STUDY OF COMBUSTION SYSTEMS FOR POWER GENERATION USING DIFFERENT FEED STOCKS

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CERTIFICATE

This is to certify that the Project Report on ***"Study of Combustion Systems for Power Generation Using Different Feed Stocks".*** Submitted to University of Petroleum & Energy Studies, Dehradun, by **Mr. Dinesh S. Bhadouria,** in partial fulfillment of the requirement for the award of Degree of Master of Technology in Gas Engineering (Academic Session 2003-05) is a bonafide work carried out by him under my supervision and guidance. This work has not been submitted anywhere else for any other degree or diploma.

Date: 23/5/2005

Dr.Himmat Singh

I am equally thankful to my counterparts Miss Nidhi Sharma and Mr. Vijay Kumar for their cooperation and help during the entire dissertation work.

I express my regards to our parents for their loving, care and inspiration.

"There are times in such projects
When the clock beats you time and again and again
You run out of energy and you just want to finish it once and forever.
Yes, this is the spirit, of twinkling star and finishes your work with flying Colours!"

Dinesh Singh Bhadouria

CONTENTS

TOPICS PAGE NO.

Executive summary

Introduction

Chapter 1: Main feed stocks for power generation in India.

Chapter 2: Specification of feed stocks according to power plant requirement.

Chapter 3: Preparation methods of feed stocks according to power plant requirements.

Chapter 4: Combustion properties & Combustion systems for various feed stocks used in power plants.

Chapter 5: Post combustion environment effects by using different feed stocks in power plants.

References.

LIST OF TABLES

PAGE NO.

Chapter 1:

Chapter 2:

Chapter 4:

Chapter 5:

LIST OF FIGURES

Chapter 1:

Chapter 3:

Chapter 4:

Chapter 5:

EXECUTIVE SUMMARY

*A*t the end of the 9th Plan, the installed capacity in the country was 1, 04,917MW and peaking shortage of 12.6% and energy shortage of 7.5% were faced in the country. During the 10th Plan it is programmed to add 41,110 MW. By the end of the 11th Plan i.e. 2011-12, it is estimated that the installed capacity requirement to fully meet the demand projected by the 16th EPS would be 2, 12,000 MW. Beyond 11th Plan the capacity addition is expected to match with demand growth and by the end of 12th Plan the installed capacity Coal plays a major role in the Indian economy. It accounts for 36% of annual energy produced. Though it is cheap & plentiful, the environmental and health impact of coal use is becoming more and more severe due to its deteriorating quality. The economy is expected to grow at a rapid pace and it is quite likely that India may also have to use inferior quality fuels which may be available at lower cost for economic generation of power. In light of such a scenario there is an increasing need to find ways of limiting pollution of air through the use of cleaner technologies and more efficient processes.

Among the new clean coal technologies, "Circulating Fluidising Bed" is one of the most promising ones. The use of this technology has been proven by the success of the number of large CFB units operating worldwide over last one decade. Superior technical and excellent environmental performance without using complicated flue gas treatment facilities and possibility of use of inferior quality fuels is the driving force for its rapid development. CFBC boilers are simple to operate & maintain as they are sufficiently close to conventional boilers.

Various fuels for power generation are:
-Solid fuels comprising of coal (domestic & imported) & lignite.
-Liquid fuels comprising of heavy oil, light oil, distillate No.2, naphtha, condensate, HSD, superior kerosene oil and refinery residue.
-Gaseous fuels comprising of Natural Gas including LNG.
-Nuclear, hydro and renewable sources of power.
-Emerging fuels like orimulsion, di-methyl ether, coal bed methane and gas hydrates.

In case of the utilities we find that over the years there has been a dominance of coal as the fuel source for power generation. 60% of the total installed generation capacity in 2001 used coal as the primary fuel. The fuel which has gained share over the period of time is gas. In 1976 its share was 0.9% while in the year 2001 the share of gas base plants is 10.3%, a cumulative growth of 6.4%. All major global projections suggest that fossil fuels will remain key for power generation and that global coal demand is expected to double by 2030. The IEA estimates that 4500 GW of new power plant will be required, of which 40% will be coal fired, with an investment value of €1450 billion. Clean coal technologies (CCT) with higher efficiencies and better environmental performance, and carbon dioxide capture and storage are crucial for this competition and for the ultimate creation of near-zero-emission power plants. It is important to note that coal offers an abundant, widely spread fossil energy resource, available at a stable price from many international suppliers. However, the future for coal fired power generation depends on continuing improvements in its environmental performance, thermal efficiency and overall economics. Indeed a sustainable future for coal will only be achieved if the deployment of coal fuelled power generation processes with much lower specific CO2 emissions can be shown to be economically attractive compared to alternatives. Ultimately the target must be to establish near-to zero- emissions power plants.

INTRODUCTION

India's population is growing at a rate of about 1.6 per cent per year, and is expected to reach 1.16 billion by the year 2010. This population growth, coupled with continued economic growth, is driving energy demand to levels above the country's production capacity. Overall, India's need for power is growing at a remarkable rate. Annual electricity generation and consumption have nearly doubled since 1990. Electricity generation has grown from 275.5 billion kilowatt-hours (kWh) to 547.2 kWh, while consumption has grown from 257.1 kWh to 510.1 kWh. The country's projected increase in electricity consumption, of between 2.6 per cent and 4.5 per cent up to 2020, is the highest for any major country.

In the face of growing demand, India's electricity sector faces problems of capacity, poor reliability, and frequent blackouts. The anticipated electricity shortage is estimated at between 11 and 18 per cent. Currently 79 per cent of electricity comes from fossil fuels, mostly coal. India is the third largest coal-consuming country in the world, behind China and the United States; it accounts for about 8 per cent of the world's annual coal consumption and about 7.5 per cent of the world's annual coal production. Nearly three-quarters of India's electricity and two-thirds of its commercial energy comes from coal, and the demand for coal has been steadily increasing over the past decade.

Besides coal, Natural gas & Naphtha are also frequently used for power generation. They have very good combustion properties & also environmental friendly fuels. The demand pattern for Natural gas is increasing very rapidly compare to any other fuels.

CHAPTER: 1

MAIN FEED-STOCKS FOR POWER GENERATION IN INDIA

*E*nergy exists in different forms in nature but the most important form is electrical energy. The modern society is too much dependent upon the use of electrical energy that it has become a part and parcel of our life.

In India the main feed-stocks for power generation are:

i. Coal.
ii. Natural gas.
iii. Naphtha.

Coal:

Coal is thought ultimately to derive its name from the Old English **col** but this actually meant charcoal at that time; coal was not mined prior to the late Middle Ages; i.e. after 1000 AD. Mineral coal was referred to as sea-coal since it was found washed up on beaches occasionally.

In India, coal is the most abundant available fossil fuel and provides a substantial part of energy needs. It is used for power generation, to supply energy to industry as well as for domestic needs. India is highly dependent on coal for meeting its commercial energy requirements. Presently about 62% of power generated in the country is from coal fired boilers. About 66% of the coal produced is consumed by Thermal Power Plants. This pattern is likely to continue. The coal based electricity generation capacity sharply increased from 8000 MW in 1970 to 51000 MW in 1995. This is expected to go up to 140000 MW by 2009-10. However, at present, the country faces an energy shortage of about 15% and peaking shortage of 30%.

Inventory of Coal Resources of India: Coal Mining in India was started in the year 1774 in the eastern part of the country in the State of West Bengal. At the beginning of this century, the total production of coal was just about 6 million tonnes per year. When India gained its independence in 1947, the coal production was nearly 30 million tonnes per year and the coal mining operation was primarily in the private sector. Till 1971-73 the coal mining operation remained primarily in the private sector and the production had come up to a level of nearly 72 million tonnes per year only. The entire coal industry in India was nationalized during 1972-73 and then on massive investments was made by the Government of India in this basic infrastructure sector. The production during 1996-97 was 286 million tonnes and coal production in 1997-98 would be nearly 298 mt. With this production growth, India now ranks as the third largest coal producer of the World next only to China and USA.

As a result of exploration carried out down to a depth of 1200m by the GSI and other agencies, a cumulative total of 245.69 Billion tonnes of coal resources have been established in the country as on 1.1.2004. The state-wise distribution of coal resources and its categorization are as follows:-

Table 1.1:State-wise Resources of Indian Coal:

State	**Coal Resources in Million Tonnes**			
	Proved	**Indicated**	**Inferred**	**Total**
Andhra Pradesh	8091	6092	2514	16697
Arunachal Pradesh	31	40	19	90
Assam	279	27	34	340
Bihar	0	0	160	160
Chhattisgarh	8771	26419	4355	39545
Jharkhand	35409	30107	6348	71864
Madhya Pradesh	7513	8233	2914	18660
Maharashtra	4653	2156	1605	8414
Meghalaya	117	41	301	459
Nagaland	4	1	15	20
Orissa	14614	31239	15135	60988
Uttar Pradesh	766	296	0	1062
West Bengal	11383	11523	4488	27394
Total	**91631**	**116174**	**37888**	**245693**

Ministry of Coal -Annual Report: 2002-03.

The coal resources of India are available in sedimentary rocks of older Gondwana formations of peninsular India and younger Tertiary formations of Northern/North- Eastern hilly region. Based on the results of Regional/Promotional Exploration, where the boreholes are placed 1-2 Km. apart, the resources are classified into Indicated or Inferred category. Subsequent Detailed

Exploration in selected blocks, where boreholes are less than 400meter apart, upgrades the resources into more reliable Proved category. The Formation-wise and Category-wise coal resources of India as on 1.1.2004 are given below:

Table 1.2: Formation-wise coal resources of India

(In Million Tonnes)

Formation	**Proved**	**Indicated**	**Inferred**	**Total**
Gondwana Coals	91199	116068	37519	244786
Tertiary Coals	432	106	369	907
Total	**91631**	**116174**	**37888**	**245693**

Ministry of Coal -Annual Report: 2002-03

Apart for above resources, about 141Bt of coal is likely to be available in Prognosticated category where estimation is highly tentative and predictive.

Table 1.3 the estimates of coal reserves in the country during last 5 years

(In Million Tonnes)

As on	**Proved**	**Indicated**	**Inferred**	**Total**
1.1.1999	79106	88427	41219	208752
1.1.2000	82396	89501	39697	211594
1.1.2001	84414	90242	39250	213906
1.1.2001(Revised by Sub-Group-II)	84414	98546	38023	220983
1.1.2002	87320	109377	37417	234114
1.1.2003	90085	112613	38050	240748
1.1.2004	91631	116174	37888	245693

Ministry of Coal -Annual Report: 2002-03

Figure 1.1: Coal fields in India

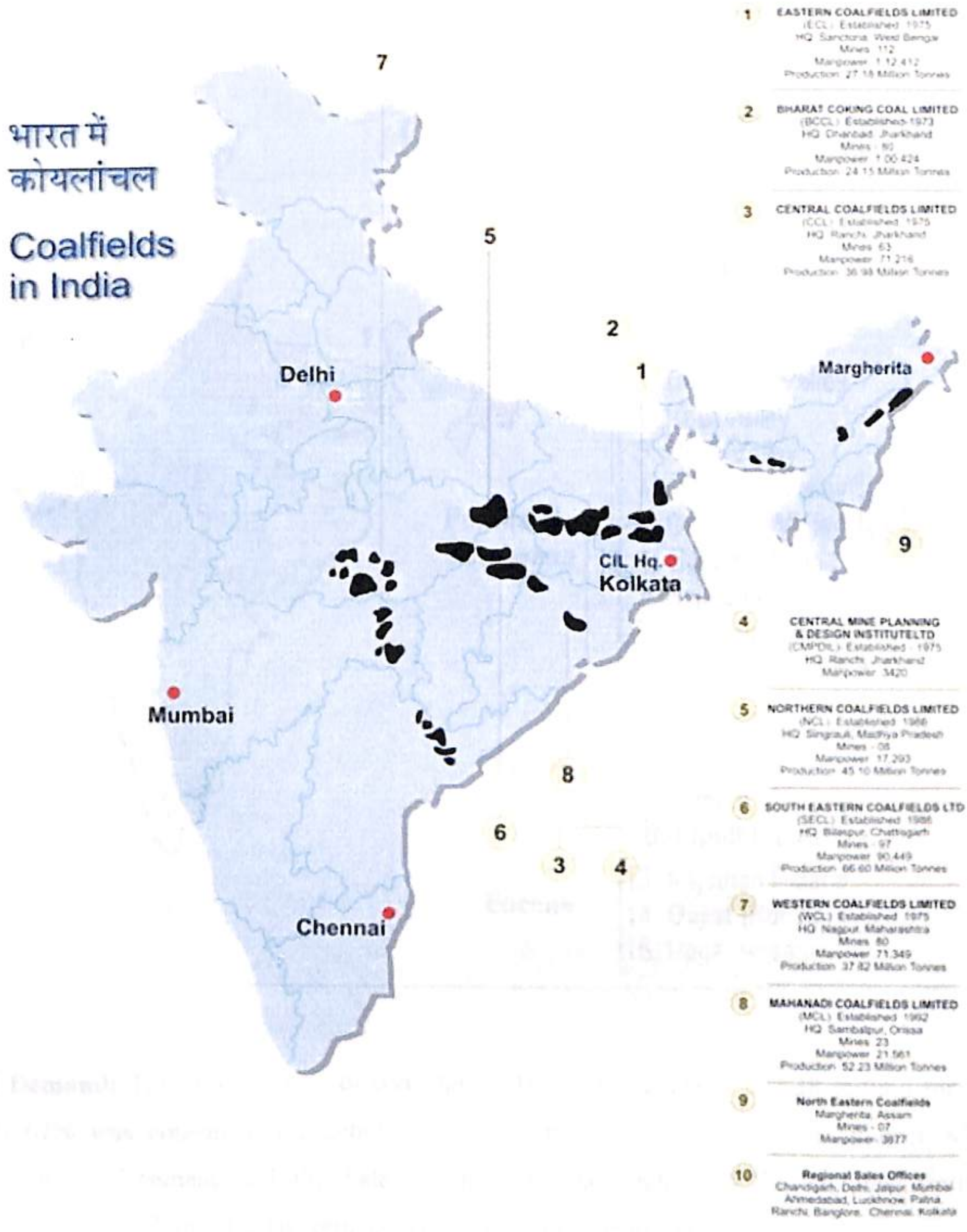
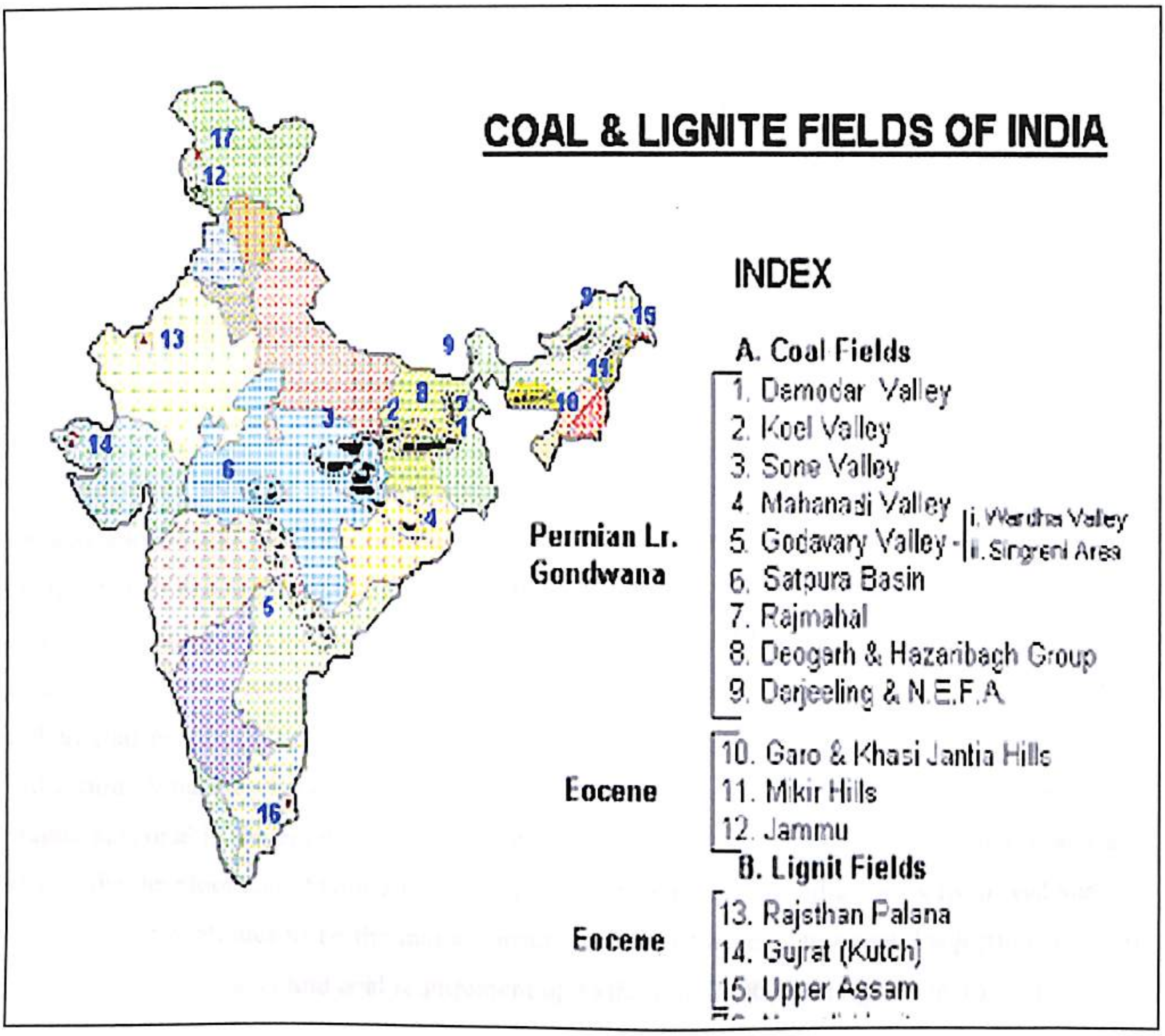


Figure 1.2: Coal & lignite fields in India



Coal Demand: The consumption of coal during 1997-98 was about 323.38 million tonnes of which 67% was consumed for generating electricity, 13% for production of steel, 4% for manufacture of cement and the balance 16% in other industries like textiles, fertilisers, refractories, brick, kilns etc. The projected coal demand is as follows:-

Table 1.4 Projected Demand

(Million Tonnes)

	1997-98	2001-02	2009-10
STEEL	41.4	51.6	68.0
ELECTRICITY	222.0	287.8	500.0
CEMENT	18.2	21.4	37.0
OTHERS	41.78	51.4	85.0
TOTAL	323.38	412.2	690.0

India has relatively large reserves of coal (202 billion tonnes) compared to crude oil (728 million tonnes) and natural gas (686 billion cubic meters). Coal meets about 60% of the commercial energy needs and about 70% of the electricity produced in India comes from coal. The coal resources which are in substantial commercial use and their utilization technologies will be vital factors in shaping economic and societal progress. Advanced technologies when applied to Indian coal resources, can improve the efficiency and minimize environmental impacts of coal utilization. A balance is necessary between short term imperatives and long term possibilities to enable sustainable development. To pursue such a strategy technologies are available and are also under development. About 70% of the electricity generated in India comes from coal and the power sector continues to be the major consumer of coal for years to come. Projections on coal based installed capacity and coal requirement up to the year 2006-07 are given in Table 1.5

Table 1.5: Installed Capacity and Coal Requirement

	1996-97	**2001-02**	**2006-97**
Installed capacity,			
- Total, MW	89372	146155	209830
- Coal based, MW	53223	81068	111068
Coal requirement, mt	215	350	500

Natural gas:

Natural gas, in itself, might be considered a very uninteresting gas - it is colorless, shapeless, and odorless in its pure form. Quite uninteresting - except that natural gas is combustible, and when burned it gives off a great deal of energy. Unlike other fossil fuels, however, natural gas is clean burning and emits lower levels of potentially harmful byproducts into the air. We require energy constantly, to heat our homes, cook our food, and generate electricity. It is this need for energy that has elevated natural gas to such a level of importance in our society, and in our lives.

Natural gas is a combustible mixture of hydrocarbon gases. While natural gas is formed primarily of methane, it can also include ethane, propane, butane and pentane. The composition of natural gas can vary widely, but below is a chart outlining the typical makeup of natural gas before it is refined.

Table 1.6:Typical Composition of Natural Gas

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

In its purest form, such as the natural gas that is delivered to our home, it is almost pure methane. Methane is a molecule made up of one carbon atom and four hydrogen atoms, and is referred to as CH_4. Ethane, propane, and the other hydrocarbons commonly associated with natural gas have slightly different chemical formulas.

Natural gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is 'wet'.

Natural gas, because of its clean burning nature, has become a very popular fuel for the generation of electricity. In the 1970's and 80's, the choices for most electric utility generators were large coal or nuclear powered plants; but, due to economic, environmental, and technological changes, natural gas has become the fuel of choice for new power plants. In fact, in 2000, 23,453 MW (megawatts) of new electric capacity was added in the U.S. Of this, almost 95 percent, or 22,238 MW were natural gas fired additions. The graph below shows how, according to the Energy Information Administration (EIA), natural gas fired electricity generation is expected to increase dramatically over the next 20 years, as all of the new capacity that is currently being constructed comes online.

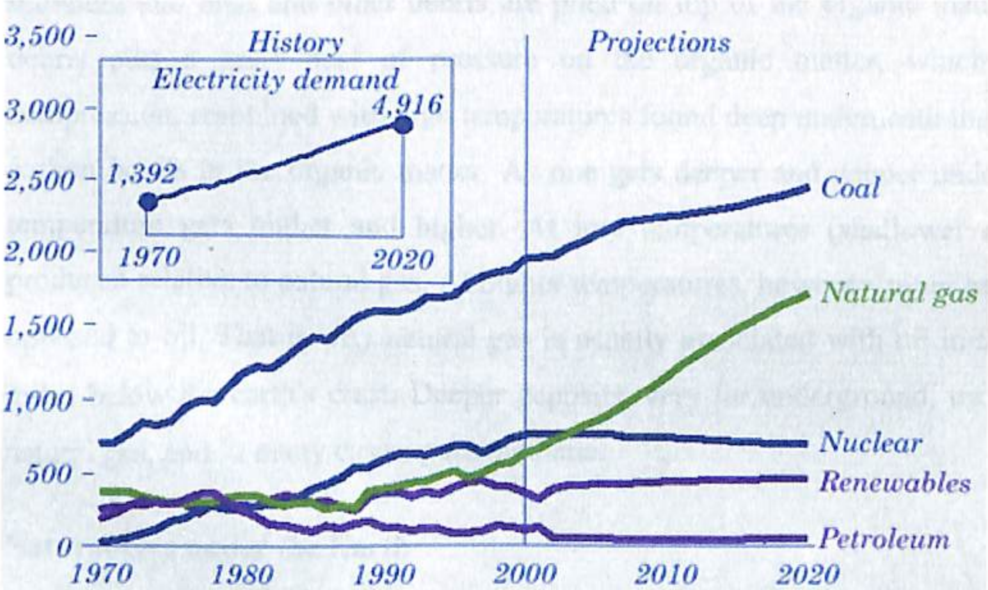


Figure 1.3:Electricity Generation by Fuel 1970-2020 (billion kilowatt hours)

Source: EIA Annual Energy Outlook 2002 with Projections to 2020.

There are many reasons for this increased reliance on natural gas to generate our electricity. While coal is the cheapest fossil fuel for generating electricity, it is also the dirtiest, releasing the highest levels of pollutants into the air. The electric generation industry, in fact, has traditionally been one of the most polluting industries in the United States. Regulations surrounding the emissions of power plants have forced these electric generators to come up with new methods of generating power, while lessening environmental damage. New technology has allowed natural gas to play an increasingly important role in the clean generation of electricity.

Formation of Natural Gas

Natural gas is a fossil fuel. Like oil and coal, this means that it is, essentially, the remains of plants and animals and microrganisms that lived millions and millions of years ago.

There are many different theories as to the origins of fossil fuels. The most widely accepted theory says that fossil fuels are formed when organic matter (such as the remains of a plant or animal) is compressed under the earth, at very high pressure for a very long time. This is referred to as thermogenic methane. Similar to the formation of oil, thermogenic methane is formed from organic particles that are covered in mud and other sediment. Over time, more and more sediment and mud and other debris are piled on top of the organic matter. This sediment and debris puts a great deal of pressure on the organic matter, which compresses it. This compression, combined with high temperatures found deep underneath the earth, break down the carbon bonds in the organic matter. As one gets deeper and deeper under the earths crust, the temperature gets higher and higher. At low temperatures (shallower deposits), more oil is produced relative to natural gas. At higher temperatures, however, more natural gas is created, as opposed to oil. That is why natural gas is usually associated with oil in deposits that are 1 to 2 miles below the earth's crust. Deeper deposits, very far underground, usually contain primarily natural gas, and in many cases, pure methane.

Natural Gas under the Earth

Although there are several ways that methane, and thus natural gas, may be formed, it is usually found underneath the surface of the earth. As natural gas has a low density, once formed it will rise towards the surface of the earth through loose, shale type rock and other material. Most of this methane will simply rise to the surface and dissipate into the air. However, a great deal of this methane will rise up into geological formations that 'trap' the gas under the ground. These formations are made up of layers of porous, sedimentary rock (kind of like a sponge, that soaks up and contains the gas), with a denser, impermeable layer of rock on top. This impermeable rock traps the natural gas under the ground. If these formations are large enough, they can trap a great deal of natural gas underground, in what is known as a reservoir. There are a number of different types of these formations, but the most common is created when the impermeable sedimentary rock forms a 'dome' shape, like an umbrella that catches all of the natural gas that is floating to the surface. There are a number of ways that this sort of 'dome' may be formed. For instance, faults are a common location for oil and natural gas deposits to exist. A fault occurs when the normal sedimentary layers sort of 'split' vertically, so that impermeable rock shifts down to trap natural gas in the more permeable limestone or sandstone layers. Essentially, the geological formation which layers impermeable rock over more porous, oil and gas rich sediment has the potential to form a reservoir. To successfully bring these fossil fuels to the surface, a hole must be drilled through the impermeable rock to release the fossil fuels under pressure. Note that in reservoirs that contain oil and gas, the gas, being the least dense, is found closest to the surface, with the oil beneath it, typically followed by a certain amount of water.

With natural gas trapped under the earth in this fashion, it can be recovered by drilling a hole through the impermeable rock. Gas in these reservoirs is typically under pressure, allowing it to escape from the reservoir on its own.

Gas market in India

Natural gas industry in India is under government control today due to its strategic importance. Till few years back, the production of natural gas in the country was totally under the control of two PSUs viz. Oil and Natural Gas Corporation (ONGC) and Oil India Ltd. (OIL). However, with the New Exploration and Licensing Policy (NELP), private players have been allowed to participate in exploration and production of natural gas. Currently, the two PSUs still account for 83 percent of domestic gas production. Marketing of gas and pipeline infrastructure is undertaken by GAIL India Ltd. Companies such as Gujarat Gas Company Ltd. (GGCL), Mahanagar Gas Ltd. (MGL) and Indraprastha Gas Ltd. (IGL) are engaged in distribution of gas and are regional players. Power and fertilizers are the two primary sectors which together account for close to 80 percent of the gas consumption. Besides, other sectors such as petrochemicals, sponge iron and transportation also consume natural gas. Demand for natural gas in India for 2003-04 was estimated at 98 mmscmd (million standard cubic metres per day). Against this demand, allocations made by Ministry of Petroleum and Natural Gas (MoPNG) stood at around 120 mmscmd. Currently, in India, natural gas forms 8 percent of the primary energy consumption as compared to 24 percent worldwide. According to India Hydrocarbon Vision 2025 report, demand for natural gas is expected to show a sharp rise in the future with the demand reaching to 391 mmscmd by 2024-25. The report also expects that the share of natural gas in total energy mix to go upto 20 percent. The demand for natural gas is expected to grow at a CAGR of more than 7 percent by 2007-08. The major force behind this demand growth will be investments in power sector. Government is planning to add power generation capacity of 41,110 MW under the Tenth Plan and over 60,000 MW in the Eleventh Plan. Fertilizer sector will fuel this demand further as major players switch from naphtha to gas as feedstock.

Gas supply to be unleashed in India in coming years

From 2004-05, Indian gas sector is going to witness phenomenal growth in supplies. In April 2004, Petronet LNG Ltd. commenced supplies at its 5 million tonne per annum (MTPA) LNG regassification terminal at Dahej. Petronet further plans to raise the capacity to 10 MTPA by 2010. It had already signed an agreement with Ras Gas of Qatar to source additional 2.5 MTPA of LNG apart from its current purchase of 5 MTPA. Shell is also likely to start operations at its regasification terminal at Hazira in April 2005, adding another 5 MTPA of capacity. Supplies from Reliance's gas find in the Krishna Godavari basin are likely to reach the market from 2007-08. These developments are likely to alter the demand supply equation for the gas market.

Table1.7: The emerging gas supply scenario in the country:

Domestic					
Tapti, Cairn, Cambay, Niko, Western offshore	15-20	2004-06	KG Deepwater	40	2007
			CBM	5	2006
Imports					
Dahej LNG	36	2004/2010	Bangladesh	10	2006
Hazira LNG	10	Apr-05	Myanmar	15-20	2007
Dabhol LNG	18	Mid 2006	Ennore LNG	10	2008
Kochi	10	2007-08			
	89-94			**80-85**	

As indicated by the above table, supply scenario for gas is set to undergo a radical change. Total supply of gas is expected to increase by 170-180 mmscmd over the next five years. However, the supply from Kochi, Bangladesh and Ennore are subject to approval and materialization of the projects.

Naphtha:

Naphtha is a general term used to describe special boiling point spirits having a boiling range of approximately 30 to 170 deg. C

Nomenclature

Naphtha is widely used in fertilizer plants and petrochemical industries as a feed stock. It is a highly volatile product, manufactured from crude oil by direct atmospheric distillation and by catalytic cracking of heavy residues. There are two types of Naphtha marketed namely, High Aromatic Naphtha (HAN) and Low Aromatic Naphtha (LAN) known as Naphtha (Petrochemical). Naphtha essentially consists of paraffinic, naphthenic and aromatic Hydrocarbons. The presence of Aromatic Hydrocarbons in Naphtha is very critical especially when it is used in fertilizer plants. In fact, the design of a fertilizer plant may entirely depend upon the composition of Naphtha available or a refinery has to produce Naphtha according to the needs and specifications demanded by a fertilizer plant. This is one of the reasons that IS Specifications for Naphtha has been withdrawn.

Naphtha is used as a fuel in fertilizer plant reformers where high temperatures are required. It is also used as a fuel for steam generation in the plants where reforming is done with the help of steam. Some gas turbines for power generation have also been installed recently which will require Naphtha as fuel.

Aromatics

The most important criterion for the selection of Naphtha as a feed stock in a fertilizer plant is its aromatic content. This is because, in a fertilizer plant, Naphtha is reformed to carbon dioxide and hydrogen in presence of a catalyst which is used for the manufacture of Urea and Ammonia.

Aromatics are basically resistant to reformation and hence, high temperatures are to be maintained or more time will be required to complete reformation which results in loss of production. Aromatics also burn with smoke releasing a fine soot of carbon which gets coated on the catalyst thus, reducing catalyst activity which in turn, reduces production. When Naphtha with high aromatic content is used in a petrochemical plant, say for example manufacture of Ethylene, production will decrease since it is difficult to convert aromatic hydrocarbons to Ethylene. Hence, low aromatic Naphtha is preferred in these types of industries.

Olefins

These are unsaturated hydrocarbon compounds and their presence in Naphtha would lead to:

a. Possible gum formation in presence of air.

b. Increased coking in the pre-heater tubes of the hydro-desulphurization section.

c. Increased hydrogen consumption in the hydro-desulphurization section.

Therefore, the olefin content in Naphtha is kept to the minimum and in manufacturing specification, it is limited to max. 1% on volume basis.

Sulphur

Sulphur poisons the nickel catalyst used in the reformer in fertilizer plants, resulting in the deactivation of catalyst thus affecting the production patterns. Large amounts of expensive catalyst may have to be replaced due to sulphur poisoning of catalyst. Hence, an upper limit on the amount of sulphur in Naphtha is specified. At times, sulphur limit is prescribed owing to the design parameters of the plant. The maximum limit 0.15% by wt. prescribed in the specification is acceptable to most of the fertilizer and petrochemical industries in India.

Distillation

The higher the distillation range, the longer will be the carbon chain length. In a fertilizer or petrochemical plant, the catalyst is designed to reform hydro-carbons having a particular carbon chain length only. In case the carbon chain length exceeds the limit, the catalyst may not be in a position to act on it effectively. This is the reason why there is a limit on distillation range. In addition to the above, distillation range ensures uniform quality of the product throughout.

Trace Elements

The trace elements like lead, vanadium, sodium etc. in Naphtha may fuse with catalyst at high temperature that they encounter in the reformer. This results in the deactivation of catalysts. Hence, it is desirable to have Naphtha free of these trace metals.

However, these trace metals concentration cannot be controlled in the Refinery.

Table 1.8: Specification of Low Aromatic Naphtha

Sr. No.	Characteristics	Test methods	NAPHTHA
1	Density @ 15 ^{0}C,g/ml.	P-16	To be reported
2	Reid Vapour Pressure @ 38 ^{0}C, kg/cm, max.	P-39	0.85
3	Sulphur (lamp) % wt. max.	P-34	0.15
4	Aromatics, % vol. Max.	P-23	10
5	Olefins, % vol., Max.	P-23	1
6	Distillation		
7	IBP ^{0}C min.		34
8	5% V.REC.@ ^{0}C,min.		45
9	50% V.REC.@ ^{0}C,min.		105
10	90% V.REC.@ ^{0}C		To be reported
11	95% V.REC.@ ^{0}C,max.		140
12	FPB ^{0}C, max.		160

CHAPTER: 2

SPECIFICATION OF FEED-STOCK ACCORDING TO POWER PLANT REQUIREMENT

Specification/quality of Indian coal for power generation:

The total reserves of coal are estimated at about 201.07 billion tonnes. The coal deposits are confined to the eastern, central and southern parts of the country. Quantity-wise reserve position is broadly as under:

Coking coal - 15%
Non-coking coal - 85%

Table 2.1:Break-up of Indian Coal Reserves according to Grade and Depth as on 1.1.96

	Grades (Superior)	Grades (Inferior)	Total (Non coking)	Coking	Total
Billion tonnes					
Total	47.22	124.04	171.26	29.81	201.07
Upto 600 m depth	43.35	112.44	155.79	23.85	179.64

Characteristics of Indian non-coking coals in general are:-

1. Low sulphur content, generally below 0.5%.
2. High ash fusion temperature, generally above 1150 °C (IDT).
3. Low Iron Content in ash.
4. Refractory nature of ash.
5. Low chlorine content.
6. Toxic trace elements are less in coal-Ash.

Table 2.2:Trace elements in Indian Coals

Sl. No.	Elements	PPM in Ash	Remarks
1.	Gallium, Lanthanum Molybdenum, Cobalt, Boron	0 to 150	Characteristically Low
2.	Copper, Lead	< 120	Low Concentration
3.	Manganese	< 100	-
4.	Vanadium, Strontium	100-200	-
5.	Tin, Yitrium	0-50	Very Low
6.	Chromium	Below 170	Characteristically Low
7.	Nickel	< 100	Usually less for general
8	Niobium	0-50	Generally Low
9.	Arsenic	< 100	Generally around 50 ppm
10.	Cadmium	<17	

Table 2.3: Average composition of Coal Ash of USA, UK & INDIA

CONSTITUENT	USA	UK	INDIA
SIO2	40-60	25-40	40-65
Al203	20-35	20-40	17-38
Fe203	5-25	00-30	4-18
CaO	1-15	1-10	0.8-8
MgO	0.5-40	0.5-5	0.9-4
TiO2	0.3-03	00-3	0.7-2.7
MnO	-	-	TRACE
ALKALIES	1-4	1-6	1-4
SO3	-	1-12	-

"SI02/A1203, ratio of Indian coal is favourable compared to UK coal from slag viscocity point of view, Fe 203 content of Indian coal is relatively low compared to both US and UK coals making the ash fusion characteristics favourable for use in power plants".

