boilers	• sorbent injection • spray dry scrubbers • wet FGD	• low NO_X burners • OFA • SNCR • SCR	• ESP

Step 3. Possible alternatives

Coal quality

The coal that will be used in this plant is a domestic anthracite. The ash content is low (19-20%). To purchase a coal with a higher quality to an additional price less than 0.4-0.55 USD/ton per lower ash content percentage, as stated in Chapter 2, *Coal quality impact on power generation cost* (page 9), is not possible. This means that the coal originally planned for this project will be used.

Stating the possible alternatives

Applicable technologies found in the technology screening step are used to find suitable power plant concepts. Four alternatives using different kinds of emission control equipment will be evaluated from a technical, environmental and economical point of view. The alternatives are presented in Table 10.7.

Table 10.7: Possible alternative configurations of a greenfield 600-MWe power plant

Technology Area	Alternative 1	Alternative 2	Alternative 3	Alternative 4
• combustion technology	• sub-critical PC	• sub-critical PC	• sub-critical PC	• sub-critical PC
• SO_x emission control	• none	• sorbent injection	• wet FGD	• wet FGD
• NO_x emission control	• low-NO_x burners & OFA	• low-NO_x burners & OFA	• low-NO_x burners & OFA	• low-NO_x burners, OFA & SCR
• particulate emission control	• ESP	• ESP	• ESP	• ESP

Technical evaluation

The alternatives that will be evaluated have to fulfill the prerequisites stated in Tables 10.1-10.4. Some of these prerequisites are gathered in Table 10.8 that shows how each alternative complies with the prerequisites. To find the outcome for each alternative, tables and information in Chapters 3 to 6 are used. As shown in Table 10.8, the NO_x emissions are very high. This is a result of using anthracite as fuel. Anthracite is difficult to burn due to a very low content of volatile matter. To achieve stable and complete combustion, high temperatures in the combustion zone are necessary. As a result the NO_x emissions become very high.

Table 10.8: Evaluation of different alternatives against selected prerequisites

Pre-requisites	Unit	Alternative 1	Alternative 2	Alternative 3	Alternative 4
SO_2	mg/MJ	850	430	100	100
NO_X	mg/MJ	300-400	300-400	300-400	80
Particulate	mg/Nm^3	50	50	50	50
Solid Waste		can be utilized	disposal only	can be utilized	can be utilized
Domestic manufacturing		All parts can be manufactured domesticaly	Most parts can be manufactured domestically. Design of soren injection system will be iimported.	Most parts can be manufactured domestically. Design and manufacturing of FGD equipment will be imported	Most parts can be manufactured domestically. Design and manufacturing of FGD and SCR equipment will be imported.

Note: *Prerequisites defined in Tables 10.1-10.4. Alternatives are described in Table 10.7.*

Step 4. Cost calculation

Investment cost calculation

The investment cost for all alternatives is calculated by adding the cost for the different technology areas (Table 10.9).

Electricity production cost

O&M data necessary to calculate the electricity production cost for all alternatives are gathered in Table 10.10. These data are found in Chapters 3-6.

Table 10.9: Investment cost calculation for a 600-MW greenfield power plant

Technology area	Investment *MUSD*			
	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**
Combustion technology*	650	650	650	650
SO_x emission reduction	-	45	90	90
NO_x emission reduction	-	-	-	45
Particulate emission reduction	30	30	30	30
Total investment	680	725	770	815

Note: *(*)includes costs for complete power plant except flue gas cleaning equipment. Alternatives are described in Table 10.7.*

Table 10.10: Calculation of fixed and variable O&M costs for the different alternatives

Technology area	**O&M Costs:** **Fixed** *(MUSD/year)* **Variable** *(UScents/kWh)*			
	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**
Combustion technology *	16 0.2	16 0.2	16 0.2	16 0.2
SO_x emission reduction	- -	3.6 0.3	7.5 0.17	7.5 0.17
NO_x emission reduction	- -	- -	- -	- 0.35
Particulate emission reduction	- 0.3	- 0.3	- 0.3	- 0.3
Total O&M: fixed variable	16 0.5	19.6 0.8	23.5 0.67	23.5 1.02

Note: *(*)includes costs for complete power plant except flue gas cleaning equipment. Alternatives are described in Table 10.7.*

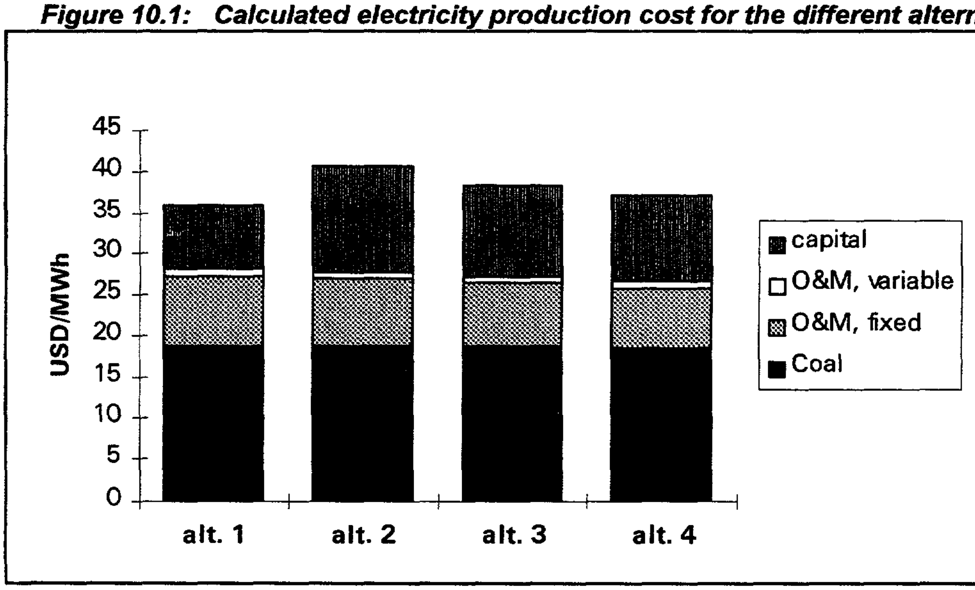
The economical presumptions that are necessary to calculate the electricity production cost were stated in Tables 10.1-10.4. These economic presumptions and all other data necessary for the calculations are gathered in Table 10.11 below.

