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Report Title

Power Generation - A Review of the Way Forward

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Abstract:

The report was prepared as a follow-up to a 1993 report on the Future of Power Generation and Combustion. The scope of the successor study was to include release inventories from the range of generating technologies, including new systems, to assist HMIP in the determination of BPEO for the electricity supply industry.

The electricity supply industry is still in an evolutionary stage post privatisation. The dynamics of the market are operating at several levels. The older steam-based capacity is competing with very efficient, low capital cost, combined cycle gas turbine systems whilst the regional electricity companies and the independent power producers are attempting to take market share from the two major coal based generators. Fuel suppliers also recognise the size of the demand in this sector and are competing to retain or develop opportunities.

There is limited scope to improve the environmental performance of the older plant at economic cost. The cost burden of new emission control equipment especially on plant destined to operate on intermediate or peak load is likely to lead to premature closure. The new capacity likely to enter operation from investments in CCGT systems should still provide an adequate plant margin. It is possible to extend useful life of boilers and secure a modest improvement in steam turbine efficiency but with limited improvement in overall electrical conversion efficiency without boiler replacement.

Technological developments are leading to a potential split in the industry. Most major utilities wish to retain steam and develop boilers using advanced steam condition with post combustion emissions controls. The Independent Power Producers are harnessing the cost advantages of CCGT currently using the availability of natural gas but with the possible switch to synthesis gas when economic to do so. The most likely route for this to develop is by the gasification of heavy oil residues and waste streams on the lines of Shell's Dutch project and others in Italy. The development of the advanced gas turbines, to be supplemented by the rapid development of fuel cells, offers high efficiency, compactness and the lowest environmental impact of all fossil fuelled systems.

The results of this work will be used in the formulation of Government Policy, but views expresses in this report do not necessarily represent Government Policy.

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FOREWORD

The report has been commissioned by HMIP as a follow-up to a study undertaken in 1993. The latter study entitled "Review of Future of Power Generation and Combustion" was a status report on current and advanced power generating technologies on which HMIP invited comment. Several responses were received, relevant comments with editorial points have been incorporated and the revised text of the original study has been appended as Part 2.

This second report entitled "Power Generation - A Review of the Way Forward" addresses the present level of emissions and has been extended to provide a release inventory from the alternative technologies. It also reviews the existing UK capacity to evaluate the generic options to modify or refurbish the older plant, to improve its thermal efficiency and to reduce emissions while extending the life of this largely under-utilised plant.

In order to provide the background for the development of the generic options, the alternative technologies have been set out again to include the most recent developments with cross-referencing to the original report.

The development of gas turbines and clean generating technology has been advancing in the USA and Europe with a considerable increase in the number of papers available on the subject. Consequently, the key issues cited in the text are as far as possible related to specific published data and a comprehensive bibliography is attached to the new report.

EXECUTIVE SUMMARY

The privatised Electricity Supply Industry is still at an evolutionary stage and one in which the dynamics of the market are operating at several levels. The older steam based generating capacity is competing with new combined cycle gas turbine (CCGT) systems and generators are now bidding to supply the grid. The Regional Electricity Companies (RECs) and Independent Power Producers (IPPs) wish to establish an increasing share of the power sold to the grid at the expense of National Power and PowerGen.

There is inter-fuel competition between energy sources. Although perhaps less visible, the competition to supply the power generating sector is fierce. Natural gas has already displaced much coal - a process which is expected to continue. Productivity gains in the newly privatised coal industry may offer the potential to halt the trend. Some generators see Orimulsion as a very competitive new energy source, while heavy oil residues may become an increasingly attractive alternative fuel source as heavy fuel oil demand falls and the oil industry requires an outlet. This is likely to arise because of the increasing constraints on the combustion of heavy oils without flue gas treatment.

Advances in gas turbine technology have established them as the core of most new fossil fuel based power plant for the foreseeable future. Gas turbines may be fuelled with natural gas or gas synthesised in a gasification process. They feature in the following systems:- CCGT, Integrated Gasification Combined Cycle (IGCC), topping cycles, e.g. in 2nd generation Pressurised Fluidised Bed and to aid the performance of ultra-super critical steam systems.

There is a growing recognition that combined cycle systems offer an attractive commercial way to exceed 50% LHV thermal efficiency consuming any fossil fuel. This represents a major improvement over the most widely used sub-critical steam systems with a proportional reduction in emissions. The power generators and their traditional suppliers are reluctant to depart from tried and trusted steam technology. This has been supported by a global survey of buyers' technical preferences, promotional papers and sceptical comments about the "unproven" nature of IGCC technology.

It is easy to draw the conclusion that the ESI will be dominated by an abundant supply of natural gas. While natural gas is available, CCGT systems offer the most efficient, lowest cost and cleanest technology. Such a conclusion, however, overlooks the medium/long term price of gas and the amount of coal and oil fired capacity which exists in the UK today, much of which has a considerable amount of useful residual life if the economics allowed it to be operated.

Analysis of the electricity supply/demand balances from the National Grid 7 Year Statement takes account of the new gas capacity scheduled to be in position over that period. It suggests a capacity surplus which could constrain the use of the older coal and oil based plant. A high gas entry scenario, for example, suggests that, in theory, the quantity of coal in the fuel mix could virtually be absorbed by Drax and Ratcliffe alone on base load. The 7 Year Statement, however, suggests little coal fired capacity would be needed in summer so coal would be spread across more stations on intermediate or peak load. In those circumstances, it seems unlikely that generators would be willing to risk new capital expenditure for emission control unless some guaranteed cost recovery mechanism could be offered. The overheads and fixed costs of retaining a large coal plant for peak load with new investment in pollution control would appear to make it uneconomic to bid into the pool so accelerated plant closure could become a distinct possibility especially if gas penetrates further or more stringent emissions limits were to be set for existing plants.

In Europe, the emissions limits related to the power sector and embodied in the Large Combustion Plant Directive are SO_2, NOx and particulates. However, in the USA, a comprehensive study of toxic emissions from coal-fired power plant was initiated as a result of the Clean Air Act Amendments which required an analysis of 189 Hazardous Air Pollutants, 36 of which were thought to be found in emissions from the power sector. Very fine micron-sized particulate matter was seen as having a possible impact on health. The studies indicate that this fine material may well not be captured by precipitators and is thus emitted with the stack gases. Analysis also suggests that trace elements such as mercury, selenium and boron are enriched in the very fine material. Some toxins may also be released in the gas phase particularly where scrubbers are not fitted. Fine particulate matter has also been found to pass through FGD systems. Traces of mercury may also accumulate in local eco-systems dependent on the concentration of emissions.

The US studies also identified acid mist formation associated with oil-fired plant where the presence of fine vanadium particles may catalyse the conversion of sulphur dioxide to the trioxide with the formation of sulphuric acid aerosols. That observation suggests the probability of more complex chemical reactions occurring which would need to be addressed in the design of FGD systems when flue gases are scrubbed after the combustion of heavy oils or Orimulsion. The only Western plant operating with a purpose-built scrubber was commissioned in the 4th quarter 1994 in Canada and is said to be operating satisfactorily.

The most significant conclusion to be drawn from the heavily funded US clean coal research programme is that direct combustion technology is not mentioned. An energy conversion stage has been identified in the several technologies highlighted producing a clean fuel gas stream for the generation of power. That is to say the conversion of the primary energy in a gasifier, the cleaning of product fuel gas and utilisation in a very efficient converter which might be a combined cycle gas turbine or a fuel cell. Their work suggests that the optimum power generation stage requires a fuel gas essentially free of sulphur, particulates and other pollutants in order to optimise the power conversion efficiency. Consequently, pollution abatement cost changes from a post combustion addition to an integral part of the clean technology. The abatement is then inherent in the design. The current and projected capital costs of these systems are lower than those based on direct combustion and flue gas treatment.

The US outlook is best summarised in the following table:-

Comparative Performance of Technologies

Technology	IGCC 2000	IGCC 2010	1st Gen PFBC	2nd Gen PFBC	Advanced PFBC	EFCC 2005	EFCC 2010	IGFC 2010
Net Elect Efficiency %	45	>50	40	45	>50	47	55	60
SO_2 emissions %NSPS	10	10	25	20	10	20	10	10
NOx emissions %NSPS	10	10	33	20	10	10	10	10
Air toxin emissions *	to meet	to meet	to meet	to meet	to meet	to meet	to meet	to meet
Capital Cost $/kW	1200	1000	1300	1100	1000	1300	1200	1100
Cost of electricity relative to PF%	80	75	90	80	70	90	80	80

Source: USDOE - Acronyms - See Glossary of Terms or Text * US Guidelines

These projected capital costs need to be set in the context of CCGT today and the efficiencies forecast for the year 2000. Plant is currently being installed at 55% LHV efficiency at a capital cost of $400-470/kW. The efficiency of CCGT will rise to 58-60% from turbines already announced for delivery within 2 years. The higher efficiencies will result in a reduction in unit cost because the additional shaft power is being achieved with little extra capital cost.

In Europe, gasification of liquid feedstocks is likely to be the initial route for the introduction of the technology. Shell has already made the investment decision to convert heavy oil residues to clean fuel gas, hydrogen and power at their Rotterdam refinery. Other refiners in Italy and Finland are following. It is becoming increasingly important as the quality of transport sector fuels is improved to reduce emissions. Gasifiers at refineries may prove to be the mechanism to demonstrate the commercial attraction of clean conversion technology to the power industry.

The dominant fuel in the UK power sector for the next few years is gas, albeit that there is a range of views about the medium to long term price. That issue alone would appear to be one of the prime determinants of future technology, the rate of closure of old capacity and the levels of emission which would result from the power generation sector. No new coal based capacity is likely to be required in the foreseeable future.

The US objective for their clean coal programme is a net efficiency of at least 50% while in Germany, the level of 45% net has been tabled for consideration as a hurdle or minimum acceptable level for the future. The use of CCGT technology in the UK, which is already able to achieve 55% on natural gas, presents an implicit acceptance of this principle. These efficiencies refer to the generation of power and it should be recognised that there is scope to utilise the 40% or more of low grade heat in industry, commerce or district heating thereby improving the overall thermal efficiency. An improvement in efficiency is also the primary way to contain CO_2 within the limits agreed by the Government in Berlin.

In the UK, there would appear to be a case to monitor air quality in the areas where coal-fired plant is concentrated to assess levels of fine toxic releases. There may also be a need to re-examine the potential reduction of ash and pyrite in Power Station Fuel in the light of recent developments in coal preparation technology. This may make a useful contribution to SO_2 reduction and trace element emissions as an alternative to low sulphur imported coals. It might also be the BATNEEC to ameliorate sulphur emissions from coal fired stations not fitted with FGD. Improved preparation should offer a lower abatement cost than flue gas treatment and other system cost savings should accrue i.e. transport and ash disposal.

In view of the adoption of gas turbines, there would appear to be a case, political factors apart, to set the emissions limits for new generating plant at the levels attainable by the guarantee limits of currently available gas turbines - namely, virtually sulphur and particulate free and very low NOx e.g. 60 mg/m^3 because they are already being met by a substantial and growing part of the UK's generating capacity.

Although CCGT appears to be the dominant technology in the UK, direct combustion will remain alongside the other clean coal options for new capacity in other parts of the world. For those companies who have opted for CCGT, there would always be the opportunity to retro-fit gasification to provide another gas supply when the price of natural gas makes an alternative source economic.

POWER GENERATION - A REVIEW OF THE WAY FORWARD

ACRONYMS AND ABBREVIATIONS

AFBC	Atmospheric Fluidised Bed Combustor/Combustion
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
BATNEEC	Best Available Technology Not Entailing Excessive Cost
BPEO	Best Practicable Environmental Option
Ca	Calcium
CCGT	Combined Cycle Gas Turbine
CCT	Clean Coal Technology
CEGB	Central Electricity Generating Board
CFBC	Circulating Fluidised Bed Combustor/Combustion
CHP	Combined Heat and Power
CI	Confidence Index (US terminology for Confidence Limits)
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COA	Coal on Ash
COS	Carbonyl Sulphide
CQIM	Coal Quality Impact Model
DTI	Department of Trade and Industry (UK)
EFCC	Externally Fired Combined Cycle
EPRI	Electric Power Research Institute (USA)
EPA	United States Environmental Protection Agency
ESP	Electrostatic Precipitator
EU	European Union
FBC	Fluidised Bed Combustor/Combustion
FGD	Flue Gas Desulphurisation
GE	General Electric (GE)

GWe	Gigawatts-electrical
Hg	Mercury
HMIP	Her Majesty's Inspectorate of Pollution (UK)
HRSG	Heat Recovery Steam Generator (US)
IAPCS	Integrated Air Pollution Control System
IEA	International Energy Agency
IEACR	IEA Coal Research
IGCC	Integrated Gasification Combined Cycle
IGFC	Integrated Gasification with Fuel Cells
ISO	International Standards Organisation
LCPD	Large Combustion Plant Directive (EU)
METC	Morgantown Energy Technology Center (USA)
MWe	Megawatts-electrical
MWt	Megawatts-thermal
Ni	Nickel
NSPS	New Source Performance Standards (US)
PETC	Pittsburgh Energy Technology Center (US)
PCFBC	Pressurised Circulating Fluidised Bed Combustor/Combustion
PFBG	Pressurised Fluidised Bed Gasification
PSF	Power Station Fuel
SCR	Selective Catalytic Reduction
Se	Selenium
USDOE	United States Department of Energy
V	Vanadium
VEW	Vereinigte Electrizitatswerke Westfalen (Germany)

POWER GENERATION - A REVIEW OF THE WAY FORWARD

1. INTRODUCTION

This report has been commissioned by HMIP to review a previous report and to extend the scope by addressing two areas which were specifically excluded from the original terms of reference. The first report, "Review of Future of Power Generation and Combustion", provided a status of technologies as of 1993. It has been revised in the light of comments submitted to HMIP and forms Part 2 of this document.

The scope of the new report has been broadened to add developments which have taken place over the past year. The two new areas requested for study were:-

i. to prepare a release inventory from the range of technologies to assist HMIP in determining BPEO for the Electricity Supply Industry

ii. to review the existing power generating capacity in England and Wales with an evaluation of the generic options to modify or refurbish the older plant to improve both thermal efficiency and emissions performance as a means of extending the life of under-utilised plant

Part 1 addresses these issues in some detail. However, it is appropriate to add certain caveats because there are a number of factors which lead to varying degrees of uncertainty regarding the portfolio of generating equipment to be operated over the next few years by a much enlarged number of companies. Factors such as the future price of natural gas, the price and quality of UK coal after the existing contracts expire, the operation of the pool price system, the interpretation of BPEO and BATNEEC in the power generation and oil refining sectors all impinge on the commercial value of the older generating equipment. Similarly, the longer term effect of the market mechanism on investment decisions may alter the pattern of capacity. These factors create differing levels of risk for any new capital investment which might be required to modify or refurbish existing plant in order to meet relevant environmental standards.

Many of these same issues have been debated over the past months in assessing the UK's longer term requirements for coal with a clear division of opinion between the optimists and the pessimists. This difference lies in the forecast level of power production from coal versus rival fuels - particularly gas. A similar uncertainty arises over the use of the oil fired capacity and the conditions under which heavy fuel oil, emulsified oil residues or Orimulsion might be fired economically on that equipment. Any such move would appear to be at the expense of coal. However, the construction of the environmental control equipment which would be needed to fire Orimulsion could not be completed before 1998 when the two major generators have fulfilled their commitment to lift coal under current contracts.

This year also sees a scheduled review of the Large Combustion Plant Directive. Germany may seek amendments to the Directive for a move towards the low emission levels they have imposed on SO_2, NOx and particulates. An early European signal for future emission standards is likely to be sought because a recent report (UNIPEDE) suggests that 220 GWe of new and replacement capacity will be needed in Europe over the next 15 years.

2. BACKGROUND

The major challenge to the UK power industry is to remain competitive and profitable whilst meeting environmental constraints. Since privatisation, increased competition from both the new independent power producers and a protected nuclear industry has resulted in much of the older coal and oil fired capacity becoming surplus. There are many years of residual life in much of that equipment so one key issue is to establish whether there are economic options which might enable the plant to be operated more cleanly and profitably.

Another issue is how the use of that capacity might be managed and whether there is a financial incentive to invest further capital in the capacity which may only be required for intermediate or peak load.

The most significant advance in power generating technology over recent years has been the improved performance of large gas turbines. Their performance in combined cycle mode operating on natural gas is superior to any other system available today in terms of thermal efficiency, emissions, capital cost and speed of construction. There has been a competitive response from the traditional power contractors and boilermakers with ultra-super critical steam and pressurised fluidised bed systems offering both improved thermal efficiency and emissions from coal but at a higher capital cost. The efficiency of large diesels has also improved and may have application in some locations.

Thermodynamically, combined cycle systems have the advantage over steam-based systems but the debate still continues on the overall conversion efficiency of carbon-based feedstock (fuel) to electrical energy when a comparative evaluation is made for coal, residual oil, Orimulsion, petroleum coke, wastes or bio-mass. However, few experts doubt the ability of the gas turbine manufacturers to improve the thermal efficiency of their designs over the next few years. Gas turbines are currently operating at 55% efficiency (LHV) in combined cycle mode on natural gas. ABB has a two stage machine operating commercially at 58.5%(LHV) and Siemens have just announced a turbine with similar performance. GE has announced their Frame 9H turbine with a combined cycle efficiency of 60% LHV available from 1997 while all leading manufacturers forecast exceeding 60% by the end of the decade as a result of improvements in materials and lead blade cooling techniques which allow them to convert a greater part of the available heat into shaft-power.

Consequently, systems which are based on making use of the combined cycles appear to have a potential inherent advantage over direct combustion steam based systems. Furthermore, the environmental advantages are greater and at lower cost in the event that a value is attached to pollutants e.g. any tax levied on emissions, liquid waste streams or land-fill. Nevertheless, a recent IEA survey of the world's utility companies suggests that their own preference is to retain steam as the basis of their coal fired capacity for many more years based on the evolution of old technology rather than move to something new albeit that flue gas clean-up and NOx control would be required.

Perhaps the greatest area of uncertainty facing the electricity supply industry in the UK is the future price of natural gas. Expert opinion appears divided. One group says that the rate at which new gas reserves have been found recently ensures an abundant supply. Hence fierce competition will continue for the foreseeable future which in turn will result in a low gas price. The other group, including some oil companies, say that the rate of growth in demand in Europe - particularly from the power generation and industrial sectors - will force negotiations for additional gas supplies around the turn of the century. Negotiations for new supplies are unlikely to be at the current low prices but at higher levels reflecting the need to earn a return on the new investment associated with the expansion of existing fields and for the development of new fields. New reserves or sources will have to be developed at the beginning of the next century to cover demand and with it the possibility of long distance movement by pipeline, or by sea as LNG, which will necessitate a price rise. Issues of supply security are also raised because of political uncertainty in the countries owning some of the newer gas resources or the countries through which pipelines would have to pass en route to the main markets.

Both schools of thought produce convincing cases to defend their respective positions but can they both be right? Is there a difference between the position in continental Europe and that of the UK? Are there smaller offshore wells which can be made captive to say one power station with a fixed price negotiated for an agreed term or for the life of the well? These are some of the most critical questions. If an abundance of gas sustains a low price scenario, the prospects of stemming the "dash for gas" in a free market would appear to be very difficult and closure of much of the old plant may be inevitable unless there were to be a change in the Government's approach to energy policy to avoid an over-dependence on gas.

If price increases occur through time, then there may be sufficient of an economic incentive to encourage the development of gasification to generate a synthesis gas or synthesised natural gas from other feedstocks. For example, heavy oil residue gasification could provide a solution to the developing oil industry problems. This route could produce hydrogen for quality improvement in transport fuels and a quantity of surplus synthesis gas available for power generation. The feedstock to such a gasification system could be supplemented by Orimulsion and/or other waste streams to match the requirements of a power plant. The economics could also draw coal in as a feedstock source for the gasifier with an increase in the natural gas price or a reduction in the production cost and thus price of coal.

The addition of wet flue gas scrubbing systems to existing plant could be sufficient of a financial burden to alter the position of power stations in the merit order e.g. the position reported to exist at both Drax and Ratcliffe at present (ref: September and November 1994 ENDS Reports). This illustrates just how sensitive the cost of generation may be to any new investment needed at existing plant. Consequently, the options have to be very carefully evaluated to ensure that the investment risks are minimised.

The role of non-base load capacity is also related to its earning capacity within the pool pricing system. At present, it is geared to reward base load operation. If investment is required for mid or low merit order plant, the potential rewards may not be sufficient to justify the expenditure - particularly given the uncertainty of future load factors. The pool price is set by the marginal plant on the system - normally by a National Power or PowerGen coal plant. The system was originally designed with two main elements - capacity payments and the System Marginal Price. The determinants of the capacity payment are the notional value of lost load (VOLL) and loss of load probability (LOLP). They remain the most arbitrary and unpredictable parts of the Pool pricing system. The System Marginal Price remains a most important element in Pool pricing. The huge surplus of capacity has meant that the LOLP payments have been low, so coal and oil based plant tend to be pushed down the merit order and off base load. The introduction of the price cap and subsequent short term loss of nuclear capacity has altered the way in which the mechanism is used encouraging the bidding of a portfolio of plant rather than the most efficient. There is no guarantee that this pattern will continue. The pool pricing system does not relate comparative environmental impact of production in the price of power either. There is no mechanism to reward low emissions from gas fired plant or the investment made in FGD.

The problems for the companies owning coal and oil fired equipment are still being exacerbated by the approval of new combined cycle gas fired plant within a market driven economy. This new capacity could only be operated at the expense of the older coal or oil fired plant. Even so, there is some doubt as to whether the merit order is being set by marginal generating costs or whether by the contractual arrangements e.g. "take or pay" which have been negotiated on some of the fuel supplies and on electricity supply agreements thereby effectively overriding the economic decision.

There is a range of options which minimise capital but offer an environmental improvement to existing combustion plant. What level of environmental improvement will be sought within the terms BATNEEC and Best Practical Environmental Option (BPEO) and how the division of national emission targets will be related back to companies and individual plants remains uncertain. The report will attempt to address these issues.

The importance of environmental limits also needs to be set in the context of the European and the US projections for replacement generating capacity. The recent UNIPEDE paper indicated an increase in electricity demand in the EU of 120 GWe up to the year 2010 and a need to replace 100 GWe of ageing capacity making a total of 220 GWe over the next 15 years. The USDOE outlook sets a range over the same period with a low forecast of 153 GWe, a high of 484 GWe and a mid-point of 279 GWe. Again much of the US demand stems from the age (and comparative inefficiency) of the existing stock. Consequently, the environmental constraints which are set for this new capacity becomes critical because much of that equipment will still be operational in the year 2040.

UK utility companies will therefore need to understand the factors which define BATNEEC, BPEO and the air quality goals which are being set. Similarly, the EU utilities will be awaiting the results of the LCP Directive review and any local response to set more stringent limits such as the German concept of an electrical conversion efficiency hurdle for new plant.

3.0 RECENT TECHNOLOGICAL DEVELOPMENTS

3.1. CCGT

Major advances in the size and efficiency of large gas turbines took place during the 1980s. The main manufacturers, GE, Siemens, ABB and Westinghouse all developed turbines with a power output in excess of 200 MWe which were tested commercially in many countries. Units such as the GE Frame 7 and 9F, along with the Siemens, Westinghouse and ABB equivalent models have now proved their reliability. Availabilities of 99.2% on line over a period of two years continuous operation are typical of their performance.

The exhaust temperature is sufficiently high that a heat recovery boiler can be installed to generate high quality steam. This can be fed into a steam turbine enabling the two turbines to operate in series or combined cycle mode. The use of the two turbines in series elevates the thermal efficiency to a current typical figure of 55% LHV operating on natural gas.

Two other features which add to the commercial attraction of the system are the low capital cost and the speed of construction. To illustrate these points, National Power recently received a bid at £300/kW for Didcot ($480/kW) which is very competitive when figures of $700-750/kW were being quoted as typical only one or two years ago. Fierce competition continues and recent bids in SE Asia have been reported at around $400/kW.

A good example of construction time would be a recent plant in South Korea which was reported in the technical press. GE built a 1900 MWe unit in 26 months from order. The first turbine was operating in open cycle mode to generate power within 7 months firing natural gas while all 8 gas turbines were operating after 1 year. The heat recovery boilers were being constructed in parallel and the combined cycle operation began after 26 months. Hence the investors received a revenue stream after only 7 months which ramped up to about 65% of total output in a year, the remaining 35% coming on line after just over 2 years. CCGT systems are very compact because the combustion turbine itself effectively generates the power equivalent of a large boiler in a fraction of the space.

In the UK, the National Grid 7 Year Statement shows some 27 GWe of CCGT capacity in the state of "Transmission Contracted" since vesting and this development will be discussed in more detail. A significant portion of the capacity is either operating or under construction.

It is clear that the technology is now widely accepted as a commercially attractive way to generate power from natural gas. A recent FT article reported a Siemens analysis of market trends which indicated that from their statistics, some 37% of all new power plant throughout the world ordered over the past decade had been CCGT equipment. The article also carried an announcement that Siemens had developed a new turbine with an efficiency of over 58% LHV operating in combined cycle mode on natural gas incorporating technology resulting from their cooperative agreement with Pratt and Whitney. ABB has introduced the GT24/26 turbines recently and an article in the summer 1994 edition of Europower cited an LHV efficiency of 58.5% again in combined cycle mode on natural gas. Two units in Sweden and one in Japan had already completed 20,000 hours of operation.

GE recently announced their latest development of the "H" series turbines with a thermal efficiency of 60% LHV operating in combined cycle mode on natural gas. The increased efficiency and power output is achieved by reducing the temperature differential between the combustor and the lead blades and this has been done by replacing air cooling of those blades by closed circuit steam cooling with a turbine inlet temperature of 1430°C instead of the 1270°C of the Frame 9F. This not only boosts the power output but also will reduce the unit capital cost because the power is achieved at little extra total capital cost.

Thermal efficiency is set to improve still further. The designers are attempting to maximise the "firing" temperature, i.e. the temperature measured between the first stage nozzle and the first stage bucket, to maximise the extractable energy. This has to be achieved while minimising the combustor temperature to minimise NOx formation. The limitation on "firing" temperature is simply one of metals or rather construction material. All the manufacturers appear confident that a combined cycle efficiency in excess of 60% LHV is achievable on natural gas by the end of the decade. The US advanced gas turbine programme was also mentioned at the EPRI Gasification Conference (Todd D.M., Joiner. J.R. 1994, Bechtel T.F. Bajura R.A. 1992). An article in International Power Generation (Nov 1994 - Singh, Prof R.) states that "combustion efficiencies (i.e. combined cycle power generation efficiencies on natural gas) are likely to rise to 65%. Advances to the gas turbine cycle may incorporate recuperation, intercooling and advances in the steam cycle."

The gas turbine itself is inherently flexible and can utilise clean synthesis gas from a gasifier. In fact, with some air compressor/turbine configurations such as that of the GE design, there is an increase of 10-15% (20-25% on the "H" unit) in the shaft power versus natural gas because of a reduction in the power required by the compressor and increased mass flow (Todd D.M. 1993). GE's annular burner system has already been proven on synthesis gas at Cool Water and the Westinghouse turbine at Plaquemine while Siemens has recent operating experience at Buggenum.

Consequently, the CCGT system appears to have a clear advantage for the foreseeable future. The only questions are whether the price of natural gas will remain stable enough to be the fuel source and whether synthesis gas, especially from refinery residues or Orimulsion, could enter the market and compete. There seems little doubt that natural gas prices will rise in some parts of the world and the US, for example, envisage the retro-fitting of gasifiers to CCGT plant when economic. In fact, papers have been given illustrating what they describe as "phased construction" which assumes the step-wise development taking advantage of the low prices of natural gas while they continue but with the flexibility to add the gasifier.

3.2 Ultra-Super Critical Steam Technology

The power industry has relied on steam for over 110 years so there is a considerable reluctance to give up a well proven technology if it can be adapted and stretched to perform even better on the fuel upon which the industry has depended so heavily in the past, namely coal. The boilermakers have a commercial incentive to retain steam because the construction of large boilers has been their life-blood. Every 500 MWe coal fired boiler would require the fabrication of over 100,000 tonnes of steel most of which would have to be assembled on site over a period of few years. In contrast, the gas turbine is factory built in a fraction of the time and the simpler heat recovery boiler associated with the "combined" cycle would not require more than 10,000 tonnes of steel, much of which could be pre-fabricated.

The steam cycle is constrained by a theoretical efficiency limit. Nevertheless, the generators are reluctant to give up proven technology for any new systems although they have now accepted CCGT technology. The boilermakers' counter to CCGT has been to stretch the steam cycle to its limit. The ultra-super critical design of boiler has been introduced which harnesses the remaining potential of the Rankine cycle. The key elements of the newer designs are thin walled tubes of special steels capable of operating at higher temperatures and very high steam pressures. Improved heat exchange and a double reheat circuit has also been introduced with corresponding modifications to the steam turbines.

Japan has built boilers for these conditions but initially opted to operate on LNG to minimise the risk of tube fouling and damage although a coal fired plant has now been built. US utilities and the CEGB tried super critical boilers during the 1970s but experienced reliability problems and reverted to sub-critical steam conditions. Denmark became the first country to commission the newer design of European supercritical boiler in 1984 to fire coal and followed in 1991 with another more advanced design at Fynsvaerket with a power plant efficiency of 42% LHV. The next boiler to be built there was also designed for ultra-super critical steam conditions. It was Elsam's Esbjerg 3 Advanced Power Plant using a 370 MWe coal-fired boiler by Stein Industrie of France. An overview of performance was presented at an EPRI Conference in Santa Barbara in February 1993 (Noer, M). The operators claimed a 45.3% net efficiency. Another article on the subject was published by Elsam (Blum, R., Kjoer, S. 1993) to illustrate the steps the company was taking in response to the direction by the Danish Parliament that Elsam are required to achieve a 20% reduction in CO_2 by 2005 from a 1988 base year.

A new CIAB Report entitled "The Current Status and Survey of Industry Attitudes to Steam Cycle Clean Coal Technology" suggests a figure of 44% LHV as the "normalised efficiency". This represents an adjustment which sets the performance at "normal" ambient operating conditions i.e. atmospheric temperatures. This was considered necessary because under Danish winter conditions, (ie. very low cooling water temperatures), Esbjerg 3 has achieved an efficiency of 46.1%. A further unit is planned for Aalborg for start-up in 1998 at a normalised efficiency of 48% *(see below). An article published recently on these designs (Sharman, H. 1994) suggests that the measurement is taken ahead of FGD and DENOX control which would reduce the efficiency by at least 1-2% dependent on the sulphur content of the coal and the power consumption of the whole emissions reduction system.

Elsam, the Danish utility group owning the Esbjerg plant, set out the components of the gain in efficiency for the Esjberg 3 ultra-super critical boiler versus more traditional steam conditions in the following terms:-

Efficiency Gain	
Double Reheat	2.0%
Higher Steam Pressure	1.0%
Higher Steam Temperature	1.0%
Better Vacuum	0.3%
Better Boiler Efficiency	0.5%
Total Gain	4.8%

Consequently, the steam conditions per se contribute less than 50% of the total gain. It should be added that the above designs also assume a coal quality which has been established over many years in the Danish utilities' purchasing strategy. The sulphur would not exceed 1% and more typically would be 0.7% with ash most probably less that 10%. The sulphur level would set an upper limit to the internal power consumption for the operation of FGD equipment. The CIAB Report drew attention to the benefits of the double reheat circuit but added that there is a capital cost penalty and a loss of operating flexibility at part or fluctuating load. Consequently, the economic decision would have to be based on site specific and total system data information outside the scope of this review.

SK Power, the other large Danish generating company, has undertaken a design study for a new 425 MWe coal-fired plant in Zeeland for a 1998/99 start-up (Noppenau, H. Hansen, S. 1994). Although it will operate with ultra-super critical steam conditions, the high conversion efficiency results from the use of an aero-derivative 120 MWe gas turbine operating on natural gas with its own generator. Instead of a heat recovery boiler, the heat from the gas turbine exhaust is to be used to preheat the boiler feedwater to 310°C for the main coal-fired boiler. Their estimated design efficiency is not given in the paper but is expected to be in the 48-50% LHV range. This is of course another approach which achieves a high thermal efficiency while limiting the use of natural gas and retaining a substantial portion of coal in the fuel mix. The decision to focus on coal is a key part of company strategy.

The major advantage of the technology is its user appeal i.e. it meets the needs of those utilities who wish to remain cautious about technology. The utilities who contributed to the CIAB report have signalled their apprehension about new technology e.g. IGCC and wish to see it fully demonstrated before they adopt it. The steam cycle, and the limited degree to which tried and trusted technology can continue to be used with modifications, still retains its appeal. The addition of a gas turbine to the steam cycle via feed water preheat offers thermal efficiencies in the same range as advanced IGCC without the risk which the utilities perceive in the gasifier. However, the CIAB report, which is based on a substantial questionnaire to the world's major utility companies, comments that steam technology will come under increasingly competitive pressure from natural gas fired units (CCGT), IGCC and PFBC within a decade in Western Europe and Japan. There is also likely to be some limitation on the fuels which can be combusted in ultra-super critical boilers. High temperature corrosion from the metals in heavy oils and Orimulsion can occur and may well limit such fuels to the lower efficiency boilers operating at sub-critical steam conditions.

A recent paper by the Chief Executive of VGB of Essen (Schilling, H.D. 1993) summarised the position regarding steam only systems. Studies by VGB assessed the limits of steam at 46% LHV at best and 47% LHV in the very extreme. Efficiencies beyond that point had to come from the combination of a steam cycle and a gas turbine.

The key question about new combustion or topped combustion systems is whether the emission levels can be achieved economically and whether there will be outlets for the by-products e.g. of flue gas desulphurisation products and PFA in the longer term. Germany has the largest yield of by-products in Europe but has had to develop outlets to absorb the make without resorting to land-fill. As in the Netherlands, the landfilling of the wastes from coal fired plant is either banned or discouraged so markets/processes for the material are necessary to accommodate the material in the building and construction materials industries.

There are no technical limitations to the use of ultra-super critical steam conditions in the heat recovery systems of CCGT or IGCC plant so there is a potentially wide application.

3.3 Atmospheric Fluidised Bed Systems

The development of atmospheric fluidised combustion flourished in the 1980s with a wide range of industrial boilers becoming commercially available in size ranges up to 100 MWt. Very few of these boilers would have been used for the generation of power other than in CHP systems. Efficiencies of around 38% LHV were typical where used for power. Over 200 units have been sold designed by companies such as Lurgi, Ahlstrom Pyropower and Stein Industrie. More recently, the size range has increased and designs for power plant boilers up to 280 MWe have been undertaken with improved thermal efficiencies of up to 44% LHV. The Emil Huchet and the Gardanne plants in France are typical of this new generation of design.

This type of boiler is particularly well suited to poor quality fuels. In the case of the two French plants, the first is operating on fine coal taken from a lagoon linked to an old coal wash plant where over 25 year of fuel still exists. The Gardanne unit is based on local high ash coal. The advantage of the system is that heat is not lost in melting the ash. The offset is that the ash and the sorbent (limestone) are mixed and the solid waste does not find a ready commercial market usually being routed to land-fill. An added disadvantage of the system the presence of some residual free lime. Under atmospheric conditions, the limestone is converted into lime which is the active sorbent. At the S/CaO ratios needed to capture SO_2, some free lime will remain in the solid waste, exacerbating the disposal problem.

Another drawback attributed to AFBC is the formation of nitrous oxide, N_2O. The lower combustion temperatures of the fluidised bed system reduces thermal NOx to a very low level. However, some of the fuel-bound nitrogen is released resulting in lower NOx emissions than on corresponding pf-fired coal plants with typical levels from commercial AFBC plants in the 100-150 ppmv range without any control equipment (Takeshita, M. IEACR, 1995). AFBC produces appreciable amounts of N_2O which may be the only major source of N_2O emission among the coal based technologies. Concentrations in the flue gas are generally in the 50-100 ppmv range on commercial plant burning coal although higher emissions have been measured in pilot plants. Some early results of N_2O emissions were suspected to have been inflated by sampling error but the data cited in the Takeshita report is based on approved test methods. By comparison, the emissions of N_2O from pulverised coal firing would be in the 0.5-2.0 ppmv range.

The IEA report added that "N_2O emissions have been overlooked for a long time because N_2O is not regulated in any country. However, in recent years, N_2O has been publicly recognised to be a potent greenhouse gas and to play a crucial role in regulating the stratospheric ozone layer (WMO, 1992)".

The technology has a role with low grade fuels but there would appear to be more attractive technologies such as PFBC when a higher quality of fuel is available.

3.4 Pressurised Fluidised Bed Systems

The lead in the development of Pressurised Fluidised Bed Combustion technology has been taken by ABB Carbon in Sweden. PFBC plants are now operating on coal in Sweden, Spain, the USA and Japan. By February 1994, over 35,000 operational hours had been achieved using the system and further orders for the plants are starting to flow because of the efficiency, environmental benefits and cost (Jansson, S.A. 1992/3/4)

The designers claim a thermal efficiency benefit of 10-15%, ie. 42.5% vs 38% LHV, over conventional state-of-the-art coal fired plants including FGD (but that comparison excluded the Danish ultra-super critical performance).

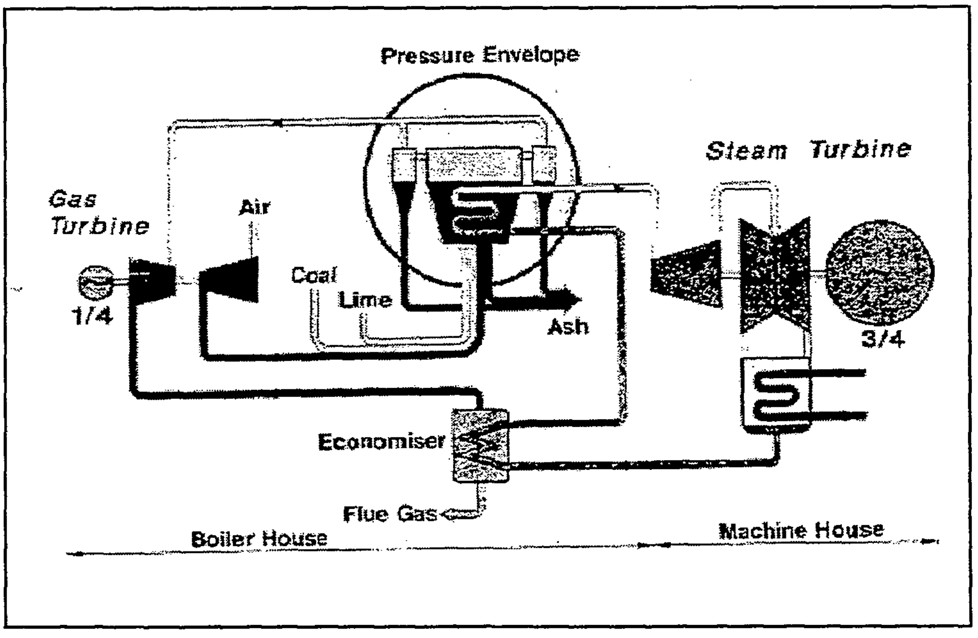
The early designs were of a module of about 85 MWe and four units are operational. The design was scaled up to 360 MWe and the first is on order for Japan with commercial operation beginning in 1997. Other utilities are evaluating this design at the currently available size along with a design of 720 MWe. These designs are expected to achieve a higher efficiency at 44-45% LHV.

ABB would claim that they pioneered the technology and could be considered to be the market leader with their bubbling bed technology. Other companies have recognised the potential and have developed their own designs. Those companies include Lurgi, Lentjes, Deutsche Babcock, Ahlstrom Pyropower, Foster Wheeler, Hitachi and Mitsubishi Heavy Industries. Lurgi, Lentjes, Babcock are working jointly with a circulating bed design while Ahlstrom has also chosen the circulating bed system.

Brief Description of Equipment

The system has three main parts:- the fluidised bed boiler placed inside a pressure vessel; a gas turbine expander coupled to air compressors and a generator; and a steam turbine with its generator (see Figure 1).

Figure 1



First Generation PFBC

Source: ABB Carbon

Coal and the sulphur sorbent (limestone or dolomite) are injected into the fluidised bed either as a water-based paste using concrete pumps or by a pneumatic system and lock hoppers. The combustion process takes place under pressure. The combustion gases from the boiler pass through cyclones where more than 98% of the particulate is removed before they are expanded through the first turbine (expansion turbine).

Steam is generated in the boiler which supplies conventional steam turbines. ABB Carbon would quote thermal efficiencies of 45% on an LHV basis or 41% HHV indicating a performance about 4 percentage points better than the standard sub-critical pulverised fuel fired boilers. ABB state the sulphur capture is about 90% and very low NO_x levels have been achieved on the Swedish plant. This is understood to have been possible because of the addition of a gas polishing or DENOX step which could be added to any of their designs.

ABB claim the following points in favour of PFBC technology on coal:-

- the sulphur is absorbed in the bed by the formation of calcium sulphate and without calcination of the limestone to form calcium oxide (for detail see Section 7)

- the capital cost of the first generation plant was at parity with PF fired capacity fitted with FGD and 20% lower than ABB's estimates of 1st generation IGCC. Their fifth plant which is already being built, is claimed to have a 20% capital cost advantage over PF plus FGD, lower fuel costs due to improved efficiency and lower maintenance costs

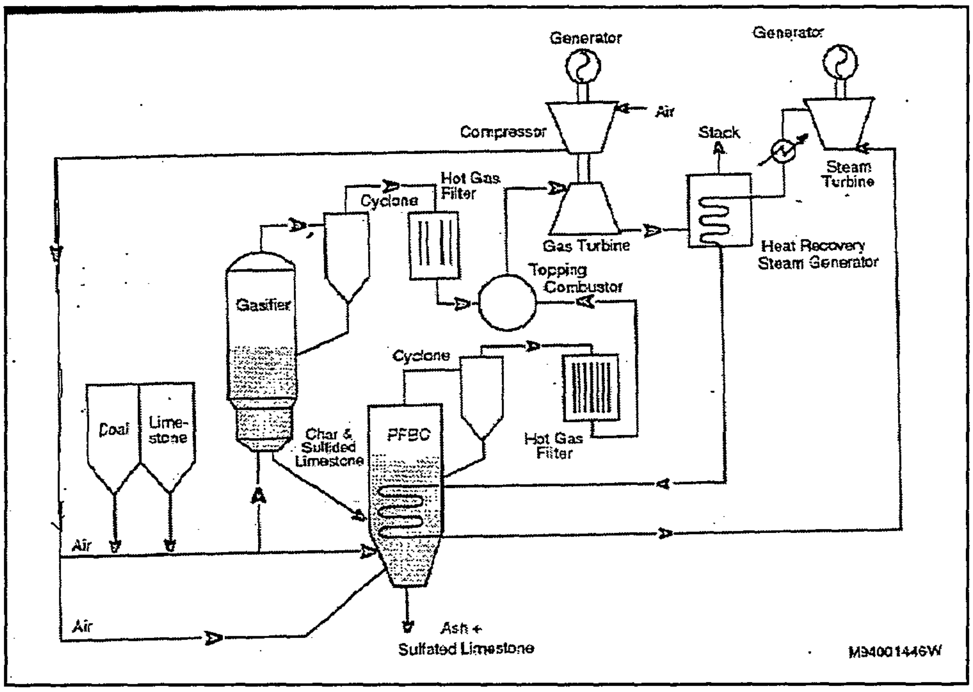
- a key marketing advantage is that it remains a boiler and is sold as a complete power generation system by a single manufacturer who will guarantee performance. This appeals to many utilities who are intuitively pro-steam

Pressurised circulating fluidised bed systems as developed by the Lurgi, Lentjes, Babcock group appear to offer some interesting alternatives to the bubbling bed ABB system. The recirculation of limestone improves sulphur capture and limestone usage. The gas cleaning system also enables the gases to be expanded in a standard gas turbine (e.g. Siemens V94.3) compared with the Stal-Laval design tailored to handle the particulate content of gases in the ABB design.

The PFBC design generates 15-20% of its power on the expansion turbine and 80-85% on the steam turbine. The technology can be taken further using hybrid designs to increase the power from the expansion turbine. Adding a topping cycle is one possibility. This can be achieved by building an external partial gasifier so that a proportion of the coal is converted to a fuel gas which is fed back to the boiler for over-firing or it is combusted separately in a modified turbine. Close bed temperature control is essential with over-firing in order to avoid approaching the ash fusion temperature of the coal and the possible agglomeration of the ash in the bed. The char from the gasifier is introduced to the boiler mixed with the fresh coal feed. The flow-plan is shown overleaf in Figure 2.

The hybrid technology has the theoretical potential to raise the thermal efficiency of the system to around 50% LHV. The PFBC system has competitive appeal as an option for new capacity based on coal. The capital cost of the ABB system is now down to about $1000/kW although this is still more than double the cost of currently available CCGT systems in the UK and the South East Asia. Nevertheless, it would appear to be a serious contender with utility companies who wish to use coal and do not wish to operate large gasifiers.

Figure 2



Second Generation PFBC

Source: USDOE

3.5 Gasification and Integrated Gasification Combined Cycle

The development of Integrated Gasification Combined Cycle (IGCC) systems has been accepted as an interesting concept for many years but is considered complex, capital intensive and insufficiently proven to be commercially acceptable by most utility companies. Over the past four years, projects have received approval and funding albeit that over half of the current projects have some form of financial assistance to provide the economic support for "first of a kind" installations.

It took some time from the initial project in Cool Water (1984) and the commercial facility at Plaquemine, Louisiana (1987) for the technology to be accepted, but on both sides of the Atlantic projects are being progressed on solid feedstocks - mainly coal - to generate power very cleanly and efficiently. Over the same time-frame the combined cycle gas turbine system has gained complete commercial credibility while in the chemicals industry, gasifiers have been operating on solid and liquid feedstocks for up to 30 years. The integration of these two processes is therefore not as complex as it might appear to be. Furthermore, the degree of integration is a function of economics. There is a trade-off between the thermal efficiency advantages of integration and the capital costs associated with achieving it. In Europe, the two key projects of this type are highly integrated. They are the Dutch demonstration plant at Buggenum and the Spanish project at Puertollano, the latter being supported by EU funding.

The process can best be considered as a CCGT plant with a dedicated gasifier producing the gaseous fuel for the gas turbine. The gasifier converts the energy contained in any carbon-based feedstock - coal, heavy oil, petroleum coke, lignite or Orimulsion - into a clean gas.

The most feedstock flexible of the gasifiers is the entrained design of which the Shell and Texaco are commercial examples, the former having two designs for solid and liquid feeds. Destec (formerly Dow) and Prenflo are also entrained gasifiers designed for solid feedstocks such as coal.

The fixed bed British Gas/Lurgi slagging gasifier, which has been proved during extended operation at Westfield in Scotland in the 1980s, has some interesting features. It has been designed for a lump coal feed and the gas cooling medium is the incoming raw feed which overcomes the problem of heat recovery boilers. It then produces tars which are recycled to extinction. Some fine coal can be introduced via the tuyeres which feed the oxygen into the bed. Petroleum coke could be substituted for coal while heavy oils or Orimulsion could be introduced along with the recycled tars giving the gasifier flexibility.

The design uses less oxygen than the entrained gasifiers and has a higher carbon conversion but requires a significant portion of its feedstock in solid form. It also produces a slightly higher heating value gas than the entrained designs because some 6% of methane is produced along with the hydrogen and carbon monoxide which also makes it an attractive source of gas for fuel cells.

The cooling of the hot gases by incoming feed eliminates the need for heat exchange and the generation of steam at the gasifier. Consequently, if the gasifier was used to generate power, some 70% of the power would come from the gas turbine, the balance from a steam turbine fed with steam from the heat recovery boiler on the exhaust of the gas turbine only. Integration is therefore not essential because the gasifier is capable of operating independently of the combined cycle gas turbine system. They need not even be on the same site because the product gas could be routed to the generator by pipeline. Hence the danger of the acronym IGCC for a range of possible process flows which are better described as gasification combined cycle systems.

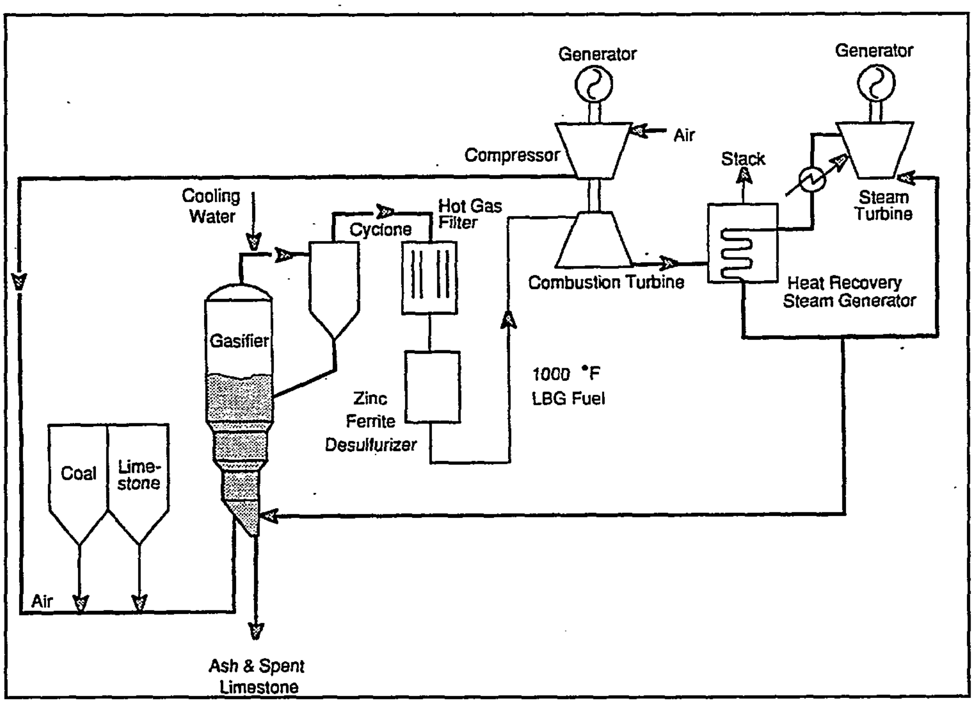
The Destec gasifier (Dow original design) at Plaquemine is a two stage entrained system with a portion of raw feed entering the second stage as a partial cooling step. To an extent, it adopts the British Gas concept of gas cooling in an entrained design. It has been selected for the Wabash River repowering project in the USA.

Fluidised bed gasifiers are also being examined for the conversion of bio-mass. Air blown systems are needed because of the reactive nature of the feed material. Results both in Sweden and Finland are encouraging particularly the Enviropower system being developed by Tampella (Bridgwater, A.V. & Evans, G.D. 1993). Air blown gasifiers have also been evaluated for fuels such as lignite and coal. The Air Blown Gasifier Cycle (formerly the British Coal Topping Cycle) has been conceived to eliminate the need for an air separation plant and regain the energy lost in operating an ASU. However, conference papers such as Simbeck, D. 1994 and Sheikh, A. 1995 suggest that there are some significant advantages in the use of oxygen and the elimination of nitrogen through the gas clean-up stage of the gasification process for the higher carbon content fuels.

Gasification is a basically simple process. The process is described in detail in Part 2 (Section 6.1 and Appendices). In summary, it is a partial oxidation process which converts most of the carbon to carbon monoxide and hydrogen while releasing the sulphur in the feedstock as H_2S. There are options at the cooling stage in entrained and fluid bed gasifiers i.e. the extraction of heat from the raw gas prior to the gas scrubbing system. The gases can be routed through a heat recovery boiler to generate steam or quenched in some way such as passing through water.

Until hot gas clean-up techniques are fully developed, as shown schematically in Figure 3, the current type of gas cleaning requires the gas to be cooled and processed in a wet scrubbing system usually based on a family of ethanolamine sorbents. These scrubbing processes have been standard in the oil industry for the past 50 years for the removal of H_2S from refinery process gas streams. The sorbent captures the H_2S at very high efficiency using fully regenerable reagents which absorb the H_2S when cool and release it on heating. Fuel-bound nitrogen is released primarily as gaseous nitrogen with some small quantities of ammonia which are extracted during scrubbing process. Particulates are also removed and filtered from the system. Consequently, a very clean fuel gas is produced which can then be fed to the gas turbine. The only gaseous emissions are those from the gas turbines i.e. NOx, which is now very low because of the techniques developed for the new designs of combustor on the gas turbines.

Figure 3



Second Generation IGCC

Source: USDOE

At the October 1994 EPRI Gasification Conference, several projects which are operating or in progress were reviewed (papers are listed in Bibliography). The application of gasification to the imminent problems of the oil industry in many parts of the world has stimulated the interest of refiners in the technology. There has been a tendency, particularly amongst utility companies, to think of IGCC as a coal or solid fuel based technology. The Conference reiterated that gasification has much broader application because the process is flexible and can convert any carbon-based feedstock to a fuel gas. Texaco mentioned that the gasifier can accommodate quantities of waste plastic or sewage sludge along with the primary feedstock as a method of safe destruction of these streams. At the conference there was very considerable interest in the rate at which commercialisation of the technology is now taking place.