Coal is a fossil fuel extracted from the ground by mining. It is a readily combustible black or brownish-black sedimentary rock. It is composed primarily of carbon and hydrocarbons, along with assorted other elements, including sulfur. Often associated with the Industrial Revolution, coal remains an enormously important fuel and is the most common source of electricity world-wide. In the United States, for example, the burning of coal generates over half the electricity consumed by the nation.

Table 2.4: Different types coal having their different calorific values and composition:

S.No.	Particular	Calorific value	Composition
1	Lignite	5,000 Kcal/Kg	C=67%,H=5%,O=20%, ash=8%
2	Bituminous coal	7,600 Kcal/Kg	C=83%,H=5.5%,O=5%,ash=6.5%
3	Anthracite coal	8,500 Kcal/Kg	C=90,H=3%,O=2%,ash=5%

The quality of coal depends upon its rank and grade. The coal rank arranged in an ascending order of carbon contents is

Lignite --> sub-bituminous coal --> bituminous coal --> anthracite

Indian coal is of mostly sub-bituminous rank, followed by bituminous and lignite (brown coal). The ash content in Indian coal ranges from 35% to 50%.

Chemical composition of the coal is defined in terms of its proximate and ultimate (elemental) analysis. The parameters of proximate analysis are moisture, volatile matter, ash, and fixed carbon. Elemental or Ultimate analysis encompasses the quantitative determination of carbon, hydrogen, nitrogen, sulfur, and oxygen. The calorific value Q, of coal is the heat liberated by its complete combustion with oxygen. Q is a complex function of the elemental composition of the coal. Gross Calorific value Q is mostly determined by experimental measurements. A close estimate can be made with the Dulong formula

$$Q = (144.4\ \%[C]) + (610.2\ \%\ [H]) - (65.9\ \%\ [O]) + (0.39\ \%\ [O]^2)$$

Q is given in Kcal/kg or Btu/lb. Values of the elements C, H, and O, are calculated on a dry ash-free coal basis.

Indian coal is classified by grades defined on the basis of Useful Heat Value (UHV). UHV is an expression derived from ash and moisture contents for non-cocking coals as per the Government of India notification. The ultimate analysis of coal used in power plants in India is readily not available. Ultimate analysis of D, E, and F grade coal is obtained as personal communication from Central Fuel Research Laboratory (CFRI), Jharkhand, India. Ultimate analysis of coal used at Dadri, Rihand, Singrauli, Chandrapur, and Dahanu power plants is obtained as personal communication from National Energy Technology Laboratory, Pittsburgh, USA. The Neyveli Lignite Corporation provided by personal communication, the ultimate analysis for lignite used at the Neyveli and Kutch power plants. These are presented in Tables 2.5 & 2.6.

Table 2.5: Elemental analysis, moisture content, and grades of typical Indian coals

Coal Grade	**C%**	**H%**	**S%**	**N_2%**	**O_2%**	**A%**	**M%**	**NCV (Kcal/Kg)**	**UHV (cal/gm)**
D	33.1	2.46	0.44	0.83	NA	25.9	7.2	4999.0	4332.0
D	30	2.48	0.57	0.69	NA	27.1	2.9	5555.0	4760.0
D	32.31	2.12	0.4	0.78	NA	25	7.3	5068.0	4442.0
E	37.9	2.4	0.53	0.8	6%	30.4	7.5	4529.0	3670.0
F1	41.87	3.33	0.56	0.94	6%	34.07	7.8	4137.0	3122.0
F2	44.47	3.37	0.35	0.99	6%	36.3	8.4	3833.0	2731.0
Average of E and F2	41.19	2.89	0.44	0.9	0.06	33.35	7.95	4182.0	-

Table 2.6: Elemental analysis and moisture content of the coal used at the seven power plants in India

Coal	C%	H%	S%	N_2%	O_2%	A%	M%	NCV
Dadri	40.3	4.16	0.5	0.9	15.92	38.22	NA	NA

Rihand	37.74	3.26	0.39	0.73	14.65	43.23	NA	NA
Singrauli	50.22	4.78	0.33	1.09	17.25	26.33	NA	NA
Chandrapur	37.69	2.66	0.8	1.07	5.78	47.0	5	3649.9
Dahanu	42.39.0	3.73	0.39	0.82	14.21	38.46	5.93	3986.37
Nevyeli Lignite	26.09	2.33	1.5	0.24	16.33	7.0	47	2229.0
Kutch Lignite	28.33	3.03	2.25	0.88	13.94	15.0	36	2900.0

NA: Not Available

C: Carbon

H: Hydrogen

S: Sulfur

N: Nitrogen

CV: Calorific value

A: Ash

M: Moisture

UHV: Useful heat value = 8900 - 138(A+M)

GCV: Gross Calorific Value = (UHV + 3645 -75.4 M)/1.466

NCV: Net Calorific Value = GCV - 10.02M

Relationship of GCV, UHV, and NCV is empirical.

Ultimate analysis of typical United States coals is given in Table 2.7 for the sake of comparison.

Table 2.7: Ultimate analysis of typical US coals

Coal	**C%**	**H%**	**S%**	**N_2%**	**0_2%**	**A%**	**M%**	**NCV (Kcal/Kg)**
Pennsylvania	65.8	4.6	2.3	1.4		19.8	1.1	6567
Ohio	64.2	5.0	1.8	1.3		16.0	2.8	6378
West Virginia	72.1	4.8	1.0	1.4		11.7	1.8	7025
Kentucky	70.9	5.1	2.3	1.5		9.8	2.3	7022
West Virginia	70.0	5.1	1.2	1.5		8.1	1.2	7522
Illinois	77.4	5.5	2.5	1.4		8.2	4.1	7027

Pennsylvania	77.4	5.2	2.4	1.4		7.5	1.1	7728
Illinois	73.7	5.1	2.3	1.6		7.9	2.0	7330

Importance of the quality of coal is illustrated by the comparison of coal used at Chandrapur Thermal Power Plant (India) and the Ohio (USA) coal. The ultimate analyses of the two coal types are given in Table 2.8. The Calorific value of Ohio coal is almost twice to that of Chandrapur coal. This means that roughly twice the Indian coal compared to Ohio coal is needed to generate same quantity of steam (electricity). Assuming 30% thermal conversion efficiency in converting thermal energy from coal to the electrical energy, coal used for generating a unit of electricity is (Kg/KWH) 0.77 for Indian coal and 0.36 for Ohio coal.

Table 2.8: Comparison (Ultimate analysis) of Chandrapur and Ohio coal

		Chandrapur (India)	**Ohio (USA)**
1	Fixed carbon	27.5%	44.0
2	Total carbon	37.69%	64.2%
3	Hydrogen	2.66%	5.0 %
4	Nitrogen	1.07%	1.3 %
5	Oxygen (difference)	5.78%	11.8 %
6	Sulfur	0.8%	1.8 %
7	Ash	47%	16%
8	Total moisture	5%	2.8
9	Gross calorific value Kcal/Kg	3400	6378
10	Coal per unit of electricity (Kg/KWH)	0.77	0.36

The coal properties including calorific values differ depending upon the colliery. The calorific value of the Indian coal (~15 MJ/kg) is less than the normal range of 21 to 33 MJ/Kg (gross). The design rating of a coal-fired burner (in USA) is at 26 MJ/Kg.

Bituminous coal

Bituminous coal Information -

Is a dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke. Bituminous coal is the most abundant coal in active U.S. mining regions. Its moisture content usually is less than 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu/ton (24 to 35 MJ/kg) on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu/ton (28 MJ/kg), on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Anthracite coal

Anthracite coal Information -

is the highest rank of coal; used primarily for residential and commercial space heating. It is hard, brittle, and black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. The moisture content of fresh-mined anthracite generally is less than 15 percent. The heat content of anthracite ranges from 22 to 28 million Btu/ton (26 to 33 MJ/kg) on a moist, mineral-matter-free basis. The heat content of anthracite coal consumed in the United States averages 25 million Btu/ton (29 MJ/kg), on the as-received basis (i.e., containing both inherent moisture and mineral matter). Note: Since the 1980s, anthracite refuses or mine waste has been used for steam electric power generation. This fuel typically has a heat content of 15 million Btu/ton (17 MJ/kg) or less.

Lignite coal

Lignite coal Information - It is brownish-black and has a high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu/ton

(10 to 20 MJ/kg) on a moist, mineral-matter-free basis. The heat content of lignite consumed in the United States averages 13 million Btu/ton (15 MJ/kg), on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Sub bituminous coal

Sub bituminous coal Information - It may be dull, dark brown to black, soft and crumbly at the lower end of the range, to bright, jet-black, hard, and relatively strong at the upper end. Sub bituminous coal contains 20 to 30 percent inherent moisture by weight. The heat content of sub bituminous coal ranges from 17 to 24 million Btu per ton on a moist, mineral-matter-free basis.

Coal Coke

Coke Information - Is a solid carbonaceous residue derived from low-ash, low-sulfur bituminous coal from which the volatile constituents are driven off by baking in an oven without oxygen at temperatures as high as 2,000 °F (1,000 °C) so that the fixed carbon and residual ash are fused together. Coke is used as a fuel and as a reducing agent in smelting iron ore in a blast furnace. Coke from coal is grey, hard, and porous and has a heating value of 24.8 million Btu/ton (29 MJ/kg). Byproducts of this conversion of coal to coke include coal-tar, ammonia, light oils, and "coal-gas". (Coke can also be made from petroleum)

Coal Jet

Jet Information - Is a compact form of lignite that is sometimes polished and used as an ornamental stone since the Iron Age.

Specification/quality of natural gas for power generation:

The specification of natural gas, which is required by power plants, is given below:

Table: 2.9

S.No.	Property	Unit	Value
1.	**Composition**	% Molar	80(Min)
	a. Methane (C1)	% Molar	10(max)
	b. Ethane (C2)	% Molar	05(max)

	c. Propane (C3)	% Molar	03(max)
	d. Butane (C4)	% Molar	02(max)
	e. Pentane (C5)	% Molar	01(max)
	f. Nitrogen	% Molar	0.1(max)
	g. Acetylene (C2H2)	% Molar	01(max)
	h. Hydrogen (H2)		
2.	**Molecular Weight**		
	a. Design (Typical)		
	b. Range		
3.	**Lower Heating Value**	Kcal/SCM	
	a. Design (Typical)		
	b. Range	Kcal/Scm	8010
	Minimum	Kcal/Scm	10680
	Maximum		
4.	**Supply Pressure**	Bar (g)	20-25
5.	**Supply Temperature**	Degree C	15
	a. Minimum	Degree C	30
	b. Normal	Degree C	50
	c. Maximum		
6.	**Contaminants**		
	a. Trace Metals	ppm (wt)	0.50(max)
	1.Pb+Zn	ppm (wt)	0.30(max)
	2.Na+K	ppm (wt)	0.50(max)
	3. Vanadium	ppm (wt)	2.0(max)
	4. Calcium	ppm (wt)	2.0(max)
	5. Magnesium	ppm (wt)	1.0(max)
	6. Sum of Heavy metals	% (wt)	NIL
	b. Liquid	Kg/Million SCM	112 (max)
	c. Moisture	ppm (wt)	10 (max)
	d. Hydrogen Sulphide	ppm (wt)	30 (max)
	e. Total Sulphur		
7.			0.6157-0.6812
	Specific Gravity		

Specification/quality of Naphtha:

Table 2.10:

Test	Method	Specification of Naphtha at NTPC's Kayamkulam power plant
Density @ 15°C,g/ml	P:16	0.682 to 0.75
Appearance	Visual	Clear & bright
Colour	Visual	Colourless
Total sulphur,% wt.	P:34/IP:36	Max 0.1
Residue on Evrp. Mg/100 ml	P:29	Max.5
Aromatic,% V	P:23/GC	Max. 20.0
Olefins,%V	P:23/GC	Max.1.0
Calorific value, Kcal/Kg (calculated) Gross Net	P:7 P:7	Min. 11300 Min. 10500
Distillation IBP, °C 50% recovered @ °C FBP, °C	P:18	To be reported Max. 130 Max.180
RVP @ 38 °C, Psi	P:39	Max.10
Lead as Pb, ppm	ASTM D-1368	Max.0.2
K.V.@ 15 °C,cSt	P:25	Min.0.5
Hydrogen content,%w	Calculated	-
C.C R,%wt	ASTM D-189	-
Particulates(mg/gal)	IP 216	-
Ash % wt	P:4	-
C/H(calculated)	(1)	Max. 6.5
Calcium,ppm	AAS/ICP	Max.2
Vanadium,ppm	AAS/ICP	Max.0.5
Nickel,ppm	AAS/ICP	Max. 0.1
Zinc,ppm	AAS/ICP	Max 0.1
Sodium & potassium,ppm	AAS/ICP	Max. 0.2
Water & Sediment,% vol.	ASTM D-2709	-

(1) C/H Ratio = (74+15 d)/(26-15d)

Where d =specific gravity @ 60/60 °F, reference U.S. Bureau of standards,

CHAPTER: 3

PREPARATION METHOD OF FEED-STOCKS ACCORDING TO POWER PLANT REQUIREMENT

Coal preparation/cleaning techniques as per power plant requirements:

COAL CLEANING METHODS

Coal Washing: Coal washing, technically called coal beneficiation, is a process by which the quality of raw coal is improved by either reducing the extraneous matter that gets extracted along with the mined coal or the associated ash or both.

Coal washing can either be dry deshaling or wet washing, though the term generally applies to the latter. In dry deshaling, the non-coaly shale and sandstone are removed without using any liquid media. In wet washing on the other hand, coal is first crushed to a smaller size and put in a liquid media whose specific gravity is adjusted to separate the lighter coal (low in ash) from the heavier coal (high in ash). The heavier coal, high in ash content, which is left behind as the residue after washing is called the reject.

In order to appreciate the claims made above, it may be pertinent to review the quality of Indian coal used for thermal power generation and the main sources of these coals.

The major coalfields supplying thermal coal and which would continue to supply thermal coal in the coming decades are Talcher and Ib valley in Orissa, Korba in MP; Wardha valley in Maharastra; North Karanpura, Jharia (non-coking seams only) and South Karanpura in Bihar; and Singrauli in UP/MP. Coal in these coalfields occurs in thick inter-banded coal seams with carbonaceous shale.

The ash range in the above coalfields particularly in Talcher, Ib, Korba and North Karanpura varies between 35% to 45% with average ash in the region of 40%. These would be the major sources of thermal coal in the future.

All post-1980 power plants have been designed to use coal with 40% or more ash. Also all such plants are larger in size i.e. 210 and 500 MW. The availability of these plants is reasonably high at 80% and 89% respectively in spite of the so-called inferior coal supplied. The key issue here is consistancy in coal quality, and not ash content per se.

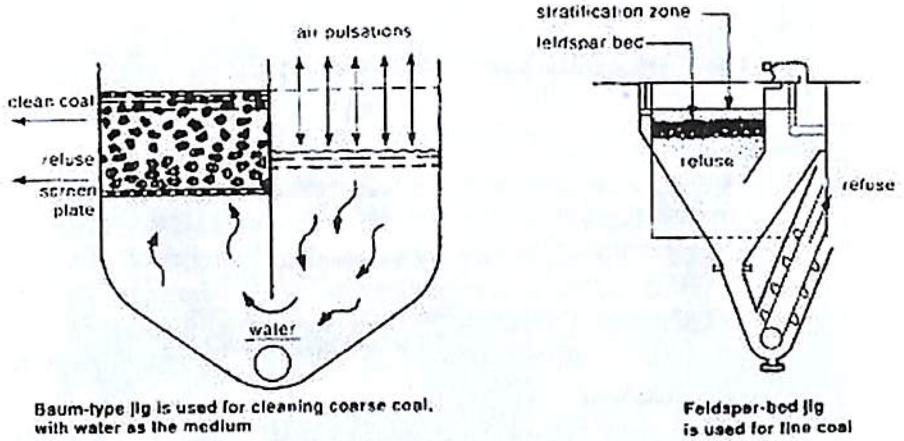
It is now proposed to benificiate the coal from around 40% ash content to 34% ash content by processes such as contra-flow, jigs or dense media bath. A reduction in ash of 6% to 8% is feasible by single process washery. The present cost of such benificiation works out to Rs. 135-150 per tonne of raw coal, with an yield of around 76% of clean coal and 24% rejects. This effectively means that the process cost for each tonne of clean coal will be Rs. 176 to Rs. 195. The investment requirement for setting up a washery will vary from Rs. 400 to Rs. 600 per tonne of annual capacity. As there will be around 24-25% rejects containing about 20-30% carbon content, an extra 15-20% mining capacity will require to be added to supply the equivalent amount of thermal energy as is available from unwashed coal.

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 sin, 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.



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

Feldspar-bed jig is used for fine coal

Fig.3.1 *Baum Jig and a Feldspar Jig for Fine Coal*

Dense-medium separators

Dense-medium vessels also operate by specific gravity difference; however, rather than using water as the separation medium, a suspension of magnetic 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 buy this method.

Key factors in the operation of any dense-medium system based on magnetite are the control equipment and the efficiency of magnetic recovery for recycle. There can be a build-up of other minerals in the medium, making control more difficult. Figure 3.2 shows example of a dense-medium bath and a dense-medium cyclone.

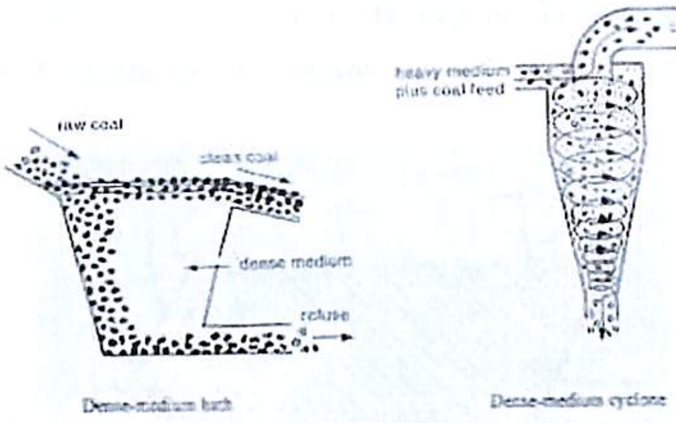


Fig.3.2 : *Dense-medium Separators*

Hydro cyclone

Hydro cyclones 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 3.3. The cyclone diameter has a significant influence on the sharpness of separation.

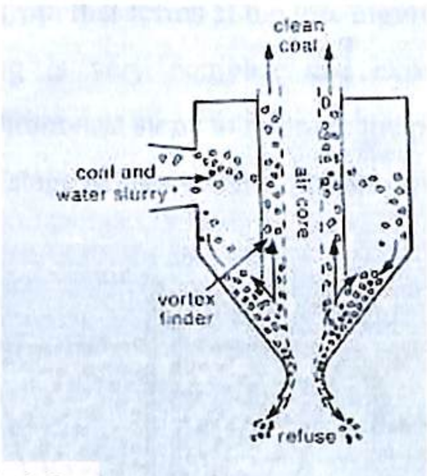


Fig.3.3 *Hydrocyclone*

Concentration tables

Concentrating tables are tilted and ribbed and they move back and forth in a horizontal direction. The lighter coal particles 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 3.4. 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.

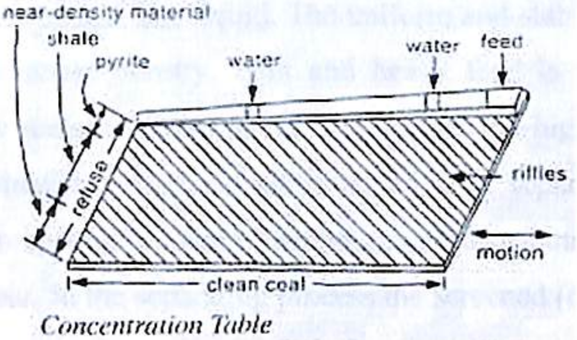


Fig.3.4 *Concentration Table*

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 3.5 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.

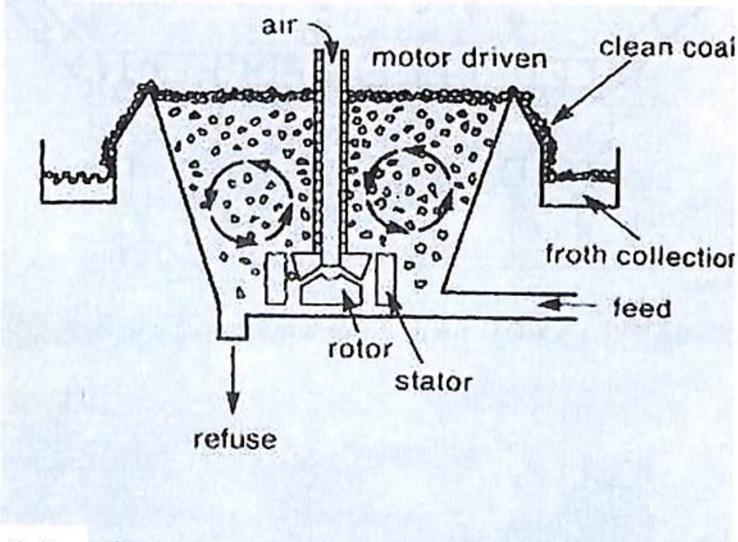


Fig.3.5 *Froth Floatation*

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 magnetic. 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 counter flow. In Figure 3.6, the floated light product such as clean coal is discharged to the right, and the sunken heavy product to the left.

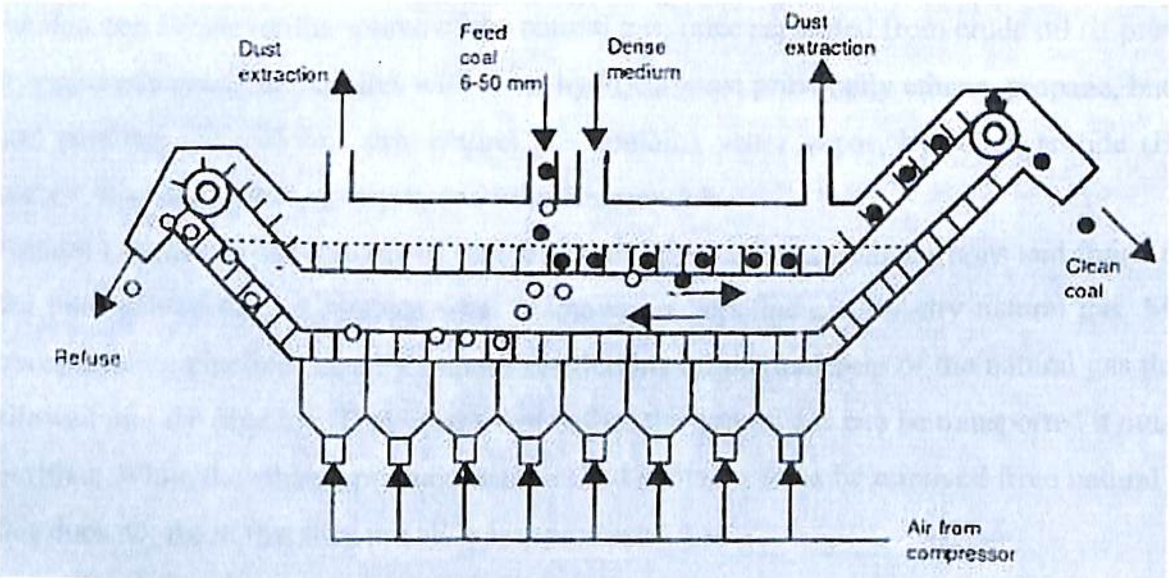


Fig.3.6 *Schematic Diagram of a Dry Separator with an Air Dense Medium Fluidized Bed*

Natural gas preparation/cleaning techniques as per power plant requirements:

Natural gas, as it is used by consumers, is much different from the natural gas that is brought from underground up to the wellhead. Although the processing of natural gas is in many respects less complicated than the processing and refining of crude oil, it is equally as necessary before its use by end users.

The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is by no means as pure. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'nonassociated gas'. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified. While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all 'waste products'.

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal

- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With natural gas that contains even low quantities of water, natural gas hydrates have a tendency to form when temperatures drop. These hydrates are solid or semi-solid compounds, resembling ice like crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems. To reduce the occurrence of hydrates, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.

Oil and Condensate Removal

In order to process and transport associated dissolved natural gas, it must be separated from the oil in which it is dissolved. This separation of natural gas from oil is most often done using equipment installed at or near the wellhead.

The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. Although dry pipeline quality natural gas is virtually identical across different geographic areas, raw natural gas from different regions may have different compositions and separation requirements. In many instances, natural gas is dissolved in oil underground primarily due to the pressure that the formation is under. When this natural gas and oil is produced, it is possible that it will separate on its own, simply due to decreased pressure; much like opening a can of soda pop allows the release of dissolved carbon dioxide. In these cases, separation of oil and gas is relatively easy, and the two hydrocarbons are sent separate ways for further processing. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas.

In certain instances, however, specialized equipment is necessary to separate oil and natural gas. An example of this type of equipment is the Low-Temperature Separator (LTX). This is most often used for wells producing high pressure gas along with light crude oil or condensate. These separators use pressure differentials to cool the wet natural gas and separate the oil and condensate. Wet gas enters the separator, being cooled slightly by a heat exchanger. The gas then travels through a high pressure liquid 'knockout', which serves to remove any liquids into a low-temperature separator. The gas then flows into this low-temperature separator through a choke mechanism, which expands the gas as it enters the separator. This rapid expansion of the gas allows for the lowering of the temperature in the separator. After liquid removal, the dry gas then travels back through the heat exchanger and is warmed by the incoming wet gas. By varying the pressure of the gas in various sections of the separator, it is possible to vary the temperature, which causes the oil and some water to be condensed out of the wet gas stream. This basic pressure-temperature relationship can work in reverse as well, to extract gas from a liquid oil stream.

Water Removal

In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead. However, the removal of the water vapor that exists in solution in natural gas requires a more complex treatment. This treatment consists of 'dehydrating' the natural gas, which usually involves one of two processes: either absorption, or adsorption.

Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface.

Glycol Dehydration

An example of absorption dehydration is known as Glycol Dehydration. In this process, a liquid desiccant dehydrator serves to absorb water vapor from the gas stream. Glycol, the principal agent in this process, has a chemical affinity for water. This means that, when in contact with a stream of natural gas that contains water, glycol will serve to 'steal' the water out of the gas stream. Essentially, glycol dehydration involves using a glycol solution, usually either diethylene glycol (DEG) or triethylene glycol (TEG), which is brought into contact with the wet gas stream in what is called the 'contactor'. The glycol solution will absorb water from the wet gas. Once absorbed, the glycol particles become heavier and sink to the bottom of the contactor where they are removed. The natural gas, having been stripped of most of its water content, is then transported out of the dehydrator. The glycol solution, bearing all of the water stripped from the natural gas, is put through a specialized boiler designed to vaporize only the water out of the solution. While water has a boiling point of 212 degrees Fahrenheit, glycol does not boil until 400 degrees Fahrenheit. This boiling point differential makes it relatively easy to remove water from the glycol solution, allowing it be reused in the dehydration process.

A new innovation in this process has been the addition of flash tank separator-condensers. As well as absorbing water from the wet gas stream, the glycol solution occasionally carries with it small amounts of methane and other compounds found in the wet gas. In the past, this methane was simply vented out of the boiler. In addition to losing a portion of the natural gas that was extracted, this venting contributes to air pollution and the greenhouse effect. In order to decrease the amount of methane and other compounds that are lost, flash tank separator-condensers work to remove these compounds before the glycol solution reaches the boiler. Essentially, a flash tank separator consists of a device that reduces the pressure of the glycol solution stream, allowing the methane and other hydrocarbons to vaporize ('flash'). The glycol solution then travels to the boiler, which may also be fitted with air or water cooled condensers, which serve to capture any remaining organic compounds that may remain in the glycol solution.

Solid-Desiccant Dehydration

Solid-desiccant dehydration is the primary form of dehydrating natural gas using adsorption, and usually consists of two or more adsorption towers, which are filled with a solid desiccant. Typical desiccants include activated alumina or a granular silica gel material. Wet natural gas is passed through these towers, from top to bottom. As the wet gas passes around the particles of desiccant material, water is retained on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the bottom of the tower.

Solid-desiccant dehydrators are typically more effective than glycol dehydrators, and are usually installed as a type of straddle system along natural gas pipelines. These types of dehydration systems are best suited for large volumes of gas under very high pressure, and are thus usually located on a pipeline downstream of a compressor station. Two or more towers are required due to the fact that after a certain period of use, the desiccant in a particular tower becomes saturated with water. To 'regenerate' the desiccant, a high-temperature heater is used to heat gas to a very high temperature. Passing this heated gas through a saturated desiccant bed vaporizes the water in the desiccant tower, leaving it dry and allowing for further natural gas dehydration.

Separation of Natural Gas Liquids

Natural gas coming directly from a well contains many natural gas liquids that are commonly removed. In most instances, natural gas liquids (NGLs) have a higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.

There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated themselves, down to their base components.

NGL Extraction

There are two principle techniques for removing NGLs from the natural gas stream: the absorption method and the cryogenic expander process. According to the Gas Processors Association, these two processes account for around 90 percent of total natural gas liquids production.

The Absorption Method

The absorption method of NGL extraction is very similar to using absorption for dehydration. The main difference is that, in NGL absorption, an absorbing oil is used as opposed to glycol. This absorbing oil has an 'affinity' for NGLs in much the same manner as glycol has an affinity for water. Before the oil has picked up any NGLs, it is termed 'lean' absorption oil. As the natural gas is passed through an absorption tower, it is brought into contact with the absorption oil which soaks up a high proportion of the NGLs. The 'rich' absorption oil, now containing NGLs, exits the absorption tower through the bottom. It is now a mixture of absorption oil, propane, butanes, pentanes, and other heavier hydrocarbons. The rich oil is fed into lean oil stills, where the mixture is heated to a temperature above the boiling point of the NGLs, but below that of the oil. This process allows for the recovery of around 75 percent of butanes, and 85 - 90 percent of pentanes and heavier molecules from the natural gas stream.

The basic absorption process above can be modified to improve its effectiveness, or to target the extraction of specific NGLs. In the refrigerated oil absorption method, where the lean oil is cooled through refrigeration, propane recovery can be upwards of 90 percent, and around 40 percent of ethane can be extracted from the natural gas stream. Extraction of the other, heavier NGLs can be close to 100 percent using this process.

The Cryogenic Expansion Process

Cryogenic processes are also used to extract NGLs from natural gas. While absorption methods can extract almost all of the heavier NGLs, the lighter hydrocarbons, such as ethane, are often more difficult to recover from the natural gas stream. In certain instances, it is economic to simply leave the lighter NGLs in the natural gas stream. However, if it is economic to extract ethane and other lighter hydrocarbons, cryogenic processes are required for high recovery rates. Essentially, cryogenic processes consist of dropping the temperature of the gas stream to around -120 degrees Fahrenheit.

There are a number of different ways of chilling the gas to these temperatures, but one of the most effective is known as the turbo expander process. In this process, external refrigerants are used to cool the natural gas stream. Then, an expansion turbine is used to rapidly expand the chilled gases, which causes the temperature to drop significantly. This rapid temperature drop condenses ethane and other hydrocarbons in the gas stream, while maintaining methane in gaseous form. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream. In addition, the expansion turbine is able to convert some of the energy released when the natural gas stream is expanded into recompressing the gaseous methane effluent, thus saving energy costs associated with extracting ethane.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

Natural Gas Liquid Fractionation

Once NGLs have been removed from the natural gas stream, they must be broken down into their base components to be useful. That is, the mixed stream of different NGLs must be separated out. The process used to accomplish this task is called fractionation. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream. Essentially, fractionation occurs in stages consisting of the boiling off of hydrocarbons one by one. The name of a particular fractionator gives an idea as to its purpose, as it is conventionally named for the hydrocarbon that is boiled off. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGLs from the stream. The particular fractionators are used in the following order:

- **Deethanizer** - this step separates the ethane from the NGL stream.
- **Depropanizer** - the next step separates the propane.
- **Debutanizer** - this step boils off the butanes, leaving the pentanes and heavier hydrocarbons in the NGL stream.
- **Butane Splitter or Deisobutanizer** - this step separates the iso and normal butanes.

By proceeding from the lightest hydrocarbons to the heaviest, it is possible to separate the different NGLs reasonably easily.

Sulfur and Carbon Dioxide Removal

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur and carbon dioxide. This natural gas, because of the rotten smell provided by its sulfur content, is commonly called 'sour gas'. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful, even lethal, to breathe. Sour gas can also be extremely corrosive. In addition, the sulfur that exists in the natural gas stream can be extracted and marketed on its own.

Sulfur exists in natural gas as hydrogen sulfide (H_2S), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 milligrams of H_2S per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as 'sweetening' the gas.

The primary process for sweetening sour natural gas is quite similar to the processes of glycol dehydration and NGL absorption. In this case, however, amine solutions are used to remove the hydrogen sulfide. This process is known simply as the 'amine process', or alternatively as the Girdler process, and is used in 95 percent of U.S. gas sweetening operations. The sour gas is run through a tower, which contains the amine solution. This solution has an affinity for sulfur, and absorbs it much like glycol absorbing water. There are two principle amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds from natural gas as it passes through. The effluent gas is virtually free of sulfur compounds, and thus loses its sour gas status. Like the process for NGL extraction and glycol dehydration, the amine solution used can be regenerated (that is, the absorbed sulfur is removed), allowing it to be reused to treat more sour gas.

Although most sour gas sweetening involves the amine absorption process, it is also possible to use solid desiccants like iron sponges to remove the sulfide and carbon dioxide.

Sulfur can be sold and used if reduced to its elemental form. Elemental sulfur is a bright yellow powder like material, and can often be seen in large piles near gas treatment plants, as is shown. In order to recover elemental sulfur from the gas processing plant, the sulfur containing discharge from a gas sweetening process must be further treated. The process used to recover sulfur is known as the Claus process, and involves using thermal and catalytic reactions to extract the elemental sulfur from the hydrogen sulfide solution.

In all, the Claus process is usually able to recover 97 percent of the sulfur that has been removed from the natural gas stream. Since it is such a polluting and harmful substance, further filtering, incineration, and 'tail gas' clean up efforts ensure that well over 98 percent of the sulfur is recovered.

Gas processing is an instrumental piece of the natural gas value chain. It is instrumental in ensuring that the natural gas intended for use is as clean and pure as possible, making it the clean burning and environmentally sound energy choice. Once the natural gas has been fully processed, and is ready to be consumed, it must be transported from those areas that produce natural gas, to those areas that require it.

CHAPTER: 4

COMBUSTION PROPERTIES & COMBUSTION SYSTEM FOR VARIOUS FEED-STOCKS

Coal combustion:

Coal is one of the most impure of fuels. Its range in trace quantities can be very diverse in terms of metals. Some of these metals include uranium and thorium. Much larger amounts of iron and aluminum can also be found. Whatever kind of coal you have, it is highly probable that it will be used for combustion. Coal combustion is the process of burning coal at very high temperatures to produce light and heat. During the coal combustion process, many hazardous chemicals are released into the environment. Coal combustion produces many greenhouse gases such as carbon dioxide that have been linked to causing global warming. It is also a source of sulfur oxides and as well as nitrogen oxides. These pollutants are very harmful to the health of humans and in some cases can be the cause of acid rain. In addition, coal combustion releases many naturally occurring radioactive materials into the atmosphere as uranium and thorium.

In fact, of all the total uses for coal, 95% is used for combustion. The remaining 5% is used for iron, steel, and coke production. The three types of coal combustion are as follows…

1) Stoker combustion: Fixed-bed or stoker combustion is a slower process compared to the other coal combustion processes. In stoker combustion, the coal is burned at 1200-1300 degrees Celsius.

2) Pulverized coal combustion: One of the major limitations of Pulverized coal combustion method is its size. However, it is the most common of the three methods. It is so common because of such high intensity combustion. In this method, combustion occurs with the use of a very fine powder/ dusty substance. The coal is burned at 1600-1800 degrees Celsius.

3) Fluidized bed combustion: Fluidized bed combustion (FBC) uses some of the most recent of coal combustion technologies. In this method, coal combustion occurs by mixing the coal with a sorbent such as limestone or other various bed materials. The fuel and the bed material mixture is fluidized during the combustion process to allow complete combustion and removal of sulfur gases. Because of this, fluidized-bed combustion is considered to be highly environmentally friendly. The coal in this method burns at 800-900 degrees Celsius.

