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THE PROSPECTS FOR COAL GASIFICATION

A thesis presented on application for the
Degree of Master of Philosophy

by

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THE OPEN UNIVERSITY

MILTON KEYNES

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A B S T R A C T

The prospects for coal gasification are considered in the light of ever increasing problems of high prices and uncertain supplies of fossil fuels throughout the world. A detailed analysis of the supply and demand for coal and gas in Britain now and in the next decade is an essential part of this work. This needs to be set in the overall context of world supply and demand. The consequences of social and political changes on energy supply are stressed as well as the consequences of technical changes.

A review of the present position of coal gasification technology, both surface technology methods and underground coal gasification methods is given in some detail. The advantages of coal gasification compared with electricity production such as energy efficiency, capital cost and environmental impact are considered. The relatively poor position of the coal industry in relation to future markets for coal and the uncertainty surrounding ultimate natural gas reserves are two important factors which are relevant to the development of coal gasification.

The domestic gas market is studied in some detail to determine the gas penetration within the various sectors and house types within this market. Future gas demand in the domestic market will be quite different from that in the 1970's. This will be due to several factors including price elasticity, insulation, low energy houses, housing policy, effect of high fuel prices on individual lifestyle etc., and each of these are considered in some detail.

A close survey of the impact of various other heating vectors in the domestic sector is given to determine their future effect on gas demand. It is concluded that even allowing for some development of heat pump, CHP and other newer technologies, their effect on reducing future gas demand will be limited. There will remain a need for a substantial gas supply even when North Sea supplies decline. If this is linked to the need for the development of alternative coal markets and the need to promote the nuclear electricity plant programme, then a credible case for coal gasification emerges.

Since energy is an essential ingredient, in all terrestrial activity, organic and inorganic, it follows that the history of the evolution of human culture must also be a history of man's increasing ability to control and manipulate energy.

- M. King Hubbert, 1962

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INTRODUCTION

The central theme of this work is to consider the prospects and resource requirements for developing coal gasification technology as a means of supplying gaseous fuel. The main emphasis will be on the possible use of substitute natural gas (SNG) as a domestic heating vector, although other markets for gas including the industrial sector will be studied.

The main advantages for SNG appear to be 1) readily available coal reserves of the order of 45 billion tons recoverable using present technology, (1) 2) relatively low investment requirements as well as production and transmission costs when compared to coal fired electric plants (2) 3) low quality coal can be used in SNG plants, 4) it is ecologically clean, 5) a readily available and paid for transmission system which will last well into the next century.

Factors which may limit the supply of SNG from coal include 1) general state of SNG technology, 2) coal and water supply availability, 3) capital availability and general economics, 4) environmental controls, 5) Government energy policies.

However, in addition to the limiting factors already stated, if SNG is introduced there are a number of other factors which are unknowns and which will remain unknown until the technology is fully established. For example, the impact of final unit size and the process design chosen for operation. These are largely unknowns now and their effects can only be predicted approximately by reference to pilot plant operations.

If coal gasification technology is used as a means of supplying a gaseous fuel a significant factor will be the future relative price of coal and gas which may affect the time of introduction of SNG plants. (As an example a recent UN Report 'The Future of the World Economy' has related the cost based prices of coal, oil and natural gas to the general price level of the economy and has concluded that cost prices for coal

will fall slightly while oil prices will increase about three times and natural gas prices about six times between 1970 and 2000).

Knowledge of approximately when SNG will be needed will be influenced by accurate information on gas reserves. Proven estimates of total future gas reserves and supplies are unknown at present, and so gas reserve figures can only be estimations. The Secretary of State for Energy has acknowledged this fact and the necessity to obtain more accurate figures of gas reserves.

In Chapter III an 'average' forecast of 2415 bn m³ (87 tcf) has been deduced with an 'optimistic' forecast of 2936 bn m³ (105 tcf). Even with the average forecast these reserves should be enough to satisfy a plateau gas demand of 59 bn m³ per year (6500 mcf) until near 2000 AD and in the case of the optimistic forecast the reserves should be able to meet such a demand for at least a further ten years. Gas reserves could even be higher than the optimistic forecast.

The actual amount of gas finally available to us from around our shores may be more than the estimated reserves. It will depend on several factors including the volume of future discoveries, government policies for taxing the oil companies, the amount of Norwegian gas brought to the UK, the future world price of gas, the decision to build a cross-channel pipeline to import USSR gas etc. Although there are still significant areas of our continental shelf unexplored the decision of Esso, the worlds' largest oil company, not to take part in the recent sixth round of licensing because the geological evidence available to it did not warrant it taking part, indicates in part that the 'boom' era of exploration may be over.

AIMS

The aim of Chapter I is to consider the possible effects on energy use of possible future advances in technical innovations and the consequences of possible social and political changes occurring nationally and worldwide, which are often overlooked by present day forecasting methods.

In Chapter II it is hoped to discuss the general properties and applications of gas and to compare these with other available energy vectors such as coal and electricity. The relative costs of production and transmission and the role of storage are important parameters to compare gas to other available energy vectors. In the development of SNG it is necessary to consider the overall energy efficiency of an SNG system, the plant investment cost, and the future availability of a suitable transmission network etc.

Chapter III will be an estimate of the amount of primary fuel in oil, gas and coal available to the UK both from its own indigenous supplies and from imports. This needs to be set in the overall context of world primary energy supplies. The lack of concrete evidence about the extent of gas reserves makes such estimations all the more hazardous. Another major problem facing the coal industry is how to remain viable in a short term situation of apparent energy surplus, so that in future years of energy deficit it may be technically capable of increased production. The supply of coal will depend on many factors including relative coal price, productivity, wage settlements, development of the nuclear industry, degree of mine automation. Coal supply needs to be reviewed in the light of the National Coal Board's 'Plan for Coal' and 'Coal 2000'.

Chapter IV dealing with coal gasification technology will review the amount of coal required for gasification, the water supply, the selection of suitable plant materials in view of the extreme conditions of temperature and pressure encountered in the gasification systems. Technologies based on the Lurgi concept, including the British Gas

slagging gasifier, need to be reviewed and compared with the present state of the second generation USA plants such as the Hygas system for coal gasification.

As a follow-up to this review of surface gasification techniques, it is necessary to consider underground gasification methods and compare them with the use of various types of coals. In Chapter V the questions of the effect on the coal resource base of developed UCG systems needs to be considered, as well as pollution effects, and techniques for upgrading the 'low BTU' gas to pipeline gas quality. Although the NCB in their 1976 Report considered that it was uneconomic at present to pursue UCG it may well, under certain conditions in the future, become a major option. (In-situ methods would probably have to be used to tap the coal energy beneath the North Sea and further research in UCG in this context seems assured). At any rate no consideration of coal gasification is complete without a review of both surface gasification (SG) and underground gasification (UCG).

Chapter VI on 'World Coal Trade and Markets for Coal' is an attempt to answer the question of the effect of estimated future world energy supply and demand on coal trade and coal markets. In this context the availability of coal cannot be divorced from the overall availability and demand for oil and the general state of the world economy.

The assumptions and consistency of the various forecasts concerning the world energy situation published in 1977 and 1978 need to be criticised and the origin of their differences understood. The main 1977 reports were from The Workshop on Alternative Energy Strategies (WAES), the CIA and The World Energy Conference (WEC). In 1978 there was a World Bank Report, a second CIA Report and Reports by the Exxon Corporation and the Petroleum Research Institute.

A whole host of factors are involved in markets for coal including proportion of coal fired electricity plants, subsidies, degree of mine automation, imports, off-peak electricity sales and relative coal to oil prices. A complete analysis of these various factors is needed before any

reasonably firm prediction of the future coal market can be attempted. In Chapter VII, 'A Sector Analysis of Domestic Gas Marketing', it is hoped to consider the question of where the gas is going within the four main housing sectors, new owner occupied, existing owner occupied, new local authority, and existing local authority. The aim is also to deal with the problems of how much domestic gas may be needed in the next decade, the market for gas after initial saturation in the sales of 'first buy' gas central heating systems. Price elasticity of a fuel for an appliance at saturation level is much greater than for an appliance at the initial growth stage. This is particularly relevant for gas as it approaches the saturation market stage in the 1980's. The effects on gas use of other factors including insulation, low energy houses, housing policy, population changes and general lifestyle are all likely to affect future gas supply.

Chapter VIII on 'Matching Supply and Demand for Gas' is to consider the problem of synchronisation of gas supply with gas demand. The development of suitable methods, perhaps based on storage, is essential to overcome the more inflexible supplies from the northern sector of the North Sea. This problem of synchronisation is critical in view of the fact that the gas industry is now 'demand led' rather than 'supply led', as in the earlier days of gas build-up of the market, which came from flexible southern sector supplies. The gas industry has already mentioned the possibilities of renegotiating some contracts and of paying producers now to keep some gas reserves until a later date.

The final chapter 'The Effects of Alternative Heating Vectors on Future Gas Demand' will consider the question of the extent of competition to gas in the domestic housing sector due to the development of other domestic heating vectors such as heat pumps, CHP schemes, active and passive solar technology, off-peak electricity etc. It is necessary to compare the results of such an analysis with the future gas demand predicted by others such as The British Gas Corporation and Energy Commission Studies.

CHAPTER I

THE ROLE OF TECHNICAL, SOCIAL, AND
POLITICAL CHANGES IN ENERGY FORECASTING

Many present day forecasting methods are based on the assumption that long term economic growth will continue as in the past. While it is acknowledged in these forecasts that in the short term, economic growth may suffer setbacks, often the only problem the forecasters appear to set themselves is the choosing of the long term rate of economic growth. The reasons given for the economic growth setbacks are often given in vague terms of world economic slumps or rising inflation, and the choosing of the long term rate of economic growth is purely a numbers game, a sort of forecasters' competition. This often bears no relation to the consequences of such factors as unforeseen technical developments, changes in the sources of available fuel, market saturation effects, willing social acceptance of a zero economic growth rate by a population not dependent on job allocation for wealth distribution, or political dislocations and their effects on the world energy situation which are now becoming a regular occurrence in world affairs. Some of these factors are capable of changing the nature and magnitude of the relationship between economic activity and energy use, but are usually completely ignored in most forecasting methods or at best treated as minor perturbations having little effect on the overall predictions.

Technical changes

When considering what may happen in the future to energy trends, it is necessary to state on what assumptions such predictions are based. In Chapter IX the effects of some technical innovations such as gas heat pumps, CHP schemes, increases in the use of mechanical ventilation and the use of domestic refuse to produce energy are all considered, but there is a limit to what technical innovations can be analysed. There are bound to be many other innovatory changes in energy technology over the next 25 years,

some of which could alter future energy demand significantly. Examples are the development of fluidised bed combustion in conjunction with combined cycles to produce electricity at an efficiency of 40%, the development of gas fed fuel cells for power production, increased use of biomass and the use of hydrogen as a transportable fuel, changes in prime mover development for electricity generation. The UK Coal Utilisation Research laboratories at Leatherhead, one of the world's key centres of research in fluidised bed combustion, have been given a large contract from the US Department of Energy and The Electric Power Research Institute aimed at developing pressurised fluid bed combustion in conjunction with combined cycle gas and steam turbines (4).

Other examples include the CHP development by the Midlands Electricity Board at Hereford (5) where heat is being sold at a third less than that available from other sources, and also underfloor heating (4).

In the field of vehicle transport the widespread use of advanced electric vehicles could dramatically alter the energy options available. This may alter the economics of wave, wind, solar and tidal sources of electricity and could provide transport more efficiently than today's vehicles (6).

Demand for SNG will be linked to the relative price of coal and labour which in turn will depend on coal productivity. This means the development of new mining technologies such as, in the case of underground mining, continuous transport of coal from mine face to surface and remote controlled mining equipment. This may include a sensor to differentiate between coal and rock, steering and guidance systems, methane gas detectors, automated construction equipment, mechanical tunneling machines etc.

In remote controlled mining or telechiric mining as it is called a robot device could be programmed to carry out quasi-manual operations when instructed by a remote human operator, whose appreciation of the situation is brought to him by CCTV.

Further technical advances which may lead to revolutionary advances

in mining technology could occur in the development of techniques for radar propagation in rock for automatic seam following methods. The production of microwave radiation from compact, solid state high resolution radar systems is being developed (7). The increased signal sensitivity of these radar systems would help to develop the necessary sophistication required in advanced mining methods for coal mines such as Selby, leading to further increases in productivity. Mine pressurisation techniques (7) for overcoming safety problems when working at great depth may lead to further efficiency in the extraction of coal energy either directly as coal or indirectly as gas.

Many present day forecasting techniques use models with data from an age of energy replacing labour but we are now moving into an era of labour replacing energy which implies energy will become more expensive than labour. Many available forecasting methods do not as yet have the necessary sophistication built into them to relate energy demand to such price increases and this represents a serious flaw if they are applied to the present day energy situation. On the reasonable assumption that energy prices are rising in relative terms then it may be expected that the number of technical changes and developments in energy technologies will increase. For example, an increase in the coefficient of performance of heat pumps, (part of the research in progress in ERG (8)) may be one likely outcome.

General energy conservation effects have been taken into account, but it is impossible to consider the full potential of energy conservation as various energy conservation technologies are still being developed. However, with increased Government grants the effects of energy conservation technologies should grow considerably. Several technologies in this field have a very high rate of return on capital investment including control of boilers, control of air-conditioning plant, heat exchanger heat recovery and recovery of flash steam or other waste heat.

Social changes

Social changes cannot be entirely divorced from technical changes.

For example, the silicon chip revolution will have its social effects and much has been written about this subject. The implications for future energy demand of a considerable increase in leisure time available to a growing proportion of the population is unknown. If this, as is likely, involves a contraction in manufacturing industry it may be accompanied by increased energy use in the domestic sector as more people begin to orientate their working lives around the vicinity of their own home. This could also mean less energy spent in transport as videophones and contravision are developed.

Market saturation in electrical consuming devices, an increase in low energy houses being built and an increasingly aged population will all affect future energy demand, and are all closely related to social change. There is also the question of 'lifestyle' with a greater percentage of the population moving away from the concept of the consumer orientated 'heady' days of the sixties with their mass production, media image, and overplayed advertisements often falsely equating happiness with possessions.

As people reach a stage where they simply do not have the finances available to continue to fuel the consumer orientated society of the mass media, they have much more time to think. This, coupled with increased unemployment due to automation and new technology, could lead to the 'information' society where more people are concerned with 'reading and thinking' rather than 'getting and buying'. Evidence of this is shown in the large increase in adult education activities and continuing education. The majority do these courses through interest alone and not necessarily as a means of furthering their careers. Such a situation will inevitably lead to some significant changes in sector energy uses.

Political changes

Devolution and its effect on energy use

It has been said that while other Western countries like West Germany and the USA have their economic problems of inflation, economic growth and balance of payments just as in the UK, these countries are all agreed

about the system i.e., capitalism, whereas Britain is still arguing about what system to adopt - capitalism or socialism. The argument goes that as long as there is this indecision about the sort of country we should live in, then Britain will be unable to concentrate its undoubted talents to facing its economic problems squarely. In this sense it would be a mistake to equate capitalism with an uncaring materialistic consumer society as it is quite possible to have a future capitalistic Britain being less consumer orientated, less growth conscious, but more socially tuned to individual needs, learning needs and information conscious. The two party system of government has caused such acute stresses in our society that social organisations like the Churches are being drawn into more and more social problems - offering their advice.

It is quite possible to have a capitalist society in which the wealth of the country is generated by a much smaller working population than at present, operating in high technology and sophisticated software such as computer programmes, insurance, banking etc.

The increase in the number of smaller parties now in Parliament has meant that the two larger ones are more conscious of the feelings and expectations of people from the outer regions of the UK. This will inevitably lead to demands from these regions for more say over their own affairs. Although devolution plans are at present stalled the eventual development of regional government in the UK is most likely and this in turn may hasten the decentralisation of energy supplies and energy decision making. This means elected representatives of the people on the ground in the regions would make the decisions. This in turn would likely hasten the development of local energy schemes within these areas.

The Political Revolution

Ordinary forecasting techniques fail lamentably to take account of the human factor involved in a political revolution such as has happened in Iran. Iran is the third largest oil producer in the non-Communist world

after Saudi Arabia and Kuwait and it should be remembered that at least (9) 40% of Iranian oil exports were taken by BP and Shell . The unexpected political development can lead to a drastic alteration in forecasts and predictions. It is quite possible there may be political changes in other leading oil producing countries which could be detrimental to the West. The unrest in many countries throughout the world makes such a possibility no longer the exception. For example, another Middle East war or a coup d'etat in Saudi Arabia could occur. The events in Iran and the Russian involvement in the Horn of Africa have put some pressure on Saudi Arabia as it is squeezed by countries hostile to the West.

Conclusion

How these technical, social and political changes will affect future energy demand is open to question. Although the indications are that the present slow rate of economic growth will continue and perhaps even end altogether this is by no means certain. The situation would be radically changed if the bottom fell out of the oil market because of an oil glut and oil prices fell. A 1% increase in GDP projections due to expansionary economic policies could lead to an extra 100 mtce in energy demand by 2000. Although it is difficult to take account of these effects, the fact that we may be moving into a completely different technical social and political era over the next 20 years from that previously, needs to be emphasised. Many energy models looking into the future, fail to take sufficient account of these changes, particularly the social and political changes.

CHAPTER II

NATURAL GAS AND SNG AS ENERGY VECTORS IN BRITAIN

General properties and uses of Gas

The main advantages of using gas as a fuel include the following:-

1) a high efficiency of pipeline transmission, 2) the ease of storage in pressure vessels or in natural or underground reservoirs or as LNG, 3) the flexibility of control and efficiency of use, 4) the combustion of gas is non-polluting, 5) gas is instantaneously available when required and there is no need for ordering or storage by the consumer, 6) the rate of heat supply is variable over a wide range at the turn of a tap.