GE gave a joint paper with Fluor Daniel on the application of IGCC to power generation. The study drew supplementary data from Destec (Plaquemine) and Air Products. They compared IGCC with conventional coal technology i.e. pulverised fuel on a cost basis and concluded the following:-

1990s IGCC	-	Plant costs higher
	-	Power generation costs similar
	-	Credits for IGCC features can produce lower capital and power costs
2000+IGCC	-	Plant costs are not higher
	-	Power generation costs lower without credits

Note: The credits being mentioned relate to the virtual elimination of SO_2 and particulate emission and very low NO_X levels, Furthermore, the CO_2 levels would be the lowest available using coal or most other fuels. CO_2 emissions could only be reduced further by the use of natural gas.

The study was undertaken from a US stand-point considering coal as a feed stock. In Europe, there has been a growing interest in gasification as an adjunct to oil refining. The demand for heavy fuel oil is declining and forecast to decline further while the demand for transport fuels grows. Consequently, the refiners are evaluating processes which convert heavy residues to hydrogen and clean fuel gas and this will be discussed in Section 5. In Italy, IGCC based on heavy fuel oil is also being pursued as a means of converting the oil currently used as a boiler fuel by ENEL into clean power. This is considered to be a more economically attractive route to produce clean power that retro-fitting their old boiler stock with FGD. The Italian Government has sanctioned a fixed electricity price for 8 years to provide an incentive for the investment and many refiners have responded.

Shell has also given a lead at their Pernis refinery in Rotterdam and is in the process of installing a 500 MWe equivalent gasifier (de Jong. T. 1993, Higman, C. Eppinger, M. 1994). Several other projects are approved or are at an advanced stage of development in Italy, Finland, Portugal and Spain.

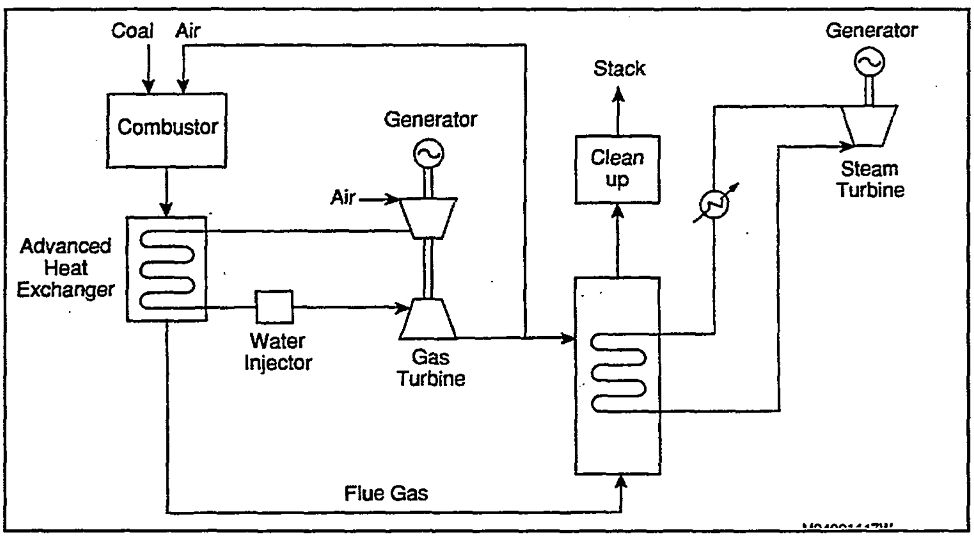
Gasification is also being considered for non-fossil fuels. Fluidised bed gasification would appear to be a potentially attractive route for the processing of bio-mass and selected lower heating value waste streams. Oxygen blown entrained gasifiers may be needed to extract the energy from the more complex wastes such as plastics, old tyres and spent lubricant where the more molecular structure and the nature of the contaminants need to be separated and extracted. Texaco has prepared several papers on this subject (Miranda, J.E. 1988).

3.6 Externally Fired Combined Cycle System

The EFCC belongs to a class of indirect-fired cycles used for power generation that feature the ability to handle ash-bearing fuels to produce energy as cleanly and efficiently as oil or natural gas-fired systems. The externally-fired cycle is an old concept in which an open Brayton cycle is used to convert thermal energy to electric power. The EFCC is inherently more efficient than a direct-fired gas turbine combined cycle because some of the turbine exhaust energy is returned to the topping part of the cycle instead of being used by a less efficient steam turbine. The cycle can accommodate a range of fuels, and the combustor can be modified to handle those fuels.

The EFCC system uses a combined cycle that transfers the heat produced by say coal combustion directly across a high-temperature heat transfer surface to generate a clean-air working fluid to the gas turbine. The hot flue gas is cooled and cleaned by an advanced flue gas clean-up system. Steam raised during flue gas cooling drives a steam turbine. This technology is well suited to taking advantage of technology improvements such as higher temperature heat exchanger and turbine components. It uses conventional generating practices thus making it readily acceptable commercially, particularly for some repowering applications. The configuration of the EFCC product system are shown in Figure 4.

Figure 4



Externally Fired Combined Cycle System

Source: USDOE

The successful demonstration of a reliable ceramic heat exchanger is critical to the success of this technology. Since 1987, the USDOE has provided cost-sharing support to a 21-member industrial consortium led by Hague International of Portland, Maine, to demonstrate a ceramic heat exchanger that will produce heated air at 1850 to 2300°F (1000-1?C) for use in gas turbines. This project, involving the construction and operation of a 2.5 MWe test system at Kennebunk, Maine, integrates a pulverised coal burning, low NO_X burner with a ceramic and metallic heat exchanger system.

A 62 MWe EFCC-based repowering project is also currently being negotiated with Pennsylvania Electric Company (Penelec) as part of the fifth CCT Programme. The proposed project would be built in northern Pennsylvania. Other participants beside the USDOE and Penelec are Black & Veatch, Hague International and Westinghouse.

3.7 Hybrid Systems

In Section 3.3 on PFBC, the use of a Topping Cycle was mentioned; this concept of adding an ancillary feature to a basic technology has been given the generic term "topping". A number of companies are developing ideas which fall within the definition and several are examining the partial gasification of coal as an adjunct to coal fired boiler systems.

The British Coal Topping Cycle concept (now renamed the Air Blown Gasification Cycle) is an air blown system in which the partial gasification stage produces a gas which is cooled and cleaned with ceramic candle filters for combusting/expanding in a turbine. The hot finely divided char and residual limestone sorbent are fed to an atmospheric fluidised bed boiler to generate steam for the steam turbine. A primary objective of the air blown system is to save the investment in an air separation unit and the loss of efficiency resulting from its internal power consumption. However, the offset is that much more gas has to be compressed and then handled through the system because of the nitrogen content of the air of about 80%. This enlarges the equipment required particularly the gas clean-up section. The ABGC concept is at the "large pilot" stage in their laboratories.

ABB has proven the PFBC system and sees topping as a further stage in efficiency improvement with few technical problems associated with annexing a partial gasifier to a boiler. It has been described above as the 2nd generation PFBC. The subtle differences between the ABB and ABGC systems are that ABB combust the gas in the PFB boiler outlet and take the char into the raw coal feed system of the boiler, whereas the ABGC design combusts the clean gas in the gas turbine and through a solids transfer system route hot char to the boiler as the only fuel.

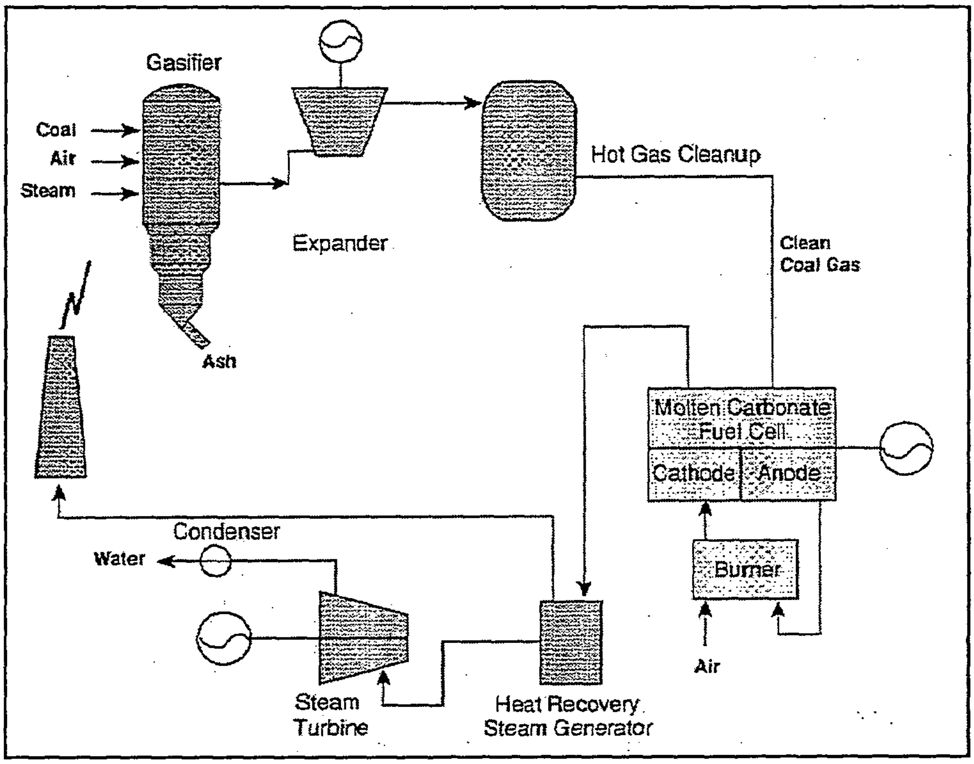
Another approach to "Topping" is the harnessing of the gas turbine and conventional steam cycles operating on different fuels. The Danish plant mentioned previously in Section (3.1) falls into this category. They anticipate gaining a further 2-3 percentage points of thermal efficiency in this way bringing the overall efficiency to the 48-50% LHV range. Again, this is a low-risk route to gain efficiency improvements and one which is familiar technology to the utilities and so one that they would more likely accept. Nevertheless, these step-out developments point towards the need to add the advantages of gas turbine technology to the steam cycle. The variations on the theme appear to stem from the wish to retain commercial control among the traditional power industry suppliers rather than allow the gas turbine manufacturers to penetrate their market too deeply.

3.8 Fuel Cell Systems

Fuel cells generate electricity directly from the electrochemical reaction of hydrogen and oxygen. Phosphoric acid based cells are already sold commercially in the States as a 200 kWe package. Molten carbonate and solid oxide cells are also being developed for demonstration at the 200 kWe and 2 MWe scale this year. Developments by MC Power Corp, Energy Research Corp and Westinghouse in the USA along with Dutch and German companies are all close to market entry.

In the US, test work is already under way on 100 kWe units using gas from the gasification of coal as a fuel gas for the cell. This work is taking place alongside the Plaquemine gasifier in Louisiana. The flow scheme envisaged by the USDOE for application in 10-15 years is illustrated in Figure 5 for an Integrated Gasification Fuel Cell (IGFC).

Figure 5



IGFC

Source: USDOE

Their paper (Morgantown Energy Technology Centre, 1994) reinforces the view that the carbon based fuel needs to be converted to gasification and the clean gas then used in the most efficient way possible.

3.9 Flue Gas Desulphurisation

FGD is being included in the section of competitive technology because the use of scrubbing systems offers a way to continue the operation of existing combustion plant while meeting sulphur emission legislation. It is also seen at the most logical (and possibly economic) way to retain steam systems by controlling emissions.

The application of FGD technology expanded rapidly during the 1980s and the trend is expected to continue. Equipment has been installed in 18 countries and as of June 1994 over 168 GWe of capacity had been completed. A further 107 GWe is planned or under construction in 9 other countries.

The IEA Coal Research FGD Handbook of June 1994 offers a status report on installations and technologies. It covers coal fired stations on a global basis and reviews the wide range of processes which have evolved to capture SO_2 alone or SO_2 and NO_X simultaneously. A previous report also listed FGD which had been installed on generating capacity other than coal - particularly oil in the few countries who use fuel oils for power production eg; Japan.

The Handbook has classified the available systems into 6 main categories:-

- wet lime/limestone scrubbers
- other wet scrubbers
- spray dry scrubbers (semi-dry systems)
- sorbent injection processes (including dry scrubbers)
- regenerable processes (SO_2 removal only)
- combined SO_2 /NO_X removal processes.

FGD systems can now be designed for coal plant to remove up to 95% SO_2, have high reliability, operate with reduced power consumption and produce a marketable product if required. The regenerable processes produce sulphuric acid or elemental sulphur and therefore may require an assured market - especially for the former. The most widely used system is the wet lime/limestone scrubber with forced oxidation which produces marketable gypsum suitable for plaster, cement and wallboard. The capital cost of FGD has fallen but remains about 20% of the capital cost of a power plant in the range of $200/kW. The Handbook then gives flow plans of over 170 different systems and suppliers with details of the rapid development of post-combustion clean-up over the past decade applied to conventional combustion technology.

Another approach to the use of limestone which has been developed by Lurgi is the circulating fluidised bed desulphurisation system. The basic chemistry is broadly similar to that of the wet limestone systems but a number of advantages are claimed e.g. the simplicity of the process, lower space requirements, a dry by-product, little or no reheating of flue gases, more than 95% desulphurisation and complete removal of SO_3. It is a dry process which enables the limestone to be re-circulated for optimum utilisation and sulphur capture. The product is calcium sulphate in the hemi-hydrate form. This form of byproduct can be mixed with water to form a material with a compressive strength similar to that of lightweight concrete and a permeability to water which is less than that of clay.

A significant advantage of the complete SO_3 absorption makes this technique an attractive option for the treatment of flue gases from the combustion of heavy oils or Orimulsion. The combustion of these products is likely to lead to the formation of SO_3 and micron size acidic aerosol because of the presence of fine particulate vanadium and nickel. SO_3 is said to be difficult to absorb in wet limestone systems. The tell-tale sign of SO_3 emission is a silvery-blue plume from the stack.

A new design not mentioned in the IEA survey is a "bio-technological" process developed by Hoogovens, the Dutch steelmakers. They have designed a system which absorbs the SO_2 in water to form sulphites. This liquid stream is then processed in an anaerobic reactor to convert the sulphites and any sulphate present to hydrogen sulphide. The sulphide is then converted in an aerobic reactor by micro-organisms to elemental sulphur. Pilot plant work suggests that the efficiency of sulphur recovery could be as high as 98% and that the capital and operating cost should be 30% lower than limestone/gypsum systems. A demonstration plant is being built to be commissioned by the Summer of 1995 and the developers are optimistic that they have a very attractive approach to handle flue gases in a manner which minimises the volume of the main pollutant - sulphur. The process is also relatively fast so the size of the vessels needed are claimed to be smaller than those required for limestone /gypsum thereby saving land.

If the Hoogovens system proves to be as attractive as the test-work suggests and they have a process which could be installed at a cost lower than that of the mainstream FGD processes, it may represent a breakthrough in post combustion control. If it can be achieved without the need to extract limestone or produce a bulky waste product, it is even more attractive and could be a significant advantage which assists in the retention of combustion based systems.

There are other lower capital cost systems available which may have application where a plant has a limited life or is operated on intermediate load. These will be mentioned in the "Modification and Refurbishment" options in Section 5.

Flue gas desulphurisation has developed substantially over the past decade and new approaches are being tried to improve performance and reduce cost further. It clearly has an important role where existing combustion based plants require emission control. The key issue for new plant will be economic dependent on whether a combustion system equipped with flue gas clean-up can produce electricity at prices comparable with CCGT or the other clean technologies while meeting the requirements of BATNEEC and BPEO.

4.0 ELECTRICITY SUPPLY/DEMAND BALANCES

4.1 Status of Investment in the UK

As mentioned in the introduction, the privatisation of the power industry has triggered a major investment programme in new generating capacity. This followed a period without significant investment since about 1976 with the exception of Drax Phase 2, (units 4, 5, and 6) and oil fired capacity at Littlebrook and Grain. However, the incentive to build new capacity has not been demand driven but results from the new structure of the electricity supply industry after privatisation. The Regional Electricity Companies are striving to reduce their dependence on the duopoly of the fossil fuel based generators while exercising their option to generate a portion of their own power to meet their demand. They have built substantial new capacity. National Power and PowerGen have responded with similar technology to remain competitive. Privatisation also opened the market to other independent power producers who saw profitable opportunities in taking market share away from the two major competitors, a move which was bound to result in a surplus of capacity.

Apart from CHP schemes, the Non Fossil Fuel Orders and Sizewell B, the choice of technology has been exclusively based on the gas turbine combined cycle system. This move has coincided with increasing availability of competitively priced natural gas from a growing number of suppliers following the privatisation of the gas industry.

The status of generating capacity currently installed is as follows:-

Table 1

	MWe
Nuclear	10.7
Coal	28.7
Oil	8.5
Gas	8.9
Pumped Water	2.0
Interconnectors	3.2
Peak Turbines	1.9
Total Capacity	63.9
Demand (1994/95)	49.1
Plant Margin	30.0%

Source: NGC

4.2 Demand Forecast

The National Grid Company (NGC) produces a Seven Year Statement annually with quarterly updates, the latest full statement available at the time of preparing this report being the March 1994 edition. It sets out in detail the opportunities for the power industry in England and Wales to use the transmission system for the seven years ahead. The Statement reviews demand, generation, plant margins, the transmission system, performance and capacity. It then identified opportunities and uncertainties until the 2001. The outlook is based both on energy requirements expressed in Tera Watt hours (TWh) and in GWe of capacity required to supply it. Each of the forecasts has an associated low and high figure corresponding to average cold spell peak demand scenarios.

The National Grid 7 year Statement sets out demand over the next few years as follows:-

Table 2: Demand Forecasts and Annual Energy Requirements

	93/94*	94/95	95/96	96/97	97/98	98/99	99/00	00/01
ACS Peak Demand (GWe)	48.7	49.1	49.9	50.5	51.3	52.0	52.7	53.3
Low	48.7	48.4	48.1	47.8	47.5	47.3	47.1	46.9
High	48.7	49.7	50.6	51.5	52.4	53.1	53.9	54.6
Annual Energy Requirement TWh +	272.7	276.0	278.5	281.9	286.5	290.5	295.2	299.2
Load Factor (%)	63.9	64.2	63.7	63.7	63.8	63.8	63.9	64.1

* indicates provisional 1993/94 outturn
\+ assuming normal weather

Source: NGC

These figures have been adjusted downwards since the 1993 forecast was prepared primarily because of a reduction in the rate of growth which has been forecast. This appears to have been done for several reasons:-

i. GDP growth assumptions made by NGC are uniform over the period whereas *Consensus Forecasts* prepared by an average of the City and academic forecasters are rather lower and non-linear.

ii. Prices and taxes would have an impact on demand. Although the second tranche of VAT has not been levied, adjustments have not been made. The recent peaks in pool price above the agreed cap might be passed through at some stage.

iii. Efficiency of electricity use and demand management will have an effect on demand in the longer term. Replacement of old electrical equipment for more efficient commercial plant and domestic appliances takes time and may be price driven. There would also appear to be more scope for the type of load management practised, for example in the Netherlands, to reduce peak demand. UK load management has been estimated to be equivalent to about 2 GWe of demand by NGC as capacity available for shedding.

iv. Embedded generating plant, (i.e. power generated for own or local consumption and not centrally despatched by NGC) and CHP are excluded from the Statement. NGC projections are based on demand on the grid. Power generation sources of less than 100 MWe which are not centrally despatched are outside the scope of the Statement. If this capacity and CHP systems were to grow faster e.g. as methods of handling wastes grow or the NFFO (Non Fossil Fuel Order) introduces more small capacity, then the demand on the NGC system would be somewhat reduced.

v. Clock changes. The NGC statement examined the possible impact of a change to Double Summertime and an alignment with Continental Time. This is thought to reduce domestic lighting by 0.7 TWh according to the 1989 Green Paper.

4.3 Generating Capacity

The Seven Year Statement gives the outlook for generating capacity as shown in Table 2. It indicates the capacity which could remain in service along with that which is scheduled to be connected i.e. it includes plant registered capacities but with some CCGT awaiting Section 36 planning consent.

Table 3: Total Generating Plant Registered Capacities

	94/5	95/6	96/7	97/8	98/9	99/0	00/1
Nuclear Plant	10633	10750	10810	10810	10810	10810	10810
Small Coal (1)	1432	1680	1680	1680	1680	1680	1680
Medium Coal (2)	4306	4306	4306	4306	4306	4306	4306
Large Coal (3)	22991	23036	23056	23056	23056	23056	23056
CCGT	8891	9551	14655	17472	21580	23673	23673
Oil	8489	8489	8489	8489	8489	8489	8489
OCGT (4)	1938	1938	2098	2098	2098	2098	2098
Hydro	2100	2100	2100	2100	2100	2100	2100
Scotland (5)	1200	1600	1600	1600	1600	1600	1600
EdF (6)	1976	1976	1976	1976	1976	1976	1976
Total Plant Available	63956	65426	70770	73587	77695	79788	79788

Source: NGC

Notes: 1. Small coal represents the 1957-1962 vintage plant of typically less than 250 MWe capacity such as Aberthaw A, Uskmouth or Willington A

2. Medium coal represents the plants built in the mid-1960s of under 1000 MWe of total capacity such as Blyth B, High Marnham or Drakelow C

3. Large coal are classified as those stations built in the late 1960s/1970s typically with 500 MWe sets such as Didcot A, Drax, Eggborough.

4. Open Cycle Gas Turbine as used for peak shaving.

5. Scotland refers to the interconnection between the National Grid and the Scottish system.

6. EdF refers the interconnection between Electricité de France and the Grid.

There are a number of areas of uncertainty associated with the capacity as depicted in the table. Some 2700 MWe of Zero Registered Capacities and Decommissionings have been notified and more can be expected as a result of the age profile of the small and medium coal plant and some oil plant.

Another key factor in any projection of future capacity is the anticipated closure programme of the Magnox Stations. NGC had assumed a staged closure beginning in 1997/8 in line with Nuclear Electric's submission to the Select Committee on the Coal Review. However, the nuclear review is in progress while some Press comment suggests that the closure programme might be linked with negotiations to secure Government agreement to build Sizewell C.

4.4 Plant Margin

The plant margin is the amount by which the installed generating capacity exceeds the peak demand. This margin cannot be considered as surplus capacity but that which needs to be in place to cover routine maintenance and repair and breakdowns. The CEGB based their targets on a typical 85% availability of equipment. They then made a further allowance for weather which might be colder than the Average Cold Spell (ACS) on which the demand forecasts are based.

The plant margin is therefore necessary for security of supply and not a surplus. The CEGB sought to maintain a margin of 24% and a review of world-wide practice suggests that it needs to lie in the 20-30% range. The privatised electricity industry has not set or been given firm standards for margin but given the high availabilities of CCGT plant, a national planning margin of 20% would appear to be appropriate.

National Grid has not attempted to predict a single scenario for future development. Instead, they have examined plant margins given 6 sets of assumptions related to possible developments. These were set against the background of the agreement between the Regulator, National Power and PowerGen to accept a pool price cap, and the voluntary sale of 6 GW of capacity in return for the Regulator not referring National Power and PowerGen to the Monopolies and Mergers Commission.

The 6 cases considered were as follows:-

CCGT

(i) Datum - all 'transmission contracted' CCGT plant to proceed;
(ii) Section 36 (S36) - only that CCGT plant with S36 proceeds;
(iii) Under Construction (E, UC) - only that CCGT plant which is currently existing or under construction proceeds.

CCGT plus closure

(iv) Datum less 6 GWe - as (i) above less 6 GWe of unspecified closures;
(v) E, UC less 6 GWe - as (iii) above less 6 GWe of unspecified closures;
(vi) S36 less 6 GWe - as (ii) above less 6 GWe of unspecified closures.

National Grid Company stress that it is not their role to forecast power demand but simply to transmit power. However, for their own planning, they need to have a comprehensive understanding of the possible pattern of developments and in particular to ensure that the transmission capacity is in place in the event that significant changes in power flow occur as a result of closure and new construction in different parts of the country.

Table 4 sets out the Statement tabulation of the plant margins which would result from the six scenarios above.

Table 4: Plant Margins (%) for Various Generation Backgrounds

	Background	94/5	95/6	96/7	97/8	98/9	99/00	00/01
1.	Datum	30.19	31.25	40.02	43.43	49.42	51.45	49.57
2.	Section 36 (S36)	30.19	31.25	39.43	39.86	40.97	39.05	37.32
3.	Under Construction (E, UC)	30.19	31.25	33.20	31.23	29.57	27.80	26.21
4.	Datum less 6 GWe of Closure	26.12	23.22	28.15	31.74	37.97	40.06	38.32
5.	S 36 less 6 GWe of Closure	26.12	23.22	27.56	28.16	29.43	27.66	26.07
6.	E, UC less 6 GWe of Closure	26.12	23.22	21.33	19.53	18.02	16.41	14.96

Source: NGC Seven Year Statement

The analysis is illuminating because the only case which reduces the margin below the nominal 20% level after 1997/8 is a case which assumes that only those CCGT plants currently under construction will be completed and that 6 GWe of capacity will be closed. The 6 GWe broadly corresponds to the total of the small and medium sized coal stations. Consequently, any new CCGT capacity which is built where Section 36 planning consent has been granted would reduce the need for a portion of the large coal or oil capacity of 23 GWe coal and 8.5 GWe respectively.

Analysis of the typical summer load which has a daily peak at around 30 GWe with less than 10 GWe of coal fired capacity required for much of the day. Operators of new CCGT capacity would attempt to run base load so the prospect for both coal and oil capacity would appear to be as intermediate or peak load.

It is difficult to make any firm forecast of the likely demand on the coal and oil stations without modelling the generating system and making assumptions. This has been done by McCloskey Coal Information Services (MCIS), editors of the FT Business Publication, Coal UK and by Oxford Economic Research Associates Ltd (OXERA) independently. It was also done by Caminus Energy Ltd for RJB Mining. The MCIS assessment in particular challenged the quantity of coal which was being assumed for the sale of British Coal (Coal UK 24 Nov 1994). The calculations were based on assumptions about the use of gas, the flow through the inter-connections and the interest being expressed both by National Power and PowerGen in the use of Orimulsion.

The key assumptions made were:-

- the growth in electricity demand is as portrayed in the NGC Statement
- the inter-connection with Scotland will be expanded and that the net imports through the two links will increase from 23.5 to 25 TWh/yr
- nuclear generation will increase from 66 TWh to 74 TWh to reflect Sizewell B and increased availability of the AGR's

- generation of the CCGTs will increase from 44.7 TWh to 95.7 TWh by 1998/99 with the average capacity increasing from 8 GWe to 14 GWe.

- Orimulsion based generation will increase from 3.7 TWh to 9.2 TWh by 1998/99 with the conversion of two sets at Pembroke to the emulsified fuel

- The oil burn would remain constant at 8.8 TWh on 2 M tonnes of fuel

Reference was also made in Coal UK to the fact that National Power was considering a plan to burn Orimulsion at Drax. The impact of such a move was not included in the MCIS assessment. Table 5 portrays the MCIS assessment versus the RJB Mining forecast for the derivation of coal burn.

Table 5: Power Supply by source/fuel in MT Coal Equivalent

	1994/95		1998/99	
	RJB	**MCIS**	**RJB**	**MCIS**
Total Demand	115.2	115.2	121.0	121.0
Nuclear	26.6	27.0	29.7	30.8
Gas	16.1	18.6	43.3	39.8
Import Links	10.4	9.8	7.6	10.4
Orimulsion	1.4	1.5	6.5	3.8
HFO	0.1	3.7	0.0	3.7
Other (Ren'ble)	0.0	0.4	0.0	1.6
Total Non-Coal	54.6	61.0	87.1	90.1
Available for Coal	60.6	54.2	33.9	30.9

MCIS also noted that separate negotiations had taken place to supply Aberthaw with coal from the Welsh mine which might improve the Aberthaw's position in the merit order at the expense of the English coal stations.

With only 31 - 34 mt of coal equivalent available to coal and limited oil burn, much of National Power and PowerGen's large unit capacity will be substantially under-utilised.

The 1994 edition of OXERA's "Generation in the 1990s" uses a different approach in making an assessment. They use two energy scenarios and four capacity scenarios which they have modelled to provide a picture of the challenges facing the industry. The energy assumptions are of high gas entry and low gas entry. Two series of annual projections result for the Seven Year Statement period. They are summarised below to show the base year and only two of the seven future years with high and low data juxtaposed:-

Table 6: Fuel Mix under two Energy Scenarios

Units mtce

	1994/5	1998/99		2000/01	
	Base	**High** *	**Low**	**High**	**Low**
Demand met by	114.3	120.3	120.3	123.9	123.9
Coal	50.1	12.4	23.4	16.0	27.0
CCGT	18.9	61.2	50.2	61.2	50.2
Nuclear	28.9	29.1	29.1	29.1	29.1
Oil	6.0	6.0	6.0	6.0	6.0
External	10.4	11.7	11.7	11.7	11.7

Source data: OXERA. Note: * High/Low refer to gas entry

Without looking at capacity, it is clear that if gas penetration is high, coal demand is reduced very substantially leaving a large part of existing capacity unused. The low gas penetration case still uses less coal than the MCIS case.

The OXERA analysis would suggest that the high gas penetration is unlikely because at least two of the possible new developments have been abandoned and Killingholme 1997 development deferred to 1999. Nevertheless, the low gas entry would appear to understate the keenness of the RECs and the independent power producers to penetrate the market. Again it suggests that much coal and oil fired equipment may not be required.

In their analysis of capacity, OXERA could account for a total of 21.4 GWe of new gas capacity which could be operational by 1999. Sutton Bridge and Marchwood have been cancelled so 1700 MWe would need to deducted. They then considered a case with low gas entry ie. only 12.7 GWe of new capacity being commissioned but with a high closure programme. All the small and medium coal stations would be closed along with some of the larger stations. Such an approach might be an economic decision but would reduce the plant margin to below the 20% level by 1997.

They then made a more detailed assessment of "active" projects and reassessed what could perhaps be described as a possible high gas case in which 17.8 GWe of new gas capacity was commissioned and with 2000 MWe closures each year for the first three years. This results in tolerable plant margins in the early years increasing to 30% plus after 1997.

On the assumption that CCGT capacity is built and approaches their high gas entry case, the RECs and IPPs would control over 50% of the capacity coming on stream. National Power and PowerGen's share of that new capacity would be 35%. Furthermore, this assessment pre-dates the Regulator's more recent statement that he would be willing to consider applications by the RECs for more than the current 15% limit on their ownership of capacity on a location specific basis. If the scenario were to develop, the quantity of coal to emerge from the analysis is only 12.4 mtce in 1998/9 roughly equivalent to the quantity consumed by Drax and Ratcliffe alone on high load. The retro-fitting of FGD at both plants is scheduled for completion in 1996. Consequently, the case for emission control investment for sulphur on the remaining coal plant would appear difficult to justify on economic grounds with such a potentially low usage.

There could still be a considerable quantity of coal in the system if the next round of negotiations were able to settle lower prices reflecting the improved productivity of a privatised coal industry. The potential to reduce production costs exists from the data submitted by British Coal to the Select Committee. The generating capacity still exists to burn it. However, other factors could influence the use and value of the capacity. Firstly, if the two major generators are forced to sell unused capacity, what portion of the emissions fraction allocated to National Power and PowerGen would they be prepared to give up and therefore what emissions limits would the new owners have to meet? Secondly, would a change of ownership lead to the application of "new plant" environmental criteria being set requiring refurbishment before an operating licence could be issued? Thirdly, could there be any guarantee of plant loading to a new owner to yield a return on investment?

At the possible low predicted loadings of much of that capacity, financing charges, manning, routine maintenance and corporate overhead would be a considerable burden which the major generators may not wish to bear so the accelerated closure case may be a pragmatic solution in spite of running tight on plant margin. Responsibility for plant margin rests with the Regulator and at present partially with National Power and PowerGen via the price cap which has been agreed. Once that period has passed, the generators would not appear to be responsible for plant margin.

If further FGD capacity were to be mandated, it is unlikely to be economic unless the plant could be assured a substantial period of time running on base load. Such a move might defer the introduction of new high efficiency plant whether CCGT or IGCC.

The use of the coal-fired stations could be eroded still further by:-

- any new applications from the RECs for new capacity

- the retro-fitting of FGD at Pembroke to fire Orimulsion and/or residues

- any possible development of gasification at one of the refining complexes primarily for hydrogen but with associated power production

- continuation of the NFFO to introduce new capacity which may not be subject to central despatch. There is also the question of the definition of renewables because it could be argued that the growing need to dispose of waste streams such as tyres, plastics and domestic refuse in an environmentally acceptable way has the potential to produce power

The plant specific data could only be predicted with any accuracy by modelling the system which is outside the scope of this study. However, it is clear from the analysis which has been done that there is likely to considerable pressure to close plant for which there is little or no forecast use other than for winter peak cover. There is also a very considerable uncertainty over the number of hours in any year that much of the coal and oil fired capacity would be in use. In those circumstances, it would appear to be difficult to provide any economic justification for new emission control investment on any of that plant unless there is a change in the legal requirements to cover short periods of operation.

There would appear to be scope to have the environmental impact of gas entry on the coal and oil capacity studied in detail by experts in economic modelling techniques.

5. OPTIONS AVAILABLE TO UTILISE EXISTING COMBUSTION CAPACITY

A number of options exist to utilise the ageing coal and oil fired boilers in an environmentally more acceptable way. They are all technically feasible but may not be economically attractive. This first section will relate primarily to technical feasibility and the economics will be covered later in Section 8.

The alternatives being reviewed fall broadly into the following categories:-

1. improvements in fuel quality
2. post-combustion clean-up
3. hybrid systems

The ultimate alternative would be to close the plant completely and this may be the most likely outcome for several plants. The National Grid 7 Year Plan suggests several years in which the summer load could be met without the need to use coal or oil capacity. This rather suggests that only limited operating hours would be required from much equipment and hence the chance of earning sufficient revenue to defray the cost of any new environmental control equipment installed at the plant might be in question.

The alternatives available in the first three categories will be explored in more detail.

5.1. Pre-Combustion Fuel Switching/Clean-Up.

5.1.1 Fuel Switching

i. Imported coal.

The first choice would be a low sulphur coal e.g. by purchasing in the international market where the bulk of the coal is traded at a sulphur level of 1.0% maximum. Several Australian, Colombian and Venezuelan coals would be no more than 0.7-0.8 % sulphur, a significant reduction. The developing reserves in Indonesia are about 0.3%S while one grade has been labelled "Enviro-coal" with a sulphur level of 0.1% and low ash. Some of these newer qualities may present other operating difficulties on boilers and precipitators designed for higher ash and sulphur coals if combusted alone but their use in blends is being tried in Europe. These sulphur levels should be compared with typical UK coals which range from 0.4-2.4% with an average of around 1.8% (Boyd Report).

The international steam coal market is very competitive and, although there have been price increases over the past few months, production is likely to keep pace with demand. To date no sulphur premium has emerged for the lower sulphur coals in the range below 1% because coal has tended to be priced on heat content. However, a price differential for quality may become more usual as the buyers adopt sophisticated tools such as CQIM to assist them in making comparative analyses of the choices of coal available in the market.

The importing of coal would limit the capital investment at the plant. Good port facilities exist and are under-utilised at present. However, if imports were to be seen as a semi-permanent solution, new deep-water terminal and receipt facilities might become attractive to obtain the freight advantage of cape-size vessels on the east coast to avoid transshipment costs through ports such as Rotterdam. Such a step would again require capital and a return on investment which reflect as a cost in some part of the chain.

ii. Gas.

The co-firing or over-firing of gas has been considered as a method of reducing sulphur and NO_x by displacing coal. However, the economics of using gas in this way are not favourable compared with its use in combined cycle capacity. The firing of gas in boilers designed for coal or oil is sub-optimal for reasons such as the shift between radiant and convective heat balance. Boilers designed to fire gas are smaller than those for coal. Over-firing to control sulphur or NOx might have limited application if very tight local emission limits existed. In the short/medium term, it is possible that quantities of natural gas could be purchased at sufficiently low prices to make generation from coal-designed capacity economic.

Another technique which has been used in the USA, for example, is to instal an aero-derivative gas turbine with its own generator alongside an existing pf boiler and route the hot gases to the wind-box or to pre-heat boiler feedwater. Hot wind-box repowering with 25% gas turbine power was reviewed at a recent EPRI Conference at a capital cost of about $150 - 175/kW (expanded later in this section).

5.1.2 Fuel Quality Improvement

i. Coal Cleaning.

The reduction in sulphur and ash prior to combustion appears to be one of the more practicable approaches for a rapid and effective way to remove a part of the sulphur in coal. Power Station Fuel (PSF) in the UK is higher in ash and sulphur than the fuels used in many other countries and higher the UK production for industrial use. The agreement to use coal with an ash content of up to 18% and a typical sulphur content of 1.6-1.8% appears to stem from arrangements which have evolved over the past 40 years of the nationalised duopoly of the CEGB and NCB. The coal has been sold on a p/GJ basis ex-mine thereby leaving the utility to pay the freight on a per tonne basis. It has allowed British Coal to minimise their production and washing costs because it enabled them to split the size range at about 1", washing the oversize and back-blending the 1" minus largely unwashed fraction to yield the PSF specification.

This specification also determined the design of the boilers and although joint studies on the effect of coal quality were undertaken, the results were regarded as insufficiently conclusive to warrant significant change from the existing supply arrangements. Subsequent work elsewhere suggests that the cost penalty of moving ash and sulphur through the system has not been fully appreciated - see below.

The impact of both ash and sulphur on boiler performance was well articulated in the mid 1980's as a result of a prestigious global survey by the Coal Industry Advisory Board. The IEA report entitled "Coal Quality and Ash Characteristics" was published in January 1985. The foreword by Helga Steeg, IEA's Executive Director, emphasised that the report represented the independent judgment of the CIAB. It also gives a very clear signal that "the CIAB believes that the increased knowledge and understanding of this subject will assist the electric utilities to achieve maximum cost effectiveness in the use of indigenous or imported coal to generate electricity".

The data was collected from the world's leading utility companies by interview and the appendix listed the wide range of international executives who were involved including representatives of the CEGB, the National Coal Board and Babcock.

The report contained an economic summary which is a consolidation of data collected from field interviews. The particularly relevant quotes are as follows:-

"From the user's standpoint, there is an indisputable case for reduction of the absolute minimum ash content in coal delivered to pulverised coal-fired boiler plants. It is a curious twist of the economic structure that causes the ash to be transported over considerable distances from the pit to the power station where, far from serving a useful purpose, it causes trouble in all directions. The case is made more curious when, after causing so much difficulty in the boiler plant, a considerable amount of money and effort has to be spent in collecting and removing the ash to a convenient dumping ground." The reference is attributed to the British Coal Utilisation Research Association.

The field studies conducted by the Committee were summarised in economic terms as follows; "It appears that an increase of 1% ash (generally passing the 10% range) results in a decrease of about 1.2% to 1.5% in boiler availability. Assuming capacity costs at about $1200/kW, the capital cost absorption penalty is equivalent to $0.95/t of coal burned per 1% increase in the ash content of the coal. Likewise, a 1% increase in ash (again **typically** over the 10% range) results in a decrease of 0.3% in boiler efficiency. Based on the field interviews, this costs about $0.67/t of coal burned. Taken together, these two factors can result in a cost penalty of about $1.62 per tonne per 1% in ash content". An IEA Coal Research report (Lee, H.M. 1986) on the same subject highlighted similar data.

Whilst the then Department of Energy must have been aware of the report, the Miners' Strike and the aftermath of pit closures appears to have created a situation where capital for investment on anything other than perceived essentials was very difficult to secure.

The CIAB report would appear to have initiated work in the USA focused on the impact of coal quality on boiler performance. Analytical tools such as the Coal Quality Impact Model (CQIM) have been developed and are becoming widely used to assess the comparative values of different coals and the value to the operator of cleaner coals. As a result of this work and the improvements in coal cleaning technology, there is a trend towards a cleaner, more consistent coal for power generation. This is being progressed in the USA, Australia and South Africa.

Similar modelling can assist the mine operators to determine the optimum product quality for a particular resource. The use of modelling techniques for optimising wash plant circuit design coupled with developments in the application of dense media cyclones, spirals and column flotation cells etc. has significantly improved coal preparation frequently at reduced overall cost because of improved yields of marketable product. In particular, it has enabled mining engineers to match size range of the coal, its washability characteristics and product quality requirements with the best combination of equipment. Much of the newer plant is smaller modular and lower in cost compared with some of the more traditional equipment.

Much work has been done on fine coal cleaning and the results suggest both ash and pyrite can be reduced considerably further than was possible 5 years ago and at an economic level of costs. Control of wash plants has also improved substantially using computer systems and on line analysers. The fine coal can be blended back into the larger coal or alternatively it could be co-fired as a slurry and this latter point will be expanded later (Battista, J.J. 1994). A paper at the 1994 Pittsburgh Coal Conference indicated improved beneficiation techniques can remove up to 90% of the pyrite from selected coals at a cost of about $150/sulphur tonne (Godfrey, R. 1994). This can only be achieved by crushing the coal to allow mineral liberation. Micro-fine magnetite can then be used as a simple extension of the well proven dense media technology which can achieve this separation. The simultaneous removal of ash and pyrite enables non-compliance US coal to be upgraded to compliance coal with the added value more than offsetting the operating cost.

There is a view that froth flotation is ineffective in reducing pyrite. This may have been true of the traditional methods of flotation. However, a description of particle behaviour is important in the understanding of flotation. The mechanism of flotation is a simple relationship between the properties of a gas, a solid and a liquid - through the effect surface tension on all three components. Even if the coal particle has broken away from a pyrite particle, they may have similar surface properties and it is possible for the pyrite to attach itself to the froth and leave the process with the coal. This effect was often observed in the older large froth flotation vessels.

In the more recent **column flotation cells**, the froth is spray washed. These conditions tend to release the heavy pyrite particles leaving the coal firmly attached to the froth and good separation can be achieved. The process, however, is particle and coal specific; not all coals behave this way. Nevertheless, many do, so pyrite reduction can result from the cleaning. The separation can be enhanced through the selection of reagents. The usual combination is a collector, frequently an oil such as diesel, and a frothing agent. The collector will attract coal rather than pyrite and by experimenting with the collector used, separation is possible on many coals.

For any given coal, it is possible to run laboratory tests relatively quickly and at low cost to see whether pyrite separation will occur. However, certain precautions are recommended if commercial application is to follow. Flotation techniques can be very sensitive to the nature of the water used and factors such as the ions present and pH can affect the gas/water response. Laboratory work might be conducted with distilled water or tap water but a more accurate assessment of commercial performance would be achieved by the use of water from the location of the intended plant.

Hence, unlike the conventional flotation systems, column flotation offers a means of reducing ash and pyrite simultaneously and at low cost on a wide range of coals but some coals may not respond. Micro-fine magnetite also achieves good pyrite separation and is the subject of a major USDOE demonstration project to be commissioned in Spring 1995 in Pennsylvania.

It is also understood that the British Coal Bretby Laboratory scaled down coal preparation research several years before it closed. To date, fine coal cleaning using flotation cells has not been introduced into UK operations. However, much of the UK coal contains about 0.8% organic sulphur with the remainder pyrite and coals such as Oxcroft or Harworth may have up to 1.7% pyrite. A proportion of that pyrite could be expected to respond to the US type of cell flotation of the fine coal or aggressive beneficiation i.e. by crushing middlings to liberate more mineral matter prior to washing. The application of these techniques will be coal specific but many major producers who supply the international steam coal market are adopting these systems quite rapidly. The improved preparation of Power Station Fuel may therefore present opportunities for the privatised UK coal industry.

In the USA, a December 1994 USDOE publication "An Overview of US Federal Coal Preparation Research" highlights the fact that coal preparation remains a key issue:-

"Coal preparation, a process that improves the quality of coal utilised for combustion and reduces the resultant pollutant, has become more important than ever".

ii Introduction of a sorbent with feed

The addition of limestone or dolomite to the fuel has been examined by a number of companies. The concept is sound in theory as a means of capturing sulphur during combustion with the spent sorbent being precipitated with the PFA. Some experimental work has been undertaken in the USA with USDOE funding.

The advantages claimed are low investment but there are potential operating difficulties associated with the introduction of calcium into the ash. Slagging and fouling can occur because of the effect of the calcium on the ash characteristics of coals. Another problem is the overloading of the precipitators because the technique is an inefficient form of sulphur capture which may require a great deal of sorbent. The spent sorbent/PFA mix is likely to become land-fill because of the variable nature of the mixture and lack of a commercial outlet. Consequently, although the technique may have application for smaller industrial boilers and possibly the smaller pf fired boilers, it is unlikely to match the needs of the larger pf boilers on many coals.

A US paper (Godfrey, R. 1994) has indicated the application of the technique to coals which have been subjected to aggressive beneficiation i.e. from which much ash and pyrite has been removed from crushed coal. The product would need to be pelletised or briquetted to improve handling because the preparation stage calls for the coal to be milled finely to achieve mineral liberation. "Self-scrubbing" coal may have application in certain environmental regimes such as in the USA where the compliance rules relate SO_2 emission to heating value. If the stack emission level is critical, then partial sulphur removal may not be satisfactory.

5.2 Post-Combustion Clean-Up

5.2.1 Flue Gas Desulphurisation

Since the application of wet scrubbing systems has been widely adopted in Europe and the USA but at a high capital cost, it will not be described in any detail but will be discussed in the economics section. It is a well proven system where the operating and capital costs are now well known. The application of wet scrubbing systems to the ageing UK plant is clearly an option but it is unlikely to be economic unless the plant is expected to have 10-15 years of residual life much of which would have to be on base load. This section will examine the lower capital cost alternatives.

i. Spray Dry Scrubbers

An IEA Coal Research Status Report - 1993 stated that some 40 systems based on spray dry scrubbing are operational in Europe and the States. The process involves injecting a spray of slaked lime slurry into a reactor or the duct downstream of the boiler but upstream of the precipitator. The slurry is atomised to a cloud of fine droplets into which the SO_2, SO_3 and HCl are absorbed to react with the lime. About 90% of the sulphur can be captured.

Although the capital costs are lower than corresponding wet limestone systems, the operating costs are higher, hence its application to part load stations. This arises because a higher sorbent/sulphur ratio is required and the cost of lime is higher than limestone. Another draw-back especially in Europe is that the waste is likely to be of no commercial value and disposal to land-fill may be constrained by criteria set for Best Practical Environmental Option.

Typical costs would be \$100/kW capital and \$400-450/t sulphur removed. It should also be noted that this techniques has been applied mainly to small utility, CHP and industrial boilers - not to the very large utility boilers.

ii.. Sorbent Injection

There are three ways in which sorbent injection can be introduced to utility boilers:-

(a) furnace sorbent injection

(b) duct sorbent injection

(c) hybrid sorbent injection

(a) Direct sorbent injection into the furnace has become established and accounts for some 4 GW of capacity in Europe and the USA. It is commercially proven but the more effective duct injection system remains at the demonstration stage. The main sorbents used for furnace injection are limestone, hydrated lime and dolomite but sodium compounds such as the carbonate or sesqui-carbonate can also be used when economically attractive.

The high furnace temperature calcines the sorbent to produce reactive CaO particles which absorb the SO_2. These products are captured in the precipitator. The high Ca/S ratios used, commonly between 2 and 4, only achieve about 50-60% removal of SO_2. This corresponds to a sorbent utilisation efficiency of no more than 25% so there is a two to threefold increase in the particulate loading on the precipitator.

(b) Duct injection of calcium or sodium sorbents is a relatively new development which has progressed as far as demonstration. Lime and sodium bicarbonate sorbents have been used but one of the key factors is establishing the right injection ratio and temperature conditions for the reaction to take place. Tests to date suggest that up to 50% of the sulphur dioxide can be captured.

Humidification of the flue gas by water spray into the duct ahead of the precipitator may improve the SO_2 removal efficiency and the effect has been illustrated on a 100 MWe unit in the USA.

(c) The term hybrid is something of a catch-all for processes which do not fit neatly into the furnace injection or duct injection category. The two most usual types are where humidification in a specially designed reactor takes place to reactivate the sorbent as in the LIFAC process or in duct injection with further quantities of sorbent (Waagner-Biro). Both processes are in commercial operation and are said to achieve 70-85% SO_2 removal.

A different and successful approach omitting furnace injection has been developed by Lurgi. They have designed a circulating fluidised bed reactor of hydrated lime for installation downstream of the air heater. Water is injected to maintain lime activity and SO_2 removal efficiency is quoted as 93-97%. Several units are operating on smaller German utility boilers, but the power requirement of the circulating bed is said to be high.

iii. Bio-Technological FGD

As mentioned in Section 3.8, two Dutch companies, Hoogovens and Paques BV have developed a Bio-FGD process based on four simple steps (Hoogovens, News Bulletin Jan 1994). The flues gases are passed through an absorber where the sulphur oxides are extracted in a water wash. The sulphur-rich water then passes to an anaerobic reactor where special bacteria convert the sulphites and sulphates into sulphides. An aerobic reactor then oxidises the sulphides to elemental sulphur.

The developers make several claims for the technology. They say the process is 30% lower in capital and operating cost than limestone/gypsum, more efficient at 98%, has no waste water to be treated and has a useful minimum volume end-product of elemental sulphur. The enlarged pilot plant phase is just being completed and there as a plan to go to a 50 MWe demonstration which they hope to complete in 1996. This development has many potential advantages particularly because it can be scaled to power or industrial application and requires no continuous flow of solid sorbent. However, its application would still be subject to the limitations of the direct combustion equipment to which it would be fitted.

5.3 Hybrid Power Systems

5.3.1 Repowering

There are many variations on this theme but in the USA, schemes have been prepared which introduce the gasification of coal and the use of combined cycle gas turbines to an existing power station. This can be done in two ways:-

1. by replacing the old boilers with heat recovery boilers taking the gas turbine exhaust gases and then use the existing steam turbines and generators for the steam cycle

2. by retaining the existing boilers with the exhaust gases of the gas turbine entering the wind-box of the boiler to provide heat in the boiler in conjunction with a reduced level of conventional firing

The first type of system is currently being developed in Indiana where the Wabash River project has recently been completed. The capital cost of power using this combination is assessed as $1380/kW on this project although that cost includes several features which are solely required for the first three years to undertake a USDOE test programme. A recent paper suggests the net, or more realistic, investment for the power plant will be under $900/kW (Cook, J.J., Bott, J. 1994 EPRI Conf). The emissions are very low compared with direct combustion processes because of the 99%+ sulphur capture of the gasifier and the use of gas turbines with their lower NOx levels.

A substantial joint study between GE and Fluor Daniel was undertaken to review the subject in depth. They drew three conclusions which add an interesting dimension to the options:-

- "Current IGCC plants cost more on average than conventional steam plant technologies **as published by the utilities**. Efficiency makes up for the extra cost over time to provide an equal cost of electricity"

- "Applications for repowering, potential for lower fuel cost or where environmental constraints exist can push IGCC to the most economic choice today by as much as 15% in aggregate"

- "Future IGCC plants (post-2000) are likely to use advanced gas turbine technology which carry an additional 7-8% cost of electricity advantage driving a step change in the solid fuel market"

The study had been undertaken with the US coal-based power market in mind. The figures are 10-15% more attractive if liquid feedstocks were available to be used and this is the developing case in Europe.

5.3.2 Gasification

Another variant on repowering is the Front End Gasification Retrofit (FEGR) (Bajura, R. 1994 EPRI Conf) where a gasifier is used to convert the fossil fuel into a fuel gas which is then fired on the boilers of the existing station. This approach was studied as part of National Power's options for Pembroke Power Station. They examined the possibility of installing a gasifier to convert emulsified bitumens to a clean fuel gas. They concluded that a stand-alone FEGR system was not commercially viable.

Shell is in the process of installing a large gasifier (500 MWe equivalent) at their Rotterdam refinery to produce hydrogen, clean fuel gas and power. This investment is being made in conjunction with a hydrocracker, an upgrading process which is a net consumer of hydrogen. Consequently, the export of power to the grid after own power consumption is expected to be between 80-100 MWe. The excellent emissions performance which results from the Shell plant will be discussed later in the section on waste streams. Other refiners are studying similar proposals to absorb the growing surplus of heavy oil residues resulting from the pressure to upgrade transport fuel quality. There is a developing synergy between the solution to a refining problem and the generation of power. It offers both industries with an economic solution if the basis for a working relationship between the two traditionally independent industries could be established.