Combustion Equations

Combustion equation for coal:

$C + O_2 \Rightarrow CO_2$ (12 kg C)+(32 kg O) $\Rightarrow$ (34 kg CO_2)

Combustion equation for hydrogen:

$2 H_2 + O_2 \Rightarrow 2 H_2O$ (4 kg H)+(32 kg O) $\Rightarrow$ (36 kg H_2O)

Combustion equation for sulphur:

$S + O_2 \Rightarrow SO_2$ (32 kg S) + (32 kg O) $\Rightarrow$ (64 kg SO_2)

Table 4.1

Fuel Analysis	.	.	.
Constituent	**Mass fraction**	**Required oxygen**	**Product mass**
.	.	kg/kg fuel	kg/kg fuel
Carbon	0,900	2,400	3,300
Hydrogen	0,030	0,240	0,270
Oxygen	0,020	-0,020	0,000
Nitrogen	0,010	0,000	0,010
Sulphur	0,010	0,010	0,020
Ash	0,030	0,000	0,030
.	1,000	2,630	3,630
Analysis of Supplied Air	.	.	.
Specific Humidity	0,008	.	.
Composition by mass	.	.	.
Constituent	Dry Air	Humid Air	.

N2	0,76280	0,75670	.
O2	0,23290	0,23104	.
CO2	0,00300	0,00298	.
Ar	0,00130	0,00129	.
H2O	0,00000	0,00800	.
SO2	0,00000	0,00000	.
.	1,00000	1,00000	.
Air required per kg of fuel	11,38	Stoichiometric A/F ratio	kg/kg
Excess Air	1,5	.	.
Actual A/F ratio kg/kg	28,45867	.	.
Exhaust Gases	.	Wet Mass	Dry Mass
Constituent	Mass	Composition	Composition
N2	21,54461	0,73210	0,74469
O2	3,94500	0,13405	0,13636
CO2	3,38469	0,11501	0,11699
Ar	0,03670	0,00125	0,00127
H2O	0,49767	0,01691	0,00000
SO2	0,02000	0,00068	0,00069
.	29,42867	1,00000	1,00000
Exhaust Gases	.	.	Volume
Constituent	Kg/kmol	Mole Fraction	Composition
N2	28	0,02615	0,77058
O2	32	0,00419	0,12346
CO2	44	0,00261	0,07704
Ar	40	0,00003	0,00092
H2O	18	0,00094	0,02769

SO2	64	0,00001	0,00031
.	.	0,03393	1,00000
Mass balance	.	.	.
Fuel	1,00000	.	.
Supplied Air	28,45867	.	.
.	29,45867	.	.
.	.	.	.
Exhaust Gases	29,42867	.	.
Ash	0,03000	.	.
.	29,45867	.	.
Supplied Air Temp.	18	C	.
Fuel Cp	3,2	kJ/(kg.K)	.
Net Calorific Value	33500	kJ/kg	.
Combustion efficiency	0,75	.	.
.	.	.	.
.	Enthalpy	Mass Flow	m*h
.	kJ/kg	kg/s	kJ/s
Supplied Air	38,31	28,46	1090,14
Fuel	64,00	1,00	64,00
Fuel Energy Supplied	33500,00	1,00	25125,00
.	.	.	26279,14
Exhaust Gases	892,07	.	.
Exhaust Gases Temp	774,	C	.

Coal Combustion Technologies

Steam turbines can run on a variety of fuels but coal continues to remain a popular choice. However, the traditional coal-fired plants suffer from two major drawback: overall efficiency levels are low and pollution levels are high.

Growing environmental concerns and the need to improve conversion efficiency levels have led to the development of clean coal technologies. The most popular of these technologies are Fluidised Bed Combustion (FBC), Pressurised Fluidised Bed Combustion Combined Cycle (PFBC) and Integrated Gasification Combined Cycle (IGCC).

Improvement in overall performance of steam turbines for thermal power plants can be brought about largely through two kinds of advancement. Firstly,through improvement in mechanical efficiency by reducing aerodynamic and leakage losses as the steam expands through the turbine. Secondly, through improvement in thermodynamic efficiency by increasing the temperature and pressure at which heat is added to the power cycle.

Supercritical Technology

The steam temperature can be raised to levels as high as 580 to 600° C and pressure over 300 bar. Under these conditions, water enters a phase called "supercritical" with properties in between those of liquid and gas. This supercritical water can dissolve a variety of organic compounds and gases, and when hydrogen per-oxide and liquid oxygen are added, combustion is triggered. Turbines based on this principle are called Supercritical Turbines. These turbines offer outputs of over 500 MW. Some manufacturers are planning to commission steam turbines of 800-1,000 MW output in the next few years.

The supercritical turbines can burn low grade fossil fuels and can completely stop Oxides of Nitrogen (NOx) emissions and keep emissions of sulphur dioxide to a minimum. For example, lignite or brown coal has high water content. So, it is normally not used for power generation. Yet, when lignite is added to water that has been heated to 600° C at a pressure of 300 bar, it will completely burn up in one minute while emitting no NOx and only 1 percent of its original sulphur content as SOx. This also eliminates the need for desulphurisation and denitrification equipment and soot collectors. Although large amounts of energy are required to create supercritical water, operating costs could be significantly different from existing power generating facilities because there would be no need to control gas emissions. The demand for cooling water is also reduced, almost proportionally to an increase in the efficiency.

Currently, supercritical power plants reach thermal efficiencies of just over 40 percent, although a few of the more plants have attained high efficiency upto 45 percent. A number of steam generator and turbine manufacturers around the world now claim that steam temperatures upto 700° C ("ultra" supercritical conditions) are possible which might raise plant efficiencies to over 50 percent, but by using expensive nickel-based alloys. Because supercritical water is corrosive, expensive nickel alloys must be used for the reaction equipment and power generators.

The main competition to supercritical system is from new gas turbine combined cycle plants which are now expedited to achieve an overall efficiency of 60 percent, making a huge difference in generating and life-cycle costs. However, the new gas turbines will release exhaust into waste heat recovery steam generator at temperatures above 600° C, thus necessitating the use of the high chromium steel and nickel alloys as used in the supercritical coal-fired plants.

The economic benefits of taking steam temperature above 635° C, the costs of nickel-based alloys are yet to be resolved. The extra costs of using nickel-based alloys can probably be compensated by reduction in the amount of material required through thinner tube walls and smaller overall dimensions of both plant and site requirements. Efforts are also afoot to develop materials which can withstand high temperatures and pressures to improve thermal efficiency.

However, increased live steam pressure may lower potential for improved performance due to auxiliary power consumption. In addition, increased pressure leads to a loss of thermal flexibility and this can also increase costs.

Fluidised Bed Combustion

During the seventies and also in eighties,, it appeared that conventional pulverised coal-fired power plants had reached a plateau in terms of thermal efficiency. The efficiency levels achieved were of the order of 40 percent in the US and the UK.The corresponding figures for India, however, were lower at 36 to 37 percent.

An alternative technology, Fluidised Bed Combustion (FBC), was developed to raise the efficiency levels. In this technology, high pressure air is blown through finely ground coal. The particles become entrained in the air and form a floating or fluidised bed. This bed behaves like a fluid in which the constituent particles move to and fro and collide with one another.

Fluidised bed can burn a variety of fuels-coal as well other non-conventional fuels like biomass, petro-coke, coal cleaning waste and wood. This bed contains only around 5 percent coal or fuel. The rest of the bed is primarily an inert material such as ash or sand.

The temperature in FBC is around 800-900° C compared with 1,300-1,500° C in Pulverised Coal Combustion (PCC). Low temperature helps minimize the production of NO_x. With the addition of a sorbent into the bed (mostly limestone), much of the SO_2 formed can be captured. The other advantages of FBC are compactness, ability to burn low calorific values (as low as 1,800 kcal/kg) and production of ash which is less erosive. Moreover, in FBC, oil support is needed for 20-30 percent of the load versus 40-60 percent in PCC. FBC-based plants also have lower capital costs compared to PCC-based plants. The capital costs could be 8-15 percent lower.

FBCs are essentially of two types bubbling and circu-lating. While bubbling beds have low fluidisation veloci-ties to prevent solids from being elutraited, circulating beds employ high velocities to actually promote elutriation. Both these tech-nologies operate on atmos-pheric temperature. The circulating bed can remove 90-95 percent of the sulphur content from the coal while the bubbling bed can achieve 70-90 percent removal.

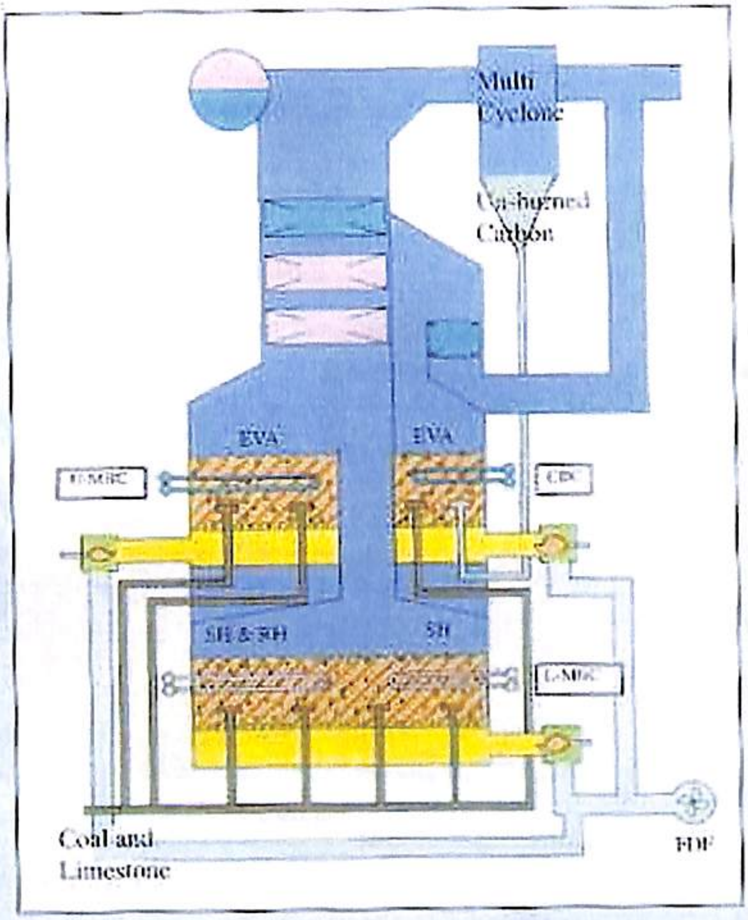
FBC thus offers an option for burning fuels economically, efficiently and in an environmentally acceptable way. Currently, size is the only limitation of this technology. While the maximum size of a PCC-based power plant unit could be 1,300 MW, FBC has achieved a maximum unit size of 250 MW.

THEORY OF FLUIDIZED BED COMBUSTION

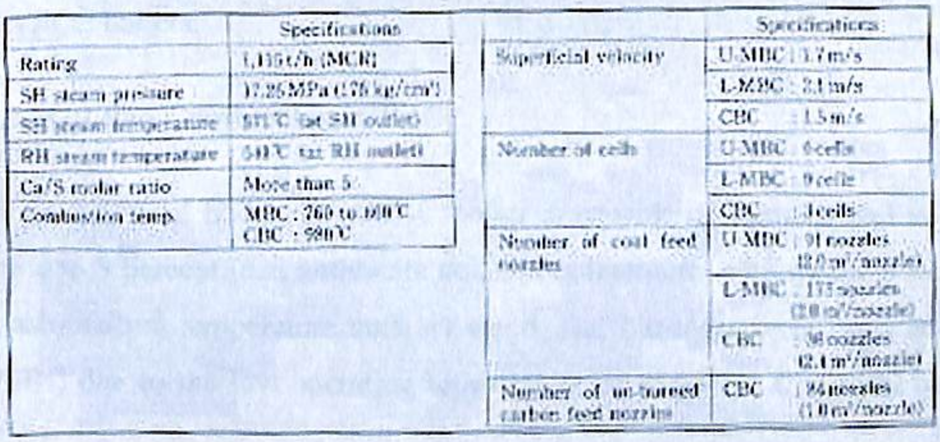
When air is supplied at the bottom of furnace in the range of a certain speed through Bed Material [BM], for which we select limestone of 1 to 3mm dia., BM gets floating and bubbling in the air. This phenomenon is called "Fluidized Bed".

When crashed coal of 10mm dia. or smaller at this unit is fed while the fluidized bed is heated up to the coal ignition temperature of around 450 deg.C, it begins to burn by itself. The fluidized bed temperature of Main Bed Cell [MBC] is controlled between 760 and 860 deg.C in a normal operation and coal is slowly burnt in the fluidized bed. Un-burned carbon is collected by Multi Cyclone [MC] at the MBC outlet to be burnt again in Carbon Burn-up Cell [CBC] for the improvement of combustion efficiency.

Since boiler tubes are arranged in the fluidized bed, heat transfer to water and/or steam can efficiently be made. Low SOx emission can be achieved by in-furnace de-sulpherization owing to the bed material of limestone and furthermore, lower combustion temperature enables and ensures low NOx emission.

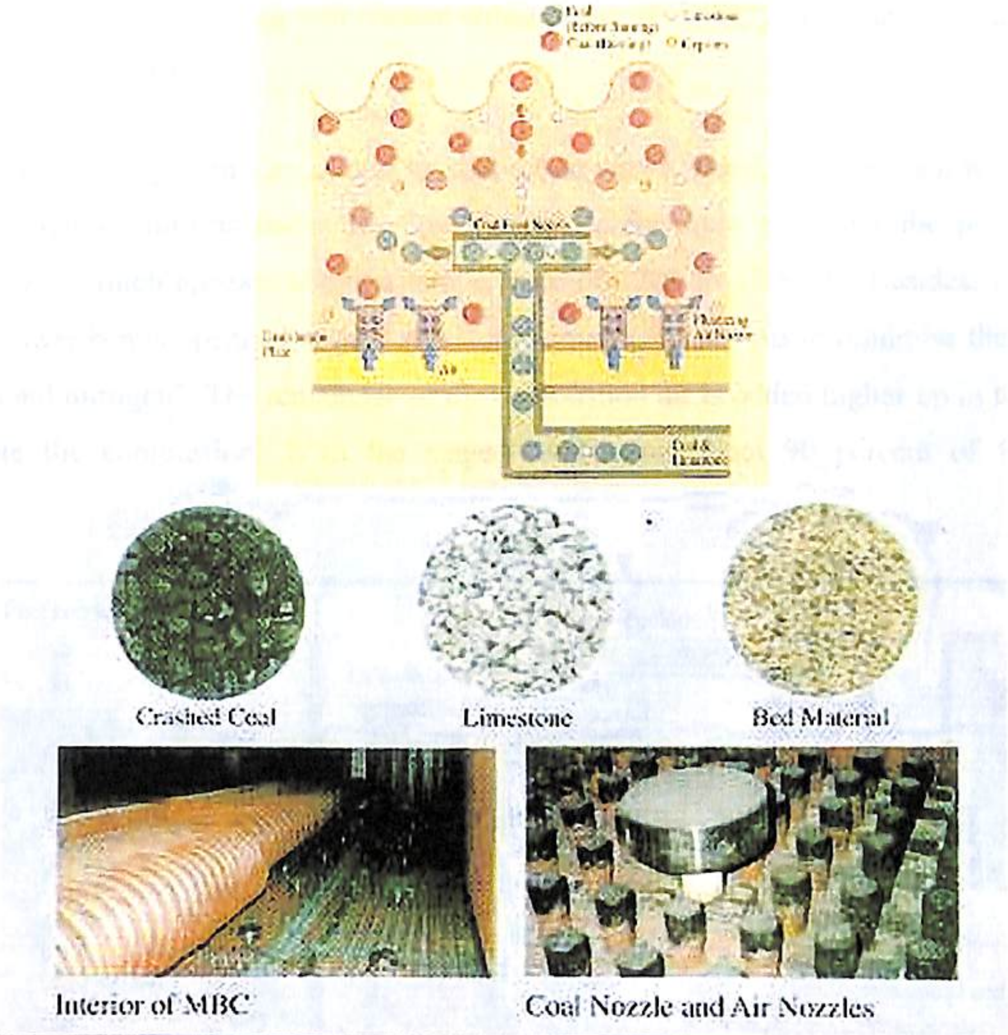


MAIN SPECIFICATIONS OF A-FBC BOILER



	Specifications
Rating	1,135t/h (MCR)
SH steam pressure	17.26MPa (176 kg/cm²)
SH steam temperature	571°C (at SH outlet)
RH steam temperature	541°C (at RH outlet)
Ca/S molar ratio	More than 5
Combustion temp.	MBC : 760 to 860°C CBC : 980°C

	Specifications	
Superficial velocity	U-MBC	1.7 m/s
	L-MBC	2.1 m/s
	CBC	1.5 m/s
Number of cells	U-MBC	6 cells
	L-MBC	9 cells
	CBC	3 cells
Number of coal feed nozzles	U-MBC	91 nozzles (2.0 m²/nozzle)
	L-MBC	175 nozzles (2.0 m²/nozzle)
	CBC	36 nozzles (2.1 m²/nozzle)
Number of un-burned carbon feed nozzles	CBC	24 nozzles (1.0 m²/nozzle)


Crushed Coal
Limestone
Bed Material
Interior of MBC
Coal Nozzle and Air Nozzles

Concept of Fluidised Bed Combustion

According to some estimates, FBC represents only about 2 percent of the total coal fired capacity worldwide, but is of particular interest and significance for use of those coals which are difficult to mill and fire in PCC boilers.

Circulating Fluidised Bed Combustion (CFBC)

Unlike conventional PC-fired boiler, the CFBC boiler is capable of burning fuel with volatile content as low as 8 to 9 percent (e.g. anthracite coke, petroleum etc. with minimal carbon loss). Fuels with low ash-melting temperature such as wood, and bio-mass have been proved to be feedstocks in CFBC due to the low operating temperature of 850-900° C. CFBC boiler is not bound by the tight restrictions on ash content either. It can effectively burn fuels with ash content upto 70 percent (Fig. 4.1).

CFBC can successfully burn agricultural wastes, urban waste, wood, bio-mass, etc which are the low melting temperature as fuels. The low furnace temperature precludes the production of "thermal NOX" which appears above a temperature of 1200 to 1300° C. Besides, in a CFBC boiler, the lower bed is operated at near sub-stoichiometric conditions to minimise the oxidation of "fuel-bound nitrogen". The remainder of the combustion air is added higher up in the furnace to complete the combustion. With the staged-combustion about 90 percent of fuel-bound nitrogen is converted to elemental nitrogen (N2) as main product.

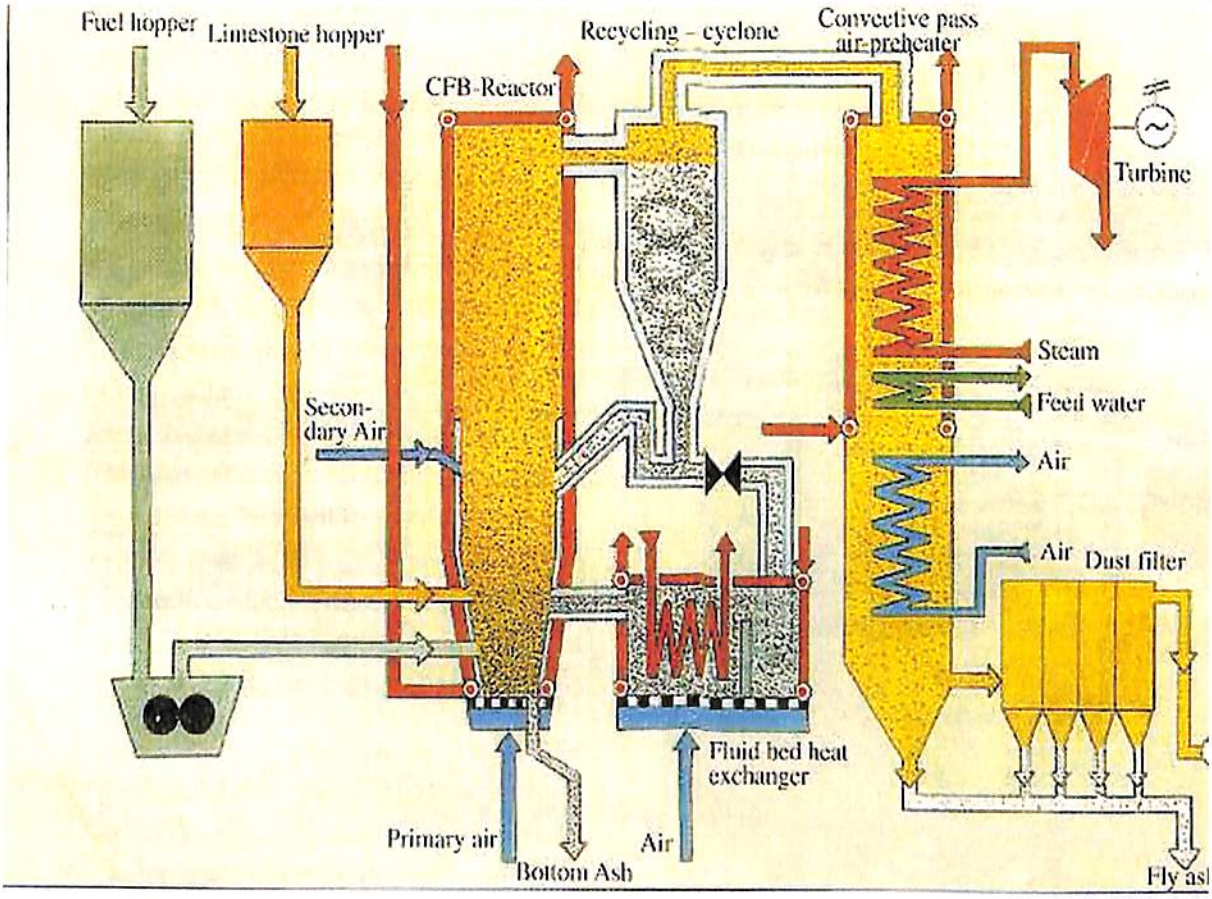


Fig.4.1 *Flow Diagram of Circulating Fluidised Bed Power Station*

Pressurised Fluidised Bed Combustion Combined Cycle (PFBC)

A new type of fluidised bed design, the pressurised bed, was developed in the late eighties to further improve the efficiency levels in coal-fired plants.

In this concept, the conventional combustion chamber of the gas turbine is replaced by a pressurised fluidised bed combustor. The products of combustion pass through a hot gas cleaning system before entering the turbine. The heat of the exhaust gas from the gas turbine is utilised in the downstream steam turbine. This technology is called pressurised fluidised bed combustion combined cycle (PFBC) (Fig.4.2).

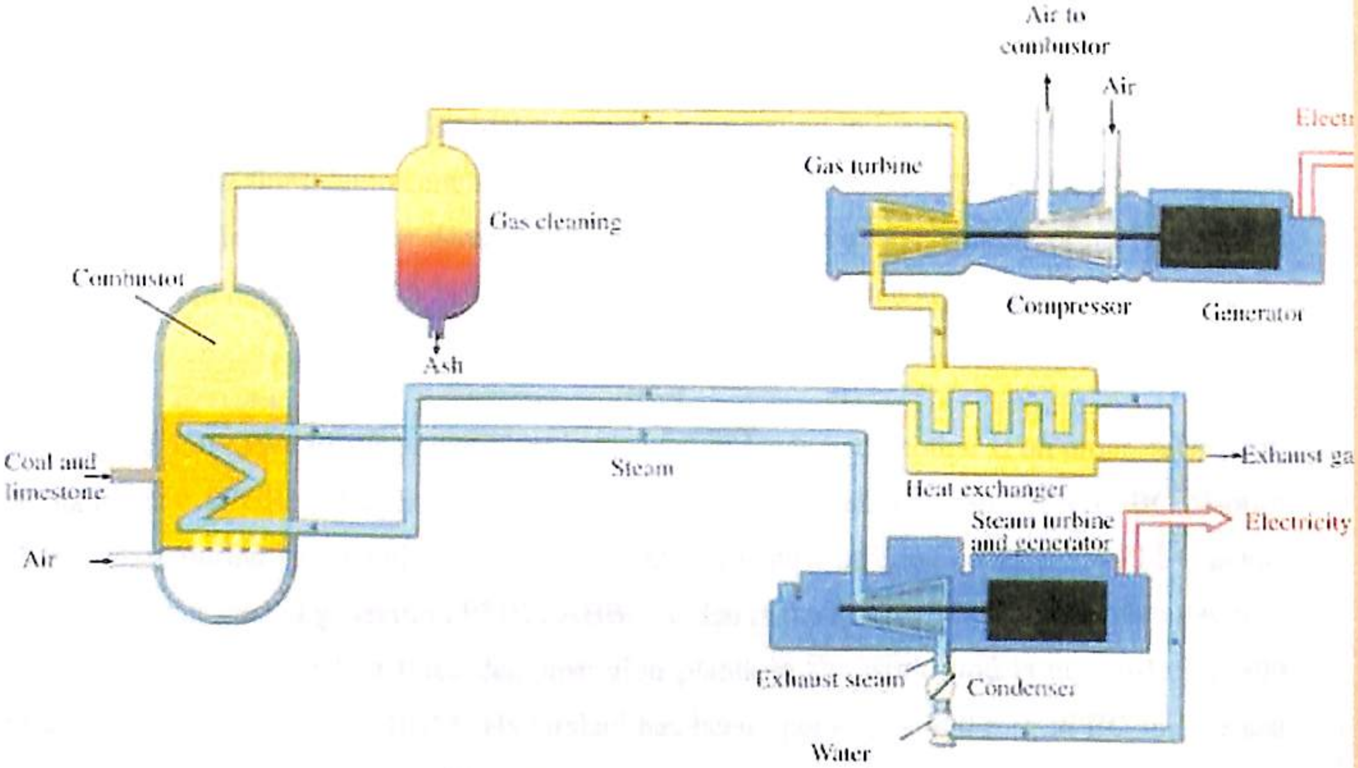


Fig.4.2 *Pressurised Fluidised Bed Combined Cycle*
Source : Coal power for progress (4th edition) World Coal Institute

The bed is operated at a pressure of between 5 bar and 20 bar and operating the plant at such low pressures allows some additional energy to be captured by venting the exhaust gases through a gas turbine which is then combined with the normal steam turbine to achieve plant efficiency levels of upto 50 percent. The steam turbine is the major source of power in PFBC, contributing about 80 percent of the total power output. The remaining 20 percent is produced in gas turbines.

PFBC plants are smaller in size than the atmospheric FBC and PCC plants and therefore have the advantage of siting in urban areas. The fuel consumption is about 10-15 percent lower than in PCC technology.

PFBC has been used only over the last few years. The development of this technology is dependent upon the compatibility of the hog gas clean-up system with the gas turbine inlet temperatures and maximum particulate size. Improvements on these two fronts would lead to greater acceptance of PFBC.

Status of PFBC Technology Development

The first demonstration plant of capacity of 130 MWe (+224 MW, co-generation) has been operating in Stockholm, Sweden since 1991 meeting all the stringent environmental conditions. Another demonstration plant of 80 MWe capacity is operating in Escatron, Spain using 36% ash black lignite. The third demonstration plant of 70 MWe at TIDD station, OHIO, USA was shut down in 1994 after a eight year demonstration period in which a large amount of useful data and experience were obtained. A 70 MWe demo plant has been operated at Wakamatsu from 1993 to 1996.

Presently, a 350 MWe PFBC power plant is planned in Japan and another is on order in USA (to be operated at SPORN). UK has gathered a large amount of data on a 80 MWe PFBC plant in Grimethrope during its operation from 1980-1992 and is now offering commercial PFBC plants and developing second generation PFBC. ABB-Sweden is the leading international manufacturer which has supplied the first three demonstration plants in the world and is now offering 300 MWe units plants. In India, BHEL-Hyderabad has been operating a 400 mm PFBC for the last eight years and has collected useful research data. IIT Madras has a 300 mm diameter research facility built with NSF (USA) grant. A proposal by BHEL for a 60 MWe PFBC plant is under consideration with the Government of India.

Integrated Gassification Combined Cycle (IGCC)

The integrated gassification combined cycle is a process in which the fuel is gasified in an oxygen or air-blown gasifier operating at high pressure. The raw gas thus produced is cleaned of most pollutants (almost 99 percent of its sulphur and 90 percent of nitrogen pollutants). It is then burned in the combustion chamber of the gas turbine generator for power generation. The heat from the raw gas and hot exhaust gas from the turbine is used to generate steam which is fed into the steam turbine for power generation.

Often, IGCC is referred to as "Cool Water" technology, a name drawn from the ranch in California's Mojave Desert that once occupied the site where it was developed. Coal all shorts burns so well with the Cool Water technology -upto 99 percent of sulphur contamination is eliminated.

The main subsystems of a power plant with integrated gasification are:

- Gasification plant
- Raw gas heat recovery systems
- Gas purification with sulphur recovery
- Air separation plant (only for oxygen blown gasification)
- Gas turbine with heat recovery steam generator
- Steam turbine generator

The feedstock which is fed into the gasifier is more or less completely gasified to synthesis gas (syngas) with the addition of steam and enriched oxygen or air. The gasifier can be fixed bed, entrained or fluidised bed. The selection of the gasifier to achieve best cost efficiency and emission levels depends upon the type of fuel.

In the gas purification system, initial dust is removed from the cooled raw gas. Chemical pollutants such as hydrogen sulphide, hydrogen chloride and others are also removed. Downstream of the gas purification system, the purified gas is reheated, saturated with water if necessary (for reduction of the oxides of nitrogen) and supplied to the gas turbine combustion chamber.

The IGCC technology scores over others as it is not sensitive with regard to fuel quality. Depending on the type of gasifier, liquid residues, slurries or a mixture of petcoke and coal can be used. In fact, the IGCC technology was developed to take advantage of combined cycle efficiency of such low-grade fuels (Fig. 4.3)

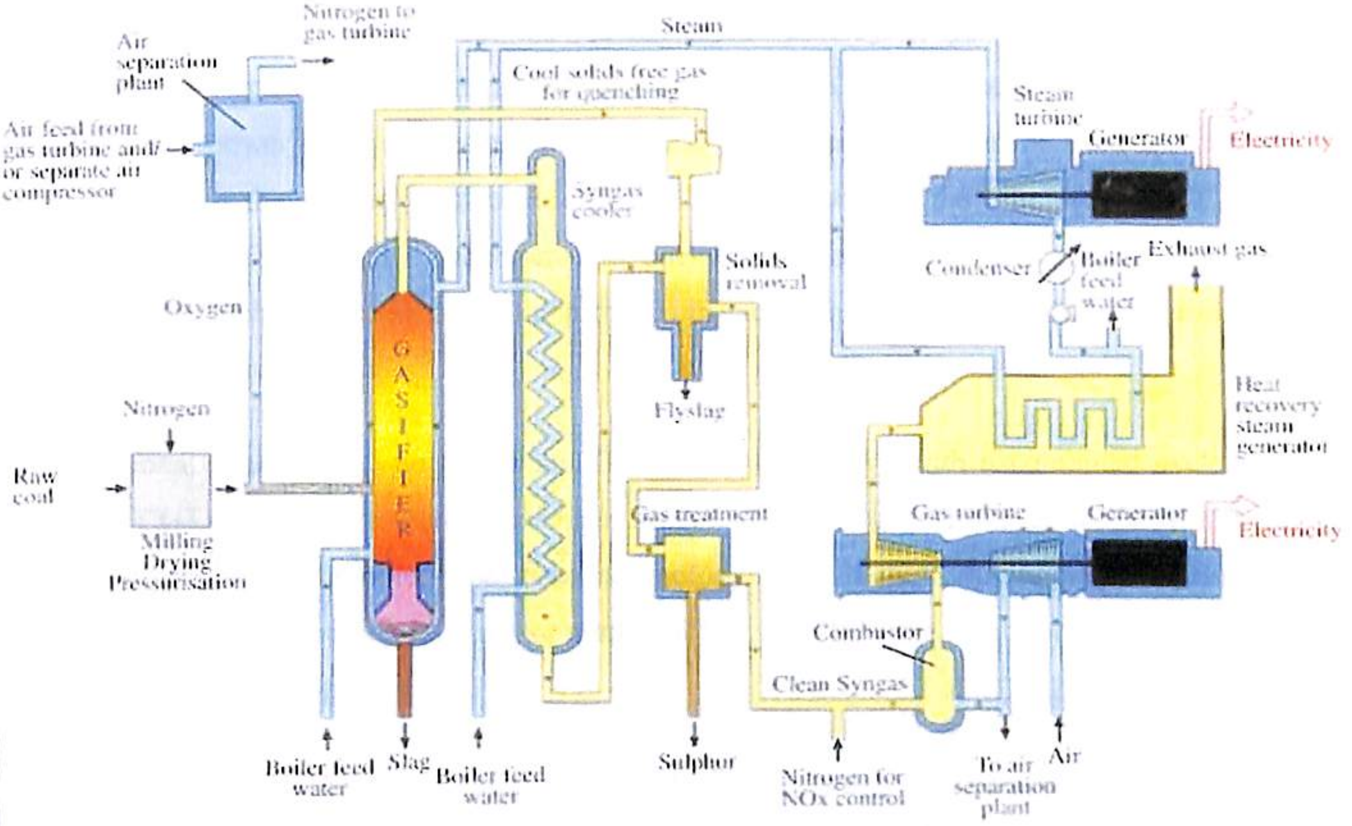


Fig.4.3 *Integrated Gassification Combined Cycle*

Source : Coal power for progress (4th edition) World Coal Institute

IGCC technology is also environment friendly. In IGCC, pollutants like sulphur dioxide and oxides of nitrogen are reduced to very low levels by primary measures alone, without downstream plant components and additives like limestone.

The low NOx values are achieved by dilution of the purified syngas with nitrogen from air separation unit and by saturation with water. The direct removal of sulphur compounds from the syngas results in the effective recovery of elemental sulphur, yielding a saleable raw chemical product. Gasification and gas cleaning are an extremely effective filter for contaminants harmful to both gas turbines as well as environment. The IGCC technology is not only environment friendly, but also efficient in power generation (upto 50 percent).

However, IGCC is an expensive option. Some companies claim that they have found an answer to the cost issue with a new technology for producing methanol. They believe that fitting this system, which produces methanol at twice the rate of conventional methods, on the back end of the gasifier units on an IGCC plant can cut the capital cost by 25 percent. The technology achieves this saving by reducing the number of gasifiers the IGCC plant needs - provided the full capacity of the power station is not required for base load running. This enables the operator to make full use of the gasifers, which account for 50-60 percent of the cost of an IGCC and become prohibitively expensive under part-time operation. When power is not required, they can be switched to methanol production. This provides the additional fuel to meet full power output at time of peak demand.

The additional benefits will not make an IGCC unit competitive with a combined cycle gas turbine (CCGT) plant where there is adequate supply of natural gas. However, a 500 MW unit could compete with traditional coal-fired technology. The biggest difficulty may arise in securing a long-term purchase contract for methanol that will allow the plant operator to keep the gasifiers in continuous operation.

The use of gasification for power generation is perceived by many as a complex and expensive technology. However, recent experience in both developed and developing countries reinforces its relevance to power generation. In India, in particular, the IGCC technology is of great relevance as we do not have huge reserves of hydrocarbons. Since coal is available, more project developers can go in for coal-based IGCC plants.

The merits of advanced clean coal combustion technologies over pulverised fired conventional combustion are enlisted in Table 4.2.