The ability to apply gas heat at a controlled temperature when and where it is needed gives it a premium value. Applications making use of this property include special heat treatment furnaces, the production of electric lamp bulbs and the fusion of gold ingots to remove blemishes. Natural gas is used for all forms of ferrous and nonferrous metal heat treatment. Its purity and its very low sulphur content weigh in favour of natural gas for firing open hearth furnaces in the iron and steel industry. It is extensively and increasingly employed as a substitute for coke in steel making operations and iron foundries.

The use of natural gas as a feedstock offers the chemical industry many advantages. These include lower capital investment since no storage facilities are needed, a constant quality feedstock and regularity of consumption. Dry natural gas is used for the manufacture of carbon black pigment which is made by burning the gas with only a limited supply of air and depositing the product on a cool surface. Carbon black is used in the manufacture of printing ink, polishes, varnishes and motor tyres. In the chemical industry an important use of gas is the production of hydrogen which is the starting point for ammonia and hence fertiliser production.

Natural gas is being increasingly used in the ceramics and tile

making industries where a clean burning source of energy is essential in the manufacturing process and in the kilns and drying ovens. The relatively clean products of combustion permit direct heating in most applications. The most obvious examples are in the food industries where direct heating with crude fuels would be unacceptable. Direct heating offers a 20% saving compared with indirect methods (10). Other industries that use natural gas include the glass and cement industries.

A comparatively recent innovation in the use of natural gas has been the self recuperative burner developed by The British Gas Corporation. This combines the functions of burner recuperator and flue in one assembly. Installations on batch furnaces in the steel and pottery industries have resulted in reductions in fuel consumption of 30-40% (10).

Although gas is more easily fired than solid or liquid fuels it has the minor disadvantage of producing a long flame which may be deficient in its ability to radiate heat. If the water occurring in most fuel gas is not removed high corrosion could occur in the transmission lines and trouble may also result from the formation of hydrates which could cause line stoppages. Hydrogen sulphide needs to be removed from the gas because of possible corrosion and the nuisance to gas consumers.

The chemical industry is the biggest customer of British Gas and bought 2.2bn therms during 1977-78 as compared with 2.09bn therms the year before. Engineering and metal goods which covers the shipbuilding and vehicle industries took 1.15bn therms which was up on the 1.02bn therms bought in 1976-77 (11). The metal industry, the food, drink, and tobacco industry and the china and earthenware industry are all major industrial customers which have increased their consumption. Commercial consumers such as the medical and educational services have also been increasing their consumption of gas.

Gas compared to Coal and Electricity as an energy vector

For a dry bituminous coal there is about 75% carbon, 5% hydrogen

and about 20% of other constituents such as oxygen, nitrogen, sulphur and mineral matter. Natural gas has 75% carbon, 25% hydrogen and negligible quantities of sulphur and undesirable constituents. There is no problem of ash formation and disposal for natural gas. Gas is more easily fired than solid or liquid fuels and gaseous fuels have the advantage that complete combustion can be obtained with very little excess air in the mixture.

For bulk heat applications such as cement kilns or large boiler plant, direct combustion is the obvious choice. For this type of duty coal can be burned as efficiently as gas or oil provided the plant is large enough to make economic the necessary coal ash handling plant and the treatment of waste gases. There will remain many energy demands for which the direct use of coal is unsuitable. They will include processes needing controlled flames or atmospheres for the protection of the product or the environment and virtually all of the smaller plants.

(12)

The relative cost of energy production are shown in Fig. (1) and Fig. (2). A pipeline gas plant costs only about a third as much per net unit of heat energy produced as a coal fired plant, (see Fig. (1)). Gas can be transported for about one eighth the cost of transporting electricity in even the most modern extra high voltage AC system (Fig. (2)). In long distance DC systems the best cost of transporting electricity is about five times as much as for gas, and this difference could further increase if the electricity industry is forced to put more of its lines underground. Fig. (3) shows relative investment costs for energy transmission facilities (13) .

One reason for the high cost of electricity energy supply systems is the difficulty of storage. This means that electric generation rates must match consumption rates almost exactly, responding instantaneously to demand fluctuations. Combined with the need for spare capacity to assure reliability this means disproportionately high investment costs compared to energy supply systems which can meet fluctuating demand and reliability requirements largely with storage as would be the case with a suitably designed gas system. Fig. (4) shows the cost of manufacturing SNG from

coal compared with natural gas from the North Sea and the cost of generating electricity at various load factors⁽¹⁴⁾.

Energy efficiency for SNG systems

The overall energy efficiency for SNG systems will be the product of the coal conversion efficiency and the gas utilisation efficiency. The efficiency of the coal conversion process to produce SNG may be taken as around 65% although lower values for efficiency may result depending on the process involved. This efficiency may be raised to about 71-75% by including the heating value of by-products such as oils, tars and sulphur^{(15), (16)}.

The gas utilisation efficiency will depend on the boiler and burner. A figure of 70% for the efficiency of an LTC boiler 'in use' has been stated⁽¹⁷⁾

. However, other estimations for the efficiency of domestic space heating devices give a value as low as 52%^{(18), (19)}. The 52% used by the GLC is very questionable and most probably wrong. To justify support from the Department of the Environment they needed to demonstrate a lower 'cost-in-use' for their district heating than for individual systems. Their engineers measured the efficiency of some oversized high thermal capacity boilers in one of their properties and came up with this figure⁽²⁰⁾. This figure was incorrectly assumed to be the efficiency of individual systems. Several years of work at the British Gas Research Centre at Watson House have demonstrated considerably higher efficiencies, particularly for the low thermal capacity boiler associated with proper controls^{(17), (21), (22)}. This figure of around 70% is now accepted by the Department of Energy and an efficiency of 70% for heating is used in their pamphlets for the public, 'Compare Your Home Heating Costs'. For well controlled systems, seasonal efficiencies of 75% to 80% have been demonstrated in the field by the Watson House British Gas Research Centre.

The higher efficiencies of the LTC appliances are a consequence of the thinner metal walls, the greater use of extended surfaces, reduced case losses and the use of fan assisted combustion. The overall energy efficiency for an SNG system could thus vary from 49% to 60% depending mostly on the gas utilisation efficiency accepted.

It is important to differentiate between bench efficiency and practical efficiency for the gas appliance. Bench efficiency is the efficiency of heat transfer to water or air under standardised conditions and the only heat not regarded as useful is the flue loss and the appliance surface losses. For most gas central heating appliances and water heaters it is 70-80%. The practical efficiency is that proportion of the heat input which is useful to the consumer. For example, a demand for hot water brings the gas and water on simultaneously, but until the delivery temperature has reached an acceptable level the water is usually allowed to run to waste. On completion of the draw off, gas and water are turned off, leaving a fully heated appliance. The heat in the appliance is gradually dissipated to the atmosphere and as far as the consumer is concerned the useful output from the operation is represented by the hot water collected in the sink. For a small draw off, the practical efficiency could be as low as 15-20%, while for a large draw off as when running a bath, the efficiency may approach the bench figure of 75%. Thus the difference between the practical and bench efficiency is a consequence of the heat storage capacity of the appliance.

Heat must be put into the metal of an appliance to get it up to the necessary temperature and unless this heat can be recovered a loss of efficiency results. The effect of heat storage extends right through the system and components such as draw off pipes, radiators etc. all heat up and cool down and take time to do so, all contributing to a loss of efficiency.

In the case of space heating, there is no absolute basis for the practical efficiency, as the real measure is the heat input needed to maintain a given level of thermal comfort. This will depend on many factors such as the fabric losses of the building, ventilation, consumer habits, controls, occupancy etc. Bench efficiency tests are carried out in ideal laboratory conditions to demonstrate the optimum thermal performances of gas appliances. The heat transfer characteristics of the factory clean exchange surfaces will be much better than in normal household installations with years accumulation of entrained dust building up with detriment to

thermal efficiency.

SNG Plant investment cost escalations

A disadvantage often quoted for SNG has been an apparent steep escalation of costs. Some of these cost escalations have been due to normal inflationary pressures and in the case of coal based synthetic fuels such as SNG to the large increase in coal costs. Although coal based synthetic fuel projects have shown a sharp escalation over the past few years the escalation in costs of nuclear plants, pipeline projects and SNG from naphtha plants has followed a similar pattern (23). Fig. (5) shows case histories of investment cost escalation for synthetic fuel projects, nuclear power, coal fired electric plants, pipeline projects and SNG from naphtha plants. Although SNG plant investment costs have risen dramatically the cost of other large scale energy developments has also risen in a relative manner.

In mid-1974 the estimated capital cost of a 2.5 bn m³ year (250 mcf/d) Lurgi plant was about £180 M (24). In 1977 a Lurgi SNG plant was estimated at about £530 M, and a Hygas SNG plant at £435 M (25).

The NCB are also in agreement (26) that although capital costs for synthetic coal projects have escalated, other energy projects of a comparative size have risen in a relative manner. Table (1) shows the relative position of SNG from coal plant investment costs compared to other synthetic fuel projects (27). While it shows that this cost is greater than SNG from naphtha plants and SNG from crude oil plants, it is not as high as plant investment costs for syncrude from oil shale or syncrude from coal. The major cost factor is plant investment costs.

The Gas Transmission System

A new transmission system will not have to be built as a very efficient system is in use at present which should last well into an era of SNG. Indeed, to make continued use of the transmission system may be a strong factor for the development of SNG in the first place as a high level of investment has gone into the development of the gas network. In the decade since natural gas was first introduced £737 M was spent on

installing the system, another £371 M in providing the additional distribution mains and a further £550 M on converting customers from town gas to natural gas (28) . Additional high pressure transmission pipelines may be needed to connect in the new SNG plants and an allowance of 50 miles of pipeline per SNG plant at about £500 000 per mile has been estimated (29) .

When natural gas reserves decline and gas is mostly made from coal as SNG it would be important from an overall financial viewpoint to know how long the pipeline system is likely to last without wholesale replacement. The burden of a new pipeline system on top of the higher priced gas from coal would further increase the cost of supplying SNG. All pipeline laid by the gas industry since the late 1960's has been to the Institute of Gas Engineers code (30) and pipelines laid before this time have either been brought up to the same standard or have been derated and operate at lower pressures. There are about 24 000 km of transmission pipe now in existence in the UK, and of these about 6 000 km form the national transmission system operating at up to 67 bar. These are mostly the larger 30", 36" and 42" mains. The majority of the remaining lengths are operated by the regions of British Gas at pressures below 37 bar.

According to British Gas it is their belief that the transmission system can continue with a minimum of maintenance well into the 21st century. (30)

. As regards the distribution system there is still some mileage of mains which are about 100 years old, but even so are in very good condition. In general the total system downstream of the transmission mains operates at pressures lower than 2 bar. British Gas estimate that the distribution system should be kept in good order into the 21st century. The current trend is to replace the jointed cast iron systems with either welded steel or plastic pipe, depending on the required operating pressure (30) . The major factor influencing service pipe corrosion is the presence or absence of an effective pipe coating. In general a life of at least 40 years can be expected from coated services with a cumulative replacement of not more

than a few percent. On the transmission system corrosion can be prevented by the use of cathodic protection backed up with an adherent coating.

Complete protection can be maintained if the system is monitored periodically (31).

Some further constraints on SNG development

In an SNG plant building programme the constraint is not so much the level of demand as the capacity to build the plants and develop the mines. As well as readily available coal deposits the plant location will depend on environmental needs and also water supply availability. The conversion plant would have a high coal requirement and would need a long life to justify the capital cost. Large blocks of reserves would be needed in the vicinity of the plant, since economy of operation requires coal transport to be minimised. Ideally gas should be made where it is required, i.e., near the consumer or a pipeline. Nearness to the consumer is most important for peak load gas, while base load gas plant is best placed adjacent to a high pressure transmission pipeline.

Generally speaking the economics of producing SNG from coal should not be considered in relation to current prices of oil and natural gas. Today's cost of SNG should be compared with the incremental cost of new supplies of natural gas or the incremental cost of electricity.

Advantages of coal gasification for production of Substitute Natural Gas

1. SNG plants have an investment requirement of about £75/kW compared to new coal mining capacity of £25/kW, coal fired electricity at about £170/kW, and nuclear electricity plants at about £280/kW (2). The average value of $1200\$/10^3$ cfd given in (27) Table I for investment in SNG plant gives a value of 49.2£/kW (1973). This is reasonably consistent with 75£/kW (1975) given in reference (2) allowing for variable exchange rates.
2. Gas is much easier to store than electricity, so that the capacity of gasification plants can be matched to average loads and not peak loads.

3. The cost of distributing gas is much lower than the cost of distributing the same quantity of energy as electricity.
4. The technology for the production of SNG is well known and investment can be made nearer the time it is required. This is an advantage it has over CHP technology which has a long lead time and so needs early investment.
5. From an ecological point of view converting coal to a clean gas has advantages in that the gasification process removes sulphur and particulates before the fuel is burned, so high sulphur coal can be used. In contrast, sulphur can only be removed in electricity production from coal by expensive stack gas scrubbers. Thus gasification enables a reduction in air pollution at lower costs.
6. Gasification plants could have a larger potential export market than power stations, since most other industrial nations also face electricity overcapacity problems as well as the UK.
7. The improvement in thermal efficiency means that the demands for cooling water and the heat released into the atmosphere are much smaller for the gasification plant per unit of heat delivered to consumers.
8. Now would be a good time to start building SNG plants as far as the construction industry is concerned, as in the late 1980's and 1990's the construction industry may be committed to building nuclear plants.
9. An SNG plant building programme would give new opportunities to industry including The British Steel Corporation as, due to high corrosion rates, there will be a high turnover in gasifiers. It is probable that by the late 1980's the North Sea market for steel in general will be drying up.

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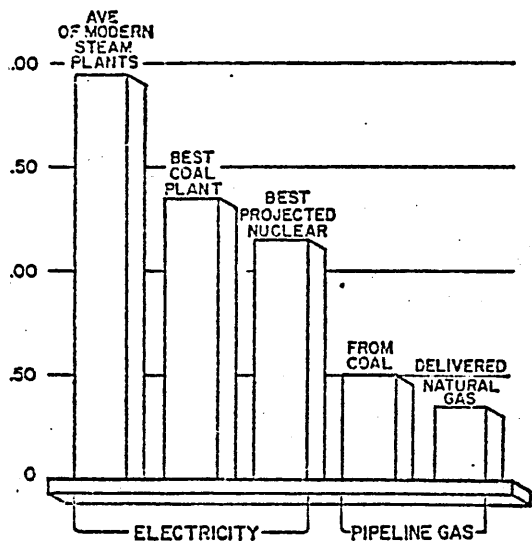


Fig. (1).

COST OF ENERGY TRANSMISSION

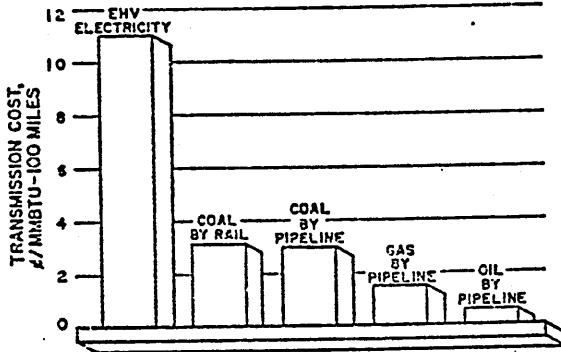


Fig. (2).

INVESTMENT COSTS FOR ENERGY TRANSMISSION FACILITIES

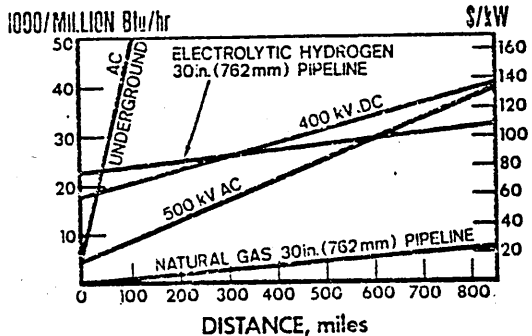


Fig. (3).

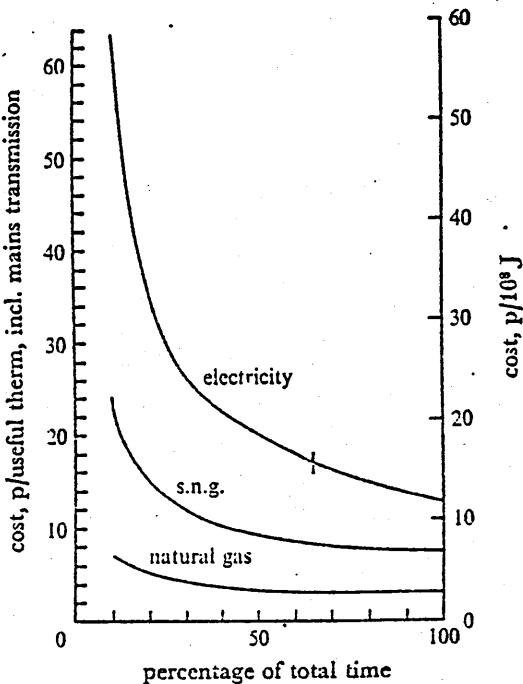


Fig. (4).