Another combination of gasification/repowering could be based on the Advanced Quench Gasifier as developed by Texaco. In a paper delivered to the EPRI Conference in October (Preston, W.E., 1994 EPRI Conf), the capital cost of gasification has been reduced by using a quench rather than a heat recovery boiler. Much of the energy can be recovered via a clean fuel gas saturator. This maximises the energy content of the fuel gas stream by saturating with steam thus increasing the mass flow to the gas turbine.

When studying design alternatives, the question of the degree of integration is important. It may not be economic or necessary to integrate because the capital cost of integration may not off-set the value of the gain in thermal efficiency. Gasification is a process which may be needed by refiners to generate competitively priced hydrogen while converting heavy residues which may have little alternative value. Clearly, this depends on the heavy fuel oil market and the alternative way of making hydrogen i.e. by reforming methane where the cost will depend on the natural gas price. However, as mentioned previously, today's distress prices for natural gas are unlikely to hold by the turn of the century if demand grows as forecast. If a gasifier were to be installed adjacent to the refinery, the potential surplus of clean fuel gas could be routed to new gas turbines for the production of power.

The gas could either be routed to a new open cycle turbine or CCGT plant. If new gas turbines were to be installed and if there were an adjacent power plant, a repowering alternative could be viable. The old boilers replaced with heat recovery boilers, the steam could be fed to the existing steam turbines. On the basis of current CCGT costs of £300/kW, the gas turbine/heat recovery portion is assessed as about 45% of the total cost of the grass roots CCGT or about £135/kW. An efficiency of say 52% LHV (dependent on steam turbine efficiency) should be attainable.

Several advantages could emerge from this type of operation:-

- The refiners' heavy residue problem is solved and they would be able to draw hydrogen, nitrogen, oxygen, steam, power and clean fuel gas from the facility
- the power plant would operate more efficiently on a source of clean fuel gas
- the more complex gasifier plant would be operated by management familiar with the process industry while the generator retains control of power generation
- the installation could be phased because the modular size of the gasifiers could be matched to the size/number of large gas turbines. Other gasifiers could be installed, fed on Orimulsion, to boost the gas production to the level of power required from the area to the grid
- The environmental advantages would be substantial. The emissions from the refinery and the power station would be reduced to very low levels of particulate and sulphur dioxide and the low NO_X levels achievable from modern gas turbines. The heavy metals would be entirely retained at the gasifier for metal recovery. The refinery fuel systems could also be operated on clean fuel gas with very low emission levels.

The detail of emissions and waste streams will be covered in Section 7.

5.3.3 Slurry Firing

In the USA, Consol (Battista, J.J. 1994) have had considerable success in reducing ash and pyrite in the natural yield of fines from run of mine coal by improved cleaning techniques of column flotation and microfine magnetite in dense media cyclones. This is a low cost step; the larger cost would only occur if the coal has to be dewatered. Consequently, they entered into a test programme with a local utility to co-fire a slurry of this very clean coal alongside the normal coal supply. They have been able to sustain heat rate at levels of up to 40% slurry firing and are now developing the concept into a commercial arrangement.

If ash and say 80-90% of the pyrite can be removed from fine coal at low cost, then this would appear to be an attractive way to reduce sulphur emissions to some degree at low cost where a plant is conveniently close to a mine.

6.0 RELEASE INVENTORIES IN ENGLAND AND WALES

6.1 Current Levels

The scope of work for the report requests release inventories for the current operation of power stations in England and Wales with an assessment of the benefits of the options. The data for National Power and PowerGen is quoted in their annual environmental performance reviews. Emissions from the new gas-based CCGT stations have been estimated on the assumption that there is a trace of sulphur in the gas and that the only significant gaseous emission would be NOx.

Calculation of plant specific future emissions would involve the modelling of the generating system by fuel, assigning a sulphur content to the fuels and then permuting the combinations of plant operating options which would be required match the demand for power. Such an assessment is outside the scope of the report. However, from scenarios for the likely fuel use and its sulphur content, it is possible to make an assessment of total emissions from the energy input.

The 1994 data issued by National Power and PowerGen is set out below outlining the total quantities of coal and oil consumed, the total emission of CO_2, SO_2, NO_X and HCl. They also summarise the tonnage of PFA sent to land-fill and that sold for re-use.

The latest published data at the date of preparation was contained in the 1994 report covering the calendar year 1993 and is tabulated below in Table 7.

Table 7: Levels of Emissions 1993

		National Power	Ave.Sul %	PowerGen
Coal Burn MT		35.25	1.6	23.0
Oil MT		1.3	2.9	1.5
Gas MT		0.44	Trace	1.0
Emissions kT	**- CO_2**	83,446		57,700
	- SO_2	1,035		842
	- NO_X	284		188
	- HCl	104		68
Emissions gm/KWh	**- CO_2**	851		852
	- SO_2	10.6		12.42
	- NO_X	2.9		2.8
	- HCl	1.1		1.0
Particulate kT		n/a		32
gm/KWh		n/a		0.47
PFA Mt/yr (Note A)		5.1		2.65

Source: Environmental Performance Reviews

Note A: The PFA produced mt/yr

National Power - 5.1 Mt by calculation of which 3.7 Mt to landfill
PowerGen - 2.65 Mt declared of which 1.9 MT to landfill

In addition to these releases, there will be a small contribution from the trace elements found in all coals. Trace elements will include many of the heavy metals in very small quantities. IEA Coal Research (Clarke, L.S, Sloss, L.L. 1992) stated that virtually every element in the periodic table could exist in coal and that many trace elements are released to atmosphere as a result of combustion. They cited arsenic, boron, cadmium, mercury, molybdenum, lead and selenium as the elements over which there was most concern. The report gave a table attributed to Nriagu, 1990, which summarised global emissions of trace elements from man-made and natural sources. Energy production was responsible for about 25% of the selenium, over 38% of the mercury, over 50% of the nickel and 74% of the vanadium expressed as a percentage of the global annual total.

The subject of Hazardous Air Pollutants will be considered in more detail in Section 7 where results of a major programme run by the USDOE are reviewed.

The characteristics of the trace elements vary. Some will volatilise in the boiler and may emerge in the stack gases. Others are usually retained either in the bottom ash or the fly ash. Mercury and selenium are two metals which will volatilise and may escape to atmosphere. However, the mechanism of their escape may be dependent on the presence of other elements such as chlorine. Furthermore, the trace quantities are very difficult to sample and measure accurately especially with so many chemical reactions occurring between the boiler and the stack. It is therefore unwise to draw specific conclusions from generalised data e.g. by assuming US-based data is necessarily transferable to a UK situation. In Section 7, this problem is developed further because it is more appropriate to identify the possibility of troublesome emissions and test for them than attempt to predict the level from existing data.

Other trace metals are said to be largely retained in the ash and removed by the precipitator. De Vito, M.S. et al. 1992 tabulated the estimates for retention and emissions from typical high quality US coals fired on a 750 MWe boiler. Those coals would have been washed. The total quantity of the following elements:- Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni and Se - leaving the precipitator was estimated at 2.4 tonnes/year. Applying this relationship to UK and the corresponding total coal burn, the total trace metal leaving the precipitators would have been of the order of 75 tonne in the year 1993/94, but only if the power station fuel had been washed across the full size spectrum as in the USA.

Further work by Consol (DeVito, M.S. et al 1994) indicated that the washing process will reduce trace elements broadly in proportion to the reduction in ash. Although they found that most trace elements would reduce in this way, As, Sb, Mn, Ni and Pb typically remain with the wash plant waste and wash better than average while Hg and Se tend to stay with the coal where only 30% and 40% respectively of the total ash reductions are observed. Hence, one of the conclusions in the DeVito paper is that "conventional coal cleaning is an effective means to reduce the concentration of trace elements in coal". To the extent that a significant proportion of Power Station Fuel remains unwashed, the emission of trace elements could be expected to be higher in the UK than the USA so the figure of 75 t/yr for the emission of trace elements may well substantially understate the release where FGD is not fitted.

The last of the elements which commonly occurs in coal and which would not be trapped in the system is fluorine. A paper by deIuliis (deIuliis,N.J. et al, 1993), presents the results of research suggesting that from the acid dew point calculations, most of the fluorine will be released to atmosphere unless FGD is fitted. The fluorine content of US eastern coals lies in the 60-80 ppm range. Clarke and Sloss, 1992 indicate that the more typical coals of the world contain 150 ppm of fluorine but on the basis that the halogens could be expected to form together, the fluorine content in UK coals could follow the relatively high chlorine content. Swaine, 1990, suggests a range of 27-202 ppm for UK coals. Consequently, the HCl emission indicated in the annual environmental report would slightly understate the total emission of halogens. These figures have been used as a basis for comparison with the clean fuel technologies in Section 7 and a projection of the levels which could be expected after completion of FGD at Drax and Ratcliffe with facilities fully operational.

The other solid waste which is mentioned in the Environmental Performance Reports of the two major UK generators but not quantified is the nature of the precipitated ash from the combustion of Orimulsion. PowerGen state that it is compacted for recycling without mentioning that it contains nickel and vanadium or that there would be a reduced performance of the precipitator which may allow 10% of the very fine ash to pass to atmosphere if the flue gases are not scrubbed. This point is again picked up in Section 7.

The likely total emissions have been calculated for three future time periods including the period after the present coal contracts have expired. The assessments have been based on the two gas entry scenarios described previously and are tabulated below in Table 8 in terms of thousands of tonnes per year. One uncertainty is whether the FGD proposed for Pembroke will be operational and the calculation has been made assuming no abatement on the oil burn.

The emissions of sulphur dioxide have been based on the sulphur content of the fuels with a sub-case for Drax and Ratcliffe base loaded with FGD operational. The NOx emissions have been calculated from the declared g/kWh figures given by National Power and PowerGen for coal multiplied by the TWh indicated in the scenarios. The gas component has been calculated on the manufacturers guarantee levels and a sensitivity was calculated from PowerGen's data on Rye House given in their Environmental Report. That suggested an upward adjustment by a factor of 1.4 to convert from the latest manufacturers data to a figure more representative of the older design of turbine.

As will be seen in the table, the impact of the gas entry is significant both on the SO_2 and NOx emission. The scenarios are those discussed earlier and drawn from data produced by OXERA broadly based on the Seven Year Statement.

Table 8: Possible Emission Levels - England and Wales

Emissions kT/yr	94/95	96/97	98/99	2000/01
SO_2 high gas entry	1,910	1,489 (1186)	624 (321)	763 (460)
NOx high gas entry	453	348	137	167
SO_2 low gas entry	1,910	1,517 (1214)	1,012 (709)	1,133 (830)
NOx low gas entry	467	378	265	295

Figures in brackets indicate an assessment of FGD at Drax and Ratcliffe fully operational

Source scenarios for calculation - OXERA

The sulphur level could be reduced further after 1998 by a reduction in the sulphur level of coal burnt and the use of FGD on the oil burning capacity. The latter step could remove about 200 kT/year from the figures given in the table. Nevertheless, if the FGD at Drax and Ratcliffe were to be considered to be too costly to operate to sell the output profitably to the grid, then the emission levels would remain in the range of 750-1,000 kT/yr.

7.0 REVIEW OF GENERIC WASTE STREAMS

7.1 Background

One of the key areas to be addressed in this report is the generic waste streams from the range of technologies being considered. The section will attempt to lay out the available data in some detail. It will not refer to any specific installed capacity but rather will relate to the type of generating equipment and fuel used.

The waste streams from each of the main technologies will be discussed separately and then will later be summarised in a comparative table. However, some caveats should be mentioned in making comparisons. It is possible to track the flow of sulphur through a system with a high degree of confidence. The tracking of nitrogen is more complex especially when coal is combusted. NOx can arise from two sources. Fuel-bound nitrogen - some of which will be converted into NOx and thermal NOx which is formed when air and nitrogen are together at high temperature in the firing zone.

The quantity of fuel-bound nitrogen will differ from fuel to fuel. Combustion Engineering's manual (Combustion - Fossil Power Systems 1981) suggests that up to 80% of the nitrogen in coal may be converted to NOx but the relationship is non-linear, being inversely proportional to the absolute level of nitrogen in the coal. The nitrogen content will vary with every coal so it is not possible to generalise on the release of NOx from power stations without a detailed knowledge of the boilers, burners etc. and the coals being combusted.

Although Combustion Engineering's relationship may hold for a range of US coals and with conventional burners, more recent research work, for example, by PowerGen and EPRI (Jones, A.R., et al 1995) on a wider range of coals and low NOx burners suggests a somewhat more complex pattern to the formation of NOx. The research suggests that the formation of NOx when low NOx burners are used will be linked to a number of factors. Their work confirms that the level of NOx will be broadly dependent on the quantity of nitrogen in the fuel but one of their key observations was that the bulk of the nitrogen associated with the volatile matter in the coal will be converted to nitrogen in normal operating conditions. However, most of the nitrogen remaining in the char, which will combust more slowly, will be released as NOx. The split of the fuel nitrogen between volatiles and char can be determined by laboratory tests but will remain coal specific.

PowerGen found that there was a good correlation between the results from their test rig and the plant data from Kingsnorth. However, when measuring NOx, it is important to relate it to other operating parameters. NOx can be reduced by reducing excess air but that would increase the level of carbon on ash (COA) and the carbon monoxide (CO) emissions. In fact, the control of NOx, COA and CO are all inter-related being linked with the type of boiler design, burner type, primary and secondary air and over-fired air. In the laboratory using a single burner rig, it was possible to reduce NOx to levels of 150-200 mg/m^3 but this was not found to be achievable on a large boiler with many burners.

It raises an important issue regarding the setting of emission levels for NOx because of the dynamic balance with carbon on ash and CO. An increase in carbon on ash reduces efficiency and may create a problem with its subsequent commercial value. The emission of CO is also a loss of potential heat and another pollutant in its own right. Consequently, there would appear to be a need to avoid specifying levels of NOx emission in isolation but consideration might be given to relating it to the levels of carbon on ash and CO emissions which can reasonably be achieved simultaneously when observing good operating practices.

The thermal NOx which will form is proportional to combustion temperature. The design of low NOx burners is based on reducing combustion temperature while retaining the efficiency of combustion. The actual performance of a boiler will therefore depend on boiler and burner design and fuel. Consequently, it is too fuel and boiler specific to be predictable with any degree of confidence. The figures used in this section will therefore be derived from observed levels given in papers for existing plant and for new technologies.

To recapitulate, any direct combustion process will release the pollutants in the fuel at the moment of combustion. In those circumstances, the options for capture of the pollutants take place either very quickly during the combustion process, as with fluidised bed combustion, or afterwards in some form of flue gas treatment system. Ash from the burning of coal as pulverised fuel will form a small quantity of clinker but the bulk of it will leave the boiler as fly ash in the flue gases. The ash in HFO or Orimulsion will remain in the flue gases.

Since particulate matter, sulphur dioxide and nitrogen oxides all require different types of capture process, three distinctly different steps may be needed for each of these pollutants separately, albeit that some designers have now developed combined SO_X/NO_X processes. Electrostatic precipitators are required to remove particulate matter when coal or Orimulsion is being fired, FGD for SO_2 control and low NOx burners and/or some form of DENOX process for NOx control. Volatile trace metals, chlorides and fluorides are likely to escape capture and be released to atmosphere unless wet scrubbing systems are fitted. Even when fitted, there is US evidence to suggest some pollutants still escape.

The gasification process converts the primary form of energy into a gas. Dependent on the feedstock (fuel), the process removes most of the solid waste as a slag and converts the sulphur into a form easily removed by scrubbing. Wet scrubbing systems will also eliminate particulate emission and capture virtually all of the trace metals.

When reviewing the generic wastes, the emission levels also need to be set in the context of current legislation and possible changes. Europe, and particularly the UK, has seen some significant changes in the choice of primary energy for power generation over the past 40 years with a switch at roughly 10 year intervals from coal to oil, back to coal and now to gas. However, the power plants were designed for a 30 year life. In considering BATNEEC, these changes may need to be taken into account particularly since technological advances would enable most generating methods to approach the emission standards which can be achieved by gas turbines with appropriate investment in abatement systems.

7.2 Recent Results of US Power Plant Monitoring

The Clean Air Act Amendments of 1990 revised a range of controls on emissions and pollutants in the USA. The Act included provisions of the so-called Title III Hazardous Air Pollutants (HAP) which completely revised the existing federal list of HAPs. The core of Title III is a list of 189 chemicals which may cause potential hazards to human health and to the environment when emitted. As a result of the Amendments, a great deal of work has been undertaken to investigate the whole question of emissions and pollution in detail. The Act required the Environmental Protection Agency (EPA) to evaluate the emissions of the 189 HAPs from industry and the electric utilities. It then has to determine the levels of control achievable by flue gas scrubbing devices.

In 1993, the US Department of Energy's Office of Fossil Energy gave five of the nation's leading environmental consultancies the task of assessing the releases from eight coal burning plants to provide the EPA with the critical data it needs to carry out their task with respect to the power sector. This programme represented the most comprehensive study ever undertaken in the USA. The EPA is directed to report by November 1995 on whether the release of these hazardous air pollutants, often referred to as air toxics, poses a health risk.

The assessment was completed during 1994 and reports have been prepared by each of the companies commissioned to undertake the work. The companies selected and the power plants assigned to them were as follows (power companies in italics):-

Southern Research Institute, Birmingham, Alabama
Northern Indiana Public Service Co. Bailly Station, Gary, Indiana
Tucson Electric Springerville Station, Springerfield, Arizona
A coal preparation plant - Blacksville No. 2 owned by Consol Inc

Battelle Memorial Institute, Columbus, Ohio
Ohio Edison Niles Station, Niles, Ohio
Cooperative Power Association Coal Creek Station, Underwood, North Dakota

Roy F.Weston, Inc., West Chester, Pennsylvania
Minnesota Power Co.Clay Boswell Station, Cohasset, Minnesota
Illinois Power Co.Baldwin Station, Baldwin, Illinois

Radian Corporation, Austin, Texas
Georgia Power Co.Plant Yates, Newman, Georgia

Energy and Environmental Research, Inc., Irvine, California
Ohio Power Company Cardinal Station, Brilliant, Ohio

The consolidation of the data from each of these reports into a single summary report has been drafted by the Pittsburgh Energy Technology Centre and is due to be published shortly.

The research programme called for the addition of a coal preparation plant to determine the extent to which washing of the coal removed trace elements. Tests were undertaken to measure 30 different potentially hazardous air pollutants known to be emitted from power plants including lead, mercury, boron and selenium along with a range of hydrocarbons. Measurements were made on solid, liquid and gaseous streams in order to establish material balances throughout the plant.

The programme objectives were:-

- to determine the ability of various types of pollution control equipment to capture toxic air emissions
- to determine the materials balances of selected pollutants
- to determine how the level of the emissions in the flue gases varies by the size of particles, an important consideration because larger particles are more likely to be captured by collection devices and less likely to be inhaled.

- to measure the relative levels of emissions in the particles and in the vapour of the flue gases since it is only the solids which are collected in the particulate collecting devices

There were also the questions of whether the volatile elements or their compounds could be passing through the complete system to the stack and whether those metals or compounds could re-enter the bio-system in some way.

In designing the test programme, the USDOE chose a spectrum of plants on the basis of size, emission control equipment and fuel. The latter included sub-bituminous Powder River basin and Lee Ranch coal of high moisture/ash content, medium sulphur Illinois Basin coals to high quality Eastern bituminous coals. Since the reports on each of the power stations run to two substantial volumes, it has been necessary to paraphrase the main findings. Summary papers by three of the five Consulting Groups were presented at the Tenth Annual Contractors Conference in Pittsburgh in July 1994. They covered the work by Radian Corporation, Southern Research Institute and Roy F Weston Inc.

The surveys found that, in general, there was excellent particulate removal efficiency achieved by the electrostatic precipitators for almost all trace elements in coal except selenium, mercury, boron and some radionuclides (uranium and radium). All other metals were captured at levels above 95% and overall particulate matter over 98%. The performance of bag-houses was somewhat better than precipitators for retaining the elements and an overall efficiency of 99.9% was quoted at one location. The UK coal-based generators all operate precipitators, but to date, no bag houses have been fitted. The performance of the precipitators enables the statutory levels of particulate in the flue gases to be met comfortably on the range of coals used. However, if levels of 50 mg/m^3 or 25 mg/m^3 were to be introduced, then bag filters might be required or the addition of more stages to the precipitator possibly including a wet stage.

Bag-houses are an efficient way of reducing the very fine particulate i.e. below 10 micron diameter. However, the fabric used for the filters is the important determinant in the degree of capture achieved. Bag-houses are used widely in the US frequently with woven glass fibre air bags. They offer a higher degree of clean-up than precipitators. The European designs tend to use needle felt or coated surfaces based on Gortex which are extremely good for capturing the very fine particulate. This is the type of equipment which might be needed to supplement precipitators if there were to a reduction in the limits for particulate in total or the PM_{10} , i.e. the material below 10 micron, if evidence emerges that the fine particulate has a proven effect on human health.

The US trials also produced evidence that the few elements Se, Hg, B and radionuclides exhibit behaviour which is distinctly different from that of the particulate matter. This has been explained by the physical and chemical transformations that occur when the metals in the coal are subjected to the conditions that exist in the boiler. A study (Randall Seeker W, et al. August 1994), summarised the work in this field. The findings suggest that Se, Hg, Sb, As and Pb are highly enriched in the finer particle size fractions. In other words, these metals are found in greater proportion in the 1 micron size than in the 10 micron size. Dry precipitator capture efficiency falls off quite rapidly below 10 micron and particularly below 4 micron. Consequently, much of this very fine material is not captured and neither are these trace elements.

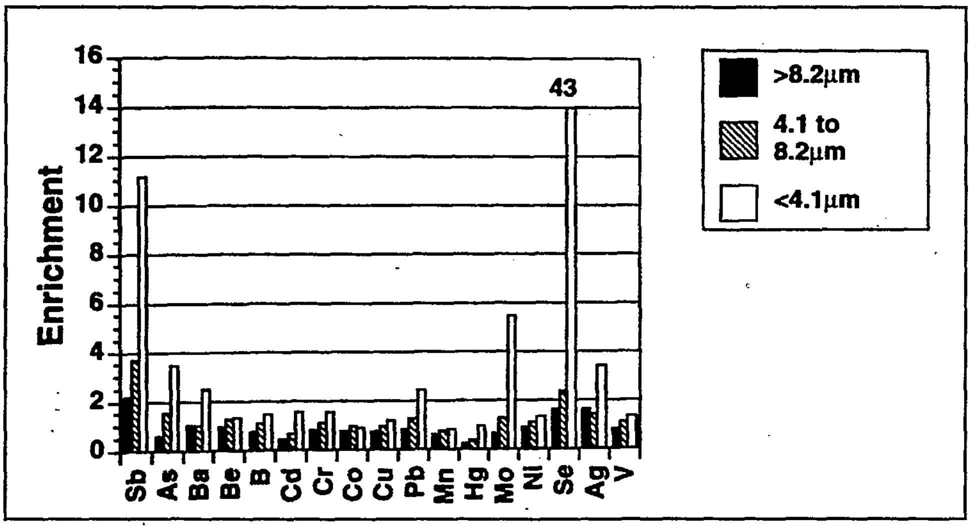


Figure 6: Enrichment of Metals in Different Particle Size Fractions for Cardinal Coal Fired Station

Source: Randall Seeker,W. et al, 1994

Similar results were found at the other power plants. Weston Inc also tested the effects of soot-blowing on the enrichment process and found that there was virtually no difference when the particulate matter was dislodged during soot blowing.

Research work on vapour pressures at boiler temperatures and excess air suggest that Cd, Pb, As, Sb, Se and Hg would be expected to volatise completely at combustion temperatures. The highly volatile metals which include Hg, Se, Be and U would certainly volatilise. These metals can also be predicted to stay in the vapour phase even at temperatures experienced in the air pollution control devices (APCD). Boron has a unique behaviour because it could be expected to condense ahead of the precipitator but equilibrium calculations suggest it becomes volatile again as HBO_2 thereby escaping capture. More detail on mercury follows in Section 7.3.

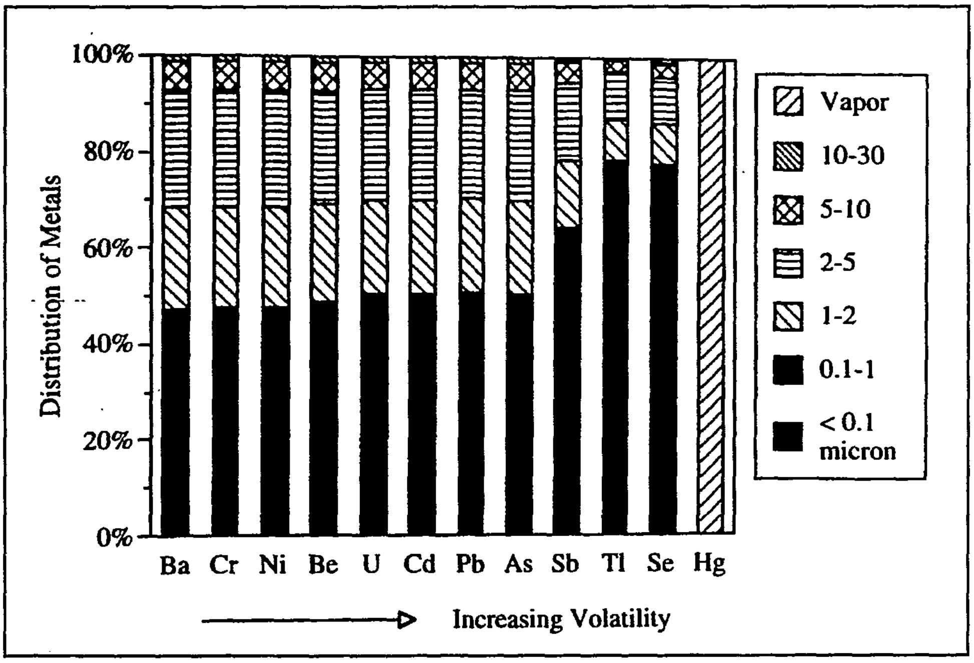


Figure 7: Predicted Distribution of Metals at APCD*

Source: Randall Seeker,W. et al, 1994 * Air Pollution Control Device

The chemical form of the Hg in the vapour phase of the precipitator plays a significant role in determining retention. Elemental mercury is the dominant species at high temperature down to a temperature of about 600°C. Below 400°C the dominant form is $HgCl_2$ especially when ample chlorine is present. The same paper states that several of the metal chlorides are more volatile than the metal itself so the chlorine content of the coal can have considerable effect on capture.

The survey has highlighted a number of issues which suggest that the USDOE were fully justified in being concerned about air toxics. Particulate release and particle size emerged as an important consideration when assessing the health impact of emissions from power plants. Particles with a diameter of 10 micron or smaller are a major fraction of the respiratory particulate matter which poses a health risk. The aerodynamic diameter determines the behaviour of a particle with regard to inertial and gravitational forces found in dirt collection equipment as well as in the human respiratory system.

The Yates Plant owned by Georgia Power Co. was monitored by the Radian Corporation (June '94 report) and their quality control was audited by Research Triangle Institute for the USDOE. The 100 MWe plant was fitted with ESPs and a second generation FGD process employing a jet bubbling reactor to combine absorption, neutralisation, sulphite oxidation and gypsum crystallisation into the reaction vessel. The plant is run on a blend of Illinois No 5 and No 6 coals with a sulphur content of 2.5%.

The particulate capture has been covered above so the relevant parts of the more detailed analysis relate to anions, selected elements and organic compounds. The results were set in the context of the detection limits and 95% Confidence Intervals (95% CI). Materials balances were calculated for 27 elements and, of these, 60% met target closure objectives of 70-130%, and 85% met 50-150%. The data tabulated below in Table 9 was quoted in terms of $lb/10^{12}BTU$ ie. the number of pounds weight of the element which would result from the combustion of about 40,000 tonnes hard coal or sufficient coal to fuel a 16 MWe power plant year-round or Ratcliffe for about 3 days on base load. In the preface to their results, they point out that the measurements of some of the substances of interest are near or below the analytical detection limits which led them to use the concept of Confidence Intervals.

Table 9 - Emission Factors

	$lb/10^{12}$ Btu	95% CI
Anions		
Chloride	742	647
Fluoride	122	67.0
Selected Elements		
Antimony	0.06	0.01
Arsenic	1.2	0.2
Barium	2.8	9.9
Beryllium	0.1	0.1
Cadmium	0.6	2.1
Chromium	5.3	49.5
Cobalt	0.7	0.8
Copper	2.0	2.3
Lead	0.6	0.6
Manganese	7.2	48.0
Mercury	3.0	0.3
Molybdenum	0.5	2.6
Nickel	40.1	43.5
Selenium	26.5	58.0
Vanadium	21.0	0.5

	$lb/10^{12}$ Btu	95% CI
Aldehydes		
Acetaldehyde	8.6	9.2
Formaldehyde	24.0	36.0
Volatile Organics		
Benzene	1.3	0.3
Carbon Disulphide	2.2	1.2
Toluene	2.0	1.0
Semivolatile Organics		
2-Methylphenol (o-cresol)	2.9	3.8
4-Methylphenol (p-cresol)	0.95	1.9
Acetophenone	3.2	0.7
Benzoic Acid	120	7.0
Benzyl Alcohol	2.8	12.0
Naphthalene	1.5	1.0
Phenol	9.2	8.8

Source: Radian Corporation

Note. The figures quoted above would need to be multiplied by a factor of about 100 to represent potential annual emissions from a 2000 MWe station operating on the same fuel blend.

Some 99% of the mineral matter was retained by the precipitator including many of the trace elements, the exceptions being chlorine, fluorine, selenium and mercury. The blend of coals contained 0.1% chlorine and traces of fluorine. A Bloom mercury speciation train analyser was used to measure the individual mercury species:- ionic mercury, elemental mercury and methyl mercury. Total mercury was measured using a multi-metals train. Ionic mercury appeared as the dominant species in the ESP inlet and outlet gas streams but ionic mercury was more efficiently removed by the second generation FGD equipment.

Selenium was the most difficult of the trace elements to measure accurately. It could be present either in the vapour phase as SeO_2 or as a component of the enriched finer particulate matter. Radian Corp could not reconcile some of the data collected and concluded that it pointed to an error in sampling and analysis. They highlighted the problem as an area for further work. Nevertheless, the theory is that selenium could actually be escaping in the vapour phase while the sampling system itself had been precipitating selenium in a filter which forms part of the Method 29 sampling train used for their measurements.

Traces of organic compounds were also present in the flue gases. The figures for aldehydes, volatile and semi-volatile organic compounds are tabulated above. The highest of the organic figures was benzoic acid which was by far the largest of the organic compounds and was equivalent to the level of the fluorine emission. Similar figures were recorded by Southern Research Institute on the Lee Ranch coal with formaldehyde at 1.4 and benzene 1.0. Southern also tested for dioxins and furans which were quoted at a level of <0.000006 lb/10^{12} Btu equivalent to 0.00006 lb/year from Ratcliffe on base load.

Radian found that there were particulate emissions from the FGD system. The result showed that much of the very fine particulate was not held back by the FGD system i.e. on particles having an aerodynamic diameter of 10 micron or less. Analysis of stack emissions indicated that 60% of the particulate emission was 10 micron or less while 30% was less than 1.26 micron. Radian said that the link between particle size, surface orientation of trace elements and the penetration of fine particles cannot be demonstrated simply by comparing the extractable and total metal concentrations of the particulate emissions from the FGD system. Fly ash penetration, the mass contribution from sulphuric acid mist and scrubber mist soluble salts (gypsum) add to the variables in the assessment of air toxic emissions as a function of surface orientation.

Their report suggests penetration mechanisms which explain the particulate emissions from FGD systems. They were:-

- direct penetration of the fly ash
- capture of the ash particles in the scrubber liquor and re-entrainment during recycle
- entrainment of scrubber-generated solids
- evaporation and penetration of scrubber mist as soluble salts
- condensation and recovery of sulphuric acid mist as particulate

Three other metals (in addition to mercury) displayed higher penetration than average. They were arsenic, cadmium and phosphorus. This again is accounted for by enrichment and their association with sub-micron particles. Hexavelant chromium was also found in traces (<0.19um/Nm^3) in the stack gases. The compound can convert to the trivalent form in 24 hours in the sample container so there was some uncertainty about the true level in the flue gases.

The studies also addressed the issues of run-off water from coal stock-piles, leaching of bottom ash and the disposal/leaching of pulverised fly ash. The run-off from stock-piles presented no environmental problems in terms of significant soluble contaminants. Neither was there a problem with bottom ash. However, in the ash pond water where many US utilities dispose of much of their PFA, traces of salts of most of the metals in the coal could be detected.

A significant change in the appreciation of environmental impact appears to have resulted from these and other USDOE analyses. The emissions measured on the new clean coal technologies such as gasification have been very carefully monitored to illustrate the level of cleanliness which could be achieved, while the true base performance of conventional power plant was not known with the same degree of accuracy. The study was initiated to establish a base case inventory of emissions from pf-fired coal.

7.3 Mercury

In parallel with the work on emissions measurement, further analysis was undertaken to assess whether there could be any health risks associated with the low levels of mercury emission. Several papers have reviewed the subject but the most comprehensive was commissioned by USDOE from the Biomedical and Environmental Assessment Group of the Brookhaven National Laboratory which makes reference to previous papers. This study reviewed all the previous material on the subject, analysed known incidents of mercury poisoning and modelled the way in which release from power plants could lead to bio-accumulation.

Where FGD is not fitted, the gases leaving the precipitators will be discharged to atmosphere. The precise form of mercury in the air remains uncertain because reactions could continue in the atmosphere before deposition. It would be in one or more of three forms:- elemental mercury, methyl mercury and ionic mercury (e.g. $HgCl_2$). **The study stressed that it was premature to draw conclusions.** However, there is a linkage which could return mercury to the biosphere. One such mechanism is via methyl or ionic mercury into water-courses and lakes. It can then be taken up by freshwater fish and can enter the human food chain particularly in small communities whose diets depend on local fish. Mercury could remain airborne for a long time and would eventually enter the oceans but with sufficient dilution that it was not considered to be a potential health problem.

Data was developed by the Brookhaven National Laboratory modelling the dispersion of plumes from stacks using a Gaussian dispersion model. The levels of mercury in the typical US coals used for modelling purposes was assumed to be 0.08 ppm which would yield an emission of 8-10$\mu g/m^3$ in the stack gases. The modelling assumed a mid-western location for a hypothetical 1000 MWe power plant. A probalistic risk assessment was made assuming the dispersion returns the emissions to land with the pollutants taken up by rain into rivers and lakes. They assumed gamefish are caught for food. This was again modelled based on statistics of diet and annual fish consumption. Many species of fresh water and sea water fish were tested for Hg to verify the precision of the data and broad agreement was found. It also provided data for the range of human intake which enabled a statistical probability of the incidence of symptoms associated with mercury poisoning.

Trace mercury poisoning can result in parasthesis. In greater concentration the symptoms can become far more serious. The results of the modelling indicated very low levels at present which represented little risk to health of the general population. However, there was some concern expressed about the sensitivity of sub populations e.g. children and pregnant women, so more research was recommended.

In response to the Clean Air Act Amendments, EPRI instigated its own series of studies into emissions from coal fired power plants. They had responded to a different part of the Act which required sources of emissions that emitted 10 tons a year of any one pollutant or 25 tons of any combination to apply Maximum Achievable Control Technology. The pollutants in question were the 189 listed chemicals. The utilities were considered as an exception to the Act but EPRI could see the extent to which their industry was vulnerable and undertook their own test programme which included a major study of mercury.

Their work on mercury was reported separately (Chow,W., 1994) and makes the point that on US coals, the uncontrolled emission would be about 1 lb of mercury per year per MWe of power or roughly one tonne/year for a 2000 MWe station (based on the average mercury level of US coals). However, the results they quote suggest a somewhat higher level of capture in the precipitators and baghouses e.g. 20-90% for ESPs and 85-90% for fabric filters than the figures reported by Radian and the other consultants. EPRI also mentioned a third test method for mercury, the Frontier-Geoscience Mercury Speciation Method, as a supplement to the other two methods. Methyl mercury was detected in stack gases but later studies cast doubt on the results suggesting an overstatement of this more toxic form.

EPRI also tested methods for the capture of mercury in gas streams and found activated carbon to be an effective method, giving better than 90% removal at a ratio of 4000 parts of carbon per unit of mercury. The costs of such a method were not given. The EPRI data, however, needs to be interpreted as the power industry's response to the Clean Air Act Amendments.

Work in Sweden was also focused on mercury capture. Linde has developed a process, also using activated charcoal, to absorb it and the mercury would be recovered as the metal by reprocessing. The volume of gas to be treated would be very large.

The USDOE studies were designed to provide a totally factual account of emissions from the eight coal fired stations as a basis for an EPA decision of the need for setting limits against the 189 chemicals listed as potentially dangerous pollutants. The studies also showed that mercury in coal is frequently found with pyrite and may be proportional to the pyrite content. The washing process therefore tends to hold back some of the heavy metals in the wash plant waste and this was found in the studies. Most power plant coal used in the USA today is likely to have been prepared by washing the full size range. It was found that ionic mercury will form with higher chlorine levels in coal. US coals are typically less than 0.1% Cl.

7.4 Mercury and the UK Position

Data produced in a world survey of mercury in coal (Raask,E. 1985 and Swaine. 1989) indicated that the mercury content of UK coals lay in the range of 0.2-0.7 ppm with say a mid-point of 0.45 ppm. If the emissions for the UK were modelled using the US techniques based on a mercury content at the mid-point of the range i.e. 0.45 ppm, the releases for an equivalent sized power plant would be five times greater than those predicted for a US power plant.

Furthermore, the chlorine content of the UK coal is considerably higher than that of US coals. The typical level quoted in the 1993 Environmental Reviews by the two major generators was 0.2% Cl. The Boyd report data coupled with RJB Mining's production pattern suggest that a chlorine content of 0.2% understates the average of current private sector production. Coals from Kellingley, Gascoigne Wood, Bilsthorpe, Welbeck and Rossington have chlorine levels of 0.4% and above. Some 10-15 mt of production could be expected to lie in this range. This suggests the possibility of a detectable level of $HgCl_2$ in stack gases. As mentioned previously, a substantial part of the 1" minus size fraction remains unwashed and therefore the mercury content of Power Station Fuel could well be higher than if the coal was fully washed for the reasons given previously.

The US modelling was based on a hypothetical 1000 MWe unit in a location remote from other plant so that emissions were only additive to natural background. They concluded that in that situation there was a very low risk to health. In the UK, the larger coal fired stations are 2000 MWe and are grouped around the main coal fields in relatively close proximity. In view of the combination of mercury and chlorine content coupled with the number of power stations, there would appear to be a strong case to take the precaution of repeating some of the US emissions tests for trace element emission from the UK coal fired stations. This should be linked with parallel measurements of ground level concentrations in the air and in local run-off water to determine whether there is any accumulation of mercury, selenium or boron resulting from the combustion of coal in power plants.

In view of the difficulties experienced in sampling and testing in the USA for these elements, it might be helpful to draw on the recent experience of one of the US consulting groups in preparing any scope of work especially in reviewing the sampling and analytical methods most appropriate to such a study.

7.5 Emissions from the Combustion of UK Coal

An assessment of emission and waste streams per 1000 MWe of typical plant operating on UK coal at an LHV efficiency of 37% has been made to provide some measure of the levels of potential pollutant which could result from the direct combustion process. Other assumptions are a net CV of 24 MJ/kg, (CRE assumption) 1.6% sulphur and chlorine of 0.2% (from National Power Environmental Review).

Two cases have been run to illustrate the differences between the levels of sulphur emission when FGD is fitted and that without FGD - Table 10. The above assumptions lead to a calculated annual coal burn of 2.6 mt for the 1000 MWe model.

Table 10

	Without FGD		**With FGD**	
	kT/YR	**g/kWh**	**kT/YR**	**g/kWh**
SO_2	81.9	13.25	7.4	1.3
NO_X	43.0	2.8	43.0	2.8
Particulate	5.18	-	-	-
HCl	7.2	1.1	-	-
Ash - PFA	296.8		296.8	
Clinker	74.2		74.2	
FGD Waste			185.0	

Note: 1. The sulphur and chlorine levels used are taken from the National Power and PowerGen environmental reviews.

The use of wet scrubbing FGD systems will remove most of the trace elements and halogen. However, the halogen will need to be extracted in order to make marketable gypsum so there are likely to be chloride rich streams which may have to be treated and environmentally acceptable disposal methods found.

7.6 Combustion - Heavy Oils and Orimulsion

The significance of the fly ash penetration in FGD systems led the USDOE to check oil fired systems and the size distribution of particulates in natural background. The latter was determined in the vicinity of the Mount St.Helens volcano. Particulate matter was found in the air but measurements led to the conclusion that naturally occurring dust was of a comparatively large particle size and would cause no health hazard. However, the very fine particle size emitted from power stations could represent a health risk which needed to be investigated.

The ash from oil combustion was known to be fine so two oil fired plants were tested and samples of the small quantity of ash produced was collected. Tests were undertaken to assess possible health effects. The fly ash resulting from the combustion of heavy oil was said to be an order of magnitude more harmful because of its micron size causing irritation and lesions in the lungs of rats (Costa, D. et al. 1994). The American Thoracic Society Conference in Seattle in May 1995 heard at least 8 papers on the subject (see References). Particulate toxicity appears to amplify an pre-existent inflammation in the lung.

In evaluating the differences in the combustion of coal and oil residues, it became apparent that the dispersion of the oil fuel on atomisation results in a very fine particle size much of which is below 1 micron. The ash largely consists of metal oxides including those of nickel and vanadium and these sub-micron particles are not collected efficiently by precipitators or bag-houses. US experience suggests that a bag-house might only remove 60-90% of the particles from the combustion of heavy fuel oil.

The other observation from Radian's work on coal was sulphuric acid mist. This is exacerbated in the case of residual oil fuels because of the presence of vanadium and nickel. The commercial manufacture of sulphuric acid by the "Contact" process is based on

$$2SO_2 + O_2 \rightarrow 2SO_3$$

a reaction which is promoted by catalysts such as platinum, vanadium or nickel. The reaction is almost complete at temperatures around 400°C hence, in oil fired plant the conditions are favourable for acid formation in the flue gas system, and this was found. Similar observations have been made in Germany where at least 5% of the sulphur in lignite is found to emerge from the boiler in the form of SO_3.

SO_3 is not as readily absorbed by wet limestone as SO_2 so if the conversion stage occurs, less is captured. The explanation appears to relate to the form in which the SO_3 exists i.e. as an acid aerosol of less than 1 micron which behaves like a gas. The wet scrubbing system would appear to have limitations where SO_3 is likely to be present in large quantities. The best alternative for the acid aerosol capture would appear to be dry scrubbing with limestone in a fluidised bed.

The reaction will be limited by the amount of oxygen in the excess air in the boiler but some reaction is almost certain to occur. It then becomes important to control flue gas temperature to avoid the system falling below the dew point of sulphuric acid.

Combustion Engineering's handbook "Combustion" confirms the problem as do the standard text books on flue gas treatment. SO_3 is highly reactive and extremely hygroscopic compared with SO_2. The reaction is enhanced by the presence of fine particles which serve as condensation nuclei. The resultant aerosol is a principal constituent of visible stack plumes which have a characteristic silvery-blue colour.

Consequently, if this knowledge were to be applied to Orimulsion, several features of the fuel - sulphur content, particle size, nature of the particle and moisture content would all lead to the strong possibility of sulphuric acid mist formation if fired on boilers designed for coal or oil. Neither Ince not Richborough power stations are fitted with FGD and were designed for coal so there is the strong possibility that sulphuric acid aerosols are being emitted to atmosphere during the current trials of Orimulsion.

The design of FGD systems for the scrubbing of flue gases from the combustion of Orimulsion presents a different set of challenges to those for coal firing. Designs may have been tested in Japan but no detailed results have been published so far. The only FGD system designed for Orimulsion in the West is at Dalhousie in Canada. A brief paper of early operating experience was prepared for the 1995 I Chem E Desulphurisation Conference in Sheffield (Sturgeon, J. et al 1995) indicating satisfactory results using a Babcock and Wilcox wet limestone system. However, the authors state that Orimulsion presented unique challenges without elaboration. In addition to the sulphur oxides, the ash contained nickel, magnesium, vanadium, zinc and traces of arsenic. Some of the ash carried through the precipitator and entered the FGD unit. They acknowledge that much experience has been gained both by the power company and the contractor which suggests some interesting chemical engineering problems.

In Europe, trials are currently being conducted in Denmark on the Aesnes No.5 plant which was designed for coal and is equipped with FGD again designed for coal. Preliminary results are not being disclosed. A private communication suggests that the sulphuric acid mist problem has been encountered because the FGD is being operated above design inlet temperature to avoid the condensation of sulphuric acid. The decision on whether Orimulsion can be used as a fuel in the longer term on equipment designed for coal will only be taken at this location after the trial is complete and the results fully analysed. In the meantime, all the results are being kept confidential.

The US data suggests that it may be difficult to overcome the escape of the fines or the formation of SO_3 especially in a system where the gas velocity is increased so substantially by the presence of the 28% water in fuel. Furthermore, the water remains in the system as vapour and there is abundant oxygen in the stage of the FGD which makes the gypsum to run the risk of making sulphuric acid. Analysis of the particle size from the combustion of Orimulsion during the initial tests at the Dalhousie Plant suggested that 98% of the particulate was less than 10 micron while 50% was less than 0.3 micron. Consequently, fine particulate "escape" or penetration through the wet scrubbing system already experienced on coal and oil is unlikely to be significantly different firing Orimulsion. The particle size analysis would suggest penetration could be substantially greater. Hence, it raised the question of whether wet scrubbing systems can retain sufficient particulate in the sub-micron size range or whether it will escape to atmosphere and cause a risk to health. All the evidence suggests that a significant quantity is likely to escape.

One of the key assumptions surrounding the direct combustion of fossil fuels like Orimulsion is that current legislation does not change. This may not be a valid assumption as new data is gathered, evaluated and related to other medical evidence on air quality. It would be surprising if the EPA does not make some recommendation as a result of the major studies which were undertaken either on trace element capture or particle size.

In Europe, the Large Combustion Plant Directive is being reviewed this year but it is also being done at a time when there is concern about the growing incidence of asthma and allergies. Evidence suggests a link with air quality, NO_X and particulates which could be derived primarily from diesel engines or from power generation. In the light of the US evidence on fly ash penetration or emission control systems where the size of the particulate release is considered a health risk, there would appear to be a case for further research to establish whether the trace element enrichment on the fine particulates or sulphate aerosol aggravates the health problem or whether a change in fuel alters the chemistry of particles.

The basis for the legal limits on particulates from the combustion of coal could reasonably have assumed the ash would be roughly the size of the milled coal i.e. about 70 micron, and would mainly consist of clays and silica. The US data suggests that a portion will be much finer. Orimulsion on the other hand yields an extremely fine dust as mentioned above high in vanadium and nickel compounds. The fact that the current legal limit of emissions is not exceeded may be irrelevant if there is a risk that the particulate matter can accumulate in humans by inhalation or via the food chain. Germany has already introduced 50 mg/m^3 as a particulate limit on coal-fired plant in a number of local areas versus the 100 mg/m^3 EU limit for new plant.

There would appear to be a case to assess UK levels of fine particulate emission especially at ground level and allow the relevant experts to review whether present or predicted levels could represent a health risk to communities or sub-populations. For example, what is the ground level concentration of fine particulate in the vicinity of a coal or Orimulsion fired power plant during adverse weather conditions and does that level of exposure represent a risk? Another question is whether stack emissions are the most appropriate point of control or whether ground level concentration is more important as the prime control point. This issue may be a minefield but limits have been legislated based on the best evidence available at the time when enacted. If further evidence suggests a need for change, then the position may need to be reassessed.

7.7 Pressurised Fluidised Bed Systems

The PFBC system has been described previously (Part 2 Section 2.1.3) and the summary of the environmental impact given in Table 6, page 51. The PFBC system has an advantage of both efficiency and sulphur capture. The sulphur absorption mechanism differs when the system operates under pressure and the calcium carbonate is not converted to lime before absorbing the sulphate. Pressure effectively shifts the equilibrium away from the formation of lime and effectively the sulphate displaces the carbonate without going via $CaCO_3 \rightarrow CaO + CO_2$. The subject was covered very comprehensively in a 1994 IEA Report on the "Management of PFBC Waste" (Nilsson, C. Lee, L.B.). Several researchers (Skeppe, 1993. Yrjas and others 1993) have studied the subject and the explanation appears to lie in the $CaCO_3/CaO$ equilibrium. A graph in the report illustrates the curve of CO_2 partial pressure versus temperature and it becomes clear that at bed operating temperature, lime exists at atmospheric pressure whereas under pressure, the $CaCO_3$ has not dissociated.

The absence of free lime has enabled the designers, ABB Carbon, to advise operators that the solid waste material i.e. the mixture of ash and sorbent, can be treated with a controlled quantity of water and will harden to a product of sufficient strength to be considered as aggregate. The report covers uses in much detail and in some respects suggests that insufficient quantities have been produced so far to explore the full range of potential uses. In this form, there is said to be a market in Sweden for road building material recognising that it is a 160 MWe unit consuming some 250,000 tonnes per year of coal. This would produce about 30 kT/Y of solid waste. However, no seal of approval or materials certification for specific uses has been forthcoming to date.

ABB Carbon quote low emission figures for the Värtan plant within the city of Stockholm. SO_2, NO_X, N_2O and CO are extremely low. The plant is able to operate at a level of gaseous emissions about 50% of the limits set for the plant when licensed but this has been achieved with a flue gas treatment or gas polishing step for both SOx and NOx. The levels are 50-80 mg/Nm^3 for SO_2, 40-60 mg/Nm^3 for NOx and below 12-36 ppmv for N_2O (Dahl, 1993).

With respect to trace elements, the experience at Värtan is that the bulk of the metals remain in the solid waste material. The IEA report supports this view. The fluidised bed is held at a temperature of about 850°C (vs 1500-1800°C on entrained gasifiers) so the trace elements tend to stay in the solid phase. Mercury is the most volatile of the trace metals and part of the mercury will enter the gas stream to pass through the turbine. It will then exit with the stack gases. Measurements taken in Stockholm suggest that about 50% of the mercury in feed will be emitted to atmosphere. To set this figure in perspective, the level of trace elements in coal is in the range of parts per million so an annual total of about 8 kilogram per year is emitted from the Värtan plant. It should be pointed out that this very low level of total emission needs to be set in the context of the mercury emissions from a typical crematorium which would normally run at hundreds of kilograms per year. Then the number of crematoria should be compared with the number of coal fired power plants.

Both atmospheric and pressurised fluid bed combustion systems have become commercially proven at a scale acceptable to the power industry. The two problems of the atmospheric system are:-

i. the disposal of residues because the presence of free lime poses problems for its use as general construction material

ii. the level of N_2O in the flue gas

The N_2O concentrations of 50-100 ppmv (Takeshita, M. - 1994) are to be expected and should be compared with pf-fired plant of 0.5-2.0 ppmv. Pressurised bed systems have superior environmental performance as indicated from Vartan at 12-36 ppmv. However, it should be recognised that these figures are based on a very limited number of PFBC plants compared with the data available on pf-fired plant.

The ability to clean flue gases to the limits stipulated in legislation raises an important point about limits, costs and the mechanism for setting levels. ABB has been able to demonstrate that flue gases can be cleaned to levels which are deemed appropriate for a plant within a major city, for example, Stockholm where the Vartan plant is surrounded by dwellings.

7.8 IGCC

Gasification with or without its integration into a combined cycle system offers a technology which can meet or exceed the most stringent of current emissions legislation in Europe and the USA . The gasification process alone breaks down the carbon-based feedstocks into a mixture of gases - predominantly CO and H_2. It will also handle a range of waste streams which will be addressed later.

The main pollutants present in most feedstocks will be sulphur and fuel-bound nitrogen. The sulphur is converted almost entirely to H_2S although there will be traces of COS and HCN leaving the reactor for removal in the gas clean-up system. Fuel-bound nitrogen would be released but some would combine with hydrogen to form ammonia which would be removed in the pre-scrubber waste water - see below.

If the feedstocks is a heavy oil residue or Orimulsion, then the other pollutants present will be compounds of vanadium and nickel. Until satisfactory methods of hot gas clean-up are developed and are proved to be economically attractive, the raw product gases would be cleaned using the standard methods of the oil industry which harness the regenerable sorbent properties of amines such as diethanolamine. Proprietary sorbents such as Selexol, Purisol, Rectisol and Sulphanol all perform a similar role in absorbing H_2S when cool and releasing it when heated.