Table 4.2: **Merits of Advanced coal combustion systems**

Parameters	**Conventional pulverised fired**	**Super critical pulverised fired**	**PFBC /CFBC**	**IGCC**	**Hybrid Cycle (Gassification in combustion)**
Maturity of	Completely	Substantially	Substantially	Mainly	Still at R&D

technology	proven and commercially available with guarantees	proven and commercial plant available with guarantees	proven and commercial plant available with guarantees	demonstration plant operational where coal is the fuel source	stage
Range of units available	All commercial sizes available (common unit size in the range 300-1000 MW_e)	All commercial sizes available	Upto 350 mw sizes available	250-300 MW_e, currently limited by the size of large gas turbine units available	Demonstration plant proposed at around 90 MW_e
Fuel flexibility	Burns a wide range of internationally traded coals	Burns a wide range of internationally traded coals	Will burn a wide range of internationally traded coals, as well as low grade coals efficiently; best suited for low ash coals	Should use a wide range of internationally traded coals, but not proven; Not really designed for low grade, high ash coals	Should use a wide range of internationally traded coals; designed to utilise low grade, high ash coals efficiently
Thermal efficiency (LHV)	Limited by steam conditions around 41% with modern designs	At least 45% now possible and over 50% subject to successful materials development i.e. further R&D	Around 44% possible, some increases likely with further R&D and/or with supercritical steam cycle	Around 43% currently possible, but over 50% possible with advanced gas turbines and further R&D	Around 43% should be obtainable, but over 50% possible with advanced gas turbines and further R&D
Operational flexibility	Can operate at low load, but performance would be limited	Can operate at low load, but performance would be limited	Can operate at low load but performance would be limited	Realistically could only operate at base load	Design suggests would have reasonable performance at low load
Environmental Performance					

CO_2		-	810	460	
(g/KWH)	830	-	585	150	-
SO_2	600	-	585	300	-
(mg/KWH	600				-
NO_x					
(mg/KWH)					
Availability	Proven to be excellent	Proven to be good	Limited experience	Demonstration so far not satisfactory	Not yet demonstrated

At a time when the government is going full speed ahead with the decision to make washing of non-coking coal mandatory in the country, the paramount question still remains unanswered. **Why wash and at what cost**? A sector still caught in the crossfire between the power utilities and railways, there are scores of practical sores that need an urgent washing before the product itself.

According to the Gazette of India notification, dated 19.09.97, all power plants situated 1000 km or more from the mining source and those in urban, sensitive and critically polluted areas (excluding pit-head plants), would be required to use only washed coal from June 2001. Interestingly, this notification is based on an evaluation of washing options for two new power stations. The applicability of this notification for existing power plants is economically and environmentally suspect.

The following advantages are claimed for using washed coal in thermal power stations:

1. Reduction in emissions of particulate matter.
2. Owing to reduced ash content in coal, reduction in size of coal handling plant at power station end; reduction in size of ash disposal unit; smaller ash ponds.

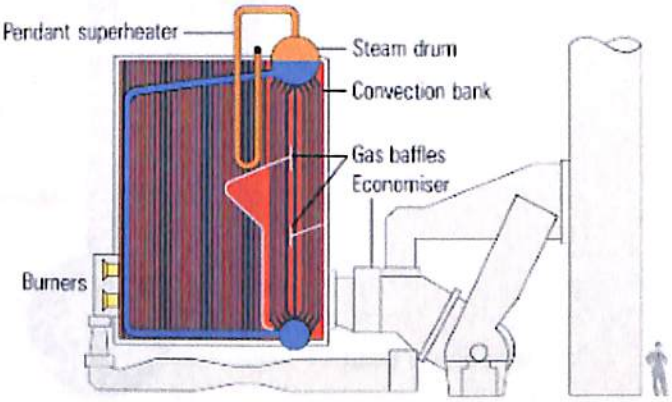
3. Reduction in ash will result in less wear and tear of ball mills, induced draught and forced draught fans; less leakage of boiler tubes and less consumption of fuel oil for flame stabilization.
4. Owing to 2 and 3 above, the capital cost of the power station will come down for the same design capacity.
5. Railways will carry thermal coal with less ash resulting in increased freight carrying capacity for the railways.
6. Reduction in freight charges to the power station.
7. Better control in thermal power station operations and the control settings would not need to be changed frequently to take care of fluctuations in the heat value in coal feed.
8. Increased plant availability and resultant higher Plant Load Factor (PLF).

Boiler arrangements for effective utilization of coal combustion in thermal power plants:

A boiler is defined as a pressure vessel which transfers heat from a heat source to a fluid. The heat source is typically combustion; however electric resistance boilers can be included into the boiler definition. The fluid in a boiler is typically water (liquid or steam) Types of boilers according to the relative positions of products of combustion:

- Water tube boiler
- Fire tube boiler

Water tube boilers:



Water-tube boilers differ from shell type boilers in that the water is circulated inside the tubes, with the heat source surrounding them. Because the tube diameter is significantly smaller, much higher pressures can be tolerated for the same stress.

Water-tube boilers are used in power station applications that require:

A high steam output (up to 500 kg/s).

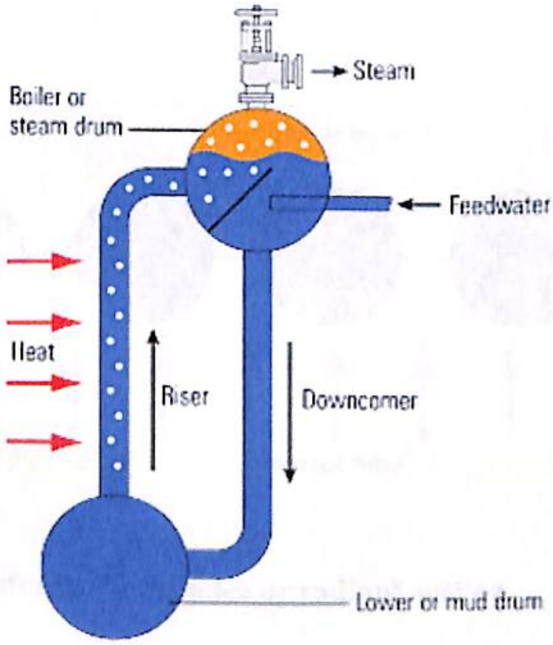
High pressure steam (up to 160 bar).

Superheated steam (up to 550°C).

However, water-tube boilers are also manufactured in sizes to compete with shell boilers. Small water-tube boilers may be manufactured and assembled into a single unit, just like packaged shell boilers, whereas large units are usually manufactured in sections for assembly on site.

Many water-tube boilers operate on the principle of natural water circulation (also known as 'thermo-siphoning'). This is a subject that is worth covering before looking at the different types of water-tube boilers that are available. Figure 4.5 helps to explain this principle:

Fig. 4.5 Natural water circulation in a water-tube boiler



Cooler feedwater is introduced into the steam drum behind a baffle where, because the density of the cold water is greater, it descends in the 'downcomer' towards the lower or 'mud' drum, displacing the warmer water up into the front tubes.

Continued heating creates steam bubbles in the front tubes, which are naturally separated from the hot water in the steam drum, and are taken off.

However, when the pressure in the water-tube boiler is increased, the difference between the densities of the water and saturated steam falls, consequently less circulation occurs. To keep the same level of steam output at higher design pressures, the distance between the lower drum and the steam drum must be increased, or some means of forced circulation must be introduced.

Water-tube boiler sections

The energy from the heat source may be extracted as either radiant or convection and conduction.

The furnace or radiant section

This is an open area accommodating the flame(s) from the burner(s). If the flames were allowed to come into contact with the boiler tubes, serious erosion and finally tube failure would occur. The walls of the furnace section are lined with finned tubes called membrane panels, which are designed to absorb the radiant heat from the flame.

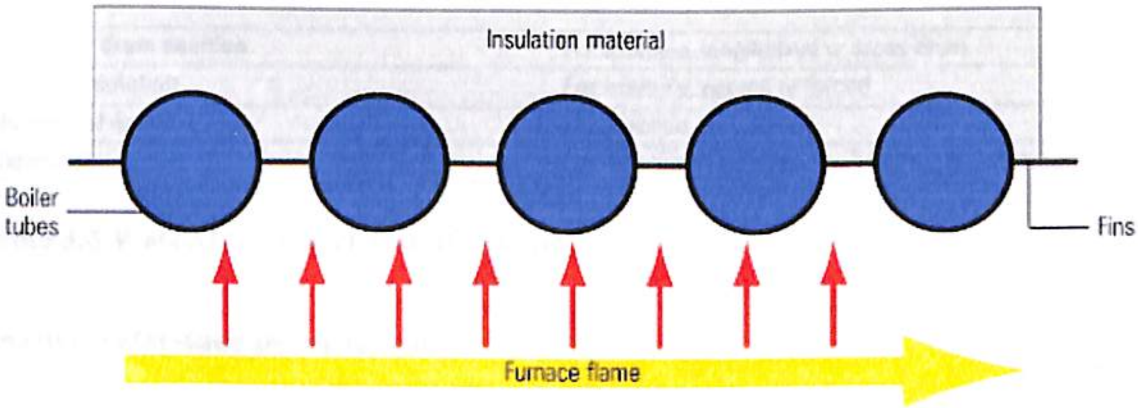


Fig. 4.6 Heat transfer in the furnace or radiant section

Convection section

This part is designed to absorb the heat from the hot gases by conduction and convection. Large boilers may have several tube banks (also called pendants) in series, in order to gain maximum energy from the hot gases.

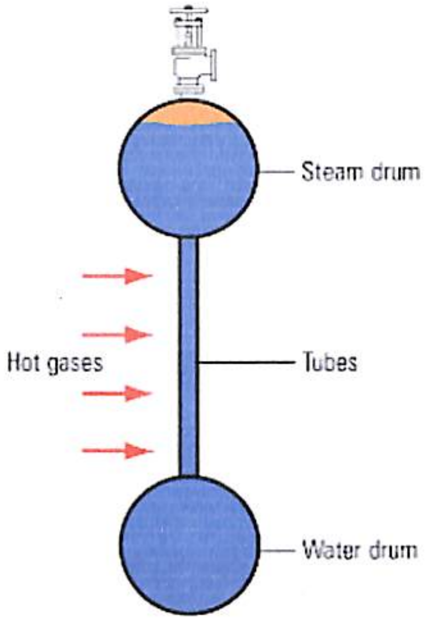
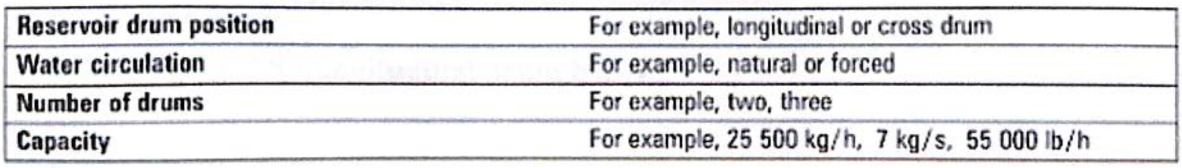


Fig. 4.7 Heat transfer in the convection section

Water-tube boiler designation

Water-tube boilers are usually classified according to certain characteristics, see Table 4.3



Reservoir drum position	For example, longitudinal or cross drum
Water circulation	For example, natural or forced
Number of drums	For example, two, three
Capacity	For example, 25 500 kg/h, 7 kg/s, 55 000 lb/h

Table 3.4 Water-tube boiler classifications

Alternative water-tube boiler layouts

The following layouts work on the same principles as other water-tube boilers, and are available with capacities from 5 000 kg/h to 180 000 kg/h.

Longitudinal drum boiler

The longitudinal drum boiler was the original type of water-tube boiler that operated on the thermo-siphon principle (see Figure 4.8).

Cooler feedwater is fed into a drum, which is placed longitudinally above the heat source. The cooler water falls down a rear circulation header into several inclined heated tubes. As the water temperature increases as it passes up through the inclined tubes, it boils and its density decreases, therefore circulating hot water and steam up the inclined tubes into the front circulation header which feeds back to the drum. In the drum, the steam bubbles separate from the water and the steam can be taken off.

Typical capacities for longitudinal drum boilers range from 2 250 kg/h to 36 000 kg/h.

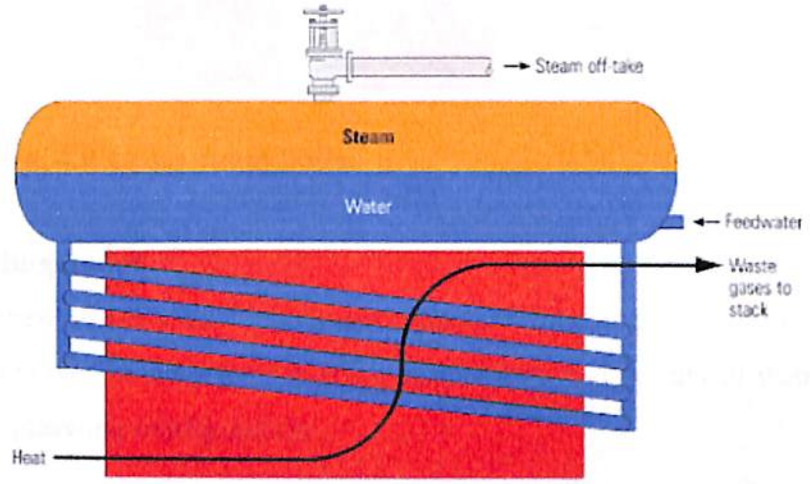


Fig. 4.8 Longitudinal drum boiler

Cross drum boiler

The cross drum boiler is a variant of the longitudinal drum boiler in that the drum is placed cross ways to the heat source as shown in Figure 4.9 The cross drum operates on the same principle as the longitudinal drum except that it achieves a more uniform temperature across the drum. However it does risk damage due to faulty circulation at high steam loads; if the upper tubes become dry, they can overheat and eventually fail.

The cross drum boiler also has the added advantage of being able to serve a larger number of inclined tubes due to its cross ways position.

Typical capacities for a cross drum boiler range from 700 kg / h to 240 000 kg/h.

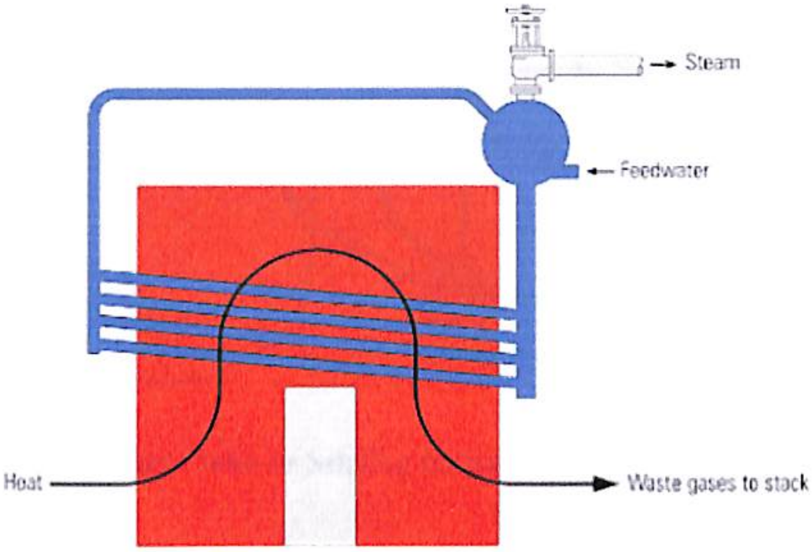


Fig. 4.9 Cross drum boiler

Bent tube or Stirling boiler

A further development of the water-tube boiler is the bent tube or Stirling boiler shown in Figure 4.10. Again this operates on the principle of the temperature and density of water, but utilises four drums in the following configuration.

Cooler feedwater enters the left upper drum, where it falls due to greater density, towards the lower, or water drum. The water within the water drum, and the connecting pipes to the other two upper drums, are heated, and the steam bubbles produced rise into the upper drums where the steam is then taken off.

The bent tube or Stirling boiler allows for a large surface heat transfer area, as well as promoting natural water circulation.

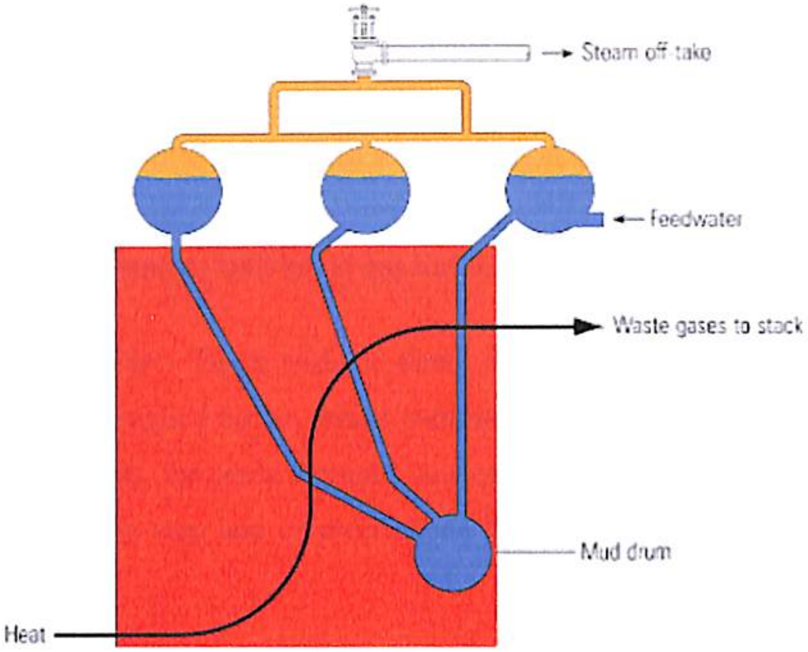


Fig. 4.10 Bent tube or Stirling boiler

Advantages of water-tube boilers:

They have small water content, and therefore respond rapidly to load change and heat input. The small diameter tubes and steam drum mean that much higher steam pressures can be tolerated, and up to 160 bar may be used in power stations. The design may include many burners in any of the walls, giving horizontal, or vertical firing options, and the facility of control of temperature in various parts of the boiler. This is particularly important if the boiler has an integral superheater, and the temperature of the superheated steam needs to be controlled.

Disadvantages of water-tube boilers:

They are not as simple to make in the packaged form as shell boilers, which mean that more work is required on site. The option of multiple burners may give flexibility, but the 30 or more burners used in power stations means that complex control systems are necessary.

Combined heat and power (CHP) plant

The water-tube boilers described above are usually of a large capacity. However, small, special purpose, smaller waste heat boilers to be used in conjunction with land based gas turbine plants are in increasing demand.

Several types of steam generating land based gas turbine plant are used:

Combined heat and power - These systems direct the hot exhaust gases from a gas turbine (approximately 500°C) through a boiler, where saturated steam is generated and used as a plant utility. Typical applications for these systems are on plant or sites where the demands for electricity and steam are in step and of proportions which can be matched to a CHP system. Efficiencies can reach 90%.

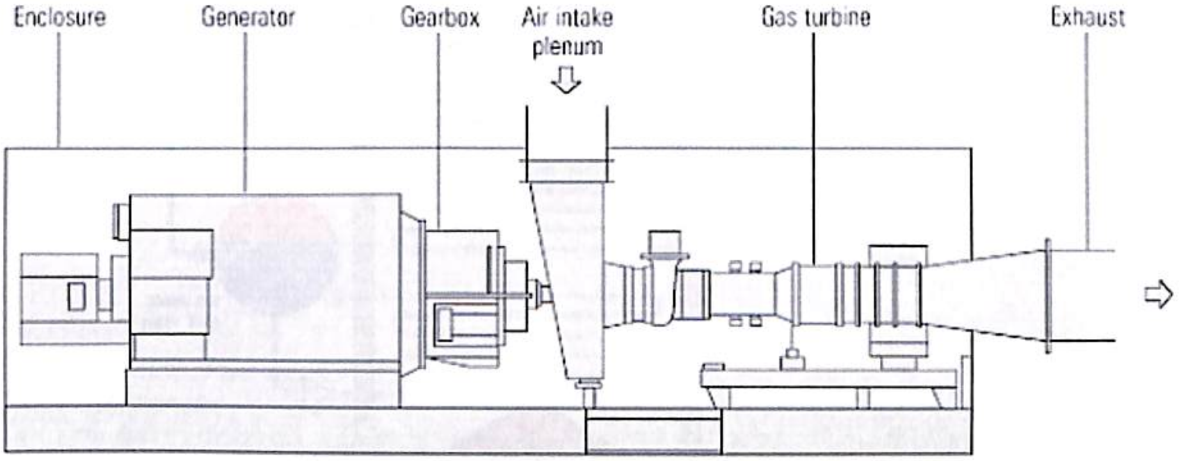


Fig. 4.11 Gas turbine / alternator set

Combined cycle plant - These are extensions to CHP systems, and the saturated steam is taken through a superheater to produce superheated steam. The superheater may be separately fired because of the comparatively low temperature of the gas turbine exhaust. The superheated steam produced is directed to steam turbines which drive additional alternators, and generate electricity.

The turndown ratio of these plants is poor, because of the need for the turbine to rotate at a speed synchronised to the electrical frequency. This means that it is only practical to run these plants at full-load, providing the base load of steam to the plant. Because of the relatively low temperature of the gas turbine exhaust, compared to the burner flame in a conventional boiler, a much greater boiler heat transfer area is required for a given heat load. Also, there is no need to provide accommodation for burners. For these reasons, water-tube boilers tend to provide a better and more compact solution. Because efficiency is a major factor with CHP decision-makers, the design of these boilers may well incorporate an economiser (feedwater heater).

If the plant is 'combined cycle' the design may also include a superheater. However, the relatively low temperatures may mean that additional burners are required to bring the steam up to the specification required for the steam turbines.

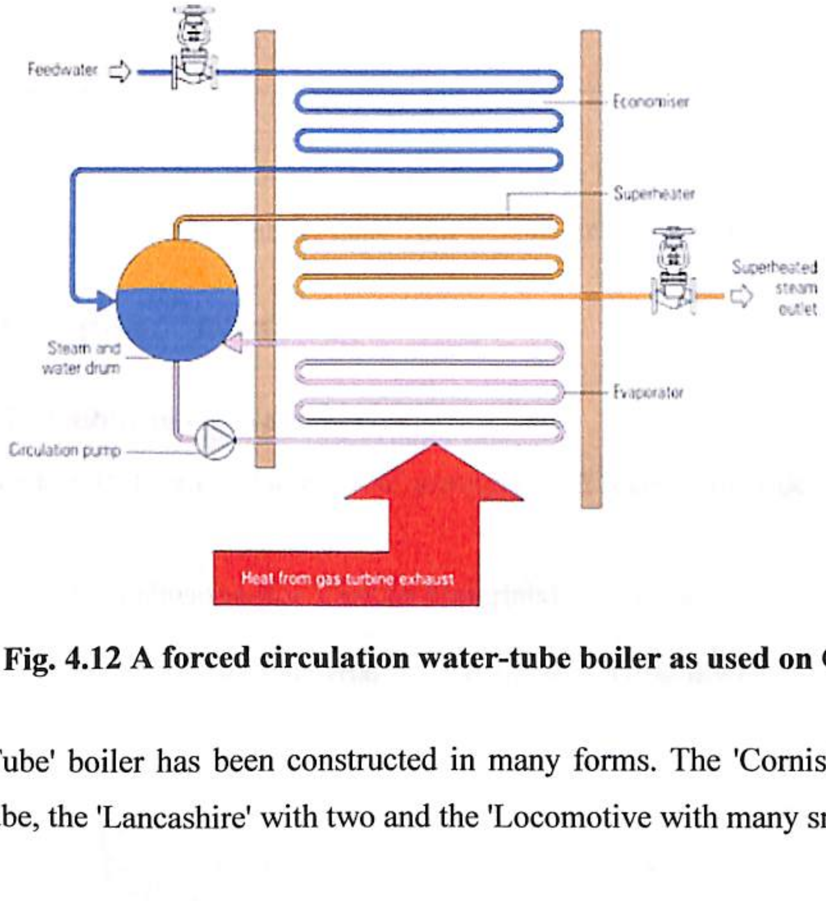
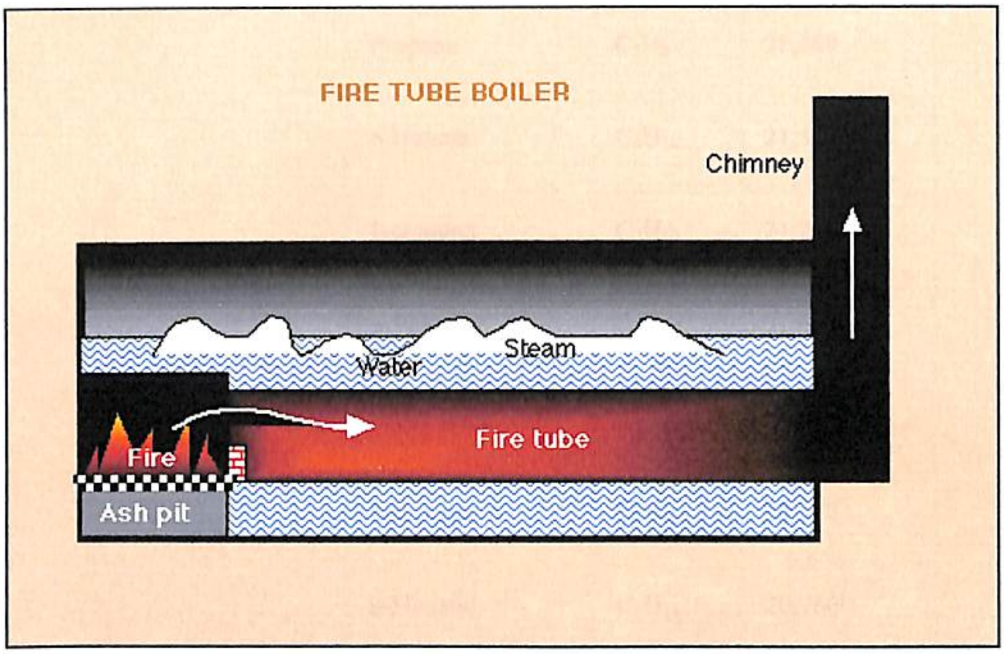


Fig. 4.12 A forced circulation water-tube boiler as used on CHP plant

The 'Fire Tube' boiler has been constructed in many forms. The 'Cornish' boiler with a single large fire tube, the 'Lancashire' with two and the 'Locomotive with many small tubes.

Figure 4.13



The tube shape is best able to resist the pressure of the steam and by having many small tubes, the surface area available to transfer heat from the hot fire gasses to the water is increased.

Natural gas combustion:

Elements of Combustion of Natural Gas

1 ft^3 natural gas + 10 ft^3 air + flame = 8 ft^3 nitrogen +1 ft^3 carbon dioxide + 2 ft^3 water vapor

Table 4.4 Heat of Combustion (for Various Materials)

Raw Material	Formula	Gross Btu/lb
Carbon	C	14,093
Hydrogen	H_2	61,095
Carbon Monoxide	CO	4,347
Methane	CH_4	23,875

Ethane	C_2H_4	22,323
Propane	C_3H_8	21,669
n-Butane	C_4H_{10}	21,321
Isobutane	C_4H_{10}	21,271
n-Pentane	C_5H_{12}	21,095
Isopentane	C_5H_{12}	21,047
Neopentane	C_5H_{12}	20,978
n-Hexane	C_6H_{14}	20,966
Ethylene	C_2H_4	21,636
Propylene	C_3H_6	21,048
n-Butene	C_4H_8	20,854
Isobutene	C_4H_8	20,737
n-Pentene	C_5H_{10}	20,720
Benzene	C_6H_6	18,184
Toluene	C_7H_8	18,501
Xylene	C_8H_{10}	18,651
Acetylene	C_2H_2	21,502
Naphthalene	$C_{10}H_8$	17,303

Methyl alcohol	CH_3OH	10,258
Ethyl alcohol	C_2H_5OH	13,161
Ammonia	NH_3	9,667

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

Firing Practices:

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units. Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NOx control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler. Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NOx control options. Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications. Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

Combustion Chamber

The combustion chamber has the difficult task of burning large quantities of fuel, supplied through fuel spray nozzles, with extensive volumes of air, supplied by the compressor, and releasing the resulting heat in such a manner that the air is expanded and accelerated to give a smooth stream of uniformly heated gas. This task must be accomplished with the minimum loss in pressure and with the maximum heat release within the limited space available.

The amount of fuel added to the air will depend upon the temperature rise required. However, the maximum temperature is limited to within the range of 850 to 1700 °C by the materials from which the turbine blades and nozzles are made. The air has already been heated to between 200

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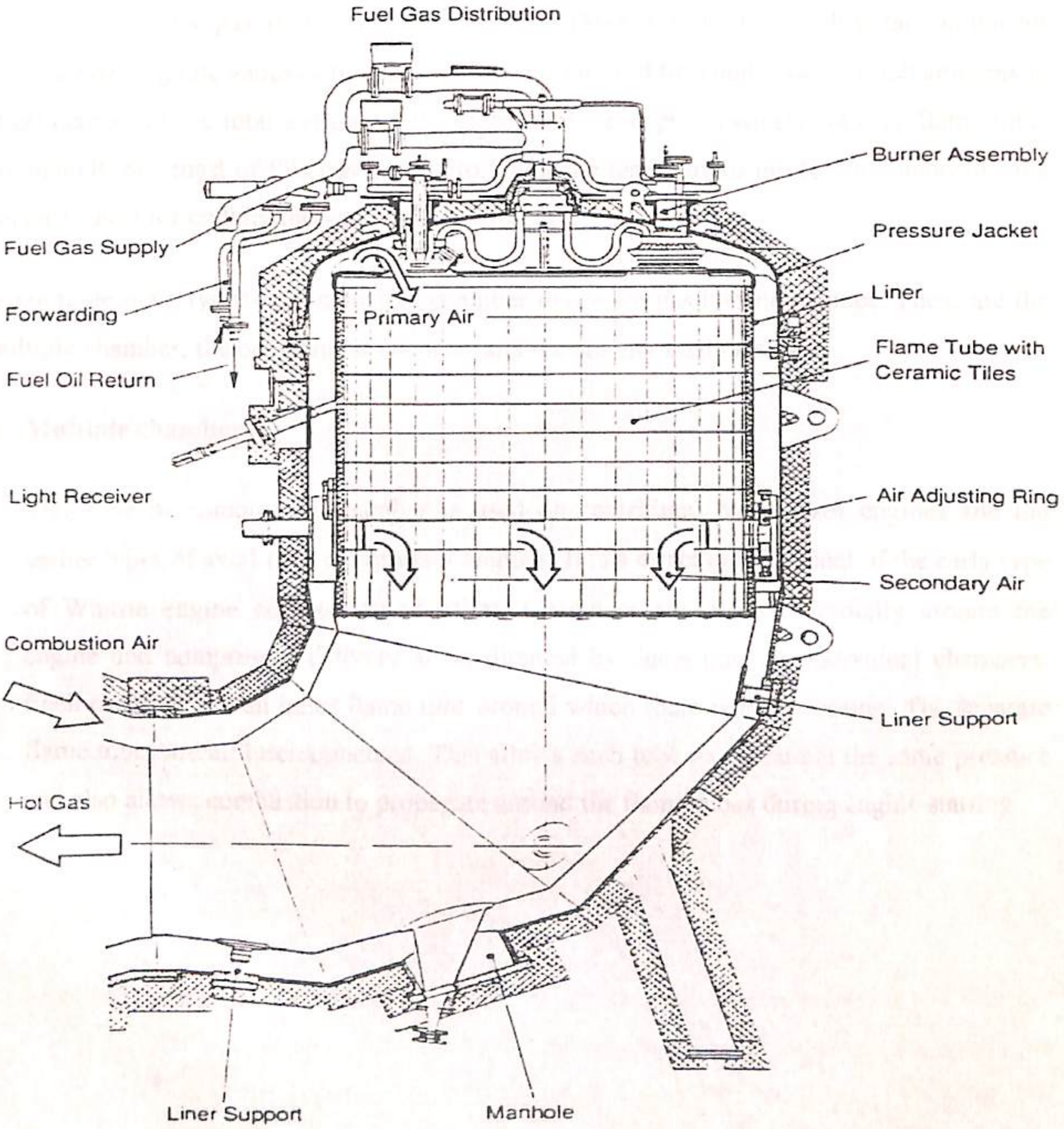


Combustion Chamber

and 550 °C by the work done in the compressor, giving a temperature rise requirement of 650 to 1150 °C from the combustion process. Since the gas temperature determines the engine thrust, the combustion chamber must be capable of maintaining stable and efficient combustion over a wide range of engine operating conditions.

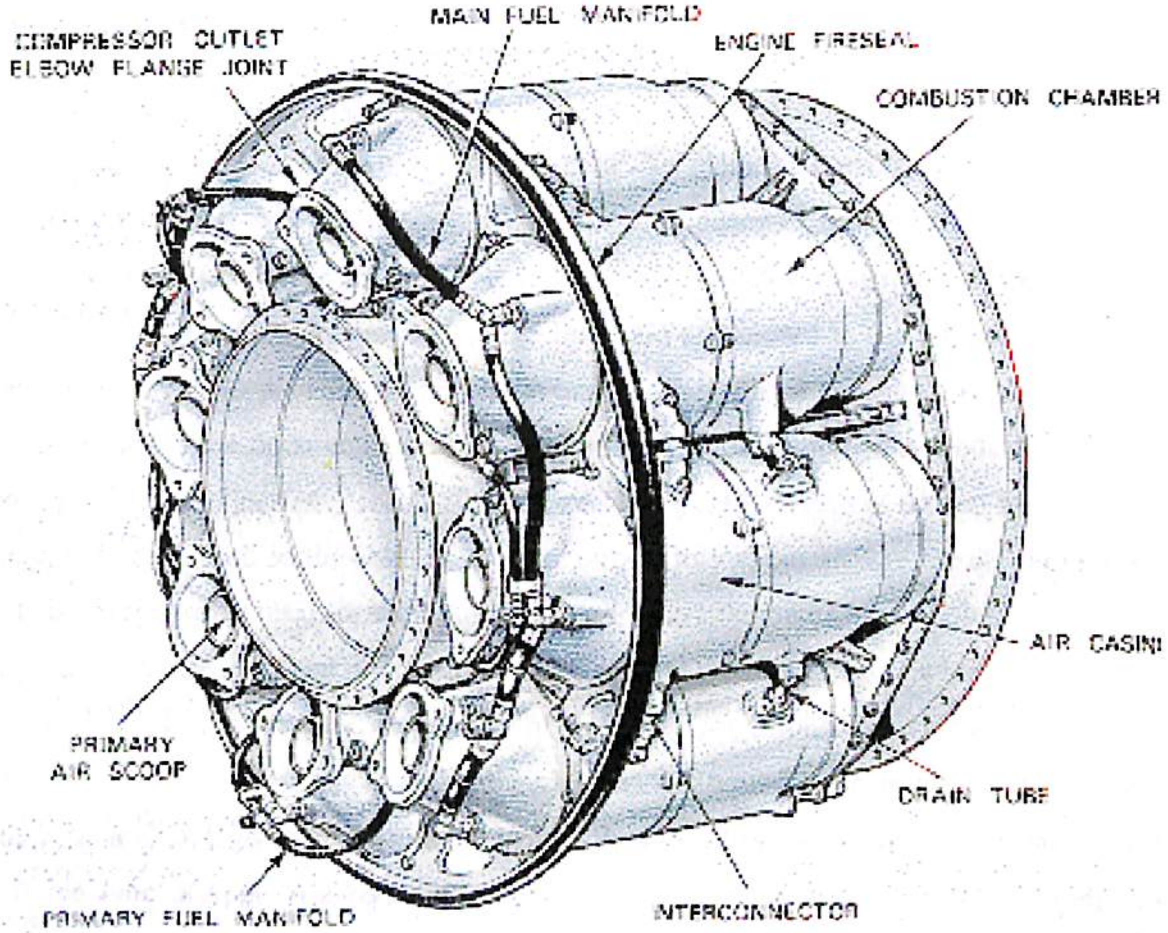
The temperature of the gas after combustion is about 1800 to 2000 °C, which is far too hot for entry to the nozzle guide vanes of the turbine. The air not used for combustion, which amounts to about 60 percent of the total airflow, is therefore introduced progressively into the flame tube. Approximately one third of this gas is used to lower the temperature inside the combustor; the remainder is used for cooling the walls of the flame tube.

There are three main types of combustion chamber in use for gas turbine engines. These are the the multiple chamber, the can-annular chamber and the annular chamber.

- **Multiple chamber**

  This type of combustion chamber is used on centrifugal compressor engines and the earlier types of axial flow compressor engines. It is a direct development of the early type of Whittle engine combustion chamber. Chambers are disposed radially around the engine and compressor delivery air is directed by ducts into the individual chambers. Each chamber has an inner flame tube around which there is an air casing. The separate flame tubes are all interconnected. This allows each tube to operate at the same pressure and also allows combustion to propagate around the flame tubes during engine starting.