BASE HISTORIES OF INVESTMENT COST ESCALATION

INVESTMENT COST, \$/Million Btu Daily Output

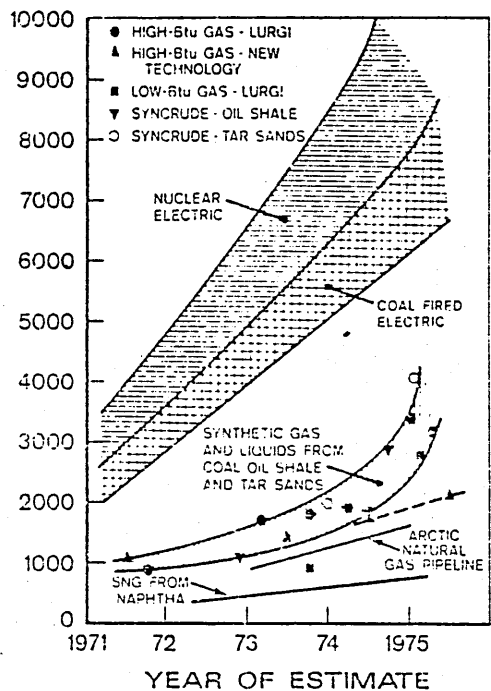


Fig. (5).

[M = 1000 (10³), MM = Million (10⁶), B = Billion (10⁹), T = Trillion (10¹²)]

PROCESS EFFICIENCY	RAW MATERIAL REQUIREMENTS (YIELD)	1972 PLANT INVESTMENT COST
SYNGAS FROM NAPHTHA	95% 220 MMbbbl/TCF	\$200-350 MCF/d
SYNGAS FROM CRUDE OIL	75% 240 MMbbbl/TCF	\$500-700/MCF/d
SYNGAS FROM COAL	66% 60 MMten/TCF	\$1000-1400/MCF/d
SYNCRUDE FROM OIL SHALE	(35 gal/ton)	\$5000-6000 bbl/d
SYNCRUDE FROM COAL	75-85% 260-350 MMten/bbl (3.4-3.8 bbl/ten)	\$6000-7000 bbl/d

SYNGAS - 1032 Btu CF SYNCRUDE - 5.8 MM Btu bbl COAL - 26.2 MM Btu ton

Table 1.

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CHAPTER III

PRIMARY ENERGY SUPPLY

Gas Supply
World Gas Reserves

The International Workshop on Alternative Energy Strategies in
(1) their 1977 Report showed that proven gas reserves stood at 61819 bn m³ (2232 tcf). Ultimately recoverable reserves, including those that are yet to be discovered, may be three or four times as large.

Natural gas provides nearly 20% of world energy production, although it constitutes no more than 8% or 9% of the world's total
(2) proved reserves of fossil fuel. With a world total of 61819 bn m³ (2232 tcf) then this suggests that natural gas reserves are around 60%
(3) of world reserves of oil. Sir Derek Ezra in his book 'Coal and Energy' has made the point that in the USA and Canada where both oil and gas production have been extensively developed, published proved gas reserves are higher than the corresponding figure for oil. The point he makes is that it is possible that when the rest of the world has been equally explored the eventual reserves of natural gas may prove to be more than 60% of oil reserves. While there is no geological justification for assuming that the ratio of gas to oil reserves for the North American continent could be applied worldwide, it is certainly possible that final world gas reserves may be nearer the figure of 75% of oil reserves favoured by the UK Department of Energy.

At the start of 1976 OPEC decided to include natural gas in its cartel policy, and so in the longer term OPEC will play a greater part as a supplier of natural gas. Out of the natural gas reserves proved at the start of 1977, 40% are in Communist countries and 34% in OPEC countries. Relatively small percentages of the reserves are in North America and Europe, being about 12% and 6% respectively. As far as Europe is concerned more than 25% of natural gas supplies in 1985 are

expected to be derived from sources outside West Europe compared
(4)
with 3% in 1973 .

UK Supplies

The supply of natural gas to the end of the century will depend on the size of the reserves and the rate of their depletion. Total reserves remaining in known discoveries at the end of 1977 were estimated (5) to be 1515 bn m³ (54.7 tcf), but exploration is continuing and it is fairly widely accepted that there is more gas still to be discovered. It is possible that the total could be as high as 2216 bn m³ (80 tcf) or above, (6) and according to the Government's Energy Policy Review Paper there is a one in ten chance that reserves might reach 2770 bn m³ (100 tcf). A decline in gas supply could be delayed by further imports of Norwegian gas, LNG from Algeria and even piped trans-europe gas from the USSR.

The absorption of large quantities of gas in the short and medium term creates pressures on the other fuels in the premium markets in the domestic and industrial sectors. To avoid aggravating these pressures there is a strong body of opinion that believes the relative price of fuels should reflect as nearly as possible their long term costs. For the gas industry this will depend on reasonably accurate information of potential reserves which should be a matter of priority for both the Government and The British Gas Corporation. The gas industry has to attempt to match supply and demand and this is not made any easier by short term 'surges' of gas supply. This may occur with associated gas supplied in conjunction with oil from an oilfield, as in the case of the Brent field, (under new purchase agreements with operators in the Southern gas fields British Gas can trim its offtake by significant amounts). The Chairman of The British Gas Corporation has indicated that the Gas Corporation is, if necessary, prepared to pay producers now to keep reserves for later use.

Frigg is one of the largest offshore gas fields yet discovered in the North Sea, with estimated recoverable reserves of more than 200 bn m³ (or 7 tcf) of gas. Frigg contains good quality gas, being low in sulphur

and largely free of heavy or wet gases. An estimated 60% of Frigg reserves lie in the Norwegian sector and the remainder in the UK sector. Frigg will mean an extra 13.8 bn m^3 per year by 1980 which is equivalent to about 20 million tons of coal or 85 million barrels of oil. The Frigg field is estimated to produce at a level of 43 million m^3 a day by the end of 1979. The Brent field ultimate reserves are estimated at about 100 bn m^3 (7) ($3\frac{1}{2} \text{ tcf}$) of associated gas. In the Northern sector Frigg gas prices are linked to world crude oil costs so The British Gas Corporation will be paying much more for these supplies.

The partners in the Frigg operation, Total and Elf Aquitaine are beginning to look at the possibilities of developing the satellite gas fields in the area. There are three named daughters of Frigg: East Frigg, North East Frigg and South East Frigg. The first two of these have a much better chance of development. Gas reserves in East Frigg are estimated to be about 8.5 bn m^3 of which some 6 bn m^3 are thought to be recoverable gas (about 0.25 tcf). North East Frigg contains about 14 bn m^3 of recoverable gas (about 0.45 tcf). South East Frigg reserves are estimated at only 1.05 bn m^3 (about .03 tcf). Total reserves in the three Frigg daughters thus comes to about 20.8 bn m^3 (0.75 tcf) (8). The Heimdal gas field with reserves of about 35 bn m^3 and the Odin field with reserves of 30 bn m^3 could also be regarded as Frigg satellites. The British Gas Corporation is the natural customer for Frigg satellite gas now that the scheme for a small diameter pipeline to Norway has more or less been shelved on economic grounds. A lot would depend on the BGC being able to offer enough for the gas to make production worthwhile, and if the operators are able to obtain enough concessions from the Norwegian Government in whose waters most of the satellites lie. Including the Heimdal and Odin fields, then the Frigg satellites could contribute approximately 83 bn m^3 (3 tcf).

There are also the large reserves of gas in the big Statfjord field which straddles the UK/Norwegian dividing line, although there seems to

be some recent doubt about the size of these reserves. The BGC would be the obvious customers for much of this gas, but Norwegian producers will want to sell their gas at the most favourable price. In current circumstances that price is related more to the continental market than to tariffs in the UK. The recent BGC announcement that a fourth line south from St. Fergus is to be built and that its diameter is likely to be 42" makes the transport of the gas to the UK more possible (9). However, it is open to question whether The British Gas Corporation will want to buy large quantities of additional gas in the next few years in view of the supplies from Frigg, Brent and the Southern gas fields. The BGC could of course pay now and take later, but another suggestion is that Norwegian gas be piped through the UK system and through a new pipeline built across the English Channel to the European market. The building of such a pipeline may be in the interests of the BGC, as in the future when North Sea supplies are depleted it may be useful to pipe USSR gas across from the continent.

With other fields still to be utilised such as the Morecambe Field in the Irish Sea, the BGC is confident that there are already enough proven reserves to continue sales to the premium market through to the end of the century at the level it will be setting in the mid-1980's of some 50 to 60 bn m³/year (18-22 bn Therms). The British Gas Corporation is now developing other options for flexible supply such as emergency storage liquefaction facilities. Also, the Morecambe Field being completely owned by the BGC will not be subject to rigid supply contracts. It has been suggested that recoverable reserves in Morecambe might be at least 69 to 97 bn m³ (.25 to 3.5 tcf) and it may be on a par with the Viking and Indefatigable fields which each contain about 125 bn m³ (4.5 tcf) (10).

Another source of gas supply in the future will be the associated gas from oilfields which will be supplied in conjunction with demand from the parent oil field. The establishment of some sort of gas collection system in the region of the Brent field, which itself will yield associated gas,

seems likely. Williams-Merz estimated that a gathering network for the whole of the UK sector could carry over a twelve year period the equivalent of about 183 bn m^3 (6.6 tcf) of reserves ⁽¹¹⁾. It would be in addition to the 6 million to 9 million tons a year of heavier gases - ethane, propane and butane - which might be used as the basis for a major expansion of the chemical industry. There is the possibility that associated gas may in some cases not be available until the oil field has been drained in say 15 to 20 years time. Some gases have a high percentage of non-combustible or inert gases such as N_2 or CO_2 , and a proportion of the reserves may be required as energy to remove the non-combustibles, so reducing the net effective proved reserves.

There are already signs that production from the Southern sector fields is starting to peak. Production of gas from the Newett field has fallen to $.018 \text{ bn m}^3/\text{day}$ (630 mcf/d) from around $.02 \text{ bn m}^3/\text{day}$ (725 mcf/d). According to Wood Mackenzie production from Hewett was expected to remain at about $.022 \text{ bn m}^3/\text{day}$ (800 mcf/d) up to 1981. They estimate that of the field's original 94 bn m^3 (3.4 tcf) of reserves about 55.4 bn m^3 (2 tcf) ⁽¹²⁾ remains to be recovered.

The effect of low prices in the late 1960's has been that there are no real incentives for further exploration in the Southern Sector. There are a considerable number of small gas fields in this area still awaiting production with reserves of about 166 bn m^3 (6 tcf). However, whether or not this will ever be developed will depend on the producers getting an economic price for their product.

When supplies start to peak the Gas Industry could call on gas piped ⁽¹³⁾ from the USSR, or imported LNG. LNG is economic at present in comparison with other fuels only because natural gas is offered on the world market at a relatively low price per therm. Once major consuming countries have sunk investment on a large scale into the necessary LNG plant, economic forces will lead to price increases. With large increases expected in world LNG trade during the 1980's, by the time the UK needs it in bulk it may be very expensive. LNG world trade at present is about 21 M m^3 per year and is

expected to reach between 150 and 230 M m³ per year by 1990 (14)

The liquefaction of natural gas into LNG is only about 70% efficient and transport by cryogenic tanker is expensive as the tankers are more complicated to build than supertankers for crude oil, and they are considerably smaller. Algerian gas supply to the UK represents about 2.8% of present total gas sales, being about 1.1 bn m³/year (391 M Therms). The BGC has paid well below the average market price for Algerian contracts with other EEC nations. Future Algerian contracts will mean obvious increases. When considering imports of pipeline gas from Algeria and the USSR, it should be remembered that a lot of the readily exploitable reserves in these two countries appear to be already committed to various markets (15)

It has been suggested that LPG could help fill the gap when natural gas supplies peak out. There is likely to be a surplus of LPG on the world market of several hundred thousand barrels a day in the 1980's. This would come about because of new LPG processing plants forecast to be built in the Middle East to convert associated gas from the oilfields which would otherwise be flared. Such surpluses are in fact over and above those requirements forecast for the US and Japan (16). Calor gas appears also to have a role to play in the gas market for uninterrupted supplies. Natural gas was expected to fully fill the gap left by the demise of the electric night storage heater. This involved about ¾ million appliances per year. However, at least 50% of this market was taken by calor gas and LPG and not as expected by natural gas (17)

Future UK gas supply

It is difficult to predict the future UK gas supply without more concrete evidence about the potential gas reserves. As the Secretary of State for Energy has pointed out, renewed efforts should be made to establish the future approximate gas reserves around our shores. There are many other factors which will influence the future gas supply including the world price of LNG, the building of a cross-channel pipeline, future markets for coal (a reduction in coal burn by the CEGB may increase

pressure on the BGC to develop SNG technology and so open up new coal markets).

The present known gas discoveries at the end of 1977 were about 1515 bn m³ (or 54.7 tcf)⁽⁵⁾. This includes Frigg 200 bn m³ (7.1 tcf) and Brent 100 bn m³ (3.5 tcf). We can estimate ultimate recoverable reserves by making an 'average' forecast and an 'optimistic' forecast. In the optimistic forecast we can assume that most of the Norwegian gas from Statfjord and the other smaller Norwegian fields Odin, Heimdal, Steipner, Velhall and Hod is piped to the UK system. Some reports⁽¹⁸⁾ have put the Statfjord reserves as high as 150 bn m³ while others have put it at 100 bn m³ and lower. If we assume the largest predicted Statfjord reserves of 150 bn m³ and the same again 150 bn m³ from the other smaller Norwegian fields, then together this gives 300 bn m³ (11 tcf). Associated gas from the Northern Sector of the North Sea has been put at about 183 bn m³⁽¹¹⁾ (6.6 tcf) by the Williams Merz Report. Other reports have put associated gas reserves considerably higher than this. The three Frigg daughters could contribute about 27.7 bn m³ (1 tcf), the Mrecombe Bay field 97 bn m³ (3.5 tcf) and the smaller Southern fields about 166 bn m³ (6 tcf). There is also the possibility of further discoveries in the Northern sector of the North Sea such as in the East Shetlands Basin. Assuming another field about half as large as Frigg is found, then this would give about 100 bn m³ (3.5 tcf) and an outside possibility of 200 bn m³ (7 tcf).. There may be further discoveries in the Celtic Sea and the Western Approaches with say, an average possible find of 138 bn m³ (5 tcf) and an optimistic find of 277 bn m³ (10 tcf).

Estimated further reserves in addition to the 1515 bn m³ (54.7 tcf) known at the end of 1977.

	<u>Average Forecast (bn m³)</u>	<u>Optimistic Forecast (bn m³)</u>
Statfjord & other smaller Norwegian fields	180	300
Morecambe & smaller Southern fields	263	263
Associated Gas (Northern)	183	400
Northern finds	100	180
Celtic Sea & Western Approaches possible finds	138	250
Frigg daughters	28	28
	<hr/>	<hr/>
	892	1421

The 'optimistic' forecast includes the maximum predicted reserves from Statfjord with all of the Statfjord reserves, and the other Norwegian gas fields being piped to the UK. It also assumes quite high quantities of associated gas and some rather large gas fields still to be found. The 'average' forecast for extra reserves works out at 892 bn m³ and the 'optimistic' forecast at 1421 bn m³. Taking a figure of 900 bn m³ and adding those already discovered we have an 'average' forecast $900 + 1515 = 2415$ bn m³ (87 tcf). The 'optimistic' forecast would yield reserves of $1400 + 1515 = 2915$ bn m³ (105 tcf).

	<u>Average Forecast</u>	<u>Optimistic Forecast</u>
Reserves up to 1977	1515	1515
Extra discoveries	900	1400
TOTAL	2415 bn m ³ (87 tcf)	2915 bn m ³ (105 tcf)

COAL AND OIL SUPPLY

Units

In coal statistics Britain has used the long ton (2240 lb or 1016 kg) while the USA has the short ton (2000 lb or 907 kg). The metric ton or tonne (1000 kg or 2205 lb) is now gaining worldwide acceptance, including the UK. Different types or grades of the same fuel may have very different calorific values. In Britain, for example, the heat energy in coal can vary from about 220 to 350 therms per ton, while on the world scale the variation is even wider, especially if lignite is included. The EEC equates 7000 calories to one gramme of standard coal, (hence 7 million kilocalories equals 1 tonne of standard coal) which means 1 standard tonne of coal is about 278 therms.

Oil is measured in tons (long or short), in tonnes or by volume in barrels. Converting barrels of oil to tons or tonnes and vice versa is often necessary as many sources of information seem to use units of measurement indiscriminately. Conversion is difficult as the specific gravity of oil varies considerably, but usually there are between 6.6 and 7.9 barrels to a tonne. However, rather than calculate the precise factor for each type of oil in the total under consideration, it is usual to employ an average conversion factor, such as the 7.33 used in BP's published statistics.

As an example of differences in conversion factors, the EEC treat 1 tonne of crude oil or oil products as equivalent to 1.43 tonnes of standard coal, the UN in their latest statistical tables (series J No. 19) regard 1 tonne of crude oil as equivalent to 1.47 tonnes of coal and 1 tonne of an oil product as 1.50 - 1.61 tonnes of coal, depending on the product, while in Britain the Department of Energy equates 1 tonne of petroleum products to 1.7 tonnes of coal⁽³⁾.

World coal reserves

At the World Energy Conference in 1977 the estimation of the world's geological resources of solid fuels amounted to more than 10,000 thousand

mtce. It was reckoned that some 640 thousand mtce were technically and economically recoverable, under the conditions prevailing today. This is equivalent to between 200 and 300 years at current rates of usage. In January 1967 Paul Averitt of the USGS estimated the world's solid fuel resources of all kinds as determined by mapping and exploration plus an estimate of reserves in unmapped and unexplored areas at no less than 15 200 thousand million tons⁽³⁾.