The gas scrubbers are usually preceded by a water wash to remove any unconverted carbon in the form of soot. Any metal compounds which have not formed slag would precipitate with the carbon and be removed as a filter cake. Lurgi has taken this process one stage further. The carbon conversion efficiency is usually about 99% leaving up to 1% of unconverted carbon as soot to be recovered. Lurgi has adapted a multi-hearth incinerator as used in metals concentrates production and recovers the heat while drying and enriching the concentrate of vanadium and nickel for metals recovery. Texaco has developed a soot recovery and recycle circuit based on naphtha which is a more capital intensive solution. If the feedstock were to be petroleum coke or Orimulsion, again sulphur and fuel-bound nitrogen would be removed as above and the vanadium/nickel as the filter cake.

If coal is gasified, the sulphur and fuel-bound nitrogen would follow the same path as previously. Most of the ash would be fused into a slag which is tapped from the reactor and solidifies to a glassy bead-like material which is essentially benign. The following tables indicate the levels measured in the flue gases of the main gasifier types.

With respect to mercury, the evidence suggests that no detectable Hg leaves with the stack gases. Two theories may both be true. Elemental mercury is said to have accumulated in cool sections of the plant where heat recovery boilers are used i.e. the Shell designs. In the quench system (Texaco) the H_2S is said to react with the mercury vapour in the gasifier to produce the stable mercuric sulphide which then is removed with other insoluble sludges as a filter cake. This very small quantity of waste is taken to a registered waste disposal site approximately 1 tonne/year for a 1000 MWe unit.

Other work in Sweden fails to clarify the issue completely. The Universities of Uppsala and Stockholm worked on the subject and drew the conclusion from a theoretical base that the mercury remained in the ash with tests on gasifier slag from UBE in Japan and Tennessee Eastman to support the findings. However, a subsequent study by Vattenfall, the Swedish State Power Board, (thought to be unpublished in English) suggests that a small portion of the mercury will remain in the sour gas stream and enter the Claus kiln. Nevertheless, it would only amount to a few kg/year and would be coal specific.

The Cool Water Project indicates similar very low results for metals in waste streams. The EPRI final report contains a most comprehensive review of emissions and indicated the disposition of metals and VOC's through the whole system. The whole plant was sampled quarterly during the last three years of operation. Some of the results are tabulated below in Table 11.

When operating on the SUFCo coal, the following results were found and verified by Radian - the US environmental consultants.

Table 11: HRSG (e) STACK EMISSION OF NON-CRITERIA POLLUTANTS Measured During SUFCo Coal Operation

Substance	Measured Concentration [A] ppmv	Detection [B] Limits ppmv
Beryllium	ND [C]	10^{-4}
Mercury	ND	10^{-5}
Fluorides	0.004	10^{-5}
Ammonia	0-3 [D]	1
Methane	0-2 [D]	1
Non-Methane Hydrocarbons	ND	1

Notes: A) Units are parts per million by volume, dry basis
B) Detection limits vary depending on sample size and analysis technique
C) ND = None Detected
D) Range shown indicates detection in only a few of samples analysed
E) HRSG - Heat Recovery Steam Generator
Source: Texaco

In a 1994 paper by Shell (Baker, D.C. 1994) - a similar picture emerged relating to the projected emissions of hazardous air pollutants. The analysis of the cleaned syngas prior to combustion in the gas turbine is set out in Table 12 - expressed in decimal fractions of parts per million.

Table 12: AVERAGE CONCENTRATIONS (ppmw) OF ELEMENTS IN SYNGAS AFTER CLEAN-UP [A]

Al	0.030	B	0.018	Mo	<0.001
Ca	0.023	Ba	0.013	Ni*	<0.002
Fe	0.034	Be*	<0.002	Pb*	0.030
K	0.020	Br	<0.001	Sb*	<0.011
Mg	0.020	Cd*	<0.007	Se*	<0.003
Ne	0.013	Cl*	<0.080	Sn	<0.010
P	0.160	Co*	<0.002	Sr	<0.027
Si	0.051	Cr*	<0.002	Th	<0.002
Ti	0.008	Cu	0.012	Tl	<0.002
		F*	<0.001	U	<0.004
Ag	<0.006	Hg*	<0.004	V	<0.002
As*	<0.003	Mn*	<0.007	Zn	0.015

Notes: A) Elements asterisked are Clean Air Act Amendment Title III Hazardous Air Pollutants < signifies below the detection limit indicated

Source: Shell

The similar set of results from the gasification of Illinois No.5 coal of relatively high sulphur were also given by Shell with analysis as follows (Table 13):-

Table 13: AVERAGE COMPOSITION OF ILLINOIS NO.5 COAL

	wt% db		ppmw		ppmw
Ash	12.6	Ag	0.13	Pb	14.99
C	68.3	As	5.70	Sb	1.44
H	4.6	B	126.7	Se	2.63
N	1.4	Ba	45.17	Sn	2.00
S	3.0	Be	1.54	Sr	20.93
O	10.1	Br	2.50	Th	2.69
		Cd	0.24	Tl	1.04
Al	0.869	Cl	568.7	U	1.47
Ca	0.893	Co	2.10	V	31.32
Fe	1.289	Cr	9.40	Zn	134.1
K	0.018	Cu	12.78		
Mg	0.083	F	98.33		
Na	0.060	Hg	0.14		
P	0.181	Mn	109.9		
Si	3.021	Mo	4.72		
Ti	0.056	Ni	13.95		

Source: Shell

Table 14 below illustrates the disposition of the elements in coal in the various streams. The paper stresses the difficulty in detecting these trace elements at such low levels of concentration and the problems of mass balance. There is evidence that on coal gasification arsenic, lead, mercury, selenium and zinc may remain within the system.

Table 14: TYPICAL ELEMENT DISTRIBUTION (%) IN SCGP FOR ILLINOIS No.5 COAL

	In Slag	In Filter Purges	In Water	In Sour Gas	In Acid Gas	In Syngas	Recovery %
Al	88	10	<0.001	-	-	-	98
Ca	87	6	0.061	-	0.006	0.009	93
Fe	106	7	<0.001	-	-	-	113
K	72	19	0.038	-	-	-	100
Mg	90	10	0.093	-	0.002	0.019	98
Na	92	18	0.040	-	-	-	91
P	92	6	0.003	-	-	-	98
Si	85	13	0.003	-	<0.001	0.006	110
Ti	99	11	0.002	-	-	-	110
Ag	52	40	0.053	-	-	-	92
As	55	8	0.088	0.059	0.024	-	63
B	59	31	15.000	-	0.020	0.111	105
Ba	97	11	0.037	-	-	-	108
Be	43	52	0.032	-	-	-	95
Br	2	111	0.011	-	-	-	113
Cd	40	34	0.029	-	-	-	74
Cl	10	97	0.970	-	-	-	108
Co	90	10	0.003	-	-	-	100
Cr	107	12	0.004	0.007	-	-	119
Cu	98	11	0.010	0.011	-	-	109
F	36	68	0.650	-	-	-	105
Hg	18	3	0.098	6	-	-	27
Mn	97	11	<0.001	-	-	-	108
Mo	111	12	0.018	-	-	-	123
Ni	62	22	0.003	-	-	-	84
Pb	33	47	<0.001	-	-	0.133	80
Sb	29	11	0.020	-	-	-	40
Sc	9	52	1.900	-	0.233	-	63
Sn	38	33	0.004	-	-	-	71
Sr	85	9	<0.001	-	-	-	94
Th	50	27	0.003	-	-	-	77
Tl	21	51	0.007	-	-	-	72
U	122	14	0.005	-	-	-	136
V	89	10	0.030	-	-	-	99
Zn	64	26	0.001	0.128	0.252	-	90

Source: Shell

Fuel-bound nitrogen is mainly converted to molecular nitrogen but, in the presence of hydrogen, some small quantity of ammonia along with much smaller quantities of cyanides will be produced. The ammonia/cyanide ratio is about 100:1. The raw gas stream is either quenched (Texaco) or water washed after the heat recovery boiler (Shell). As mentioned, the water wash is primarily to trap soot. The NH_3 and HCN will largely be washed out and removed from the wash water in the stripper. The NH_3 and HCN is then routed to the Claus plant where it is combusted alongside the hydrogen sulphide. Lurgi has designed special burners for this purpose to ensure the NH_3 and HCN is completely destroyed. These gases are introduced through the control part of the burner into the hottest zone which completely destroys both gases leaving nitrogen while the H_2S is introduced through burners in a ring around the central NH_3 burner. Lurgi has perfected the design particularly to avoid any risk of ammonium sulphide formation in the sulphur transfer system. Texaco has also developed a proprietary process to achieve the same goal.

Carbonyl Sulphide (COS) is hydrolysed in some circuits and the H_2S fed to the gas scrubbing system. Lurgi's Rectisol system can accommodate COS and convert in one stage.

In the summary of Shell's paper (Baker, D.C. 1993), they stress that most of the trace elements are tightly bound in the inert slag - which is essentially non-leachable. Only single carbon compounds, i.e. CO and CO_2 remain. No polycyclic organic or phenolic materials are present even at the parts per billion level. Essentially all the fuel-bound nitrogen emerges as nitrogen.

In tabulating the disposition of trace pollutants from a 500 MWe IGCC plant on US coal, Shell have expressed the materials in terms of tonnes/year.

Table 15: Projected emissions of trace constituents for a 500 MWe SCGP-combined-cycle power plant

Pollutants		Emissions - Tonnes/yr
Contribution from combined-cycle island HAPs		
(a)	As, Be, Cd, Co, Cr, Hg, Mn, Ni, Pb, Se, HCl, HF	0.43
(b)	COS, HCN, CS_2	0.26
(c)	Formaldehyde listed hydrocarbons	0.00032
Non-HAPs		
(d)	Al, Ti, Zn	1.3
(e)	H_2S, NH_3	0.0055
(f)	Non-methane hydrocarbons, methyl mercaptan	0.0023
Contribution from SCOT thermal oxidizer HAPs		
(a)	as above	n.a.
(b)	as above	<1.3*
(c)	as above	n.a.
Non-HAPs		
(d)	as above	n.a.
(e)	as above	<0.7*
(f)	as above	n.a.

Source: Shell (Baker,D.C. - 1993)
Notes: * Based on assumed emissions of 3 ppmv COS and 3 ppmv H_2S
n.a. not applicable

The environmental performance of IGCC is very good and Shell conclude the paper by stating that "even with conservative engineering assumptions, this technology may well establish a bench-mark for new coal-based power generation".

British Gas/Lurgi

The previous comments relate to the performance of the entrained gasifiers. The British Gas Lurgi moving bed design has a number of features which are advantageous versus entrained systems. The carbon conversion is substantially higher, the oxygen consumption lower and the heating value of the product gas higher, being one of the only designs to yield a quantity of methane as well as the CO and H_2.

The raw product gas is cooled by the fresh feed entering the reactor which produces a broad spectrum of complex organic liquids such as phenols, thiocynates, cyanides and ammonia. The hydrocarbons are recirculated back to the gasifier to extinction and any carry-over to the gas clean-up system is treated through the liquor extraction, solvent extraction and processing steps as illustrated in the table below.

Several reports were published on the Westfield Project (Lacey,J. et al - 1990), (Borril,P.A.; Noguchi,F. - 1981), (Ebbins,J.R.; Ruhl,E. - 1988), (Beishon,D.S.; Hood, J.;Veirrath, H.E. - 1989). The results of the trace element and emission levels are set out in Table 16 and 17.

Table 16: Trace element balance for Pittsburgh 8 coal gas not included in the balance as values below detection limits)

Element	In		Out		Total	
	Coal	Flux	Slag	Liquor	Recovered	
	%	%	%	%	%	notes
Al	99.1	0.9	118.5	-	118.5	1,3
Fe	98.3	1.7	92.4	0.05	92.4	1
Na	95.0	5.0	106.8	0.31	107.1	1
K	98.0	2.0	103.6	0.04	103.6	1
Mg	29.4	70.6	94.6	-	94.6	1,3
Ti	95.3	4.7	115.4	-	115.4	1,3
Mn	16.8	83.2	95.2	-	95.2	1,3
Sr	69.8	30.2	96.2	-	96.2	2,4
Ba	78.1	21.9	94.5	-	94.5	2,4
Se	97.3	2.7	104.5	0.5	105.0	2
Cr	95.2	4.8	114.2	-	114.2	2,4
Co	94.3	5.7	107.5	0.1	107.6	2
Th	99.0	1.0	99.0	-	99.0	2,4
Cd	83.5	16.5	65.2	-	62.5	2,4
Sb	96.6	3.4	79.0	7.7	86.7	2

Source: British Gas (Beishon,D.S.; Hood, J.;Veirrath,H.E. - 1989)

Notes:
1 - Analysis by atomic absorption
2 - Analysis by neutron activation
3 - Liquor value not available
4 - Liquor value below limit of detection

Table 17: RESULTS FOR THE PURIFICATION OF WASTE WATER
Illinois No. 6 Coal

Component mg/1	Liquor In	After Solvent Extraction	After Stripping	After Biological Oxidation	After Activated Carbon	After Reverse Osmosis
Free NH_3	5100	5100	20	<1	<1	<1
Fixed NH_3	2000	2000	<1	<1	<1	<1
Phenols	8000	200	100	<1	<1	<1
Carbonates	7000	7000	100	10	10	<1
Thiocyanates	800	800	800	<1	<1	<1
Cyanides	100	100	<1	<1	<1	<1
Sulphides	1200	1200	<1	<1	<1	<1
Nitrates	20	20	20	800	800	800
5,5 dimethylhydantoin	120	100	100	<1	<1	<1
COD (Chemical Oxygen Demand)	30000	40000	3000	500	120	10
TOD (Total Organic Carbon)	8000	9000	800	150	25	<10
Chlorides	2000	2000	2000	2000	2000	60

Source: British Gas (Lacey, J. Davies, H.S. 1990)

The table illustrates that the clean-up stages of the process can reduce the pollutants to very low levels. Consequently, each type of gasifier is able to break down the feedstock to release the pollutants in a form which can be captured very efficiently.

7.9 Gasification of Waste Streams

The gasification process has been described previously as partial or substoichiometric oxidation under conditions which maximise the yield of carbon monoxide and hydrogen for a given feedstock. Since the Texaco gasifier, for example, operates at severe conditions i.e. high temperatures and pressure, the conversion of feedstock to gas is virtually complete, eliminating the production of tars, phenols or other hydrocarbon-based byproducts.

This type of gasifier, preferably fitted with a quench system rather than a waste heat boiler, is able to accommodate a range of waste streams. The quench has some operational benefits for waste processing since the capital cost is lower and it is more able to cope with higher metals content in feedstocks such as spent lubricant. Although Texaco has demonstrated the technique with both oil residues and coal as the main fuel, many forms of waste have been processed. Industrial wastes such as scrap plastics, tyres, municipal wastes and sewage sludge can be handled. Furthermore, hazardous wastes such as streams from the chemical or oil industry can be processed. The advantage of gasification over incineration is that the higher reactor temperatures followed by gas clean-up eliminate the risk of dioxins in the flue gases.

Texaco has written several papers on the gasification of waste streams including two recent papers on the gasification of mixed plastics and tyres. (Curran, P.F. Simonsen, K.A. 1993) Volk, W.P. 1994). They also list the types of chemicals and refinery wastes as:-

-	phenolic waste water	-	isobutyraldehyde
-	off spec. chemicals	-	waste oils
-	tank bottom sludge	-	contaminated oils
-	halogenated solvents	-	oil-water emulsions
-	refinery off-gases	-	aqueous solutions with metals

The waste material does not necessarily have to be processed separately but could be a slipstream of 5-10% of feed alongside other material. The advantages of the system are that the carbon is converted while the inorganic components either are locked into the slag as a benign glassy waste or as filter-cake from the gas cleaning system enabling metals to be recovered. The ability to dispose of the complex molecular structure of chlorinated plastics and tyres in a completely clean way appears to offer significant environmental advantages.

There is also the question of dioxin formation in the gasification process. Two papers address the subject (a. EPA 540/R-94/514a, April 1995, b. Ritter, E. Bozzeli, J.W. 1990) and indicate that dioxins are not formed. The EPA paper is based on a very comprehensive study which they undertook on the Texaco Gasification Process in treating hazardous wastes such as plastics. The summary states that the Texaco process has the ability to:-

- "produce a usable syngas product"
- "achieve 99.99% Destruction and Removal Efficiencies for organic compounds"
- "produce a non-hazardous primary solid residue - coarse slag"

The dioxin level was so low that it fell outside the detection limits. The explanation is provided by the Ritter paper which took chlorobenzene as a surrogate for plastics. The researchers found that decomposition in the presence of hydrogen was very rapid. The relevant extract from the Abstract of the paper is as follows:-

> "Decomposition in the presence of hydrogen was observed to occur much faster than pyrolysis in an inert gas. In addition, the presence of hydrogen accelerates the destruction of the chlorinated aromatics via a catalytic gas phase process. The specific reaction responsible for this catalytic conversion is a displacement of the aromatic chlorine by atomic hydrogen. Chlorobenzene dissociation to Cl + phenyl radical is the initiation step in He and H_2 with: $Cl + H_2 \text{---->} HCl + H$ rapidly continuing the chain. The slightly more rapid conversion of dichlorobenzene is attributed to the higher chlorine content and a somewhat weaker carbon - chlorine bond.
>
> O_2, if present, can initiate the chain mechanism by reaction with hydrogen to form $HO_2 + H$. This explains the lower temperature required for conversion when O_2 is present. The dissociation of chlorobenzene to phenyl and chlorine atom is not thermodynamically favourable so that the oxygen/hydrogen system shows much faster reaction."

On the evidence of these papers, the process of gasification does appear to convert complex hydrocarbons in an environmentally acceptable way without the problems of dioxins or other complex hydrocarbon emissions. The presence of oxygen and the formation of hydrogen coupled with temperature ensure that the molecular structure is broken to single carbon compounds.

Summary

Summarising, the Table 18 sets out the comparison of the technologies in the form of g/kWhr generated for SO_2, NOx and CO_2. It also shows the percentage of sulphur capture, the levels N_2O and CO in ppm and mg/cubic metre for completeness compiled from a range of data from references given including National Power and PowerGen Environmental Reviews and the gas turbine manufacturers guarantee levels for NOx.

Table 18: SUMMARY OF ENVIRONMENTAL IMPACT BY TECHNOLOGY

Technology	% SO_2 Capture	SO_2 g/kWh	NOx g/kWh	CO_2 g/kWh	N_2O ppm	CO mg/m^3
PF	0.0	10.6	2.9	850-950	10	Low
PF + FGD	90	1.1	2.9	980	10	Low
PF + FGD + DENOX	90	1.1	1.0	990	10	Low
CFB	88	1.2	1.0	900	165(a)	150
PFBC eg. Vartan	92	1.0	0.9*	840	25	20-40 (b)
IGCC	99.8	0.01-0.02	0.15(c)	750	0.5	15-20
Air Blown Cycle	90	1.1	1.0	740	75-130	20-40
CCGT	-	trace	0.3	400	2	20

Notes * with Denox (a) possible test error (b) Vartan figures (c) turbine maker's assessment on syngas

In attempting to summarise this section, the consensus of technical opinion appears to support gasification as the cleanest of all the available technologies. For the fuels with a more complex hydrocarbon structure and with a metals/high sulphur content such as heavy oil residues, Orimulsion or tyres/waste plastics, the US research work points very clearly to the benefits of gasification.

Some might suggest that the PFBC systems offers an alternative for coal because the bulk of the ash and sorbent are locked into a solid form which may find a commercial use. It is considered to be a more practical approach and avoids the chemical processes currently associated with gas clean-up for a gasifier - which many utilities perceive as a drawback. It may take some years to establish gasification combined cycle based on coal in Europe but the growing interest in oil residue gasification to generate hydrogen and clean fuel gas suggests it is becoming commercially attractive. When the gasifier is operational at the Shell Pernis refinery in 1997, the particulate and SO_2 emission will be extremely low and the NOx is predicted to be about 9000 t/year.

The concept is perhaps well summarised in an abstract of a paper given by Arthur D Little Ltd at the Institute of Petroleum in March 1995:- "The future use of partial oxidation (gasification) is the ultimate sink for otherwise unusable black, high sulphur and high metals content residual hydrocarbon streams and coal. This process will increase substantially as we move into an age of environmental awareness."

8. ECONOMICS OF OPTIONS

Section 5 reviewed the options available to abate emissions from the existing coal and oil fired plant. The generators are likely to have internal methods of assessing capital costs, financing charges and the overall operating costs of abatement equipment which would be company confidential. Consequently, to avoid the risk of debate on assumptions and calculation, most of the cost data for this section has been drawn from two sources:-

a. the House of Commons Trade and Industry Committee Report on Energy Policy and the Market for Coal

b. the recent IEA Coal Research report on Air Pollution Control Costs for Coal Fired Power Stations (Takeshita, M. 1995)

Since the generating capacity being considered is largely coal-based, it is appropriate to set the economics in the context of the conclusions of the Committee. Paraphrasing, the main conclusions were:-

i. British Coal's (now RJB Mining) deep mine production costs are likely to fall sufficiently far and fast to justify the much lower price of £1.33/GJ offered to the generators for 1997/98

ii. The relative uniformity of costs at British Coal's deep mines means that the intended price in 1997/98 would not need to increase unless the volume sold to the main generators reached at least 45 million tonnes

iii Over a five year period, the potentially profitable capacity far exceeds the market currently envisaged

These conclusions suggest that coal was envisaged as the fuel which offered the lowest marginal cost of power to the generators on the pool pricing system. A substantial part of the Committee report addressed the environmental implications of coal use. This relatively high sulphur level of UK coal was acknowledged versus internationally traded coals. The only two ways of reducing sulphur from existing plant were cited as switching to low sulphur imported coal and the fitting of FGD.

The main disadvantage of FGD quoted was its cost - both capital and operating costs and the reduction in efficiency which for a modern station is quoted as a reduction from 38% to 36% LHV. The total cost was assessed at 0.55 p/kWhr with a footnote that some unpublished evidence suggested higher costs. In the ENDS reports indicating the generators' reluctance to operate Drax and Ratcliffe, a cost of 0.6p/kWhr was quoted which was cited as the factor causing a change in the merit order assuming that capital and operating costs are fully recovered in bidding into the pool pricing system. With respect to these two plants, it is also possible to argue that the investment which will have been made by the time the installations have been completed are sunk funds. Consequently, the out-of-pocket costs to the two generators are only the operating costs which would be less than the 0.6p/kWhr

The capital cost of full FGD is acknowledged as high and although capital costs have reduced since Drax and Ratcliffe were ordered, the figure quoted for Pembroke is still high. The cost figure of 0.55-0.6 p/kWhr has been given on the basis of a high load factor. If FGD were to be required for intermediate load (or even peak) the fixed costs would have to be spread proportionally over fewer operating hours, the variable cost added and the total cost would then be towards a half of the total generating cost. At Pembroke, figures of £120/kWe for the power plant alone or £180/kWe including port/solids handling facilities have been quoted in Power UK. The combined cost is the more realistic capital cost of the project although it is understood that the Harbour Board might be willing to accept the financial burden of the jetty facilities to attract the additional trade from limestone and gypsum movements. The total investment also needs to be compared with £300/kWe for a new CCGT plant based on the Didcot investment. Furthermore, flue gas treatment on the older plant would reduce efficiency to 33-35% while new CCGT offers an efficiency in the 55% range.

These FGD costs are in line with those quoted in the 1994 IEA Coal Research hand-book. The later 1995 IEA Coal Research Report provides additional data on costs drawn from sources in a number of countries. They considered a spectrum of sulphur, NOx and particulate reduction steps and drew the conclusions paraphrased below:-

- fuel switching is a possible route to ameliorate sulphur emissions with a capital cost of between $25/kWe and $119/kWe (Rupinskas and Hiller, 1992). However, on US eastern coals, the range was $25-31/kWe

- coal cleaning deserved attention as a possibly cost-effective method of sulphur reduction. A conventional cleaning cost of $2-3/t offers a low cost route and even if the degree of cleaning is increased to $5-7/t to reduce pyrite more significantly, the combination of cleaning and a simpler FGD system could offer SO_2 removal at a cost of $459-639/t

- repowering was reviewed to cover plant where major modification or refurbishment was essential. Schemes which retain the old steam turbines and generators have been examined but currently, the cost is relatively high at over $1400/kWe

- most of the report considers the range of FGD technologies along with NOx control and precipitation of particulates. The high capital cost of retro-fitted systems is stressed because of usual need to modify existing plant configurations to make room for the flue gas treatment vessels and ducting

- wet scrubbing is by far the most popular system with a market share of 84% of the total capacity. Wet limestone/gypsum has proved to be the most popular at 70% share of all installations. The German average cost was $313/kWe while Drax was quoted as the next highest at $263/kWe. Some of the more recent systems have broken below the $100/kWe level usually on new plant

- spray dry scrubbers offer a lower cost alternative at a capital cost of $72-150/kWe but a higher operating cost that limestone/gypsum plus a disposal cost of the waste to land-fill.

- sorbent injection processes are lower still in capital cost at $30-120/kWe. No operating costs have been quoted on a cents/kWhr basis but the cost per sulphur tonne removed range from similar to limestone/gypsum to more than double

- advances in wet scrubber technology have taken place in the USA, Europe and Japan. Higher SO_2 removal efficiencies are now possible offering 95% or more removal while the capital and operating costs are being reduced by improved corrosion and erosion resistant materials. Simplification of designs has also taken place to reduce power consumption, reduce the number of vessels, the solids handling and by-product management and flue gas reheat

A similar summary of data was presented on NOx control. The analysis draws attention to the fact that the level of capital and operating costs is closely related to the degree on NOx reduction which is required to achieve compliance. The least cost reductions result from the use of over fire air and low NOx burners. These steps combined would secure a reduction of between 25-55% in NOx dependent on the design of boiler. Capital costs for such equipment would be low i.e. typically in the range of \$20-40/kWe.

To achieve a significantly greater reduction in the range of 70-80%, Selective Catalytic Reduction would be required at a cost in the range of \$50-150/kWe. The operating costs of such systems would be in the range of 4-9 mills/kWhr compared with 7.2-7.4 mills/kWhr for wet scrubbers removing SO_2.

The conclusions in the IEA Report are that "The cost of air pollution control technologies have reduced considerably over the last decade. Their reliability and removal efficiency have improved through the accumulated experience in several countries, particularly Germany, Japan and the USA."

"Overall, air pollution control for a 90% reduction in SO_2 emissions and 80-90% reduction in NOx emissions may increase the cost of electricity by about 15-20% depending on technical and economic considerations. ..... These are broadly the incremental costs of the clean use of coal."

In applying these conclusions to the subject of existing UK capacity, it has to be set in the context of the likely demand for the coal fired capacity. This, in turn, depends on the more probable gas penetration scenarios which suggest the bulk of the coal forecast to be required could in theory be absorbed by Drax and Ratcliffe on base load. Consequently, the balance of the coal required would be spread rather thinly for intermediate/peak load. However, it seems unlikely from the NGC Seven Year Statement that coal will be required as base load capacity so the burden of cost for the existing FGD will have to be recovered over fewer operating hours or on fewer kWhrs generated thus increasing the unit cost proportionally making it more difficult to place the electricity into the pool.

It does not appear economic for either of the major generators to commit new capital at the levels of cost indicated above in order to clean flue gases on plant destined for intermediate or relatively low load. It would appear more likely that their economic analysis would lead them to opt for closure rather than commit capital on such an uncertain basis if the emission standards for existing combustion plant were to be tightened.

An apparent anomaly is the proposal to instal FGD at Pembroke. Perhaps the logical explanation is that the price negotiable for the fuel offers a return on the new investment, recovers operating costs and generates power at a cost which guarantees its sale to the grid on base load. If the project goes ahead, then under the present pool price arrangements, it would have to be assumed that an equivalent amount of coal based plant would be displaced. It would either mean the closure of an equivalent of National Power or PowerGen capacity and a reduction of a further 5 million tonnes of coal demand.

There does not appear to be a post combustion investment option which is economically viable to achieve a reduction in SO_2 emissions from existing plant under the present pricing structure for bulk electricity supplies. Any attempt to introduce tighter limits would appear to risk accelerated closure of plant which still has many years of residual life. This could also lead to an over-dependence on gas albeit with very low emissions levels.

The one possible route to be re-examined which might achieve some reduction of sulphur and ash in UK coal to ameliorate the emissions is that of coal cleaning. This was also referred to in the IEA Report. One US assessment of cost is \$150/t sulphur versus much higher figures for flue gas treatment. Estimates made on the potential cost saving through the complete use cycle suggest that the savings should offset the additional cost of washing. Australian data for the advantages of flotation cells for fine coal cleaning indicate a 4-6 month pay-off for plant based on fuel upgrading (Osborne D, 1993).

9.0 DISCUSSION

The issues and economics of UK power generation and the use of existing surplus capacity are complex. They relate to technologies available, the dynamics of the energy market and to the interpretation of environmental constraints such as BPEO. There is a growing recognition that there is an interdependence between energy resources, their utilisation and the environmental constraints which can influence international competitiveness particularly through electricity costs. Timing and the need to make decisions on new investment are becoming another factor. Should more CCGT capacity be built at high thermal efficiency or should wet scrubbing systems be installed more widely. If the latter, they may take 3-4 years to build and could extend the operation of a moderately efficient plant until the second decade of the next century. How does this extension of inefficiency stand against the incremental investment which might be needed to move to a more efficient and cleaner technology? The Government's stance on CO_2 is also important because that alone should bring pressure to increase efficiency.

Several other pressures arise from different sectors. There is growing evidence of concern over ground level pollution from vehicles which will most probably lead to an improvement in transport fuel quality. The 1996 reduction on diesel sulphur is likely to leave some refiners short of hydrogen and with a surplus of heavy oil residue. The implications of any reduction in the benzene content of gasoline also create a problem for refiners. A decision on this issue will political rather than technically proven. However, any move to limit the benzene content of European gasoline to say 1.0% benzene may well result in a switch from sweet North Sea crudes to higher sulphur Middle Eastern crudes as the most economic option. Such a move would also mean a greater demand for hydrogen and a potentially larger fuel oil surplus. Gasification is a possible solution to redress the balance.

A growing awareness of particulate emissions and air quality which are becoming linked to the increase in the incidence of health problems such as asthma, not only impinges on the transport sector but also raises the question of whether the historic emission limits on power stations are appropriate in the light of new US and other evidence. Stack emissions expressed in mg/m^3 may appear to be small but a 2000 MWe coal based power plant would emit some 17,000 cubic metres per minute or 7,000 tonnes of fine dust per year unless FGD is fitted. Even then, there is evidence that very fine particles may pass through an FGD system and the possibility that they may represent a risk to human health.

The completion of the study of toxic air emissions from coal fired power plants in the USA poses some challenges to the Environmental Protection Agency later this year. They must decide on where to set new emission standards for many substances currently not included in legislation. Europe is likely to watch developments with considerable interest.

There is also growing pressure to accommodate society's production of waste materials. The cost of routing wastes to land-fill is rising rapidly. Land-fill gas then needs to be absorbed into boilers or heating systems. The incineration of domestic refuse is a growing activity again with the capability of generating local power and/or space heating. The gasification of spent lubricants, old tyres, sewage sludge, farm litter etc. appears to be of growing interest while some groups see set-aside land as an opportunity to grow short rotation coppice which could offer the prospect of bio-mass to add to the "renewable" materials available for conversion by gasification. The third Non Fossil Fuel Order requires a total capacity of 400 MWe to be taken into the grid. Land-fill gas and waste combustion are mentioned explicitly in the text as materials which must be accommodated.

Although these latter issues may appear to be peripheral, their steady development appears inevitable and the capacity thus introduced is eroding the market available for the power into the grid produced from the direct combustion capacity already being made surplus by the new CCGT plant. Furthermore, the assumption that the Magnox stations would be phased out by the end of the century is no longer valid because BNFL has indicated their intent to refurbish the spent fuel reprocessing equipment which suggests the stations may be run for several more years. Consequently, there is no simple answer. Investment decisions have to be company and location specific. The expenditure of new capital on such plant is only likely to secure the approval of a company's board after a very considerable amount of study to minimise risk and the least risk decision may well be closure.

In reviewing the very many papers which have been written over the past 2-3 years, it is becoming clear that the challenge of alternative technologies has created an impetus on several fronts to improve the performance of power generation equipment. This move has been led by the developments in gas turbine technology.

Where natural gas is available, and where its use in the power generation sector forms an acceptable part of a national Government's energy policy, then combined cycle gas turbine systems offer the highest efficiency, lowest capital cost and the cleanest form of generation at present. The cleanliness of the fuel and its high hydrogen/carbon ratio favours it above all other fossil fuels. The areas of uncertainty are long term availability, medium-long term price and whether methane becomes more valuable as a building block for other products (e.g. to make blend components for upgrading transport fuels) than as a fuel for the generation of power. The UK may be more fortunate than other European countries for local gas supplies. However, the price in the longer term is likely to be influenced by the dynamics of the international market for gas.

If power is to be generated from other fuels such as coal, heavy oil residues or the introduction of Orimulsion as an abundant new source of energy, a range of technical options is emerging. Advanced steam cycles appear capable of delivering up to 46% LHV efficiency but would need to be base loaded to take advantage of the high efficiency and limited flexibility of the double reheat circuits. A similar level of efficiency should soon be attainable using PFBC technology and super-critical steam conditions. IGCC offers 45% LHV efficiency on oil residues using the currently available turbines and this is set to improve with the introduction of the new range of gas turbines, steam turbine improvements and/or the development of humid air turbine technology.

A gas turbine is needed to assist any of the above technologies to reach 50% LHV efficiency. The Danish SK Power design of ultra-super critical steam incorporates a gas turbine in series, as does the second generation PFBC system with an external partial gasifier. New turbine design, hot gas clean-up and application of improved steam cycles will also raise the thermal efficiency of the gasification combined cycle to the 50-52% LHV range.

The gains in turbine efficiency already attained and the potential for improvement create the attraction of the technology on other fuels. The extraction of some 67% of the energy in the gas turbine with the steam turbine taking the balance is thermodynamically more efficient than a small gas turbine in series with a conventional steam boiler. The recent advances in gas turbine efficiency and resulting from the USDOE advanced gas turbine programme provide ample evidence that gasification combined cycle systems will draw ahead of all direct combustion based systems firing coal, oil or Orimulsion. This fact was effectively acknowledged in a paper by National Power in 1994 when the most attractive option after CCGT on natural gas was IGCC fed on Orimulsion (Googh D J, Hotchkiss R, 1994).

Which of the technologies will become the most favoured will depend on capital cost, customer acceptance and emission limits. One of the most critical factors influencing future choice of technology is the environmental limits set for new plant (and possibly the continued use of existing plant). The extent to which a threshold thermal efficiency might be introduced is also important because these decisions could limit technological choice. Based on the data above for ultra-super critical steam, CCGT and the potential of PFBC and IGCC, it is hardly surprising that Germany has drafted an ordinance proposing a 45% minimum thermal efficiency for new plant. This has been held in abeyance since the Spring because the German utilities have come to a voluntary agreement to stabilise CO_2 emissions without the need for a legislated efficiency hurdle. The UK has already set off down this road with some 10 MWe of CCGT plant operational in the 53-55% LHV efficiency range and more under construction using the later gas turbines.

The decisions, both in terms of emissions limits and timing, relate to the very large requirement for new and replacement capacity on both sides of the Atlantic over the next 15 years. It amounts to a total of about 500 GWe in the USA and Europe with the Far Eastern market growing even more rapidly. The purchase decisions will also relate to power industry preferences but with Independent Power Producers evaluating opportunities perhaps against different criteria.

9.1 Power Industry Perspective on the Steam Cycle

Two reports have been prepared by the Coal Industry Advisory Board which articulate the power industry's views on steam and on clean coal technologies. In order to provide a balanced assessment of views, the extracts of the conclusions of both reports are set out in the next two sections.

The CIAB report on Industry Attitudes to Steam Cycle Clean Coal Technologies indicates the utilities current preference to order steam based equipment. This is an understandable reaction and can be achieved with hybrid combustion systems, second generation PFBC and flue gas clean-up.

"Based on the facts arising from the technology survey and the opinions discovered by the industry survey, the CIAB concludes the following:-

- Clean, recently commissioned PF-fired plant is achieving high efficiencies; one operational plant has an efficiency of 46% with steam conditions of 240 bar and 560°C. These units can meet all current environmental regulations and reach availabilities in excess of 90%.

- It is believed that by the early years of the next century, PF-fired units will be in operation with steam conditions of about 350 bar and up to 650°C, made possible by the development of new materials. This could give efficiencies approaching 50%, based on the standard conditions outlined in this paper.

- A considerable amount of new PF-fired plant will be installed in the countries of South East Asia (predominantly China) and the Indian Sub-continent over the next ten years. This will be predominantly sub-critical in type.

- The prospects for new coal-fired plant in Western Europe and North America will be constrained by the strong competition from natural gas fired units. In these areas, and in Japan and Australasia, environmental performance is a key issue in selecting new plant. Additionally, in Western Europe and Japan high thermal efficiency is a major factor.

- The largest AFBC currently in operation is rated at 165 MWe, but a unit of 350 MWe is currently being commissioned. Efficiencies should be roughly comparable to PF-units with the same steam conditions.

- Atmospheric fluidised bed combustion has a future role throughout the world as a specialist technology for the utilisation of difficult fuels (eg high ash or high moisture).

- A major hurdle for the adoption of new coal-fired technologies is the reluctance of utilities to opt for a new technology until it has been comprehensively proven on a commercial scale."

The debate then becomes one of the most cost effective way to introduce integrated pollution control, BATNEEC and BPEO. Gasification combined cycle systems have several advantages, but in practice, more time may be needed to prove the systems to the satisfaction of some utilities. The marketing of the technology also needs to be reviewed to offer greater client appeal. Nevertheless, there appears to be agreement that it is the cleanest of the technologies.

To the power industry, IGCC may appear to be a complex process. Buggenum or Puertollano have large heat recovery boilers, a number of unfamiliar vessels, pumps and pipework which may appear daunting to those familiar with boilers. However, this is standard technology in other major industries. If it is possible to opt for an environmentally superior system and the techniques are available to reduce or eliminate most of the traditional emissions from power generation, then should they not be adopted if available at costs competitive with the alternatives? This might well be an area which the independent power producers might wish to explore.

A critical issue is the level at which SO_2, NO_X, particulate and VOC emissions might be set and whether they are expressed as a ground level concentration or as a stack emission. Similarly, the acceptable levels of liquid and solid waste streams would need to be reviewed simultaneously in the context of the integrated approach to pollution prevention and control. There may be a need to harmonise the levels which can be tolerated within the eco-system and the levels which are economically attainable. Technologies such as gasification with wet scrubbing systems are technically capable of removing sulphur to levels well below that which would be required for power generation. However, hot gas clean-up as and when developed to economically attractive systems may offer higher thermal efficiency with marginally poorer sulphur control. This raises a question of interpretation of BATNEEC in the context of the advanced technologies.

Analysis of a great deal of the available data suggests that the gas turbine in combined cycle mode is the most efficient converter of energy to electricity. Operating on clean gas, it is also virtually sulphur and particulate free with low NO_X levels attainable using systems such as dry low NO_X combustors.

It is important to recognise the points of measurement and conditions prevailing when quoting conversion efficiency as fuel energy related to bus-bar energy. With direct combustion systems, the efficiency should be net of the internal power consumption of FGD and DENOX processes and should be quoted for a given sulphur/NO_X capture. For IGCC, some observers will multiply the cold gas efficiency of a gasifier and the efficiency of the CCGT to assess the combined efficiency. However, it must be remembered that the cold gas efficiency is defined as the energy in the feedstock compared with the energy in the product fuel gas after removal of sulphur. Consequently, the defined efficiency of, say, Puertollano would effectively appear lower than if operated on a high quality steam coal because of the very high sulphur and ash content of the feedstock. There is a considerable heat of combustion available from burning of sulphur but one would never burn it for its heating value and then have to absorb SO_2 as a waste stream.

Perhaps the most significant challenge is to examine technologies which help to smooth out the daily and seasonal demand for electricity. In the UK, there will not only be a large surplus of equipment but also a considerable amount of under-utilised plant. It ought to be possible to design systems which allow major components of plant to be operational in off-peak periods producing a by-product. The most promising route would appear to be gasification where the product gas could be used to make a range of chemicals. Alternatively, the CO and H_2 mix could be converted to synthetic "natural" gas i.e. high heating value gas and British Gas has a process for such a conversion. Either way, the gasifier could be fully loaded while switching the gas stream to power generation when required. The economics have been explored in the USA to some extent but in the context of very low natural gas prices. The solution to the environmental and efficiency challenge would appear to be closer integration between industries.

9.2 Power Industry Perspective on Clean Coal Technology

The most comprehensive survey of the utilities' attitude to clean coal technology was conducted by the IEA and published in 1994 entitled "Industry Attitudes to Combined Cycle Clean Coal Technologies".

Helga Steeg, the then Executive Director, set the context of the survey in her foreword highlighting the role which coal would continue to play in power generation throughout the world. She drew attention to the fact that IEA energy forecasts show global coal consumption increasing from 2275 mtce in 1991 to 3363 mtce in 2010. Hence, a growing need to support the development of new clean technology.

The report, which was consolidated from a questionnaire, reflects a perception among potential users that combined cycle gasification technologies have some way to go to prove their technical and economic viability. It tabulates the capacity committed in the form of IGCC and PFBC plant and sets out criteria for commercial acceptance of coal combined cycle technologies. Perhaps the most signification acknowledgement is the statement that the Buggenum plant "is expected to be the cleanest coal power station ever constructed". In a paper to the EPRI Gasification Conference 1994, Demkolec stated they were confident that the second Dutch plant could be built at double the size with only a 50% cost increase making it competitive with conventional steam based generation with flue gas clean-up.

The conclusions of the report are given below so that the user perception is understood.

All respondents to the CIAB questionnaire believed that coal was an important long-term element of a balanced secure fuel supply portfolio for power generation. The use of coal for power generation was considered essential to the continued economic growth of many countries. Specific conclusions are quoted verbatim and were:

- "There is considerable power utility interest in advanced clean coal technologies which potentially provide a significant commercial opportunity. However, a key concern was the high capital cost of CCT (Clean Coal Technology) - as defined for the purposes of this report. CCT was currently seen as too expensive and hence a major barrier to its commercial application.

- Several respondents emphasised the substantial environmental benefits that can be achieved by the wider application of currently available state-of-the-art pulverised coal generating technologies combined with flue gas desulphurisation, and low NO_X burner technology.

- Most power utilities indicated that they will utilise CCT when the technologies are adequately demonstrated, the economics are attractive and the environmental performance needs have been demonstrably required. But, because these technologies are currently too expensive, caution is needed in raising expectations in advance of commercial realities.

- In this regard, several power utilities wish to see substantial operating experience (several years) with CCT's from a number of commercial demonstration plants before being satisfied on commercial aspects, in particular, their long term performance. Others would accept a much shorter probationary period. It is clear however that, at the moment, many utilities are concerned by the lack of a proven track record of truly commercial scale operation from which the operational reliability and overall performance could be established.

- Barriers to the commercial deployment of CCT were regarded as being a function of the perceived risk which would be minimised by the demonstration plants under construction in various countries. Most power utilities saw the Buggenum plant in the Netherlands as a crucial test of IGCC particularly with respect to reliability, availability and maintenance aspects. Likewise, regarding PFBC/CC technology, the progress at Vartän, Tidd and Escatron was being followed with considerable interest.

- Some utilities believed that the global warming issue damages the prospects for CCT. While higher efficiency is the most immediately available option for controlling emissions of CO_2 from coal-fired generation - paradoxically, the global warming discussion hinders the introduction of higher efficiency, environmentally friendly CCT's as long as sufficient natural gas is available.

- It was suggested that all new technology of significance requires considerable government support in its early formative years. Examples include nuclear power, the space and aircraft industry, electronics and communications. So far, most of the development of CCT's had been undertaken by private industry. It was felt, by the majority, that Governments could be doing more to hasten the commercial introduction of CCT's. Encouragement and assistance with commercial demonstration projects, 'fast track' regulatory conditions and some form of risk sharing were areas where governments could play an important future role. Equally, a minority of respondents were opposed to government involvement believing that the choice of technology is a commercial decision best left to power companies - in compliance, of course, with environmental regulations.

- It was considered that manufacturers had marketed their products effectively but that it was too early for aggressive marketing of products still considered to be in their infancy.

- In noting the negative image of coal, particularly with the general public, many respondents felt that considerable effort was now required to rectify this by all participants in the coal chain. In particular, it was believed that the public and governments should be made aware of the considerable potential of new technologies capable of improving the environmental performance of coal combustion, but also of the practical issues impeding its early implementation was seen as an important element in promoting clean coal technology.

Overall, based on the responses to the questionnaire, it is concluded that advanced Clean Coal Technologies (CCTs) show considerable potential but that further commercial demonstration and development are essential. There is undoubtedly an important future market for CCT. However, while power utilities clearly see no potential benefits from enhanced environmental and efficiency performance over existing technology, they are not prepared to pay extra for it, and are reluctant, indeed in most cases unwilling, to take the full commercial risks of early deployment."

Institutional barriers related to the perceived risk of new technology still exist. Although this is understandable, the real risk has to be set in the broader context of experience of the technologies in other industries, a thorough understanding of the technologies and corporate objectives with respect to emissions. The IEA/CIAB report was based on questionnaires to the major utilities, boilermakers and coal companies. The questions were appended in the report. Many of them can only be described as leading questions prompting the answers expected and, of course, relate exclusively to coal.

From the stand-point of technology, facts disprove the perception that combined cycle systems and gasification has a long way to go. As mentioned previously, near 40% of new generation capacity over the past 10 years has been combined cycle gas turbine technology based on natural gas so the power industry is accepting the excellent performance of gas turbines. Gasification has been used commercially for 30 years and there is currently about 11 GWe equivalent of gasification capacity operating in the chemicals industry.

The matching and/or integration of two proven systems does not incur the level of risk which the power industry perceives primarily because of a lack of experience of the technology. If the objectives are to achieve a clean and efficient use of fuels, there would appear to be an incentive to follow the lead of the Dutch, Spanish and US to make it happen. This would be more positive than the type of comment cited in the CIAB report from one utility "we would need to see at least another half a dozen the size of Buggenum utilising different coals in operation for several years before IGCC was considered commercial".

The lower risk approach, and one which is likely to be economically more attractive, is the gasification of liquid feedstocks such as heavy oil residues possibly with minimal integration. The development of systems in or adjacent to oil refineries may stimulate independent power companies to enter the market say using CCGT technology on syngas while hydrogen and other by-products could be routed to the refineries.

9.3 US Approach to Clean Technologies

A substantially different view is being expressed in the USA. Several significant reports can be cited perhaps led by the USDOE who are quite clear on the way they see technology developing. The main thrust of the US programme is being coordinated by the USDOE Morgantown Energy Center. Many papers signal a clear perception of the way ahead especially with their reserves of coal. Like the UK, competition in the power sector has increased by the entry of Independent Power Producers seeking a share of the market and assessing the range of available technologies.

The mid-point demand for new capacity from now until 2010 is 274 GWe. USDOE consider that could vary from between 200 and 500 GWe dependent on economic growth and to an extent the competitiveness of high efficiency systems. They have the dual goal for coal-based technology. It should have:-

- an LHV efficiency of 50% or more
- a capital cost of $1000-1200/kW.

Five variants on technology are being pursued:-

- Integrated Gasification Combined Cycle
- Advanced Pressurised Fluidised Bed Combustion
- Externally Fired Combined Cycle
- Advanced Gas Turbine
- Natural gas and Integrated Gasification Fuel-Cells.

The interesting feature of the US programme is that in all but the fuel cell case, gas turbines form the key part of every system. This would appear to relate to capital cost, length of the construction period and the high efficiency compared with their chosen goal of over 50%. Ultra-super critical steam systems do not feature anywhere in the US Clean Coal Programme. This would appear to result from their research work and the conclusion that advances in efficiency can only result from the use of combined cycles. They would also be conscious of the high labour content associated with field construction of large boilers, the high cost of sophisticated materials in such bulk and the time required to stress-relieve and test welding in those materials.

In a recent paper to the American Power Conference (Salvador,L.A.;Bajura,R.A. - 1994) each of the technologies was summarised with a capital cost, efficiency and emission levels in a time frame up to 2010 see Table 19. The emissions were all measured in terms of a percentage of New Source Performance Standards (NSPS) i.e. the standards currently set for new power plant.

Table 19: Comparative Performance of Technologies

Technology	IGCC 2000	IGCC 2010	1st Gen PFBC	2nd Gen PFBC	Advanced PFBC	EFCC 2005	EFCC 2010	IGFC 2010
Net Elect Efficiency %	45	>50	40	45	>50	47	55	60
SO_2 emissions %NSPS	10	10	25	20	10	20	10	10
NOx emissions %NSPS	10	10	33	20	10	10	10	10
Air toxin emissions	to meet	to meet	to meet	to meet	to meet	to meet	to meet	to meet
Capital Cost $/kW	1200	1000	1300	1100	1000	1300	1200	1100
Cost of electricity relative to PF%	80	75	90	80	70	90	80	80

Source: USDOE

These figures need to be compared with CCGT at $480/kW today (based on the Didcot bid) or around $350-400/kW in recent Far Eastern bids and the prospect of at least 60% LHV efficiency by 2000. However, the cost of electricity is less predictable because of the uncertainty of the natural gas price.

To illustrate their commitment to these technologies, there are 12 projects under construction in the USA to consolidate their confidence in the way ahead. Unlike the questionnaire approach of the CIAB, the USDOE has used technical and economic logic to lead then to a very clear view of best technology. They have recognised the thermodynamic advantage of the two cycles i.e. the Brayton cycle and the Rankine cycle while acknowledging that the cleanest technology is that which converts the energy in feedstocks such as coal into a clean gas thereby releasing the pollutants in a way which allows capture in the most efficient way. The point that is emphasised both by the USDOE and studies like that by GE/Fluor (EPRI Conference papers) are that the cost of electricity actually falls as a result of using these advanced systems as do the releases of all the pollutants and CO_2.

One interim step on the path to clean coal technology is to take advantage of the CCGT while natural gas prices are low. The plant could then be retro-fitted with a gasifier when the price of natural gas has risen to a point which makes it economic. Phased construction has been outlined as a way to introduce gasification combined cycle systems.

There is a view beginning to be expressed within the States coal industry that a great deal of money has been spent on the environment to date without anything tangible being achieved. Part of the reasoning results from the perception that abatement is only possible at a cost which could ultimately penalise US competitiveness in the global market. This view of cost is reinforced by the concept of a trade in permits and a value/penalty on emission with little or no evidence to indicate the benefits to society of better air quality resulting from steps taken by the power sector. The view only addresses an existing situation of direct combustion and capture of SO_2 and NOx without consideration of the forecast growth in power consumption.

The other view is that most of the investment in the US Clean Coal Programme has been well spent and the results to date have now set clear guidelines on the way ahead. The elegance of the new technologies stems from the need for a clean fuel to optimise the combined cycle gas turbine performance. Consequently, any "abatement" is inherent in the design rather than an added cost of post combustion clean-up.

9.4 The UK Position

The most critical factor in the privatised electricity industry would appear to be the ability to produce power at the lowest cost to ensure a market into the pool. Historically, this related to the marginal cost of fuel when fuel costs were the most influential factor. The evidence given to the House of Commons Energy Committee on the consequences of electricity privatisation indicated that the cost of generation from imported coal was 1.66 p/kWh and 2.2 p/kWh from British coal. The added cost of FGD was quoted as 0.53 p/kWh. New gas capacity was quoted as 2.64-2.89 p/kWh.

It is difficult to reconcile that data with the order in which the plant is currently operating with so much gas on the system. It suggests that generation is not being set by marginal fuel price but by other factors. Furthermore, the FGD operating penalty discourages its use if the generators have adequate head-room under their official emission limits to avoid incurring those costs. If the price of gas is considered stable in the short-medium term for base load supplies and the Didcot CCGT capital cost of £300/kW is typical of investment for 55% LHV efficiency, there would appear to be limited incentive to invest £180/kW on FGD to incur an operating cost penalty of 0.5-0.6 p/kWh at Pembroke.

The capital costs associated with the other flue gas scrubbing techniques may be lower than limestone/gypsum systems. However, there is still a capital and operating cost to be recovered from an uncertain demand on an intermediate load station. It is difficult to see that any capital or operating cost recovery can accrue to the companies under the current pool price mechanism. Any tightening of emission requirements on the existing coal capacity without some offset of financial relief would appear favour gas and lead to accelerated closure of coal and oil capacity. The differential capital cost between abatement investment and CCGT is so relatively small that the risks associated with investment in emission control are unlikely to be taken.

9.5 World Coal Industry Position

The main suppliers of the world's coal appear to perceive continued growth in the market for steam coal mainly for power generation. Several attempts have been made at international conferences to highlight the vulnerability of coal to environmental pressures and the need for clean technologies if their market share is to be maintained. Most US companies and major exporters have reviewed their product qualities and have started a programme of upgrading their coal preparation facilities. However, none of the major coal producers appear willing to take a share in developing the new clean coal technologies which might go some way to ensuring their market in the future.