Table 10.11: Data for calculating the electricity production cost for the different alternatives

	unit	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Construction period	*months*	36	36	36	36
Operating time	*hours/year*	6,000	6,000	6,000	6,000
Availability, incl. overhaul	%	90	90	90	90
Coal price	*USD/MWh*	7.2	7.2	7.2	7.2
Electricity production	MW_e	600	600	600	600
Plant net efficiency	%	37	37	36.6	36.6
Investment	*MUSD*	680	725	770	815
O&M costs:					
fixed	*MUSD/year*	16	19.6	23.5	23.5
variable	USc/kWh_e	0.5	0.8	0.67	1.02
Rate of return	%	7	7	7	7
Economic lifetime	*years*	20	20	20	20

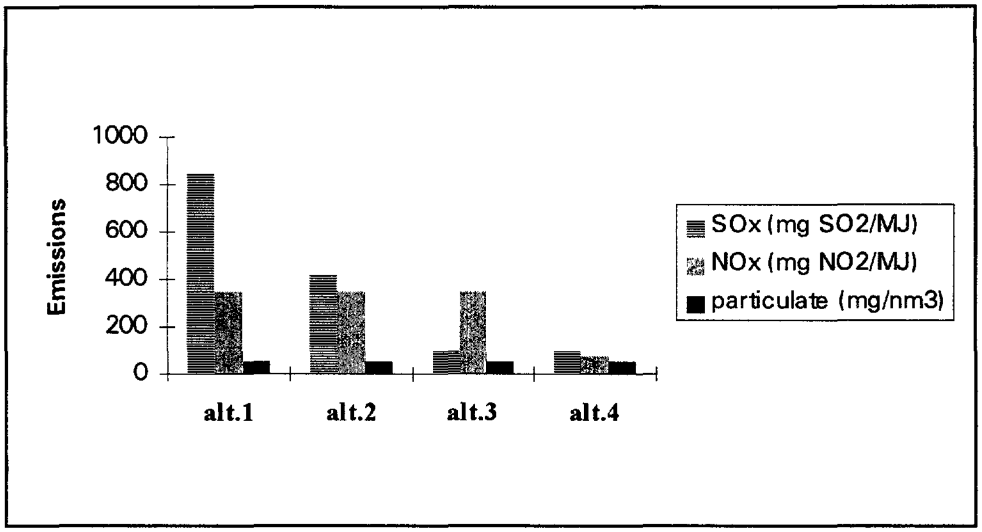
Based on information above the electricity production cost is calculated. As shown in Figure 10.1, alternative 4 results in the highest electricity production cost and alternative 1 the lowest. This is natural, since alternative 4 includes the most sophisticated emission control equipment. The figure shows that the electricity production cost varies between 55 USD/MWh and 67 USD/MWh depending on the extent of emission control equipment included. The emissions connected to each alternative are shown graphically in Figure 10.2.

Figure 10.1: Calculated electricity production cost for the different alternatives



Note: *Alternatives are described in Table 10.7.*

Figure 10.2: Emissions of SO_2, NO_x and particulate associated with each alternative



Technology recommendation

Result

The result of the technical and economic evaluation is shown in Table 10.12 below. Both the investment and the electricity production cost increase with decreasing emissions. The table shows that the cost of sorbent injection in this case is 0.5 UScents/kWh, the cost of wet FGD is 0.7 UScents/kWh and the cost of SCR is 0.5 UScents/kWh.

Table 10.12: Result of environmental, technical, and economic evaluation of different alternatives

	Unit	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Investment	*MUSD*	680	725	770	815
Electricity production cost	*USc/kWh*	5.5	6.0	6.2	6.7
Emissions					
SO_2	*mg/MJ$_{fuel}$*	850	430	100	100
NO_X	*mg/MJ$_{fuel}$*	300 - 400	300 - 400	300 - 400	80
particulate	*mg/nm^3*	50	50	50	50

***Note:** Alternatives are described in Table 10.7.*

When the cost/ton of SO_2 removed is calculated, sorbent injection removes sulfur at a cost of almost 1,400 USD/ton and wet FGD removes sulfur at a cost of 1,000 USD/ton. The cost of NO_x reduced by the SCR in this case is 2,000 USD/ton NO_2.

Recommendation

The recommendation is to followup with feasibility studies for alternative 2 and 3. Alternative 1 which is a plain plant without any emission control equipment except for an ESP, is eliminated due to higher emissions. Alternative 4 which includes a SCR system is eliminated due to higher costs. At this stage it is considered sufficient to use primary measures to reduce NO_X emissions.

Alternatives 2 and 3 both include sulfur emission control equipment. The difference is to what extent the SO_2 is removed. A wet FGD plant is included in alternative 3 and sorbent injection in alternative 2. Comparison between alternatives 2 and 3 shows that wet FGD has the following advantages and disadvantages in comparison with a sorbent injection process:

- higher removal efficiency,
- higher investment and electricity production cost, and
- lower cost/ton SO_2 removed.

When a high degree of desulfurization is needed, a wet system is more cost efficient. Both these alternatives shall be studied in more detail in the feasibility study. Special emphasis will then be made on the maturity of the sorbent injection technology.

Possibility to comply with future more stringent environmental requirement.
It is possible that the environmental requirements will become more stringent in the future. This means that if the plant will be built without a SCR system and without a wet FGD system, the layout of the plant shall be such that a future installation of a SCR system and a wet FGD is possible.

BOILER RETROFIT

Step 1. Project definition

This project concerns retrofit of a 100-MWe oil-fired peak load power plant. The task is to upgrade the plant to a coal-fired base load plant. Due to high oil prices, the plant operating cost is very high, and therefore the acquired number of operating hours of the plant are few. The existing turbine and generator are in good condition and can be reused. After the retrofit, the plant must be able to meet more stringent emission requirements. The reconstruction work will include demolition of the existing oil-fired boilers and installation of a new coal-fired boiler in a new boiler house. The new boiler will be equipped with modern flue gas cleaning equipment. The major benefit of this project is that the capital cost for converting the existing plant to a base load plant is lower than building a new plant.

This retrofit is project financed. In concern of a good project economy, the financing parties have posed high environmental requirements as to assure a long annual operation time and to avoid further refurbishment for environmental upgrade in the near future. The high environmental requirements are posed also for goodwill reasons. Therefore, in this project the environmental performance are more important than the maturity of technology. To summarize, the objectives for retrofit of the plant, as defined in Table 9.2, are reduced operating costs, increased unit availability, increased unit lifetime, and reduced environmental impact.

The main prerequisites from Tables 9.3 through 9.6 are determined and the result is shown in Tables 10.13 through 10.16. These prerequisites will be used for technical and economical evaluation of different possible boiler and flue gas cleaning concepts.

Table 10.13: General prerequisites

Type of project:	commercial
Plant:	
• size:	100 MW_e
• number of units:	1
Coal:	
• type:	domestic high volatile bituminous coal
• ash content:	29.6 %
• sulfur content:	1.8 %
• heating value:	30.4 MJ/kg
Date of commissioning:	January 2000

Table 10.14: Economic prerequisites

Project economy	
• rate of return:	7%
• economic lifetime:	20 years
Financing policy:	project financing
Purchasing policy:	turn key
Requirements on local manufacturing:	as much as possible

Table 10.15: Environmental prerequisites

SO_2:	160 mg/MJ *(requirements of financing parties)*
NO_X:	250 mg/MJ *(requirements of financing parties)*
Particulate:	90 mg/MJ *(requirements of financing parties)*
Wastewater:	comply with World Bank requirements
Solid by products/waste:	wet or dry disposal

Table 10.16: Operational prerequisites

Operation time:	7,200 hr/yr
Availability factor:	88% including overhaul period
Load change rate:	4% per minute
Minimum load:	40%

Step 2. Technology screening

Technology screening is done against criteria and selected requirements from Table 9.7. The screening is done in combustion technologies, SO_x, NO_x, and particulate emission reduction technologies (Table 10.17). Although this is a project-financed commercial project, the requirements on low investment cost combined with acceptable environmental performance are higher than the requirement on maturity of technology. The waste products will be used for landfill only.