Figure 4.14



A multiple combustion chamber

- **Can-annular chamber**

This type of combustion chamber bridges the evolutionary gap between multiple and annular types. A number of flame tubes are fitted inside a common air casing. The airflow is similar to that already described. This arrangement combines the ease of overhaul and testing of the multiple system with the compactness of the annular system. This is the simplest of combustion arrangement and consists of a cylindrical metal can shaped housing containing a metal liner or flame tube. Air from the compressor is ducted to the combustion chamber by the casing surrounding the compressor diffuser outlet. This casing may surround all the hot parts of the engine and hence reduce the outside surface temperature to an acceptable level.

The combustion chamber liner consists of a heat resistant metal cylinder which is closed at one end by a dome shaped cap. Fuel is sprayed into the combustion chamber from a nozzle at the closed end where it is ignited by a special spark plug. Air from the compressor flows around the outside of the liner between it and the outer combustion chamber casing. A series of holes or orifices in the liner admit the air into the central region where it sustains combustion. The exhaust gases exit through the open end of the liner and are ducted to the turbine. The holes in the liner are arranged to provide air for the actual combustion of the fuel and also additional larger holes towards the open end admit air for cooling of the combustion products. The flame temperature inside the liner may reach 2000 degrees centigrade which is far too hot for the rest of the engine to cope with so the cooling air is required. Only about 25% of the air entering a gas turbine is burnt the rest is used for cooling. The detailed arrangements of the holes becomes quite complicated, they are required to produce swirl within the flame tube which assists in the complete and stable combustion over a range of operating conditions. The surface of the liner is also kept cool by rings of very small holes which provide a boundary layer of cool air within the flame tube. The hole sizes are arranged so that the pressure drop between the outside and inside of the flame tube is kept to a minimum, any drop in pressure at this point will reduce the efficiency of the engine.

The flame tube/liner arrangement holds a flame within the combustion chamber which unlike a piston engine burns continuously. Ignition of the fuel is only required once during starting of the gas turbine.

The flame tube is made of a corrosion and heat resistant metal such as stainless steel or nimonic. Over a period of time the tube may became distorted due to thermal stresses and heat cycles. Small amounts of distortion depending on the engine type can be permitted. Cracks due to thermal fatigue can also form in the flame tube and often between the holes, these may be repaired by welding if not too severe. The overhaul manual for a particular engine will normally detail acceptable limits of distortion and cracking for the combustion chamber components.

The combustion chamber liner will be suspended at a number of points inside the engine. The liner will normally be aloud to "Float" slightly and may appear loose, this is to allow for thermal expansion and so prevent the liner from distorting unnecessarily.

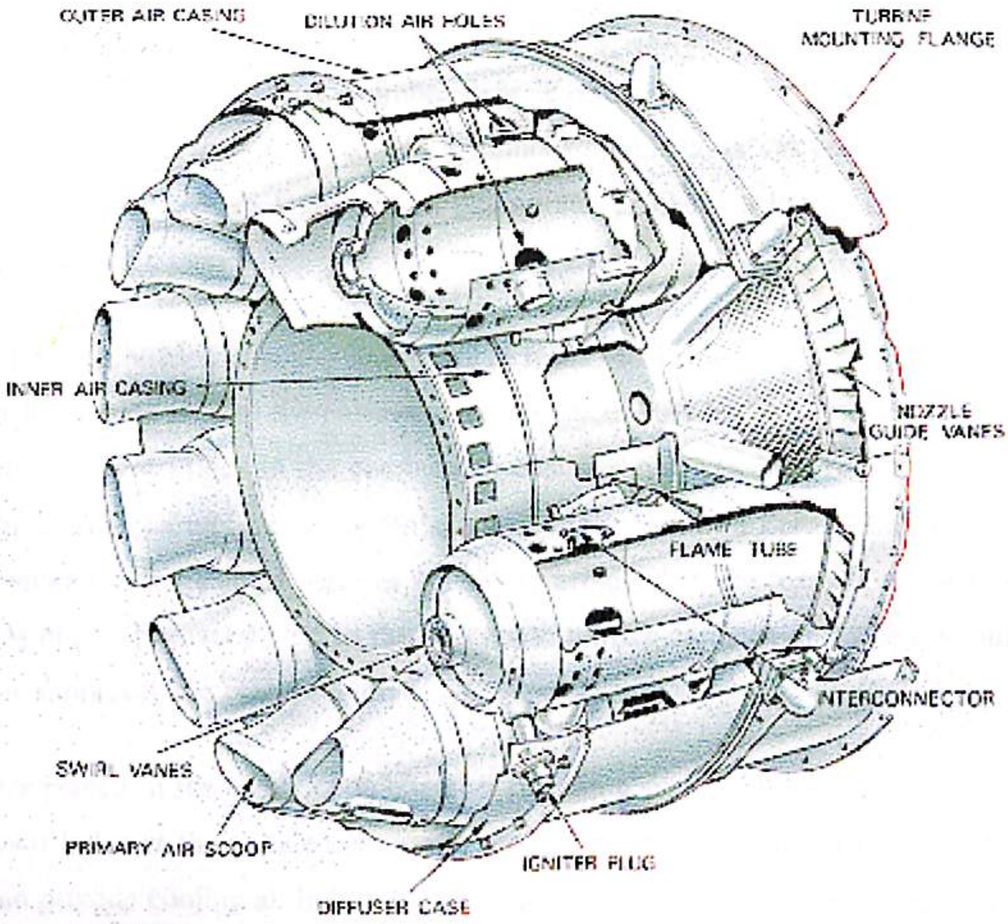
During the operation of the combustion chamber, carbon deposits may build up in the flame tube and around the burner nozzle. Certain engines run cleaner than others but if excessive carbon deposits build up, the combustion process can be detrimentally effected. Carbon around the burner may upset the fuel spray pattern and reduce the atomisation quality. Carbon can also block or modify the air holes which leads to less efficient air distribution. If the spray pattern is very poor the resulting flame may continue outside the combustion chamber area and create an uneven temperature distribution around the turbine and associated components, this will lead to eventual burning of components and failure. It is possible to "De-carbonise" combustion chamber components, great care is needed as devices such as fuel burner nozzles and ignitor plugs should be not brought into contact with abrasive materials.

Ignitor plugs and burner heads should only be cleaned with soft materials soaked methalayted spirit or electrical cleaning solvents.

A single can type combustion chamber exhibits a number of advantages over other types. The main advantage is simplicity, a single burner is installed and the liner can be easily removed for inspections and maintenance. In small engines, achieving efficient combustion becomes difficult as the internal dimensions and burning length required are relatively small. A can type chamber holds a single relatively large flame for a given size of engine.

The disadvantage of a can combustor is that the engine may not be as compact as with other types. The engine will not be symmetrical about its axis, for some small starter units which may be mounted on larger engines, compactness, weight and minimum external dimensions are important.

Figure 4.15



A can-annular combustion chamber

- **Annular chamber**

This type of combustion chamber consists of a single flame tube, completely annular in form, which is contained in an inner and outer casing. The main advantage of the annular combustion chamber is that for the same power output, the length of the chamber is only 75 per cent of that of a can-annular system of the same diameter, resulting in a considerable saving in weight and cost. Another advantage is the elimination of combustion propagation problems from chamber to chamber.

An annular combustion chamber is required to do exactly the same job as a can type unit but is physically arranged in a different way to reduce the overall size of the engine. The combustion chamber liner is rapped around the axis of the engine and instead of one, a number of fuel nozzles are used.. The combustion chamber liner is often arranged to double back on itself, in which case it is referred to as a "reverse flow combustion chamber". A reverse flow combustion chamber saves on the overall length of an engine and provides a longer burning area for the gases to travel through.

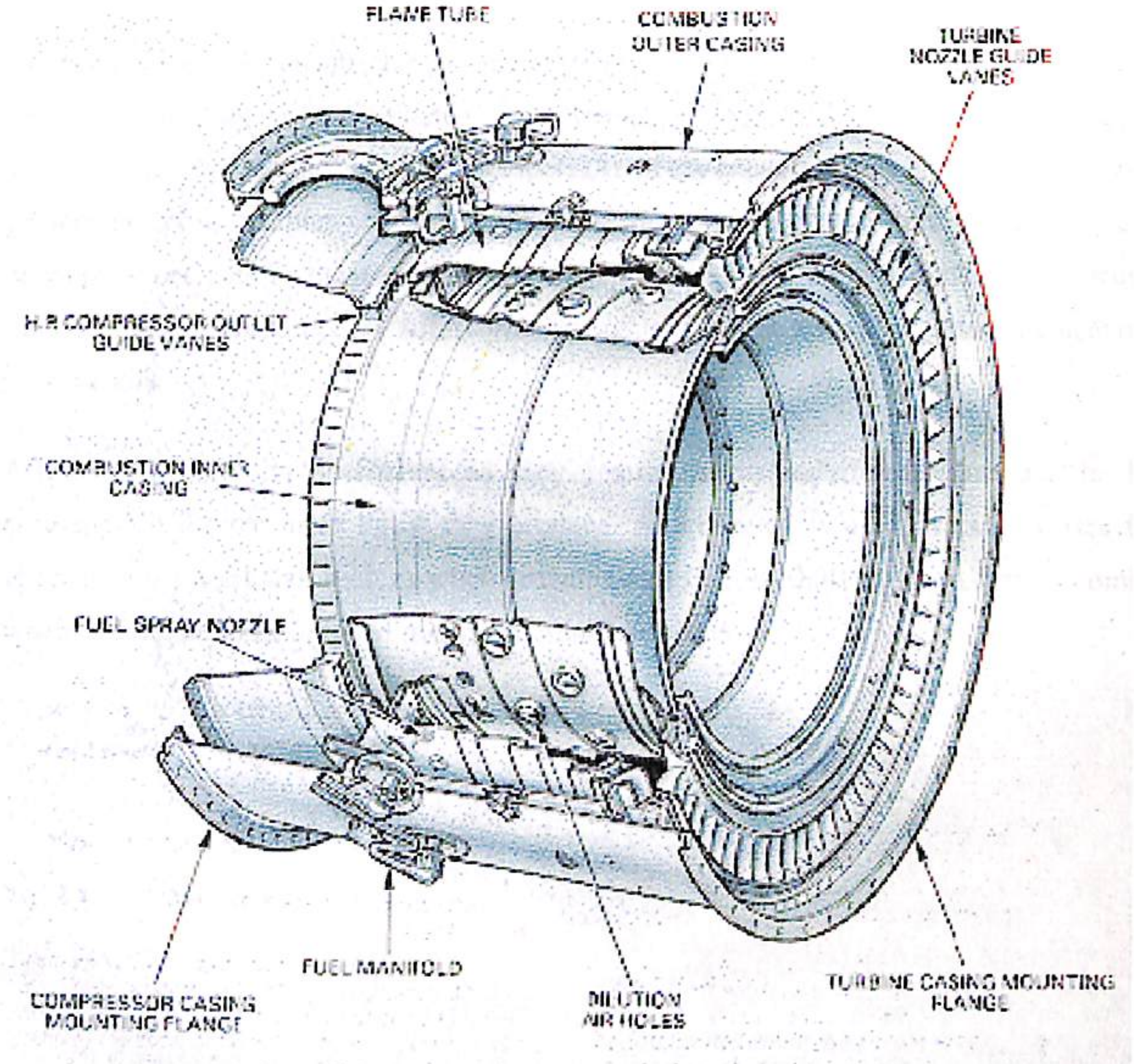
A reverse flow combustion chamber arrangement results in a ring of fuel burners being placed at the back of the engine around the exhaust circumference. Fuel is distributed to the burners by a pipe manifold or by drillings in the combustion chamber outer casing. The spray patterns from the individual burners are of a cone or fan shape or in the case of a Lucas aerospace engine, five burners produce flat fan shaped patterns which are arranged in the form of a pentagon. One or more ignitor plugs are placed next to the burners to initiate combustion, once one burner lights up the flame spreads to the others rapidly.

Air holes are placed in the combustion chamber liner in a similar manner to that in the can type system. Small holes at the nozzle/burner end provide air for combustion and then larger holes down stream provide cooling air before the gases are passed to the turbine system. Air which has been bled from the compressor may also be supplied to the burners directly to assist in the atomisation process.

The annular combustion chamber reduces the overall size of an engine but it is more integrated into the engine construction and is therefor more difficult to remove and inspect. The combustion chamber liner is arranged to form a radial chamber around the shaft which connects the compressor to the turbine, fuel is admitted to the chamber through the turning shaft from a series of radial drillings placed in it. As the shaft rotates at high speed, the fuel is thrown outwards and atomised into a fine disc shaped spray. The fuel is ignited and burned with a similar air distribution to that of the other combustion chamber types. The hot gases from the combustion process are guided by the liner outwards and along the engine axis or back towards the centre depending on the type of turbine wheel used. The whole radial liner is enclosed in an outer casing which is pressurised with air from the compressor.

Fuel has to be supplied to the combustion chamber through the engine shaft, this requires a seal arrangement at the cold end near the compressor to ensure that it does not leak out into the other engine systems i.e. the oil supply to the bearings.

Figure 4.16



An annular combustion chamber

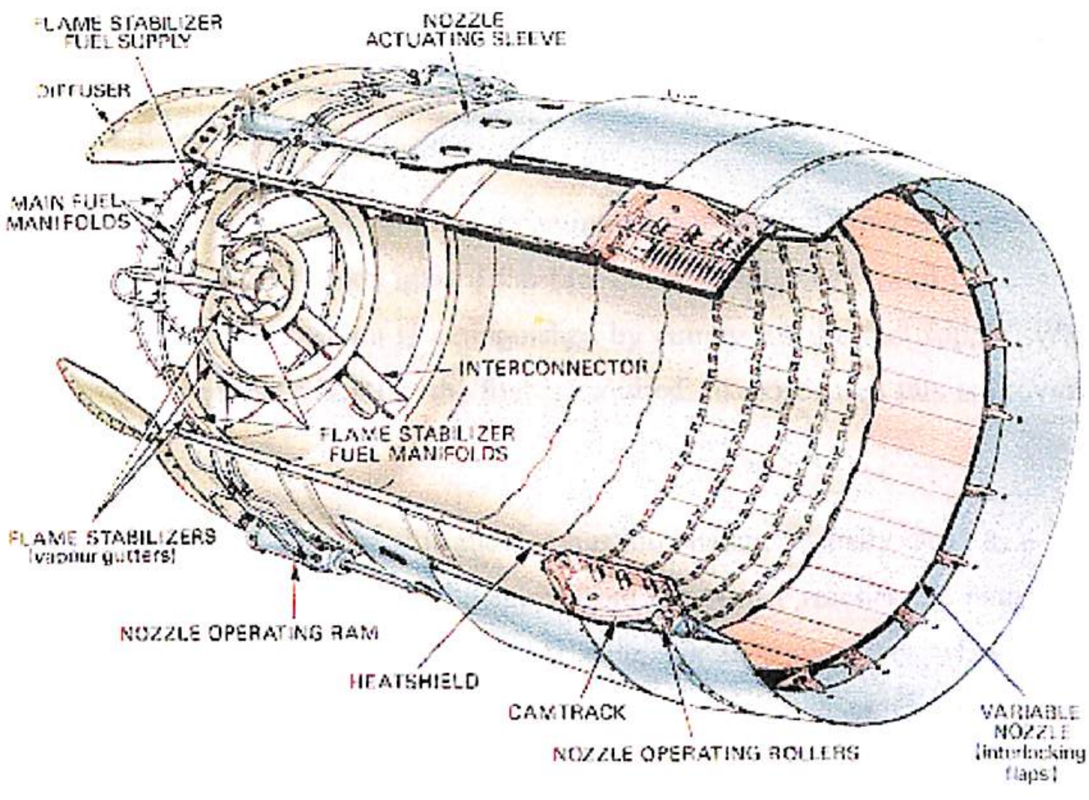
Afterburners

In addition to the basic components of a gas turbine engine, one other process is occasionally employed to increase the thrust of a given engine. Afterburning (or reheat) is a method of augmenting the basic thrust of an engine to improve the aircraft takeoff, climb and (for military aircraft) combat performance.

Afterburning consists of the introduction and burning of raw fuel between the engine turbine and the jet pipe propelling nozzle, utilizing the unburned oxygen in the exhaust gas to support combustion. The resultant increase in the temperature of the exhaust gas increases the velocity of the jet leaving the propelling nozzle and therefore increases the engine thrust. This increased thrust could be obtained by the use of a larger engine, but this would increase the weight, frontal area and overall fuel consumption. Afterburning provides the best method of thrust augmentation for short periods.

> Afterburners are very inefficient as they require a disproportionate increase in fuel consumption for the extra thrust they produce. Afterburning is used in cases where fuel efficiency is not critical, such as when aircraft take off from short runways, and in combat, where a rapid increase in speed may occasionally be required.

fig 4.17: *Typical afterburning jet pipe equipment*



Burners

As mentioned in the previous chapter, fuel is admitted to the combustion chamber through one or more nozzles called burners.

Burners are required to spray fuel into the combustion chamber in a very fine atomised form. Fuel under pressure is forced through a very small orifice which causes it to break up into tiny droplets. Compressed air from the compressor or a separate pump is sometimes mixed with the fuel inside the burner, this will assist the process of atomisation. Certain designs of burner incorporate a valve which shuts off at low pressures and helps to maintain atomisation. The Rover gas turbine uses compressed air from a motor driven pump to assist atomisation which improves ignition and starting performance. The burner air supply pump is known as an emulsion pump as it creates a fuel/air emulsion.

A cone shape spray pattern from a burner is normally required, as the engine ages this may deteriorate due to carbon deposits and abrasion from the fuel. The fuel has to be adequately filtered to ensure that no foreign matter enters the burner and clogs it up. Burner units are often fitted with small filters to further prevent damage due to foreign matter contaminating the fuel supply

Starting and Ignition Systems

Gas turbines unlike piston engines employ a continuous combustion process to provide the heat input to their working cycle. Once ignited the fuel burns continuously until the engine is shut down, at this point the combustion is extinguished by cutting off the fuel supply. When a gas turbine is started, a means of igniting the fuel is required, in most cases this is provided by an electric spark.

One or more ignitor plugs are placed in the combustion chamber usually close to a fuel burner nozzle. When the fuel is switched on the spray from the burner reaches the plug and ignites. Most small gas turbines only have one ignitor plug, but in some cases when an engine is constructed with an annular combustion chamber, two are fitted at opposite sides of the combustion chamber.

Warning

Gas turbine ignition systems can be dangerous! Lethal voltages are present particularly in the high energy types. Always allow several minutes to elapse before dismantling an ignition system so that any capacitors can fully discharge. Always make sure the casing of any ignitor unit is electrically bonded to the engine casing.Poor or loose connections can develop potential differences whilst the sparks occur.Never operate an ignitor unit without the ignitor plug connected.

There are three basic types of ignition systems which are used in small gas turbines.

High Tension Ignition

This process is not dissimilar to piston engine ignition systems. A step up transformer or "ignition coil" provides a high voltage spark. A DC current is applied to the transformer primary and is interrupted by contacts in a trembler mechanism. The trembler mechanism is operated by the magnetic field from the transformer windings. This arrangement is similar to an ordinary electric bell and vibrates many times per second, this produces a stream of sparks at an igniter plug which is connected to the transformer secondary. A capacitor is connected across the trembler contacts which suppresses arcing across them and reduces radio frequency interference. The capacitor often forms a partial resonant circuit with the transformer and will increase the power of the spark.

A high tension ignitor unit usually consists of an integrated unit which will work from a 12 to 30 V battery DC supply. The high tension voltage may be anything up to 30,000 volts but at a low current of a few mA. Ignitor units are sealed to prevent the ingress moisture from causing arcing of the high tension voltage. It is possible for ignitor units to be fitted with two outputs which feed two separate ignitor plugs. Care must be taken not to operate an ignitor unit when the plugs are disconnected, otherwise it may breakdown internally and become permanently damaged.

High tension ignitor plugs resemble car type spark plugs. An insulated central electrode is placed inside an earthed casing with an exposed gap. The high voltage flashes over across the gap providing a near continuous arc. The gap is usually quite large up to about 4 mm. Fuel is sprayed through the spark and quickly ignites, sometimes a partial shield is placed around the plug which controls the air flow through the spark, excessive air flow may "blow" the spark out.

The HT cables which connect the ignitor units and plugs together are usually screened coaxial type cables which reduce radio interference. The outer screen may also form a conducting earth return for the system.

Over a period of time the ignitor plug may become fouled with carbon deposits, these may interfere with its operation. Gap-type ignitor plugs may be cleaned with solvents. As with automotive plugs, the spark gap may require adjustment for best performance.

High Energy Ignition

This system is quite different to the high tension system, instead a lower voltage high current spark is achieved by discharging a capacitor into a special plug. A trembler system and a step up transformer provide a source of high voltage. A rectifier converts the transformer output to a DC voltage which charges a capacitor of a few microfarads capacity, the capacitor acquires a charge of up to several thousand volts. A special sealed discharge tube is connected between the capacitor and the ignitor plug, at a predetermined voltage the discharge tube breaks down and a pulse of energy is passed to the ignitor plug, this discharges the capacitor. The process repeats itself several times per second as the capacitor repeatedly re-charges producing a succession of very violent and hot sparks.

High energy ignition uses a special type of plug. A surface discharge plug is used which breaks down at a relatively low voltage. A central electrode is surrounded by a semi-conducting material which flashes over and dissipates the spark energy. The energy released is expressed in joules, the energy is released from the stored charge in the capacitor and may amount to several joules. The spark energy fills the area around the plug tip and is very effective at igniting the fuel.

High energy igniters are common in gas turbines and are required to operate in temperatures well below freezing. Cold jet fuel is remarkably difficult to ignite, it is for this reason that high energy ignitors have become common in small gas turbine engines.

The original high energy ignition systems used a trembler coil system to provide a high voltage to charge the capacitor from a nominal 24V battery supply. More modern ignitor units use an electronic inverter to step up the voltage, these are characterised by a whistling sound which rises in pitch between successive sparks. Care must be exercised when connecting up electronic ignitor boxes as they may be damaged if the correct DC input polarity is not observed.

If an ignitor unit is dismantled for any reason care must be exercised as the capacitor can remain charged for a period of time after disconnection of the DC supply. Always allow several minutes to elapse before opening up an ignitor unit. Some ignitor units are sealed to prevent the ingress of moisture, other units can be stripped down to there component parts which eases repairs.

The interconnecting cable between an ignitor unit and its plug is made up off a heavy duty coaxial cable. The cable maintains effective continuity so that the spark energy is not reduced by the cable resistance, the outer conductor provides a solid earth return. The connections made by the HT cables should always be checked for tightness so that good electrical conductivity is maintained The Rover 1S series and Garrett engines use high energy ignition. A hand started version of the rover also uses a little generator to provide power for a high energy ignitor.

When attempting to clean a high energy surface discharge plug care should be exercised. The semiconductor surface can be damaged by abrasives and should only be cleaned with solvents. Carbon deposits may aid in providing a discharge path across the surface of the plug and are not detrimental to the plug operation.

Torch Ignitor

A third type of gas turbine ignitor is known as a torch ignitor. A small nozzle sprays fuel into a burner unit which is similar in construction to a blow lamp. A small pump provides fuel which is ignited by a high tension spark or a high energy spark, a portion of air from the engine compressor is also diverted into the burner. The torch ignitor is used to form an initial flame in the combustion chamber from which the main fuel system is ignited. A valve is used to shut off the fuel supply to the torch ignitor when the engine has successfully lit up. The tourch ignitor shut off valve is normally operated by an automatic sequencing system which is controlling the engine start cycle.

Ignition systems in gas turbines can normally be heard operating when the engine is stationary. High tension systems usually produce a "hissing/buzzing" sound which can be heard at the engine exhaust. High energy systems produce a series of "Cracks" or "Ticks" which can also be heard from the engine exhaust when the ignitor is operated. High energy igniters may also be heard during the initial stages of a gas turbine spooling up on the starter.

Failure of a gas turbine ignition system usually results in an accumulation of unburnt fuel in the combustion chamber during an attempt to start the engine. A drain system is provided to allow this fuel to run away, this must always be allowed to happen before a second start cycle is attempted. Any excessive delay in the light up of an engine will result in a "Wet" or "Torched" start, here the fuel will burn out through the turbine and into the exhaust system. Wet starts produce flames in the exhaust and can be detrimental to the engine, wet starts can also lead to high exhaust gas temperatures. Although sometimes spectacular wet starts can also become a fire hazard.

Faults in ignition systems can be approached in a similar way to any other electrical system problem. Individual components may fail and bad connections exist between components. Old surplus ignitor units can be effected in many ways, the capacitors become electrically "leaky" or go short circuit. The trembler mechanism employs contacts which get dirty or become out of adjustment. A suppresser capacitor is fitted across the trembler contacts which also fail. The discharge tube fitted to an ignitor unit consists of two graphite electrodes sealed in a glass envelope, the envelope is filled with a rarefied gas such as argon. The glass envelope may become cracked or the seals around the metal electrodes can fail. Certain types of discharge tube are connected with nuts and bolts, care must be exercised when attempting to undo these fasteners as any force on the tube will break it.

Ignition systems are operated during the start cycle of an engine and during the period when power is supplied to the starter motor. Engines employing an automatic start cycle shut off the ignition after a predetermined time delay or when the starter is cut out. It is often useful to be able to rotate an engine with the ignition turned off, a switch on the engine control panel will normally be provided to facilitate this. Rotating a gas turbine engine with the ignition and fuel turned off (HP cock closed) is often referred to as a "Dry cycle" or "Blow out". Rotating a gas turbine engine with the fuel turned on (HP cock open) and the ignition switched off is referred to as a "Wet Cycle".

It is often useful to test the ignition with an engine stationary; care should be exercised in case fuel vapour has collected in the combustion chamber. It is advisable to dry cycle the engine first to clear any flammable fuel vapour.

Testing Burners

Burners may be tested and the fuel spray pattern inspected. This may be done in a number of ways. In engines which are equipped with just one burner, the spray pattern can be investigated by removing the burner from the combustion chamber and reconnecting it to the fuel system so that it discharges into a container. The engine is rotated by the starter and the HP cock opened, at this point fuel should be seen to spray from the burner. Spray patterns vary according to the design of the engine but generally the pattern should consist of a cone shaped fine mist which is evenly distributed. The spray should not turn into a bubble like film or break up into larger droplets. When operating the burner from the engine driven fuel pump, the characteristics are only valid for starting speeds but this process does give an indication of the state of the burner. Poor atomisation of the fuel at lower pressures and flows will indicate a potentially faulty burner nozzle.

With a fuel burner removed it is useful to inspect it for carbon deposits at the same time. Carbon formation around the burner will degrade the spray pattern and may also effect the air distribution around it. Accumulated carbon should be removed very carefully, metallic objects should not be used as they can scratch the burner head and damage it.

Burners can often be tested when removed from an engine by constructing a test rig. A simple rig can be constructed by using a pressure pump and a bleed valve. Fuel is supplied to the burner from the pump and the pressure/flow varied using a needle valve to bypass or spill fuel back to the pump inlet. Electric car fuel injection pumps are useful for this purpose; also some surplus aircraft priming pumps find an application here. The pressure required depends on the burner but generally around 100 PSI is adequate for a simple test, a pressure gauge should be fitted to monitor the pressure supplied to the burner. Hydraulic pumps may be suitable provided they are fitted with a relief valve; maximum pressure should not exceed about 200 PSI.

Fuel supplied to a burner must be filtered to a high standard so that particles of dirt in the fuel do not damage it. Solvents may help clean a burner but care should be exercised so that any rubber seal components do not become damaged by the solvent. It may also be possible to use an ultrasonic cleaning bath to clean a burner if one is available.

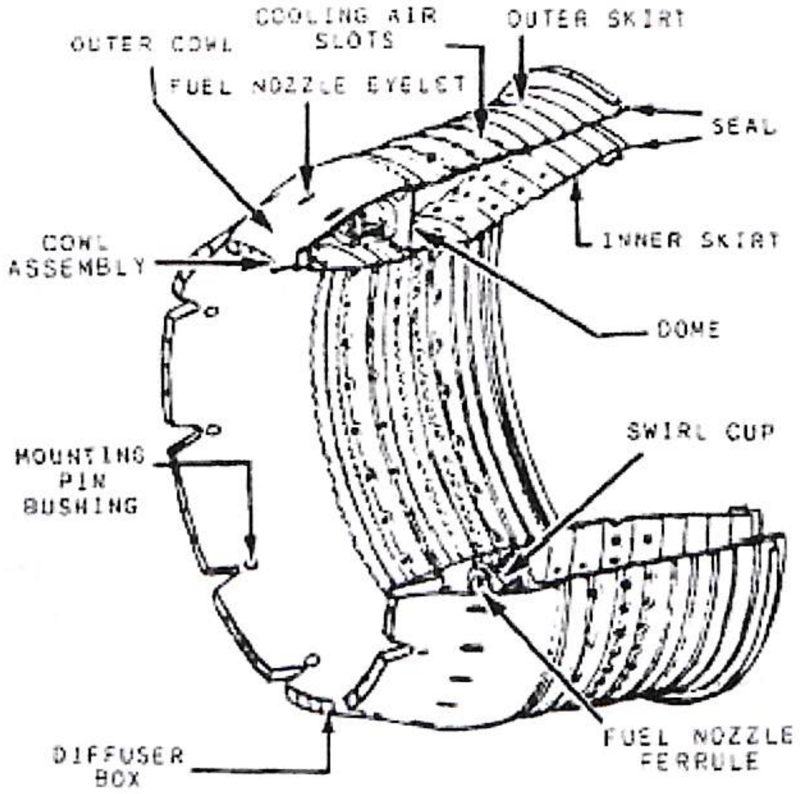
With the manufacturer's data available burner characteristics can be more closely investigated, certain adjustable types can be optimized when fitted to a test rig.

The spray from burner nozzles is very fine, take care not to breath in the spray and operate the burner in a well ventilated area. Obviously the spray is also flammable; keep it away from any naked lights. Take care with high pressure fuel feeds and do not restrict flows with figures etc.

Torch ignitors also consist of burner units; these may be tested with the above apparatus.

Combustion liner: The combustion chamber must operate over a wide range of conditions. It must withstand high rates of burning, have a minimum pressure drop, be light in weight, and have minimum bulk. The inner and outer liners or shrouds are perforated with many holes and slots throughout their length. Air is admitted through these holes to protect the liner and to cool the gases at the chamber outlet.

Figure 4.18



The through-flow passages are used in practically all modern engine combustion chambers. In the through-flow path, the gases pass through the combustion section without a change in direction.

The annular combustor liner (fig. 4.18) is usually found on axial-flow engines. It is probably one of the most popular combustion systems in use. The construction consists of a housing and liner.

On large engines, the liner consists of an undivided circular shroud extending all the way around the outside of the turbine shaft housing. A large one-piece combustor case covers the liner and is attached at the turbine section and diffuser section.

The dome of the liner has small slots and holes to admit primary air and to impart a swirling motion for better atomization of fuel. There are also holes in the dome for the fuel nozzles to extend through into the combustion area. The inner and outer liners form the combustion space. The outer liner keeps flame from contacting the combustor case, and the inner liner prevents flame from contacting the turbine shaft housing.

Large holes and slots are located along the liners to (1) admit some cooling air into the combustion space towards the rear of the space to help cool the hot gases to a safe level, (2) center the flame, and (3) admit air for combustion. The gases are cooled enough to prevent warpage of the liners. The space between the liners and the case and shaft housing forms the path for secondary air. The secondary air provides film cooling of the liners and the combustor case and shaft housing. At the end of the combustion space and just before the first-stage turbine nozzle, the secondary air is mixed with the combustion gases to cool them enough to prevent warping and melting of the turbine section. The annular-type combustion chamber is a very efficient system that minimizes bulk and can be used most effectively in limited space. There are some disadvantages, however. On some engines, the liners are one-piece and cannot be removed without engine disassembly.

Naphtha combustion system:

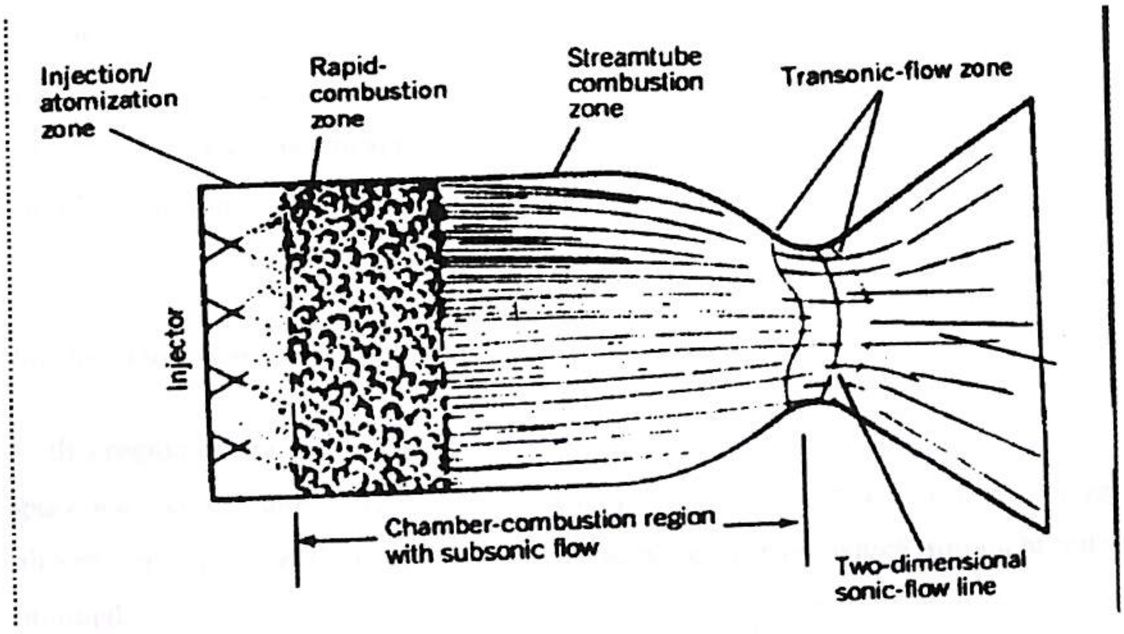
Combustion Process:

To understand the combustion mechanism in a rocket motor it is often helpful to break up the combustion chamber into a series of discrete zones, and thereby study these zones individually. In actually, the boundaries of these zones are difficult to define and transition from one zone to the next is gradual. The thickness of these zones is heavily influenced by choice of propellants and the properties unique to them, the operating conditions (i.e. mixture ratio, chamber pressure, etc.), the injector design and the chamber geometry. Typically, a rocket motor consists of a flat injector plate and a cylindrical combustion chamber, however, other configurations exists (i.e. spherical combustion chambers).

The illustration below shows the three major zones within the combustion chamber. They are:

- Injection/atomization zone
- Rapid combustion zone
- Stream tube combustion zone

Figure 4.19



Injection/Atomization Zone:

The liquid propellants are injected into the combustion chamber via injection orifices at velocities typically between 7 to 60 m/sec (20 to 200 ft/sec). The injector design affects the combustion process significantly (see injector types below). Some important parameters are number and size of orifices, distribution of orifices, and injector orifice angles.

When the liquid fuel and oxidizer are injected into the chamber the individual jets are broken up into small droplets. This region is relatively cold, however, heat transferred via radiation from the rapid combustion region causes most of the small droplets to vaporize. At this point chemical reactions are occurring, but at a minimal level since the zone are relatively cool. Also, the region is heterogeneous, with fuel and oxidizer rich regions.

Rapid Combustion Zone:

In this zone chemical reactions occur rapid due to the increasing temperature caused by the liberation of heat during the reaction. Any remaining droplets are vaporized and the mixture is fairly homogeneous due to local turbulence and diffusion of gas species. The gas expands causing the specific volume of the mixture to increase and the gas begins to move axially with significant velocity. There is some transverse motion of the gas as high-burning-rate regions expand towards cooler low-burning-rate regions.

Stream Tube Combustion Zone:

In this region chemical reactions continue but at a reduced rate. The axial velocity of the gas continues to increase (200 to 600 m/sec). Transverse convective flow decreases to almost zero and the flow forms small streamlines across which turbulent mixing is minimal.