In Western Europe the most important parameter for procuring the required new coal supplies of about 40/45 mtce by 1985⁽¹⁹⁾ will not be production but imports. The contribution of indigenous production to the total coal supply is estimated to fall from 87% (1973) to 79%⁽¹⁹⁾ (1985). In the EEC as a whole coal production estimated at 220 mtce in 1985 is expected to be markedly lower than the objective of 250-255⁽²⁰⁾ mtce set in 1974.

UK Coal Reserves and Production Estimates

The known reserves of coal in the UK are massive. About 100 000 million tons of coal are in known coalfields and a further 60 000 million tons could exist elsewhere on the basis of current geological knowledge. Reserves which could be recovered using present technology are of the order of 45 billion (thousand million) tons, worth about £1 000 billion. Those collieries which already exist contain some 4 billion tons of recoverable coal worth nearly £100 billion. A further 2 billion tons are⁽²¹⁾ estimated to be available at collieries now being planned.

The NCB's 'Plan for Coal' is aimed at the creation of new mining capacity to produce 42 million tons a year by the mid-1980's. About half of this capacity will be in the shape of new mines and half at existing pits. In this way it is hoped the exhaustion of older mines will be offset and output expanded to 135 million tons a year, of which 15 million tons may come from opencast operations. The huge mine at Selby in Yorkshire alone will produce 10 million tons a year. On the supply side it is certain that Britain's known coal reserves would support

a higher level of production, using current mining techniques, for many generations ahead. Bearing this in mind the NCB recommended that an annual colliery output of 150 million tons by the end of the century should be adopted as a target for planning purposes. This was known as (21) 'Plan 2000' .

As well as the Selby coal reserves other major new possibilities already identified and their possible recoverable reserves are: Vale of Belvoir and East Leicestershire 500 million tons; Park (Staffs) 100 million tons; South West of Coventry 100 million tons; Margam (South Wales) 30 million tons; Musselburgh (Scotland) 50 million tons. Exploitation of these reserves would depend, of course, on planning permission being obtained. On present information there are about 450 (21) million tons of coal which could be mined using opencast techniques .

The process known as coalification goes from peat, to lignite, to bituminous coals of increasing hardness and finally to anthracite. Energy values of the various coals increase with the four coalification stages of peat through to anthracite. Peat has a value of 10 kilojoules per gramme (kJ/g), lignite 20 kJ/g, bituminous coal 30 kJ/g, and anthracite 34 kJ/g. The United Nations defines coal which has a gross energy value of over 5700 Kcal/kg (approximately 24 kJ/g) as hard coal, and coal (21) having an energy value of less than this as brown coal .

The active population while still growing will do so only at a slower rate than of recent years. Thus the coal industry might have to compete for new labour in a much tighter labour market. The recruitment of young labour may pose problems due to demographic factors and increased length of education. Because of poor prospects for employment growth, labour productivity has to be raised by improvements in mining techniques. Although considerable investment is needed in the NCB programme, it is (22) still considerably less than North Sea oil or nuclear Power . The fact that coal requires less capital per ton produced than any other fossil form of energy renders financing problems less stringent.

There are many factors that will affect the supply of coal. These include:-

1. Future CEEB power stations building plans for coal, oil and nuclear plant.
2. The possibility of EEC subsidies to make coal in the EEC more competitive with cheaper imports.
3. Government subsidies for NCB coal stocks, Scottish and Welsh coal, and the building of the second stage of the Drax B coal fired power station ahead of time.
4. The reduction in the requirement for coking coal due to the recession in the Steel Industry.
5. The relative price of coal to oil as a feedstock for electricity power stations.
6. The age and inefficiency of much coal fired plant leading to less use than other more modern oil and nuclear plant.
7. The possible development of a 2GW cross channel link between Britain and France to export 1 mtce per year by wire.
8. The future rate of closure of old uneconomic pits and the development of high productivity Royston type pits in the NCB 'Plan for Coal' development programme.
9. An increase in open cast mining.
10. Insufficient knowledge about probable total gas reserves.
11. The possibility of cost inflationary effects due to coal prices leading the general level of inflation because of very large wage settlements.

All of these factors are considered in detail in Chapter VI, but some comments are necessary at this stage. Many of the factors mentioned will be working against the coal industry acquiring its projected target for coal burn as set out in 'Plan for Coal' and 'Plan 2000'. For example, the projected growth in the supply of coal by the NCB is not accepted by

(23)

the CEEB in their recent corporate plan . The CEEB is forecasting a total coal burn of about 65 - 75 million tons of coal a year by the mid-1980's as against the figure of 85 million tons which the Government

(24)

put in its Green Paper on Energy Policy . The bulk of electricity stations presently under construction are oil fired, oil/gas fired, or nuclear powered. Only 5% - excluding Drax B - is coal fired. Coal fired stations in the CEEB system are estimated to fall to about 63% in 1980 compared to 72% in 1975 . An important factor in estimating future coal use will be the effects of the coal inflation likely to be caused by the substantial wage claims pursued in the coal industry. It has been estimated that if coal prices were to rise 6% faster than inflation, due to very large wage claims, then coal demand in 1981 could be only 112.5 tonnes and only 105 million tonnes in 1986 .

(26)

It is clear that the Government is committed to keeping the coal industry in business for the short to medium term in the belief that strong markets for coal will become clearer when North Sea oil and gas production starts to decline. The problem is that no-one can say for sure when this will happen, especially as the full potential of gas reserves is not known. Fig.(1) shows the market for coal assuming gas reserves of about 1660 bn m³ (60 tcf) . This shows the market for coal starting to recover after about 1985 and the underlying assumption is that oil will begin to price itself out of the market from the mid-1980's. However, if gas reserves finally turn out to be 2216 bn m³ (80 tcf) or even 2770 bn m³ (100 tcf) as is quite possible, then the recovery in the markets for coal could be considerably delayed.

(27)

The potential of the NCB to live up to the 'Plan for Coal' and 'Plan 2000' is clearly possible especially with the improved productivity rates brought about by modernisation schemes and future closures of old uneconomic pits. Fig.(2) shows the production targets set by 'Plan for Coal' and 'Plan 2000' . However, bearing in mind the economic factors mentioned and the problem of obtaining future markets for the coal

(28)

produced the 'Plan for Coal' and 'Plan 2000' may be on the high side. On the other hand, some of the other projections such as the CEGB projection of 110 million tons of coal by 2000 seem unduly pessimistic. The table below gives the hoped for production and a low estimate for the case of large gas reserves and high wage settlements. The actual supply may come somewhere between.

Coal Production (million tons coal)

<u>Plan for Coal and Coal 2000</u>		<u>Increased Gas Reserves and High Coal Mining Wage Settlements</u>	<u>Estimated possible Production</u>
	(High)	(Low)	
1985	135	115	125
2000	170	135	150

World Oil Reserves

For oil most published estimates relate to proven reserves such as the BP Statistical Review (29). The 1976 Review showed that world reserves stood at 88.3 thousand million tonnes at the end of that year, representing about 30 years supply at 1976 rates of production. This estimate is not very far removed from the 91.6 thousand million tonnes of total proven recoverable reserves given by the 1974 World Energy Conference (30). In the UK the Department of Energy estimated total recoverable reserves, including probable and as yet undiscovered resources. The UK figures given in mtoe were, oil 233, gas 171, coal and lignite 645 (10% recovery rate), coal and lignite 3225 (50% recovery rate). These are based on modest recovery rates which may be on the low side. They are higher than the BP figures which refer only to proven reserves.

The UK North Sea reserves represent only about 4% of world reserves. Oil reserves are being developed in other places such as Alaska and Mexico and there are also oil shale developments. The director of the Mexican State Oil Company estimated in 1977 that probable reserves could be 'far superior' to 60 thousand million barrels or twice as much as the US

combined proven reserves of 31 thousand million barrels at January 1977 .
However, these are probable reserves and even if the highest Mexican hopes were realised the reserves will only add about 10% to the world total of proved reserves.

It is probable that the USA by the early 1980's will be relying even more on imports for its oil requirements. The USSR has vast oil reserves but at the moment it is having difficulty in meeting the calls of other East European allies. Also the reserves are in some cases in very inhospitable areas which may make them uneconomic to develop. At one time US shale oil reserves were regarded as a potential major factor in the world's energy supply prospects. Shale deposits are located in several areas including the Green River formation in Colorado, Utah, and Wyoming. However, the problem of developing them has proved far greater than anticipated. The Federal Energy Administration's National Energy Outlook hardly mentioned shale oil in its 1976 Report (31) .

Production costs for shale oil and tar sands have more than doubled over previous estimates (20) . For example:-

Production costs for Shale Oil

National Petroleum Council USA 1972 : 4.32 to 7.25 \$/Barrel

US Federal Energy Administration
Feb. 1976 : 12 to 30 \$/Barrel

Production costs for Tar Sands

National Petroleum Council USA 1972 : 5 to 6 \$/Barrel

Syncrude Canada Ltd. 1976 : 13.7 \$/Barrel

Sir David Steele, Chairman of BP, has stated that oil companies would have to find the equivalent of 250 fields like the big Forties field in the North Sea if they were to replace the crude oil likely to be consumed in the world between now and the end of the century (32) . The

(1)
WAES MIT Report has indicated that oil will be getting scarcer and its price rising fast over the next 10 to 15 years. However, the gloomy predictions of the 1977 WAES Report and others, including the World Energy

(33) Conference and the first CIA Report (34) appear to be premature in the light of more recent predictions based on a slow down in the growth of energy demand. These later predictions include the giant US Exxon Corporation (35), the US Petroleum Industry Research Foundation (36), a second CIA Report (37), the World Bank (38) and Professor P. Odell (39).

As a result of these later predictions it would appear that supply problems for world oil will not be a threat until well into the 1990's. The effect of these predictions are discussed more fully in Chapter VI on 'World Coal Trade and Markets for Coal'. It is sufficient to say at this point that even if the large undiscovered reserves predicted in some of these reports prove to be there in part, like the Mexican reserves already mentioned, they are unlikely to greatly extend the life of the world's proven oil reserves.

UK Oil Reserves and Production Estimates

When discussing oil and gas reserves we should remember that whereas we can extract about 75% from a gas field, current technology is only extracting some 40% from our oil fields (40). So there is room for improvement in secondary and tertiary oil extraction techniques. Crude oil production from the Continental Shelf in 1977 was 37.7 million tonnes (41).

It is calculated that the 17 oil fields in production or under development should produce rather more than 100 million tonnes a year in the first few years of the 1980's. This total will probably start to decline in 1983, but there are 6 or more fields in which development should start in a year or two and these should peak in 1983-1985. Present proven reserves of 14 billion barrels (42) in the North Sea could sustain a production of about 130 M tons throughout the decade. It is reasonable to assume that exploration activity could yield a further 7 billion barrels of reserves which would supplement production, (Fig.3).

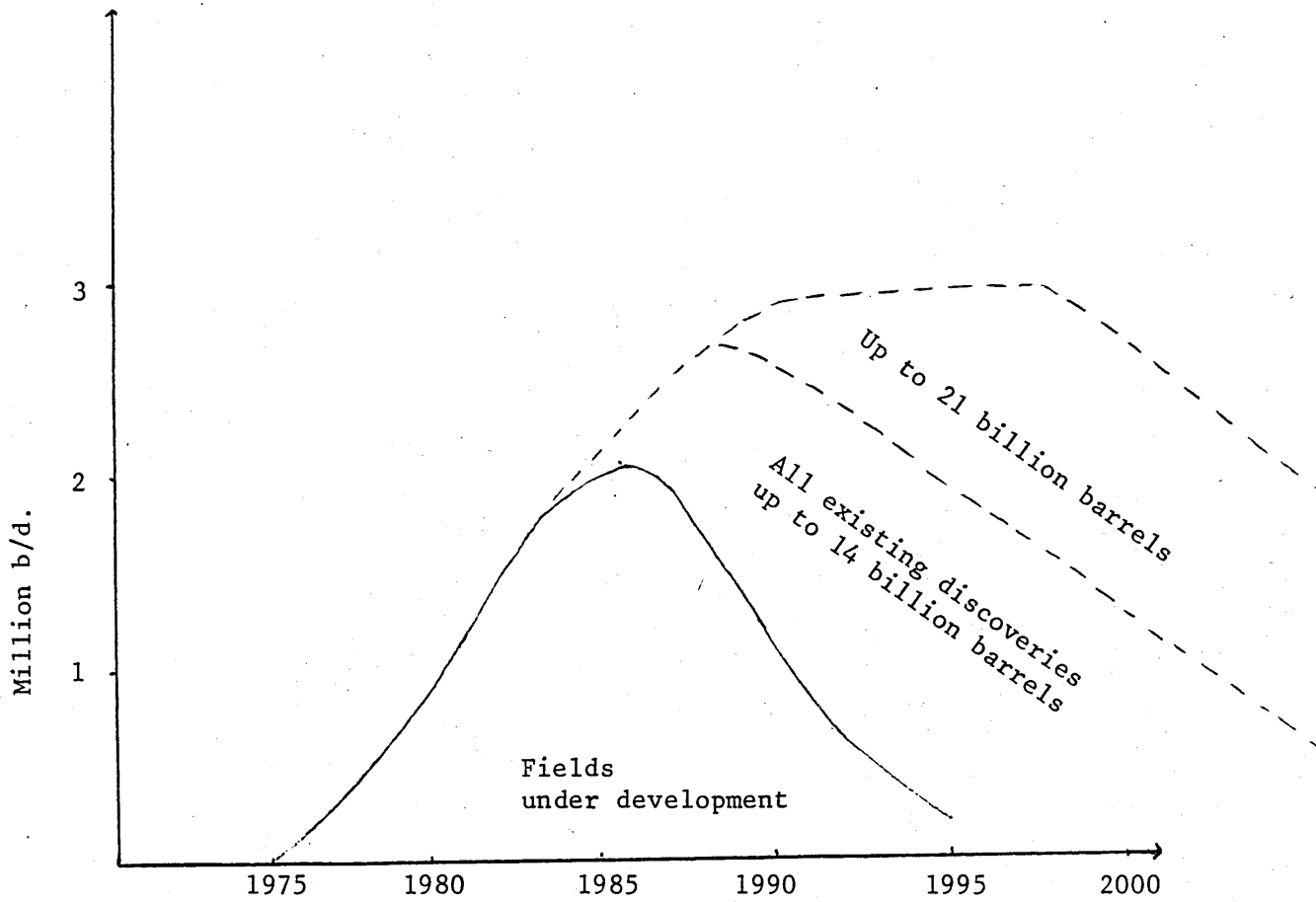


Fig.(3). Unrestricted North Sea Development

Taking into account estimates of reserves in areas designated but not yet licensed, total recoverable reserves could reach 4.5 billion tonnes (44) . This would consist of the Department of Energy estimate of 3000 million tonnes of oil in the North Sea, plus 1500 million tonnes (5) of oil in the Celtic Sea and Western Approaches . The exact nature of the UK oil production profile will depend on ultimate recoverable reserves and on Government depletion policy. If depletion controls are exerted on the Celtic Sea resources, then a delay of five years could maintain (44) production above 150 million tonnes of oil per year up to 2000 . (45)

Fig.(3) compares with the UK Offshore Operators Association Forecast for existing oil fields which are commercial or likely to be commercial, (Fig.4).