Table 10.17: Screening criteria for the retrofit of an oil-fired power plant

Technology area	Maturity of technology	Waste product
Combustion	low requirements	disposal
SO_x emission	low requirements	disposal
NO_x emission	low requirements	
Particulate emission	low requirements	

Applicable technologies

The screening is done by comparing the requirements defined in Table 10.17 with the information in Chapters 3 to 7. The existing steam turbine is not designed for supercritical temperatures and pressure levels, which is why supercritical PC boiler technology is omitted. The following technologies are applicable in this case:

Table 10.18: Applicable technologies for retrofit of a 100-MWe oil-fired boiler

Applicable combustion technologies	Applicable reduction technologies		
	SO_x	NO_x	Particulate
• Subcritical PC boiler • ACFB boiler	• sorbent injection • spray dry scrubber • wet FGD	• low NO_x burners + OFA • SNCR • SCR	• ESP

Step 3. Possible alternatives

Coal quality

The coal that will be used in this plant is a domestic high volatile bituminous coal. The coal quality as defined in Table 10.13 is not very high. Although the ash and sulfur contents are high at 30-31% and 1.8%, respectively, it is not possible to purchase a coal in the region with a higher quality at an additional price less than 0.4-0.55 USD/ton per lower ash content percentage, as stated in Chapter 2, *Coal quality impact on power generation cost* (page 9). This means that the coal originally planned for this project will be used.

Stating possible alternatives

Applicable technologies from the technology screening step are now combined to alternatives. In this step, SNCR and SCR are omitted as the requirements on NO_x reduction are not high enough to justify the high investment and O&M cost of these technologies. Four alternatives with different kinds of emission reduction equipment and thereby different emissions and costs remain to be evaluated from a technical, economic and environmental point of view. The possible alternatives are described in table 10.16.

Table 10.19: Different alternatives for retrofit of a 100-MWe oil-fired boiler

	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5
Combustion technology	• ACFB	• sub-critical PC	• sub-critical PC	• sub-critical PC	• sub-critical PC
SO_x emission reduction	• none	• wet FGD	• spray dry scrubber	• hybrid sorbent injection	• furnace or duct sorbent injection
NO_x emission reduction	• none	• low-NO_x burners & OFA	• low-NO_x burners & OFA	• low-NO_x burners & OFA	• low-NO_x burners & OFA
Particulate emission reduction	• ESP	• ESP	• ESP	• ESP	• ESP

Technical evaluation

The alternatives have to fulfill the main prerequisites of the project as stated in Tables 10.13 through 10.16. Some of theses prerequisites and the outcome for each alternative are shown in Table 10.20 below. To find the outcome, tables and information in Chapters 3 to 6 are used.

Table 10.20 shows that alternative 5 with furnace or duct sorbent injection will not comply with the SO_2 emission requirement specified in Table 10.15. Alternative 5 will therefore be omitted from further investigation. Alternatives 3 and 4 using hybrid sorbent injection and a spray dryer will comply with the SO_2 emission requirement only if these systems are designed for very high removal efficiencies.

Table 10.20: Evaluation of the alternatives against certain main prerequisites

Evaluation against certain prerequisites						
Prerequisite	**Unit**	**Alt. 1**	**Alt. 2**	**Alt. 3**	**Alt. 4**	**Alt. 5**
SO_2	*mg SO_2/MJ fuel*	120 - 60	120 - 60	120 - 355	240 - 120	590 - 355
NO_x	*mg NO_x/MJ fuel*	80 - 150	115 - 175	115 - 175	115 - 175	115 - 175
Particulate	*mg/ Nm^3*	10-25	10-25	10-25	10-25	10-25
Solid waste		can only be landfilled	can only be landfilled	can be utilized or landfilled	can be utilized	can only be landfilled
Local manufacturing		Design of ACFB boiler must be imported but most parts can be manu-factured locally. Design and some manufacturing of FGD equipment will be imported.	Most parts can be manufactured locally. Design and some manufacturing of FGD equipment will be imported.	Most parts can be manufactured locally. Design of FGD equipment will be imported.	Most parts can be manufactured locally.	All parts can be manufactured locally.

Note: *Main prerequisites defined in Tables 10.13-10.16. Alternatives are described in Table 10.19.*

Step 4. Cost calculation

Investment cost calculation

The investment cost for all remaining alternatives is calculated by adding the cost for the different technology areas (Table 10.21). For the hybrid sorbent injection system and the spray dryer in alternatives 3 and 4, respectively, a cost in the upper range is chosen as these SO_2 removal systems have to be designed for very high removal efficiencies.

Table 10.21 Investment cost calculation for retrofit of a 100-MWe oil-fired boiler

Technology area	**Investment** *(MUSD)*			
	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**
Combustion technology *	45	45	45	45
SO_2 emission reduction		30	17	14
NO_x emission reduction		3	3	3
Particulate emission reduction	5	5	5	5
Total investment	50	83	70	67

** Includes the cost for the boiler only, which is about 30% of the cost for a entirely new plant. Alternatives are described in Table 10.19.*

Electricity production cost

In order to calculate the electricity production cost for all remaining alternatives, O&M data and project specific economical data need to be found. Table 9.9 in chapter 9 is used to calculate the total O&M costs for the alternatives, as shown in table 10.22.

Table 10.22: Calculation of fixed and variable O&M costs for the different alternatives.

Technology area	O&M cost fixed *(MUSD/year)* and variable *(USc/kWh)*			
	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 4**
Combustion technology *	5.7 0.97	4.3 0.56	4.3 0.56	4.3 0.56
SO_2 emission reduction	- -	1.2 0. 15	0.9 0. 3	0.6 0.3
NOx emission reduction	- -	- -	- -	- -
Particulate emission reduction	0.5 -	0.5 -	0.5 -	0.5 -
Total O&M: fixed variable	6.2 0.97	6.0 0.71	5.7 0.86	5.4 0.86