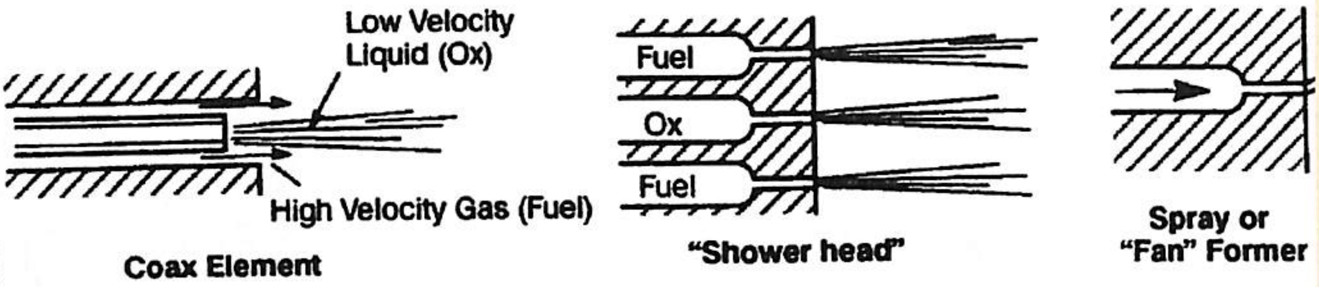
- **Injector Types:**

  The purpose of the injector is to introduce fuel and oxidizer into the combustion chamber in a manner fit for combustion. Typically this is done through a series of orifices arranged in a particular pattern. There are many configuration for injectors – here are a few of them:

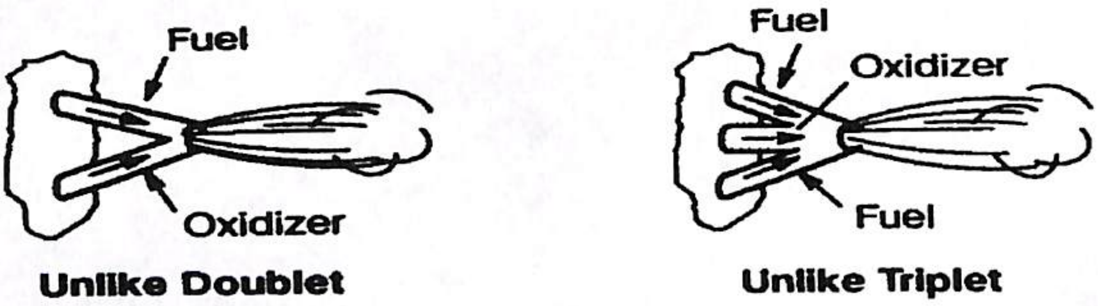
Figure 4.20

No

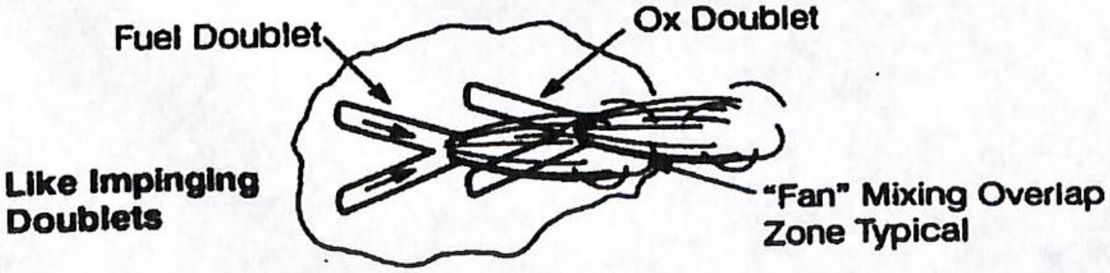
impinging



Unlike-impinging elements



Like-impinging elements



Cost of Generation by Various Fuels at 80 % PLF

The cost of generation of the various fuel types at 80% PLF for base load operation is Summarized below:

SUMMARY OF COST OF GENERATION BY VARIOUS FUELS AT 80 % PLF (Rs/kwh)

COST AT 80 % PLF	DISTANCE IN km								
	200	300	500	800	1000	1200	1500	1800	2000
Domestic Coal PH	1.56	1.59	1.62	1.69	1.73	1.77	1.83	1.88	1.92
Domestic Coal LC	1.58	1.63	1.73	1.88	1.97	2.06	2.20	2.31	2.36
Imported Coal At Port	2.15	2.18	2.22	2.29	2.32	2.36	2.42	2.48	2.52
Imported Coal LC	2.11	2.15	2.22	2.32	2.39	2.46	2.56	2.65	2.69
Lignite At PH	2.11	2.14	2.18	2.25	2.28	2.32	2.38	2.44	2.48
LNG At Port	2.16	2.19	2.23	2.29	2.33	2.36	2.42	2.47	2.51
Naphtha At Port	4.33	4.36	4.39	4.46	4.49	4.53	4.59	4.64	4.68
Naphtha At LC	4.19	4.22	4.27	4.36	4.41	4.47	4.55	4.62	4.66
Gas Along Pipeline	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49	1.49
Diesel At LC	5.96	5.96	5.96	5.96	5.96	5.96	5.96	5.96	5.96

The above results have shown variation in cost of generation of coal based power plants (domestic and imported) and lignite with distance between pithead/port and load centre as applicable.

Cost of Generation by Various Fuels at 30 % PLF

Comparison of cost of generation of peaking plants (30%PLF) by types of fuels is given below. As coal and lignite based plants are base load stations and cannot operate at low PLF as peaking plants, cost of generation of these types of plants is not considered in the analysis.

SUMMARY OF COST OF GENERATION BY VARIOUS FUELS AT 30% PLF (Rs/kwh)

COST AT 30% PLF	DISTANCE IN km								
	200	300	500	800	1000	1200	1500	1800	2000
Gas At LC	2.66	(Along HBJ Pipe Line)							
LNG At Port	3.45	3.52	3.61	3.78	3.88	3.98	4.13	4.27	4.37
Naphtha At Port	5.61	5.68	5.78	5.95	6.05	6.15	6.29	6.44	6.54
Naphtha At LC	5.36	5.39	5.44	5.53	5.58	5.64	5.72	5.79	5.83
Diesel At LC	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48	7.48

The above results indicate that to meet peaking requirement, gas based plants along HBJ pipeline followed by LNG based plant at port are cheaper options as compared to Naphtha based plants at 30% PLF. Also Naphtha based plant at load centre with transportation of Naphtha is a cheaper option as compared to Naphtha based plant at port and transmission of power. Diesel is the most expensive option.

CHAPTER: 5

POST COMBUSTION ENVIRONMENT EFFECTS BY USING DIFFERENT FEED-STOCKS IN POWER PLANTS

Emissions from Coal Fired Thermal Power Plants in India

Emissions from coal usage

The main emissions from coal combustion at thermal power plants are Carbon dioxide (CO_2), Nitrogen oxides (NO_x), Sulfur oxides (SO_x), Chlorofluorocarbons (CFCs), carbonaceous material (soot), and air-borne inorganic particles such as fly ash, also known as suspended particulate matter (SPM) and other trace gas species. Carbon dioxide, nitrous oxide, and chlorofluorocarbons are greenhouse gases. Evidence accumulated by the Inter-governmental Panel on Climate Change (IPCC) suggests that emissions of these greenhouse gases might be responsible for climate change, a global concern. Possible consequences projected by IPCC include:

- a rise in sea levels
- a more vigorous hydrological cycle that may increase the severity of floods and droughts and may cause more extreme climatic events; and
- ecological change that could threaten agricultural productivity

Oxides of nitrogen and sulfur, also play an important role in atmospheric chemistry and are largely responsible for atmospheric acidity. Particulates and black carbon (soot) are of concern in the radiative forcing of the earth. They also have a significant negative impact on human health causing lung tissue irritation and are linked to cancer and other serious diseases.

The pollutants emitted from thermal power plants depend largely upon the fuel burned, the furnace design, the excess air, and any additional devices used to reduce the emissions. At present, the only control device used in thermal power plants in India is electrostatic precipitator to control the emission of fly ash (SPM). CO_2, SO_2, nitric oxide (NO), soot, and SPM emissions from each of the thermal (coal-fired) power plants in India have been computed using basic principles of combustion. These calculations are based on a theoretical ideal and the input data, such as chemical composition of the coal used in the power plants, coal used per unit of power, excess air used during combustion, and the power generation from each plant. This input data has been collected from the published information. The present method to estimate the emissions is one of the many available methods for emissions inventory process. The other methods used in different countries are based on the guidelines recommended by IPCC, and may require large resources. Emissions from combustion of the supplementary fuels such as high-speed diesel (HSD) and furnace oil used in small quantities are not counted in the present calculations.

Emission of carbon dioxide and sulfur dioxide:

Utilities mostly burn coal with approximately 10 -30% excess air. Carbon as obtained from Ultimate analysis is converted to CO_2 after the reaction (combustion) is complete. Some carbon is emitted in the form of soot and some carbon remains unburned and mixes with the ash. Different combustion technologies affect the types and concentrations of resultant species e.g. fixed bed combustion results in higher carbon content in the ash.

Carbon in the coal is converted to carbon dioxide (CO_2) by the reaction

$$C + O_2 \rightarrow CO_2$$

Similarly, hydrogen and sulfur are converted to moisture (H_2O) and sulfur dioxide (SO_2) by the reactions

$$H_2 + O_2/2 \rightarrow H_2O$$

$$S + O_2 \rightarrow SO_2$$

Table 5.1, as an example, gives the computation of oxygen required for burning one kg of coal used at the Chandrapur thermal power station and the combustion products.

Table 5.1: Computation of combustion products for the Chandrapur coal

Species	**Mass**	**Oxygen required**	**Products**	**Reaction**
Carbon	0.3769	0.3769 x (32/12) = 1.01	CO_2: 0.3769 x (44/12) = 1.38	$C + O_2 \rightarrow CO_2$
Hydrogen	0.0266	0.0266 x (16/2) = 0.21	H_2O: 0.0266 x (18/2) = 0.24	$H_2 + O_2/2 \rightarrow H_2O$
Sulphur	0.008	0.008 x (32/32) = 0.008	SO_2: 0.008 x (64/32) = 0.016	$S + O_2 \rightarrow SO_2$
Oxygen	0.0578			
Nitrogen	0.0107			$N_2 + O_2 \rightarrow 2NO$
Ash	0.47			

Oxygen required to burn 1 Kg of coal = 1.01+0.21+0.01–0.05 = 1.18 Kg
Air required = (Oxygen required)/(Mass fraction of oxygen in the air) = 1.18/0.233 = 5.06 Kg = stoichiometric airTotal air (stoichiometric + 20% excess) = 5.06x1.2 = 6.072 Kg
6.072 air = 1.415(6.072 x 0.233) oxygen + 4.474(6.072 x 0.767) nitrogen.The combustion product with 20% excess air will contain:
0.2348(1.415 – 1.18) Kg O_2 and 4.48(4.47 + 0.01) Kg N_2.

Table 5.2 gives the computation of the flue gas composition from burning one Kg of Chandrapur coal at 20% excess air, as an example.**Table 5.2:** Flu gas composition with 20% excess air

Product	**Mass/Kg coal**	**Mol. wt**	**Kmoles/Kg coal**	**% volume**
CO_2	1.38	44	0.03136	15.39
SO_2	0.016	64	0.00025	0.12
O_2	0.24	32	0.0075	3.68
N_2	4.61	28	0.1646	80.77
		Total =	0.2038	

Emissions of oxides of nitrogen from coal:

Oxides of nitrogen (NO_x) are (i) nitrous oxide (N_2O), (ii) nitric oxide (NO), and (iii) nitrogen dioxide (NO_2). NO_2 is mostly formed by oxidation of the NO, which is discharged in combustion products. About 90% of the NO_x is in the form of NO. NO is formed by two mechanisms: (i)oxidation of atmospheric nitrogen, known as 'thermal NO' and (ii) oxidation of nitrogen that is chemically bound within the fuel, known as 'chemical NO'. The amount of NO_x varies widely with boiler conditions. NO_x emissions are generally functions of flame temperature, excess air, percentage of boiler load, nitrogen content in the coal, and rate of gas cooling. In pulverized coal flames, about 30 - 35% of nitrogen in coal gets converted into NO and remaining nitrogen in the coal gets converted into molecular nitrogen. The actual mechanism, whereby atmospheric nitrogen is oxidized, goes through a complex chain of reactions initiated by oxygen atoms. We can however calculate equilibrium concentrations of NO, using the following reaction:

$$N_2 \quad + \quad O_2 \quad \overset{--}{>} \quad 2NO$$

This is a lumped reaction. Generally accepted principal reactions are

$O + N_2 = NO + N$
$N + O_2 = NO + O$
$N + OH = NO + H$

The concentration of nitric oxide (NO) is given by

$$x_{NO} = K_{10.1} (x_{N_2})^{0.5} (x_{O_2})^{0.5}$$

Where X is the species concentration and $K_{10.1}$ is a equilibrium constant and depends upon the temperature of the gas.

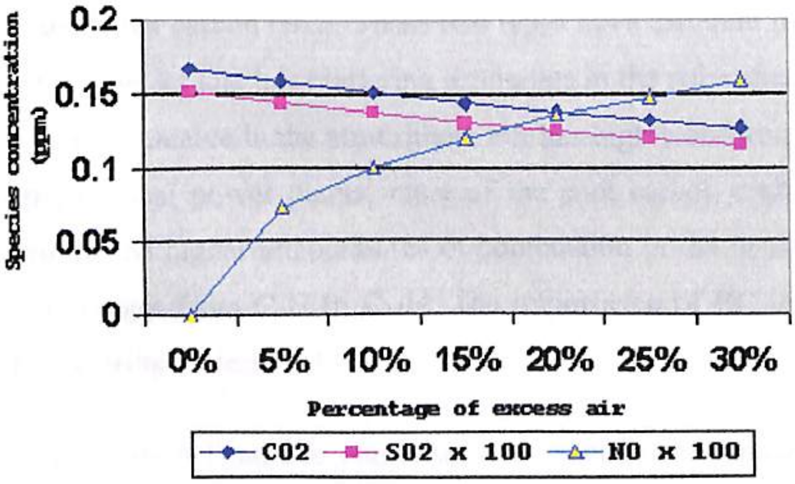
Concentration values X for O_2, N_2, CO_2, SO_2, and NO for the Chandrapur coal, as calculated by the above method, are given in Table 5.3. The value of the equilibrium constant $K_{10.1}$ computed at 1700 K is 0.007824.

Table- 5.3: Species concentrations in flue gas for the sample coal

Air	**X(O_2)**	**X(N_2)**	**X(CO_2)**	**X(SO_2)**	**X(NO)**
Stoichiometric	0	0.831333	0.167148	0.001512	0
5% excess	0.010483	0.8293267	0.158754	0.001436	0.00073
10% excess	0.019970	0.8274488	0.151213	0.001368	0.001006
15% excess	0.028597	0.8257412	0.144356	0.001306	0.001202
20% excess	0.036475	0.8241817	0.138094	0.001249	0.001357
25% excess	0.043699	0.8227519	0.132352	0.001197	0.001484
30% excess	0.050345	0.821436	0.127069	0.001149	0.001591

Figure 5.1 gives a comparative behavior of the CO_2, SO_2, and NO concentrations (in mole fraction) for 5 - 30% excess air. NO concentrations increase, while the concentrations of CO_2 and SO_2 decrease with the increase in excess air.

Fig 5.1 **:Combustion products per kg of coal**



Species concentrations (PPM) in the combustion products for the Chandrapur coal are given in Table 5.4.

Table 5.4: Species concentrations in parts per million (ppm)

Excess Air %	CO_2	SO_2	NO
0	167148	1512	0
5	158754	1436	730
10	151213	1368	1006
15	144356	1306	1202
20	138094	1249	1357
25	132352	1197	1484
30	127069	1149	1591

Carbonaceous material and black carbon:

Incomplete and/or inefficient combustion processes of fossil fuel generate carbonaceous aerosols. The emitted carbonaceous (soot) aerosols are of two types, namely organic carbon (OC) and black carbon (BC). These two types have different properties in the atmosphere. OC is a reactive species and has scattering properties in the solar spectrum[12] while the BC, on the other hand, is non reactive in the atmosphere but has highly absorbing properties in the solar spectrum . In the thermal power plants, most of the soot carbon emitted would be in the form of BC because of the higher temperatures of combustion in the furnaces. When the soot is formed the analysis ranges from C_8H to $C_{12}H$. The importance of BC in the radiative balance of Earth is gradually being understood.

The soot carbon from the combustion of coal in the Indian thermal power plants has been calculated on the basis of prevalent combustion characteristics. It is assumed that approximately, 10% of the coal carbon goes in the bottom ash and about 2% of the carbon forms the soot that may emit with fly ash. Electrostatic Precipitators (ESPs) used in the thermal power plants in

India, remove about 99% fly ash from the stack. 1% of the generated fly ash, which contains 2% soot carbon is emitted into the atmosphere. These soot particles are sub-micronic in size. Similar assumption has also been used for calculation of soot carbon from lignite based thermal power plants in India (viz. Kutch and Neyvelli power plants).

Suspended Particulate matter

The fly ash in the form of Suspended Particulate Matter (SPM) is a major pollutant from coal burning power plants in India. SPM has been calculated on the basis of the ash contents of the coal. It is assumed that 85% of the ash in the coal goes out through the stack as fly ash after the combustion. Electrostatic precipitators (ESPs) working on 99% efficiency rate allows only 1% of the formed fly ash to emit as SPM.

Based on the input parameters and the ultimate analysis of coal used for power generation, emissions of CO_2, SO_2, NO, soot carbon and particulate matter from each of the power plants has been computed. Input parameters (operating conditions) are actual air supplied, electric power generated per day, and coal used for unit power generation. Thermal power plants also use small quantities of diesel oil and furnace oil (FO) as supplementary fuels to boost the combustion and heat content. In the thermal power plants run by National Thermal Power Corporation (NTPC), supplementary fuel consumption is 0.2 to 0.3 ml/unit of power. The supplementary fuel consumption in old thermal power plants may range from 1 to 4% of the fuel. Emissions from combustion of these supplementary fuels are not accounted in the computations at present.

For the estimation of emissions of above mentioned species from the Indian thermal power plants, the available values of the ultimate analysis of coals used in the seven thermal power plants namely Chandrapur, Dhanau, Singrauli, Dadri,Rihand, Kutch, and Nayveli, are used. Most of thermal power plants in India use E and F grade coals only. An average of ultimate analysis of E and F2 grade coals is used for the remaining 74 thermal power plants. The excess air used in the individual power plants, kg coal used for unit (kwh) power generation, and per day power generation is available and is listed. NO calculations assume equilibrium reactions and 1700 K gas temperature.

CO_2 emissions are estimated based on the carbon content in the coal and the excess air used at the power plants. 12% carbon (based on the measurement data, it is assumed that 10% carbon remains unburned and mixes with the ash and 2% carbon forms soot) is subtracted before calculating emissions of CO_2. Figures 3 and 4 provide the computed data for CO_2 emissions from coal fired thermal power plants assuming 88% of coal carbon to undergo combustion. Table 5.5 provides CO_2 emissions per day from power plants.

Table 5.5: Computed values of CO_2 emission per day from power plants

CO2 (Thousand ton)	Number of power plants	Coal used per day (million tons)
40-50	5	0.16
30-40	3	0.08
20-30	9	0.15
10-20	24	0.3
0-10	40	0.43

Total CO_2 emissions per day from all the coal fired power plants in India was 1.1 thousand tons per day in 1997-98 and annual emission has been computed to be 395 million tons. Yearly estimates of power generation and emissions are based on the plant load factor (PLF) for individual power plant. PLF is the ratio of the actual power generation and the installed capacity. Knowing the yearly power generation, the annual emissions are computed. Estimate of CO_2 emission from power sector in India for 1990 is 213 million tons. CO_2 emission estimates based on the present calculations seem to compare well with this estimate made for 1990. CO_2 emissions per unit of electricity from power plants in tabular form are given in Table 5.6.

CO_2 (Kg/KWH)	Number of power plants
1.4 - 1.8	4
1.2 - 1.4	9
1.0 - 1.2	27
0.8 - 1.0	40
0.6 - 0.8	1

Computed data indicate that CO_2 emissions per unit of electricity from most power plants range between 0.8 and 1.2 kg/KWH. Some plants have between 1.2 and 1.4 kg/KWH. Four plants have CO_2 emissions more than 1.4 kg/KWH. This number reflects operational inefficiency due to poor coal quality or operating conditions. One power plant has this number less than 0.8 kg/KWH.

Fig 5.2 re 3: CO_2 emission per day from Indian Thermal Power plants

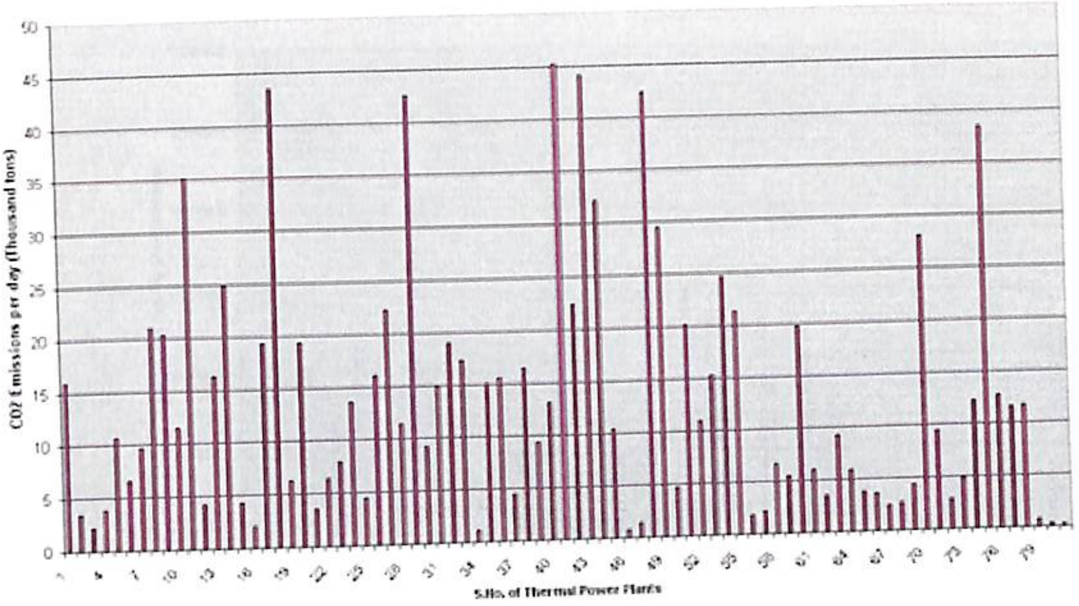
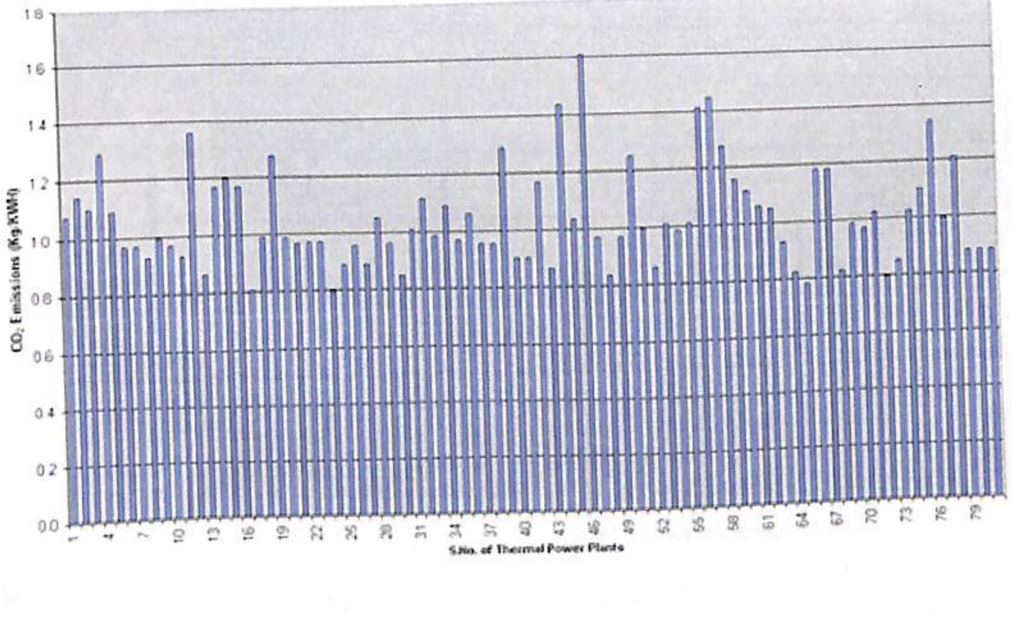


Fig 5.3 CO_2 emission per unit of electricty from Indian Thermal Power Plants



In general the sulfur content in Indian coals compared to the US coals is low. Figures 5.4 and 5.56 show the computed data for SO2 emissions from thermal power plants in India assuming that no control technology is in use. A total SO2 emission per day from all the power plants in India has been estimated to be 7.6 thousand tons per day and 2.8 million tons per year. Average SO2 emission per unit of electricity from Indian thermal power plants has been found to be 7.4

Figure 5: SO_2 Emissions per day from IndianThermal Plants

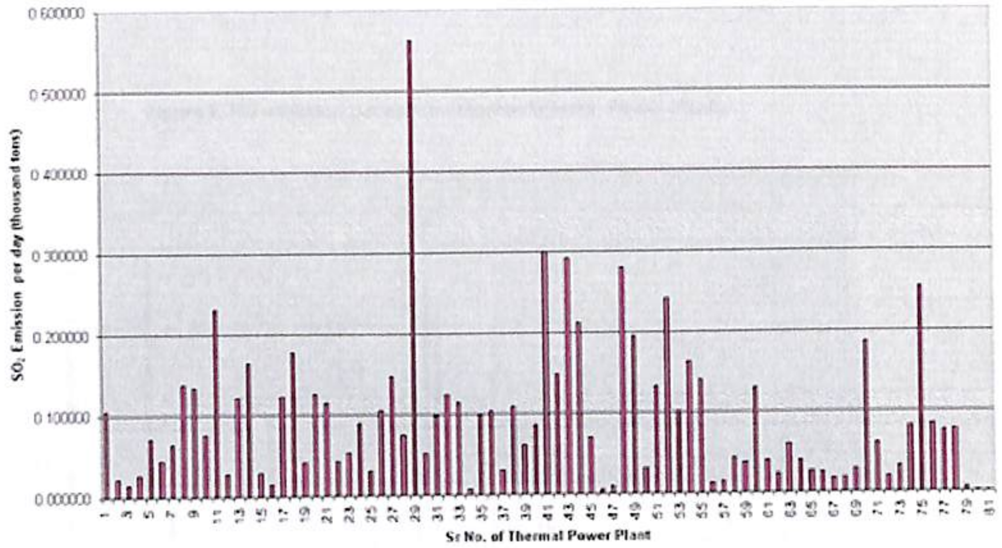
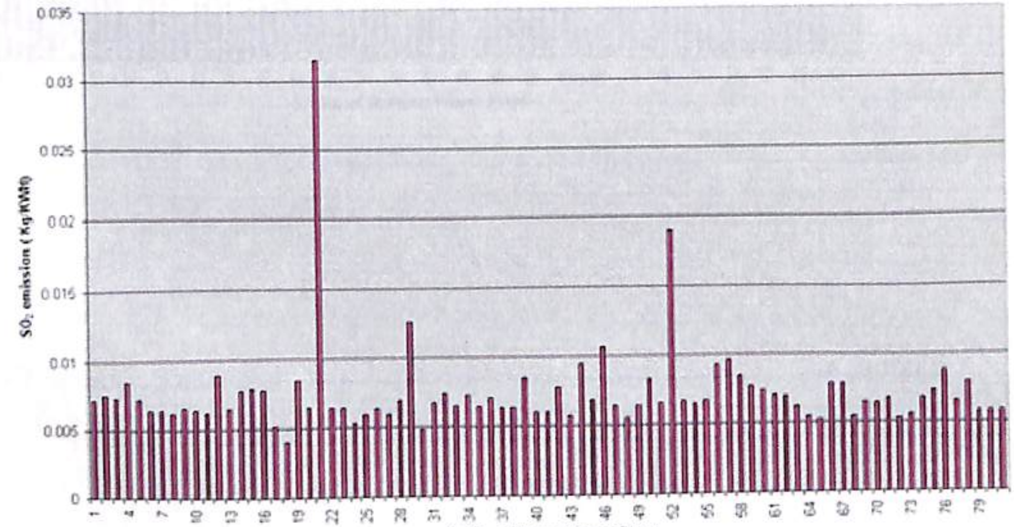


Figure 6: SO_2 emission per unit of electricity from Indian Thermal Power Plants



Figures 7 and 8 give the computed data for NO emissions. NO emissions are based on equilibrium reaction and an average gas temperature of 1700 K. This is a theoretical ideal. In reality the gas temperature in the boiler varies from 900 k to 2500 K and the reaction also occurs in several phases. Present estimates of NO emissions from thermal power plants are 7.9 thousand tons per day and 2.9 million tons per year. The Nellore thermal power plant has been found to be largest emitter of NO per unit of electricity with a value of 13.1 gm/KWH. Plants like Faridabad, Harduaganj, Tanda, Korba II&III, Kothagudem, Ennore, Barauni, Muzaffaurpur and Patratu are also amongst the larger emitter of NO per unit of electricity generated (emission ranges from 10 to 12 gm/KWH). Most of the other plants have NO emissions in range of 6-10 gm/KWH.

Figure 7: NO emission per day from Indian Thermal Power Plants

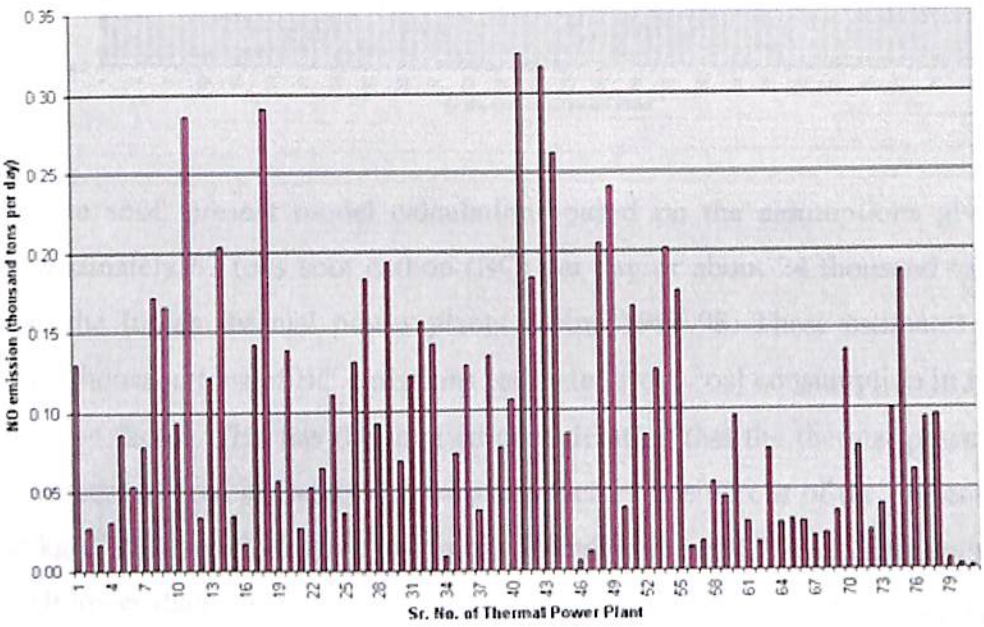
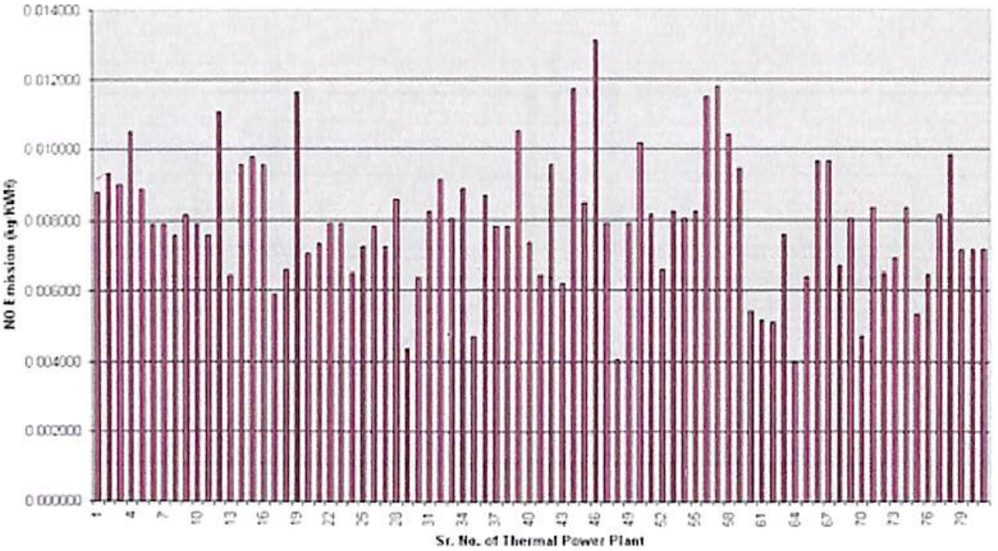


Figure 8: NO emission per unit of electricty from Indian Thermal Power Plants



For the soot, present model calculations based on the assumptions given before, show that approximately 67 tons soot carbon (BC) per day or about 24 thousand tons per year is emitted from the Indian thermal power plants during 1997-98. These estimates are much lower than 608.4 thousand tons of BC emissions estimated from coal consumption in India based on average emission factor. This has the implied consideration that the thermal power plants are the major consumers of coal in India. The emission factors arising out of the present calculations are 0.08 gm/kg of coal and 0.06 gm/kg of lignite in Indian thermal Power. This emission factor for coal is much lower than average emission factors for BC of 1.0, 0.325 and 0.2 g/kg proposed for under-developed, semi-developed and developed countries respectively for industrial use of hard coal, hard coal briquettes, coke, oven coke, gas coke and brown coal coke. However, Soot emission factor of 0.08 gm/kg for coal obtained from the present calculations compares well with the emission factor of 0.075 proposed for industrial use of hard coal Figures 9 and 10 show the soot (BC) emissions per day and per unit of electricity from power plants in India. The Nellore thermal power plant with an estimated emission of 0.1 gm/KWH has been found to be the largest emitter of soot. The other large emitter thermal power plants include Faribdabad, Harduaganj, Korba II& III, Kothagudem, Barauni, Muzaffarpur and Talchar NTPC where the soot emission range from 0.08 to 0.1 gm/KWH.