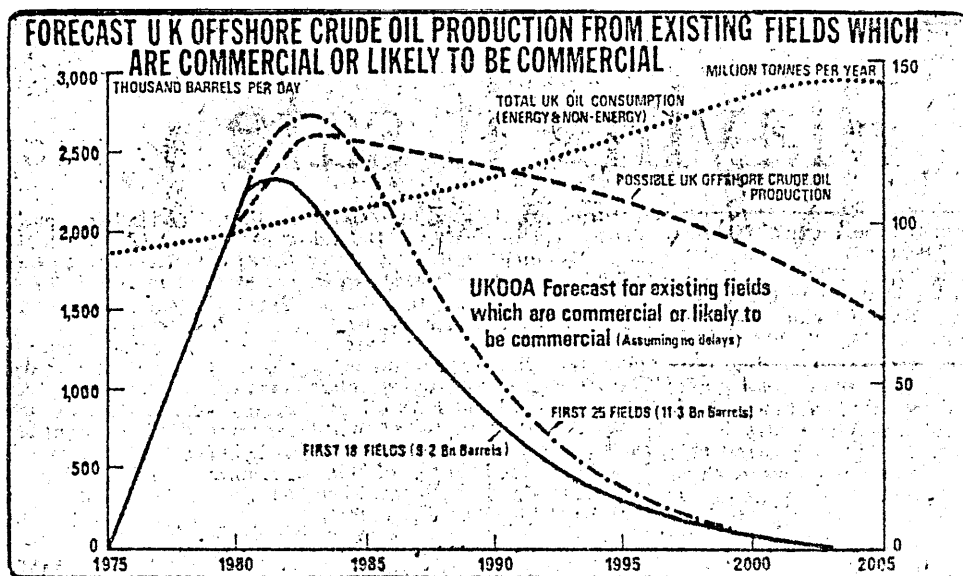


Fig.(4)

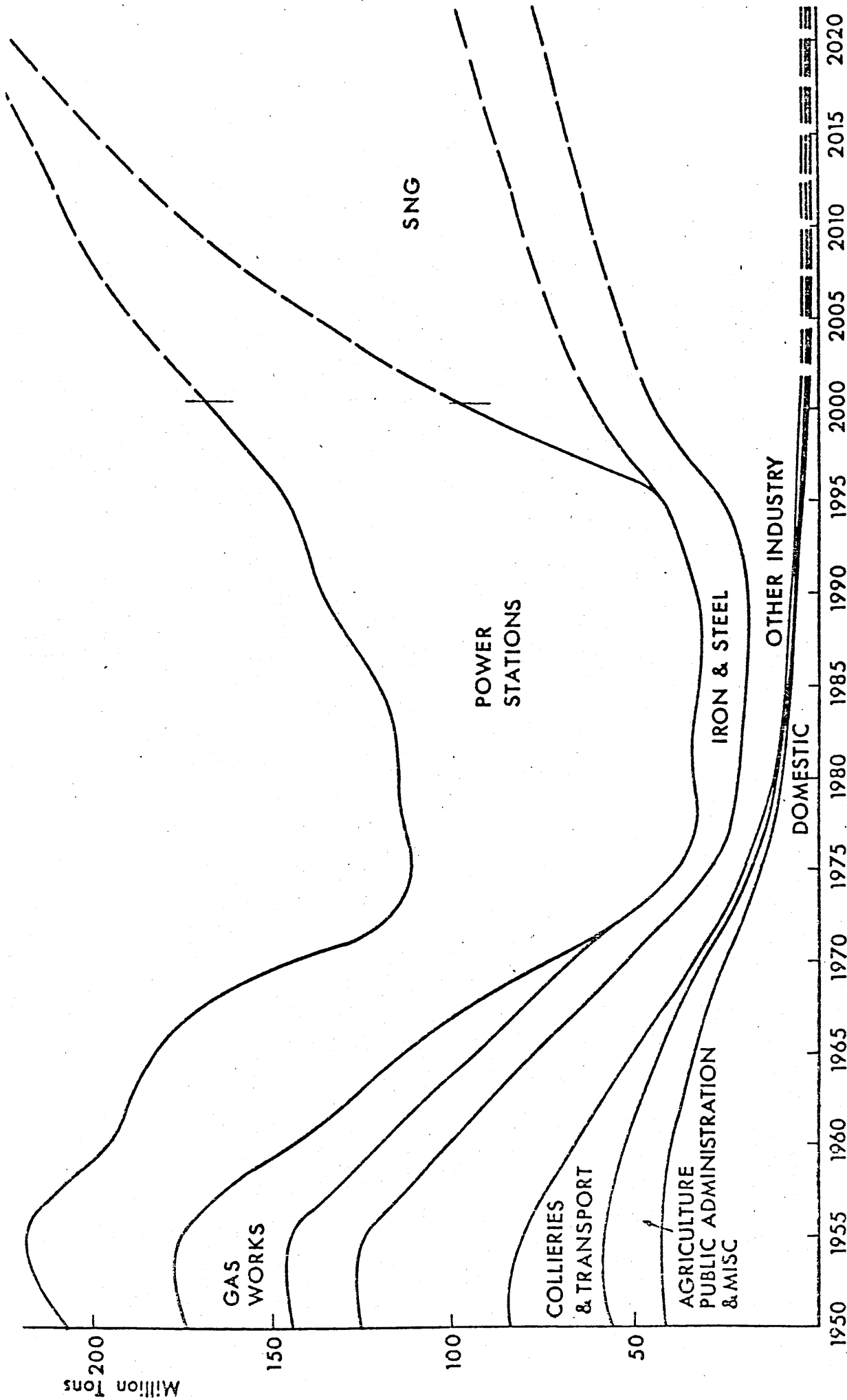


Fig.(1). MARKETS FOR COAL (assuming gas reserves of 1660bn m³ - 60 tcf).

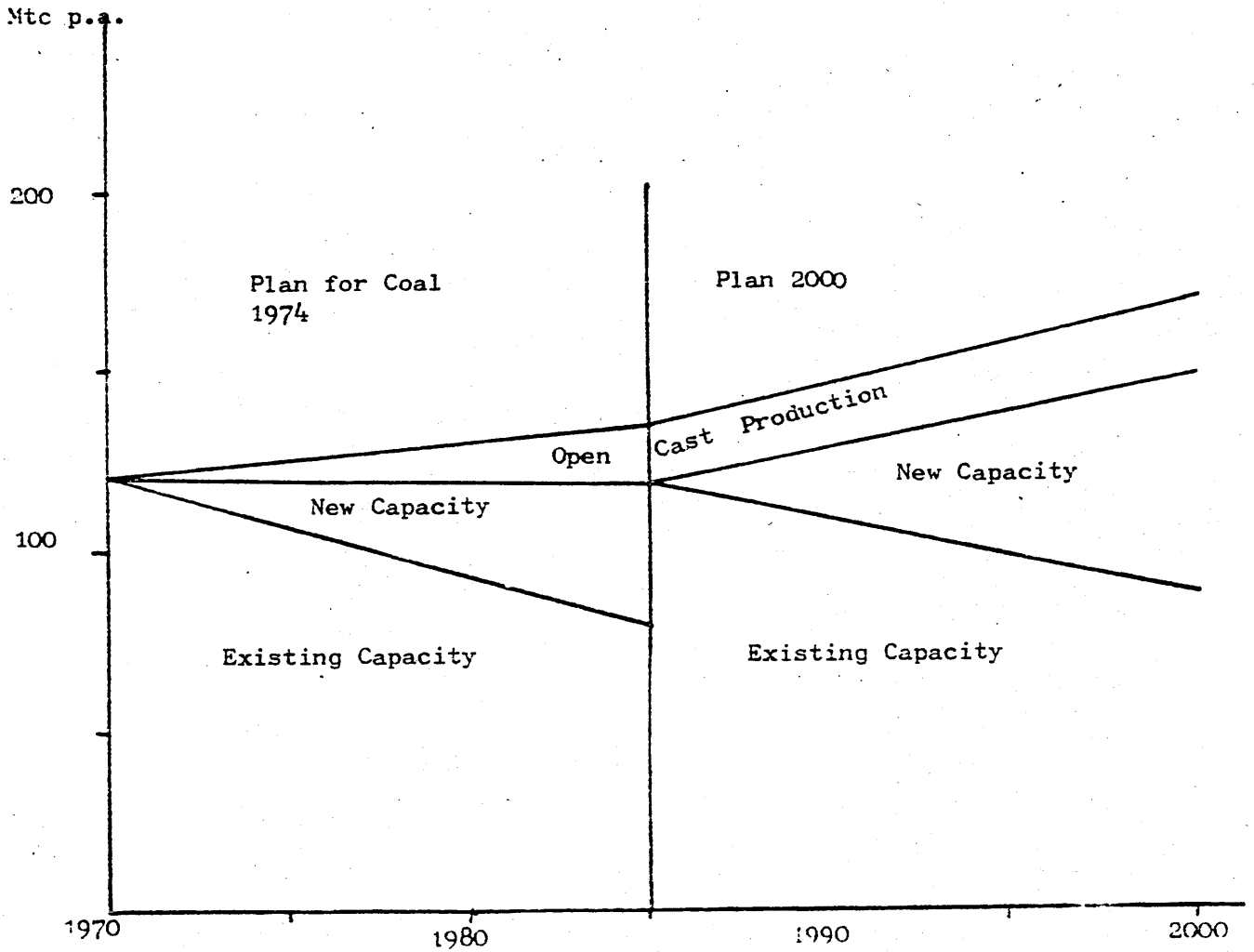


Fig.(2).

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CHAPTER IV

COAL GASIFICATION TECHNOLOGY

Resource requirements, efficiencies,
and by-products of SNG processes

A plant producing 2.5 billion m³/year (250 mcf) of SNG would require at least 6 million tons of coal per year (1). This will depend on the process and rank of the coal. This means a block of at least 150 million tons of uncommitted coal reserves would be needed to cover a 25 year plant lifetime. Also, a large supply of coal should be maintained in storage to guard against supply interruptions. The plant would consume of the order of 3 million gallons per day of water to the cooling systems.

A plant based on a once through water cooling cycle would require very large amounts of water. A considerable amount of water would also be used in the process as steam. In general this must be fresh water.

Manpower requirements for a typical coal gasification plant are not well defined, but for a 2.5 billion m³/year (250 mcf) plant maintenance and operating labour may be about 500/600.

Some of the gasifiers of the second generation type plants will be the largest pressure vessels ever built. For example, a Hygas commercial unit would require two reactors about 80 m high with an approximate outside diameter of 8 m (2). The vessel would require about 22 cm thick wall and would weigh about 1700 tons. An additional 10 per cent in weight would be added by the refractory lining.

The selection of materials for the aqueous systems requires careful consideration. The high temperatures and pressures leading to very intensive corrosive atmospheres require exceptional materials. Inorganic linings such as brick or cement can be considered, but most are limited by temperature. More expensive alloys such as Hastelloy C, Inconel 625, and titanium may be preferred to austenitic stainless steel or carbon steel in some applications, depending on the nature of the attack and the operating

(3)

temperature .

From an ecological point of view the gasification process removes sulphur and particulates before the fuel is burned and trace elements such as heavy metals are removed in the clean up process.

To avoid transport problems and costs to bring coal from the mine to the SNG plant, the plants would be best situated near the coal mine itself. The Trent Valley would appear an ideal setting for the first plants as this would be near to a plentiful water supply. SNG plants based on imported coal would be best situated near the ports of entry of the imported coal to avoid the costs of inland transport.

The efficiency of coal conversion processes to produce substitute natural gas is in the range of 65-75%⁽⁴⁾ by including the heating value of by-products such as oils, tars and sulphur. The thermal efficiency of the Lurgi process has been reported as 69%. This includes the heating effect of by-products.⁽⁵⁾ This compares with a recent assessment for the thermal efficiency of the Fischer-Tropsch synthesis of 70%, which includes energy consumed in mining the coal and allowance for export power and sulphur.⁽⁶⁾ The thermal efficiency of the synthoil process for the liquefaction of coal is estimated at 67.8%. The main product in this process is heavy fuel oil suitable for use in a power plant.

A recent development in coal conversion technology is the development of the 'coalplex' which involves the production of SNG in conjunction with other products such as methanol and ammonia.⁽⁷⁾ It has been estimated that if large amounts of SNG and synthetic gasoline are produced, such plants will be able to produce methanol, ammonia, and other products at higher thermal efficiency and lower capital cost than plants producing only chemicals from coal. The thermal efficiency of the South African Sasol plant co-producing gasoline and gas is 55%,⁽⁸⁾ but producing gasoline alone the efficiency is reduced to 35%. This cannot be rigidly compared with the Fischer-Tropsch synthesis efficiency as the efficiency parameters are different in each case.

Besides the product gas a standard SNG plant would produce as by-

(4)

products about 300/450 tons per day of sulphur (primarily as H_2S), 100/150 tons per day of ammonia as well as amounts of hydrogen cyanide, phenols, benzene and oils and tars.

Gasifier Types

Most of the interest in coal gasification has centred on substitute natural gas that could be piped economically over long distances. There are three types of gas - solid contact that are usually used. These are fixed, fluid and entrained beds. Fixed bed processes such as the Lurgi method have the coal fed in at the top. The coal moves downward, counter-current to the gas stream; oxygen and steam are fed from the bottom. The temperature at the bottom of the reactor is higher than at the top. Devolatilisation of the coal takes place at a low temperature and relatively large amounts of heavy liquid hydrocarbons are produced in the gasifier. Ash is removed from the bottom of the gasifier. In this type of reactor it is necessary to control the bed porosity to enable the gases to flow uniformly through the coal bed. The coal feed must therefore be of fairly uniform size and contain a minimum amount of fines. Recent research by BGC using the slagging gasifier has greatly increased the range of coals suitable for gasification. The residence time of coal in the reactor is much higher than in the suspension-bed type.

In the conventional suspension-bed reactor, solids and gaseous streams are contacted concurrently and high temperatures are required to achieve the complete reaction of coal and gases in short periods of time. The Koppers-Totzek and Bigas methods would be classed as conventional suspension-bed reactor types. To achieve a high temperature in the reactor requires relatively large amounts of oxygen. Ash is removed from the gasifier as slag. Operations of this type are not generally sensitive to the type of coal (noncaking or caking).

Fluidised bed gasifiers such as Winkler, Hygas, and Synthane allow intimate mixing and contacting of gas and solids and provide a relatively long residence time compared with a suspension-bed gasifier. The gasifying

medium, (oxygen, steam, hydrogen) is fed in at the bottom and acts as the fluidizing medium. Dry ash is removed continuously from the fluid bed.

Gasification using oxygen and steam produces a raw gas which after purification yields a synthesis gas consisting of carbon monoxide and hydrogen. This can be converted completely into hydrogen and this process may play an important role in the conversion of coal into liquid fuels by hydrogenation. Alternatively the carbon monoxide and hydrogen can be made to recombine in a number of different ways to produce, for example, liquid hydrocarbons (Fischer-Tropsch process), methanol (ICI low pressure process) or SNG.

The use of air instead of oxygen in gasification processes reduces the capital cost and increases the efficiency, but results in a low calorific value gas. This is because of the diluent effect of the nitrogen, and makes the gas unsuitable for synthesis and uneconomic for transmission over long distances. Higher temperatures favour synthesis gas production, (a mixture of CO and H₂) while at lower temperatures significant percentages of methane result. Strictly speaking the term 'synthesis gas' applies only to a mixture of carbon monoxide and hydrogen. In practice, however, it is now used to designate any primary gasifier off-gas even if it contains appreciable proportions of hydrocarbons.

Gasifiers may be operated either at atmospheric pressure or under elevated pressure. High pressures favour methane production and are also desirable in cases when the product gas is used to make chemicals from coal by a high pressure conversion process. One of the problems of pressure operation is the difficulty of feeding coal at atmospheric pressure into the pressurised vessel and of removing ash from the vessel. When producing SNG, pressures up to 65-70 bar can be required at the inlet to the transmission pipeline. Some of the treatment processes, such as CO₂ removal, also benefit from higher pressures. Pressure is likely to be required also in the end uses for the processed gasification gases.

Effect of coal characteristics
on conversion

The whole range of rank from lignite through sub-bituminous to high quality bituminous coal can be used to produce SNG. In wartime Germany brown coal was the feedstock and in South Africa a high ash coal, near the boundary line between bituminous and sub-bituminous coal is used. The differences of rank which permit good bituminous coal to command a much higher price in conventional uses because of its high heating value give much less advantage in conversion. The cost of the coal used is more important to the economics of the process than the quality of the coal as measured by rank. A lignite produced by low cost opencast mining could be a more economic feedstock than a good bituminous coal from a high cost underground operation. A process that can use any kind of coal is the ideal.

The use of caking coal is difficult in any of the processes that use heat to break up the structure of the coal because of its swelling and agglomerating properties. This may be overcome by destroying the caking property by pretreatment as in the Synthane process or by modifying the plant and applying close process control as at the Westfield Research Centre of British Gas. The melting point and general characteristics of the ash are important. Those processes that discharge the ash as a solid prefer ash of high melting point, while those that discharge a molten residue prefer ash of low melting point.

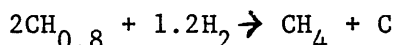
The quality of the coal has one direct influence on the cost of the products of conversion. A coal high in ash or in moisture will give a lower yield of hydrocarbons per ton of raw coal and therefore increase the unit cost of the product as against a coal of lower ash and moisture. In this case, all other things being equal, the better quality coal will have an advantage. In conversion to gas the process is less dependent on the properties of the coal than in conversion to oil, since the main function of the coal is to provide the carbon and the heat. For the production of SNG those coals with more volatile matter give a higher

proportion of methane in the synthesis gas produced by the first stage, and correspondingly simplify the final methanation stage. High volatile coals give a reactive char and permit the use of lower temperatures in the gasification process.

The Westfield Research Centre has tested a number of USA coals including sub-bituminous and caking in both the Lurgi and the slagging gasifiers. The Lurgi process can handle coals high in ash with a low ash fusion temperature and of high reactivity. Western USA sub-bituminous coals gave good results. The slagging gasifier has difficulty with coals of ash content above 15/20% if the ash is refractory and if the moisture is high. It prefers coals of low reactivity and low ash fusion temperature. The slagging process should be able to treat most USA and British coals.

Production of pipeline gas by hydrogasification plus methanation

Some recent gasification technologies employ the concept known as hydrogasification. In this system, the incoming coal is initially reacted in a reactor with a hydrogen rich gas to form substantial amounts of methane directly:



The hydrogen rich gas for hydrogasification is manufactured from steam utilising char leaving the hydrogasifier reactor. The key to the increased efficiency of the modern coal to 'high BTU' gas processes is hydrogasification in which appreciable quantities of methane are formed directly in the primary gasifier. The heat released by methane formation is at a high enough temperature level to be used in the steam-carbon reaction to produce hydrogen. Thus less oxygen is used to produce heat for the steam-carbon reaction and less heat is lost in the low temperature methanation step. These factors lead to a higher efficiency of methane production of 65-70% in contrast to 50-55% by synthesis gas methanation. The primary inefficiencies with the synthesis gas methanation method are 1) the methanation reaction is highly exothermic and 2) all the product methane is produced by catalytic methanation. Significant heat is released

from the process at this point, but this heat is released at such low temperatures that it is of little value for the rest of the process. Although some of this heat can be used to raise steam, much of the heat is discarded, constituting a process inefficiency.

Conventional gasification technologies

Lurgi

Lurgi is the only currently available fully commercial coal gasification technique being considered applicable to the production of synthetic pipeline gas. Other commercial processes such as Koppers-Totzek, and Winkler are unsuitable in that they operate at pressures only slightly above atmospheric pressure and have high oxygen requirements and low conversion efficiencies.