In part, this may be because the Coal Industry Advisory Board has indicated the utilities' desire to retain steam and use coal. Furthermore, in the short term, the industry is enjoying price increases as a result of high demand in S E Asia so they will hope a firm market continues without the need for them to "seed" their own future growth.

10.0 CONCLUSIONS

It is most difficult to draw succinct conclusions from such a complex problem as evaluating the way forward for power generation in England and Wales. The privatised Electricity Supply Industry is still at an evolutionary stage and one in which the dynamics of the market operate at several levels. The older steam based generating capacity is competing with new CCGT systems and generators are bidding to supply the grid based on their total production costs. The RECs and IPPs wish to establish an increasing share of the power sold to the grid at the expense of National Power and PowerGen.

There is inter-fuel competition between energy sources. Although perhaps less visible, the competition to supply the power generating sector is fierce. Natural gas has already displaced much coal - a process which is expected to continue, while productivity gains in the newly privatised coal industry may offer the potential to halt the trend. Generators see Orimulsion as a very competitive new energy source, while heavy oil residues may become an attractive alternative as HFO demand falls and the oil industry requires another outlet.

It is easy to draw the conclusion that the ESI will be dominated by an abundant supply of gas. Where gas is available, CCGT systems offer the highest efficiency, least cost and cleanest technology for new plant. Such a conclusion, however, overlooks the medium/long term price of gas and the amount of coal and oil fired capacity which exists in the UK today, much of which has useful residual life if the economics allowed it to be operated. Nevertheless, the electricity supply/demand balances from National Grid's 7 Year Statement takes account of the new gas capacity scheduled to be in position over that period. Analysis of the Statement suggests a substantial capacity surplus which could constrain the use of the older coal and oil based plant. This would also indicate that the probability of needing new coal based capacity in the foreseeable future is virtually nil.

In the present situation, the pool pricing mechanism should favour coal as the fuel with the lowest marginal cost but it appears to favour gas. Is the pool price mechanism driven by economics or by other commercial arrangements? Current operating patterns suggest the latter. Furthermore, no mechanism has been put in place to recognise or reward clean power generation so the pool pricing system inhibits new investment in emission control equipment.

The generation/duration curve shows a limited requirement for coal-fired plant and little required for base load. In theory, the coal "allocation" could virtually be absorbed by Drax and Ratcliffe alone on base load, given a high gas entry scenario. Assuming the pool price rewarded the generators for operating their FGD equipment, the pollution from the coal burning sector would be under control. However, the 7 Year Statement indicates that the summer load would not require coal; hence most of the coal capacity would only be required on intermediate or peak load. In those circumstances, it is unlikely that generators would be willing to risk new capital expenditure for emission control unless they were guaranteed cost recovery. The overheads or fixed costs of retaining a large coal plant for peak load could be uneconomic so accelerated plant closure would appear to be a distinct possibility if CCGT plant continues to be built or more stringent emissions limits are set for existing plants.

In Europe, the emission limits related to the power sector and embodied in the Large Combustion Plant Directive are focused on SO_2, NOx and particulates. However, in the USA, a comprehensive study of toxic emissions from coal-fired power plant was initiated as a result of the Clean Air Act Amendments which required the analysis of 189 Hazardous Air

Pollutants, 36 of which were thought to be found in emissions from the power sector. Very fine particulate was thought to have a possible impact on health. Studies indicated that this fine material may well not be captured by precipitators and may be emitted with the stack gases. Some toxins such as mercury and selenium may also be released in the gas phase particularly where scrubbers are not fitted. Fine particulate matter such as vanadium compounds have also been found to pass through FGD systems. Mercury may also accumulate in the local eco-systems dependent on the concentration of emissions. There would appear to be a case to monitor air quality in the areas where coal-fired plant is concentrated in order to assess the level of fine particulate and toxic releases in view of the close proximity of the large coal fired stations in England.

The US studies also identified acid mist formation associated with oil-fired plant where the presence of fine vanadium particles catalyse the conversion of sulphur dioxide to the trioxide with the formation of sulphuric acid. That observation suggests the probability of complex chemical reactions creating challenging technical problems for the design of FGD systems to scrub flue gases when Orimulsion is combusted as a fuel. The only Western plant operating with a purpose-build scrubber was commissioned in the 4th quarter 1994 in Canada and technical results are only just emerging. Nevertheless, from the US data, particulate penetration and acid aerosol escape could be predicted as possible problems. Dry fluidised bed scrubbing systems claim an advantage in this application.

With regard to new plant and relevant technology, a global survey of utilities companies by the Coal Industry Advisory Board has summarised the utilities' preference to retain steam - possibly adopting ultra-super-critical technology when necessary. They have tended to dismiss advanced technologies until fully proven elsewhere. However, they acknowledge that IGCC is the most environmentally acceptable of the options for the use of solid and liquid hydrocarbon fuels. Analysis of the releases from the alternative technologies supports the view that gasification combined cycle systems offer the lowest impact on the environment, stand to become the most efficient option after CCGT and are rapidly approaching the most economic alternative to CCGT as the cost of the gas turbines and oxygen production fall.

The most significant conclusion to be drawn from the heavily funded US clean fuels research programme is that of an energy conversion stage before the clean gas is used i.e. the conversion of the primary energy in a gasifier, the cleaning of product fuel gas and utilisation in a very efficient converter e.g. a combined cycle gas turbine or fuel cell. The optimum power generation stage requires a fuel gas essentially free of sulphur, particulates and other pollutants to optimise thermal efficiency. Consequently, pollution abatement becomes an integral part of these clean technologies so the cost abatement changes from a post combustion addition to an inherent part of the design.

In Europe, gasification of liquid feedstocks is likely to be the initial route for the introduction of gasification technology. Shell has already made the decision to convert heavy oil residues to clean fuel gas, hydrogen and power at their Rotterdam refinery. Other refiners in Italy and Finland are following. This becomes increasingly important as the quality of transport sector fuels is improved to reduce emissions from that sector. Gasifiers at refineries may prove to be the mechanism to demonstrate the commercial attraction of clean conversion technology to the power industry.

Another area for the application of gasification may be the conversion of waste streams such as plastics and tyres where the US data indicates that the operating conditions in a gasifier eliminate the risk of dioxins from the conversion of these types of material.

In the UK, the least cost route to ameliorate sulphur emissions from existing coal fired stations not fitted with FGD would appear to be to re-examine the reduction in ash and pyrite in Power Station Fuel in the light of recent developments in coal preparation technology. Techniques now available for the cleaning of fine coal could remove up to 90% of the pyrite in many coals. This may make a useful contribution to sulphur and trace element reduction promising a lower abatement cost than flue gas treatment while offering other cost savings resulting from a reduction in inert solids handling and disposal through this system.

The dominant fuel in the power sector for the next few years is gas albeit that there is a range of views about the medium to long term price. That issue alone would appear to be one of the prime determinants of future technology, the rate of closure of old capacity and the levels of emission which would result from the power generation sector. The other determinants would be:-

a. any change in Government policy designed to limit the country's dependence on natural gas

b. any Government moves to discourage further decline in the use of the UK's substantial coal reserves

c. more stringent limits which might be set for emissions from existing power stations and refineries

The trend to advanced technologies would be accompanied by an improvement in conversion efficiency. The US objective for their clean coal programme is a net efficiency of at least 50% while in Germany, the level of 45% net has been considered as the hurdle or minimum acceptable level for the future although held in abeyance at present. The use of CCGT technology in the UK, which is already able to achieve 55% on natural gas, can be interpreted as an implicit acceptance of this principle. These efficiencies refer to the generation of power only but it should be recognised that there is considerable scope to utilise the low grade heat in the area of power stations by encouraging industry, commerce or district heating schemes to use this heat thereby improving the overall thermal efficiency.

The adoption of gas turbine combined cycle systems would appear to suggest a case, political factors apart, to set the emissions limits for new generating plant at the levels attainable by the guarantee limits of currently available gas turbines - namely, virtually sulphur and particulate free and very low NOx e.g. 60 mg/m^3 because they are already being met by a substantial and growing part of the UK's generating capacity. The availability of gasifiers which have been fully proven in other industries offers an alternative source of clean gas where economic. Nevertheless, in setting the limits for SO_2, consideration should be given to ground level concentrations and natural background. It is technically possible to remove virtually all traces of sulphur in wet scrubbing systems but at some loss of efficiency. The development of hot gas clean-up techniques may offer tangible efficiency benefits but with a small increase in sulphur emission. The emission level should perhaps be related to the unit of output e.g. mg/kWhr.

A wide range of power generation technologies is now available with gas turbine based systems taking a substantial part of the business traditionally held by the boilermakers. The local preferences of the generating companies will ultimately be the determinant of technology in matching fuel availability and lowest electricity costs to environmental limits.

11. RECOMMENDATIONS

Tightening of the sulphur emission legislation from existing coal or oil plant which would require further capital investment in flue gas treatment is unlikely to achieve its objective. It may only accelerate closure of coal plant and loss of local coal market. Consequently, such a step would not be recommended. However, the study of evidence in the wide range of papers which have been cited lead to a number of recommendations listed below:-

1. There would appear to be a case based on German evidence to reduce NOx beyond the levels achievable with low NOx burners alone. The level of reduction and the need for investment in selective catalytic reduction would need to be based on the relative forecast contribution from the power and transport sectors in conjunction with the air quality standards being sought. The NOx levels may also need to be set against acceptable levels of CO and carbon on ash.

The results of the USA studies and the possible linkage to health risks lead to the main recommendations being focused on those issues. There appears to be a need to gain a better understanding of the contribution which the power sector may be making to the total pollution in the UK with compounds not currently prescribed but implicit in the Environmental Protection Act.

2. A survey should be undertaken to assess the emission of trace elements, in particular mercury, selenium and boron. Simultaneously, the chlorine and fluorine levels should be measured to assess whether there is an interaction with mercury and whether the HCl and HF emissions have increased. There may be merit in inviting US input into preparing the scope of work, sampling and test procedures to benefit from their recent experience.

   The possibility of higher chlorine content in coals results from the mine closure programme and the fact that many mines which have been selected for retention are known to have a higher chlorine level.

3. Measurements of the quantity, size distribution and quality of fine particulate emissions should be undertaken to assess the magnitude of the contribution made by the power sector versus the transport sector. This should cover both coal and heavy oil based plant. A survey of fine particulate capture techniques would be a valuable addition, including capital and operating costs, in order to provide a basis for a cost benefit analysis.

4. The emissions data should be compared with guidelines on air quality supplemented by appropriate medical research at specialist units such as those at the Department of Health, the University of Newcastle, the University of Aberdeen and the MRC at Leicester to determine whether there is a risk to human health from fine particulate or other non-prescribed emissions including Hg, HCl or other hazardous air pollutants related to the application of BPEO.

5. More precise modelling of emissions from the permutation of plants, fuel choice and gas penetration scenarios should be considered in order to assess the range of emissions which could result with or without further flue gas clean-up investment. The corresponding levels of CO_2 could also be modelled to complete the emissions analysis.

6 A review of coal preparation procedures should be undertaken in the light of recent US and Australian developments in wash plant technology by an expert familiar with those processes. The review would assess whether the current high levels of ash and sulphur in Power Station Fuel represent an optimum from the cost and emissions standpoint. Since the US also found mercury and pyrite tend to co-exist in coal, any move to improve coal preparation should reduce Hg emission.

7. Consideration should be given to set emission limits for new plant at levels currently achievable by CCGT systems, recognising that subsequently, some amendment might need to be considered to accommodate hot gas cleaning systems as and when fully developed/economically viable.

8. Further analysis of use cycles should be initiated to consolidate the view already held by the USDOE that energy conversion represents the most attractive way to handle the dirtier fossil fuels when operated in conjunction with combined cycle gas turbines, fuel cells or advanced PFBC systems.

9. Gasification as an alternative to combustion based processes should be considered for the disposal of waste streams such as plastics, spend lubricant and old tyres etc. It might be possible to consider schemes of this type under the NFFO mechanism.

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Annex A

Review of Future of Power Genertaion and Combustion

DOE Report No. DOE/HMIP/RR/93/067

Revised November 1995

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APPENDICES

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1.0 INTRODUCTION

The agreed objective of the study is to review the future of power generation from fossil fuels in order to provide information upon which to base modifications to the Chief Inspector's Guidance notes and plan future research on "Advanced forms of Combustion Plant". This would be coupled with the aim to ensure that HMIP is aware of the potential for all forms of power generation from those fuels.

The objective calls for a status report on current power generating technology and on clean energy conversion technologies which are available for producing power from coal, heavy oil residues and Orimulsion. The study is set within the framework of relevant EEC and UK environmental legislation, both in place today and that which can be reasonably anticipated as a result of scheduled reviews mandated by existing legislation. It would cover an indication of the emission limits attainable with selected technologies including comparative data to relate costs to those of natural gas based plants.

The scope of the study is to be broad and to include technologies which are now available or are in a sufficiently advanced stage of development to be considered for commercial application in the conversion of the fuels to electrical power with references to areas for research.

1.1 Background

For over 110 years, the generation of electrical power has been primarily based on steam, using a range of fossil fuels which have been combusted directly in a boiler to provide the heat required. Sir Charles Parsons' invention of the multi-stage steam turbine replaced the reciprocating steam engine in 1891 because of vibration damage to adjacent buildings and low efficiency so the first major change in technology stemmed from an environmental issue.

The efficiency of conversion from fuel to electrical energy has approached the limits of the simple steam cycle and is starting to move to combined cycle systems. Conventional steam systems have barely achieved 40% efficiency so some 60% of the input energy is being lost in the cooling system and to atmosphere. Most of the plant installed in Europe and the USA is operating below that efficiency because the average age of boiler stock in Europe of is about 20 years and about while in the USA it is about 30 years.

The future choice of fuels for power generation will be progressively determined by emission standards. Further EEC legislation may limit emissions to the point where the direct combustion of heavy complex hydrocarbon fuels in power plants may not be permitted without full flue gas treatment. Such a step would place a low ceiling on efficiency. Substantial efficiency improvements would be needed particularly if any precise targets are set to reduce CO_2 emissions ie. the CO_2 per kWhr of power produced is substantially reduced by efficiency improvement.

The privatisation of the UK electricity supply industry has modified the generators' choice of primary energy and their commitment to local coal. Natural gas has entered the power sector and a substantial increase in usage is forecast throughout Europe for this purpose. Low sulphur imported coal, heavy oil residues and Orimulsion may also become attractive sources of energy as new technologies are adopted in response to emission controls in other sectors. The steps taken to control emissions to date reflect measures to deal with an existing situation. Technologies best suited to the efficient and clean production of power in the future do not appear to have been fully assessed in the context of the environmental problems facing other industries, for example, oil, steel and chemicals.

Major advances in gas turbine design have occurred over the past decade and these developments open up a range of possibilities for improved thermal efficiency with dramatically reduced emissions. The use of combined cycle systems appears to be emerging as the best available technology which in turn may influence EEC emission levels when they are revised in 1994. Developments such as second generation Pressurised Fluidised Bed Combustion PFBC and Ultra-super Critical Steam harness a gas turbine in series to boost efficiency.

Tighter emission control could lead to potential problems of heavy fuel oil disposal which in turn could initiate some interesting synergies between the oil and power industries. Opportunities then exist to transfer technologies, which have been used for many years in the chemicals industry, to the oil industry for gas production and power generation. Projects are now being developed in several European countries and may create another level of competition for the supply of energy for power generation.

Perhaps the most critical factor relating energy, the environment and economic growth together is the low efficiency of power generation, its distribution and use. Some of the UK's ageing coal-fired capacity is little more than 32% efficient. A station such as Drax should approach 38% LHV (Lower Heating Value) but may lose about 1.5% on completion of the Flue Gas Desulphurisation (FGD) equipment.

The latest natural gas-fired Combined Cycle Gas Turbine (CCGT) should be capable of 55% LHV and new blade materials and lead-blade cooling techniques are expected to raise this to around 60% net within 6 years. Fuels cells are also approaching commercial levels of cost and reliability offering 60% efficiency and are already at the large pilot scale. Power generation costs are not yet competitive with power plant generation but some US operators see potential in using fuel cells in the field to debottleneck at substations where they could be economic. An Integrated Gasification Combined Cycle (IGCC) operating on oil could achieve a conversion efficiency of between 43-45% LHV if operated as a stand-alone facility today with further efficiency improvements up to 50 % LHV confidently forecast. Modified PFBC and USC steam systems claim efficiencies in a similar range.

A further area for examination is to question the assumption that there is an overall cost benefit in economies of scale. The CEGB settled on the design of 2000 MWe stations close to sources of fuel but isolated from their markets. It minimised the opportunity to utilise any of the low grade heat and added considerably to transmission losses. Under the guidelines for operation of a privatised electricity supply industry, the responsibility for line loss and its control has not been assigned to any one company. The grid is simply there to transmit from generators to marketers at a transmission cost which includes any loss. The advent of smaller and more compact high efficiency units offers scope to assess the true systems cost and the assumption that the large units are the most efficient.

2.0 CURRENT TECHNOLOGIES AND THEIR LIMITATIONS

This section reviews the present fossil fuel based power generating technologies. The comments address the perceived advantages of steam based systems and indicate the limitations inherent in the steam cycle. The traditional technology will be described along with an outline of fluidised bed technologies and the recent move to combined cycle gas turbines which has been more commonly labelled the "dash to gas". The drawbacks of direct combustion for the control of emissions and pollutants will also be examined in some detail in the second part of the section.

2.1 Direct Combustion

As an introduction to combustion it might be appropriate to offer a definition of the process. Combustion may be described as a chemical reaction releasing heat energy and taking place at a high temperature sufficient to complete the reaction. It is usually the direct firing of a fuel with sufficient oxidant to release all its heat close to the burner for subsequent absorbtion in a boiler or furnace. When combustion is applied in the context of conventional power generation, the heat release takes place in a boiler to generate steam which acts as the heat transfer medium converting heat energy into rotation through a steam turbine.

Since the start of commercial power generation, coal has been the dominant fuel. This was displaced in the 1950/60s by heavy fuel oil in some countries, with a return to coal again in the 1980s. Several methods of firing coal have been use over time as the size of boilers has become larger. Chain grate, travelling grate and spreader stoker boilers are still to be found in industry but for about forty years, the standard large boiler for power generation has been fired by pulverised fuel (PF). The basic design of oil fired boilers follows the pattern of the PF-firing version with appropriate adjustments to combustion chamber size matching the relative speeds of combustion of oil and coal.

2.1.1 Pulverised Fuel

Pulverised fuel firing was introduced for large boilers partially because of the relatively high carbon losses experienced on chain grate and stoker type boilers and partially to overcome size limits imposed by this type of firing. The carbon losses in the stoker-type designs of boiler were in the range of 4-8% compared with 0.4% on a properly designed pulverised boiler (1). Furthermore, double screening of the coal was often needed to remove fine coal from stoker fuel, adding to the fuel cost and the dumping of fine coal on colliery waste tips. The advent of pulverised firing enabled a wider size range of feed coal to be used so 0-40 mm or 0-50 mm has become the most widely specified size range for the power sector. This broader range also resulted in a significant increase in the quantity of mined coal which could be marketed.

The first stage in the preparation of pulverised fuel for combustion is the milling of the coal to a fine powder in the less than 70 micron range as an integral part of the boiler feed system. The size of the milled coal is critical to the speed and completeness of combustion which underpins the thermal efficiency of this type of boiler. The particle size fired will also be determined by the quality characteristics of the coal especially by factors such as volatility and ash content. The fine coal is swept out of the mill by a stream of primary air to a cyclone system or classifier which allows the fine coal to flow to the burner and recycles oversized coal the mill for further grinding.

The fine coal is then burnt to release its heat. The fine ash particles pass out with the flue gases as a fine powder. About 90% leaves the boiler as fly ash or as the UK industry tends to call it, Pulverised Fuel Ash (PFA). It is then removed by electrostatic precipitators where it is captured for disposal. This last step will be discussed in the section on waste disposal. A small portion of the ash agglomerates to form clinker which falls to the bottom of the boiler where it is removed.

The PF system has become the universal standard for burning coal on large power generation boilers typically up to 650 MWe. Boiler design and operation is well understood and accepted so the power industry management have become totally accustomed to its use. In the late 1980s, designs were prepared for 900 MWe units, for example, Fawley B, but the plans were abandoned. The advent of more stringent emission controls introduces a sulphur capture process into the power production stage which will adversely affect efficiency.

The more general application of pollution control also challenges some of the traditional assumptions about how and where pollutants should be removed ie. that the combustion process is the key stage of use and that any resultant pollutants should be captured post combustion. For any new system, more fundamental questions need to be asked about the fuel, the potential pollutants, the level of emissions or wastes tolerated and where in use cycle the pollutants could be most effectively removed. That process could take place before, during or after use and becomes very relevant when considering the heavy oil residues or Orimulsion where higher levels of sulphur with vanadium and nickel need to be removed.

2.1.2 Fluidised Bed Combustion

The development and commercialisation of the fluidised bed concept had taken place in the oil industry in the 1940s when fluid catalytic cracking was developed to upgrade heavy oils to transport fuels. The principle on which it is based is that solids will behave as a liquid if fine particles are aerated. Fluidisation therefore involves the suspension of solid particles in an upward flowing fluid usually a gas.

In the oil industry, the bed material was a catalyst in the form of fine particles which became coated with carbon during the reaction stage of the process. It was regenerated by combusting the carbon off the particles in a stream of air before recycling the hot catalyst. There was a logical progression of the technique from the removal of carbon by burning to use of the fluidised bed as a medium for combustion by introducing coal or lignite as a fuel. In the coal based system, the solid phase is coal ash and fresh crushed coal feed. Limestone could also be added in a similar size range as a sulphur acceptor or sorbent, (covered in Section 2.2) with combustion air providing the fluidising medium. The air enters at the base of the combustor with an upward velocity sufficient to create turbulence and the rapid mixing of the solids. The techniques have been developed for an oil feed on a laboratory scale and licences are available through CSL but few if any have been taken up. ABB is re-examining ways in which oil could be introduced as a mechanism to handle heavy oil residues.

The temperature of coal fired fluidised bed combustors must be kept below 950°C in order to avoid clinker formation from the fusion of the ash and its adverse effect upon the fluid properties of the bed. It must also be kept above 800°C to obtain acceptable combustion efficiency.

There are three primary categories of fluidised bed combustion system devised for solid feed which are divided effectively by particle size and fluidising velocity used. They may also be run at atmospheric or elevated pressure. The three categories are as follows:-

a. Shallow beds

Lump coal of a narrow size range, ca. 10 to 50 mm is burned in a bed of inert material - usually sand - at fluidising velocities in the range 2.0 to 3.0 m/sec. Static bed depths range between 100 to 450 mm. The coal tends to burn rapidly on the surface of the sand bed and to a lesser extent in the freeboard, allowing compact combustor design. This type of system is usually found in smaller boiler plant below about 30 MWt capacity, and originated in the UK in the early 1970s as an advance on the grate firing systems widely used in industrial boilers. This design approach does not lend itself readily to a high level of sulphur removal because of the limited contact time with any sorbent present.

b. Bubbling beds

A much deeper bed is utilised, typically 0.5 to 1.4 metre, with a wider range of coal sizes. Fluidising velocities range from 1.0 to 3.5 m/sec, but at the upper end of this range the elutriation or size separation of bed material causes unburned carbon losses to rise and recycle of bed material is necessary to maintain a high combustion efficiency.

The attractive features of the bubbling bed combustor are enhanced by pressurised operation, and considerable development effort has gone into the use of pressurised fluidised bed combustion in open-cycle gas turbines (2).

c. Circulating beds

This design uses combustion air velocities in the range 6.0 to 9.0 m/sec. which entrains a significant proportion of the bed material made up of unreacted carbon, ash and partly reacted sulphur acceptor. Hot cyclones at the combustor outlet collect most of this material, and return it to the bed. The concept of bed depth no longer applies as there is a continuous circulating flow of solid bed material.

Fluidised bed technology has become commercial over the past decade and about 200 units have been sold. Fuel flexibility is the key advantage and the technology is well suited to poor quality fuels such as peat, forest wastes, high ash coals etc. However, there are several factors limiting its application to power generation. The atmospheric systems have a thermal efficiency of about 38% maximum and this is not seen as having sufficient of an advantage over more conventional firing to appeal to utility companies. There is also a size limit of around 80-100 MW thermal for bubbling beds although TVA has now built a 165 MWe unit and about 200 MWt for circulating beds which makes them better suited to industrial application than to power generation other than where smaller combined heat and power systems have been required eg. Swedish district heating plants. There is a circulating bed unit in Nova Scotia at 200 MWe and one of 250 MWe under construction on France.

Pressurised fluidised beds have some significant advantages. In the pressurised version, coal is burnt directly under pressure in the fluidised bed. Steam is generated and superheated in tubes immersed in the bed which operates at a typical temperature of 870°C. The flue gases are cleaned of particulates in cyclones and then expanded through a gas turbine which drives the air compressors for the system and a small power generator. The steam is expanded through a steam turbine which drives a second but larger generator. It should be noted that the gas turbine in this instance is an expansion turbine. It is driven by the pressure in the system unlike the combustion gas turbine which operates on a fuel source. About 20% of the total power would be produced by the generator on the expansion turbine.

The low bed temperature reduces the NOx level from the combustion process and ABB Carbon of Sweden, who are the sole marketers of the technology, claim a thermal efficiency of 44-46%. The first 4 modules of 85 MWe each were built in Stockholm (2), Tidd in the USA (1) and Escatron in Spain (1). Two larger plants of 350 MWe are under construction in Japan with commercial operation expected in early 1994. These new units will be equipped with ceramic candle filters as well as cyclones to reduce particulate emission.

All the pressurised units control the sulphur dioxide emission by introducing limestone into the bed with the coal. This will be discussed later under emission control in Section 2.2.

2.1.3 Combined Cycle Gas Turbine Systems

The most recent form of power generating system installed in the UK is the CCGT. The gas turbine has existed for many years but major advanced in the technology of large industrial machines has taken place over the past decade. The designers were able to develop ways to increase the tolerable temperature by cooling the leading blades internally which enhances the conversion efficiency. These higher temperatures in turn led to higher exhaust temperatures which allows a heat recovery boiler to be installed in series. The heat recovered produces high grade steam which is fed to a steam turbine. Each turbine drives a generator and because the gas and steam systems are linked in series, the technology is described as a combined cycle.

With current technology, the gas turbine would produce about 66% and the steam turbine 33% of the total system power. The size of turbines has increased and GE, for example, offer a gas turbine of 225 MWe Frame 9FA which is capable of about 375 MWe in combined cycle mode. Siemens and ABB offer a similar size of machine, the Siemens V 94.3, for example, having an output of 220 MWe. The thermal efficiency of the combined cycle system operating on natural gas is 55% LHV and according to the companies, they have had these advanced turbines operating for the past 3 years at very high levels of reliability.

Two further points should be made at this stage. Firstly, the combined cycle system operates equally well on natural gas or synthesis gas from a gasifier. Dependent on the turbine design, the only modification necessary to accommodate synthesis gas might be the combustors. Effectively, a CCGT is an integral part of an Integrated Gasification Combined Cycle (IGCC) system. Secondly, gas turbines operate at their highest efficiency and availability on a clean fuel so cleaning prior to combustion would leave no particulate or sulphur oxides in the flue gases. Combustor NOx can be controlled at very low levels and all three manufacturers have signalled they are now willing to guarantee a level of around 50 mg/m^3 or 25 ppm dry including ABB (3).

No other technology is able to approach such a low NOx figure without some form of flue gas clean-up. It is the capability of the gas turbine to operate at such high efficiency and low

NOx at a very competitive cost which is likely to influence any new plant emission standards if based on Best Available Technology or Best Available Environmental Option.

There will soon be some 10 GW of CCGT generating capacity on natural gas in the UK and planning permission has been granted for several more units. More detail of the combustion gas turbine development will be given later.

2.1.4 Limitations of Combustion Systems

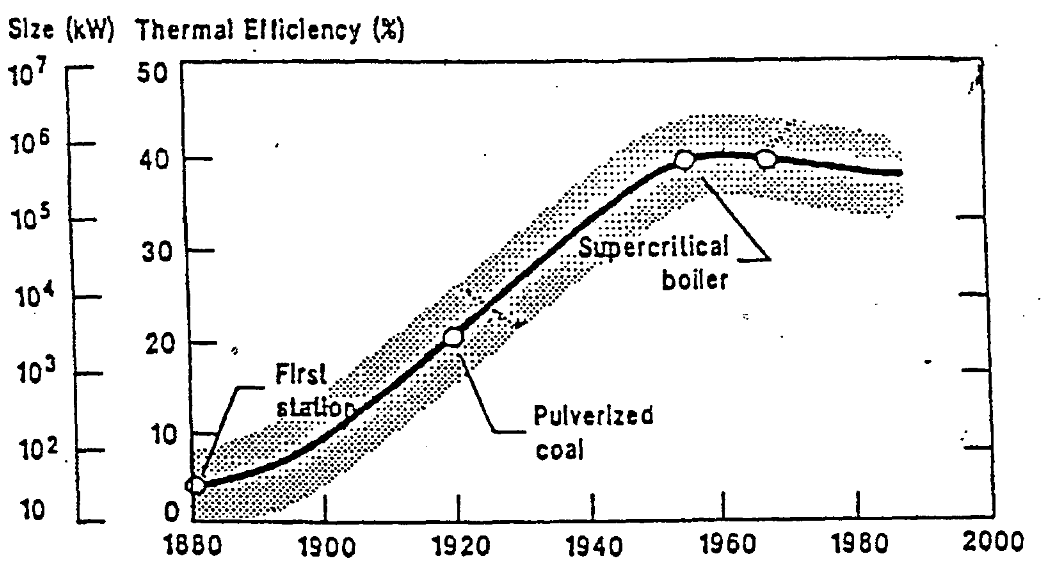
This first section addresses the physical limitations of the steam cycle and other factors which have an adverse effect on the performance of the systems. Emissions and waste product disposal will be kept in a separate section.

a. Thermal efficiency

Figure 1 shows a chart prepared by EPRI displaying the evolution of efficiency over the past century. The efficiency being measured is the energy content of the input fuel versus the energy equivalent of the electricity generated measured at the bus-bar (on leaving the plant for the grid). There was a very steady increase until the 1960s when supercritical steam conditions were achieved. There were some experiments at the time to take pressures higher but it did not develop commercially. A decline has taken place in recent years reflecting the power consumption of post combustion clean-up equipment which has been retro-fitted to existing units for emission control purposes.

Figure 1

EVOLUTION OF POWER PLANT EFFICIENCY



Source. EPRI

Efficiency may also be expressed as Lower Heating Value (LHV) or Higher Heating Value (HHV). The most usual is LHV because it reflect the net recoverable heat. The latent heat of the water in the stack gases is not recoverable in commercial systems albeit that it is present to be recovered in theory. The HHV effectively quantifies the theoretical figure, inflates the efficiency and is not infrequently used to market the advantages of one system versus another.

The thermodynamics of the steam cycle were set out by Rankine in the last century. The Rankine Cycle defines the limits within which the steam cycle can function. The maximum thermal efficiency at the accepted industry standard steam conditions of about 540°C and 140 Bar pressure is around 38%. Recent attempts have been made to move up to 580°C and 300 Bar to ultra-super critical conditions using materials such as very thin walled boiler tubes of special steel and double reheat steam systems. Efficiencies in excess of 43% have been achieved but on a very limited number of plants ie. one in Denmark fired with coal and one in Japan operating on gas. The capital cost appears to be high. The Danes have achieved an efficiency in the range of 45% with a breakdown of the contributory factors part of which results from a low cooling water temperature.

The concept appeals to the conservative power industry management as a mechanical engineering solution and an extension of technology established for a century. Nevertheless, the improved thermal efficiency does nothing to solve the emissions problem which still has to be handled by flue gas scrubbing. Furthermore, the increases in thermal efficiency may mask some of the real issues, for example, the physical size of the facility, the enormous field construction workload and the lead time between design and start-up compared with the newer, cleaner and more compact alternatives. The interest on capital during construction would be significantly greater than with CCGT or IGCC systems.

The thermal efficiency of a large power plant boiler is dependent on a number of interactive factors associated with fuel quality. The presence of any contaminants could absorb heat from the system. Ash and moisture in coal are perhaps the two best examples. Ash absorbs heat to raise its temperature while moisture requires heat to evaporate it. That heat is not recovered - it will escape to atmosphere through the stack. The quantity of useful heat which can be extracted to raise steam will also be dependent on heat recovery at the cooler end of the boiler dictated by the dew point of sulphuric acid. The higher the sulphur content, the higher the back-end temperature thus reducing the heat recovery in the economiser section.

Heavy fuel oil contains a very small quantity of ash but can easily contain 3.5% sulphur. Natural gas is fired directly into boilers in Japan, the USA and the Netherlands and burns very cleanly albeit at a thermal efficiency considerably lower that the new CCGT systems.

When firing coal, mineral matter will be released by combustion during its time in the furnace. The combustion time is relatively short and is related to flame temperature. The need to reduce NOx has led to the widespread use of low NOx burners where the flame temperatures are reduced to minimise NOx formation as far as practicable. Carbon burnout becomes more difficult and the residual carbon on ash may rise. The higher the ash content, the higher the risk of unburnt carbon loss and loss of efficiency.

Some of the ash may melt and form a coating on the walls of the furnace tubes. Dependent on the type/thickness of the ash, this will reduce heat transfer and the quantity of steam generated. This phenomenon is known as slagging and is confined to the combustion area of the boiler. It is cause by fused or semi-fused particles of ash impinging on the boiler wall tubes. Heat transfer can become impeded downstream of the combustion section where fouling can occur as the gas temperatures fall below the ash softening temperatures external to the combustion area eg. in the convection section. The management of the ash in the boiler is one of the major considerations in the design of PF systems.

The partial blockages caused by these deposits increases gas velocities and reduces heat transfer. The build-up of deposits may be partially removed by soot-blowing but it is the most common reason to bring the boiler down for physical cleaning. Ash is therefore a significant factor in determining boiler efficiency both in absolute terms and the potential generation capacity measured in terms of theoretical power output versus the actual while on line. Its significance can perhaps be illustrated by the fact that in the mid-1980's it is believed to have cost the CEGB many million £/ year because of shutdowns caused by slagging and fouling (4).

In the USA, the Electric Power Research Institute (EPRI) were concerned about the effects of coal quality on boiler performance and sponsored some development work which resulted in a computer based tool called the Coal Quality Impact Model (CQIM) (5). It focuses on boiler performance versus a range of coal quality parameters and appears to have become the preferred analytical system on both sides of the Atlantic. PowerGen, National Power and British Coal (CRE) all have copies of the CQIM model.

b. Mill Wear

When firing coal, mill wear is inevitable. Ash is present in all coals but very high levels exist in the current coal supplied by British Coal to the generators known as Power Station Fuel (PSF). This adds to operating costs because of the loss of steam and boiler efficiency by running with worn mills. The boiler output has to be restored by additional fuel input but as mills wear further, the classifiers may have to be opened up to allow more coal to enter which will then burn out less well exacerbating the inefficiency.

Well prepared coal with a limited amount of mineral matter will mill easily and with moderate power consumption. Mineral matter is usually harder to mill than coal and it is the ash forming components which cause most of the mill wear. The pyritic material is usually very hard while silica especially in the form of quartz is both hard and abrasive. Consequently, this type of mineral circulates in the mill until reduced sufficiently to escape into the boiler. It may remain in the mill 30 times longer than the coal causing excess wear while consuming power wastefully. As mills begin to wear, the coal may not be milled to the ideal size range. The boiler may call for more fuel which may open the classifier and allow larger coal particles to enter the burner. These larger particles may not burn out as completely leaving a higher level of carbon on ash and a reduced efficiency. Mill wear and boiler efficiency are therefore inter-related.

There is a significant cost associated with the milling of mineral matter which is an immediate saving on a per tonne basis for every tonne of ash removed ahead of milling.

c. Perceived Economies of Scale

In hindsight, the selection of 2000 MWe stations close to the mines may not have been the most prudent decision when assessing the complete cycle efficiency to convert and use the energy cleanly.

2.2 EMISSION AND POLLUTION CONTROL

This section will address the various forms of emission and waste from the current range of commercially available combustion technologies along with comments on the methods of containing these streams.

One key limitation to the direct combustion process is that the pollutants inherent in the spectrum of fuels with the exception of natural gas are converted to gaseous or solid waste materials:-

2.2.1 Gaseous Emissions

When combusted, the sulphur compounds are converted into sulphur dioxide as represented by

$$S + O_2 \text{ --------> } SO_2$$

The temperature of combustion is such that it will release nitrogen compounds trapped in the fuel. Nitrogen from the air will also react with oxygen in the combustion zone of the boiler to form oxides of nitrogen usually referred to as NOx to cover a family of nitrogen oxides present but mainly NO and NO_2. Fuel nitrogen will also be released and the chemical reactions taking place in the boiler are complex. The reaction is among other factors proportional to temperature but there is a delicate balance between completing the combustion process for efficient use of fuel and restricting the temperature to minimise NOx formation. Most low NOx burners, for example, pre-mix or stage the combustion so that the flame is cooler and the process is speeded up. The reaction is summarised as

$$N + x\tfrac{1}{2}O_2 \text{ --------> } NOx$$

Fluidised bed boilers, especially of the atmospheric type, have a tendency to produce N_2O which is a more persistent greenhouse gas than the other nitrogen oxides. The potency factor versus that of CO_2 is about 150 times greater. In a Swedish State Power Board study (6), N_2O levels of 165 mg/m^3 were measured from atmospheric fluidised bed boilers. The measured level halved on the PFBC designs although ABB Carbon would now say it is totally controllable on their commercial designs. The Swedish study found levels of N_2O in PF-fired systems at a about 10 mg/m^3. The nitrous oxide level is seen as a draw-back on AFBC systems (see comments later on the British Coal Topping Cycle design concept).

Particulates are released from the combustion chamber into the flue gases as a result of the combustion of coal, heavy residual oils or Orimulsion. Mineral matter in the coal is released as ash while small quantities of metal oxides are produced when heavy oil fuels are burnt. The particulates are controlled in coal combustion by the installation of electro-static precipitators which remove at least 99.8% of the particulates to contain emissions within the prescribed limits.

Precipitators were not installed on capacity originally designed for oil. The "ash" content was always considered to be too low. It is only more recently that there has been some concern about the metals contained in the ash, namely vanadium and nickel. This has arisen primarily in connection with Orimulsion but heavy oil residues from Venezuelan, Mexican and several heavy middle eastern crude oils would have similar metals content.

2.2.2 Flue Gas Desulphurisation

Where boiler plant has been installed for some time and a reduction in emissions is required, there are few alternatives but to clean the flue gases. A wide range of technologies have been developed for the removal of sulphur oxides from flue gas streams but the one which is dominant is the wet scrubbing process using a limestone or hydrated lime slurry to absorb the gas to make gypsum. The FGD system is usually installed downstream of the electrostatic precipitator (ESP).

The chemistry is simple:

$$SO_2 + H_2O \dashrightarrow H_2SO_3 \qquad (1)$$

$$CaCO_3 + H_2SO_3 \dashrightarrow CaSO_3 + CO_2 + H_2O \text{ .... limestone} \qquad (2a)$$

$$Ca(OH)_2 + H_2SO_3 \dashrightarrow CaSO_3 + 2H_2O \text{ ....lime} \qquad (2b)$$

and common to all wet limestone/lime systems. The introduction of an oxidation stage converts the calcium sulphite to calcium sulphate bihydrate otherwise known as gypsum.

The wet limestone/lime scrubber is usually divided into two categories according to the type of oxidation: forced-oxidation or natural-oxidation. In forced oxidation, air is introduced to the absorber reaction products at pH 5.5 to 6.5 to produce the reaction:

$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \dashrightarrow CaSO_4.2H_2O \qquad (3)$$

This method is used widely in Europe and Japan for the production of a saleable gypsum. It yields relatively large gypsum crystals which are easy to de-water.

Natural oxidation uses the limited quantity of residual oxygen left in the flue gases to partly oxidise the calcium sulphite according to a combination of reaction 3 with reaction 4 below. This was employed in the earlier plants, mainly in the USA.

$$CaSO_3 + \tfrac{1}{2}H_2O \dashrightarrow CaSO_3.\tfrac{1}{2}H_20 \qquad (4)$$

The product is a sludge containing calcium sulphite hemihydrate as the main product. The sludge is difficult to de-water and is usually disposed of as landfill.

The efficiency of scrubbing is typically 90% on limestone/gypsum systems. A range of additives or performance enhancing reagents coupled with modified design have been introduced in some countries raise the efficiency towards 95% but this is only at extra capital and/or operating cost.

If gypsum is to be marketed for plasterboard manufacture, then the quality must be high. The chlorine content present in many coals will produce soluble chlorides and render the gypsum hygroscopic. It is therefore imperative that the chloride is removed from the gypsum either by the installation of a pre-scrubbing stage ahead of the limestone circuit or by washing the product gypsum with water to dissolve the chloride. Either way, it leaves a chloride-rich waste stream to be disposed of from the site. This appears to have resulted in a major issue with the Rivers Authorities in Yorkshire because of the situation at Drax and it may force the routing of the raw gypsum product to land-fill. In the Netherlands where the land-filling of wastes in not permitted, one company is using the low grade heat from the power station to evaporate the chloride liquor with the objective of producing an ice-clearing salt for roads.

The European demand for gypsum is limited so alternative outlets have been sought through reprocessing. The main option adopted at some German plants is the modification of the gypsum molecule to the hemi-hydrate usually called alpha gypsum or Plaster of Paris. This has a market as a cement substitute but the operating cost is higher.

While limestone is by far the most widely used reagent in flue gas desulphurisation, other reagents such as ammonia, sodium carbonate and the magnesium salts in sea water are also used where local conditions make them attractive. These systems are unlikely to find application in the UK and will not be considered further other than to mention that Scottish Power has recently revealed that they wish to make a planning application to construct a sea-water scrubbing process at Longannet (ENDS Report May 1993).

The more fundamental issue about the removal of sulphur as SO_2 and then as gypsum is that to remove 1 molecule of sulphur, the process step requires the addition of 1 molecule of calcium, 4 of oxygen and 2 of water of crystallisation. This has a bulk 5.5 times greater than the offending sulphur. There is an energy consumption in winning the limestone, transporting, milling, processing and returning the waste to land-fill which can make little economic sense for any new plant. The removal of sulphur prior to combustion as inert material at the feed preparation stage or as H_2S to be recovered as elemental sulphur is far more efficient and cost effective.

In the USA, work undertaken in conjunction with the USDOE and EPRI suggests that up to 90% of the pyrite can be removed by aggressive beneficiation with a range of coals and also by column flotation of the naturally occurring fine coals. These techniques will not remove organic sulphur but their application to coal cleaning could make a significant contribution to sulphur reduction at low cost. A US paper suggests the cost would be $150/S tonne versus about $1000-1200/St for FGD. It is possible that UK coals do not respond to the same degree as some Appalachian coals but papers by UMIST suggest UK coals would respond to treatment.

Furthermore, equation 2a indicates that CO_2 is displaced from the limestone to accommodate the sulphate. Consequently, FGD increases CO_2 emissions both by the process itself and by the electrical power it consumes which would have to be replaced by burning more fuel. There would also be an additional CO_2 contribution from the whole system ie. the fuel consumed in mining, transport and waste disposal of the limestone/gypsum.

2.2.3 NOx Control

The control of NOx by the two major UK generators has been limited to the retro-fitting of low NOx burners. The designers aim to control the mixing rates of the fuel and combustion air to inhibit the formation of NOx and it is possible to reduce the emission by about 50% versus the older burner designs. Nevertheless, the claims can be misleading because on many coals, the NOx reductions can only be achieved with loss of efficiency. As mentioned previously, the cooler flame often results in an increase in unburnt carbon on ash. This not only means higher fuel consumption to maintain boiler output but may mean that the ash quality is not acceptable as a by-product because it may discolour products such as cement or building blocks. There is a trade-off between meeting unit NOx emission, total NOx emission and performance.

In Germany, NOx reduction has been achieved largely through investment in selective catalytic reduction which as been abbreviated as DENOX in the remainder of the report because it has been most widely adopted. Dependent on the level of NOx in the flue gases, the capital cost may be 50-60% of the cost of FGD. The total annual emission from the power sector in the western part of Germany has been reduced to 100 kt/yr with unit emissions for new plant set at 200 mg/m^3. Selective non-catalytic reduction processes have also been developed but a 1991 Report (7) indicates only 7 installations of this type versus 190 installations using catalysts. The UK power sector emits about 1 mt/yr in total with no plans to move to NOx control on stack gases. This figure has declined with the implementation of the low NOx burner programme and the significant reduction in the coal burn.

The Dutch have done a great deal of research in this field and their results suggest that it is not possible to reduce NOx on the burners alone below 370-400 mg/m^3 firing coal or heavy fuel oil. NEI, however, has developed new burners primarily for the US market which are expected to achieve 300-310 mg/m^3 firing coal on front wall and corner fired boilers. No orders have been placed in the UK for these burners. Their previous range of low NOx burners met the Large Combustion Directive levels which call for 650 mg/m^3. One key issue is whether the present level will be held or reduced in the current review of the LPC in the light of technological development.

The Dutch work also indicated that it was possible to fire natural gas to meet 60 mg/m^3 without flue gas treatment and refinery gas at 160 mg/m^3. The reason for the higher level at a refinery is the presence of hydrogen in the fuel gas streams leading to higher flame temperatures.

The new designs of gas turbine can operate at very low NOx levels. GE for example would now be willing to guarantee 50 mg/m^3 (or 25 ppmv) for both natural gas and syngas firing. Even in the 1984 Cool Water demonstration, the low levels of NOx were less than 50% of the Californian standards for stack gas emissions (61-69 lb/hr vs 140lb/hr standard) or ie. an actual of 25 ppmv (8).

The standards achievable by the gas turbine coupled with the thermal efficiency in combined cycle mode suggest that the levels to be set at the 1994-95 LCP Directive review for new plant may well be influenced by these levels based on Best Available Technology.

2.2.4 Solid Waste Disposal

The combustion of coal produces two forms of ash, bottom ash or clinker, and Pulverised Fuel Ash (PFA) collected by the precipitators. The PFA is removed either for use in building blocks and cement, or in routed to land-fill. Some 90% of the ash is typically PFA. Recently, about 50% of UK production has been channelled to land-fill and that figure may increase with the decline in the construction and building industries and the increased use of low NOx burners. The decline in coal burn may offset that trend.

PFA may be handled in powder form or slurried with water and pumped. Lagoons have been used in the past as a low cost method. When they have become full, sites above ground have been prepared by flanking the area with bund-walls. The PFA is dumped into the cavity thus created which would be capped with soil when full. Trace heavy metals in the coal and chlorine can combine to form soluble chlorides which may leach from the wastes when routed to land-fill. The slurry or surplus water would have a pH of about 12 and this must be reduced to about 9 before discharge.

It is understood that neither National Power or PowerGen make financial provision for the development of new land-fill sites so their true disposal cost is likely to increase substantially in the next few years.

The Dutch Government has banned the routing to land-fill of solid wastes from the combustion of coal. Consequently, their research group, Novem, has developed a number of processes to convert the ash into a range of marketable products. A single company, Vliegasunie, has also been made responsible for the collection, preparation and marketing of the ash from all plants. The 5 Dutch generating groups effectively pay the difference between costs of operating the reprocessing system and the revenue from sales.

The Hazardous Waste Directive of December 1991 will be mentioned in Section 3.4

2.2.5 Fluidised Bed Wastes

The main drawback to fluidised bed wastes from atmospheric systems is that the ash in the coal is completely mixed with the spent limestone used to absorb the SO_2. This mixture will also contain some residual lime. Since the chemistry of the ash in every coal is slightly different, it is thought to be too inconsistent to be formed into any type of building material. There is virtually no use for this mixture so it is normally routed to land-fill. In PFBC systems, the chemistry of absorption differs and free residual lime is not present. This material is said to harden with controlled addition of water to form a usable synthetic aggregate.

The Coal Research Establishment has undertaken a great deal of research on the disposal of this type of material but there still appears to be a lack of a commercial outlet. The broad conclusion is that is would have to be routed to land-fill but that because there is unused lime present, the chemical mix would make it self-hardening after it has been wetted which should prevent any leaching.

In the context of integrated pollution prevention and control, the use of limestone does not appear to be the right approach to the problem. The energy content of the complete use cycle would almost certainly illustrate the system debits more than offset the credit of energy conversion efficiency. The matter could only be resolved by undertaking the analysis but the absorption of sulphur into other compounds purely increases the bulk of the material to be absorbed for some industrial application or disposed of as land-fill. Complete use cycle analysis has been undertaken in Australia, the USA and Canada. The extension of the CQIM model quantifies many of the costs through the chain.

2.2.6 Possible Control of Sulphur Levels in UK Coal

The quality of coal produced by British Coal for the major generators contains more ash than coals traded internationally. British Coal's tariff perpetuates a situation which has existed for many years whereby high ash Power Station Fuel (PSF) is offered as the "lowest cost" fuel on a price structure which provides neither party with an incentive to change the status quo. The production cost is minimised by limiting the degree of preparation. In this way, British Coal allows its customers to carry the consequential costs of moving substantial quantities of inert mineral matter through the entire system.

The present pattern of flow is as follows. Wet run of mine coal is routed to a Rotating Probability Screen which splits the coal within the range of 5-25 mm. The coal in the size range above the cut point is washed and if necessary crushed to reduce any 100 mm plus material not wanted in the market. The undersized stream remains unwashed and flows forward for blending. Any coal required for the sized market is extracted from the washed stream and is sized appropriately.

The balance of the washed material is recombined with the unwashed finer coal to form Power Station Fuel (PSF). The ash is controlled at the highest level permitted in the contract by adjusting the split point on the screen so that the blend of washed and unwashed coal produces PSF within the specified range. In other words, ash is left in the coal intentionally in order to meet a high ash specification.

The rationale for the high ash level appears to have been based on two premises:-

- o deeper washing would be more costly and would result in a loss of marketable coal in the waste stream routed to minestone disposal

- o the present boiler stock was designed for this level of ash and there would be little, if any, tangible advantage in reducing it

The coal price has been negotiated on the basis of heat content expressed as a cost per Giga Joule, not a cost per tonne. In theory, therefore, the ash content should not influence the cost of energy supplied. However, this assumes that inert matter can pass through the system at no cost penalty, an important point which can be proved to be totally incorrect. There is a high cost associated with passing so much inert material through the system. (This whole topic is the subject of a confidential report prepared for ETSU by DJW.)

The high ash level also allows pyrite, which could otherwise be reduced, to remain in the coal. Iron sulphide or pyrite forms the major part of the inorganic sulphur in coal. It can be liberated by washing and some intermediate crushing. In Australia and the USA, a great deal of work has been done recently to address the benefits of better coal quality on boiler performance and emissions limitation. Improved coal preparation has been widely adopted in those countries with particular attention to sulphur removal from the fuel ie. removal before combustion rather than after. This would appear to be a faster and cheaper step to ameliorate sulphur emissions from coal combustion and is a preparation step which would benefit the advanced clean coal technologies to be described later. Furthermore, a reduction in ash content of coal would reduce the quantity of PFA to be disposed of to land-fill possibly reducing it to a level which could be absorbed into marketable product.

British Coal must have been aware of the impact of ash on the combustion process. The has three representatives sitting on the Coal Industry Advisory Board of the International Energy Agency. They included British Coal's chairman and a senior member of CRE. A report dated Jan 1985 provided data on the economic impact of ash level on power plant efficiency and availability. Evidence was drawn from all the major power generators by an international panel who circulated an questionnaire and conducted an interview programme.

The report stated that "for every 1% increase in ash (generally after passing the 10% ash level) there is a 1.2-1.5% decrease in boiler availability and a 0.3% in boiler efficiency. There is a comparable capital cost impact as well to offset consequential outage". The report stresses that this is only one side of the coin because ash chemistry rather than quantity can be even more significant. It is this type of data which can now be more precisely determined by analytical tools such as EPRI's Coal Quality Impact Model (CQIM). Data was quoted in economic terms as well in a contribution by BCURA now administered by CRE. Rather similar conclusions were drawn in an IEA Coal Research report in 1987. Consequently, it would appear that British Coal were pursuing a commercial decision to limit washing not one based on the scientific evidence available at the time to which they contributed.

Even if British Coal has reduced ash in some cases from 18% to 16% for power plant use, similar production is washed to 6% for industrial use. The power station fuel remains a blend of washed large size coal and largely unwashed coal in the 0-12mm range back-blended to the upper level of acceptable ash without considering the generators' consequential costs (or associated environmental impact) of extraneous mineral matter.

2.2.7 Chlorine

The chlorine content of some British coals is high certainly by comparison with internationally traded coal. There is a tolerance limit of 0.35% Cl at most power stations but some power plants are sensitive so BCC attempt to avoid a chlorine penalty by spreading their higher chlorine coal production to as many power plants as needed to absorb output. This step increases the transport costs to the generators and is absorbed into their operating costs.