Figure 9: Soot emission per day from Indian Thermal Power Plant

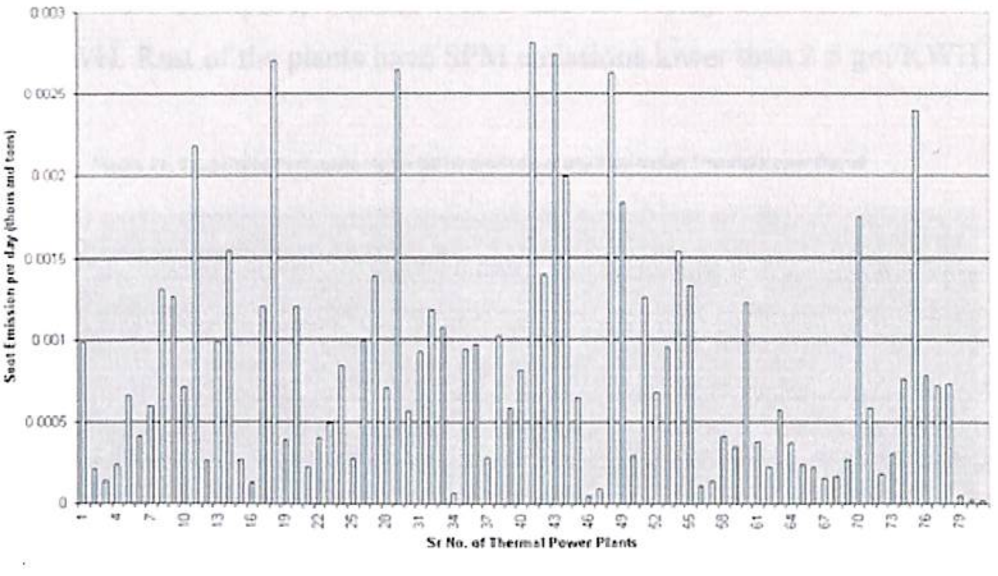
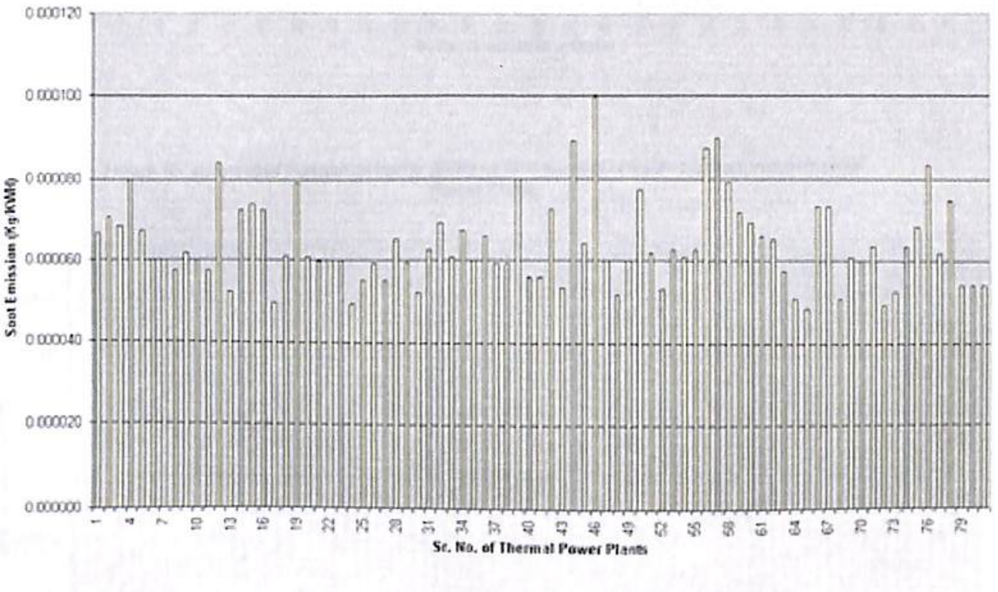


Figure 10: Soot emission per unit of electricity from Indian Thermal Power Plants



The ash contents in the coal consumed in the thermal power stations is responsible for the emission of 2.3 thousand tons of SPM in the form of fly ash per day and about 0.8 million tons SPM per year. Figure 11 and 12 show the SPM emission per day and per unit of electricity from power plants in India. The Chandrapur, Kothagudem, Nellore, Baauni and Muzaffarpur thermal plants have been found to be amongst the largest emitter of SPM per unit electricity. About 3 to 3.5 gm of SPM/KWH has been estimated to have emitted from these plants. The plants like

Faridabad, Harduaganj, Obra, Panki, Paricha, Tanda, Korba II & III, Satpura, Ennore, Patratu, Calcutta, New Cossipore, Talchar NTPC and IB Valley TPS emit in the range of 2.5 to 3 gm SPM/KWH. Rest of the plants have SPM emissions lower than 2.5 gm/KWH.

Figure 11: Suspended Particulate Matter (SPM) emitted per day from Indian Thermal Power Plants

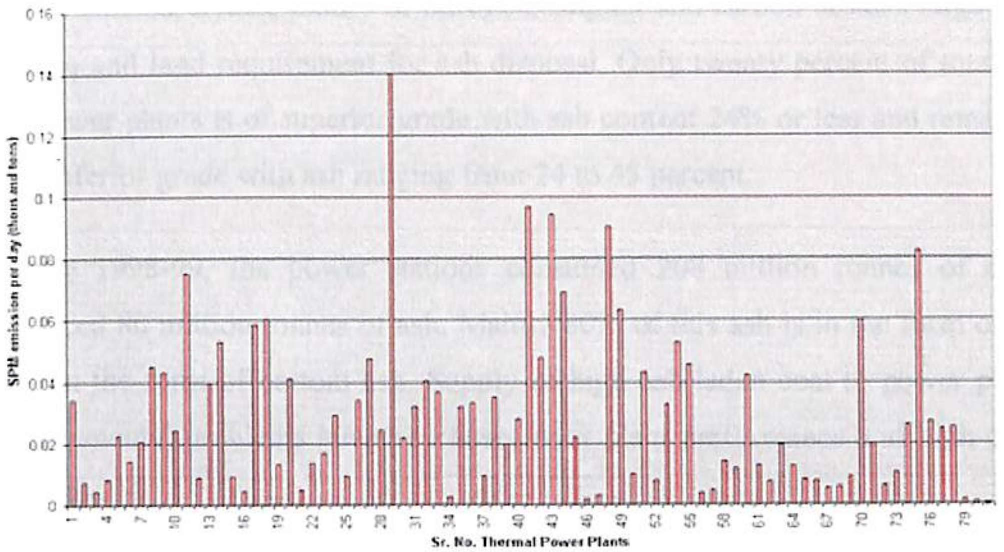
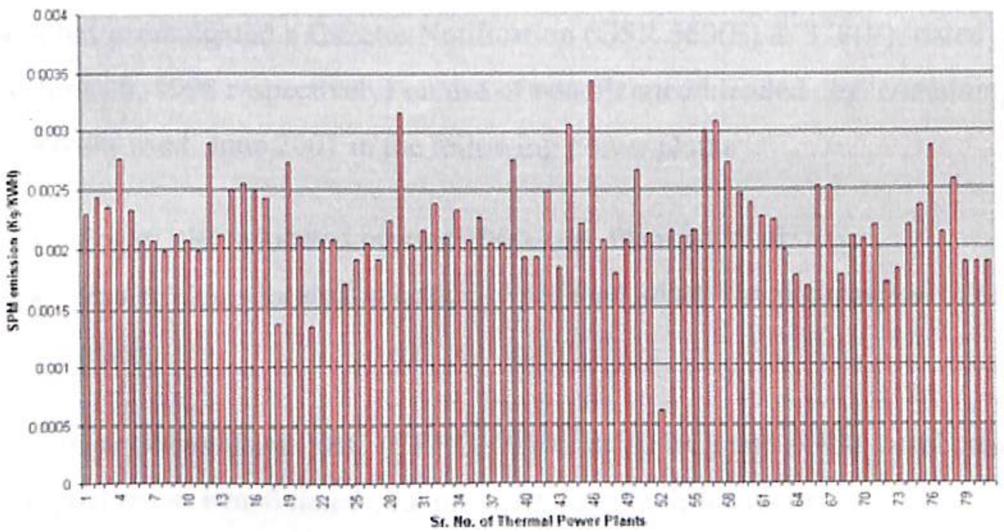


Figure 12: Suspended Particulate Matter (SPM) emitted per unit of electricity from Indian thermal Power Plants



Environmental Issues In Coal Based Power Generation

Seventy percent of total installed capacity of electricity generation in the country is from coal based thermal power plants. Increased dependence of power sector on the inferior quality of coal has been associated with the emissions from the power plants in the form of particulate matter, toxic elements, flyash, oxides of nitrogen, sulphur and carbon besides large volume of water for cooling and land requirement for ash disposal. Only twenty percent of total coal transported to the power plants is of superior grade with ash content 24% or less and remaining eighty percent is of inferior grade with ash ranging from 24 to 45 percent

During 1998-99, the power stations consumed 208 million tonnes of coal, which in turn produced 80 million tonnes of ash. Mainly 80% of this ash is in the form of flyash and balance 20% in the form of bottom ash. Supply of high ash laden coal to power plants not only poses environmental problems but also causes poor plant performance and high cost for O & M and ash disposal.

The Ministry of Environment & Forests, Govt. of India constituted a Committee headed by the Chairman, Central Pollution Control Board (CPCB), to suggest the measures for improving the quality of coal supplied to the power plants. On the recommendation of the Committee, Govt. of India has promulgated a Gazette Notification (GSR 560(E) & 378(E), dated September 19, 1997 and June 30, 1998 respectively) on use of beneficiated/blended coal containing ash not more than 34 percent w.e.f. June 2001 in the following power plants :

- Power plants located beyond 1000 kms. from pit head;
- Power plants located in critically polluted areas, Urban areas and in ecologically sensitive areas.

The power plants using FBC (CFBC, PFBC & AFBC) and IGCC combustion technologies are exempted to use beneficiated coal irrespective of their locations.

Benefits of Beneficiated coal

One of the solutions to the problems associated with the use of inferior grade coal is beneficiation for reduction in ash content. This will not only reduce the ash content to required level but also enrich the coal with reactive materials for better thermal efficiency, plant availability and plant output thereby reducing operating/maintenance costs, load on transport system and oil support in boiler.

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.

According to the Central Fuel Research Institute, Dhanbad , if the entire power coals which are to be transported over 1000 km in the year 2001-02 are washed and the ash level is brought down from 40 to 34%, it is likely to reduce 11 million tonnes in transport, 8 million tonnes fly ash and 23 million tonnes of carbon dioxide (a green house gas) emissions.

There is a general recognition that improvements in the quality of coal utilized in power generation would not only reduce environmental pollution but also lead to improvements in power plant operational efficiencies. Coal preparation has been the subject of various studies and pilot plant tests carried out by Indian and international institutions. These studies have highlighted that, in the majority of cases, it is technically feasible and economically viable to reduce the ash content of raw coal to 32-34% range, with net benefits to power plants.

Requirements of Beneficiated/ Blended coal

Based on Specific Coal Consumption (1998-99) and the Plant Load Factor (PLF) projected for the year 1999-2000, the Central Electricity Authority (CEA)has estimated the requirement of coal for existing and the plants to be installed under Ninth Plan. The coal requirement would be 87.14 million tonnes per annum . Out of which, the Coal India Ltd. would able to meet the requirement of 68.48 million tonnes per annum coal from their sources (by existing washeries and blending of domestic coals). The remaining quantity could be met by blending imported and domestic coal at coastal thermal power plants and changing the linkages suitably.

Cost of beneficiated Coal

According to a study conducted by M/s Mc Montan Consultants, Germany under the Asian Development Bank (ADB) project, the cost of washing of coal ranges from Rs. 103/tonne to Rs. 172/tonne for ash level of 34%, the average being Rs. 132/tonne.

The findings from the few coal preparation plants commissioned in India indicate that the power plant performance has been enhanced. Presently, beneficiated/blended coal is being supplied to Dadri (U.P.), and Badarpur (Delhi) Power Plants of National Thermal Power Corporation (NTPC), Dahanu (Maharashtra), Power Plant of Bombay Suburban Electricity Supply (BSES) and Rajghat & I. P. (Delhi) Power Plants of Delhi Vidyut Board (DVB). The comparison of various parameters on annual average basis with raw coal and blended coal used in Dadri Thermal Power Station of NTPC indicates significant improvement in plant performance (Table 5.7).

Table 5.7: Comparison of coal quality and cost of raw coal and blended coal

Parameters	**Raw Coal**	**Blended Coal**	
	96-97	**97-98**	**98-99**
Coal Quality			
a) Moisture, %	10.5-10.6	11.52	12.70

b) Ash, %	39-40	34-35	34-35
c) Gross Calorific Value (GCV), Kcal/kg	3400-3500	3800-3900	3800-3900
Coal & Transport Cost			
a) Coal cost, Rs./MT	446-552/-	765/-	765/-
b) Transport cost, Rs./MT	724/-	800/-	924/-
Performance Reliability			
a) Sp. Coal consumption, kg/kwh	0.69	0.647	0.644
b) Boiler availability, %	87.3	91.3	94.8
c) Boiler efficiency, %	86.5	87.5	87.8
d) Aux. Power Consumption, %	7.8	7.4	7.3
e) Plant Load Factor (PLF), %	82.5	87.2	91.4

At present, there are six coal washing plants in India for power grade coal beneficiation. These are as follows

Beneficiated Plants --------- Capacity

- Piparwar Washery, Bihar 6.50 Mt/y of raw coal
- Bina Deshaling Plant, MP 4.5 Mt/y of raw coal
- Bilaspur washery, MP 2.5 Mt/y of raw coal
- Girdih washery,Bihar 2.5 Mt/y of raw coal
- Kargali washery ,Bihar 1.5 Mt/y of raw coal
- Dipika washery , Orissa 8.0 Mt/y of raw coal

In addition, a number of coal washing plants are planned in Talcher, Ib Valley and North Karanpura coalfields for treating inferior quality non-coking coal.

Options for Beneficition of Coal

- **Blending of selected raw coals with clean products:** as most of the washeries are used to get feed from multiple sources, the process which was once applied to coking coal beneficiation seems least promising.
- **Mixing the untreated smaller fractions with beneficiated coarse coal fractions of a raw coal feed,** as is practised in Piparwar and Bina washeries. Earlier studies at CFRI on the washability charateristics of some non-coking coals showed that the amount of free dirt/sand having relative density greater than 1.80-1.85 may be very high. About 20-45% of the finer fractions (5-10% of the whole coal) that is included in the prepared coal enhances the wear and tear of the boiler tubes and auxiliary units. A typical view of Piparwar Washery is shown in Fig. 12.

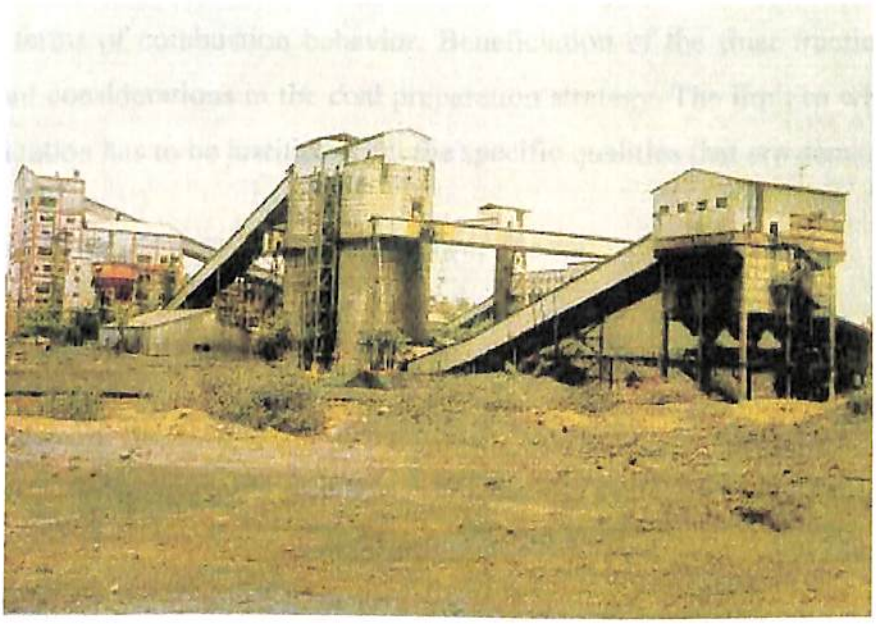


Fig. 5.12 *Coal washery at Piparwar at CCL.*

- **Blending the low ash foreign coal (raw/clean) with raw indigenous coal of high ash:** Mixing of one tonne of imported coal of 10% ash content with 4 tonnes of Indian coal at ash level 40% results in a blend of 34% ash content. Though not practised in general, this may be an option in near future, particularly for the thermal power stations in coastal areas.The reduction in import duty on thermal coal from 85% in'93-'94 to 10% in '97-'98 has been an incentive for import of coal particularily for the coal based power stations.

However, blending of coals of widely different ranks may cause undesirable differential combustion behaviour in the burners, which need to be taken into account during blending of coal.

- **Mixing of coarser and finer size beneficiated coal:** With the advent of modern High Capacity Processor (HCP) including efficient cyclone circuit, it is possible to commission 350-600 tonne per hour washing system for beneficiation of both coarse and intermediate fractions. In the economic analysis for the Bilaspur Coal Washery Project, despite limitations in density of separation, the H.M. Cyclone was found to more efficient than the jigs.

In first two cases, the desired overall ash content and the level of moisture content are maintained but the quality of the washed coal in terms of its end utilization in power stations may not be always assured. Washing of such coals down to an ash level of 34% reduces the transport cost and environmental pollution. However, it may not assure quality of the washed coal in terms of combustion behavior. Beneficiation of the finer fractions becomes one of the important considerations in the coal preparation strategy. The limit to which coal needs washing or preparation has to be justified from the specific qualities that are demanded for the boilers.

Coal Ash Management in Thermal Power Plants

Introduction

The rapid increase in the capacity of thermal power generation in India has resulted in production of huge quantity of coal ash. As per the available estimate the production of coal ash in India including both fly-ash and bottom-ash is likely to touch 90% million tonnes per annum by 2000 A.D. In view of high cost of disposal and environmental pollution caused by its generation and disposal, the gainful utilisation of coal ash to maximum extent is of vital importance. The coal fired plants are among the polluting sources as indicated by environmentalists and pollution control agencies. Mere disposal of ash at less cost may not always be the best which may off set the environment and aesthetic of the particular locality. This stress for proper management for its disposal and utilisation.

Management Strategy

The associated activities in the management strategy of ash produced in a thermal power plant are:-

1. Generation of ash,
2. Types,
3. Collection,
4. Storage and Transportation,
5. Disposal.

Generation of Ash

In a coal fired plant pulverised coal is used instead of lump coal for greater efficiency of boiler. The pulverised coal on combustion produce fine residue known as ash. The ash content in Indian coals ranges between 25% to 40% and even more.

Types

In a coal fired plant the ash produced as a result of burning of coal may be identified as fly-ash and bottom-ash. Out of the total ash, 20% is bottom-ash, stored within the premises of the plant and the remaining is fly-ash which immediately gets scattered over a wide area. This adversely affects the atmosphere and aesthetics of the nearby plant area.

Collection

Efficient extraction of ash after identification is the most important activity in the management strategy. The water filled ash hoppers are used to received the furnace bottom-ash and stored for periodic discharge. The fly-ash extraction is done efficiently by installing the ESP prior to the stack. By this the fly ash can be easily collected upto an extent as high as 98%. The water impounded bottom-ash hopper receives the bottom-ash from furnace and periodically discharged for transfer through transport line once in every eight hours through ash slurry sump to ash pond. The dry-free flowing ash called fly-ash collected in the fly-ash hopper, is handled by independent system. The ash is collected pneumatically from the fly-ash hopper in a dry state and carried to a collecting tank where it mixes with water to form slurry.

Storage and Transpiration

The bottom ash and fly ash as extracted are stored temporarily before transportation to the disposal areas. They are stored in a slurry sump of adequate capacity depending upon the type of disposal i.e. wet or dry the transportation of which can be done by pump or lorries.

Disposal of Coal Ash

There are two ways of disposing the ash,

i. Wet Disposal,
ii. Dry Disposal.

The dry disposal system has an advantage that the ash can be readily utilised for various purposes. As per the thumb rule calculation suggested by the Central Pollution Control Board, the required area for an ash pond of 10M deep per 1 MW installed capacity of coal based thermal power plant is about 1.5 acres.

Environmental Problems of Ash Disposal

The coal-ash pollutes the air as well as water too and requires a huge land area for its disposal the value of which cannot be compensated by money specially for a country like India, where land population ratio is much less as compared to other countries. Disposal of this ash apart from space problem causes air, land and surface water pollution also.

In the presence of coal ash when obnoxious gases like SO_2, NO_x and Hydrocarbons are released into the environment, syner-gistic chemical reactions take place. It degenerates the thriving of flora and fauna in the adjoining region. Dust bowl conditions are invariably created in dry weather around the power plant by which the nearby aquatic bodies are affected badly during excessive humid period.

Ash management of c.t.p.p.

The Chandrapura Thermal Power Plant of Damodar Valley Corporation (D.V.C.) consists of three 130 MW units and three 120 MW units, with an installed capacity of 750 MW. The plant site is by the side of the Damodar river about 3 Km away from Dugdha Washery of B.C.C.L. The site is selected on consideration of proximity of source of water, fuel and potentiality for ash disposal. The coal consumption and ash generation of C.T.P.P. is shown in Table 5.8

Table5.8: Details of capacity, Coal Consumption and Ash Generation of C.T.P.P.

Unit No.	Capacity (MW)	Coal Consumption (tons/hr)	Ash Generation (tons/hr)	Remarks
1.	130	85	35	Stack Height=80M.
2.	130	85	35	
3.	130	85	35	Ash type generation
4.	120	70	31	fly-ash- 80% bottom-ash- 20%
5.	120	70	31	
6.	120	70	31	

Source:DVC

Ash handling system of c.t.p.p.

The ash handling system is designed on the basis of series of slurry pumping and recirculation of hydrovector water due to shortage of water. Fly ash is removed by vacuum created by hydroveactors and bottom ash by hydroejectors and discharged into a common concrete sump. The slurry is then removed by hydroseal pumps in series pumps in series through eight inches hard alloy steel cast iron pipes (Ascholite) to the disposal area. Hence the slurry collects in a fill area with raised bunds. Ash settles out and clear water overflows and goes back to river. One ash handling system is common for two units. For six units of C.T.P.P., there are three numbers of ash handling systems and ash control rooms.

There are two ash ponds in C.T.P.P. which are about to be filled up and another one is under construction. Whenever the ash pond area nearer to the discharge point forms a heap like deposition, these heaps are dozed off with the help of dozers so that it can get more disposal area. The dozing is also done to avoid air pollution due to dry ash in the summer season.

Utilisation

Utilisation of coal-ash is always practise than its disposal. There are various methods of utilisation of coal-ash along with established engineering technologies some of them are mentioned below:

a. Manufacturing of building materials.
b. Making of concrete.
c. Manufacturing of pozzuolana cement.
d. Road construction etc.

In all the above cases financial constraint discourages the entrepreneurs to take up the work. In view of the environmental impact of disposal, Government may give attractive subsidy and create marketing facility so that entrepreneurs may come forward to use as their raw material.

Oxyfuel combustion for coal-fired power generation with co2 Capture: Oxyfuel or O2/CO2 recycle combustion is a highly interesting option for lignite-based power generation with CO2 capture, due to the possibility to use advanced steam technology, reduce the boiler size and cost and to design a zero-emission power plant. This technology, however, also poses engineering challenges in the areas of combustion and heat transfer, boiler design, boiler materials, energy-efficient oxygen production and flue gas processing. The overall challenge is to design a robust plant that has a sufficiently low total cost of electricity so that it is interesting to build, but it must also have a sufficiently low variable cost of electricity so that it will be put in operation as a base load plant once it is built.

Global warming is one of the largest environmental challenges of our time. Increased carbon dioxide level in the atmosphere is the dominating contributor to increased global warming. Carbon dioxide is emitted to the atmosphere through combustion of fossil fuels in power plants, automotive engines, for industrial use and for heating purposes. The world is currently depending on the use of fossil fuels for its energy supply, and will continue to be so for a long time yet to come, due to the abundant sources of in particular bituminous coal and lignite. Small-scale renewable electricity production is available on the market today, but the cost of avoiding CO2 emissions through renewables (e.g. wind power) is at present very high. In addition, instabilities (with an increased risk of power outages) are usually induced in a power grid when a significant proportion of the power production comes from a large number of small generators. In the very long term, large-scale heat and power production technologies based on sustainable energy sources will have to be developed. These technologies are not commercially available, and the opportunity to find time for their commercialization will be given through near-term development of technology for emission-free fossil-fuel utilization.

The three main options for reducing CO2 emissions from fossil-fuel based energy conversion are) increasing the fuel conversion efficiency 2) switching to a fuel with a lower fossil carbon content and 3) capturing and storing the CO2 emitted from the fossil fuel. Vattenfall is actively investigating all three options and is prepared to apply any of them whenever found to be technically and economically possible. In order to make alternative 3 feasible, Vattenfall has taken the strategic decision to play a leading role in the development of emission-free fossil-fuel ased power generation and has started the project "Carbon-Dioxide Free Power Plant". The project deals ith CO2 capture, transport and storage, with main focus on lignite-fired power plants with CO2 capture. The aim is to develop a commercially viable concept until 2015. Furthermore, Vattenfall is taking part in the development of CO2 capture technologies as the coordinator of the EU Framework 6 project ENCAP (ENhanced CAPture of CO2). Vattenfall is also a partner in the EU-projects CO2STORE and CASTOR. The concepts for power generation with CO2 capture are usually divided into three different groups, post combustion capture, pre-combustion capture and oxyfuel combustion capture, as shown in Figure 5.13 and as widely explained in the literature. Vattenfall has chosen to focus its main efforts within CO2 capture on the oxyfuel area, in particular on the O2/CO2 recycle combustion of lignite. This does not necessarily mean, however, that the O2/CO2 recycle combustion will be Vattenfall's preferred technology when it is time to build power plants with CO2 capture. As a producer of electric power rather than of power plants, however, Vattenfall has identified both the opportunities with O2/CO2 recycle combustion capture, and the challenges that must be faced, in order to make this technology a viable alternative the day a decision will be made on what capture technology to actually build. The present paper gives a structured overview of both opportunities and challenges with the O2/CO2 recycle combustion, mainly from a technology point of view, but also economic aspects are treated. In particular, attention has been given to describe problems connected to the flue gas cleaning that must be resolved, a topic that has often been omitted in earlier power plant studies.

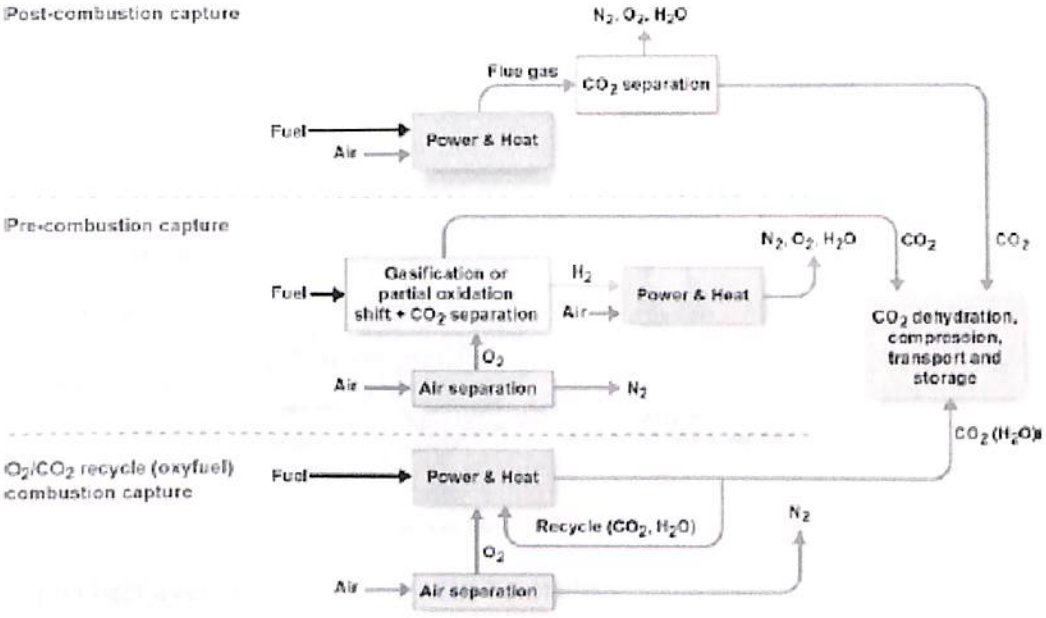


Figure 5.13: The three basic concepts for power generation with CO2 capture

O2/CO2 Recycle Combustion of Lignite

The principle of O2/CO2 recycle combustion of e.g. lignite in a pulverised fuel (PF) boiler can be seen in Figure5.12. This kind of concept is related to the investigations that Vattenfall have been performing together with university partners so far and is described by Andersson et al. Instead of air, oxygen (95% purity or higher) is fed to the boiler, and a major part (70-80%) of the CO2-rich exhaust gas is recycled back to the boiler to control the combustion temperature. The remaining part of the flue gas, (consisting mainly of CO2 and water vapour and small quantities of Ar, N2, NOx, SOx and other constituents from air leakage and fuel) is cleaned, compressed and transported to storage or another suitable application, such as enhanced oil recovery (EOR). Provided that the gas is dry, it might be possible to sequester the sulphur with the CO2, although this is needs further investigation. The steam power cycle is of the standard type that can be found in conventional coal-fired steam power plants. Since power plants grow old and must be replaced, and with the advent of CO2 emission penalties, Vattenfall has its focus on O2/CO2 recycle combustion applied in new built power plants with advanced steam data where, unlike in the retrofit cases, an optimized process design based on best available technology can be made.

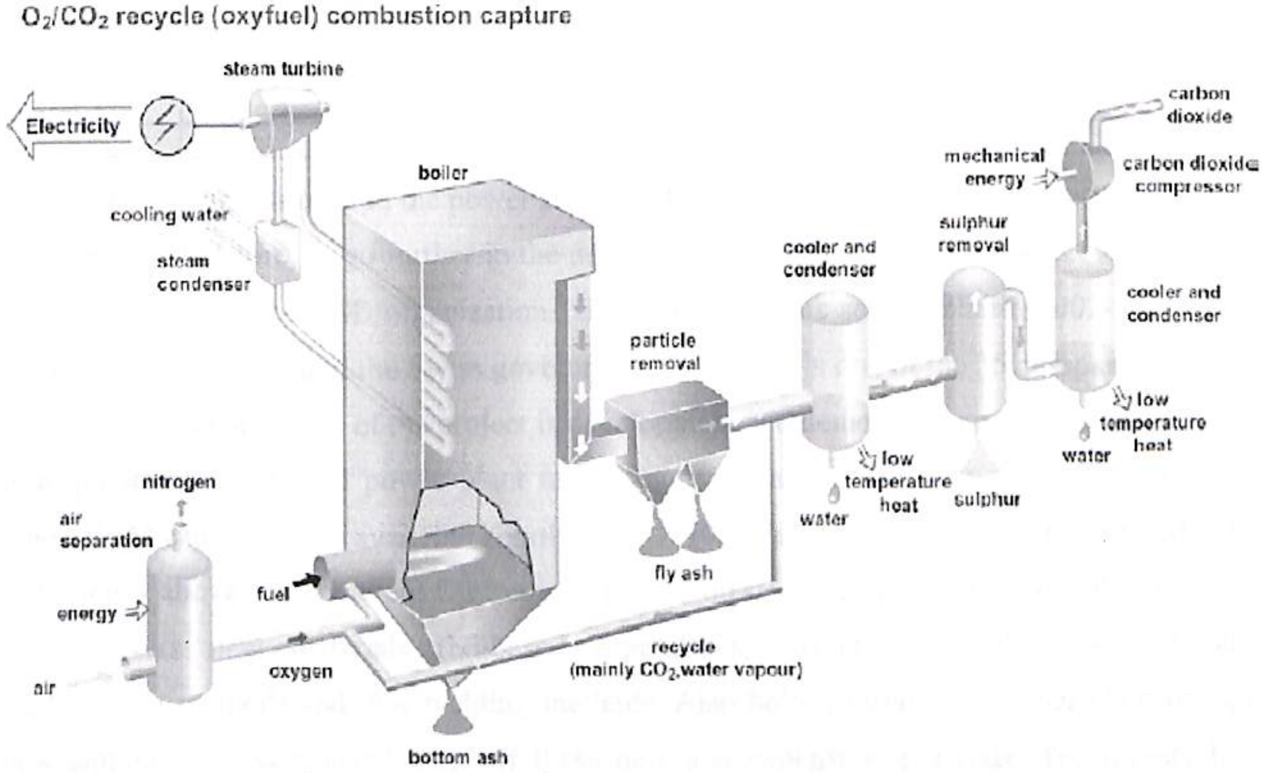


Figure5.142: The principle of O2/CO2 recycle combustion in a PF boiler.

Opportunities with O2/CO2 Recycle Combustion of Coal

The advantage of ongoing technology development for enhanced steam cycle efficiency

One of the main opportunities with O2/CO2 recycle combustion of coal in new plants is that the steam cycle is able to take advantage of the ongoing development to increase steam cycle efficiency through the use of advanced steam technology and lignite drying. This advantage is shared with coal-fired post-combustion capture power plants. The development of advanced steam technology is not specifically linked to the CO2 capture field but more in general to the development of materials for extremely high pressures and temperatures, in combination with ew boiler and turbine designs. During the 1990's, power plants were built with very advanced steam data, such as Vattenfall's lignite-fired units in Germany. Also several hard-coal fired and natural-gas fired plants have been built. Data for some plants are shown in Table 5.9. All data in Table 5.9except for the Lippendorf and Niederaussem are

Table 5.9: Data For Some Advanced Steam Power Plants Without Co2 Capture

Power Station	Capacity (MW)	Steam parameters	Fuel	Efficiency (% LHV)	Commissioning year
Lippendorf	2*920	260 bar/554°C/583°C	Lignite	42.6	1999
Niederaussem K	950	275 bar/580°C/600°C	Lignite	45.2	2002
Haramachi 2	1000	259 bar/604°C/602°C	Bituminous		1998
Nordjylland 3	400	290 bar/580°C/580°C/580°C	Bituminous	47	1998
Skærbæk 3	400	290 bar/580°C/580°C/580°C	NG	49	1997
Avedore 2	400	300 bar/580°C/600°C	NG	49.7	2001

For the ferritic materials used in the power plants in Table 5.9, the limit for the materials lies just above 600°C. Therefore, to go further in the development of steam data, the project AD700 has been initiated within the VGB organization. The project is in its second phase (2002-2005) and 50% financed by the EU and the Swiss government. Vattenfall is one of the 35 companies taking part. The technical objective of the project is development and demonstration of an economically viable, pulverised coal-fired power plant technology with a net efficiency of more than 50% (without CO2 capture) to be available shortly after 2010. The long-term target after year 2020 is net efficiency above 55% (without CO2 capture) based on steam temperatures above 800°C.

AD700 covers new materials (Ni-based superalloys, austenitic steels), new materials manufacturing methods and new welding methods. Also boiler, turbine and other plant design issues will be addressed using these of these new and expensive materials. The project has recently decided on a large-scale test facility in the German Scholwen power plant. Raw lignite contains roughly 50% of moisture, meaning that a non-negligible amount of the heat released during combustion is employed to evaporate water. Future lignite-fired plants will probably include lignite drying by using low-temperature heat from the steam power cycle or the flue gas. This will boost the efficiency to levels comparable with bituminous coal. The additional investment cost for lignite drying is likely to be balanced by the increase in plant efficiency so that the specific investment cost in EUR/MWhe is unaffected.

Reduced boiler heat losses and compact boiler design

In the air-fired boiler, large quantities of inert nitrogen are heated as a consequence of the combustion process, and although this nitrogen is cooled down again, it has a temperature above the ambient as the exhaust gas is released. The heat loss with the flue gas in a conventional air-fired boiler amounts to up to 10%. A significant part of this loss is the heat energy that leaves with the nitrogen in the flue gas. In the O2/CO2 recycle combustion boiler, there is no bulk nitrogen in the gas path, which in turn means that the heat losses with the flue gas can be significantly reduced. With the development of lignite drying through the use of low-temperature process heat, the inert flow through the boiler and thus the heat loss from the boiler will be further reduced. Many studies, both theoretical and experimental, that are related to the combustion of coal in an O2/CO2 atmosphere have been focusing on retrofit of existing PF boilers , where the boiler geometry is determined by the air-firing case, and where it has been a target for the O2/CO2 recycle case to obtain combustion conditions (flame temperature, heat transfer) as similar as possible to those of the air firing case. Therefore, the recirculation of CO2 from the boiler exhaust has been rather significant (typically around two thirds of the flue gas), in order to imitate the conditions during air firing, when nitrogen is present as an inert. Most likely, a first generation of new oxyfuel boilers will also adapt this boiler design philosophy. With increasing knowledge and refined tools for modelling of combustion of lignite in an O2/CO2 atmosphere, it will be possible to refine the boiler design for the second and third generations of boilers. A major target will be to reduce the rate of, or even entirely avoid externally recycled flue gas. To maintain the flame temperature within acceptable limits, internal recycling of flue gas inside the boiler can be used. This will reduce the size of the boiler significantly, which means that the efficiency loss due to thermal radiation to the environment will be reduced (this loss is already today quite small though, around 1% of the fuel thermal energy), and also reduce the electric power requirement for the flue gas recirculation fans. A significant reduction of the boiler size will also lead to a reduction in boiler investment cost, since the cost of the boiler is more or less proportional to the weight of the boiler parts. Almost pure oxygen will be available for the combustion process in the boiler. This means that it will be possible to control and optimize the combustion process through the injection of oxygen in dedicated areas inside the boiler, which is not possible in air-fired boilers. This means that the boiler design will have an additional degree of freedom compared to conventional air-fired boilers, which can be taken advantage of to control combustion conditions, emission formation and temperature distribution. When oxyfuel combustion is applied to a CFB boiler, opportunities to significantly reduce the amount of flue gas recycle exist. In a CFB boiler, the combustion temperature can be controlled through the recirculation of bed material, meaning that CO2 recycle need not be very high, and that the boiler size and cost can be reduced in an easier manner than for the PF case. Alstom. have reported that pilot scale testing of oxyfuel CFB with O2 concentrations of up till 70% is being performed.