Commercial operation of the Lurgi fixed bed high pressure gasifier started in 1936 at Hirschfelde and made town gas from lignite. Thirteen (9) industrial plants have been built throughout the world. A recent one is the air blown unit for the combined gas/steam turbine power generation plant at Lunen, Federal Republic of Germany. As well as the Lunen plant there are commercial plants at Zaluži Most, Czechoslovakia (lignite) for town gas, and Sasolburg South Africa (coal) for synthesis gas.

The Lurgi gasifier is a reactor for the carrying out of counter current gasification of coal in a moving bed, under pressure, preferably at 20 to 30 bar (Fig.1). The high pressure non-slugging, steam-oxygen gasifiers are capable of producing up to $0.2 \text{ bn m}^3/\text{year}$ (20 mcf) of 16.5 MJ/m^3 (450 btu/scf) heating value gas at pressures up to 30 bar. In a one year testing programme completed in September 1974 at Westfield, Scotland, the feasibility of the methanation step using gas from a Lurgi generator was demonstrated. This unit produced an average of $.02 \text{ bn m}^3/\text{year}$ (2.0 mcf) at 37 MJ/m^3 (979 btu/scf) during the test (10).

Sized non-caking coal is fed by lock hoppers into the pressure gasifier and steam and oxygen are introduced below the grate at the bottom of the gasifier in amounts that will cool the grate and prevent clinkering of the ash. The grate is rotated and the ash is collected in a lock hopper from

which it is removed periodically. The coal is spread evenly over the entire bed by a distributor located near the top of the gasifier. Raw gases leave the top at about 850F and are scrubbed and cooled before further treatment (11). The coal at the top of the gasifier moves slowly down through different temperature 'zones' in the bed. Devolatilisation of coal occurs in the upper zone, gasification in the middle and chiefly combustion (oxidation) in the lower zone.

One of the advantages of this process is that the countercurrent flow of reactants in a fixed bed reactor allows the efficient use of the heat released during the oxidation of the coal, near the base of the gasifier. The hot gases transfer a large part of this heat to the incoming coal as they pass through the coal in the upper levels of the gasifier.

The disadvantage of the Lurgi system is that it requires a sized coal. Fines produced in mining must either find suitable outlets in other parts of the gasification plant or they must be briquetted to produce a suitable sized feed which adds to coal costs. Development work at Westfield has been aimed at methods to accommodate both caking coals and fines using (10) the slagging gasifier technique.

Fixed bed gasifiers of the Lurgi type are basically low throughput devices that require a large number of gasifiers occupying a large area. Production is only approximately $0.1 \text{ bn m}^3/\text{year}$ (10 mcf) of SNG per gasifier, compared with $0.8 \text{ bn m}^3/\text{year}$ (80 mcf) for newer processes. (10)

Lurgi have concluded that their present 20-30 bar is optimum for fixed bed gasification, particularly with regard to production of methane in the reaction bed and the 70 or more bar required for distribution of SNG as pipeline gas from coalfields to population centres could best be reached by supplementary compression. (12)

In the WESCO Lurgi project in the US, 30 gasifiers are required for a standard $2.5 \text{ bn m}^3/\text{year}$ (250 mcf) plant. This uses about 25,100 tons per day of sub-bituminous coal. Actual specific oxygen consumption is influenced by the coal's reactivity. It ranges (in units of $\text{vol O}_2/\text{vol}$

dry crude gas) from 0.1 for highly reactive lignites to about 0.18 for low reactivity blast furnace coke. Most coals fall in the range of 0.12 to 0.16.

The counter current mode of operation as applied in the Lurgi Pressure gasification process provides for optimum heat and mass transfer and consequently results in the very high thermal efficiency of better than 90%⁽¹³⁾. This is accompanied by low oxygen consumption, an outstanding feature of the Lurgi process. Because of the rather high efficiency of the Lurgi gasifier the overall efficiency of SNG production is about 70%

The British Gas Slagging Gasifier

The slagging gasifier is a logical development of the Lurgi gasifier which it both improves upon and complements. It operates under conditions under which no excess gasification steam is supplied and the ash melts to be run off as a liquid slag. This leads to a lower steam consumption, a higher output, a lower aqueous liquor production and an improved thermal efficiency. It will be particularly applicable to those coals which are of low reactivity and have a low melting point ash; coals which in a Lurgi gasifier require large quantities of excess steam to prevent clinkering of the ash.

The conventional Lurgi gasifier, using excess steam to avoid clinker formation, operates in the range 6.0 - 10.0 mols of steam per mol of oxygen⁽¹⁰⁾. For slagging operation the steam: oxygen ratio range is between perhaps 1.0 and 1.5 mols/mol. Changing from non-clinkering to slagging conditions results in a fivefold reduction in steam requirement⁽¹⁰⁾, which is one of the major reasons for a slagging gasifier being attributed with a high thermal efficiency. Under slagging conditions practically all of the steam supplied is used in gasifying the fuel and the amount of undecomposed steam is negligible. A higher output is possible when the undecomposed steam content is low. The higher temperature in the gasification zone will also influence the output.

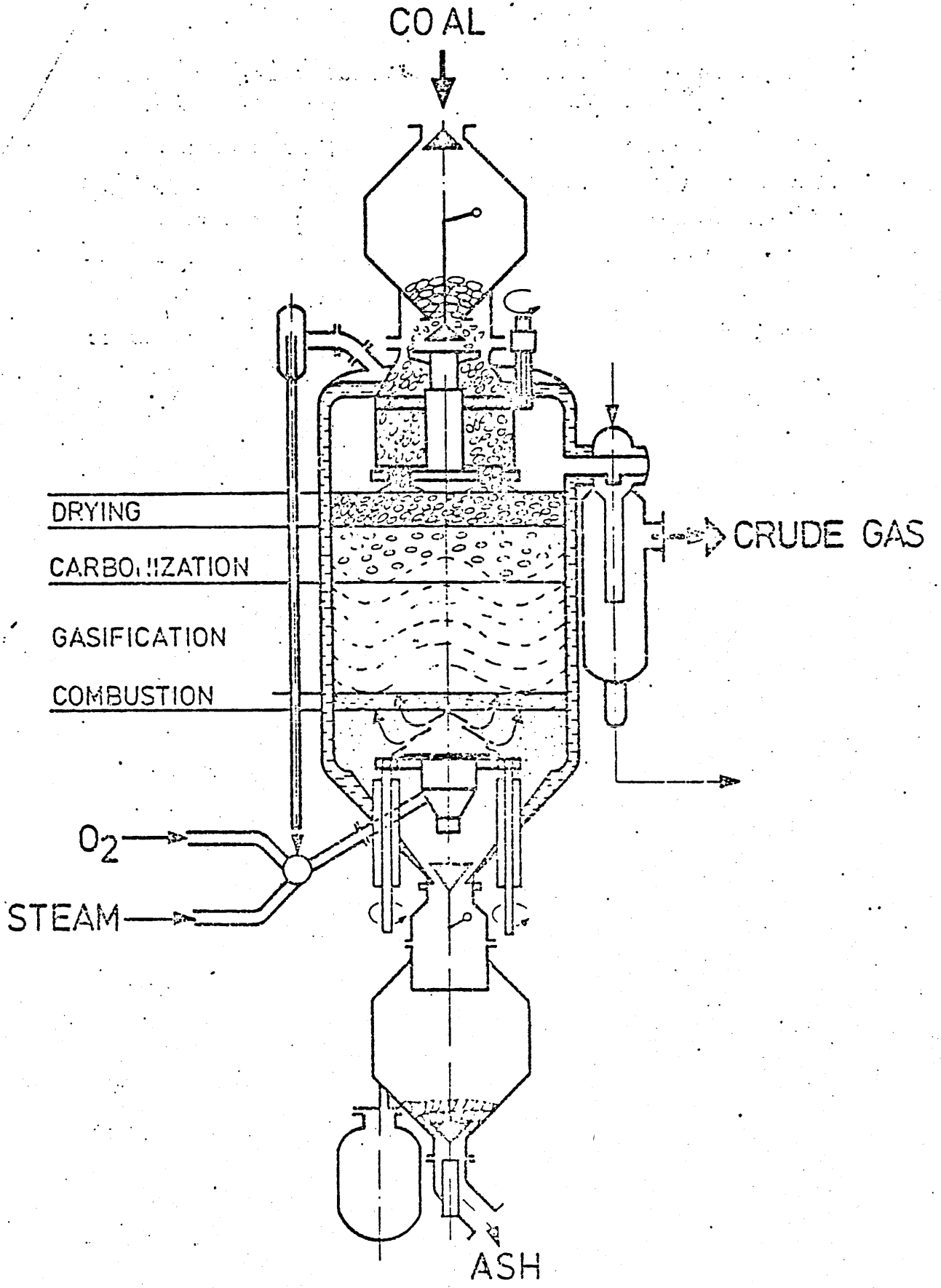


Fig.(1). The Lurgi Gasifier.

Fuel can be injected through the tuyeres into the high temperature reaction zone and ash is removed in the form of liquid slag through the tap and dropped into the quench vessel where it is removed as a glasslike frit. Operating conditions of the gasifier are 20-30 bar and about 1300°C⁽¹⁴⁾. The main feed is as lump coal through the lock hopper. The high pressure fixed bed slagging system has demonstrated a high volume throughput up to four times of that produced in a conventional system removing ash as a solid⁽¹³⁾. The slagging gasifier is also capable of handling coals with ash of high fusion point.

A potential disadvantage is that the oxygen consumption may be higher than with the standard Lurgi gasifier. This may be because the slagging reactions are slightly endothermic and absorb some of the heat liberated by the oxygen.

The coals tested at Westfield ranged from a US Western, non-caking, sub-bituminous coal from Montana to an Eastern strongly caking coal. The Eastern coals consisted of Illinois coal with a free swelling index of 3 and Pittsburgh coal with a free swelling index of 7⁽¹⁵⁾. All these coals were gasified successfully, throughputs tending to be lower with the higher swelling and caking coals and when gasifying finegrades. Steam consumption rose with increasing swelling number since this tends to be associated with decreasing char reactivity.

The Composite Gasifier

The British Gas Corporation have proposed a project aimed at extending the capabilities of their present high pressure slagging gasifier for the manufacture of SNG to utilise a greater proportion of fine coal and a wide range of coals and to maximise throughput. The project would involve the construction of an experimental slagging gasifier initially arranged to obtain relevant design and performance data, but with the ultimate objective of investigating and developing a system capable of handling both fine as well as lump coal. The development is foreseen as leading to the series coupling of a fully entrained or suspension gasifier to the base of a fixed

bed gasifier to form a single thermally and physically integrated unit known as the Composite Gasifier.

Essentially the entrained-flow fixed-bed composite gasifier is a unit for gasifying lump and fine coal with a mixture of steam and oxygen or steam and air. The unit is divided into two physically and thermally linked sections. In the first, coal is fed into a fixed bed where steam, oxygen and the gases from the second section are blown upwards through the bed. In the second section fine coal is blown into an empty chamber with oxygen and a minimum of steam where the coal is fully gasified at high temperature.

Advanced coal gasification technologies

Processes intended to improve on Lurgi as the basic gasification step are under development. These are Hygas (Institute of Gas Technology), CO₂ Acceptor (Conoco Coal Development Corporation), Synthane (ERDA) and Bi-Gas (Bituminous Coal Research, Inc.). However, the CO₂ Acceptor process is not normally regarded as a hydrogasifier.

All of these processes have the following common features:-

1. Continuous fluid-bed or entrained-bed gasification at elevated pressure equivalent to or higher than Lurgi.
2. More effective contacting of raw or lightly pretreated coal with hot, hydrogen rich gas at pressure to form more methane directly by hydrogasification of the coal than Lurgi.
3. The use of less oxygen, or none at all, in the production of the hydrogen-rich (synthesis) gas from the residual char remaining after the primary gasification step.
4. The need for a final catalytic methanation step to achieve a production of pipeline quality. The percentage of the total methane formed in this step however varies substantially from process to process.

The methane produced in the primary gasifier as a percentage of the total methane produced is an important parameter. In all of the above-

mentioned processes this figure is higher than the Lurgi process. For the Hygas process it can vary from 60% to 80%, the CO₂ acceptor process has a figure of 55%, the Bi-Gas method 48% and the Synthane process (4) 70%. These figures compare with the Lurgi process figure of 46%. The greater unit size envisaged for certain of these future processes and the availability of higher pressures for pipeline distribution are important factors in the operating costs.

A number of these more advanced processes require large volumes of hydrogen. These include the Hygas process and the Hydrane process developed by the US Bureau of Mines. If new coal gasification plants are built for SNG based on conventional Lurgi and advanced Lurgi slagging processes, then they could be regarded as hydrogen sources for the more advanced processes. This could help discourage progressive deferment of large plants based on available processes because of fear of economic obsolescence. Development of the advanced processes should mean a reduction in the number of gasifiers required to produce the same amount of gas as in the Lurgi process. Cost estimates for production of SNG by the advanced second generation processes are estimated to be about 25 per cent cheaper than cost estimates for SNG from the Lurgi process. However, it should be noted that the costs of conventional gasification can be calculated with some precision, due to the experience found in industrial installations, while estimates for the newer processes can be obtained only by extrapolating laboratory or semi-industrial scale results with all the uncertainty that involves.

Fig.2. shows the comparative investment breakdown for different pipeline gas processes (16). Investment proportions for coal preparation and gasification plus costs for oxygen and hydrogen range from 43.7% for Bigas to 72.4% for the CO₂ acceptor process, while the proportions for purification and methanation range from 8.6% for the Hygas oxygen method to 33.0% for Bigas.

Considering plant investment for coal feeding, gasification, power

recovery, shift conversion and oxygen plant, the Hygas steam oxygen process comes off best because of its predicted low oxygen consumption. The investment for the steam iron Hygas process is high because the addition of the steam iron reactor and associated power recovery equipment costs more than the oxygen plant they replace (17).

Investment in acid gas removal units is lowest for those processes (such as the CO₂ acceptor) using air instead of oxygen to produce raw gas of relatively low CO₂ content. Investment costs for the methanation step are highest for the Lurgi process as it is carried out at much lower pressures and the product gas must be compressed to the delivery pressure. Investment costs for steam, water and utilities shows that it is least in the case of the Hygas steam-iron process where steam and power are produced entirely by energy recovery. The Synthane process has the highest costs for this section of plant as it produces all the required steam and power by burning char produced in the gasifier (17).

(In one volume it is impossible to give full plant details of all the various SNG processes available. However, a full review of most processes may be found in references 1a to 9a).

Comparative Investment Breakdown for Different Pipeline Gas Processes

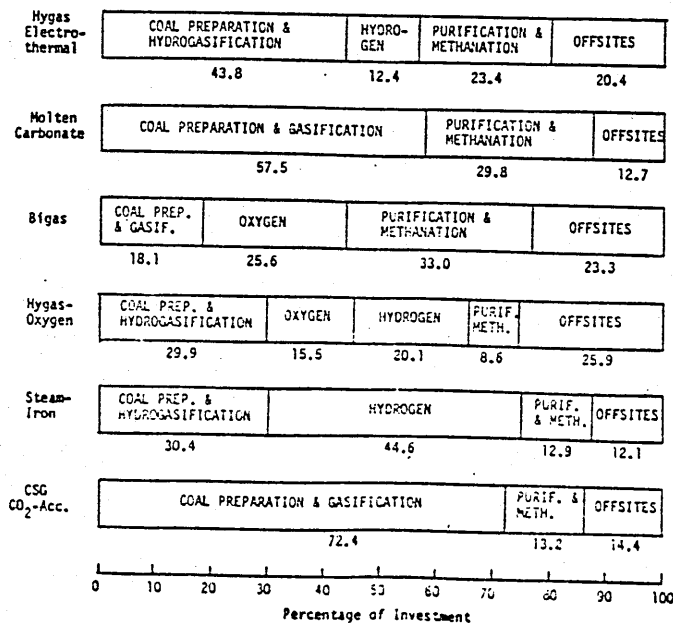


Fig. (2)

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CHAPTER V

UNDERGROUND COAL GASIFICATION

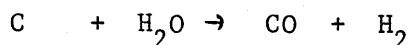
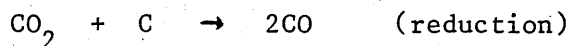
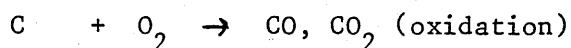
Underground coal gasification was first suggested by Siemens in 1868 and the first patent was granted in 1909 to Anson Betts with small scale experiments being conducted in England by Sir William Ramsey prior to World War I (1). The Soviet Union was the first country to seriously investigate the process of 'in situ' coal gasification. Extensive development work started in that country in 1933 and small commercial plants operated for some time near Moscow and at Yuzmo-Ainsk in Siberia (2).

Between 1945 and 1960 experimental work was carried out in the UK and the USA, but much of the work was exploratory with the only successful trial conducted in Britain at Newman Spinney in 1960 (3).

Only in the Soviet Union were two existing commercial-scale sites kept going producing gas in sufficient quantities to generate 100MW of electricity at each site, as most of the other work ceased due to the abundance of cheap oil and natural gas in the energy markets in the 1960's.

Since about 1971 there has been renewed interest and the US Bureau of Mines revived experimental work on UCG near Hanna in Carbon County Wyoming (1).

The chemical reactions which take place in the process of gasification are as follows:-



In the combustion zone carbon and some of the tar and volatile hydrocarbons are burned to produce a high temperature gas stream containing CO₂ and water vapour, which react in the gasification zone. The combustion and gasification zones advance into the coal seam as burning occurs, leaving a void in which the unsupported roof will eventually fall.

Lignite and sub-bituminous coal seams with an inherent moisture content of between 10 and 40% are considered to be the most acceptable for successful 'in situ' gasification as these coals generally have adequate permeability for air linkage.