* *Includes cost for combustion system, steam cycle and balance of plant.*

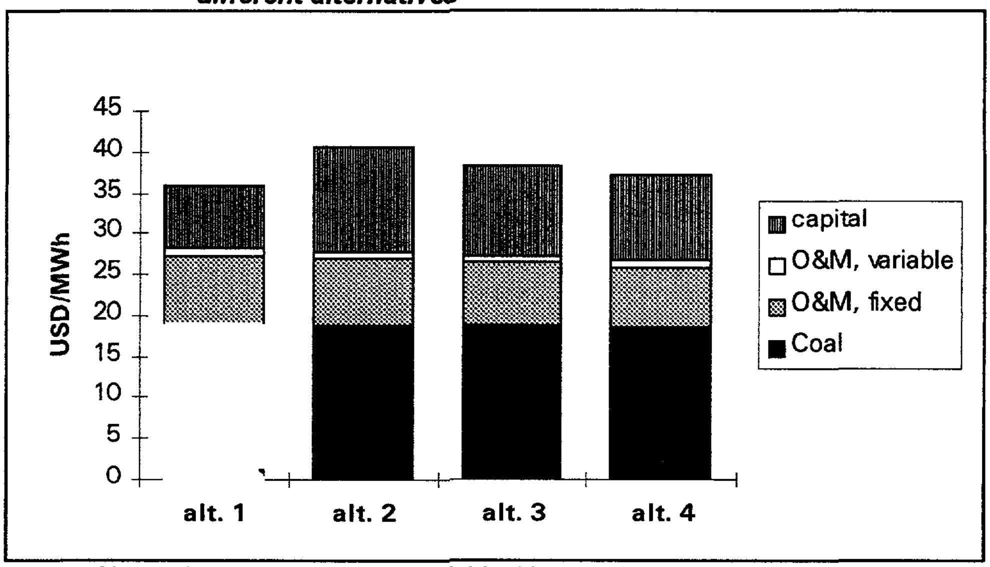
The economical presumptions that are necessary to calculate the electricity production cost were stated in Tables 10.13-10.16. These economic presumptions are listed in Table 10.23 along with other economic data for each specific case from Tables 10.21-10.22.

Table 10.23: Data for calculating the electricity production cost for different alternatives

Data needed to calculate the electricity production cost					
	unit	**Alt. 1**	**Alt. 2**	**Alt. 3**	**Alt. 4**
Construction period	*months*	36	36	36	36
Operating time	*hours/year*	7,200	7,200	7,200	7,200
Availability factor	*%*	88	88	88	88
Coal price	*USD/MWh*	7.2	7.2	7.2	7.2
Electricity production	*MW_e*	100	98.5	99.25	99.75
Plant net efficiency	*%*	37.5	37	37.3	37.5
Investment	*MUSD*	50	83	70	67
O&M costs					
fixed	*USD/year*	6.2	6.0	5.7	5.4
variable	*USc/kWh_e*	0.97	0.71	0.86	0.86
Interest rate	*%*	7	7	7	7
Economic lifetime	*years*	20	20	20	20

With data from Table 10.23, the electricity production cost is calculated. As shown in Figure 10.3, production costs are highest for alternative 2 and lowest for alternative 1, although all alternatives are fairly close. It is natural that alternative 2 results in a higher production cost than alternatives 3 and 4 since it includes more advanced sulfur removal equipment. Clearly, such an advanced system is not economical for a boiler of this size. However, it is interesting to note that alternative 1 with a ACFB boiler, results in lower production cost that any alternative with a PC boiler. The figure shows that electricity production cost varies between 35 USD/MWh and 41 USD/MWh.

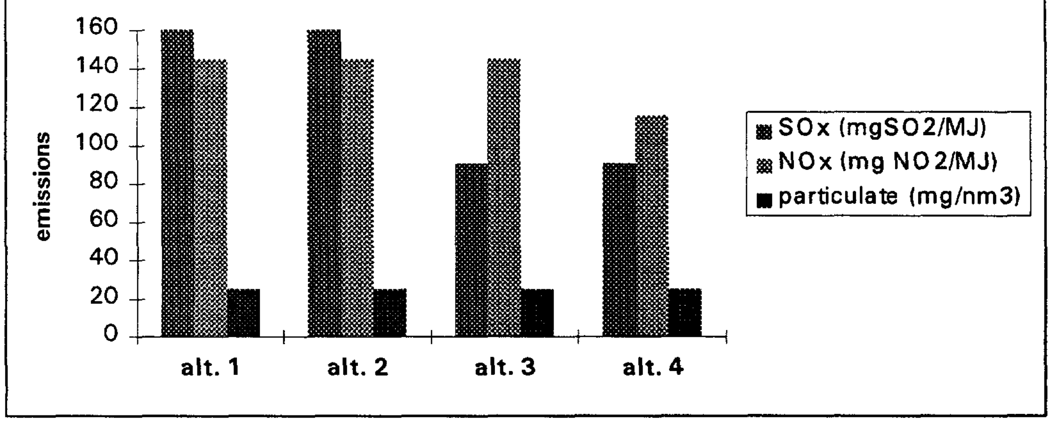
Figure 10.3:* *Calculated electricity production cost in USD/MWh for the different alternatives



***Note:** Alternatives are described in Table 10.19.*

The emissions corresponding to each alternative are shown graphically in Figure 10.4. All alternatives can comply with the environmental requirements specified in Table 10.15, but alternative 1 results in the lowest emissions.

Figure 10.4: Emissions of SO_x, NO_x and particulate for each alternative



Technology recommendation

Result

The result of the technical and economical evaluation is shown in Table 10.24. For the PC boiler options, both investment and electricity production costs increase with decreasing emissions. An interesting result is that the ACFB boiler, which has the lowest emissions, appears to be the most economical choice.

Table 10.24: Result of the technical and economical evaluation for the different alternatives

	Unit	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Investment	*MUSD*	50	84	68	64
Electricity production cost	*USc/kWh*	3.5	4.1	3.8	3.7
Emissions					
SO_2	*mg/MJ*	90	90	160	160
NO_x	*mg/MJ*	115	145	145	145
particulate	*mg/Nm^3*	25	25	25	25

***Note:** Alternatives are described in Table 10.19.*

When the cost/ton of SO_2 removed is calculated, hybrid sorbent injection removes sulfur at a cost of almost 370 USD/ton. The cost with a spray dryer is 470 USD/ton and wet FGD removes sulfur at a cost of 680 USD/ton. The nature of the ACFB alternative is such that the cost for SO_2 reduction can not be separated from the total cost.

Recommendation

The first recommendation is to study alternative 1, a ACFB boiler, more in a detailed feasibility study. The technology is not yet mature in India and China, but the process has the best environmental performance at the lowest cost. These characteristics are more important to the financing parties than maturity of technology.

Alternatives 2, 3 and 4 all include a PC boiler with sulfur emission reduction equipment. The recommendation at this point, is to further investigate alternative 3, with a spray dry scrubber. A wet FGD plant as included in alternative 2 can easily be designed to comply with the sulfur removal requirement. However, this alternative has the highest investment and electricity production cost and should therefore be eliminated. The wet FGD technology is not competitive for such small boilers.

The sulfur removal systems of alternatives 3 and 4 both have to be designed for very high efficiencies if they are to comply with the sulfur removal requirement. Alternative 4 with a hybrid sorbent injection system has the lowest investment and results in the second lowest electricity production cost. If a hybrid sorbent injection system of satisfying efficiency can be designed, this alternative could be interesting to study further, but since there are very few reference plants, this technology represents many uncertain parameters. The cost difference between spray dry scrubber and hybrid sorbent injection is very small and the spray dry scrubber technology is more proven. Therefore, alternative 3, a PC boiler with a spray dry scrubber, is recommended for a feasibility study along with alternative 1.