Most of the chlorine will be emitted with the stack gases as hydrochloric acid but this is not usually highlighted as a contributor to acid rain. A report by IEA Coal Research (9) estimated HCl emission in the range of 250-300 KT/year with outcrops of high concentrations particularly in the NW of England. This would appear to be a problem to be addressed in future legislation but one which is overcome by gasification technology.

3.0 A POSSIBLE ENVIRONMENTAL SCENARIO

Introduction.

The reason for setting out a section on the possible environmental developments on a broader basis stems from a perception that selected emission goals could be achieved at modest cost if industries were willing to cooperate more closely. There is considerable scope for improving energy efficiency and reducing emissions in a number of areas. In hindsight, it is also an indictment of 20th century society and technology that energy has been considered as such a cheap commodity that 60-65% is wasted without questioning the inefficiency of its use. Improved efficiency is the key to CO_2 control with a proportional reduction in other emissions. The technologies which offer improved efficiency coincidentally could virtually eliminate sulphur and particulate emissions and substantially reduce NOx.

If the oil and power industries recognised that they may have a common problem with an attractive joint solution, significant progress could be made. Similarly, the coal industry could well study the form and quality of its product best suited to the clean coal technologies which are emerging. In summary, complete use cycle analyses are needed to understand the optimum route for the conversion of any fuels in the most environmentally acceptable way.

The key factor is to break from past practices to ask more fundamental questions about the pollutants generated in the combustion of most of the fossil fuels, with the possible exception of natural gas, and assess how those pollutants can be most effectively removed. Such an assessment points the way to the solution to clean energy technology but it may take legislative action on emission and waste control to trigger the change. Furthermore, there will be some institutional barriers to be overcome, again based on resistance to change and a need to understand how to evaluate risk when technology transfer is taking place.

3.1 Large Combustion Plant Directive Review

The pattern of European demand and resultant inter-fuel competition is likely to be progressively determined by EEC environmental legislation. Perhaps the most significant legislation enacted to control emissions from the bulk use of fuel has been the Large Combustion Plant (LCP) Directive of November 1988. The key elements are well known.

The part of the document most relevant to the outlook for coal, fuel oil and gas demand and the future selection of power generation technologies is the Schedule for the review process set out in Articles 3 & 4 of the Directive. In 1994, the Commission is to review the progress made in each country since 1989 and propose changes where considered necessary. By July 1995, a similar review must be undertaken to set the limits for new plant "in the light of the state of technology and environmental requirements". There is nothing to preclude these two steps being taken together if it was thought to be advantageous, and some observers consider this should be the preferred procedure.

The pattern of the discussions is relatively easy to predict. Germany had largely completed the retrofit of FGD and DENOX in the former Federal Republic by the beginning of 1989. Local standards have been set well below the unit emission levels mentioned in the LCP Directive. SO_2 limits have been halved, NOx limits reduced to 200 mg/m^3 for new plant in general and to 150 mg/m^3 in 15 major urban areas.

The Dutch and Danes have taken similar steps and the lower levels being achieved today are likely to be a major influence on the limits set at the 1994/5 review. Based on local research, the Dutch Government enacted the 1990 Ordinance limiting NOx from the firing of natural gas to 60 mg/m^3 and refinery gas to 160 mg/m^3.

France would have little problem in supporting tighter limits when more than 80% of its production is from nuclear sources. Sweden already has very stringent controls of emissions, for example, NOx at 50 mg/m^3 , and waste disposal controls so if they are elected to become a member of the EEC, they too would support tight limits.

Italy has set sulphur limits on heavy residual fuels at the EEC limit of 400 mg/m^3 at the stack by 1998. This means that any power plant not fitting FGD must burn 0.25% sulphur fuel oil, and no such fuel exists in the quantity needed. Hence their move to gasification of heavy oils because some 22 million tonnes of high sulphur heavy fuel oil is still burnt in the power sector.

3.2 Small Combustion Plant Directive

The Large Combustion Plant Directive does not apply to fired heaters below 50 MWt. Consequently many industrial boilers and furnaces are currently outside the emission constraints. A further Directive has been drafted and is being reviewed covering the size range 1 MWt - 50 MWt. The draft proposes that the current SO_2 limit for 50 MW should be extended to 1 MW.

There is currently a debate over allowances to accommodate the use of high sulphur indigenous fuels such as coal and lignite. A new Directive seems likely although is slow in its passage through review procedures. Most observers are inclined to the view that the likely outcome of a new Directive for industrial plant will simply be to switch the sector to natural gas.

3.3 Environmental Protection Act

The Environmental Protection Act is a very comprehensive new approach to pollution control which radically overhauled the UK protection control system. It articulated the approach to the full spectrum of issues while acknowledging the need to comply with the broader EEC Directives to which the Government has agreed as a result of community membership.

The fundamental principles of the Act are perhaps best summarised in the system of Integrated Pollution Control. Responsibilities for control have been clearly assigned to HMIP and the NRA with much responsibility delegated to the local level operating under a series of Chief Inspector's Guidance to Inspectors. Other fundamental concepts of the Act are those of Best Available Technology Not Entailing Excessive Cost (BATNEEC) and Best Practicable Environment Option (BPEO). BATNEEC is seen as a means of encouraging three key points:-

- o to prevent or minimise the release of the most polluting substances
- o to render harmless all substances released
- o to control releases in the way which is best for the environment (BPEO)

3.4 Hazardous Waste Directive

The Hazardous Waste Directive received EEC approval on 12 December 1991 and is to be implemented by 12 December 1993. Under the terms of the Directive, ashes and/or cinder from the combustion of coal become classified as hazardous wastes and, if routed to land-fill, the sites must be registered, the quantities recorded and the run-off monitored. The prime concern was expressed in the Annexe III, H13 of the Directive which refers to leachate particularly the chlorides of the heavy metals which exist as trace elements in most coals. In the UK, the main control will be the Special Waste Regulations.

The Directive requires the lining of dump areas in certain soil structures so that leachate cannot enter water courses. Compliance is unlikely to be possible without considerable additional cost. Consequently, the disposal of ash will become an increasing cost burden to power plant operators with a growing incentive to keep the quantities of ash to a minimum.

In Germany, a levy of 12 DM/t (say £5/t) (Apfallabgabe) has been proposed for any disposal to land-fill which would be in addition to the actual cost to a plant operator. This has not been implemented to date but the thinking lies behind the debate on a draft land-fill Directive which is currently being considered in Brussels.

As mentioned earlier, the Dutch no longer permit the disposal of the wastes from the combustion of coal to land-fill because of the risk of ground water pollution from leachate..

In the UK, there would appear to be conflicting evidence between a Warren Spring Report which is quoted by the power generators to say that fly ash does not produce toxic wastes versus Dutch/German evidence to the contrary. Academic hydrologists also have data to show the levels of heavy metals compounds in leachate. The explanation appears to be one of definition. PFA would have been considered non-hazardous under the older UK definition of hazardous wastes. The Germans and Dutch have set more stringent limits which have been embodied into the Hazardous Waste Directive which now defines PFA as hazardous because of the risk of toxic leachate entering water courses. The way in which it will now be interpreted in the UK would appear to rest with HMIP.

3.5 Integrated Pollution Prevention and Control

A proposal for a council directive on an integrated approach to pollution prevention and control (IPPC) for industrial pollution was adopted by the EEC Commission on 14 September 1993. The IPPC Directive aims to establish new rules for authorization of industrial sites. It provides for a harmonised system of permits throughout the Community and is set to begin in 1995. It is also embodied in the Fifth Environmental Action Programme which the EEC Council formally adopted on 1 February 1993 defining guidelines and a programme for the Community environmental policy up to the year 2000.

It is broadly based on the principle that in finding a solution to one pollutant should not create another, for example, the disposal of FGD wastes. The underlying principle holds the key to how coal, heavy oil residues, Orimulsion and petroleum coke will need to be processed in the future and forces a more critical analysis of some of the option for energy production and use. It will tend to militate against direct combustion processes and this point will be developed later in the text.

3.6 French Memorandum

Another relevant text is contained in the French Memorandum (10). The proposals were made to the EEC by the French Delegation in May 1990 and suggested that because the LCP Directive would only have limited impact on the oil industry, an extension of emission control was necessary. The key elements of the proposals were:-

a. to limit emissions from the refineries as operating units. (Refinery heaters fall outside the size definition required by the LCP Directive if taken singly)

b. to reduce sulphur from all sources of emission in the petroleum chain with a reduction in the sulphur content of all fuel products

The Dutch Government was invited to nominate a chairman for a Steering Committee. A member of their Department for the Environment was appointed. The Committee then commissioned a comprehensive study and the work was awarded to the London office of Arthur D Little Inc (ADL), the international consultants, in the autumn of 1991. The results were presented to the Committee in June 1992 in The Hague and a report has been prepared entitled "Integrated Approach for Sulphur and Sulphur Dioxide Limits in the European Refining Industry" (11).

In the introduction to their analysis, the ADL text stated that oil currently contributes 46.6% of all the EEC SO_2 emissions. With the completion of Europe's present flue gas desulphurisation programme on coal fired stations, oil's contribution would increase to 50% by the year 2000 if no steps are taken. Hence, the oil industry is very vulnerable to continued pressure on sulphur reduction. The report also mentioned that limits set for NOx emissions in the power sector could well influence the choice of technology used by the oil industry to reduce sulphur in products.
The position is exacerbated by a political view within the Community that the most effective way to secure a substantial sulphur reduction would be to press the oil industry into making the proposed quality improvements. It is seen as the only way to tackle the emission problem from the transport sector, and to achieve an improvement in the level of pollution in urban areas. Clean-up on user equipment is not seen as practical or cost effective. The oil industry is also considered to be capable of designing and operating the processes required.

The subject is still being reviewed by the Commission and the oil industry but there appears to be an acceptance that more stringent action will be formulated and drafted into some form of legislative change in the medium term. The European Oil Industry Association referred to a draft Sulphur Framework Directive in their August 1993 newsletter so the topic is progressing through the legislature.

3.7 Air Toxics

An issue of concern in the USA is air toxics, ie. emissions of arsenic, mercury, lead and other toxic metals present in the flue gases from the direct combustion of fuels such as coal and petroleum coke. Limits on total emissions are likely ie. a total tonnage per year per plant. Although legislation has been drafted, there has been a delay because of the problems of defining the limits and agreeing the techniques for their measurement. The repeatability of test methods at the very low levels of these compounds in the coals has been the main cause of the delay.

Research work by mining companies such as Consol Coal Inc (12) suggest that the emissions problem can be ameliorated by improving fuel quality, for example, by better preparation of the coal in the washing (or beneficiation) stage, or by scrubbing the flue gases. Another alternative would be the adoption of advanced clean technology (gasification) to achieve the emission targets being discussed.

An assessment of environmental damage collected in Poland and the eastern part of Germany (where large quantities of lignite have been combusted on old equipment) is said to suggest that the impact of air toxics should be a source of concern in Europe as well and this in turn may be a trigger to action within the EEC. However, in most cases East European power plants do not have precipitators so the problem is significantly more acute that in the USA, or Europe.

3.8 Benzene and Volatile Organic Compounds

A further concern in Europe is the EEC legislature's attitude toward benzene levels in gasolines/diesel and the leakage of other volatile organic compounds into the atmosphere. Much of the concern centres on the inherent toxicity of benzene linked with vapour losses from the transfer of fuel at distribution terminals, service stations, while refuelling vehicles and from diurnal loss (fuel tank breathing).

A set of staged proposals has been being considered. Stage 1a and 1b cover the installation of equipment for vapour capture and return at terminals and service stations ie. during bulk handling respectively. Stage 2 relates to recovery of vapour during refuelling of vehicles. There are two possibilities:-

a. recovery at the service station via a vapour return system on each pump nozzle

b. recovery on the vehicle in an activated carbon canister so that other fuel system losses are captured as well

Stage 2 has passed to the circulation of drafts in Brussels which suggest a more targeted approach to relate the need for vapour return systems to the throughput of the service station rather than its location. The debate which is developing is focused on the relevance of that approach in achieving the goal of VOC reduction and the disparity it raises between member countries.

The US has been pursuing a regime to reduce benzene as far as practicable. Some German cities and Länder have also advocated the US limits for Europe. There is considerable controversy over the wisdom of removing benzene from the fuel while simultaneously debating vapour recovery systems. That debate is set to continue and although the "belt and braces" approach may not be defensible logically, it may be passed by the legislators. If benzene were to be reduced significantly further, then the hydrogen required to rebalance the product yield is substantial and would exacerbate the growing demand for hydrogen by the refiners probably forcing more companies to gasify heavy residues.

3.9 Possible Oil Industry Response

The oil industry already faces a number of problems associated with a market requirement for cleaner products throughout the product range eg. lower sulphur in diesel fuel and gas oil. Legislation emerging on refinery emissions and benzene would add to those problems. The two key issues are:-

a. how to handle the declining demand for heavy fuel oil

b. management of their hydrogen demand

The market outlet for high sulphur residues may ultimately be limited to ships' bunkers and even then it might be restricted to use outside coastal waters. There is already pressure to limit emissions in selected European ports requiring ship-operators to use lower sulphur bunkers. The constraint has been applied voluntarily to ferries in the Baltic. Limits may be extended to areas of the North Sea where there is high traffic density.

The refiners' solution in the past has been to invest in conversion processes which upgrade the heavier fractions to the lighter transport fuels. However, in the US and most of Europe, the simple steps have already been taken and more expensive "deep" conversion processes would now be required. These processes break down the complex hydrocarbon molecules and then using hydrogen, saturate and desulphurise as a second or finishing stage. Consequently, such processes consume a considerable quantity of hydrogen and energy which is a debit to the yield and bears a considerable level of associated capital and operating costs.

The incentive for a refiner to make the investment is the price differential between heavy fuel oil and the clean products such as diesel, jet fuel and gasoline. In Europe, that differential is unlikely to result in a return on investment which is much greater than the cost of capital. Consequently, it is unlikely to attract the oil companies' limited funds so their options appear to be:

a. to sell the streams at some low or break even price to avoid any process investment

b. to gasify the streams to produce a synthesis gas which could be used as a source of supplementary hydrogen and refinery fuel gas, or combusted in a combined cycle gas turbine system to generate power

It is these options and the probability that there will be a growing availability of unmarketable residues which focus an interest on solutions for the clean disposal of high sulphur and high metals content material. Such streams will include petroleum coke, vis-breaker tars, vacuum residual oils, asphalts from the de-asphalting process and other high viscosity residues.

The ADL report (11) mentioned that a reduction in heavy fuel oil demand in Europe of 20 million tonnes per year is forecast within the next 5 years which could fuel about 10 GW of generating capacity without any supplementary feedstock. Other forecasts suggest substantially greater volumes being exported from eastern bloc countries as they process their heavier crude oils on simple hydroskimming refineries to meet their local transport fuel needs. Consequently, a global surplus of heavy fuel oil and availability of Orimulsion creates a competitive source of liquid feedstock. The most recent assessments of IGCC costs for liquid feedstocks suggests that current capped pool prices could be met from heavy oil residues or Orimulsion dependent on the assumptions on load factor and life of the asset.

3.10 UK Power Industry Position

The Commission for the Environment in Brussels will have perceived major changes to the pattern of UK primary energy use - far removed from the balance which existed when the Large Combustion Plant Directive was enacted in 1988. The significant increase in the use of natural gas, the move to imported lower sulphur coal and relative lack of emission control equipment suggests that it would be difficult to defend the lenient emission targets which were set for the UK in 1988 in recognition of the need to protect the UK coal industry. The disparity with the German total emission levels is bound to bring pressure on the UK when the emission limits for existing and new plant are negotiated during the review of the LCP Directive. Greater attention is also likely to be focused on NOx limits especially with member countries already imposing emission limits below that which can be achieved by low NOx burners alone.

The lack of any pro-active environmental initiative by the UK power companies may be one of the key factors in the EEC's perception of the UK response. Apart from the FGD at Drax and Ratcliffe with the retro-fitting of low NOx burners, the two major generators will be seen to have tried to introduce Orimulsion without flue gas treatment while retaining their right to burn BS standard fuel oil which currently permits use of high sulphur oils. These steps all run counter to the approach of the utility companies in several continental countries.

Summary

The main conclusion from this section is that amendments to existing legislation are likely to be introduced for new power plant. Emission standards may well be set to curtail the direct combustion of complex or poly-aromatic hydrocarbons (ie. heavy oils, pet coke, Orimulsion and coal) on any power plant unless full flue gas treatment has been installed. Current controls set country targets and new plant emissions without specific constraints on individual existing plants. Consequently, other technological solutions would need to be found to handle the "dirtier" fossil fuels. Limits set from new plant would most probably be extended to existing plant after a few years of grace and then would be expected to meet the more stringent limits with appropriate investment in emission control equipment or close.

4.0 REASSESSMENT OF POWER TECHNOLOGY

In the light of the environmental outlook, tighter emission controls appear highly probable and desirable. It is therefore timely to ask some more fundamental questions about the way fossil fuels have been used and the way in which they could be prepared in a more appropriate and environmentally acceptable way. We are attempting to convert dirty fossil fuels into electricity as efficiently as possible and at lowest cost. This must embrace minimising pollution and the costs must reflect the whole system including safe disposal of all waste streams.

Are we trying to solve the right problems? The debate on acid rain and the contribution of sulphur dioxide appears to presume that the release of sulphur in the oxide form is inevitable. Flue gas clean-up is no solution for new plant. It may have been the only suitable process available to capture SO_2 from existing direct combustion plant but it makes little sense in the context of an integrated approach to pollution prevention and control. For the most part, the process simply converts a gaseous pollutant into a solid waste.

There is a real danger that if industries try to solve their own problems in isolation, for example, by fine tuning existing combustion technologies, they may fail to spot the opportunity to break with tradition and approach the subject from a totally different and more effective viewpoint.

How can the sulphur compounds in fossil fuels be captured most efficiently and economically? The answer has to be as H_2S at an intermediate stage in its use, not as SO_2 after combustion. SO_2 capture is 90% effective (perhaps 95% with additional reagents but with corresponding effluent problems in adding such reagents) while H_2S can easily be removed with a 99.8% efficiency of recovery with a final conversion stage into elemental sulphur. Absorbtion of H_2S is a standard oil refining process but is unknown in the power industry. For every tonne of sulphur collected as elemental sulphur, 5.5 tonnes of gypsum would be produced if sulphur dioxide were to be removed by limestone scrubbing.

The solution would appear to be to clean the fuel before it is burned. With gasification and by cleaning the fuel as a gas under pressure in the absence of nitrogen, the volume of gas to be handled would be only 1% of that processed in a flue gas desulphurisation system. That has significant capital and operating cost savings along with real waste disposal cost advantages.

How can high levels of NOx reduction be achieved from power generating technologies without the use of catalytic methods? Present NOx levels can be met by CFBC and PFBC technology using ammonia injection. An alternative is by the combustion of a clean gas in gas turbines. The fuel gas can either be natural gas ie. CH_4, or as a CO/H_2 mixture. The most recent designs of gas turbine are already guaranteed at 50 mg/m^3 and this may hold the key to where the new NOx limits might be set.

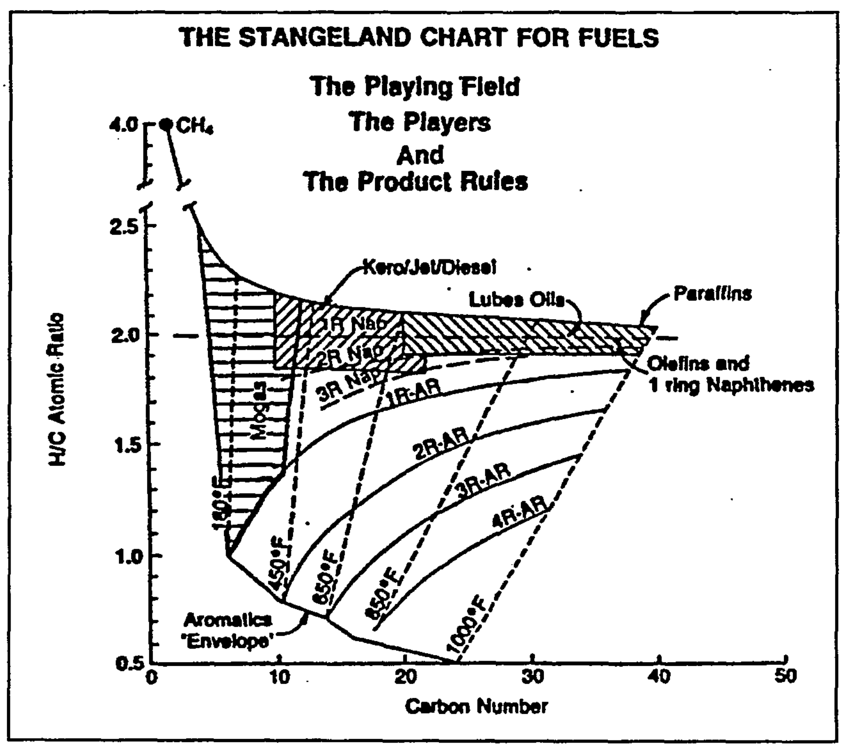
What is the most efficient commercial power generation system for the foreseeable future? The answer has to be the combined cycle gas turbine system for reasons which have been mentioned. The turbines will operate equally well on natural gas or synthesis gas. In fact, the latter increases the power output by 10-15% from the same size of machine because of an increased mass flow.

The combined cycle system simultaneously offers the highest conversion efficiency and virtually sulphur free flue gas with very low NOx emissions, so it could well become the BATNEEC and BPEO when the limits are reviewed. The specific capital investment in terms of £/kW is now lower than all the direct fired alternatives when fitted with the full flue gas clean-up systems.

Assuming the power industry is only allowed a short period of time to bring old plant to the emission standards of new plant - say 5 years - then the direct firing of the dirtier fossil fuels may not be permitted in Europe by the end of the decade unless full flue gas clean-up is installed. It can therefore be argued that the power industry has to be looking for long term reliable sources of low cost clean gas. There is a robust case to support predictions of a steady increase in natural gas prices after 1996 (13) and recent moves by the gas supply industry suggest this is already happening. The alternative to natural gas would be clean synthesis gas produced from materials which are otherwise unmarketable - heavy oil residues, Orimulsion, petroleum coke and possibly coal if competitively priced.

How can refinery residues best be utilised effectively when the bulk of the sulphur and all the metals have been concentrated into a liquid containing up to 90% carbon? This is another key question. The Stangeland chart was developed by Chevron and is a plot of hydrogen/carbon ratios against carbon number for the complete family of hydrocarbons Figure 2. At the one extreme there is methane and at the other residues including 4 ring aromatic compounds. The plot then super-imposes the envelopes for the transport fuels and lubricants with respect to the residue streams. If heavy residues are to be converted into anything marketable as a liquid transport fuel, a very substantial quantity of hydrogen has to be introduced into the process.

Figure 2



Could the oil refiners have a solution to their own residue disposal problem and make a considerable contribution to the generators needs? There would appear to be a remarkable synergy between the two industries just waiting to be developed.

Where would hydrogen come from particularly in that quantity? At what price? Even at the lowest possible price of hydrogen from the reforming of methane, the economics of investing in heavy residue conversion are not attractive. The current price differential between heavy fuel oil and gas oil/gasoline lies in the \$100-135/t range ie. with fuel oil at \$60/t, gas oil at around \$160/t and premium gasoline at \$195/t. If bulk hydrogen is priced between \$500-600/t and a tonnage equivalent to 35% of the residue is required to produce a transport fuel, then such a step does not appear to be economic even at a low value for the residue.

If heavy oil residues were to be gasified in an entrained gasifier such as the Shell or Texaco designs, the hydrogen could be produced more cheaply - effectively from water. Gasification appears to be the key. The conversion of the surplus residue streams would produce supplies of low cost hydrogen for the refiner along with an ample supply of clean fuel gas. The total gas make is likely to be far greater than a refiner would need. This is where the advanced power generating systems would feature. All the surplus clean gas could be converted into power to meet any anticipated level of emission standards.

Gasification is a very attractive way to dispose of oil industry residues cleanly and the process is equally applicable to Orimulsion. It appears to be a more financially attractive option than other deep conversion processes such as coking even at power prices well below the current UK pool price.

Are there any other benefits associated with this type of equipment? Gasifiers would need a very large supply of oxygen from an integrated air separation unit (ASU). The presence of such a facility alongside a refinery offers other commercial opportunities. It would enhance the thermal efficiencies by full integration. Estimates suggest that dependent on the degree of integration, between 0.5 and 3.0% gain in power plant efficiency could result. There would also be a bulk source of oxygen or nitrogen to the refinery. Oxygen could be used to improve cat plant regeneration while BOC has developed an oxygen based Claus sulphur recovery enhancement process. CO and H_2 would also be available for chemicals synthesis processes if required but it would be refinery specific.

The "cold pool" which is associated with an ASU would enable gas suppliers to harness other techniques -molecular sieves or PSA to reprocess lean hydrogen streams. Much of the low H_2 content spent gases are currently burnt as fuel gas but they could be reprocessed to recover hydrogen at relatively low cost. The ASU is also cheaper to build and operate if taking an air supply from a large gas turbine compressor. The optimum oxygen purity from the ASU for gasification lies in the range of 87-95%.

Consequently, a gasifier appears to integrate very well with a refinery - but is there a problem of integration with power production? This need not arise if the feed source is not integrated too closely. One solution could be to supplement the gasifier feed with Orimulsion. Another may be to accept residue streams from other affiliate refiners or purchase material in the market. There seems to be little doubt that Orimulsion will enter the power industry market but European emission standards will soon force it to be gasified. The existence of a gasifier close to a refinery site offers a perfect receipt/processing location.

Some may argue that it is more efficient to install a coker and gasify the coke. However, studies suggest that the return on investment is lower while the handling of liquids reduces the power plant investment by 10-15% versus solids so there will always be a cost advantage in favour of liquid feedstocks over solids. The viscosity is almost irrelevant, because if the residue can be pumped, Shell and Texaco have burners which will gasify it. Pumpability is therefore the limiting factor which is a more complex representation of flow than viscosity alone.

The market for fuel oil is steadily declining, crude supplies are forecast to be heavier and sourer, eastern bloc fuel oil surpluses could reach 50-80 MT/year and the reserves of Orimulsion exceed the total reserves of oil in the North Sea. So there would appear to be a place for gasification in the power sector.

The technical and economic case now points to energy conversion as an essential step in the clean use of dirty fuels with gasification as the main conversion process. Developments of this type are now being progressed in Italy where the Ministry of Industry has approved 5,600 MWe of new gasification-based generating capacity (14) for the conversion of heavy oil residues. Italy may be considered a special case because some 21 Mt/year of heavy fuel is still used in direct fired equipment in the power sector and the installation of FGD has not been undertaken. The high sulphur heavy fuel oil could not be replaced economically by sufficient low sulphur fuel oil. Consequently, the conversion of heavy oil to gas for new IGCC plant solves ENEL's emission problem and retains the outlet for the refiners' fuel oil. The Government has given an 8 year price guarantee to encourage the investment and when the programme is complete, the nation should be able to meet the EEC Directive without Government subsidy.

Four projects are well advanced using Texaco technology. They are at the ISAB refinery in Syracuse - (507 MWe), the SARAS refinery in Sardinia - (508 MWe), the API refinery in Ancona - (220 MWe) and the AGIP refinery at Sannazzaro - (250 MWe). Another 9 projects are at an advanced stage of design and close to approval and reports describe the interest and the emissions levels anticipated (14). The projects may be considered to be commercial in spite of the price guarantee because it effectively provides a return on investment from a current heavy fuel oil price. The oil industry faces a decline in the HSFO price so the real value of the heavy residues would be well below heavy fuel oil price and still yield a return on investment.

Finland, the Czech Republic and Portugal are also well advanced in planning IGCC capacity linked to refineries while most refiners are studying hydrogen management because of an imminent shortage resulting from the implementation of the Gas Oil Sulphur Directive which becomes effective in 1996. Shell has announced a large gasifier (500 MWt) as part of its programme to upgrade Pernis for the 21st century. This point is expanded in Section 9.

Texaco has also announced a 250 MWe IGCC plant in Puerto Rico based on Orimulsion and their research has proved it to be an excellent gasifier feedstock. Their latest paper emphasises the flexibility of the gasifier to use any carbonaceous feedstock and convert it to power. They have also announced two other IGCC plants of 225 and 260 MWe respectively based on pet coke and coal. Four pet-coke IGCC plants were announced at the recent EPRI Gasification Conference while in a private communication, GE say they have 8 IGCC commitments at present and prospects of 17,000 MWe of capacity under study.

The entrained gasifier is relatively fuel flexible dependent on its design. Shell recommend different designs for solid and liquid feedstocks. Texaco use a slurry feed for coal and therefore can adapt to liquid feeds easily. The lining of the reactor might need to be altered if slag from coal was being handled and this has led Jacobs H & G to suggest that the Texaco gasifier in quench mode could be considered as a fuel flexible system able to take advantage of the lowest cost feedstocks through time with the ability to remove pollutants efficiently and at competitive cost.

In concluding this section, one therefore has to question whether tighter environmental regulations are that much of a burden per se. New environmental controls may in fact be the catalyst required to create new business opportunities through the application of existing technology to two or more industries, namely oil, power generation and industrial gases. The synergies should consolidate the long term future for these industries in the confidence that they can comply with emissions limits. IGCC is therefore likely to be introduced to power generation either via the oil industry or through joint ventures linked to the oil industry rather than an initiative from the electricity supply industry.

5.0 ASSESSMENT OF FUELS AND QUALITIES

This section is an assessment of the primary fossil fuel resources which are likely to be used for power generation in future. It is important to understand the physical and chemical characteristics of these energy sources and, in particular, the form in which the contaminants exist so that the efficiency of their release and capture can be optimised. It is equally important to broaden the analysis to study the complete use cycle of these fuels rather than to consider a single stage of the cycle in isolation as has been the past practice.

5.1 Coal

Coal still represents some 70% of the world's fossil fuel reserves and about 45% of the world's input to power generation. Even if UK coal were to continue its decline as a power station fuel, the demand for internationally traded coal is forecast to continue its present rate of growth and many countries, including developing countries, will remain highly dependent on coal. Furthermore, coal is likely to underpin the price structure of the international energy market in future influencing the price of gas, Orimulsion and heavy residual oils.

Appendix (1) provides more detail of coal quality but a few points are relevant in assessing coal as an energy source. Table 1 gives an outline of the British Coal quality by sales region.

Table 1

BCC Sales Group	Volatile Matter %	Ash % As Rec	Sulphur	Chlorine	Net CV MJ/kg
Yorks	28-32	12-14	2.0-2.3	0.05	23-26,5
NE Group	28.5	11.0	1.7	0.5	28.5
Selby	26-30	8-15	1.2-1.8	0.2-0.4	23-26.5
S Yorks	27-29	13-17	1.1-2.1	0.2-0.5	22-26.5
Midlands	28-31	13-17	1.3-2.9	0.2-0.6	23-25.4
Notts	28-30	7-18	0.6-2.0	0.3-0.6	23-24.1
Range	26-32	7-18	0.6-2.9	0.05-0.6	22-28.5

Source: British Coal

The history of coal and the traditional way in which it has been burned is now tending to inhibit the approach to its future use. The power industry and the equipment manufacturers on both sides of the Atlantic still perceive it as a fuel for direct combustion. However, an understanding of clean coal technologies depends on the acceptance of coal simply as another hydrocarbon in a solid form.

The main characteristics of coal which separate it from other forms of hydrocarbon stem from its method of formation from vegetation. Mineral matter and moisture occur in coal but not in gas or oil. The carbon to hydrogen ratio is also different. There are other points of difference but they are of less significance. The mineral matter content which will turn to ash on combustion typically lies in the range of 5-8% for UK coal but the inclusion of unwashed finer coal in product routed to Power Station Fuel (PSF) raises the ash content to 18%. The sulphur level of PSF is 1.6-1.8% although some stations will accept at levels up to 2.8%.

Internationally traded coals have considerable less ash and sulphur than UK coals. A sulphur limit of 1% maximum has been set by most importing countries while Sweden requires 0.7% max. Ash content varies eg. 3-4% for Indonesian, 8% for Colombian or Venezuelan to 8-14% for Australian. Consistency of quality is one of the key features of the international trade which has reinforced the need for good preparation of coal.

Two exceptionally high ash coals should be mentioned because they are associated with projects which may be quoted out of context. They are the Escatron and the Puertollano projects in Spain both based on high sulphur and high ash coals. Escatron is a pressurised fluidised bed demonstration on high sulphur, high ash coal. (25% ash - 5% S). Puertollano is an IGCC demonstration project operating on a 50/50% blend of 5.5% sulphur petroleum coke with little ash and 50% ash local Spanish coal. It is important that observers should recognise that the economics of a technology should not be assessed on the basis of one-off demonstrations using such extremes of quality where the sulphur recovery system alone would form a major part of the investment.

The chemical composition of the ash will tend to vary with each seam of coal but will comprise mainly silica and alumina. Its behaviour on combustion will be influenced by many other minerals which may be present such as the alkali metals, iron, chlorine and trace elements. Direct combustion may release some of these elements with the formation of products which corrode and foul the boiler as mentioned previously in the section on PF-firing. The combustion process may make the ash chemically active because trace elements will react with any chlorine present to form soluble salts which may leach from the ash if dumped as land-fill.

When assessing coal as a feedstock for advanced technologies, the chemical compounds which need to be captured are sulphur, alkali metal oxides, trace metals, chlorine and the ash.

5.2 Heavy Oil Residues

The spectrum of heavy refinery residues which should be considered are as follows:-

- vacuum residue oils
- visbreaker tars
- asphalts from solvent deasphalting
- other "out of spec" or high viscosity residues
- petroleum coke

Each of these groups of fuels is slightly different particularly with respect to the sulphur and metals content. They will be described in detail in Appendix 2 as a series of qualities with a brief description of their origin in the refinery flow scheme. These streams are likely to become increasingly available as a feed for reprocessing over the next few years as the market declines.

As a general observation, the heavier the residue becomes, the greater the concentration of the sulphur compounds and the metal pollutants from the original crude oil. Each source of crude will have its characteristic distillation pattern and contaminant content which almost "finger-prints" the source. North Sea crudes are light, low in sulphur and extremely low in metals. Middle Eastern crudes are heavier but with a range from Arab Light to Arab Heavy and some other heavy crudes high in both sulphur and metals. Many Western Hemisphere crudes are very heavy and high in sulphur while Venezuelan and Mexican are very high in vanadium and nickel. Orimulsion falls within this category because the resource is simply a vast deposit of natural bitumen.

The range of residues being discussed result from at least one stage of the distillation process. Consequently, not only are the contaminants concentrated in this fraction but also the structure of the hydrocarbon molecules becomes very complex. They would typically contain about 88% carbon. This is important because, as mentioned previously, at such a high carbon levels there is no simple or cheap option open to the refiner for reprocessing. Any deep conversion process to produce gasoline or diesel from residue will require large volumes of hydrogen. It would either have to be generated separately at high cost or within as a form of gasification stage within the process. The capital cost, energy consumption and relatively poor yield of finished products does not make the deep conversion processes a financially attractive option.

Historically, heavy residue has been blended with marketable blending component such as gas oil to produce a pumpable liquid marketed under the general classification of heavy fuel oil. The shrinking demand for fuel oil and the continued growth for transport fuels which drive the refining production, will force a decision on the oil industry very soon. Their options are also set out in the Appendix but gasification appears to be the most commercially attractive choice with the opportunity to take a slip-stream of hydrogen from the yield of synthesis gas.

The key compounds which need to captured in the handling and use of heavy oil residues are therefore sulphur, vanadium and nickel. The compounds of vanadium are almost all toxic while those of nickel are carcinogenic and therefore need to be recovered in a form which enables reprocessing to the pure metal.

5.3 Petroleum Coke

One process option which has been used widely in the USA but to a much lesser extent in Europe is fluid coking. It is an upgrading or conversion process which is based on carbon rejection ie. the heavy residue is reprocessed to extract useful hydrocarbon leaving carbon as the residue. Such a process inevitably concentrates the metals and sulphur still further and leaves a solid which is more costly to handle in any subsequent stage of utilisation.

There are niche markets for fine quality coke ie. low sulphur, low metals material with a good carbon crystal structure but this is limited and can only be made from a few crudes such as those from the N Sea. The bulk outlet for the petroleum coke is as a fuel for the cement industry. However, cement quality is critical and is sensitive to both excess sulphur and metals contamination. There is now a growing surplus of unmarketable petroleum coke in the US Gulf Coast area for which the only environmentally clean processing would be gasification. Projects such as the Delaware City Energy Project are now being progressed to use this material.

Europe has a limited number of units but is unlikely to choose the technology in the present circumstances. The handling and feed preparation equipment required feed solids into a gasifier are 10-15% more than that for liquids so the refining industry takes that into account when assessing when to stop processing residues. There is also unlikely to be a long term market for the heavily contaminated coke as a direct combustion fuel.

A typical petroleum coke would contain 90% carbon, 4% hydrogen and from 2-4% sulphur. The vanadium plus nickel content could easily reach 1000 ppm if derived from a number of Middle East and Western Hemisphere crudes.

5.4 Orimulsion

Orimulsion is set to become a very competitive new source of energy. Its low production cost could allow the fuel to be discounted against the price of international coal and heavy fuel oil with a margin available to the user for the installation of pollution control equipment or new technology. The significance of its potential role in the energy market can only be understood by assessing the resource, the fuel and its quality, the ways in which it can be used and the implications of those options.

Background.

Orimulsion is the name which has been given to a new fuel developed by BP and Petroleos de Venezuela SA. Venezuela has been a supplier of crude oil to the oil industry since 1917. Oil production peaked in 1970 at 3.7 M Barrels/day but has declined considerably since then to a level of about 1.7 MB/day at present. There are, however, huge deposits of a very heavy crude oil in the Orinoco belt which have not been exploited to date. It takes the form of a bitumen or extra heavy hydrocarbon. It is too viscous to pump without heat and therefore more difficult to extract, store and transport than crude oil.

The size of the deposit at 190 Billion tonnes of hydrocarbon or 290 Billion tonnes of coal equivalent. BP's Statistical Review of World Energy quotes recoverable reserves of the heavy fuel as 64 Billion tonnes coal equivalent which assumes a 22% recovery factor and that may be very conservative.

If set alongside the large coal reserves around the world, it is the fourth largest deposit and is larger than the reserves of the current leading exporter, Australia. Put in another way, it would represent 25% more energy than the current level of oil reserves in Western Europe. The deposit therefore offers enormous potential for Venezuela so there is a substantial incentive to develop a technology which would enable the material to be marketed in a commercial form.

The application of an emulsification technology has provided a solution by converting the near solid fuel into a material with the flow characteristics of a fuel oil. This has been achieved by mixing it with additives and about 27% water.

Production costs should be relatively low and the trade press suggest around $20/tonne, so there is a considerable margin available to discount the fuel against the international coal price or that of heavy fuel oil in order to establish a market.

Fuel Quality.

The "Orimulsion Handbook" (15) gives ranges for a number of the points in the commercial specification which suggests that the product is not consistent throughout the deposit. This is hardly surprising in view of its size. The heating value is comparable with coal and typically 27.2 MJ/Kg net, with a range of 25.5-27.8 MJ/Kg net.

The ash content of up to 0.25% is high for a liquid fuel, heavy fuel oil being typically less than 0.1%. Of greater concern is the fact that the ash consists almost entirely of metal compounds rather than the clays and sands found in coal. Two of the metals, vanadium and nickel are present at 300 ppm and 80 ppm respectively and form compounds which are toxic. The sulphur content is given as 2.4-2.9% for design purposes although 2.7 or 2.8% is cited as typical. A full specification is given in Appendix 3.

Orimulsion has very good combustion characteristics because of the droplet size in the emulsion. Whereas coal has to be milled to a fine powder with say 70 micron maximum and heavy fuel oil atomised with steam, Orimulsion would have a droplet size of about 20 microns at the burner and therefore burns quickly and efficiently. Excess air can be minimised while still attaining virtually 100% carbon conversion into heat.

The fine droplets also result in a very fine particle size of the residual dust. The magnesium shown in the analysis is added to counter any possible corrosion in the boiler, a level of 450 ppm is usually included. This could be excluded from Orimulsion destined for gasification feed.

There are few handling problems with Orimulsion. It can be pumped easily when warm. Hot water rather than steam is used because temperature is critical to prevent boiling of the water in the fuel and a breakdown of the emulsion. If used as a feed to a gasifier, it would be routed direct to the burner rather than being fed through a preheat train to prevent any risk of breakdown.

5.5 Natural Gas

The fuel which has drawn so much media attention over the past years has been natural gas. Its attraction has been a combination of availability and price with a degree of competition from companies such as Enron challenging British Gas's dominance in the market. The so called "dash for gas" was stimulated by a number of factors. The privatisation of the Electricity Supply Industry was the key element with 12 Regional Electricity companies all able to invest in generating capacity to meet a proportion of their own supply. They wished to develop their own capacity in order to be less dependent on the two major generators. They also believed that they could secure a lower cost of power with this strategy.

Another key factor is that it is a clean fuel. It can be considered to be virtually pure methane (CH_4). The fuel gas is almost sulphur free so it combusts to carbon dioxide and water without SO_2 emission. NOx can be controlled at very low levels as mentioned previously so it is an excellent environmental choice. The carbon dioxide per unit of production is also the lowest of the generating options by virtue of the high efficiency and the lower C/H ratio of natural gas. The investment is therefore the least vulnerable to any proposed energy or carbon tax.

There are certain gas fields which contain some H_2S but the levels are considered to be manageable with conventional gas cleaning processes. The Miller field has a relatively high level of CO_2 but it is segregated and not put into the UK gas grid.

The major uncertainty is the future price of natural gas. This will be addressed in Section 7.

5.6 Fuel Handling and Storage

Reference has been made to handling previously and will be summarised here. The handling of solid fuels will always be more expensive than oil because of the equipment required and its operating cost. Solids offloading from a ship would cost a minimum of £1.00/t while stockyard handling both at the port and the power plant is assessed at £0.5-0.75/t. The current cost of rail transport from the UK mines to power plants averaged £4.50/t in 1992 from Department of Transport annual statistics.

Fine coal can also be an environmental problem because dust becomes airborne and spreads over a wide area. Measures have to be taken to suppress and minimise the loss of coal as dust and the nuisance it causes to communities adjacent to stocking areas. In the Port of Rotterdam, for example, coal storage areas have been surrounded by high embankments to deflect high winds and reduce dust being carried into residential areas. A number of internationally traded coals have to be delivered with a minimum level of surface moisture to prevent dust during unloading and from being blown from stockpiles. That additional moisture detracts from boiler efficiency. In Stockholm, coal has to be stored in underground caverns or fully enclosed in silos. Similarly, the Bewag installation in Berlin is fully enclosed. The storage of coal in open piles which is widely practised in the UK may come under closer scrutiny as part of the real cost of coal usage.

Petroleum coke would have costs similar to those of coal. There are no particular precautions which have to be taken which are not taken with coal but it can be very dusty.

A liquid can be moved at a fraction of the cost of solids movement - virtually at the cost of power to pump it over the distance required. The heavier oil streams may be of high viscosity but they will pump at a high temperature. A gasifier feed system may however need to be designed so that any dead legs can be flushed with distillate in the event of a shut-down or emergency. This would be standard refinery practice.

Individual qualities are discussed in Appendix 2 where possible incompatibility of asphaltene streams with paraffinic fuel oils can cause precipitation and blockage. These problems have all been experienced by the power generators when burning heavy fuel oil.

Pumpability is the prime measure of the handling characteristics of a fuel rather than viscosity and temperature. Texaco and Lurgi both state that their gasifier will gasify anything that can be pumped to the burner.

6.0 ENERGY CONVERSION TECHNOLOGY - OPTIONS

The section will be split into three parts to address the sub-sets of energy conversion:-

a. from one form of primary energy to another

b. from energy to electricity

c. the concept of exergy in making most effective use of temperature over the widest possible range

The main thrust of this section will therefore be focused on gasification because the technology converts the energy in the raw material and releases the contaminants in a form which can be easily captured. The section will include data on technical options, capital, operating data and recent developments.

A. Energy Conversion into Energy

6.1 Gasification

The basic principle of any gasifier is that of conversion. The design objective is to convert one form of energy (coal, oil or coke) into another form - namely gas - with the highest efficiency possible. A key measure of performance is the Cold Gas Efficiency which is defined as the energy in the product gas at ambient temperature expressed as a percentage of the energy in the original fuel. Most gasifiers can achieve at least 80% Cold Gas Efficiency and over 99% carbon conversion can be expected on many coals or oil residues. Much of the remaining energy in the feed can be extracted as usable heat. The influence of feed quality on efficiency will be examined later.

The process may be described as the partial combustion of the fuel with oxygen (of 87-97% purity) in conjunction with steam where the endothermic carbon/steam reaction is the temperature moderator, or with air. Air blown systems are being studied for power generation applications and will be discussed later.

The principal reactions can be summarised as:

Endothermic Partial Combustion	$C + H_2O \text{ -----> } CO + H_2$
Exothermic Steam/Carbon	$C + \frac{1}{2}O_2 \text{ -----> } CO$

although about 10 intermediate reactions will be taking place simultaneously some of which will be utilising the oxygen. The temperatures, pressures and feedstocks being converted will be the determinant of the equilibrium between the key reactions and the resultant gas mix.

The primary source of carbon as the feedstock to a gasifier could therefore be coal or any of the heavy oil residues including petroleum coke. In this context, Orimulsion would behave in line with other heavy oil residues. All of those fuels have complex molecular structures with some associated hydrogen, nitrogen and contaminants of ash, sulphur and metals. In the reducing atmosphere of the reactor, the sulphur is converted to H_2S together with smaller amounts of carbonyl sulphide (COS) and sometimes carbon disulphide (CS_2).

The mineral matter can be withdrawn from the reactor as ash or slag (as would be the case with a coal feed), or it can remain as particulates in the gas stream where it would be extracted through the gas clean-up system.

The significant advantage of the gasifier is that a totally clean gas can be produced prior to its ultimate use as a combustion fuel. Processes to remove H_2S from fuel gases have been standard in the oil industry for at least 50 years. They will clean the raw synthesis gas with an efficiency of at least 99% of the sulphur (99.8% is a typical design standard) and remove all particulates. The product gas from most commercial designs is almost entirely $CO + H_2$ which can be used for the synthesis of chemicals or as a fuel. The ratio can be adjusted by the "shift" or water-gas reaction - ($CO + H_2O \longleftrightarrow CO_2 + H_2$) - enabling more of the CO to be reacted with steam to form hydrogen. This may be an attractive route to produce low cost hydrogen for a refiner or for chemicals production but is of little value if its use is to be a fuel in gas turbines.

Note. The cold gas efficiency can be somewhat misleading if comparisons between feedstocks to a gasifier are made in isolation. The combustion of sulphur produces recoverable heat but it is the process step which the gasifier is designed to eliminate. If a high sulphur feed and a low sulphur feed are gasified, the highest cold gas efficiency will occur with the lower sulphur feedstock. However, it would be inappropriate to consider a lower figure as a notional penalty to the process. The benefit is a pure elemental sulphur stream which may have a market value. The definition of the measure of efficiency simply relates to the energy conversion from the feed to the product fuel gas which will be sulphur related.

Three gasification systems may be considered for the generation of power:-

- entrained flow
- fixed bed
- fluidised bed

Brief descriptions are given below:-

a. The entrained flow gasifier.

The most widely used of the designs is known as the entrained flow gasifier because the reaction takes place in an entrained fluid flow or total suspension. The feedstock, which enters the reactor with steam and oxygen, may be in the form of pulverised coal of 0.1 mm size or as a liquid hydrocarbon. An operating temperature of 1500-1900°C and pressure of 25-50 bar is typical of the design. At these temperatures and with coal as a feedstock, the ash melts to form a slag which drains to the base of the reactor where it is drawn off as a slag. If firing oil residues, any metals compounds will leave the reactor with the gas stream and will be recovered from the gas scrubbing system. The main commercial companies offering these designs are Shell, Texaco, Krupp Koppers, Dow and VEW.

Although there are differences in design detail between these companies, the basic principles are similar albeit that Shell uses a dry feed for solids with up-firing of the feed in the reactor while Texaco uses a slurry and down-firing. The research work and field experience has proved the versatility of the technology in converting a wide range of hydrocarbons whether coal, other solid fuels or liquids. The research has indicated that certain coals gasify more easily and completely than others. Consequently, although the gasifier can physically convert all coals, the commercial choice might be focused on the most responsive coals leading to a selective feedstock market comparable with that for metallurgical coal.

The first demonstration of this technology for power generation from coal was the Texaco Cool Water project in the USA in 1984. This was a technical success primarily structured towards proving the reliability of the gasifier and the very low levels of emission which could be achieved. The project was not set up to assess the system efficiency or the order of magnitude capital cost. A very comprehensive report produced by the US consultants, Radian, summarised the emission performance (as per Ref 8).

A plant for the commercial generation of power from lignite was designed and built by Dow for their Plaquemine chemical works in Louisiana. Operation started in 1987 and has continued since then providing power and process steam. It is currently the largest IGCC unit in the world. The technology is considered to be successful and economic. The main design difference versus the Shell or Texaco system is the subdivision of the reactor into two linked sections allowing the reaction to take place in stages. A small quantity of slurry feed is injected into the second stage which cools the raw product gas and adds to the yield.

The first European demonstration is the Demkolec-designed plant at Buggenum in the Netherlands. It is being commissioned at the present time. Demkolec is a company which has been created by the Dutch power industry to take responsibility for the design and operation of the demonstration. They have chosen the Shell gasifier linked to an air separation unit supplied by Air Products and gas turbine by Siemens. The design is a 250 MWe unit on a single shaft ie. the gas turbine, steam turbine and air compressor share the same shaft.

The other European demonstration now progressing is the Krupp Koppers Prenflo technology which has been selected for a 325 MWe plant in Spain at Puertollano, south west of Madrid. The feed is to be a blend of local high ash coal with high sulphur petroleum coke. It is scheduled for a 1995 start-up. The project is part of the EEC Thermie programme.

b. The fixed bed gasifier.

The fixed bed gasifier is an older design concept in which lump coal is charged into the top of the reactor through a lock hopper system with the steam and oxygen entering close to the bottom in counter-flow to the coal. Pressure is in the range of 10-100 bar. Reactions take place progressively as coal moves slowly down the reactor, and gives rise to the alternative name "moving bed gasifier". The long-established Lurgi gasifier supports the bed on a rotating grate and uses a high steam to oxygen ratio to keep reaction temperatures in the range 800-1000°C. This allows the ash to discharge through the grate as a dry powder. The process is used at the largest commercial gasification complex in the world at Sasol in South Africa, and was the basis of the world's first IGCC plant at Lunen near Dortmund which began operation in 1972.

British Gas has developed a high temperature version of the basic design to obtain higher specific output and thermal efficiency. Less steam is used than in the Lurgi process and the steam/oxygen mixture enters through tuyeres at the gasifier base. Reaction temperatures of around 1600°C melt the coal ash and allow it to be discharged from the gasifier hearth as liquid slag thus giving it the name of a slagging gasifier.

The calorific value of the gas is higher than that produced in entrained gasifiers by virtue of the carbonisation reactions in the bed. This results in about 6% methane in the CO/H_2 mixture. It is the only gasifier design which produces a small proportion of this higher calorific value gas. The methane is considered to have some advantages if the clean gas is used in fuel cells. The process was demonstrated successfully at Westfield in Scotland at the 500 t/d scale.

A minor drawback to this process is the need for a carefully sized coal feed to maintain bed permeability. When coal is mined mechanically, a substantial portion of fine coal is produced. The finer coal would need to be briquetted in order to reconstitute it into a form which the gasifier can handle. This is seen as an economic penalty versus the entrained gasifier.

British Gas/Lurgi have recently been nominated for a commercial scale trial in Round 5 of the US Clean Coal Technology Programme. The Camden Clean Energy Project is a partnership of Duke Energy Corp, GE, Air Products Inc and Chemicals Inc who plan to build a 480 MWe unit based on a British Gas/Lurgi oxygen blown unit.

c. Fluidised bed gasifier

The concept of using fluidised bed as a converter rather than a combustor for gasification has attracted considerable interest particularly among researchers developing cleaner technologies for the use of the reactive European and US lignites or brown coals. The basic design introduces coal, milled to the 1-5 mm size range, into an upward flow of steam and oxygen adjusted to a flow rate which fluidises the "bed" of coal while the reactions take place. In general, reaction temperatures have to be kept below the ash fusion temperature to avoid ash clinkering and disturbance of the flow patterns within the gasifier. However, the air/steam blown KRW and U-Gas gasifiers are designed to operate at higher temperatures with ash agglomeration in order to improve carbon conversion with the less reactive hard coals (16). Air blown systems have been developed because of a perceived need to minimise the capital cost by avoiding an air separation unit.