If successful UCG would extract coal energy without extensive mining thereby vastly increasing the recoverable portion of coal resources. Such a process may lower the capital investments and operating costs than required for mining. The environmental impact of UCG would be different to conventional mining. With present technology a borehole would be required every 30m so that even for a small site capable of providing gas for a 100 MW generating station, 20-50 hectares of land would be in use per year ⁽³⁾. This is about six times that covered by the average British opencast site. On the other hand most of the pollutants from the underground process would remain in place and the wastes and hazards of underground mining would be avoided. UCG would use less water and can use poor quality water which reduces the competition for drinking and irrigation quality water.

UCG can access around 80% of the coal in place. With about an 80% conversion efficiency (80% of the energy in the coal is recovered), the overall efficiency is some 65% ⁽⁴⁾. The gas produced is dirty and of low calorific value. Normally this has been about 4-5 MJ/m³ which is far below the 20 MJ/m³ of the old town gas made by carbonising coal in retorts. Recent evidence before the Select Committee on European Communities (Coal) ⁽⁵⁾ has indicated that much of the gas generated by underground gasification leaks away and has a low calorific value.

To upgrade this low calorific value gas two methods may be used. These are to use gasifying agents other than air, or to treat the gas on the surface. If oxygen was used instead of air, the calorific value could be doubled, but the scale of oxygen use (about 2000 tonnes/day for a 100MW site ⁽³⁾) would be such that the final gas cost would be much higher. Treating the gas on the surface would appear to be the more economic option.

(6)

The NCB study found that although SNG from UCG is uneconomic compared with natural gas, costs are of the same order as those from surface gasification plants. There is not a great deal of coal within or near existing coalfields which is potentially suitable. The table shows a comparison of the economics for UCG with surface gasification (SG) done by two separate studies. In each case the final gas cost by UCG is less than the final gas cost for SG. The coals used in the Gulf study by Garon were Illinois Eastern, moderately swelling bituminous coal about 3m thick and 183m deep, and Western Rosebud sub-bituminous coal about 9m thick and 183m deep. The coals used in the Bechtel Corporation study were 9m thick Western coal about 107m deep and 1.8m thick Eastern coal about 305m deep.

TABLE 1

	<u>SNG selling price using Eastern coal (\$/GJ)</u>		<u>SNG selling price using Western coal (\$/GJ)</u>	
	<u>UCG</u>	<u>SG</u>	<u>UCG</u>	<u>SG</u>
Gulf Study	2.27	3.28	1.49	2.37
Bechtel Study	4.77	5.28	3.34	4.38

Problem areas

Combustion control is essential to control gas quality and yield. Contact between coal and reacting gas should be such that production of CO₂ and H₂O is minimised, and all free oxygen in the inlet gas is consumed and so is the coal. These conditions are best approached at the beginning of any run, but heating value decreases as time goes on. This trend reflects increasingly poor contact of gas with coal resulting from large void volumes from dissipation of heat through adjoining strata and from roof collapse. Roof collapse may result in gas leakage, surface subsidence and seepage of ground water into the coal seam. The major proportion of costs would be in drilling, representing about 60% of costs. Increasing the borehole spacing from the present average of 30m to around 60m may reduce costs substantially.

UCG Projects in Belgium and the USA

Full scale work was begun in July 1978 on a 1000 metre deep 'in situ' coal gasification project at Thulin in the Hainaut Province, South West Belgium (2). The scheme has been put forward by the Belgian Institut National des Industries Extractives to exploit their coal reserves at depths considered unminable by conventional means (9). The method makes use of high pressure air which should allow high flow rates through small diameter holes so keeping down the drilling cost. The disadvantage of gasification at great depth is that lower porosity derived from greater pressures reduces permeability; this problem is expected to be solved by fracturing the coal seam prior to ignition. The compensating factors of deep gasification are reduced ground water infiltration and gas leakage which cause problems in underground projects at shallower depths.

The first stage is to inject air into the ignited seam and if successful a gas with a calorific value between 3.4 and 4.2 MJ/m³ will be produced. The second stage is to inject pure oxygen and is expected to bring the gas to a calorific value of between 5.0 and 6.3 MJ/m³. The third and final stage is to add hydrogen and should result in a gas with between 29.3 and 33.5 MJ/m³, comparable to natural gas (2).

In America the Lawrence Livermore Laboratory under the US Department of Energy have carried out tests in Wyoming and Montana on coal at depths from 165 to 1000m (10). Chemical high explosives are used to break up large coal zones into permeable rubble which forms underground packed beds. The broken coal is gasified by injecting steam and oxygen at the top and withdrawing the product gas from the bottom. The calorific value of this gas is less than half that of natural gas.

The Morgantown Energy Research Centre of the US Department of Energy is developing the concept of the co-flow generator to gasify Eastern US coals (10). This idea uses boreholes drilled downward from the surface and curved to run almost horizontally within the plane of the coal seam. Using natural cracks in the coal and additional vertical wells if needed, the

coal between the deviated wells is gasified by injecting air to make a low calorie gas. The reverse flow stream generator concept has been used in the USSR (11) and the number of vertical wells is reduced and so concern over roof collapse is minimised. In this case a third directional well is used and the reaction zone is allowed to progress back towards the air injection post. One vertical well at the end of the injection well replaces the two required by the co-flow concept.

Some future developments

'In-situ' methods of energy extraction will demand the development of new technologies. This may be for underground coal gasification techniques on land or even for the extraction of energy in coal seams under the North Sea. 'Hydrofracking', the loosening of strata by hydraulic pressure, is one technique which may be used so that gases and liquids necessary for the process may interact more smoothly. The operation of deep underground control bases may lead to safety problems in some cases, especially in situations of great depth perhaps at 1300m where the strata temperature may be 50°C. (12) The development of mine pressurisation techniques may be the answer especially if relatively few personnel are involved. If the extra pressure was achieved by the addition of inert gases then men and machinery could work in complete safety as no concentration of methane could form an explosive mixture in such an atmosphere.

Although the use of laser drilling systems is quite speculative, the use of an infra red laser tuned to the absorption frequency for methane would be particularly useful in improving safety in deep mining situations.

Although the NCB 1976 study concluded that it was presently uneconomic to develop UCG technology in the UK, this may not always be the case. It could well arise that the price of coal for surface gasification (SG) plants could be so prohibitive, due to the slowness to change from old uneconomic pits to modern automated Selby type pits, that UCG may become a better proposition than relying totally on coal imports to supply SG plants. The political implications of too heavy a reliance on imports are

well documented in the case of oil, and may act as a deterrent against any temptation by the coal industry to become too reliant on imports. The continuing research effort required to develop 'in-situ' methods for extraction of coal energy from normally inaccessible areas, such as beneath the North Sea, should help to keep this technology in readiness to further develop if it becomes economically viable in the light of future energy developments.

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CHAPTER VI

WORLD COAL TRADE AND MARKETS FOR COAL

Coal Imports

Suggestions have been made that our energy problems could be helped by importing cheap coal from abroad. The world coal price of about \$30 per ton is about half the EEC average of \$65, while the UK price stands at about \$45 per ton . The CEEB (1) (2) have indicated that they will give consideration to importing cheaper foreign coal if NCB coal is not competitive. However, there are powerful vested interests preventing a thorough examination of the idea of importing coal to the UK and EEC, including German mine owners and the unions in Germany and the UK. It has been predicted (1) by BP and Shell that imports to Europe by 1985 could be 120 million tonnes. As well as the CEEB and BP and Shell, the National Coal Board has also considered the possibility of importing coal. There are many opportunities in the world for mining coal more cheaply than in Europe; the big oil companies are exploring for coal in the USA, Canada, Australia, South Africa, Indonesia and Latin America.

When considering coal imports it should be remembered that there are many other countries importing much more coal than the UK. In the UK imports of coal between April 1977 and March 1978 came to 2.66 million tons (3) . Japan, France, Canada, Italy and the USSR together in 1977 accounted for over 120 million tons of coal imports, which is over half (4) the total world imports of anthracite and bituminous coals . Those countries importing in excess of 5 million tons per year were Belgium, Federal Republic of Germany, Bulgaria, The Netherlands, GDR, Czechoslovakia, Denmark. For those countries importing in excess of 2 million tons per year the UK comes fifth after Finland, Spain, Brazil, and Yugoslavia. The UK is thus 17th in overall placing of world coal importers. The possibility of coal imports cannot be looked at in isolation without considering the overall world potential for exports and the general world energy

supply and demand situation.

Coal exports

It is generally assumed that the increase in world coal trade in 1977 was attributable to three factors - 1) increasing steam coal exports, 2) new mine production capability, 3) global stability of metallurgical coal demand. Peters and Schilling (5) have pointed out that if sufficient incentives are provided then it is technically possible to increase world coal production from 2.59 thousand million tons in 1975 to 13.06 thousand million tons in 2020. This figure is about 5 thousand million tons higher than that resulting from the present plans of individual coal mining countries. The additional quantity of coal amounts to 40% of total world coal production. If this was to be available for export then suitable infrastructure (5) and effective transport facilities would be necessary. The ease of mining this coal may to some extent be offset by the enormous investment needed in roads, railways and ports. The strong energy self sufficiency (6) policies of many of the coal exporters may affect exports to a certain extent, but most coal producers believe that the lack of economic incentives is the main obstacle to increasing coal outputs and exports. Producers may not be disposed at a time of surplus to develop new sources with all the capital investment in infrastructure and mines without an assured market.

The recent increase in the exports of coal from South Africa have coincided with the opening of the new port at Richards Bay. Coal exports from South Africa more than doubled in 1977 from what they were in 1976. France was the principal South African coal export market followed by Japan, Italy and the USA. It is significant that the Transvaal coal owners association considers the more significant increases in South African coal exports to be in Israel, South Korea and Taiwan as well as Japan and South America. They estimate coal exports of about 40 million tons to Israel (7) and Taiwan by the mid-1980's.

The world's exports of anthracite and bituminous coals come from Eastern Europe and the Soviet Union (34.4%), North America (30.9%),

(4)
 Africa and Oceania (24.3%) and Western Europe (9.0%) . While the
 US, USSR and China are all expecting large increases in total production
 (8)
 only a restricted growth in exports is projected . USA coal exports to
 Europe declined by 25% in 1977. This marked drop is due to several factors
 including the lower steel demand, environmental opposition to coal, labour
 problems and restrictive government and stage regulations. In 1977 coal
 exports from Poland achieved a record level with principal export markets
 as USSR, France, Finland, Italy, Czechoslovakia and Denmark. An unknown
 quantity will be the effects of the new and large coalfields planned in
 Colombia, Venezuela, Mexico and Iran. Some of these countries also have
 plans for new steel industries. Following from this a proportion of the
 new production will be placed on the world market and there will be imports
 of coking coal into these countries for the steel industries.

(4)
Principal World Coal Exports
(thousand metric tons)

	<u>1960</u>	<u>1975</u>	<u>1977</u>
USA	34,456	60,238	49,318
Australia	1,584	30,428	35,527
South Africa	950	2,687	12,705
Poland	17,497	38,348	39,210

World energy demand and supply

Future world coal trade, both imports and exports will be influenced by the general energy demand and supply situation throughout the world.

There have been many reports produced over the last two years concerning the general world energy supply and demand with particular emphasis on oil. In 1977 there were the WAES (9) , OECD (10) , and CIA (11) , reports which all indicated that world oil demand would outstrip supply sometime in the mid to late 1980's. The WAES study predicted that by 1985 the non-Communists world oil demand would be 60 million barrels per day. It

assumed that the Communist world would be self-sufficient and it predicted the demand for OPEC imports to be in the range of 36 million to 39 million barrels per day. The OECD study predicted a world demand for OPEC oil of 35 mbd by 1985. The CIA report put demand for oil in the non-Communist world at 70 mbd by 1985. This report assumed a 25 mbd supply from outside OPEC leaving a demand for OPEC oil of 45 mbd. This gave a total OPEC demand of 50 mbd with a projected OPEC production capacity of 38 mbd. Considerable doubt has arisen since these reports were published about the urgency of the supply problems predicted by them to arise in the mid-1980's. These doubts arise because of the slower rate of economic growth in the industrialised world than in the past. This is due to higher energy costs and other factors such as a slower population growth. Slower growth in energy demand will result also from a reduction in the energy/GDP ratio away from a 1-to-1 ratio.

(12)

A more recent CIA report has indicated enough recoverable oil in the world to maintain current consumption rates for 60 to 90 years. The giant US Exxon Corporation have predicted a considerably lower rate of growth for energy demand for the 1980's compared to their prediction of 1977. Their two estimates are compared as follows:

(13)

	<u>USA</u>	<u>Europe</u>	<u>Japan</u>
1977 estimate	2.8%	3.4%	4.0%
1978 estimate	2.3%	2.9%	3.9%

(14)

The Petroleum Industry Research Foundation also predict that OPEC production will not have to rise greatly to satisfy world demand in 1985. The World Bank has predicted more oil supply will be available and taking these reports together it is clear that the oil supply problems expected in the 1980's may not reveal themselves until the 1990's. However, there is always the possibility of the unexpected happening, not least in the political sphere where the recent troubles in Iran could lead to another re-appraisal of the whole world oil supply situation. If we ignore for the

(15)

(16)

present analysis these exceptional events and base predictions on normal supply and demand cycles, then with the more optimistic outlook of the latter reports regarding world oil supply, the pressure to increase world coal trade may be reduced for the time being. Sir Derek Ezra in his book (17)

sets US coal exports at around 100 million tonnes as a maximum, while the WAES report assumes coal exports will be much higher.

Markets for coal

Proportion of coal-fired electric plant

The CEEB has under construction about 12GW of capacity consisting of 6GW of oil-fired plant, 4GW nuclear and the 2GW Drax coal-fired plant.

All of the CEEB large oil-fired stations are relatively new and will not be scheduled for retirement until the late 1990's. The proportion of nuclear power throughout the whole UK is steadily growing and it should rise from its present level of about 12% to 20% when all the AGR reactors (18)

are on stream. Between now and the mid-1980's about 3GW of old coal-fired plant will be closed down. The proportion of coal-fired plant will fall from 65% in 1976 to about 51% in 1980 for the whole of Britain (19)

, while for the CEEB alone the estimated percentage of coal-fired plant in 1980 will fall to 63% from a level of 72% in 1976 (20)

The age and relatively low efficiency of much of the coal-fired capacity will have two main disadvantages. The coal price advantage over oil would have to be considerable to make it worthwhile for the CEEB to give preference to the inefficient coal plant. Also, the 4GW of nuclear plant will be base load power which will displace some of the coal-fired plant which will result in a reduced coal take.

Coal/Oil price relativity

If present price relativities between coal and oil were to continue the CEEB would burn in 1984/85 about 75 million tons of coal. If coal prices were to increase more rapidly than oil this figure could be as low as 64 million tons of coal (21). With some Government subsidies the electricity coal burn may be maintained to suit the NCB up to 1990.

The CEEB forecast of 65 million tons of coal a year by the mid-1980's (22)

appears more realistic than the 85 million tons of the Government green paper on energy policy (23). This would be a result of a reduced percentage of coal-fired plant, an increased nuclear component displacing some coal plant from base load, with a consequent reduction in coal burn, and an insufficient price advantage of coal over oil because of considerable coal supplies still coming from high cost low productivity pits over the next ten years. An additional factor could be that the CEEB may want to avail itself of cheap coal imports.

Productivity & new high technology mines

The price competitiveness of coal is linked to productivity and increased mechanisation of pits as at Selby. Productivity at the Royston pit is projected at 7 tons per man shift compared with the NCB national average of 2-3 tons per man shift (24). Productivity at pits receiving 'Plan for Coal' investment is already about 24% higher than average for the industry and this will rise to about 60% on completion of the investment projects (25). It may be 1988 before the whole of the planned 20 million tons of new mine capacity is in production. While this will gradually reduce the losses through exhaustion of some of the existing 80 year old pits, the development to mechanised Royston and Selby type pits may not be fast enough to prevent coal price rises making coal an unattractive proposition for the CEEB. As well as the 'Plan for Coal' for the introduction of 40 million tons of new capacity up to 1985, from 1985 to 2000 the NCB estimate the need to be about 60 million tons of additional new capacity (26). By this time two-thirds of the industry's deep mined output could be coming from completely new high technology mines at rates of production 3 or 4 times the present national average.

Subsidies

Subsidies from the Government for NCB stocks, the Drax plant and Scottish and Welsh coal may help in the short term, but it is important for the NCB that these subsidies do not become a permanent feature of the coal industry. Every effort should be made to increase the rate of installation of new modern pits and to increase the closure rate of old

inefficient pits. The same can be said for the proposed EEC subsidy to take effect for three years from 1st January 1979⁽²⁷⁾. This is for a sales subsidy of about \$12 per tonne on 12 million tonnes of Community coal sold in intra Community trade. The subsidy should cover a substantial part of the price gap between EEC and third country power station coal.

Cheap imports

The question of cheap coal imports is another possible problem for NCB in spite of temporary EEC subsidies. The SRI World Energy Study, reported in the Financial Times European Energy Report⁽²⁸⁾, predicts that while France and Italy may eventually import about 90% of their coal needs by 2000, with West Germany importing about a third, the UK imports would be about 10% of coal needs. This may be influenced by the fact that the UK present coal-fired electricity generating capacity is located near the mines rather than on the coast. Germany presently subsidises its coal industry heavily as production costs can be up to \$70 per ton as against \$30 to \$36 for imports⁽²⁹⁾. So Germany will be a major coal importer in Europe along with France. At the moment there are few ports in prospective coal exporting or importing countries capable of handling ships with a capacity of 100 000 to 200 000 dwt which is the optimum size for world coal trade. In Europe few ports can handle bulk carriers of over 80 000 dwt. the only exception being Rotterdam. While undoubtedly world trade in coal will grow, the rate of growth may be reduced with the general reduction in world oil demand and a lowering of the energy/GDP ratio taking effect⁽¹³⁾⁽¹⁴⁾⁽¹⁵⁾. This may temporarily reduce the urgency to greatly increase coal imports until the 1990's.