Possibility to comply with future more stringent environmental requirements

It is possible that the requirements on NO_x reduction will become more stringent in the future. Therefore the layout of the plant shall be such that a future installation of a SCR system is possible.

11. ENVIRONMENTAL GUIDELINES AND REQUIREMENTS

PROPOSED WORLD BANK REQUIREMENTS

The proposed guidelines from the World Bank (Ref. 1) apply to fossil fuel-based thermal power plants or units of 50 MW_e or larger. In these guidelines, primary attention is focused on emissions of particulates less than 10 microns (μm) in size (PM_{10}), on sulfur dioxide and on nitrogen oxides. It is also stated that in order to minimize the emission of greenhouse gases, preference may be given to the use of natural gas as a fuel.

Air pollution

The levels set in the guidelines on air pollution can be achieved by adopting a variety of low-cost options or technologies, including the use of clean fuel. In general, the following measures should be seen as the minimum that need to be taken:

- dust control capable of 98-99% removal efficiency, such as fabric filters or electrostatic precipitators should always be installed;
- low NO_x burners combined with other combustion modifications should be standard practice;
- the range of options for control of SO_2 is greater depending largely on the sulfur content in each specific fuel:
  - below 1% sulfur, no control measures are required;
  - between 1 and 3% sulfur, coal cleaning and sorbent injection or fluidized bed combustion may be adequate; and
  - above 3% sulfur, flue-gas desulfurisation or other clean coal technologies should be considered.

The limit values set shown in Table 11.1 represent a basic minimum standard; more stringent emission requirements will be appropiate if the environmental assessment (EA) indicates that the benefits of additional pollution controls, as reflected by ambient exposure levels and by other indicators of environmental damage, outweigh the additional costs. All emission requirements should be achieved for at least 95% of plant operation time, averaged over monthly periods. Though metals are not listed in the emission requirements below, they should be addressed in the EA when burning some types of coal or heavy fuel oil which may contain cadmium, mercury etc.

Table 11.1: Maximum emission limits for coal-fired thermal power plant set by World Bank

Pollutant	Removal effiency	Concentration mg/m^3 (ndg)	Specific emission levels $tons/day/MW_e$
PM_{10}	99%	50	-
NO_x	40%	750 (6% excess O_2 - assumes 350 Nm^3/GJ)	-
SO_2	-	2,000	0.20 (0.1 recommended for incremental above 1,000 MW_e).

***Source:** World Bank (1996)*

Ambient air

The World Bank also states that, in the long-term, countries should ensure that ambient exposure to particulates (especially to PM_{10}), nitrogen oxides and sulfur dioxide should not exceed the WHO recommended guidelines. These recommendations are summarized in Table 11.2.

Table 11.2: WHO recommendations for ambient air quality

Pollutant	Max. emission increment, 24-hour mean value *[mg/m³]*	Max. emission increment, annual average *[mg/m³]*
SO_2	100-500*	10-50*
NO_x	500	100
Particulates	100-150*	-

** Actual values depend on background levels of sulfur and dust. Maximum allowable incremental emission is low in higly polluted areas and vice versa.*
***Source:** WHO (1987).*

However, in the interim, countries should set ambient standards which take into account benefits to human health of reducing exposure to particulates, NO_x and SO_2; concentration levels achievable by pollution prevention and control measures, and
costs involved in meeting the standards.

For the purpose of carrying out EAs, countries should establish a trigger value for ambient exposure to particulates. This trigger value is not an ambient air quality standard, but is simply a threshold which, if it is exceeded in the area affected by the project, will mean that a regional and/or sectoral EA should be carried out. The trigger value may be equal to or lower than the country's ambient standard for particulates, nitrogen oxides and sulfur dioxide, respectively.

Water pollution

For liquid effluents from thermal power plants (both direct and indirect waste or cooling water) the following levels should be achieved, shown in Table 11.3.

Table 11.3:* *Emission limit values for some parameters in effluents from thermal power plants.

Parameter	Maximum value
pH	6-9
Suspended solids	50 mg/l
Oil and grease	10 mg/l
Total residual chlorine	0.2 mg/l
Chromium, total	0.5 mg/l
Chromium, hexavalent	0.1 mg/l
Copper	0.5 mg/l
Iron	1.0 mg/l
Nickel	0.5 mg/l
Zinc	1.0 mg/l
Temperature increase	$\leq 3°C$*

** This should be considered at the edge of the zone where initial mixing and dilution takes place. If the zone is not defined, 100 meters from the point of discharge should be used.*

Source: *World Bank (1996).*

CHINESE REQUIREMENTS

There is a national standard in China that regulates emissions from coal-fired power plants. This standard is called "Emission standards of air pollutants for coal-fired power plants" and it regulates emissions of SO_2 and particulates, but does not yet include standards for NO_x emissions. There is also a standard on ambient air quality which regulates both SO_2 and NO_x concentrations, which is described below. China has a standard regulating water pollution in integrated wastewater discharges and a standard on how to secure surface water quality in water bodies with variable sensitivity. These Chinese standards are listed in Ref. 2.

Air pollution

The Chinese standard on air pollutants only depends on the height of the emission source using the dispersal ability of the atmosphere to secure ambient air quality. This means wind speed at the outlet of the emission is taken into account when deciding the neccesary stack height. The characteristics of the area (urban or rural, hilly or plain) are also taken into account.

Boiler type, type of cleaning devices and ash content in coal also have an impact on the limit values as does whether it is an existing plant or a new installation. If the Chinese regulations are translated into emissions per energy input or volume of flue gas, the following (Table 11.4) emission limit values are allowed for a new installation with a stack height of 240 meters. There are also provincial standards in China concerning air pollution which are sometimes more stringent than the national standards.

Table 11.4: Emission limit values for coal-fired power plants

Parameter	Tons per hour	Emission per net energy input mg/MJ	Emission per m^3 (ndg) if 6% O_2 content mg/m^3
SO_2	14.6	2,500	6,800
Particulates	0.56	100	273

Source: Chinese standards listed in Ref.2.

Ambient air quality

The standard for ambient air quality is divided into three different levels. There are both 24 hour mean limit values and momentary limit values, for dust (PM_{10}), SO_2 and NO_x. The different levels are described in Table 11.5.

Table 11.5: Ambient air quality levels.

Level 1	The air does not effect the nature or the health of humans even after long-term exposure.
Level 2	The air does not have a harmful effect on the health of humans or the environment, in cities or in the countryside no matter what length of time of exposure.
Level 3	The air is not acute or chronically toxic for humans and admits a normal variety of flora and fauna in cities.

Source: Chinese standards listed in Ref.2.

Linked to the different levels, land areas are divided into three categories with respect to geography, climate, ecosystem, politics, economy and air quality. Category 1 includes national nature reserves, tourist areas, historical localities and recreational resorts. Category 2 includes cities and the countryside and Category 3 includes localities or industrial sites where the level of air pollutants is high, or areas with heavy traffic. The ambient air quality for some pollutants can be seen in Table 11.6.

Table 11.6: Ambient air quality standard for dust, SO_2 and NO_X.