Oxygen has however been chosen for the gasifying medium in many designs such as the High Temperature Winkler process to gasify lignite in a new German project. The KOBRA project, currently being developed in Lunen near Cologne, has selected the Winkler partial gasification technique in a "topping" cycle. The project is being supported by the German government. The char is combusted in a fluidised bed boiler while the raw gas from the gasifier is cleaned by conventional wet scrubbing as used by all oil refiners. The technique may well be better suited to lignites and low grade coals than the entrained gasifier because of the mineral content of the ash. The German lignite from the Rhine area produces an ash which is unusually high in calcium, magnesium and iron and illustrates the point that there is likely to be a need to match coal qualities and gasifiers rather than assume that there is a universal process for every coal.

d. Gas yield

The gasification process reduces the feed to a relatively consistent quality of gas. The gas qualities and typical performance data for solid and liquid feedstocks is set out in Table 2 and 3 respectively.

On coal, the yield as shown in Table 2 will be somewhat more variable because of the range of coal types and the subtle differences in gasifier technology. Coal will produce more carbon monoxide than oil but the dry fed processes are significantly higher than the Texaco process at 60-65% vs 50%. Similarly, the fixed bed gasifier produces methane while it is virtually undetectable in the entrained gasifier product.

Table 2

PROCESS	Lurgi	BGL	Texaco	Shell	PRENFLO	Tex PetC
	{---Moving	Bed--------}	{----------	---Entrained	------------	--------}
Largest Unit T/day	800	1000	1000	2000	1200	2000
Ash Type	dry	slag	slag	slag	slag	cake
Coal Feed	dry	dry	slurry	dry	dry	slurry
Coal Size mm	{----6---	----40-----}	{----------	pulverised--	-<0.1-------	--------}
Dry Gas Composition %						
CO	20	57	49	65	60	53
H_2	39	27	34	30	26	32
CO_2	29	6	16	2	4	14
CH_4	10	7	-	-	-	-
Inerts (N_2 + Argon)	2	3	1	3	10	1
Cold Gas Efficiency %	84	89	74.5	80	77.5	77.4
Consumption kg/kg feed						
Oxygen	0.43	0.55	1.19	0.89	1.03	n/a

When based on oil residues, the CO production is consistently in the 47.5-51.0% range while the hydrogen is 41.4-46.0%. The cold gas efficiency is in the range of 82-85% although care must be exercised in the definition of the term applied to contaminated residues (see note above).

The cold gas efficiency will also represent the percent of the energy in the feed which can go forward to the gas turbine. Some of the remaining heat is not lost but is recovered in the steam system albeit at a lower efficiency. The remainder of the energy in the feed is absorbed in stimulating the endothermic gasification reaction.

Table 3 gives the yield data for a range of oil residues using the Texaco process.

Table 3

SYNTHESIS GAS FROM VARIOUS OIL FEEDS

Feed Type	Fuel Oil	Vac Resid	Vis Resid	Asphalt	H-Oil Bot	Orimulsion
Composition Wt%						
Carbon	87.2	83.8	85.4	84.4	84.3	61.0
Hydrogen	9.9	9.6	9.9	9.7	8.9	7.4
Nitrogen	0.7	0.3	0.3	0.5	1.1	0.26
Sulphur	1.4	6.2	4.0	5.0	5.6	2.8
Oxygen	0.8	-	0.2	0.3	-	-
Ash	-	0.04	0.15	0.08	0.1	0.1
C/H Ratio	8.8	8.7	8.6	8.7	9.5	8.2
HHV kcal/kg	10111	9628	9490	9500	9490	6800
Product Gas Composition						
Carbon Monoxide	47.5	48.3	51.2	51.2	51.2	41.4
Hydrogen	45.8	44.2	43.7	43.7	41.5	45.1
Carbon Dioxide	5.7	5.2	3.3	3.3	5.3	10.7
Methane	0.5	0.6	0.1	0.1	0.3	0.1
Nitrogen + Argon	0.2	0.2	1.5	1.5	0.4	1.8
Hydrogen Sulphide	0.3	1.4	1.3	1.4	1.3	0.9
Carbonyl Sulphide	-	0.1	0.1	0.1	0.1	0.01
Cold Gas Efficiency	84.7	84.1	81.9	82.0	82.0	82.0

6.1.1 Gas Clean-up - Wet Scrubbing

A wide range of proprietary gas cleaning systems are available for the treatment of raw gas. All are well established and widely used in the oil and chemicals industry for reducing the sulphur content of synthesis gas streams. They are very efficient and can reduce sulphur levels so that the risk of catalyst poisoning is minimised where the gases are reprocessed, or minimise emissions when used as fuel gases. The efficiency would be at least 99% sulphur reduction on the raw gas. At those levels, the combustion of the clean gas would result in SO_2 concentrations well below the limits set by current emissions control legislation. Most of the processes can remove CO_2 as well as H_2S. The range of processes on offer for advanced power generation systems has been reviewed by Thambimuthu, 1993 (17).

All of these processes utilise fully regenerable sorbents which usually release the H_2S on gentle heating. The cleaned gas passes on for use in a gas turbine or chemicals production while the H_2S is fed to a Claus kiln or similar process for the recovery of sulphur as pure elemental sulphur. This stage of the process offers the most significant environmental benefit because the potential pollutant is not only captured with maximum efficiency but also is converted into its absolute minimum bulk as 99.7% pure marketable elemental sulphur, a raw material for chemicals. Alternatively, sulphur could be stored without creating an environmental hazard.

The gasification process may produce a very small quantity of unreacted carbon or soot particularly on heavy oil residues. A naphtha-based soot recovery system was therefore designed into the Texaco and Shell systems to remove the soot and recycle it back into the raw feed system. Shell, in conjunction with Lurgi, have reviewed this step of the process and have opted to filter out the soot. They have then adapted a multi-hearth incinerator, as used in the metals refining industry, where they burn the soot thereby recovering the heat as steam. They claim it is more efficient than the naphtha circuit which was a net consumer of steam (required to recover the naphtha).

As mentioned previously, the ash in coal will form a slag and will be removed at the reactor. If heavy oil residues or Orimulsion were used as the feed, the metal residues would pass into the gas clean-up system and would be removed as a filter cake. The other advantage of the multi-hearth incinerator approach is that the vanadium and nickel compounds would be removed with the soot. The soot would burn leaving a dry metal oxide concentrate which would be ideal for metals recovery. Vanadium and nickel refiners have already shown interest in tapping this source of ore concentrate which is by far the best environmental solution for this type of waste stream.

6.1.2 Hot Gas Clean-up

Whereas the present methods of gas cleaning are very efficient in sulphur capture, the temperature of the gases from the reactor must be substantially reduced in order to use the excellent range of sorbents. In an ideal system, the gases should be cleaned at reactor temperature so that the maximum possible heat could be transferred to the gas turbine. Hot gas clean-up remains one of today's most challenging subjects for research. Three main categories of material have to be removed:-

i sulphur compounds

ii particulate matter

iii oxides of the alkali metals

In attempting to tackle the problem, the chemistry of the mix is relevant because it addresses the question of what is meant by "hot" in the context of the clean-up process. As mentioned, it would be "ideal" to clean at the reactor outlet but these temperatures, alkali metal oxides sublime and are very corrosive. Unless removed, they would condense in the gas turbine, sticking to or corroding the blades. There are no processes for gas phase absorption of these substances at high temperature although research has identified some possible ways forward. Consequently a temperature reduction step must be undertaken to condense these oxides. Hot gas clean-up is therefore determined by the sublimation temperature of about 580°C, very substantially lower than reactor temperature.

The sequence of removal would be to extract the particulates such as ash from coal or metal compounds from oil residues first using ceramic candle filters followed by sulphur capture. The filters must have a high efficiency to protect the turbine from erosion with high reliability and tolerable pressure drop. Systems have been tried with some success in the UK (Grimethorpe), Sweden and the USA. Sulphur capture is more of a challenge and alternative systems have been laboratory tested. Processes based on the use of zinc ferrite and zinc titanate appear promising although a presentation by Research Triangle Institute suggested that there is a narrow temperature window of operation and the risk of melt-down of the sorbent because of the risk of exothermic side reactions.

GE has undertaken a major research programme and they hope for success within the next few years. However, they consider that there is more scope to improve system efficiency by using a clean fuel. That would enable improvements to be made to the gas turbine taking advantage of the Carnot cycle. Hot gas clean-up could benefit all IGCC, PFBC and Topping Cycle systems once perfected but its development should not hold back the establishment of clean fuel technologies.

The development of hot gas clean-up is an integral part of the hybrid "Topping Cycle" being developed by the British Coal Corporation. It cannot achieve the predicted thermal efficiencies without perfecting the cleaning technology. This employs air blown fluidised bed partial gasification as the first stage with the addition of limestone to the bed to "fix" the hydrogen sulphide produced as calcium sulphide. The carbon residues and partly reacted limestone are transferred to a fluidised bed boiler where the calcium sulphide is converted to calcium sulphate. The solid wastes would be similar to those of a fluidised bed system mentioned earlier.

B Energy to Electric Power

6.2 Combined Cycle Gas Turbines

During the 1980s, the major manufacturers of large gas turbines, GE, Siemens and ABB, made a great deal of progress in the design of very large combustion turbines. Single turbines with a power output exceeding 200 MWe were developed and tested in commercial installations in many countries. Units such as the GE Frame 7 and 9F along with the Siemens equivalent models have now proved their reliability. Results of 99.2% on line over a period of two years continuous operation are typical of their performance.

In Korea, nearly 1900 MWe of gas turbine capacity at one plant has exceeded 55% gross thermal efficiency over the past two years. Similar figures have been experienced on the 60 hz machines in the USA. A recent load test on a GE Frame 9F at Gennevilliers near Paris achieved a record 215 MWe, the highest output for a single gas turbine run on natural gas.

The gain in efficiency coupled with the low level of emissions achievable without gas clean-up are very attractive features of the system. The CCGT system is currently the lowest cost investment or power generation and the quickest to build. It is extremely compact because the combustion turbine itself effectively generates the power equivalent to a large boiler in a fraction of the space. Typically, a 500 MW boiler would contain 100,000 tonnes of steel most of which would have to be field fabricated over a period of several years. The gas turbine is factory built in a fraction of the time and the simple heat recovery boiler associated with the "combined" feature would not require more than 10,000 tonnes of steel much of which could be pre-fabricated.

The combined cycle system therefore appears to have all the advantages for the foreseeable future and the only question is whether the price of natural gas will remain stable to be the fuel source or whether synthesis gas could compete.

6.3 Integrated Gasification Combined Cycle

The gasification and the CCGT technologies have been proved separately but to harness the best features of both for the continuous generation of power suggests that process integration is very important. The degree of integration may be location and fuel-specific and there are a number of levels at which integration could be considered. The gasifier and the power island need to be linked but there are also advantages of integrating with the ASU. It is this process of integration which the utility companies wish to observe before ordering new plant if IGCC is considered to be a stand-alone power generating facility.

The Shell heat recovery system would extract high grade heat which would be fed to the steam turbine to produce power. The Texaco process would make less high grade steam at that stage with a minor debit in efficiency but at reduced capital cost while the H & G/Nykomb variation on the Texaco quench gasifier recovers some low grade heat in a saturator into the clean gas stream thereby increasing the mass flow through the gas turbine.

Integration with the ASU has some significant benefits. The air supply could be taken as a bleed from the gas turbine compressor while it could be operated at a higher pressure so that the nitrogen could be expanded through the gas turbine thereby recovering much of the energy of compression and providing additional NOx control. ASU integration could therefore add between 0.5 and 3% to the system efficiency. The base efficiency for IGCC would be between 42-43.5% LHV on oil residues or coal but would be reduced to about 41% on Orimulsion because of the water content of the fuel.

6.4 Advanced Direct Combustion with FGD and DENOX

The limitations of the steam cycle have been mentioned but boilermakers and the turbine manufacturers have reviewed the ways to improve the proven technology for new systems. They have stretched the steam cycle close to its limit. The ultra-super critical design of boiler has been introduced which secures the remaining potential of the Rankine cycle. The key part of the design is thin walled tubes with higher steam pressure and temperature and with additional reheat.

Japan has built boilers for these conditions but has opted to operate on LNG initially but have now built a coal based unit, the gas unit being used to minimise the risk of tube fouling and damage. Denmark commissioned the only European boiler of this type in 1992. It is the Esbjerg 3 Advanced Power Plant using a 370 MWe coal-fired boiler designed by Stein Industrie of France. Supercritical units have been built in the Netherlands and Finland to BEL designs and an ultrasuper critical unit is under construction in Germany. An overview of performance was presented at an EPRI Conference in Santa Barbara in Feb 1993 (18). The operators claimed a 45.3% net efficiency from the boiler but such a degree of improvement over traditional steam conditions raised some questions about the basis of the calculations. The Danish utility company, Elsam, set out the components in the following terms:-

Double Reheat	2.0%
Higher Steam Pressure	1.0%
Higher Steam Temp	1.0%
Better Vacuum	0.3%
Better Boiler Efficiency	0.5%

	4.8%

Limited detail was provided on the technical aspects of the boiler. The capital cost is said to be high because of the specialised alloys required for the tubes. In spite of the efficiency gain, the use of coal by direct combustion does not overcome the emission problems so flue gas clean-up for SO_2 and NOx would be required. FGD has been fitted but NOx emissions are quoted at 650 mg/m^3 which is the current LCP Directive limit for new plant.

The technology remains attractive to power plant management and the thermal efficiency could be improved further with the use of a gas turbine in series. The advanced cycle is clearly an attractive option but does not appear to solve the associated environmental problems of direct combustion on new plant in the most cost effective way. The advanced steam conditions could be equally well applied to PFBC or IGCC systems.

6.5 Direct Combustion of Modified Fuels

During the 1980s several companies explored the use of surfactants and other combustion additives to improve the handling characteristics and combustion qualities of coal and heavy oils. The prime motives were:-

a. to limit the loss of gas oil needed to blend the residue into a marketable form

b. find a fuel suitable to be fired on spare oil burning capacity

Much research work was undertaken into coal water mixtures for example and coal/oil mixes. The theory was that if water could be used to form a stable emulsion or mixture which would create a fuel with satisfactory combustion characteristics, then water plus an additive should be much cheaper than marketable distillate.

For oil application, US companies focused on magnesium based additives such as magnesium sulphonate. It was found to be a good inhibitor to limit the high temperature corrosion by vanadium. The magnesium modified the vanadium from the oxide to the magnesium vanadate which is a high melting point solid rather than a corrosive liquid. In the same period, Exxon Research ran a substantial programme of research using zirconium salts but the work was never applied commercially.

Fuel Tech Inc., another US company, went one stage further and promoted a package which included traces of platinum as a catalyst to improve combustion. It was so finely divided that it was introduced as a suspension in water which became an emulsifier for the fuel. The company went bankrupt in 1983 without establishing the concept commercially.

Petroferm Inc in Florida has introduced an emulsified fuel as PEP-99 (19). They claim "six reasons why a PEP-99 emulsified fuel is better for your boiler". None of the reasons given overcome the fundamental question of pollutant capture.

Hamworthy, the UK company, introduced a system for injecting water into fuel oil to improve combustion. Again this was introducing an alternative way of atomising the fuel on smaller boilers to improve burn-out.

Much of the research and development done by BP on Orimulsion related to earlier work carried out on HFO and tar sands. The Canadian Wolf Lake tar sands deposit at Athabasca reinforced the need to find a method of pumping heavy residues over long distances with a cheap "carrier". These techniques achieve many of their goals from the standpoint of handleability and combustion. The work done by BP linked in with parallel work on coal/oil and coal/water mixtures. Although the technology was robust, the economic incentive to switch from fuels in their conventional form has not yet developed.

The presence of water in an emulsion is said to reduce flame temperature and thereby the NOx, but there is some conflicting evidence over this claim on the very large UK utilities boilers. Work done by CEGB Marchwood Laboratory and Esso at Abingdon support some reduction in NOx in selected circumstances but the improved burn of some fuel oils may result in improved combustion at a slightly higher temperature. No specific references were found with the exception of a cover of a report by Cunningham (20). Use of water to reduce temperature does not approach the NOx reduction possible by staged (low NOx) burners.

None of these techniques overcome the fundamental problem of direct combustion - namely particulates, SO_2 and the relatively high level of NOx emission.

6.6 Direct Fuel Combustion in Gas Turbines

Development of combustion techniques to burn dirty fuels semi-directly in gas turbines has been taking place in the US and Germany. For example, GE, Westinghouse and Siemens have all experimented with staged burners so that the fuel is gasified in the first stage to partially eliminate solid contaminants and the product gas fired in the burners of the gas turbine as a second stage (21). Effectively this compresses the gasifier into the burner system.

The firing of "dirty" fuels in gas turbines is a commercial option which has been done in a few countries where cheap fuel drives the choice of technology. It can only be done with significant design compromises where cost is traded against thermal efficiency, emissions and on-stream time.

GE has installed turbines to run on heavy fuel and even crude oil, for example, in the Middle East. The emissions are high because there is no mechanism to limit sulphur, NOx or particulates other than by treating the flue gases. Nitrogen oxide control is exacerbated by limited combustion control and the fact that all the fuel-bound nitrogen would be released as NOx. These methods have only been used in areas paying little attention to emission levels.

The firing temperature also has to be limited, typically to no more than 2000°F in order to leave the particulates in a powdery state which will hopefully pass through the machine to atmosphere. Higher temperatures would lead to some degree of fusion which in turn could result in agglomeration and sufficient "stickiness" to adhere to blades. Since most of the oil residues contain vanadium and nickel, an inhibitor is added eg. magnesium, which controls the hot corrosion of V_2O_5 but increases the ash deposit. Solids slowly build up on the nozzles and blades so the machine has to be taken off-line frequently, cooled and washed free of deposits. Those shut-downs may be a significant penalty to some power generators.

Westinghouse has experimented with a number of systems for the direct combustion of dirty fuels in combustion turbine systems. They are currently progressing research under the US Government's Clean Coal Technology programme using a slagging combustor upstream of the main gas turbine burner system. A paper covering these developments was read at the 1992 American Power Conference in Chicago and is mentioned in the list of references (22).

The drawback with all direct combustion processes is that the contaminants in the fuel are left in the flue gases. The sulphur combusts to SO_2, the solids become particulates and the NOx levels depend on temperature/burner design with trade-off between burn-out, temperature, NOx and CO levels.

6.7 Fuel Cells

Fuel cells are being developed in a number of countries and offer considerable potential for the conversion of energy into electrical power. Large units are under test for commercial application in the USA and Japan with much of the work related to their operation on synthesis gas produced from gasification. Research is also progressing in the Netherlands and Germany.

Japan has already adopted the phosphoric acid cell on selected islands as a means of generating power at 40% efficiency and cleanly. The developments which offer the greatest potential are the solid oxide and the molten carbonate cells where a conversion efficiency of 60% is anticipated. Two US companies have made significant advances. Ztec Corporation of Boston has developed an advanced planar solid oxide cell with a specific view to operate it as an Integrated Gasification Fuel Cell. Efficiencies in excess of 60% are claimed and at a size scheduled for demonstration at over 1 MW shortly. They operate at high temperature so much of the heat is recoverable as steam and could be routed to a steam turbine.

Energy Research Corporation has already demonstrated a 250 kW molten carbonate cell on a methane rich fuel gas. They are developing a 1 MW unit and examining the use of lower temperature catalytic gasification in order to increase the methane content of the gasifier product.

Both companies are interested in targeting a specific US market need for modest but efficient generating capacity not to replace ageing fossil fuel fired equipment but for a programme to debottleneck sub-stations with up to 2 MWe of fuel cell capacity fuelled by natural gas or synthesis gas. The Energy Research Corporation recently took a 100 kW cell to the Dow gasifier at Plaquemine. The test is to assess the sensitivity of the cell to traces of sulphur in order to determine the degree of clean-up required in order to avoid deterioration in cell performance. Emissions from fuel cells would be minimal and the determinant is likely to be the cell itself rather than the level of emission from it.

The Netherlands Energy Research Foundation are well advanced in developing molten carbonate cells and have a 1 kW stack operational. They aim to have a 250 kW stack operating in 1995 with a view to testing it on both natural gas and the syngas from Buggenum.

In theory, fuel cells appear to be an attractive format for energy conversion technology. There are, however, two key issues which must be recognised. Firstly, the degree of fuel gas cleaning required to obtain commercial run lengths on the cells is not yet established. If the cell becomes "poisoned", then it has to be rebuilt or replaced, so the cost of gas cleaning to the prescribed levels is an important part of the capital investment. Secondly, the electrical current density of the cells is relatively low, so the physical land area required for a multi-mega watt unit is considerable. The key will be the capital cost of the system compared with the alternative technologies available when they are considered commercially reliable.

6.8 Magneto-Hydro Dynamic

Magneto-hydro dynamic methods of generating power offer the simplicity of converting the fuel directly into electricity by passing high temperature gases through a magnetic field. The exhaust gases still contain sufficient energy to raise steam and generate more power with a conventional steam turbine system. Although work was abandoned some years ago in the UK, there is still a major research programme in the USA and a 2000 hour run on a 28 MWe test rig has been achieved burning coal. There are many materials problems to be overcome primarily because such high temperatures are involved eg. 3100°F within an intense magnetic field. Design of key components calls for a combinations of powerful magnets, metals, ceramics and cooling systems all operating for extended periods at these high temperatures.

The present schedule of US research sees the first commercial plants entering service in the period 1998-2005. The high thermal efficiency would again have to be offset by the need to clean up the flue gases if the system were to be run on the dirty fossil fuels. This would pose some major technical challenges because the very high temperatures would reduce any mineral matter to sub-micron size particles leaving the combustion zone in the vapour phase. This is bound to raise the capital cost of any flue gas treatment system.

The largest of the US programmes is being run by the Montana Power Company under the sponsorship of the USDOE. Montana hope they will be given approval and funding for a demonstration plant under Round V of the Clean Coal Programme. A paper was read in Santa Barbara in February 1993 (23). Net efficiencies of 60% are calculated including the power consumed in FGD when the systems have been fully developed.

6.9 High Efficiency Diesels

The report has tended to concentrate on the size of power station which has evolved in the UK. However, there is interest in efficient generating capacity in the 10-50 MWe range particularly when there is a possibility of combined heat and power (CHP). The potential of this market has been exploited by the manufacturers of large diesels - companies such as Sulzer (24). They have developed marine engines operating on heavy fuel oil which can be equally well used to drive a generator and conversion efficiencies of up to 50% have been claimed on power alone. If the low grade heat is recovered and utilised for space heating, the efficiency is improved still further.

One such installation was recently made in the City of London for CHP application. Where a stable balance between power demand and heating exists, this type of facility is said to be economic. The key problem again is that the engine combusts the fuel and will therefore convert the fuel sulphur into SO_2 which would then have to be removed by scrubbing.

Gas engines have also been used in some of the small CHP proposals in the UK. The ability to generate power efficiently close to the market and then use the low grade heat for space heating has considerable appeal and is precisely how the Scandinavian countries are able to achieve high thermal efficiencies in the use of fuel. The development of these smaller units not only erodes the demand for power from the very large generating plant but challenges the contention that economy of scale is important in power generation. That is to say is there merit in considering 4 x 500 MWe modules as the ultimate efficient unit or are the economic pressures to provide the most appropriate size for a more local market.

6.10 The British Coal Topping Cycle

The Coal Research Establishment has undertaken a considerable amount of research into the concept of a partial gasification process which they describe as a Topping Cycle. Topping cycles are not unique to British Coal and their application is being assessed in several countries including the USA and Sweden on 2nd generation PFBC designs.

The British Coal design is a hybrid of an IGCC process which uses an air blown gasifier in a fluidised bed to release a low heating value gas. The sulphur is partially captured by introducing milled limestone into the bed. The hot dusty fuel gas is then passed through candle filters to remove particulate matter and is expected to be sufficiently clean to be combusted in a gas turbine. The gasification is designed to be incomplete and the hot char/spent limestone mix is fed into a fluidised bed boiler to raise steam. It is therefore a combined cycle with gas and steam turbines driving generators.

British Coal conceived the design as a means of reducing capital cost and raising conversion efficiency. Their aim is to eliminate the Air Separation Unit and the need to cool the reactor gases prior to combustion in the gas turbine. They also considered it was necessary to develop a clean coal technology in an attempt to secure an on-going demand for coal and the future of their industry. They predict a conversion efficiency from coal to electricity of 2-3% better than the entrained flow systems in IGCC format. British Coal continue to seek Government support for the development of the technology but to date, the Government has not been willing to approve a major sum for a demonstration plant. Research work is continuing into the hot gas clean-up techniques which might be used in a system.

In the analysis section references will be made to the Topping Cycle because there are some areas of concern about the technical feasibility of the system which have been challenged but not fully addressed. Furthermore, the concept of sulphur capture and solid waste disposal to land-fill on a design for the 21st century flies in the face of all the environmental signals related to integrated pollution control. It is conceivable that a commercial outlet might be found for the solid waste but that assumes a demand in the construction industry competing with natural and other waste materials.

The clean use of coal in the generation of power is vital to the global economy. However, the 5 Rounds of the US Clean Coal Programme has now started to highlight the advantages of oxygen blown systems and the potential for advanced gas turbines which encourage channelling all the fuel gas from the gasifier through the gas turbine rather than bypass some 30% into the steam cycle only. Application of the Maude Formula (Ref) suggests that the BC Topping Cycle does not have a constant thermal efficiency advantage over oxygen blown IGCC but in fact the efficiencies converge and cross over at around 50%. This arises because of the progressive efficiency gain of complete gasification and passage of all the gas through the combined cycle versus partial gasification with the char combustion only contributing to the steam cycle.

The clean-up and handling of lean gas in such quantities is another significant problem and is one of Prenflo's main arguments for the use of oxygen. They emphasise the advantages of eliminating the 80% of nitrogen from the system especially through the gas clean-up train. The UK Government's encouragement of coal research is very laudable but the British Gas Slagging Lurgi gasifier has already been proven at Westfield and the technology is being taken up in New Jersey. British Gas has more intellectual property on coal conversion technology than any company in the UK and this is perhaps where the encouragement should be directed.

6.11 Compressed Air Storage with Air Humidification

EPRI has done a considerable amount of work on the use of underground caverns as a buffer for power generation. The concept is to store compressed air in a cavern and expand it through a turbine when required. The system would be run by an IGCC system but the facility would effectively be undersized against its peak demand. During low load period, the turbine would drive a compressor and high pressure air would be routed to the cavern. The performance would be enhanced by using their concept of the humid air turbine. The concept appears attractive and EPRI has been presenting it at conferences for at least 2 years. However, the idea is not yet being taken up commercially. The US utility reaction is a reluctance to invest in intermediate load capacity. That role is usually played by existing equipment which has passed its prime.

C. Energy Efficiency and Exergy

6.12 Implications of Process Integration

For convenience, the efficiency of converting energy to electricity has been the prime focus of the report. However, the losses of useful energy remain a matter of concern. The use of low grade heat has been tackled positively in many areas in north Europe by the application of district heating schemes. The most obvious efficiency improvement is the use of the residual heat in processes such as drying, evaporation, horticulture or space heating. Combined heat and power is widely used in the Scandinavian countries and the application of smaller modular generating systems can be very efficient if the heat to power balance can be maintained.

Denmark has implemented a national plan to utilise the heat energy more effectively. Local authorities have cooperated with utility companies to instal commercial and domestic heating systems based on the use of the hot water or low pressure steam from the power plants. In 1987, for example, 46% of their heating was already based on CHP or district heating schemes and this figure is forecast to increase to 56% by the turn of the century. Over the same period, the share of individual heating units is forecast to fall from 47% to 27%. This move has already led to the conversion of an average 37% electrical efficiency across the country to about 55% thermal efficiency. One of the utility companies makes the point that if the current Danish efficiency could be applied at a stroke in China, it would save more coal than the whole of Europe currently burns. Consequently, in terms of CO_2 and other pollutants, the key is to improve efficiency.

This simple example of low grade heat applies equally at higher temperatures. Temperature to a gas turbine may be considered as if it were a head of water to a water turbine. The higher the temperature or elevation of the water, the greater the power which can be generated by the respective turbine. There are of course materials limitations but the theory holds. In many of the routine requirements for heat, temperature is not a key factor. In food industry, for example, 200°C is the maximum temperature used in most of the processes. In the oil industry, most oil products will start to thermally "crack" at about 400°C so the products would not be heated above that level in any of the refining stages unless structural change was intended.

The maximum temperature of the flame in any directly fired heater, however, would lie between 2000-2350°C so neither the oil industry nor the food industry actually use this temperature to advantage. They do not need many fired heaters, the processes would work equally as well with steam heaters at the temperatures required by the process. Gas turbines on the other hand are designed to take advantage much higher temperatures. The lead blades cannot accommodate flame temperature yet but the latest designs operate at 1270°C and GE has firm plans for designs which will operate at about 1500°C and should be introduced over the next 6 years.

The study of the best use of temperature has been given the name of exergy. It is the systematic analysis of the application of temperature in the most effective way which will hopefully draw the attention of engineers and designers to structural changes in their approach to energy use. It becomes progressively clear that there is a great need to break from the inefficiencies which have resulted from the world's low cost energy policies of the past and assess ways in which process or industry integration can be mutually beneficial.

7.0 SYSTEMS COMPARISONS AND ANALYSIS

This section will address the options in economic terms and discuss the sequence in which the technologies might evolve. The discussion is set in the context of the broader outlook for energy and the interactions which could arise. These views may not match the traditional outlook for the power generating industry primarily because the use of energy must be looked at as a whole and not by sector because growth in the demand for transport fuels coupled with tighter emission controls may force structural changes on the energy industries.

7.1 Capital and Operating Costs

As a result of discussions and two EPRI conferences, it has clear that the cost estimates for IGCC systems have started to fall substantially. It stems from the competition developing between companies to design and build plant on a commercial basis (as opposed to bespoke nature of any demonstration plant) coupled with some significant changes in the design concepts.

Until recently, IGCC power generation was largely associated with coal where costs in the range of $1900-2100/kW installed were being quoted for a demonstration type investment on a grass roots site. British Coal has frequently cited a figure $1935/kW for other companies' designs of IGCC as a comparative basis to promote and secure research funds for their Topping Cycle Concept which they have estimated at about $1250/kW when developed. In a 1993 paper this was amended to $1450/kW for IGCC and an estimated $1305/kW for their Topping Cycle. The level of $1935/kW was the budget cost for the Buggenum project and the figure has been widely quoted. EPRI were quoting $1450/kW for coal-based IGCC in 1992 and were estimating PFBC marginally lower for the new ABB Model P 800 (350 MWe). Both technologies were very competitive with conventional pulverised firing of coal fitted with FGD only ie. without DENOX. If NOx control were to be included, then the advanced coal technology has a competitive advantage.

An important factor to remember is that the Buggenum demonstration has been designed by a company created with sole responsibility for managing the project. The company name is Demkolec and they have specified all the design details while Shell, Air Products and Siemens supplied technology and components. None of the three supplying companies have had the opportunity to meet together to optimise the design for commercial application so it is not valid to attribute the capital cost to Shell or the Shell gasifier. Texaco gave detail of a coal-based project for Tampa Electric in Florida which is progressing under a Clean Coal III award including GE hot gas clean-up technology at $1500/kW installed. Hence a "second generation" demonstration plant has already been reduced in capital cost from $1935 kW to $1500/kW in about 2 years adding credence to estimates for commercial plant.

Texaco gave papers at the 11th and 12th EPRI gasification conferences (25) indicating that they can now offer IGCC on an oil feed for $1100-1200 kW for what they describe as an advanced quench system. EPRI has accepted the basis of these costs which make them very competitive especially for processing oils which cannot otherwise be sold. Discussions with Texaco suggest that there should be at least a 10% differential in capital cost for the use of an oil feed rather than coal because of the savings in coal handling and preparation equipment. This would need to be recognised and included if petroleum coke were to be used but in the recent EPRI Conference, 4 petroleum coke gasification projects were announced in the USA.

Costs are also quoted for a grass roots site but any proposal to use heavy oil residues would suggest that a gasifier would be located adjacent to or on a refinery site thereby decreasing the cost and creating the opportunity for further integration. Texaco stress there are a series of levels at which integration could be done because refineries need steam, hydrogen, nitrogen, fuel gas and possibly oxygen. Availability of oxygen could help to de-bottleneck existing Claus kilns and save investment in sulphur recovery. They point out that integration would be refinery specific but would reduce the capital and operating costs of the system. If refiners require additional hydrogen, then a slip-stream from a gasifier could be produced for less than half the cost of the most attractive alternative ie.a methane reforming process.

Lurgi currently quote $1400/kW for a grass roots IGCC plant based on the Shell gasifier operating on oil. They would use the Shell gas cooler system which forms part of their licensed technology and increases thermal efficiency. H & G/Nykomb's costs are broadly similar to those of Texaco because they have a preference for the flexibility of the Texaco gasifier and would opt for a quench system. They have patented their own heat exchange and heat recovery methods with an expander and saturator they would argue have some advantages. They have estimated that it is possible to generate power for less than 2.5p/kWhr using Orimulsion at $50/T. This figure is based on 10% interest over 15 years. This project was recently quoted in the trade Press (26) and is being studied as a source of power for ICI Runcorn electrolysis plant.

Table 4 summarises this data and gives possible capital costs:-

Table 4

UNITS - $/kW					
YEAR	**CCGT NAT GAS**	**IGCC RESID**	**IGCC COAL**	**PF+FGD + DENOX**	**IGCC DEMO**
1995	750	1100-1300	1400-1600	1600	1935-2000
1998	700	1100-1200	1300-1500	1650	-
2000	600	1000-1100	1150-1300	1550	-

The financing costs will relate to assumptions being made about long term interest rates and internal guidelines on methodology. However, on the continent and in the UK, there appears to be a growing awareness among some banks and pension fund managers that they need to secure some long term investments at lower interest rates for terms up to 20 years. This could substantially reduce the financing charges of projects for the financing charge frequently may equate to the fuel cost.

Operating and maintenance costs are estimated to be about 0.4 p/kWhr and appear to be relatively insensitive to the type of advanced system. This may not be true of the conventional plant retro-fitted with FGD both because of the sheer size of the equipment making repair that much more expensive and the fact that materials of construction/duct linings have improved considerably as operating experience has been gained.

Fuel costs will relate to the efficiency and the price assumption for the fuel source. A guide to IGCC efficiency is 43.0-43.5% on an LHV basis which has been indicated by Lurgi and Texaco.

The actual cost of generation per kWhr will be the sum of the fuel component, the O & M cost and the financing charge. The most significant of these components is the financing charge because it can vary according to assumptions or company financial policy. It would appear to have been the main component of misunderstanding in the Coal Review and White Paper where the generating costs were being biased in favour of the company presenting the case. The coal industry suggested that the major generators had a low asset value and minimal financing costs so the costs of generation were effectively fuel plus incremental O & M costs. Gas generating costs were quoted included a high financing component. In some cases, it is understood that the CCGT investment was being written off in the period of the fixed price gas contract.

It is possible to select figures to prove a number of cases and because of this difficulty, the Swedish Government requires power companies to make the comparisons on a common basis. They insist that the alternative fuels are compared on the basis of a totally new plant designed to meet all the environmental regulations with generating costs to include the management and safe disposal of all waste streams. This is an equitable way to assess the position but the analysis should include local environmental tax regimes such as an energy, carbon, sulphur or NOx tax.

The US has introduced a somewhat similar concept for comparative assessment using the term "externality factors" which is effectively creating a notional cost penalty on the emission of SO_2, NOx and CO_2. 27 Regulatory Bodies have proposed or adopted the concept as a mechanism for ranking alternative technologies for new power plant proposals. They include Massachusetts, Washington DC, New York State and the Bonneville Power Authority.

7.2 Comparative Cycle Efficiencies

Set out overleaf is a brief summary of the anticipated electrical conversion efficiencies which could be anticipated for the gasifiers versus alternative technologies.

Table 5

THERMAL EFFICIENCY ASSUMPTIONS - Units % LHV

Technology	1990	2000	2010
PF + FGD + DENOX	35	39 (44) (1)	46(1)
AFBC	38	38	44(1)
PFBC	41	43	48
IGCC	42.5	46-50	50
CCGT	48	58	60

Note 1. Ultra super critical data in parentheses

7.3 Comparative Emissions and Wastes

The following table attempts to set out the key environmental features of the options in some perspective related to gaseous emissions.

Table 6

SUMMARY OF ENVIRONMENTAL IMPACT BY TECHNOLOGY

Technology	% SO_2 Capture	SO_2 mg/m3	NO_x mg/m3	CO_2 g/kWh	N_2O ppm	CO mg/m
PF	0	2450	800	950	10	Low
PF + FGD	90	200	800	980	10	Low
PF + FGD + DENOX	90	200	100 - 150	990	10	Low
CFB	88	300	200	900	165	150
PFBC eg Vartan	92	170	50*1	840	10	20 - 4C
IGCC	99.8	2 - 30	50	750	0.5	20
High Temp Winkler	98	50	50	740	n/a	20
BC Topping Cycle	90	300	100	740	100 - 165	20 - 40
CCGT	-	nil	50	400	2	20

*1 with Denox *2 Vartan figures

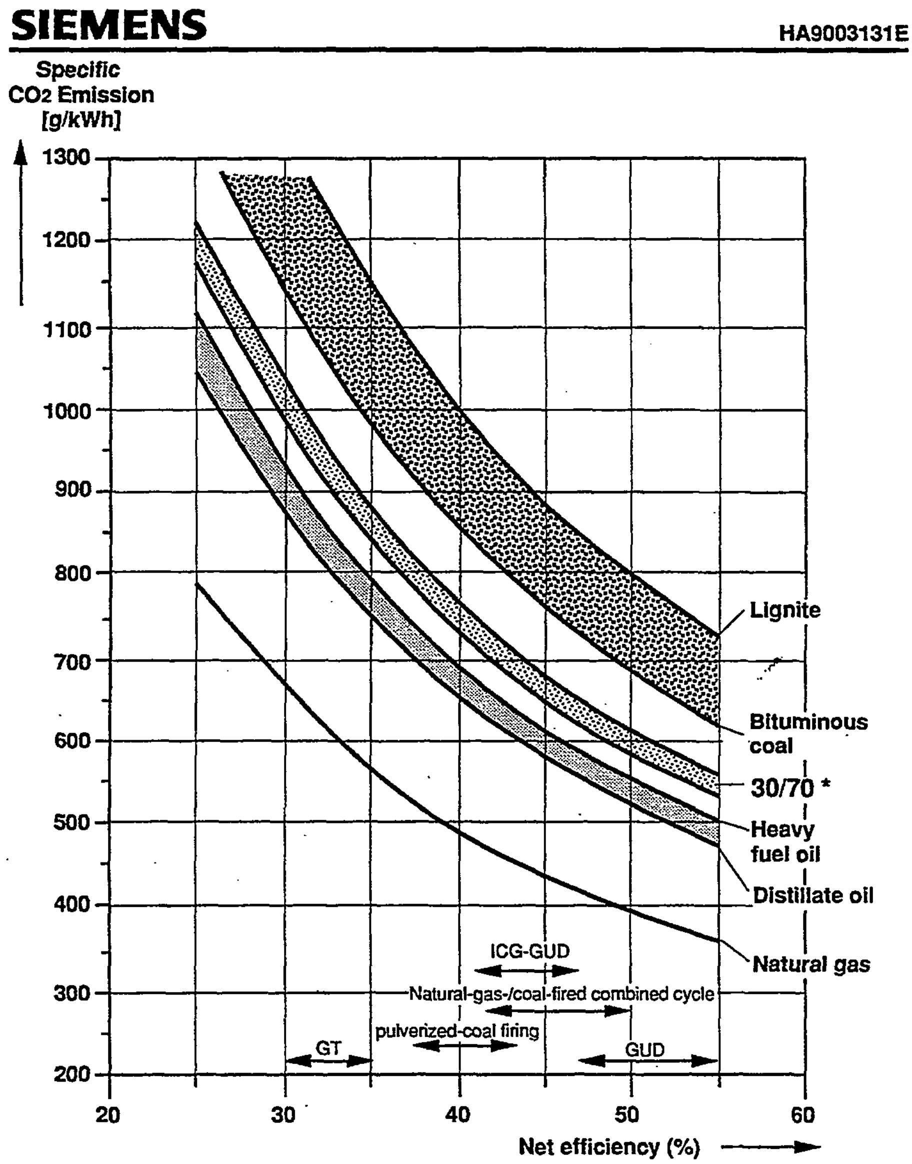
With regard to the solid waste materials, the sulphur will be produced initially as a pure liquid and if it is to be marketed, this is the usual form for transportation. It will solidify to a totally stable benign material which could be routed to land-fill but a market is expected to exist for the foreseeable future in the chemicals industry. Gases from the Claus kiln are usually recycled to extinction.

If the feed-stock is coal, then the ash will be removed as a slag which is a glassy or sandy substance totally benign and suitable for concrete or small aggregate. No problems of disposal are anticipated and a market could be developed. If the feedstock is an oil residue or Orimulsion, then the vanadium and nickel would be removed as a filter cake. Shell/Lurgi have developed a technique to use a multi-hearth incinerator to remove any residual carbon while recovering the heat creating a metal concentrate which is of considerable interest to the metal extraction companies as a source of these valuable metals.

The remaining effluents from the gas clean-up system would be liquid. Here, processes are available to meet the most stringent standards called for by local requirements. It is possible to reprocess most of the aqueous streams back to boiler feedwater or for injection water while designs are possible for "dry" systems, that is to say elimination of any liquid effluent. The Buggenum demonstration in the Netherlands has been designed as a dry system.

7.4 Carbon Dioxide Emissions

The combustion of any fossil fuel will result in the production of carbon dioxide. The quantity produced will be a function of the quantity of carbon in the fuel and the efficiency with which it is used. Natural gas has the highest hydrogen content of the fuels and therefore yield the least quantity of CO_2 per unit of heat released. Coal and heavy oils combust to produce more CO_2 than methane but the world could not exist on a single source of energy. The practical solution to carbon dioxide control would appear to be to improve efficiency of use. The following chart has been produces by Siemens and other companies to illustrate the family of emission curves which exist relating fuels and technologies.



* Fuel heat ratio natural gas/coal
(e. g. fully fired combined-cycle power plant)

KWU T1/T123/Ha/Gs/28.05.1990

Specific CO_2 Emission from Different Power Plants as a Function of Net Station Efficiency

7.5 Future of Surplus Generating Capacity

The construction of the new CCGT in the UK, which is now expected to exceed 21 GW within 5 years, will result in a substantial surplus of conventional direct combustion equipment in the hands of National Power and PowerGen. They have licences to burn heavy fuel oil and coal within the total emission limits and many of their assets may now be at minimum book value. There is a case which they could table to suggest that the cheapest next increment of power they could generate would be to develop a low cost FGD system for their old capacity on the grounds that FGD would provide them with a lower cost alternative to grass roots CCGT. Consequently, there is a possibility that inefficient combustion plant may be retained in the generating stock longer than necessary unless a form of Guidance Note is structured to impose new plant emission standards on any attempt to refurbish is old capacity in that way. It would appear to be more important to develop generator confidence in new clean technology than to stay just within existing legislation and extend the life of low efficiency plant. Unfortunately, it is possible to use costs and economics selectively to support any case of this nature.

The counter to such a proposal should emerge from an analysis of the use cycle because the energy content of the total cycle coupled with the additional CO_2 emission resulting from the use of FGD should offset most of the capital and operating cost savings of retaining old plant. The approach which has been used in Germany is that if a power company applies to refurbish a plant or make major alterations, the emissions standards which are set for subsequent operation are those of applicable to a new plant ie. with respect to SO_2, NOx, particulates and any other local constraints waste disposal.

The more appropriate use of the older UK equipment could be selective repowering using some of the existing steam plant as the second stage of a combined cycle and again this could be done very effectively at locations such as Fawley, Pembroke and the Thames. This would enable a liquid feed of heavy oil residue or Orimulsion to be gasified with the clean gas routed to new gas turbines and heat recovery boilers. It is difficult to see how coal can retain its competitive advantage against gas and the conversion alternative on liquid feed which is also capable of generating hydrogen credits.

8.0 Analysis

Introduction

The power generating industry appears to be approaching a water-shed where there will have to be a departure from the simple steam cycle for the use of dirty fossil fuels. Power plant management on both sides of the Atlantic are reluctant to see the passing of steam and the introduction of what they see as a more complex alternative. However, the drive for change stems from the combined need to raise conversion efficiency and particularly to reduce all forms of pollution.

The technological choices are numerous with ultra-super critical steam and fluid bed combustion options and the more advanced technologies of CCGT, IGCC, topping cycles, humid air turbines, compressed air storage and fuel cells. Some of these technologies are proven while others need several years of development and a breakthrough to become commercial.

In the competition for research funding in Europe and the USA, it is not easy to separate the commercial from the experimental. This classification is made somewhat more confusing in the USA because the US Department of Energy has supported a massive Clean Coal Programme encouraging a broad spectrum of development while EPRI has a parallel research programme run on behalf of its sponsoring utilities. Submissions for funding and conference papers contain very appealing claims for concepts which may be many years away from commercialisation.

During the recent EPRI/Engineering Foundation Conference in Santa Barbara on "The Economic and Environmental Aspects of Coal Utilisation V", the range of technical options were discussed. It also became apparent that a few of the more competitive utilities were commissioning their own small consulting groups to advise on advanced technology so that they could invest wisely and ahead of their competitors who await EPRI research findings for guidance anticipating that change is inevitable.

One of the key questions underlying this study is how the energy contained in the complex hydrocarbon fuels can be converted into a more usable form such as electricity as efficiently and as cheaply as possible within acceptable emission limits. Analysis of all the available data from a technical and an economic standpoint suggests that the most appropriate generating technology is based on the combined cycle gas turbine with gasification providing the conversion step between the fuel and the generating system. Its basic simplicity enables the energy content of any contaminated fuel to be converted into re-usable energy while releasing the contaminants in an easily recoverable form. This holds for coal, heavy oil residues or Orimulsion and could be extended to waste lubricants, sewage sludge or used tyres.

The EPRI Conference examined other advanced cycles including solid oxide and molten carbonate fuel cells along with other gas turbine based cycles. With virtually all of those options, the fuel which was envisaged for the future was synthesis gas based on gasification of the primary energy source. Furthermore, each of the advanced technologies appeared to be predicting that the energy conversion to electricity would approach 60% efficiency whether via CCGT, fuel cells or by the magneto-hydrodynamic process. Which one of those options will take the lead will ultimately depend on economics but an assessment of the probability of success based on existing technology transfer suggests that a steady improvement in gas turbine efficiency is the most certain of the developments. Advances in metallurgy and ceramics technology which would be needed to make MHD commercial would also raise the efficiency of a gas turbine to 60% if the same materials technology were to be applied to lead blade fabrication. Similarly, if hot gas clean-up is developed satisfactorily, the techniques would benefit all gasifiers and the gain in thermal efficiency would result.

The entrained gasifier has significant advantages in minimising volumes of gas handled through the cleaning process and the wastes produced. From the process engineering point of view, the elimination of inert materials from any system is essential whether as nitrogen from a gas stream or ash in a coal stream. Designs for air blown gasifiers have been developed to eliminate the need for the ASU investment but careful economic analysis is needed to evaluate the trade-off between the capital cost of an ASU and the cost of oversizing the gasifier/gas clean-up system to accommodate the 80% nitrogen content of the air. Furthermore, the process economics need to reflect the introduction of a solid sorbent into a system, which bulks up other solid waste to make disposal as land-fill almost inevitable. Such a step is hardly consistent with developing views of good environmental practice. This is one of the major shortcomings of fluidised bed combustion systems in general including the British Coal Topping Cycle.

With respect to advanced combustion systems, ABB Carbon are leading the promotion of PFBC technology. Other companies such as BEL are also offering systems. They believe that the 350 MWe unit could be developed to 48% efficiency ultimately. ABB also claim that a utility wants to be able to rely on one company to design, build and guarantee a complete plant on a turn-key contract basis. They do not see any company offering an IGCC system on that basis. This will be discussed later.

There appears to be a growing opinion that the gas turbine is the most likely prime mover or converter for the core of advanced power generating systems. This move has already started in many parts of the world using natural gas because of its current competitive price. As natural gas prices rise, the source of gas is likely become synthesis gas. The latter could become competitive very quickly if the raw material from which it is made is low priced for other reasons eg. petroleum coke, Orimulsion or unmarketable heavy oil residues.

The development of gasifiers over the past 30 years have enabled the operating pressure to be increased to about 80 bar with a temperature in the 1600 - 1800°C range. Their versatility has been proven with a wide range of coals and heavy residues in the large number plants operational in the chemicals industry. Making synthesis gas on a larger scale for power is therefore technology transfer, not demonstration of new technology. There is a danger that too much emphasis is being placed on the outcome of Buggenum without recognising it as an assembly of proven parts.

8.1 Use of Total Life Cycle Analysis

Historically, each industry has tended to analyse its own operations in terms of production costs and competitiveness in the market place. The significance of the radical changes in attitude to environmental issues has not been fully recognised in some industries and there is a tendency to retain a narrow perspective e.g. UK coal industry and the European oil industry.

The technologies exist today to make major improvements in the clean use of energy but, in order to make an accurate assessment of the value of the alternatives, it is important to look at the costs associated with the complete use cycle. The use of coal, for example, even today is not optimised in the UK. What is considered to be the lowest cost production for British Coal has become the basis of the commercial arrangements with their largest customers, but it fails to recognise the significant cost penalty in carrying an unnecessarily high level of ash through the power generation and transport system. If coal is to remain competitive, further work needs to be undertaken to assess the optimum level of sulphur and ash reduction appropriate to the current situation and to clean coal technologies such as gasification.

Similarly, as has been mentioned previously, if the oil refiners have no other outlet for heavy oil residues as fuel oil because it can no longer be burnt directly, then the conversion of these residues to synthesis gas will be necessary. Those residues will be produced as a result of making transport fuels which are expected to continue their historic pattern of growth. Whether the gas is used for power generation, petrochemicals, transport fuels synthesis or a mixture of these new opportunities can only be optimised by use cycle analysis and economics.

8.2 Institutional Resistance to Change

There is likely to be a significant level of resistance to change partially based on uncertainty and part conservatism. Resistance could manifest itself in three sectors of institutional influence:

a. the learned societies

b. financial institutions

c. the insurance companies

A. There has been a tendency to consider power generation as the preserve of a limited number of Institutions eg. the Institutions of Mechanical and Electrical Engineers. However, many of the environmental clean-up processes and clean fuel technologies are process or chemical engineering. The Fairclough Initiative has drawn out a signal that the larger Engineering Institutions wish to retain their identity and independence. The notional "demarcation" suggests a degree of conservatism. There is only limited recognition that the complexity of many advanced developments will required the pooled resources of many engineering disciplines working together in teams.

B. The banks have perhaps become over-sensitive to risk and so support traditional or proven technology. Nevertheless, the challenges of improved efficiency and a cleaner environment in the power generation sector call for a break with tradition. This may mean that a communications programme is appropriate to explain the reasons for change and the type of equipment available to achieve the new goals. The process of education may be slowed down if power plant management remains luke-warm. Fortunately, selected banks have supported oil gasification based power ventures in Italy and this may initiate the recognition of change and manageable risk.

C. The insurance companies were initially reluctant to insure CCGT because they collected past performance data on liquid fuel-fired "peak shaving" turbines which were very misleading. GE and Siemens have had to undertake a substantial programme of orientation to establish confidence in the equipment but degree of caution raises a question over the insurance of IGCC technology at the early stages of introduction. Two points appear to arise from this concern. Firstly, there is a question of whether the insurance companies are being asked to insure against poor management decisions. Their concern has a great deal to do with consequential loss if a new plant is off line for an extended period. Secondly, GE have decided to avoid the problems of the banks and the insurance companies by creating their own finance house for advanced technology projects. This illustrates the confidence they have in the technology and the market potential.

8.3 General Discussion on Evolution of Alternatives

An important aspect of operator and institutional concern is that of marketing the new style IGCC plant. The client wants a total package from one main supplier who will guarantee performance. Several US utilities are recognising the merits of IGCC and the application it could have in the USA for the clean use of coal. However, there is some degree of resistance to any concept which involves negotiating a licence with companies such as Shell, Texaco or Destec simply to obtain the right to incorporate one key component within a complete generating system. They want a turn-key package and a single supplier who will provide the guarantee. They do not want a Texaco licence for the gasifier, an industrial gases company building an ASU while GE, Siemens or ABB supply the gas turbine. Yet another company may be needed to construct the total unit. A company such as Fluor in the US or Lurgi in Europe have the skills to embrace such a project but there is no equivalent company in the UK who could currently offer an advanced power plant package.