Zero-emission power plant

In pre-combustion and post-combustion capture, it is the CO2 that is removed from a mixture of gases. Typically, it is estimated in these cases that 85-90% of the CO2 from the power plant can be captured. In the oxyfuel case, on the other hand, it is water and non-condensable gases that are removed from the CO2-rich stream. Fractions of CO2 may be dissolved in the water as it is condensed out from the CO2 rich exhaust, and some more CO2 may be lost during the process of removal of non-condensable gases. Nevertheless, almost all of the CO2 will be captured, and if deemed desirable, there may be a possibility for co-capture of other pollutants, mainly sulphur oxide. Should cocapture not be possible, the absence of bulk nitrogen in the flue gas means that the equipment for flue-gas desulphurization (FGD) and nitrogen oxide removal (deNOx) will have a smaller volume, and thus be cheaper, than the corresponding equipment for air-fired power plants. Furthermore, acid water-soluble pollutants will be dissolved in the water condensed from the process and not emitted to the atmosphere, which may very well be the case in atmospheric coal-fired boilers. The cleaning of the condensed water can be done with methods already commercially available. Also the particles that remain in the flue gas after the particle removal unit will to a large part be removed with the flue gas condensation. Altogether, with careful design, the O2/CO2 recycle combustion power plant may offer a possibility for zero-emission or close-to-zero-emission not only of CO2 but also of other harmful substances.

Challenges with O2/CO2 Recycle Combustion of Coal

Boiler design

As described above, opportunities have been identified for boiler efficiency improvement and cost reduction for the O2/CO2 combustion with or without recycle of flue gas. In order to be able to develop and take advantage of these opportunities, there are several challenges related to the boiler that must be faced.

***Fundamentals*:** Combustion of coal in an O2/CO2 atmosphere has been investigated experimentally on laboratory and pilot scale to increase the knowledge of combustion characteristics, and to support development of CFD modelling tools. A review of some studies can be found in [13] Many studies have a retrofit objective. There is a need for more experimental and modelling work enabling scale-up and optimization of the operating conditions of PF boilers with internal recycle, and reduced external recycle. Flame properties must be determined, as well as the combustion process, heat transfer, gas phase kinetics, behaviour of sulphur and nitrogen in an O2/CO2 atmosphere, ash-behaviour, slagging and fouling, and composition of deposits. Evaluation of the resulting emissions has been made and a general conclusion appears to be that no major operational difficulties are encountered when recirculating a large amount of flue gas. Another frequently encountered conclusion is that NOx formation is reduced compared to combustion in air, but it is not clear how the NOx formation from fuel nitrogen is depending on the combustion process.

Unlike the N2 molecule, the CO2 and H2O molecules are emitters of thermal radiation, meaning that when N2 is substituted with CO2 in the boiler, the heat transfer characteristics will change. There will be a need for verification and validation of reliable heat transfer models that include the changed thermal radiation characteristics. Concerning combustion and heat transfer, it is desirable that not only manufacturers' in-house codes but also commercial codes are developed and validated to fit the boiler performance in an O2/CO2 atmosphere.

Design: Combustion of coal in pure oxygen gives a high flame temperature, which will cause ash melting and enhance the formation of NOx. The suggested solution to this in a PF boiler is usually an external recirculation of flue gas, as shown in Figure 5.14. Since it is desirable to reduce the external recirculation rate to reduce the boiler size and increase the efficiency, the challenge is to design a boiler with internal recirculation of cooled gases inside the boiler to cool down the flame. This is very much the same as the thousands of existing oxyfuel applications in industry. As long as there is an external recirculation, it must also be decided at which point in the flue gas stream this recycle should be extracted. Most likely the recirculated stream should be extracted after a primary particle removal, to avoid extensive build up of particulates. Usually it is assumed that the stream is extracted before the flue gas condenser, although this is not obvious. Furthermore, a strategy for adding the oxygen in the boiler must be developed, so that NOx formation and CO-levels can be kept low. Another challenge is related to the air leakage into the boiler. It must be determined how the boiler should be sealed or even work with overpressure to minimize air leakage, or if leakage air should be dealt with in the downstream gas cleaning process.

Materials: Higher CO2 contents in the flue gas means that the heat flux to the walls and superheaters will be higher and high-temperature corrosion is therefore likely to occur more rapidly in an O2/CO2 combustion boiler than in an air-fired boiler. The reported increase of fouling and of SO3 in the deposits will also increase the risk of corrosion. Corrosion testing is therefore necessary. Also, field-testing of an existing boiler before and after retrofit to O2/CO2 combustion would be a useful way to investigate the increased corrosion risk. With increased knowledge of corrosion behaviour, requirements of boiler materials can be determined more accurately.

Oxygen production

In general, studies of the oxyfuel technology for CO2 capture from coal assume that the oxygen is produced with a cryogenic air-separation unit (Cryo-ASU), although membranes and chemical looping are sometimes mentioned for future concepts, Cryo-ASU is the only available large-scale technology for oxygen separation from air at present. It will most likely be the technology employed in the first generation of O2/CO2 recycles combustion capture of CO2. The Cryo-ASU may be either of the low-purity kind, producing oxygen with 95% purity (the remaining 5% being mainly argon) or of the high-purity kind that produces oxygen of more than 99% purity. The high-purity Cryo- ASU is more expensive and more energy consuming than the low-purity Cryo-ASU. Roughly, the electric power consumption of a Cryo-ASU may amount to 20% of the plant gross power output for the O2/CO2 recycle combustion power plant, which of course is very detrimental to plant efficiency. In Figure 3, the main flows of mass, thermal energy and electric power are shown for the coal-fired O2/CO2 recycle combustion power plant. The gross electric power output, which is produced by the electric generator, is partly consumed by the power plant internal consumption to drive e.g. feedwater pumps and flue gas recirculation fans. The two main consumers of energy in the plant are however the CO2 compression and the compression of air to the Cryo-ASU, which severely penalizes the plant net efficiency. Through optimisation of the CO2 compressors and introduction of intercooling between the compressor stages, the energy consumption for CO2 compression can be minimised. In many studies the compressers are assumed to use electric power from the grid or internal electric power. Since the motor drives are very large, almost two hundred MW in a 1000 MW plant, most likely they will be steam turbine drives. This means that a new optimization factor is introduced, namely the steam consumption in these drives. More efficient heat integration between the Cryo-ASU and the rest of the power plant will be a necessity. In this was shown to be some 60 MW saving in a typical 1000 MW unit, including SOx removal. The replacement of the Cryo-ASU with some other means of less energy consuming oxygen separation from air has not been fully explored. As can be seen in Figure 5.15, there are three major sources of low-temperature heat in the plant. If any of this heat, in particular the low temperature heat that may otherwise be a loss, could be employed for oxygen production, this might reduce the efficiency penalty caused by the oxygen production. In the EU-project ENCAP, three non-cryogenic options for O2 separation from air are being investigated:

1) Membrane separation through ceramic oxygen-ion transfer membranes 2) Ceramic Auto Thermal Recovery and 3) Chemical looping combustion. The application of any of these technologies to the O2/CO2 recycle combustion of coal must lead to a closer integration of the oxygen production with the rest of the power plant process. It is too early to definitely judge these methods and determine which is the most suitable for O2/CO2 combustion capture. It is at present not obvious that there is a benefit in terms of efficiency, investment cost and, in the end, the cost of electricity with these technologies compared to the Cryo-ASU.

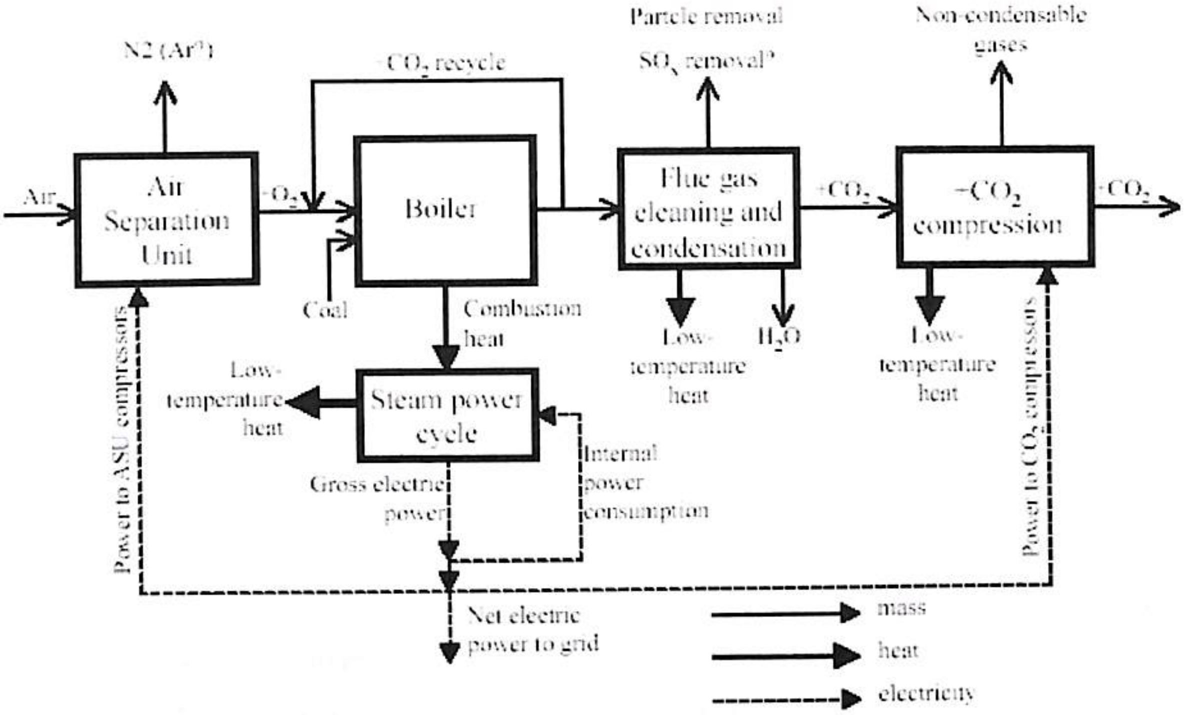


Figure 5.15: Mass, heat and electricity streams in the O2/CO2 recycle combustion plant. "+CO2" and "+O2" symbolizes that the streams may contain more than their main constituents

CO2 purity requirements and flue gas cleaning

Depending on the target for the CO2 (EOR or storage), the requirements on the purity of the CO2-rich stream that leaves a power plant with CO2 capture will probably differ. This topic has not been much dealt with in process analyses of power plants with CO2 capture, and there are several question marks in this area that require attention. One major challenge is the technical and economical optimum specification.

Economically, for the O2/CO2 recycle combustion, it may be preferable if SOx, NOx, non-condensable gases and the last fractions of water in the CO2 rich stream need not be removed, since this will reduce the plant investment required, and also most likely reduce the energy penalty caused by the CO2 capture. This might, however, require use of more expensive materials in e.g. CO2 compressors and pipelines.

Technically, it is a question about how clean the CO2 must be for transport and further usage/storage, but also about how clean CO2 it is possible to obtain with different purification steps such as particle removal, water condensation, dehydration, SOx removal and removal of non-condensable gases, and how to minimize the loss of CO2 to the atmosphere during the purification process.

Particle removal after the boiler is primarily a question of reducing deposits in the recirculation of the flue gas and what can continue with the flue gas stream from the process. This particle removal will probably be by cyclones in a primary step within the recirculation loop and with electro-static filters (ESP) or fabric filters thereafter in the reduced gas stream. The choice depends on system configuration, operating requirements, energy and economical analyses. Not all particles will be removed in an ESP though, but most of the remaining particles in the stream that is not recycled will end up in the flue gas condensate.

Flue gas condensation is a well-known method for heat recovery from moist flue gases to improve the overall efficiency in combined heat and power plants, and to remove pollutants in the case of waste incineration. Usually, flue gas condensation technology is focused more on heat recovery than on efficient removal of moisture

and pollutants. Also, there is an issue of scale-up. The fuel thermal input in a lignite-fired power plant boiler may very well be above 2000 MWth, whereas existing flue gas condensers are connected to boilers where the fuel thermal input is an order of magnitude smaller. It should be noted that with the introduction of lignite drying, the water contents of the flue gas will be reduced, but still significant residual moisture will be condensed and removed from the CO2-rich flue gas. In addition, the concentration of acid gases in the flue gas from oxyfuel combustion should be higher than in conventional flue gas. Corrosion-related issues must therefore be carefully handled for the flue gas path way and for the flue gas condenser.

SO2 removal from the flue gas is well-known technology for large lignite-fired power plants, but it is also rather costly. There are two main issues that need to be resolved in the O2/CO2 recycle combustion case. The first issue is Power to CO2 compressors

whether it is possible to co-capture SO2 with CO2 and if the resulting stream has a composition that is acceptable for transport and storage, and is compliant with legal demands. If the answer is yes, the expensive desulphurization system could be omitted. Theoretically, the critical constants of SO2 lie close to those of CO2, therefore SO2 with the concentrations found in the flue gas should be easily mixed with CO2 under most operating conditions of the CO2 processing. The main obstacles for the co-capture of SO2 with CO2 will be related to corrosion problems in connection to transport and storage, the concerns of safety, environmental regulation and legal related issues. The second concern is if it is possible to remove SO2 from the flue gas in a process that is integrated with other gas cleaning processes, for example flue gas condensation, in a way that is more compatible with the requirements on both SO2 removal and CO2 recovery. Presently, both issues are open questions.

Dehydration to remove the water still remaining in the flue gas after the flue gas condenser may very well be necessary to avoid corrosion and hydrate formation, in particular if the SO2 is not removed from the CO2-rich stream. The dryer the CO2 stream, the higher the allowance for the corrosive components in the CO2 stream. The final dehydration of CO2 should be integrated into an intermediate stage in the CO2 compressor train, exactly where is depending on the water solubility in the CO2 under various pressures. Based on physicochemical properties of the CO2 stream, including the choice of the dehydration processes, it will be possible to make an optimisation of primary water removal and further dehydration.

Removal of non-condensable gases, including N2, Ar, excess O2 and NOx will take place as an integrated part of the CO2 compression train if necessary. A phase transfer of CO2 to the liquid state may be performed and thereafter the non-condensable gases are flashed from the liquid CO2. A high selectivity of the non-condensable gases for the separation is required in order to achieve a high CO2 recovery and avoid that CO2 is emitted to the atmosphere. Connected to this is the lack of knowledge of physical properties for mixtures of high-pressure CO2 and noncondensable gases. To avoid emission of NO when releasing the stream of removed non-condensable gases to the atmosphere, it is important to ensure either that the fuel nitrogen is mainly converted to N2 in the combustion process or that the stream of non-condensable gases is treated to convert the NO to N2 through for instance ammonia injection at an appropriate gas temperature. Another issue related to the non-condensable gas content in the flue gas is how much effort should be made to avoid that these gases enter the power plant. N2 and NO formation from the fuel-nitrogen during the combustion cannot be avoided. There may also be some air leakage into the boiler, in particular with the fuel feed. The excess O2 in the combustion should from this point of view be kept as low as possible, but some excess O2 will e necessary to ensure complete combustion. Depending on the oxygen separation method, the oxygen that enters the O2/CO2 recycle boiler may also very well contain argon and minor fractions of nitrogen. An overall economic and technical analysis will be necessary combined with boiler and combustion designs in order to decide whether to avoid as much as possible of the non-condensable gases upstream of the CO2 processing or to separate them during the CO2 processing.

Process Integration – The Overall Technical Challenge

The opportunities and challenges described above all sum up to the overall technical challenge, which is the overall power plant layout. Generally speaking, a power plant with CO2 capture has a lower thermal efficiency than the equivalent plant without CO2 capture. Energy-efficient integration of lignite drying, O2 production, flue gas cleaning and recirculation in combination with boiler design and steam cycle layout will be necessary in order to minimize the negative impact of CO2 capture. One issue that must be considered is that there are large quantities of low-temperature heat available, as indicated in Figure 5.15. Clever use of this heat so that the heat loss to the environment can be minimised will be a challenge. In the case where oxygen is produced with a Cryo-ASU, use of the cold waste N2 for reduced temperature of the cooling water or for flue gas condensation could also be an option to consider. An additional target during the design phase is that the power plant must be robust in operation and have a high reliability, availability and maintainability, which must be considered when evaluating process integration options.

Cost of Electricity – The Driving Force for Power Plant Investment

From an investment decision point of view, plant economy is a major challenge for all concepts with CO2 capture. A power plant will not be of interest to build unless it is economically viable, regardless of its technical performance. A power plant with CO2 capture will not only have a lower thermal efficiency than the equivalent plant without CO2 capture, it will also have a higher specific investment cost, as shown schematically in Figure5.16. A power plant with CO2 capture will first of all need to have a sufficiently low predicted total cost of electricity (COE)so that it is interesting to build, and also have a sufficiently low variable cost of electricity so that it will be operating as a base load plant once it is built. The gap in COE between plants with and without capture will have to be financed through sale of CO2 for e.g. EOR and/or through the avoidance of emission penalties.

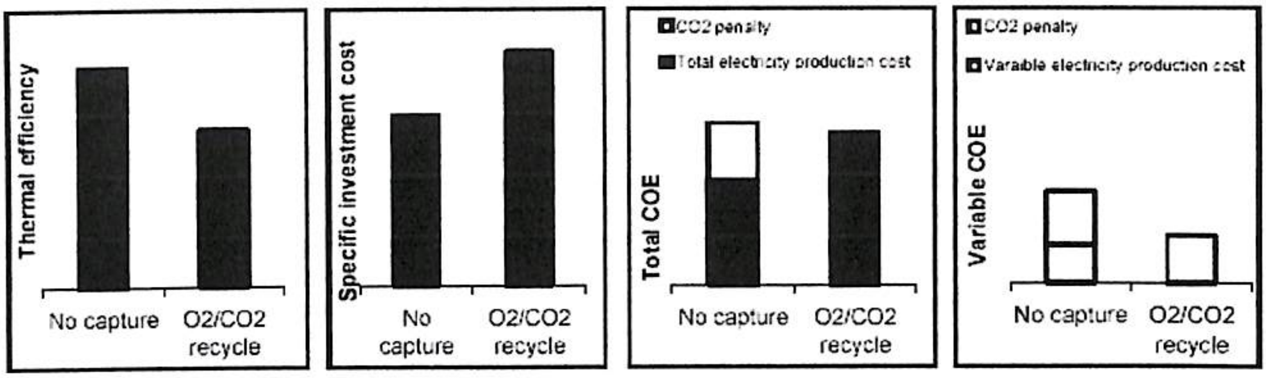


Figure 5.16: Schematic illustration of differences between lignite fired plants with and without CO2 capture through O2/CO2 recycle combustion Variable costs are the fuel cost, variable O&M costs and CO2 emission penalties. Lignite is a very cheap fuel, and as mentioned above the O2/CO2 recycle combustion power plant has the potential to be a zero-emission or close-to zero- emission power plant, meaning that it will not be subject to any significant economic CO2 penalty. The typical expected economic performance (excluding cost for transport and storage) of a lignite-fired O2/CO2 recycle combustion power plant of around 900 MWe gross power production is shown in the two rightmost diagrams in Figure 4. In the case of a CO2 emission penalty of, say, 20 EUR/ton CO2, the total COE will probably be slightly lower for the O2/CO2 recycle combustion case than for a conventional power plant. The decision when to put the power plant into operation once it has been built, will be made based on the variable COE. Due to the reduced thermal efficiency, the power plant with O2/CO2 recycle combustion capture will have a somewhat higher fuel consumption than the non-capture plant, but the cost for CO2 emissions will be so significant for the non-capture plant, that its variable COE will be much higher than for the O2/CO2 recycle combustion plant. This means that it is the O2/CO2 recycle combustion plant that will have an advantage in the dispatch, be operated first and have the most operating hours of the two, and consequently it is this plant that is the most interesting to build of the two. The comparison of total and variable COE for power plants with and without CO2 capture is however not sufficient for a decision on to actually build one of several investigated concepts. COE for new power plants that are built must be compared with COE for other power plants on the same deregulated market. New power plants must be found to have a sufficiently low total COE to be profitable and a sufficiently low variable COE to be put in baseload operation. The development of lignite-fired power plants with O2/CO2 recycle combustion for

CO2 capture is highly interesting, due to the possibility to use advanced steam technology, reduce the boiler size and cost and to design a zero-emission power plant. It may also have the economic performance that is required from a base-load plant operating on a deregulated electricity market with CO2 emission penalties. In order to realize this power plant concept, work is required on combustion and heat transfer to enable a good boiler design. A reduction of the required energy consumption for oxygen production and an integration of the CO2 removal process are important to improve plant efficiency. Several topics connected to flue gas treatment need to be given more attention as an integrated part of the power plant studies. There is also a lack of physical properties data for pressurized CO2 with impurities. A design with enhanced performance and reduced cost of a lignite-fired O2/CO2 recycle combustion power plant is the overall target of one of the sub projects of the currently ongoing EU-project ENCAP, where Vattenfall acts as the coordinator.

Emissions from Gas Power Plants in India:

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NOx), carbon monoxide (CO), and carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NOx formation in natural gas combustion is thermal NOx. The thermal NOx mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N2) and oxygen (O2) molecules in the combustion air. Most NOx formed through the thermal NOx mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NOx is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NOx emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level). The second mechanism of NOx formation, called prompt NOx, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NOx reactions occur within the flame and are usually negligible when compared to the amount of NOx formed through the thermal NOx mechanism. However, prompt NOx levels may become significant with ultra-low-NOx burners. The third mechanism of NOx formation, called fuel NOx, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NOx formation through the fuel NOx mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NOx control systems such as low NOx burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO2 emissions. Boilers combusting unprocessed natural gas may have higher SO2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases

CO2, CH4, and N2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO2 results in CH4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH4, CO, and VOC produced is insignificant compared to CO2 levels. Formation of N2O during the combustion process is affected by two furnace-zone factors. N2O emissions are minimized when combustion temperatures are kept high (above 1475oF) and excess oxygen is kept to a minimum (less than 1 percent).Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N2O also favor emissions of methane.

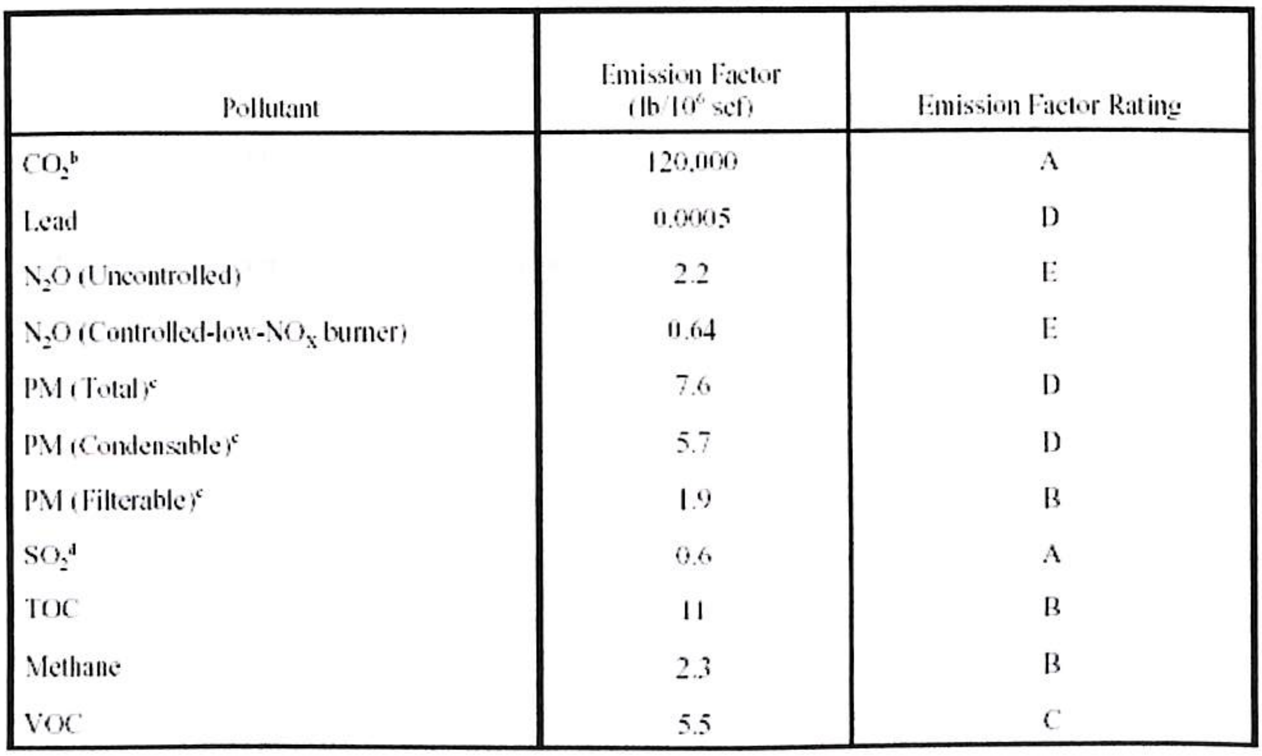
Controls

NOx Controls -

Currently, the two most prevalent combustion control techniques used to reduce NOx emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NOx burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NOx emissions by two mechanisms. Primarily, the recirculated gas acts as a dilutent to reduce combustion temperatures, thus suppressing the thermal NOx mechanism. To a lesser extent, FGR also reduces NOx formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NOx emission rates for these systems. An FGR system is normally used in combination with specially designed low NOx burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent.

Low NOx burners reduce NOx by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NOx formation. The two most common types of low NOx burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners. Other combustion control techniques used to reduce NOx emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NOx emission rates. Gas reburning is similar to the use of overfire in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to rovide increased reduction of NOx to NO2. Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NOx emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH3) or urea into combustion flue gases (in a specific temperature zone) to reduce NOx emission. The Alternative Control Techniques (ACT) document for NOx emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.12 Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NOx for applications on wall-fired boilers and a 13 percent reduction in NOx for applications on tangential-fired boilers.11 In many situations, a boiler may have an SNCR system installed to trim NOx emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NOx reduction. The SCR system involves injecting NH3 into the flue gas in the presence of a catalyst to reduce NOx emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NOx reduction efficiencies for SCR control ranging from 80 to 90 percent.12 Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 5.9,5.10,5.11, and 5.12 Tables in this section present emission factors on a volume basis (lb/106 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/106 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Table 5.10. Emission factors for criteria pollutants and greenhouse gases from natural gas combustion



Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

a . Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from lb/106 scf to kg/106 m3, multiply by 16. To convert from lb/106 scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

b Based on approximately 100% conversion of fuel carbon to CO2. CO2[lb/106 scf] = (3.67) CON) (C)(D), where CON = fractional conversion of fuel carbon to CO2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2x104 lb/106 scf.

c All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM10, PM2.5 or PM1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

d Based on 100% conversion of fuel sulfur to SO2. Assumes sulfur content is natural gas of 2,000 grains/106 scf. The SO2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO2 emission factor by the ratio of the site-specific sulfur content (grains/106 scf) to 2,000 grains/106 scf.

Table 5.11. Emission factors for speciated organic compounds from
Natural gas combustion

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene^{b,c}	2.4E-05	D
56-49-5	3-Methylchloranthrene^{b,c}	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene^{b,c}	<1.6E-05	E
83-32-9	Acenaphthene^{b,c}	<1.8E-06	E
203-96-8	Acenaphthylene^{b,c}	<1.8E-06	E
120-12-7	Anthracene^{b,c}	<2.4E-06	E
56-55-3	Benz(a)anthracene^{b,c}	<1.8E-06	E
71-43-2	Benzene^{b}	2.1E-03	B
50-32-8	Benzo(a)pyrene^{b,c}	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene^{b,c}	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene^{b,c}	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene^{b,c}	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene^{b,c}	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene^{b,c}	<1.2E-06	E
25321-22-6	Dichlorobenzene^{b}	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene^{b,c}	3.0E-06	E
86-73-7	Fluorene^{b,c}	2.8E-06	E
50-00-0	Formaldehyde^{b}	7.5E-02	B
110-54-3	Hexane^{b}	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene^{b,c}	<1.8E-06	E
91-20-3	Naphthalene^{b}	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene^{b,c}	1.7E-05	D

Table 5.11. Emission factors for speciated organic compounds from Natural gas combustion (continued)

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

a . Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from lb/106 scf to kg/106 m3, multiply by 16. To convert from 1b/106 scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

b Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

c HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

d The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

Table 5.12. Emission factors for metals from natural gas combustion

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

a Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from lb/106 scf to kg/106 m3, multiply by 16. To convert from lb/106 scf to 1b/MMBtu, divide by 1,020.

b Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

CONCLUSION

CONCLUSION

In the Asia Pacific region India ranks third after China and Australia in coal production and second in consumption as Australia exports 70 per cent of its output. Though the current level of coal production in India of 328 million tonnes per annum is impressive, the coal industry faces several problems which, if not tackled expeditiously, will only worsen in the years to come.

First, for many years opencast mining has been favoured over underground mining. This has led to severe land degradation on a large scale, environmental pollution and reduced quality of coal due to it getting mixed with non-mineral matter. The ash content of domestic coal ranges from 30 per cent to 50 per cent as compared to imported coal which, though high in sulphur, has an ash content of 8 per cent to 17 per cent and therefore a higher calorific value.

Second, unconstrained demand according to one estimate is projected to rise to 620 million tonnes by 2011/12. Based on current production India has enough reserves to last 235 years, but economic mining practices are generally limited to depths of 300 meters and 25 per cent of the reserves are beyond this depth. Further, extractable reserves in opencast mines are rated at 63 per cent of proven reserves. If production is to be doubled, the extractable reserves to production ratio will drop to 50 years or even less, if land acquisition for new mining is not possible.

Third, around 90 to 100 million tonnes of ash are generated each year at power stations. Though fly ash can be used in the cement and other industries, India is able to absorb only 11 per cent of this ash compared to 25 per cent by China. Installation of washeries at pitheads can reduce to some extent the ash content, but progress has been slow. Legislation is now in place requiring power stations more than 1000 km from pitheads to use coal with an ash content of upto 34 per cent. Blending of imported and domestic coal has been recommended, but of the 9 million tonnes of non-coking coal that is currently imported, only 2 million tonnes is for power plants on the southern and western coastal areas while the bulk is used by the cement industry. Clean coal technologies, such as Integrated Gassification Combined Cycle (IGCC), where the coal is converted to gas which is then burnt, are available, but plants based on these technologies are more expensive than the conventional plants and need to be modified to suit Indian coal specifications. NTPC is planning to set up a 100 MW demonstration plant at Dadri in collaboration with BHEL.

Fourth, is the high cost of transportation of coal by rail. At a distance of 750 km the transport component in the coal price is more than 50 per cent and increases for extended distances. Carrying capacity of the railways can at times be a constraint, if there are competing demands from other sectors e.g. movement of iron ore. The issue of transportation costs has been partially addressed by setting up pithead power stations and transmission lines for dispatch of power to the load centres. However, this does not solve the problem of ash generation. The combined effect on the environment of opencast mines and power stations in close proximity sets a limit to the extent to which pitheads power stations can be set up.

Finally, Coal India is the second biggest employer in the world with 5,00,000 employees after General Motors which ranks second in the Fortune 500 list. The comparison ends here. The output per miner per annum in Coal India varies from 152 to 2621 tonnes compared to 12,000 tonnes in the USA and Australia. Further, in three of its subsidiaries 200,000 employees are engaged in underground mining of just 23 million tonnes of coal per annum and cannot be made redundant or the mines closed. Further, Coal India is required to absorb about 4000 persons every year who are displaced from their land due to coal mining activities. Despite these factors Coal India has been able to make some reduction in total staff but obviously, in terms of increasing productivity, has a long way to go.

The gas era began with the discovery of the western offshore gasfields and the laying of the Hazira-Bijapur-Jagdishpur (HBJ) pipeline to feed the gas to western and northern India. Power plants with an aggregate capacity of 6,000 MW and fertilizer plants were set up along the HBJ pipeline. A plan to supply the four southern states with gas, through a pipeline similar to the HBJ, did not take off because of restricted gas availability. In the meantime gas demand continues to grow and currently is projected at double the present availability. Combined cycle gas fired power plants have a shorter gestation period for construction and higher thermal efficiencies than coal based plants and do not generate any ash. Also transport of gas by pipeline is safer and more convenient than movement of coal by road or rail and the capacity of a gas pipeline can be increased relatively easily by installing additional compressors.

To meet the gap between gas demand and indigenous availability the options are a) import of gas by pipeline from neighbouring countries b) import of gas in the form of LNG and c) increased E&P activity within the country.

Currently the price of domestic gas is fixed by government lower than what its calorific value demands. LNG will be priced at international costs of production, liquefaction, transportation and regassification and subject to some hard negotiations between buyer and seller. Domestic coal prices were administered till 2001 and are now set by the coal companies. The fob price of imported coal does not fluctuate widely as in the case of oil but ocean freight costs are more variable. Expensive naphtha has been used in power plants as a transition fuel before switching to gas. The relative economics of using various fuels will depend on the load centre location. According to a recent study, at a distance of 800 km between the source and the load centre, the cost of delivered energy is cheapest with domestic gas supplied by pipeline, followed by pithead power stations supplying "coal by wire" and then by coal fired power stations at the load centre. At port locations far away from the pithead, LNG scores over domestic as well as imported coal.

In the medium-term, Reliance plan to move gas from the KG basin across peninsular India to meet demand in Maharashtra and Gujarat, again initially displacing naphtha consumed in their own petrochemical plants. They have also reportedly made overtures to NTPC to sell gas to them and buy power for distribution on a quid pro quo basis. With the laying of this pipeline, it would be both economic and feasible to set up gas based power plants in Andhra Pradesh and northern Karnataka along the route of the pipeline. These new sources of supply will enable India to leapfrog over China, to become the second largest gas user in the Asia Pacific region after Japan. Meanwhile, planned expansion of existing coal based plants and those already approved are unlikely to be dropped, nor it is possible to convert coal based power plants to gas. This will give some breathing space to the coal industry.

In the longer term, however, the picture will change. It is more than likely that new discoveries will take place both in the KG basin and in the western deepwaters where in 2003 ONGC launched one of the world's biggest exploration efforts. Once the plants of Petronet LNG and Shell are up and running, other LNG suppliers will find it attractive to set up LNG terminals. The Dhabol plant could be revived in the medium to long term. GAIL has expressed its desire to build an all-India gas grid to connect various sources and load centres and also integrate with any natural gas pipeline supply from neighbouring countries. These developments will definitely shrink the market for domestic coal in the northern, western and southern regions, unless some of the major problems facing the coal industry that have been outlined earlier, are resolved. Gas could even enter the heartland of the coal industry if supplies from Bangladesh materialise. But there is little doubt that domestic coal will remain a major, if not the largest, energy source over the next 15 years for the power sector. The role of domestic coal in providing energy security to the country is also vital. Japan, which imports virtually all its energy supply, has a very diversified portfolio of oil, gas and coal, apart from hydropower. The coal consumption level is 60 per cent that of India, on a calorific value basis, despite its adverse environmental impacts.

Coal plays a major role in the Indian economy. It accounts for 36% of annual energy produced. Though it is cheap & plentiful, the environmental and health impact of coal use is becoming more and more severe due to its deteriorating quality. The economy is expected to grow at a rapid pace and it is quite likely that India may also have to use inferior quality fuels which may be available at lower cost for economic generation of power. In light of such a scenario there is an increasing need to find ways of limiting pollution of air through the use of cleaner technologies and more efficient processes.

Among the new clean coal technologies, "Circulating Fluidising Bed" is one of the most promising ones. The use of this technology has been proven by the success of the number of large CFB units operating worldwide over last one decade. Superior technical and excellent environmental performance without using complicated flue gas treatment facilities and possibility of use of inferior quality fuels is the driving force for its rapid development. CFBC boilers are simple to operate & maintain as they are sufficiently close to conventional boilers.

Thus finally the conclusion is that coal remains the king for power generation so we have to find out new combustion technologies for the better utilization of this resource.

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