		Normal dry gas		
		Level 1 [mg/m^3]	Level 2 [mg/m^3]	Level 3 [mg/m^3]
PM_{10}	24-hour mean value	0.05	0.15	0.25
	Occasional basis*	0.15	0.50	0.70
SO_2	24-hour mean value	0.05	0.15	0.25
	Occasional basis*	0.15	0.50	0.70
NO_X	24-hour mean value	0.05	0.10	0.15
	Occasional basis*	0.10	0.15	0.30

** Limit values should not be exceeded at any time.*
Source: Chinese standards listed in Ref.2.

Water pollution

There is one standard for integrated wastewater discharge which is linked to a standard on environmental quality for surface water. Depending on the characteristics of the intake water as well as those of the water body receiving the wastewater, the standard is divided into three levels with different limit values for pollutants. However, the limit values of some serious pollutants in wastewater are the same for all levels. In Table 11.7 below, the substances which are not included have been added and given as an interval depending on the level as described above. The highest values represent the limit values for level 3 which represents wastewater sent to a sewage treatment plant or for biological treatment. The interval for pH is valid for all levels.

Table 11.7: General limit values for certain parameters in wastewater

Parameter	Limit value
pH	6 - 9
Suspended solids	70 - 400 mg/l
Oil and grease	10 - 30 mg/l
Chromium, total	1.5 mg/l
Chromium, hexavalent	0.5 mg/l
Copper	0.5 - 2.0 mg/l
Nickel	1.0 mg/l
Zinc	2.0 - 5.0 mg/l

Source: *Chinese standards listed in Ref.2.*

For some industries, specific limit values are valid, according to the integrated wastewater standard. Power plants are not included in this list. The discharge of water used for cooling purposes is restricted according to the environmental quality standard for surface water, where all kinds of influence by human is included. No specification is connected with the limit values. The maximum increase in temperature is 1°C in summer and the maximum decrease of temperature in winter is 2°C, as weekly mean values.

INDIAN REQUIREMENTS

The Government of India has issued guidelines which require all thermal power plants to obtain a "No objection Certificate" from the relevant State Pollution Control Board before a "Letter of Intent" is converted into a license. The Ministry of Environment and Forests has to give the statutory clearance for setting up the power plant. Documents that describe Indian requirements are listed in Reference 3.

Air pollution

In India there are only standards on dust emission from power plants and no general emission levels given on NO_x or SO_2 The dust emission standard adopted for thermal power plants in India is described in the Table 11.8.

Table 11.8: Dust limit values for power plants

Boiler size *MW*	Emission standards in India *mg/m³ (ndg)*		
	Old*	New	Protected area
< 210	600	350	150
≥210	-	150	150

* *Boilers with electrostatic precipitators installed before December 31, 1979.*
***Source:** Central Pollution Control Board (1984, 1986).*

However, to secure an acceptable ambient air quality with respect to SO_2 the power plant has to fulfill the following demands on stack heights, shown in Table 11.9. In general, Indian coal is characterized by high ash content (more than 40%) and a low sulfur content (well below 1%). The effort to limit environmental impact has, thus, been mainly addressed to particulate emissions.

Table 11.9: Requirements on stack height due to boiler size

Boiler size *MW*	Stack height *m*
< 200/210	$H=14 \times Q^{0.8}$
200/210-500	220
≥ 500	275

***Note:** Q = SO_2 emission in kg per hour.*
***Source:** Central Pollution Control Board (1984, 1986).*

Ambient air quality

The national ambient air quality standard in India defines ambient air quality requirements in different areas, as shown in Table 11.10.

Water pollution

India also has standards for liquid effluents from thermal power plants, shown in Table 11.11. The limit values are set for parameters that are applicable to each effluent, eg. condenser cooling water, boiler blowdown, and cooling tower blowdown.

Table 11.10: Ambient air quality for different locations

Category	Particulates *µg/m³*	SO_2 *µg/m³*	NO_x *µg/m³*
Industrial area			
• annual average	360	80	80
• 24 hours	500	120	120
Residential and rural			
• annual average	140	60	60
• 24 hours	200	80	80
Sensitive			
• annual average	70	15	15
• 24 hours	100	30	30

***Source:** Central Pollution Control Board (1994).*

Table 11.11: Limit values for parameters in wastewater discharges

Parameter	Limit values
pH	6.5-8.5
Temperature increase*	≤ 5°C
Free available chlorine	0.5 mg/l
Suspended solids	100 mg/l
Oil and grease	20 mg/l
Copper	1.0 mg/l
Iron	1.0 mg/l
Zinc	1.0 mg/l
Chromium , total	0.2 mg/l
Phosphate	5 mg/l

***Note:** (*) Compared with intake water temperature.*
***Source:** Central Pollution Control Board (1986).*

SUMMARY OF ENVIRONMENTAL REQUIREMENTS

The environmental requirements on power plants are less strigent in China and India compared with the World Bank guidelines. Neither India or China stipulates the reduction of NO_x emissions and both rely on stack height and dispersion effects to a large extent in the case of emissions of particulates and SO_2. The ambient air quality standards in China and India are in the same range as the WHO recommendations as referred to by the World Bank.

Regulations on water pollution in China and India are less stringent than those of the World Bank concerning suspended solids and oil and grease. On heavy metals the limit values are less stringent in China, but in India the limit values are rather more stringent than the World Bank requirements.

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APPENDIX. COAL CLEANING METHODS

A coal cleaning plant may consist of different reduction, cleaning and dewatering/drying methods. Different combinations may also be used. The basic commercial cleaning methods, as well as environmental considerations in general, are described in the following section.

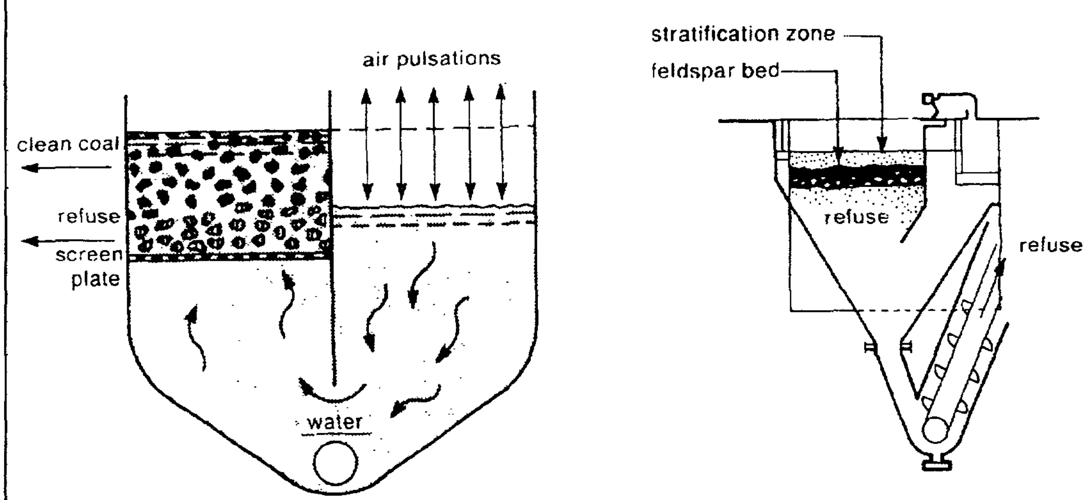
Jigs

The methods operate by differences in specific gravity. Jigs rely on stratification in a bed of coal when the carrying water is pulsed. The shale tends to sink, and the cleaner coal rises. The basic jig, Baum Jig, is suitable for larger feed sizes. Although the Baum Jig can clean a wide range of coal sizes, it is most effective at 10-35 mm. A modification of the Baum Jig is the Batac Jig which is used for cleaning fine coals. The coal is stratified by bubbling air directly through the coal-water-refuse mixture in this cleaning unit.