Much of the uncertainty or mystique about IGCC stems from the technology appearing to be complex. To the oil refining or chemicals industry it is simple, it is basic chemical engineering. Consequently, there may well be the need for a level of education in a multi-disciplinary subject. The case for change, and the limited associated risks, needs to be properly articulated along with the benefits which will result.

The tightening of emission controls is the most significant driving force for change but another key economic factor is the medium to long term price of natural gas. Shell, BP and Prof Odell (13) all predict a price increase after the 1996-7 period. The reasoning is that demand then exceeds the quantities currently contracted and that additional supplies will need to be negotiated. Those supplies are likely to outside UK waters and the forecast growth will result in a price increase. The level of price will relate to the supply/demand balance and the sources involved. Norway would be the obvious first choice but at some stage, LNG from Algeria, Nigeria or the Middle East will be required as a supplement. Even local N. Sea sources will be more costly to develop when separation equipment has to be installed to remove condensates.

There are also advocates of Russian gas because of the very large reserves which exist in the east of the country eg. Siberia. Although there is a sound theoretical case to link it to the

European gas grid, there are some major concerns about the sheer distances and investment involved, the physical stability of the terrain over which the pipeline would pass, the political stability of the independent states along its path and the charges demanded for wayleave etc. The consensus view therefore appears to be that natural gas prices will rise significantly and therefore the appeal of a clean synthesis gas from the gasification of the "dirtier" hydrocarbons will become progressively attractive.

A dimension to the gas price issue which should perhaps be mentioned at this stage in connection with price relates to whether today's low UK contract gas prices are continuous or interruptible. The basis on which many of the claims of low cost electricity have been based appear to be based on the low interruptible price. If that is the case, it raises the question of the price differential which would be needed for continuous supplies or the price premium which the gas suppliers would demand for gas to the power industry during peak periods. If the year round price were to be significantly higher, it would close the gap between natural gas and synthesis gas very much more quickly.

The first sources of feedstock for the manufacture of synthesis gas would be the oil refiners. There are a number of UK opportunities for integrated plant operation. Oil companies could forge links with power generators or buyers at existing UK sites such as Pembroke, Fawley or the Thames. The advent of gasifiers at refineries simultaneously creates a totally clean way to process Orimulsion. Every refinery has an ocean receipt facility, storage and pumping capability so could provide low cost import capability for the fuel.

Coal would follow when the fuel is competitive with liquid feeds on the basis of cost/kWhr generated.

8.4 Strategic Energy Policy Issues of Gasification

The question of the life of power plants has been raised in the context of the period in which any one of the fossil fuels has been economic for power generation. The life span of any one of the fuels has been about 10 years since the 1950s and the signs are clear that the amount of gas fired capacity installed and planned will leave UK consumers very vulnerable to price increases later this decade. The generators will have become an exceedingly large captive market for a limited number of suppliers so major price increases appear highly probable. This trend has been signalled by the oil industry and its advisors. One strategic counter may be to have some IGCC capacity in place as soon as practicable so that some ceiling can be put on the natural gas price.

9.0 Possible Inspector's Guidelines

The present range of Chief Inspector's Guidance to Inspectors sets out a range of criteria against which Inspectors should judge Environmental performance. The notes are based on the Environmental Protection Act underpinned where relevant by the EEC Directives.

In the context of development in technology for the control of emissions and other pollutants from power plants, there would appear to be a strong case to move to more stringent controls. The role of direct combustion of dirty fuels for power generation is likely to be phased out by the adoption of very clean combined cycle gas turbine systems. Hence, there would appear to be a case to phase out the Guidelines on combustion plant replacing them with standards set for gas turbine for all new plant giving sufficient lead time to implement the changes.

On the assumption that these developments take place, the present Guidance Notes appear to cover the developing situation in principle with some minor amendments of detail. The two key sets of notes are No.2 and No.11 relating to gas turbines and gasification. These would ultimately take over from No.1 - the notes on large boilers and furnaces as they are phased out or as amended to impose emissions limits which can be achieved by full flue gas treatment.

Amendments to Notes No.2 and No.11 may be needed in order to adjust to the levels which the respective manufacturers of turbines and H_2S cleaning systems believe they can guarantee e.g. NO_x levels of 50mg/m^3 for the turbine. The level of effluent pollution may need to be adjusted in the light of the individual fuels ie. metals such as nickel and vanadium will be more significant if oil or Orimulsion is the feedstock, while trace organo-sulphur or chlorine compounds may be more significant in a coal-based system. A more detailed analysis of the current systems would be necessary to advise on levels which could be achieved.

It would also be prudent to qualify the setting of tighter limits with an appropriate review system because it might be possible to set more stringent sulphur limits for example on a wet scrubbing system such as Rectisol while hot gas clean-up might offer higher thermal efficiency once commercially developed but at a marginally higher stack gas emission levels for sulphur. It should also be mentioned that the Rectisol process is more expensive than Purisol or Selexol but can reduce SO_2 emission to a few parts per million while the other two are in the 20-40 mg/m^3 range. The minor commercial problem with Rectisol is that Lurgi and Linde hold the exclusive licence which could constrain competitive bidding.

Another issue which might perhaps be considered is a condition or caveat in granting permission for gas fired capacity. It is understood that in some countries, the use of CCGT has only been granted if there is sufficient space on the site to accommodate a gasifier and feedstock storage at a later date. A forward plan of this nature would overcome one of the issues of surplus generating capacity because the fuel is no longer competitive. Since the 1950s, the most economic fuel for power generation has lasted about a decade, coal giving way to oil, a reversion to coal and now a swing to gas. A power plant has a life expectation of say 30 years, so on that pattern of fuels much capacity could have been considered sub-optimal for 60% of its useful life. The advent of IGCC overcomes that problem because some gasifier designs can be made feedstock while synthesis gas or natural gas can be fed to the gas turbine. If tighter emission standards were to lock new generation capacity into the use of the gas turbine, this flexibility might prove commercially attractive.

In the context of the role of Guidance Notes and the onus of responsibility, the recent negotiations between Shell and the Dutch Department of the Environment are very relevant because it indicates where the initiative and responsibility for the environment lie in the context of the energy industries. Shell developed a 20 year investment plan for their largest refinery in Europe at Pernis in the Port of Rotterdam. They took the total programme to the Ministry complete with the environmental benefits which would result from its implementation. The plan was to gasify much of the heavy residue in order to achieve three goals:-

- more hydrogen for the reduction of sulphur in marketable products
- clean fuel gas for use on the refinery furnaces to minimise emissions of SO_2 and NOx
- sufficient electrical power for the refinery with 85 MW to export to the grid

Shell sought approval of the plan which will achieve very low emission levels in return for assurances that if they progressed with the scheme, there would not be a change in the emissions levels they were volunteering to meet ie. sulphur and particulate free and very low NOx. The scheme was agreed by all parties. This initiative would appear to be a model of how a responsible energy company should be interpreting the environmental signals and has shown itself to be willing to be pro-active. This approach appears to be far more positive than the alternative operating just with the limits set by legislation.

10.0 Future Research

There are a number of areas of research which would appear to merit support. Although combustion techniques would appear to be a fruitful area, a great deal of work has already been done which has identified the parameters for the formation of thermal NOx. The case which has been developed in this study suggests that pollution control is best achieved by cleaning a fuel before the final combustion stage and this appears to be the most attractive area to pursue. The areas of research are set out in the following paragraphs in a sequence of priorities which might enable short term benefits to be achieved:-

1. Use Cycle Analysis

Several references have been made to the value of use cycle analysis. Simple studies indicate considerable scope to understand and optimise existing cycles for coal, selected oil products and biomass. However, assessing the cycles in their entirety can be complex and best suited to systems analysis techniques probably harnessing a computer to handle the data. Whether the work calls for University research or whether a combination of specialist consultancy skills may more appropriate is a matter for discussion but it is a field which should be developed in order to evaluate the contribution which technological development can make to pollution control and provide guidance on cost/benefits.

2. Coal preparation

Several areas of work could be followed by examining the application of mineral ores processing to coal. A very substantial quantity of the inorganic sulphur - mainly pyrite, - can be released by crushing prior to washing.

A great deal of research has been done at both UMIST and Nottingham University on fine coal cleaning and there would be scope to extend it. Froth flotation techniques can be made more mineral specific ie. to remove pyrite and ash, while micro-fine magnetite technology is developing in the USA for a similar purpose (27). There are also techniques of removing organic sulphur which might be examined. BP Research has developed a "Hyclean" process with a 3-phase separation technique which could well be applicable to the cleaning of coal.

A reduction in ash and sulphur would improve the performance of the UK power generation boilers and also allow a small addition of limestone to the coal to extract organic sulphur during combustion rather than after - without the need for FGD. The extent to which chlorine and traces of heavy metals can be removed is also of importance especially where FGD systems have been installed and where chlorides and trace metals are starting to appear in liquid effluent streams.

This latter step may only be an interim measure. The preparation of coal for gasification is of more interest. If the pyrite and ash can be removed at the mine and the fine coal transported as a slurry by pipeline, there would be a very substantial transport saving (28). Reduction of sulphur and ash reduces the capital cost of the gasifier and clean-up system, increases conversion efficiency and helps to minimise the disposal of waste streams from the power plant. A reduction in the chlorine would also easy the design conditions for the heat recovery boiler.

3. Hot gas clean-up

British Coal are examining the subject as part of the topping cycle programme but it is focused on particulate removal with some sulphur reduction. As mentioned, it is also researching the technology in the range of 580^{0}C not at reactor outlet temperatures of 15-1800^{0}C. There is scope to research the more fundamental issues of alkali metal and sulphur capture at the higher temperatures, perhaps at a University with a specialist inorganic chemistry department, because the ultimate break-through for coal would take place if the efficiency losses of otherwise excellent wet-scrubbing systems could be overcome.

4. Ceramics and Metallurgy

The large gas turbine has been developed substantially in a relatively short time but there is still a potential 300-600^{0}C of temperature as yet unexploited which could be used if improved materials, coating or cooling systems can be developed for the leading blades.

There would appear to be the need to develop ceramics, metals and coatings for very high temperatures which could be done by specialist independent laboratories or in conjunction with a major aero-engine or turbine maker in order to develop materials. Similar materials might be required in the commercialisation of fuel cells.

5. Exergy and thermodynamic efficiency

As another part of the need for systems analysis, there appears to be scope for research into the thermodynamic efficiency of the more advanced power generation systems to ensure optimum heat integration. This field of interest has been highlighted recently by two important papers on exergy from the University of New Brunswick and the University of Utrecht (29).

Exergy is the study of the best use of temperature. It is the systematic analysis of the application of temperature in the most effective way which will hopefully draw the attention of engineers and designers to structural changes in their approach to energy use. It becomes progressively clear that there is a great need to break from the inefficiencies which have resulted from the world's low cost energy policies of the past and assess ways in which process or industry integration can be mutually beneficial. It is a subject which needs to be introduced more widely into chemical engineering courses in this country and applied to advanced power generating and energy intensive industries.

6. SO_2, NOx and the Ecosystem

An analysis of the effects on the ecosystem were considered to be outside the remit of this report. However, in the context of Integrated Pollution Control, some of the issues need to be addressed because technology can now offer choices on emissions which need to be defensible in the context of their impact on the ecosystem. The options for SO_2 control, and to a lesser extent NOx, raise the issue of just how low the emission limits might need to be set to achieve the air and water quality being sought. There is a danger that the levels requested of one industry may go beyond that of scientific good sense. For example, synthesis gas can be cleaned to a sulphur content of parts per billion. Such low levels may be required to prevent catalyst poisoning if being used as a chemicals feedstock but it could hardly be justified for use in gas turbines. Nevertheless, there is presumably a threshold level which would harmonise with the naturally occurring background.

Natural processes including that of vegetative decay eg. leaves or pine needles etc. is acidic so the measurement of acidity in lakes may well provide a misleading guide to the contribution from atmosphere. It is therefore important that the sulphur cycle is understood and other methods of amelioration are assessed. The use of limestone for pH control lakes might have greater value than say its use in FGD systems. Much work has been undertaken in this area but it would be unfortunate if on-going programmes were terminated prematurely by reductions in Government funding.

A very significant joint research project was undertaken in 1983 known as the Loch Fleet Project. Funding has only been granted until March 1994 and as a result of the privatisation of the electricity supply industry, the power generators and British Coal have indicated their intent to withdraw further funding. There is no scientific reason for stopping the monitoring for it is important to understand the longer term results of the liming which took place in the 1980s and the point at which it needs to be repeated to provide stable pH levels. The management of the water quality has enabled a correction in the accumulated acidity and created conditions in which salmon and trout can spawn. It is also important to establish the contribution of acidity in the rain and that which is leached from the coniferous needles.

This and any similar monitoring projects would appear to remain a key area of on-going research because it is important to understand the level of background SO_2 in the atmosphere when assessing, for example, whether 2 ppm, 20mg/m^3 or 50 mg/m^3 of emission is the appropriate level from a new power station. Hence, the Loch Fleet project and other monitoring programmes would appear to be an essential adjunct to complete the understanding of fuel use cycles.

11.0 CONCLUSIONS.

The prime determinant in the selection of fuels and technology for power generation capacity is likely to be the emission standards set by legislation for new plant and the lead time given for the upgrading of existing equipment to meet similar levels of pollution control. The anticipated changes will bring increasing pressure on both the power and the oil industries. The latter, in particular, has to find ways of utilising heavy oil residues in an environmentally acceptable way.

There are no processes for the direct combustion of fossil fuels which enable the contaminants to be extracted other than by flue gas treatment. FGD results in an efficiency penalty and an increase in CO_2 while NOx control has a similar efficiency penalty. Fluidised bed boilers offer a partial solution for fuels such as coal but may not meet the more stringent emission standards anticipated without the addition of some form of flue gas clean-up. Most combustion clean-up processes convert gaseous pollutants to a solid or liquid pollutant and therefore do little to solve the problem in the context of the integrated approach to pollution control which is currently being pursued. FGD and DENOX control systems are capital intensive processes which, if added to new conventional capacity, would elevate the total installed cost to a level now exceeding the cost of IGCC for liquid feed and is comparable on coal.

One interim measure to reduce emissions from existing UK coal-fired power plants would be to reduce the sulphur in the coal rather than attempt any further FGD investment. This could be achieved relatively quickly by deeper and more complete washing of PSF, if necessary by contracting out coal preparation. An alternative would be to import low sulphur coal from the international market. Nevertheless, in view of the improvements in productivity which have been achieved by British Coal recently coupled with the use of the coal cutting equipment for many more hours per week there should be a way to utilise UK resources while being competitive in both price and quality.

The introductory stage of advanced generating technology in Europe is likely to be gasification of oil residues. Gasification has many advantages as a technology which will convert the complex hydrocarbon streams into a consistent quality of gas. The gas can be completely cleaned and the other pollutants recovered for re-use or safe disposal. The cleaned gas is a mixture of CO and H_2 but the ratio of the two can easily be adjusted according to need. In the context of environmental constraints likely to be imposed on oil refiners, the process offers low cost hydrogen for the hydro-desulphurisation of refined products, clean gas for refinery fuel and a potential surplus of gas for the generation of power. This step is the most likely to draw gasification into power generation as an adjunct to refining. Lurgi, the German licensee of gasifier technology, sum up the position on oil residues as a classic example of turning a disposal problem into a secondary source of raw material ie. clean syngas, elemental sulphur and metal concentrate.

The refiners' alternative of deep conversion processes will progressively concentrate the contaminants into smaller quantities of residue which can only be gasified. Lurgi therefore conclude that it is not a question of whether the refiner needs a gasifier but what size it should be and timing. Several major oil companies see gasification as the solution to residue disposal which offers considerable scope for integration both for gasifier product streams and heat. However, the industry has some reservations about the management of strong ties with another industry such as power because of the length of contractual commitments which might be required. This may offer scope for third party participation whereby another company would make the investment, process the streams on behalf of the oil company, returning useful streams to them and marketing the clean gas or power generated. Hence the introduction of power generation from IGCC is more likely to be introduced into the UK by the oil industry or a joint venture processing oil or Orimulsion rather than by the power industry.

Texaco, Shell, Dow and Lurgi market proven gasification technology which has been used in the chemicals industry for the past 30 years. British Gas has successfully demonstrated a process for coal and has a fund of technological data on the general subject. The gas clean-up systems are standard in the oil industry. The process reliability is very high and sufficient to consider syngas as an alternative to natural gas.

Although gasification has been commercial for 3 decades, IGCC based on coal is a more recent extension of the process. Texaco demonstrated the concept of generating power in 1984, Dow in 1987 and shortly, Shell will demonstrate the concept in the Netherlands. The most recent Texaco costs for the advanced quench system suggest that IGCC technology on coal make the technology competitive with direct combustion based generation, while the use of residual oils or Orimulsion could be competitive with the new CCGT plants on a cost per kWhr basis.

There is no single organisation currently offering a turn-key IGCC power generation package as a main contractor. H & G/Nykomb Synergetics offer the coordination skills to assemble such a package but at present would sub-contract the construction. That position may well alter as demand for the systems increases.

Although the process flows may look complex to power station engineers, the IGCC system uses basic and proven chemical engineering design, most of which is standard in the oil and the chemicals industry, with very high levels of reliability. IGCC, particularly associated with refinery operation, suggests the need for base load capacity or some form of co-production of a petro-chemical product.

From the standpoint of Inspector's Guidance to Inspectors, little would appear to be needed other than to revise the existing Gas Turbine Guidance text to reflect the NOx limits attainable on the latest turbines and set sulphur limits at meaningful levels with respect to air quality objectives. Very low sulphur levels can be achieved by current scrubbing systems such as Rectisol or Purisol but the absolute level should perhaps be set in the context of the environment rather than that which could be attained technically in this instance.

The Guidance Notes on turbines would be seen to ultimately replace the Large Boiler Guidance notes as direct combustion processes are phased out. There would be a need to review the notes on the gasification processes to ensure that they reflect the developments in technologies for the solid waste and liquid effluent streams with some degree of flexibility to accommodate the future use of hot gas clean-up techniques as they are developed. It is not inconceivable that thermal efficiency gain may need to be traded off against marginal adjustments in absolute emission levels.

These conclusions have been prepared in the context of the review which was commissioned as a discussion document.

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APPENDIX 1

Coal Quality Related to Gasification

Most of the data available on the characteristics of coal have been developed for either the conversion of metallurgical coal into coke or the combustion of steam coal as a boiler fuel. Considerably less data has been published on the qualities which are important if the coal is to be gasified.

Several factors need to be considered when assessing coal which is to be converted rather than combusted. This appendix will address a few of the key points which were of importance to the companies developing gasification in their choice of test coals. However, factors mentioned can be accommodated in the design and offer a considerable flexibility to the user. Nevertheless, some coals will gasify more easily than others and it is quite possible that these would become the preferred gasifier feedstocks at least for the early years while consolidating commercialisation of the technology.

i. Ash Content

The ash content of a coal to be gasified will influence the thermal efficiency because heat will be taken from the system to melt the ash and will be difficult to recover from the molten slag stream. Consequently, the general guideline in coal selection would be to minimise ash. Shell and Texaco would prefer the coal to have less than 20% ash albeit that there is no absolute maximum. There is no upper limit for the gasifier to function satisfactorily and this may be the drive to use gasifiers on some local high ash coals. Such an example is the Puertollano project in Spain where 45-50% ash coal is to be blended with very low ash petroleum coke.

Nevertheless, the use of high ash and high sulphur coals represents a capital cost in the sizing of slag handling facilities and the gas clean-up system. This would represent an efficiency debit to the process and add to the financing charges when assessing the cost per kWhr. There is a case for examining the potential for reduction in the ash in coal destined for use in gasification. There are a number of advanced cleaning processes which should be examined to liberate pyritic sulphur from coal. If the size of coal is reduced to allow liberation, there is a corresponding release of clean coal

ii. Reactivity

The reactivity of a coal becomes significant in gasifiers. Shell, for example selected a range of coals for testing and identified US coals such as Blackville No 2, Pike County and Dotiki coals along with Alcoa lignite as good gasifier feed. They also tested Colombian El Cerrejon coal which was also found to gasify well.

In the early 1980s, Gasunie in the Netherlands studied a major gasifier project and their coal selection process followed a similar pattern to that of Shell with Cerrejon and some Australian coals showing very good characteristics.

iii. Slag Viscosity

The viscosity of the slag produced from the molten ash can be an important feature of design influencing the slag handling system and the time needed to clear the material from some parts of the system. Viscosity relates mainly to the relative amounts of iron, calcium, silica and alumina in the ash.

iv. Fouling and Corrosion

The quantity of alkali metals, heavy metals and chlorine present will influence the levels of corrosion and the materials of construction, choice of refractory etc.

v. Age and Rank of Coal

The age and rank of the coal will influence some of the factors mentioned above. Lignites and young coals tend to be more reactive but lignites have a lower heating value and high moisture. This could penalise them on transport costs dependent on source. The Dow Plaquemine project is based on local Texas lignite while the German KOBRA project is based on more reactive brown coals.

vi. Yield and Coal Type

Shell has undertaken a great deal of research in the development of their coal gasifier and some of than data has been published. The two key tables are set out below showing the differences in coal gas efficiency by coal and the corresponding carbon conversion. The results tend to reinforce a view that as commercial coal gasification for power generation develops, the choice of coals will focus on those which gasify more readily. A more universal gasifier may only develop if there is a call for such technology. There would not appear to be a case to design and develop such equipment at this stage.

Several references to coals are given in a range of papers prepared by Shell and Texaco which are mentioned in the main list of references.

APPENDIX 2

Heavy Oil Residues

Set out below are notes on each of the heavy residuals which were considered relevent to the study. A simplified refinery flow plan is attached to this Appendix which includes the position in the flow scheme where a possible gasifier would be placed.

Vacuum Residue

Vacuum residues result from a distillation process. The crude oil is subjected to a primary distillation stage at atmospheric pressure. This separates all the light products such as LPG, naphtha, jet fuel, gas oil and marine diesel. However, it will leave a long residue containing the lubricant fraction and a heavy gas oil which can be upgraded easily by catalytic cracking. Consequently, a second distillation stage may be used under vacuum conditions which allows the separation of these valuable streams to be done below the temperature at which the oils would start to thermally "crack".

The vacuum residue could be considered to be the "natural" waste stream from the distillation process which would historically have been blended into marketable heavy fuel oil. The viscosity would be adjusted by blending in a quantity of a middle distillate such as gas oil. In many refineries, it is now more likely to be considered as a feed for the deep conversion processes such as vis-breaking, hydro-cracking, coking or solvent deasphalting. Typical qualities are given in Table 1 of this Appendix.

Refiners who have no deep conversion capacity at present may be faced with the choice of a low return on a conversion process, a low price for an "unmarketable" product stream or gasification which would produce a large quantity of gas.

Vis-breaker tar

A vis-breaker is a thermal cracking process which breaks the molecular structure of the complex hydrocarbons to produce lower viscosity blendstocks for lighter distillate products.

The residue - often referred to as a tar - contains about 85% carbon and 9-10% hydrogen. Its sulphur content is related to the level of sulphur in the crude but is frequently 4%. The vanadium, nickel and sodium may also be high. It has an extremely high density for an oil - namely 1.1 gm/cm^3 and may need substantial quantities of blend-stock to accommodate it into marketable fuel oil. Such a step may be a debit to the refiner who may be forced to accept fuel oil price for otherwise marketable distillate.

Deasphalter Residues - from Solvent Deasphalting

This classification of heavy residue has been described in this way to distinguish it from the range of asphalts that are marketed for road-making etc. The latter are all prepared products to meet specified user conditions. The deasphalter residue is primarily a waste from the deasphalting of oils to be used for upgrading. Solvent deasphalting is designed to remove all the asphalt from lubricant feeds and from cat cracker feed. A cat cracker relies on the chemical activity of a catalyst in the form of a fine powder which would be contaminated by any significant level of metals in the feed. Consequently, the parameters which set the split between cat feed and deasphalter bottoms is the level of metals which can be tolerated in the cat feed, the balance remaining in the spent stream along with the bulk of the sulphur. This will be related to the level of metals in the crude and so will differ by crude oil source. Table 2-4 gives a series of figures for the vanadium and nickel content in the streams from several crude sources and alternative processes.

Another critical element in the split point is the ability to physically handle the asphalt waste, particularly whether it remains liquid at a manageable temperature or whether a solid. Directionally, a refiner would want to avoid solids handling but the balance is economic dependent on whether the upgraded material is more valuable that the handling/disposal cost of a solid waste stream.

Other high viscosity residues

This is a catch-all category which will depend on the refinery configuration and its complexity. Most of the larger refineries around the world would have a cat plant and many would be linked to a petro-chemicals complex.

One residue which would therefore fall into this category is steam cracker tar ie. the residue from an ethylene manufacturing process usually called a steam cracker. This stream has some unusual properties because it may contain up to 20% asphaltenes. This family of very complex hydrocarbons can cause compatibility problems if blended into fuel oil. Asphaltenes may precipitate in the presence of paraffinic material such as blending components from North Sea crudes. They also have a very high density of about 1.1 gm/cm^3.

Another difficult stream to blend into fuel is the resudue from the cat cracker itself. It may contain fine catalyst, usually silica or alumina based, and has a highly aromatic content with a high density. This material is a good partner for steam cracker tar because the inherent solvency of the aromatics can keep the asphaltenes in solution while the viscosities are complementary. Table 2 gives typical Esso data for possible cat plant waste streams alongside deasphalted asphalt.

Petroleum Coke

Petroleum coke is the only solid residue stream which is likely to emerge from the oil refining process. It is the waste product from some of the licensed coking processes and results from the extraction of virtually all the recoverable liquid hydrocarbon from the vacuum residue feed. It therefore has a very high carbon content along with a concentration of most of the sulphur and mineral residues from the original crude oil.

Its quality will vary in relation to the type of crude and the coking process used but to simplify the analysis, the delayed coker will be considered rather than processes which have been designed for niche coke markets. Petroleum coke has a typical carbon content of about 90% with 3.5-4% H_2 and 2% nitrogen. The sulphur will vary according to the crude but may easily be over 5% while ash may be in excess of 0.5% mostly as vanadium and nickel salts.

TABLE 1

Arabian crude assays - vacuum residue quality

	Arabian Light (Berri)	Arabian Light (Export blend)	Arabian Medium (Zuluf)	Arabian Medium exRas Tanura	Arabian Heavy (Safaniya)
Whole crude Inspection					
API°	36.8	33.1	30.4	28.6	27.4
S int%	1.12	1.86	2.60	2.81	2.80
Pour °F	-5	-65	-70	-15	-49
Vacuum Residue (1000°F+)					(1049°F+)
Yield vol%	13.1	18.4	24.6	22.6	23.2
API°	13.1	8.3	6.7	5.1	3.0
S wt%	2.95	4.12	5.07	5.81	6.0
N_2 wt%	0.14	0.31	0.44	0.34	-
N_2 wt%	11.20	10.48	10.22	9.96	-
Ramsbottom carbon wt%	12.9	19.1	22.9	23.9	27.7**
Asphaltenes wt% (Cg)	1.1	5.2	18.5	11.5	-
Ni ppm	2	13	52	39	64
V ppm	6	75	125	82	205
F_2* ppm	24	15	88	10	30
Visc, CS at 100°C	154	651	3200	2580	55,000
at 135°C	43	130	400	402	2,827

* Values may be high, due to iron

** Conradson carbon

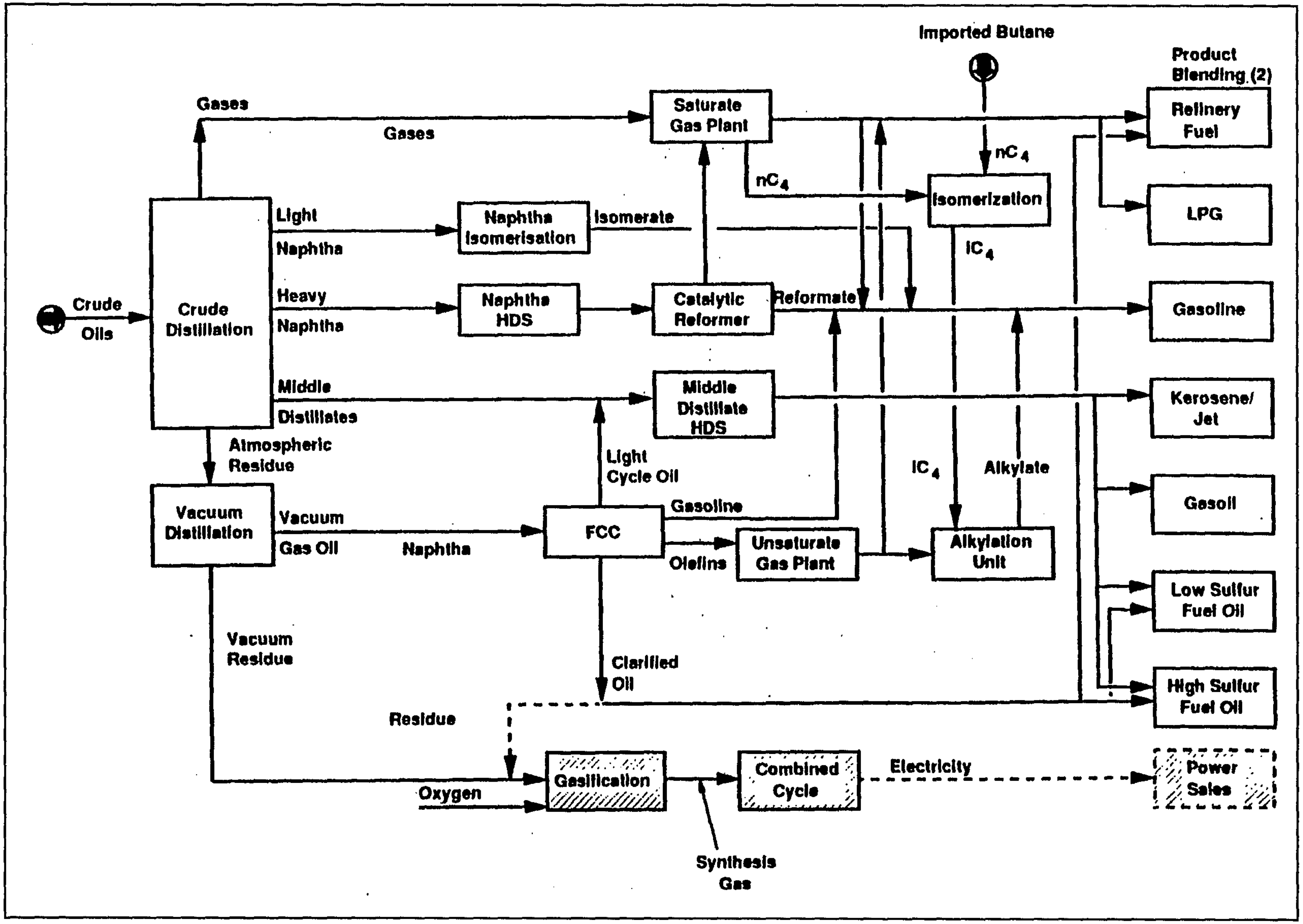
TABLE 2

Inspections of Potential Gasification Feeds

Data on various Streams

Stream	Deasphalter Asphalt	FCCU Slurry 1	FCCU Slurry 2	FCCU Slurry3
SP GR	1.0502	1.0703	1.063	1.101
Sulphur, wt%	4.92	2.90	6.5	2.46
Con.carbon, wt%	24.5	0.1	0.1	-
Nitrogen, wppm	3570	2100	3000	1700
Carbon, wt%	85.2	89.32	-	89.42
Hydrogen, wt%	9.52	7.56	-	7.40
C/H, wt ratio	8.95	11.8	-	12.1
NI, wppm	CA.50	0.1	0.1	-
V, wppm	CA.200	0.1	0.1	-
BR No, CG/G	-	-	10	-
RI @ 67 C	-	1.6759	-	-
Viscosity @ 210 F, CST	-	9.7	-	14
15/5 Distillation, F				
IBP	930	-	450	535
5 LV%	1010	-	600	647
10 LV%	1050	-	655	678
20 LV%	1100	-	715	719
50 LV%	> 1200	-	790	794
80 LV%	> 1200	-	875	916
90 LV%	> 1200	-	930	1059
95 LV%	> 1200	-	980	1166
FBP	> 1200	-	1100	1299

VACUUM RESIDUE GASIFICATION AND POWER GENERATION



APPENDIX 3

GASIFICATION

1 Shell and Shell/Lurgi

The Shell Gasification Process was developed over 30 years ago and has been licensed widely around the world. Shell has in fact chosen to develop two systems, one based on solid feed and the other for a liquid feed. The former has been retained by Shell and the licence is marketed from London and the Hague. The other has been marketed primarily by Lurgi for many years. This latter technology can accommodate all heavy oil residues.

The Shell coal gasifier would be used for petroleum coke. The solid feed is milled to a fine powder and then introduced to the reactor with high pressure nitrogen. Oxygen is introduced in the quantities required and the temperature controlled by steam as a moderator which also reacts with the carbon in the feed. Shell claim an efficiency advantage of at least 0.5% over the slurry-fed systems.

The corresponding oil gasifier is highly flexible and insensitive to small fluctuations in carbon/hydrogen ratio in the range of liquid fuels being considered. Consequently, a very consistent quality of product gas can be achieved after cleaning. The feedstock may be any pumpable liquid hydrocarbon. Provided the feed can be pumped at a convenient temperature to get it into the gasifier then it will gasify satisfactorily.

The clean gas could be reprocessed with a Shift conversion stage to enrich the hydrogen steam or it can be used as a CO/H_2 mixture in a combined cycle gas turbine. In the latter mode, the Lurgi design configuration generates 60% of the power on the gas turbine and 40% on the steam turbine. The Shell design removes the bulk of the heat from the gasifier in a waste heat boiler by generating steam. The gas conditions are aggressive to materials of construction so this stage of the process may represent a section of high materials cost. Lurgi believe the cost is justified by thermal efficiency. Designers may differ on this first cooling step and some prefer a quench system which will be described later.

A metals content in feed of up to 1000 ppm can be handled satisfactorily and there are few sources of oil residue which are that high in metals.

The sheer volume of gas produced from the gasification of heavy oil output might present a problem to a refinery unless some of the production is absorbed into power generation. The application of gasification technology therefore introduced an opportunity to establish a new relationship between refining and power generation with scope for refiners to generate power or utilities to enter joint ventures with refiners. The synergy or opportunity for integration of refining processes and gasifiers offers potential economic advantages. Recent Lurgi papers on the subject are shown at the end of this section.

2 Texaco

The Texaco gasifier system is broadly similar in flow plan to that of Shell but with one basic design of gasifier feed system which can accommodate coal, petroleum coke or residual oil. Texaco has therefore opted for a wet fed system regardless of the fuel. They would mill and slurry a solid fuel and feed prepared liquid or other liquid fuel direct to the burner. A slurry fed system costs more than the liquid option because of the feed preparation equipment and the investment/operating costs associated with the handling of solid fuels.

Texaco then offer options on the gas cooling system. The waste heat boiler or a quench system is available dependent on the application. In the context of chemicals manufacture, there has been some preference for the quench unit. For power generation designs where conversion efficiency is more critical the heat recovery route has the advantage. The absolute advantage is regularly questioned both in terms of cost benefit and fuel source because the dirtier oil based fuels could in theory foul the boilers and reduce availability. (This has not been Lurgi's experience with the Shell design.)

Texaco has introduced what they are now describing as an advanced quench system at a significantly lower capital cost for a total IGCC package of between $1100-1300/KW. Texaco would claim some marketing advantage in being able to use the same basic gasifier for a range of fuels. They have also fully evaluated Orimulsion and have concluded it is an excellent gasifier feed with a 99.5% carbon conversion. The only design feature which has to be included is a separate feed line to the burner because the emulsion breaks down when heated. It must reach the burner as a cold feed whereas other fuels are usually introduced hot. Several Texaco papers covering gasification of residues and Orimulsion are again referenced at the end of the appendix.

3 Nykomb Synergetics

Texaco, Shell and Lurgi have each developed gasification systems which have been patented. Nykomb Synergetics, based in Sweden, has structured its business activity in a way which offers a comprehensive service to potential clients for integrating gasification project development with specific technical and financial expertise.

The company has created links with Jacobs, H & G in the UK who undertake some of the project engineering. They have established strong working relationships with the gasifier companies, gas turbine builders and air separation companies, so that they can manage the integration of complete projects for power utilities, clients or refiners frequently leaving the client the final decision to select the prime suppliers.

Nykomb has taken patents on a process flow system which recovers heat from the Texaco gasifier used in the quench mode and returns some of the useful energy from the low grade heat sources to the gas stream in a saturator. This not only aids heat recovery but helps to maximise the mass flow through the gas turbine. A licence agreement has just been signed with the ISAB refinery in Italy and with SARAS.

Nykomb also believes that history has proved large scale power plants are built with a life span which exceeds the era of a single type of fuel. Many of the CEGB stations were built for a life of 30 years or longer. The fuel choice of the 1950s would have been coal, followed in the 1960s by oil until the price increases of the 1970s when coal returned. The 1990s have seen a so called "dash to gas" and a major displacement of coal. Could Orimulsion or heavy residue be the next most competitive fuel source?

Hence, within the life of a power station, there have three or four cycles in the fuel choice. Nykomb considers that there are commercial benefits to developing a flexible fuel system. They believe in the inherent flexibility of the gasifier, especially Texaco's design which could offer a power company the freedom to purchase the lowest cost hydrocarbons in the market with the guarantee of efficiency and extremely low emissions.

They also consider that with land and planning permission becoming progressively difficult, there is merit in introducing flexible or "Multi Fuel Generation" schemes to obsolescent sites as a means of refurbishment, particularly where they are adjacent to refineries. The benefit of these sites is the existence of a supporting utilities infrastructure and, most importantly, authorisation to generate power. The improvement in the technology employed by moving from fuel burning to fuel gasification will ensure that higher environmental performance will remain within most predictable new requirements. Higher thermal efficiencies will reduce the thermal loading of the atmosphere or local rivers.

It should be emphasised than Nykomb can only offer gasifier technology from other companies and neither of the main licensees offers the total IGCC package. Lurgi or a company such as Nykomb would need to integrate the design and bring together suppliers of the fuel conversion stage with the turbine makers, ASU suppliers and the power generating equipment. Consequently, to date, there is no single company that offers a turn-key IGCC system as a complete generating package.

4 Krupp Koppers PRENFLO System

The Krupp Koppers Prenflo gasifier evolved from the same parent as the Shell design. However, they have developed it further and in what they describe as an innovative way in conjunction with Siemens. They have recently been awarded their first commercial contract to build an IGCC unit at Puertollano. This 300 MW unit is designed for a blend of local high ash coal (47 wt% ash) and petroleum sulphur (5.5% sulphur). The thermal efficiency is said to be 45% (ISO) net although it is qualified as being achievable on "standard" coals and one must question whether such a low blend could be considered as standard. Emissions from the fuel mix are designed to be very low and will be summarised in comparative table later.

5 British Gas/Lurgi

The British Gas/Lurgi gasifier is of the fixed bed slagging type, not an entrained gasifier of which the Shell and Texaco designs are examples. The technology has been developed for coal and was demonstrated very successfully at Westfield.

The most significant difference between this type of gasifier and the entrained design is that lump coal is fed into a vertical reactor from the top with the oxygen and steam entering lower down the reactor through tuyeres. The reaction takes place as the column of coal slowly moves down the reactor and the ash melts to be drawn off from the bottom as a slag. The temperature of reaction is lower than that in entrained gasifiers at around 1500°C. This lower temperature alters the composition of the gas with an increase in the methane content because of a carbonization stage in the reaction zone, the balance of the product gas being CO and hydrogen.

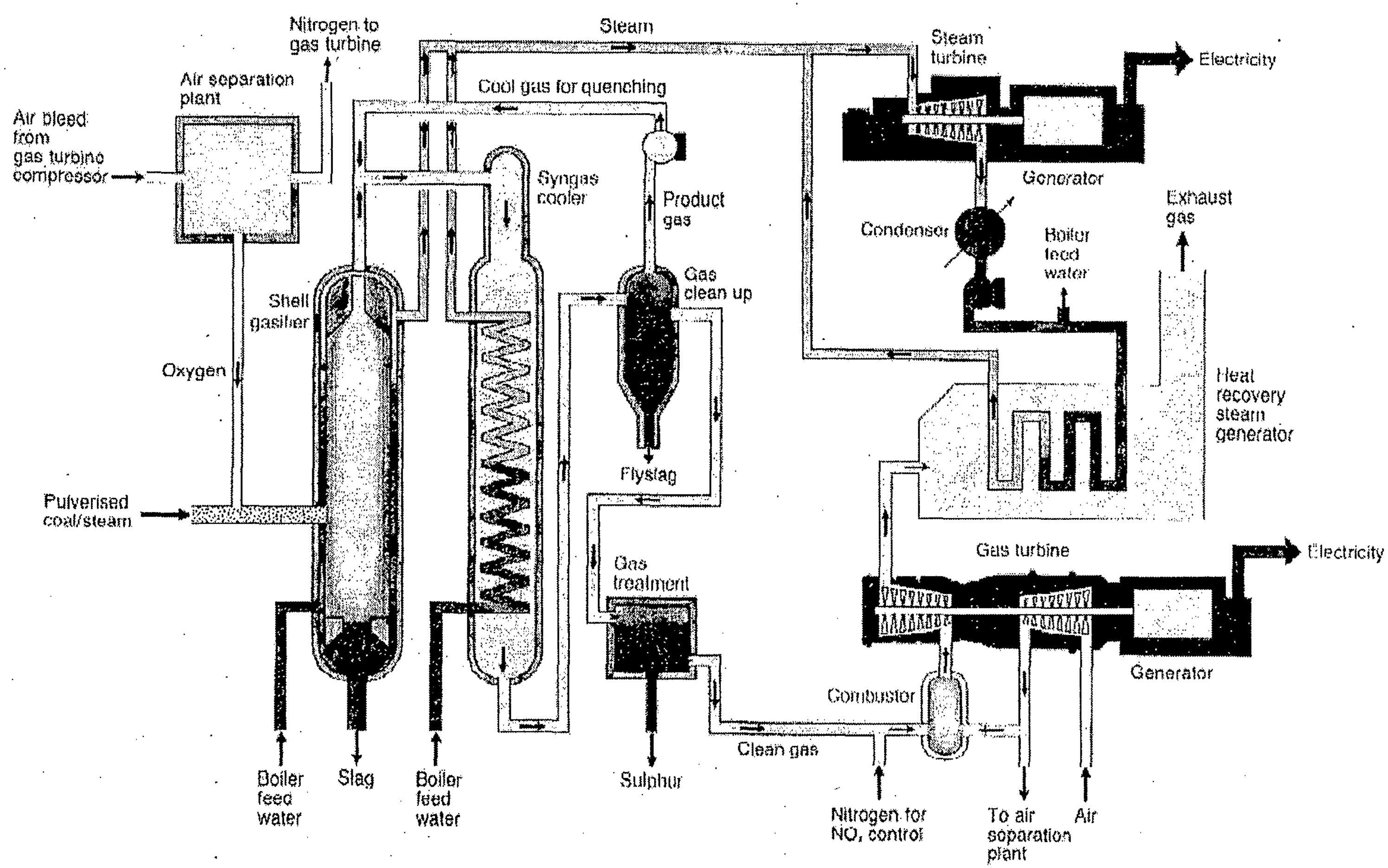
The main drawback of the fixed bed design is the need for a sized or lump feed. Since the output from modern coal cutting equipment results in at least 50% of relatively fine coal, much of the feed would have to be briquetted. Consequently, the feed preparation step is a greater cost penalty than the milling required for the other gasifiers. The main advantage is high cold gas efficiency and methane content which has been of considerable interest to some of the US companies developing fuel cells. Another is that there is a high yield of tar and complex liquid hydrocarbons which need to be separated from the gas stream and recycled to destruction.

6 Destec (Dow)

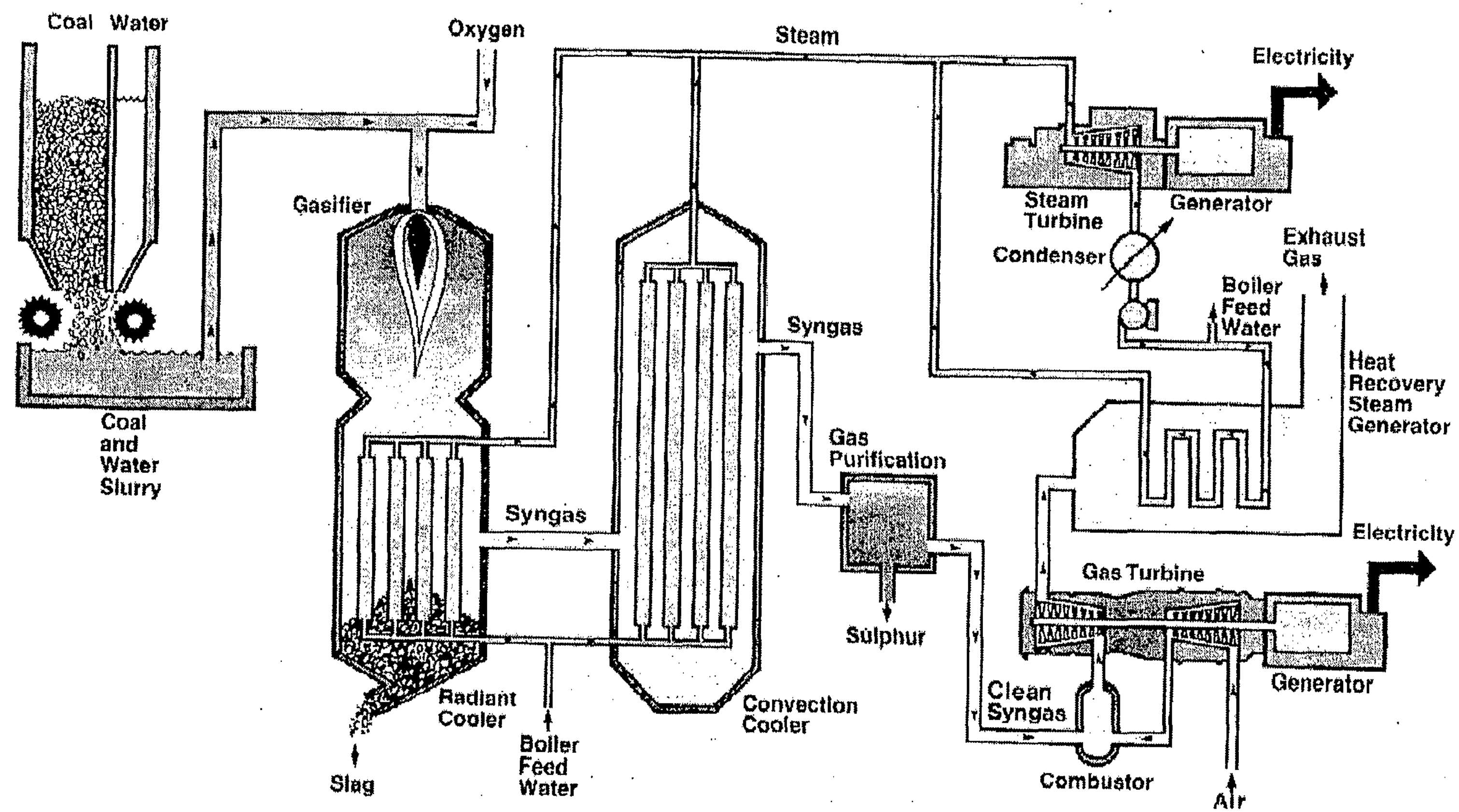
Dow developed a coal gasifier as an integrated combined cycle system to provide power for their chemicals plant at Plaquemine in Texas. The design was initially based on the use of local lignite but is applicable to many coals. The gasifier is now being marketed under the name Destec. The Plaquemine plant is the largest IGCC unit operating at present with 375 MWe of capacity. It has been producing power very reliably since 1987.

Destec has solved the problem of the syngas cooler duty by introducing a second stage in their gasifier. This feature has much the same effect as the counter-current principle in the Lurgi and the BGL/Lurgi slagging gasifier. Addition coal/water slurry is injected into the hot gases leaving the first stage of the gasifier at about 1550°C. The injected water is vaporised and part of the coal reacts with the steam to form additional gas. Hence, instead of generating steam in a syngas cooler, part of the heat in the gas leaving the first stage is used for drying the feed and the production of additional gas which enhances the coal gas efficiency of the process. The temperature at which the gases leave the second stage of the gasifier is about 900°C. This is much higher than the temperature at which the gases leave the Lurgi or the BGL gasifier. This may less attractive from the point of view of efficiency but the big advantage is that the gas leaving the gasifier contains hardly any tars or oxygenates cf. the BGL design. The small amounts which are being formed are absorbed on the char which is also being formed. This char is recycled and reinjected into the first hot stage of the gasifier and eventually gasified.

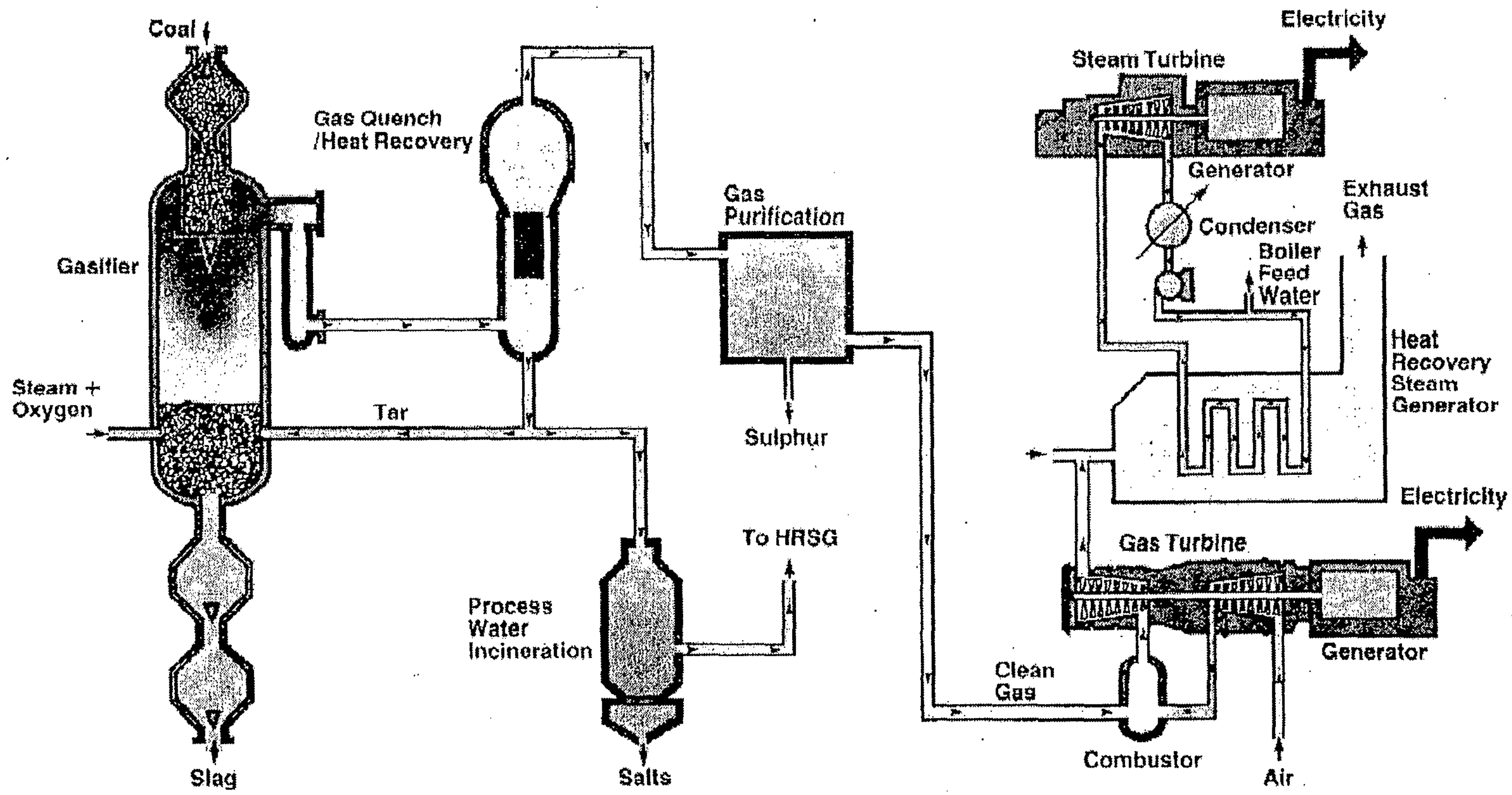
The Shell coal gasification process
Combined cycle electricity generation



THE TEXACO PROCESS IN AN IGCC SCHEME



THE BRITISH GAS/LURGI PROCESS IN AN IGCC SCHEME



THE DOW ENTRAINED-FLOW GASIFICATION PROCESS

COMBINED CYCLE ELECTRICITY GENERATION