For intermediate sizes the same principles are applied, although the pulsing may be from the side or from under the bed. In addition, a bed or hard dense mineral is used to enhance the stratification and prevent remixing. The mineral is usually feldspar, consisting of lumps of silicates of about 60 mm size. Figure A1 shows a Baum Jig and a feldspar jig for finer coal.

Jigs offer cost effective technology with a clean coal yield of 75-85 % at about 34 % ash content. The jigs are used more frequently than dense-medium vessels because of their larger capacities and cheaper costs.

Figure A1: Baum jig and a feldspar jig for fine coal



Baum-type jig is used for cleaning coarse coal, with water as the medium

Feldspar-bed jig is used for fine coal

Source: *Couch (1991).*

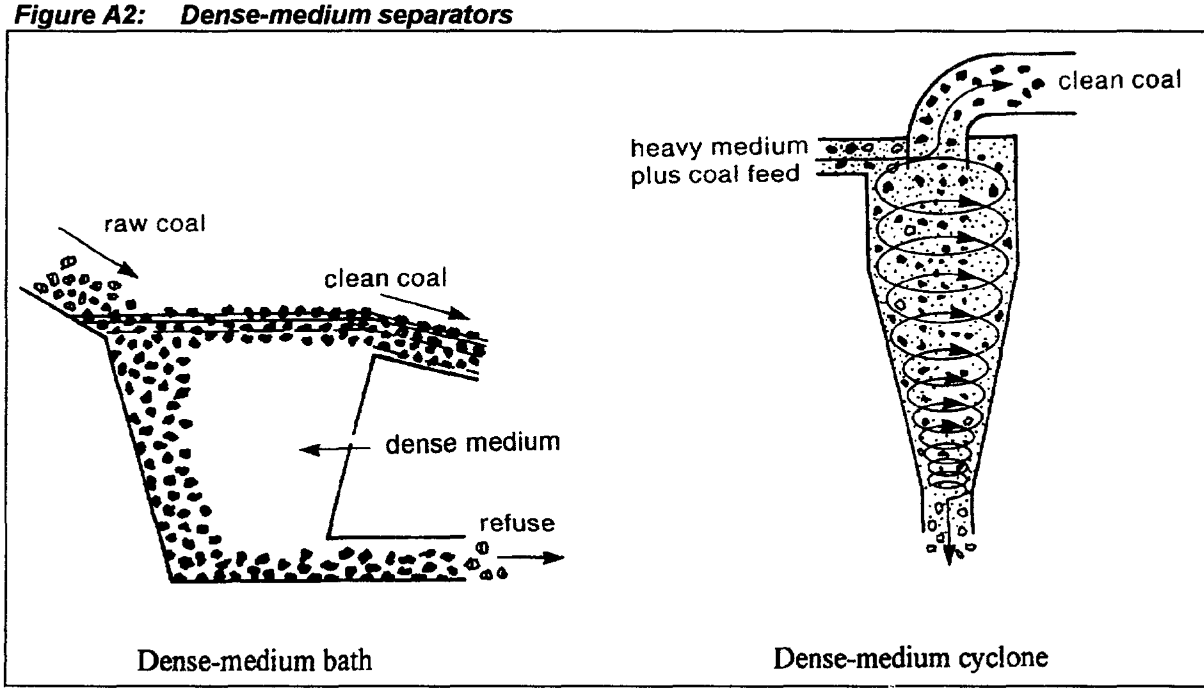
Dense-medium separators

Dense-medium vessels also operate by specific gravity difference; however, rather than using water as the separation medium, a suspension of magnetite and water is used. This suspension has a specific gravity between that of coal and the refuse and a better separation can be obtained. The slurry of fine magnetite in water can achieve relative densities up to about 1.8. Different types of vessels are used for dense-medium separators such as baths, cyclones and cylindrical centrifugal separators. For larger particle sizes, various kinds of baths are used, but these require a substantial quantity of dense-medium, and therefore of magnetite. For smaller sizes, cyclones are used where the residence time is short and throughput relatively high. Cylindrical centrifugal separators are used for coarse and intermediate coal.

Dense-medium cyclones clean coal by accelerating the dense-medium, coal and refuse by centrifugal force. The coal exits the cyclone from the top and the refuse from the bottom. Better separation of smaller-sized coals can be achieved by this method.

Key factors in the operation of any dense-medium system based on magnetite are the control equipment and the efficiency of magnetite recovery for recycle. There can be a build-up of other minerals in the medium, making control more difficult. Figure A2 shows example of a dense-medium bath and a dense-medium cyclone.

Figure A2: Dense-medium separators

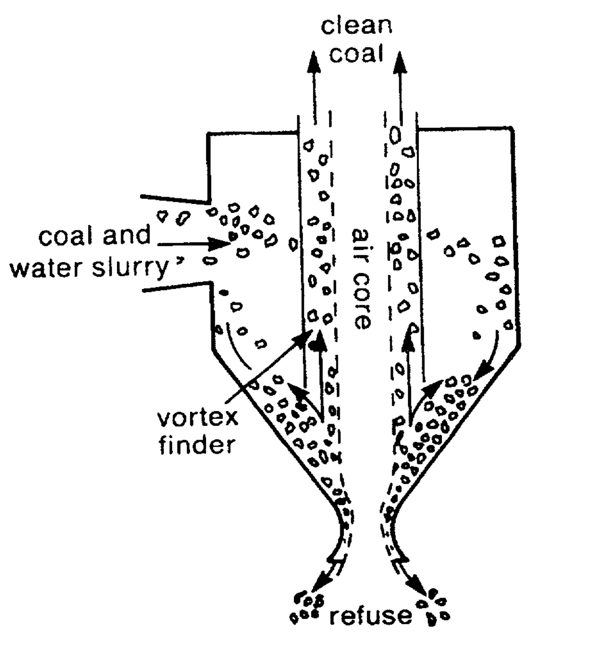


Source: *Couch (1991).*

Hydrocyclone

Hydrocyclones are water-based cyclones where the heavier particles accumulate near the walls and are removed via the base cone. Lighter (cleaner) particles stay nearer the center and are removed at the top via the vortex finder, see Figure A3. The cyclone diameter has a significant influence on the sharpness of separation.

Figure A3: Hydrocyclone

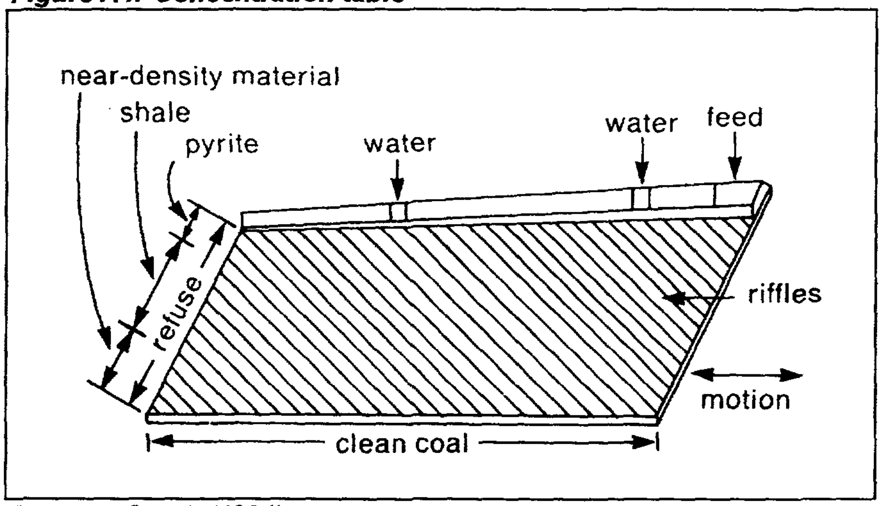


Source: Couch (1991).

Concentration tables

Concentrating tables are tilted and ribbed and they move back and forth in a horizontal direction. The lighter coal particles are carried to the bottom of the table, while the heavier refuse particles are collected in the ribs and are carried to the end of the table, see Figure A4. Fine coal can be cleaned inexpensively with this unit, however, the capacity is quite small and they are only effective on particles with specific gravities greater than 1.5.

Figure A4: Concentration table

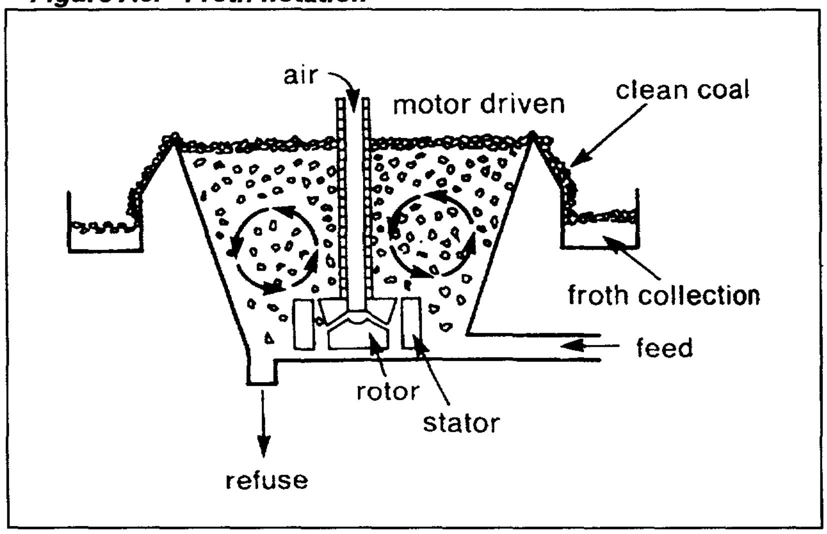


Source: *Couch (1991).*

Froth flotation

Froth flotation is the most widely-used method for cleaning fines. Froth flotation cells utilize the difference in surface characteristics of coal and refuse to clean ultra fine coal. The coal-water mixture is conditioned with chemical reagents so that air bubbles will adhere only to the coal and float it to the top, while the refuse particles sink. Air is bubbled up through the slurry in the cell and clean coal is collected in the froth that forms at the top. Figure A5 shows an example of froth flotation. This type of cleaning is very complex and expensive and is principally for metallurgical coals. One of the commonest stepz to improve the performance of a flotation unit is to separate the pyrite at an earlier stage using cyclones, spirals or tables.

Figure A5: Froth flotation

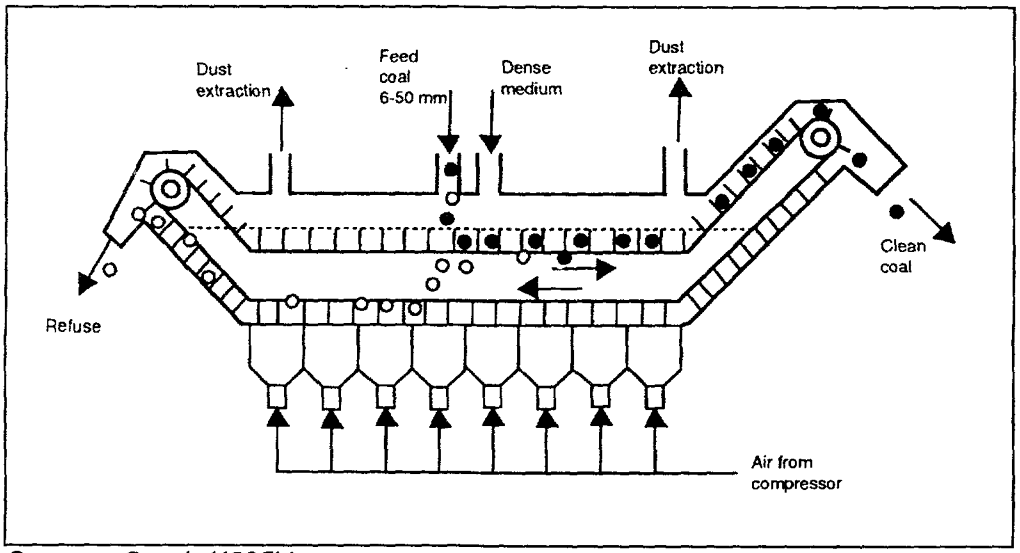


Source: *Couch (1991).*

Dry cleaning

The dry coal preparation technique uses an air dense fluidized bed which makes use of the character of an air-solid fluidized bed-like liquid. The uniform and stable air-solid suspension is formed, which processes a certain density, light and heavy feed is separated by density in suspension. The low density material floats up to the top and the high density material sinks down to the bottom. Two qualified products are obtained after separating and removing the magnetite. The separator is comprised of an air chamber, an air distributor, a separating vessel as well as a transportation scraper. In the separating process the screened (6-50 mm) coal and dense medium are fed into the separator, the compressed air from an air receiver is provided to the air-chamber, and then uniformly to the distributor which fluidize the dense- medium. The comparative stable fluidized air-solid suspension which processes a certain density is formed under certain technical conditions. The feed is stratified and separated according to its density. The separated materials are transported in counterflow. In Figure A6, the floated light product such as clean coal is discharged to the right, and the sunken heavy product to the left.

Figure A6: Schematic diagram of a dry separator with an air dense medium fluidized bed



Source: *Couch (1995b).*

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