Coking coal

Another problem is the cut back in coking coal requirements by the steel industry which has meant a loss of several million tons per year to the NCB. Sales of coking coal in 1977/78 were only 14½ million tonnes - over 3 million tonnes less than the previous year. Britain has had to import small amounts of coking coal to satisfy the steel industry. New reserves

of coal suitable for coking have been discovered. The demand for coking coal is expected to be strong for many years to come and a world shortage of this type may develop. The new deposits may enable sizeable import contracts to be avoided. Opencast mining is an essential source for some coking coals and smokeless coals, and also is a source of good quality steam coal to mix with the output from deep mines to produce a marketable quality of coal. The opencast executive of the NCB is being charged with increasing production from 11 million tons to 15 million tons by 1980. The industry foresees opportunities to raise production beyond that point (30) to some 20 million tons a year in the 1980's .

Cross-channel electric link

An attempt to improve the markets for coal has been the recent decision to construct a cross-channel electricity link between the UK and France which will enable the CEGB to burn up to 1 million more tonnes of coal a year (31) . The expectation is that the CEGB will be able to export coal generated electricity during the night and thus about 1 million tonnes of coal will displace an equivalent amount of oil burned in UK power stations. However, when the French system takes on an increased nuclear capacity in the future the rough equivalence in costs between oil and coal-fired electricity on which the scheme depends could be upset.

Industrial and domestic sectors

The present level of coal use in the industrial market is around 11 million tonnes (22) . New techniques for coal burning such as the shallow bed fluidised bed concept may help to reduce the relative capital cost of coal plant. The domestic market also stands at around 11 million tonnes (22) , although solid fuel will continue to be under intense competition from the sale of gas fires.

There is also the question of the effects of the cost inflation likely to be caused by the substantial wage claims pursued in the coal industry. (32) It has been estimated by EML that if, as a result of very large wage claims, coal prices were to rise somewhat faster than inflation then coal

demand by 1985 could be as low as 105 million tonnes.

Off-peak electric sales

There is yet another factor which may have a profound effect on coal burn and that is the sales of off-peak electricity. Until 1990 at least winter off-peak electricity will be produced by coal-fired power stations (33)

The costs of producing off-peak electricity will be directly related to the price of coal. Domestic off-peak electricity sales were 28% lower in 1977/78 than in 1973/74, which compares with general domestic electricity sales which were 7% lower in 1977/78 than in 1973/74 (34). A reduction in the off-peak electricity market would mean a further reduction in the need for coal-fired plant.

Considering these factors together there is a strong likelihood that the projected coal burn in 'Plan for Coal' of 135 million tonnes of coal by 1985 will fall short of its target by about 15 to 20 million tonnes. The real question is to know what happens after 1985. The coal can be produced but it will not have a market unless coal gasification plants are built. This would be enough for at least 4 coal gasification plants each producing 250 mcf/d. The implication of reducing the amount of coal-fired electrical plant and using this proportion of coal supply in gasification plants would leave the way open for a steady build up of nuclear capacity to about 30-40 GW by 2000AD (33). This would ensure the future of the nuclear industry at the same time as satisfying the coal industry by giving it another more efficient use of coal. Coal gasification plants would be able to provide an export potential as many other Western countries will have an oversupply of electrical capacity. Already the British Gas Corporation is working with American consortiums with a view to setting up coal gasification facilities in the USA. Lucas (35) has estimated that producing SNG throughout the year and storing it works out much cheaper than the cost of developing gas supplies from hostile and distant waters in the North Sea.

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CHAPTER VII

A SECTOR ANALYSIS OF DOMESTIC GAS MARKETING

The UK consumption of natural gas has increased four-fold over the last 20 years. In the past 10 years gas consumption has grown at the rate of 15% per annum compared with a growth of total energy consumption of just over 2%.

A total of 15.1 bn therms of gas was sold by the British Gas Corporation during the 12 months ending in March 1978. This compares with 13.8 bn therms sold in the previous year. The British Gas Corporation forecasts sales of over 18 bn in 1982-83 (1)

As well as supplying a large sector of the domestic market, gas now supplies about 25% of industrial energy needs compared to 4% in 1965. Industrial gas sales now assume a major part in excess of 40% of all gas sales (2). In terms of numbers this means that some 70 000 of Britain's 14.5 million gas users consume nearly half of all the gas sent out. However, the impact of gas in the domestic market has been the most drastic. The existing gas share of the total domestic energy market is more than 43% (3), and this is expected to rise to over 50% by 1980 (4) reaching 55% by 1986 (5).

The gas share of the total energy market within the gas supply area (6) has continued to rise and is now 79% for all sectors including domestic, industrial and commercial. For the central heating market the gas share (6) in the GSA has increased from 75% to 90% between 1973 and 1977. The increased use of natural gas in the domestic market has, by displacing less efficient fuels, been instrumental in holding total heat supplies relatively constant. Domestic sales went up from 6.1 bn therms in 1976-77 to 6.9 bn therms in 1977-78, while industrial sales went from 6.1 bn to 6.4 bn and commercial sales rose from 1.5 bn to 1.7 bn therms (1). Domestic sales rose by 12.6% at a time when comparatively few new houses were being built and when modernisation programmes were operating at a depressed level. Much of the extra gas sold to domestic users during 1977-78 was for central heating

with more than half a million new gas fired installations completed during the year. Table 1. illustrates the growth of the domestic gas fired boiler market (7)

The four sector domestic market

Fig.(1), Fig.(2), and Fig.(3) illustrate the growth of the total central heating market in the sixties and seventies. Fig.(1) shows that the market was dominated in the early sixties by the rapidly growing rate of installations in privately owned existing homes. Following the adoption of Parker Morris standards in 1967 there was a trend towards 100% installation of minimum heating standards in new local authority housing. By the early seventies the total market would have started to decline but for the rapid growth of existing local authority housing. During 1972-74 there was an upsurge in local authority modernisation schemes and an upgrading of housing stock which more than compensated for any decline in any other sector. In 1974 and 1975 the recession and the cutback in capital expenditure by local authorities is shown as a downturn in the market, which together with a decline through saturation of the owner occupier market led to a reduction in the overall market. Fig.(2) shows the gas share as a percentage in each market sector, and Fig.(3) shows the total growth in all types of central heating. The new local authority sector has not yielded anything like the same market penetration for gas as the existing local authority, the existing owner occupier and the new owner occupier sectors. There appears to be considerable competition between gas and electricity in this sector with each seeking to maximise the return on expensive capital investment. Those responsible for the installations in new local authority houses do not necessarily authorise installation of the type of central heating that the user may prefer, who may have little choice. Decisions made by the local authority on central heating installation are based on other factors such as capital costs, speed of installation, political considerations etc. It is significant that

the running costs of the central heating installations do not have to be met by the local authority.

Of the 16 million houses in gas supply areas in 1976 nearly 50% had some form of central heating. As about two-thirds may have reasonably modern heating systems this limits the potential from existing houses for first acquisition gas central heating. The existing owner occupier market has about 40% of dwellings still without central heating, i.e., about 3½ million houses. Also, about 60% or 3 million local authority houses (4) have no central heating. The rate at which these dwellings in gas supply areas will acquire central heating, if ever, since about half were built before 1914 will depend on whether local authorities have funds for modernisation. In the owner occupier and detached houses the levels of saturation are very high. The main potential will now be in smaller pre-war houses or flats occupied by middle-aged and working class (9) customers. Nearly half of these dwellings are owned by local authorities.

The growth of the domestic market could undergo a considerable slowdown in the early 1980's and by 1990 a situation of static gas sales could be reached with low energy gas heating housing gains being offset by the displacement of older gas central heating installations, fires and water heaters, either by demolition of properties or by replacement with more efficient future gas heating systems.

Replacement market

In the replacement market about 2% of gas central heating systems are purchased to replace a gas system. About 25% of gas fire sales, (4) 60% of cookers and 33% of water heaters replace existing gas appliances. The motives for replacement sales are complex and are based on considerations such as lifestyle and not just technical obsolescence, and not least 'real' income levels. In gas central heating the number of replacements at present is small but will start to build up to significant levels by the mid-1980's, and by 1985 the number of gas central heating replacements could well exceed first time acquisitions. Fig.(4) shows the possible sales

of replacement central heating systems for gas assuming an average life span of 15, 17 and 20 years (9)

There is a real potential for gas to replace oil, solid fuel and electricity in existing homes having central heating systems. There are about 3 million such homes in gas supply areas and about half have electric central heating (9)

<u>Homes owning (GSA)</u>	<u>'000</u>
Electric central heating	1596
Solid fuel central heating	957
Oil central heating	439
	<hr/>
	2992

About two thirds of the electric potential replacement exists in owner occupied homes of the small type (9). In the long run these will change to full gas central heating as incomes increase and houses change ownership.

Replacement gas fire sales may reach about 50% of total gas fire sales by the early 1980's. Gas fires have become a major market over the past 15 years with sales rising to over 1 million appliances per annum at one time, mainly the radiant convector type (10). Since peaking in 1971 there has been a considerable reduction and recently out of 13.4 million homes with gas there were 11.4 million gas fires in 9.7 million of these homes (10). Part of the sales drive for gas fires is built on the replacement of solid fuel fires. Solid fuel is now used in less than one quarter of main living rooms. If current rates of sale continue the market will be two thirds saturated in 5 years time and there will be few solid fires left to replace. So a replacement market will be needed to avoid a sharp sales drop-off. The boom years for selling gas fires were 1964-69 and by 1980 these fires should be due for replacement. Fig.(5) (9) indicates the possible sales growth of replacement gas fires.

As far as cookers are concerned there is room for expansion. While electricity has advanced in terms of prices, features and appearance, gas

leads in running costs and performance. At present there are no gas ovens to compete with electric models which incorporate separate grills. More people will buy electric despite the premium in running costs. In 1977 over 20 manufacturers produced electric ovens while only 5 produced gas models. Hot plates were produced by 15 electric manufacturers and 15 by gas manufacturers. However, of the 15 gas, 10 were 'foreign' and not approved by the British Gas Corporation. Gas manufacturers have so far failed to use the idea of common standard components (11)

Insulation and gas use

Table 2. shows the relation between energy saving and cost for insulation, and Fig.(6) shows the effect of insulation on total consumption which confirms the prime importance of roof insulation and the very limited benefits of increasing the thickness of the insulation beyond 2" (12) . Fig.(7) shows the effect of insulation on annual gas consumption (12)

The proportion of the total load represented by space heating will be reduced considerably and the relative importance of the hot water load will increase. The effect of the improved u-values combined with the tendency to reduce room sizes will mean that the lower consumption together with the increasing fuel costs will highlight the influence of installation costs. The effect of this will be 1) there will be a longer payback period and this will inhibit the customer investment necessary to change over from one fuel to another, 2) the capital costs of providing the heating system will assume greater importance to the probable detriment of gas and to the advantage of electricity.

At present roof insulation is the most popular with about 38% of all homes and installations having acquired it, and the rate of installation is about 20% per annum. Only about 2% of present dwellings have cavity wall insulation. More gas centrally heated homes have some form of insulation (about 68%) than those heated by solid fuel (about 50%) and those heated by electricity (about 43%) (4) . The effect of increased insulation will thus be less marked in gas heated homes than for homes

heated by other fuels.

Low energy houses

A low energy house is essentially a building which is thermally 'light'. It stores relatively little heat energy and responds quickly to changes in temperature. When heated on an intermittent basis it has a lower average energy consumption for heating than a building which has an identical rate of loss through the fabric but is thermally 'heavy'. This is because there is a greater dissipation of stored heat during the period when the heating is off and this needs to be made up again at the start of the next heating period. The effect of insulation, building shape, climate and exposure can result in a doubling of annual energy cost for a heavyweight building with a slow response plant and poor insulation compared with a lightweight building with a fast response plant and a good standard of thermal insulation (13). Also, temperatures within the insulated building will change more rapidly under the influence of sunshine and human activity. Heat lost in ventilation air will represent a greater proportion of the heat load. It would be common to have excessive heat gain on one side of the building and insufficient on the other, which gives rise to the need to redistribute heat within the building.

Effects of population, housing policy and domestic lifestyle


In recent years the number of independent households has grown at a much faster rate than the adult population. There is evidence that major demolition of existing property has now ceased due to government policy. The large slum clearance programmes of the late 1960's have been stopped. Modernisation and renovation of existing houses is now gaining more prominence. The number of old age pensioners in the population is now about 25% and these factors combined may lead to a substantial reduction in the number of new houses being built.

Allowances must be made for the differing roles within the family which contribute to the energy demand pattern. Differences between households in the same socio-economic group can be very wide. This is

shown by the recent survey of the Scottish Building Research Station , where a difference of 4 : 1 was observed between the upper and lower deciles of energy consumption by families housed in similar local authority housing. Also, evidence indicates extensive use of intermittent (15) heating in the UK. Deeson has estimated on the basis of distribution of working adults amongst households in the UK that between 40 and 61% of dwellings are unoccupied during the working day.

Consumption in the domestic sector has remained about constant over the last 15 years in spite of increases in standards of comfort. This is due to improved appliance design and operation with little to do with (2) building insulation . New houses probably have controls on their central heating installations and therefore the realised savings will be near to the theoretical limit. About a third of the present housing stock which has some form of central heating has no automatic controls. A reduction of one degree in the internal temperature maintained throughout a heating season can save about 10% of the energy input.

The following changes are likely to take place in the future to help reduce demand for gas in the domestic market:

1. An increase in the number of low energy dwellings and small households (1 and 2 person) which will all require less heat.
2. A limit to the growth of the domestic gas market with annual domestic gas sales following an  shaped growth curve and approaching a plateau level by the late 1980's. This will be brought about by saturation of the market for central heating, as well as a reduction in useful heat required because of improved efficiencies for gas boilers and increased insulation measures.

Since the 1960's the growth in primary energy needed to meet the demand for higher domestic heating standards has been held down by the displacement by gas of less efficient fuels. The scope for this over the next decade will be much less.

3. A requirement for smaller more efficient heating appliances and more sophisticated easy-to-operate control systems.
4. A reduction in the space heating load.

Effect of price mechanisms and price elasticity

In 1975 only 4.6% of total consumer spending went on fuels and light (16) with a further 3.5% on petrol and oil . The Index of Domestic Retail Energy Prices for fuel and light has undergone a 3.3 fold increase since 1966, and in the same period expenditure on energy as a proportion of (17) income has fallen by 0.4% . This means that in spite of the three-fold rise in electricity prices since 1973, consumer spending on fuel still accounts for only a comparatively small part of total consumer spending except in a minority of hardship cases. The price of fuel is a key factor in energy conservation and it has a major influence on the efficiency with which energy is used. One factor which blunts the price mechanism as an arbiter of all energy supply is that there are fuel consuming devices and processes in which the cost sensitivity is similar, and there are wide variations in efficiency and fuel consumption over a narrow range of total (18) cost . Manufacturers in a competitive position have in the past tended to use the less efficient plant with lower capital cost.

The price elasticity of gas is a measure of the responsiveness of gas demand to changes in the price of gas. The basic determinants of this price elasticity include 1) the availability of substitutes as the demand for gas will be more elastic if there are close substitutes for it, 2) the proportion of income spent on gas (gas consumption will depend on the relative price of gas and the level of income in the long run), 3) the number of uses to which the gas can be put. The greater the possible uses of gas the greater its price elasticity will be.

The impact of a price increase on gas demand will be modified by the price of new appliances and the economic life of old appliances. The increased insulation will reduce the heating demand which, with higher prices, will increase the importance of installation costs. This may inhibit a change from one fuel to another, so reducing the price

elasticity.

It is in the planning stage that the relative price of the different fuels will have a considerable effect on the decision making process. That portion of gas consumption that is using the existing stock of appliances is fairly insensitive to price changes except the utilisation might diminish. In the new or saturation market, i.e., that part of consumption not committed to appliances already in existence, the price variable should play a more important role.

(19)

Balestra found that the price elasticity of a fuel for an appliance at saturation level is about 20 times that of a fuel for an appliance which is at the initial growth stages. The new demand for gas in the period τ is given by $F_{\tau}^* = (F_{\tau} - F_{\tau-1}) + \gamma_g F_{\tau-1}$ where $F_{\tau} - F_{\tau-1}$ is the increment in total fuel consumption between period $\tau-1$ and period τ and γ_g is the depreciation rate. (See Appendix I). Thus the new demand for fuels is greater than the incremental change in fuel consumption $F_{\tau} - F_{\tau-1}$.

The rate of depreciation is related to the average age of the stock of all appliances. The average age of the stock of appliances would be lower in a new market such as gas than in an older one such as coal. At present, given the particular conditions existing in the gas market, the depreciation rate may be very small and not much greater than zero. There may exist a kind of 'demonstration' effect that tends to counteract the depreciation rate. If in a given area all houses are equipped with gas appliances, then if new houses are added to the development in question, the chances are that they will also be equipped with gas appliances. This will be partly because of the readily available gas supply and partly because of the demonstration effect.

For further expansion in the mature stage of development from the mid-1980's gas must rely more heavily on the normal growth of population, housing etc. Spectacular advances in gas consumption will no longer be as possible as before. During the early period gas demand did not depend on the population expansion for its spectacular advance. During this

initial growth period gas replaced other fuels due to its competitive advantages of price and quality.

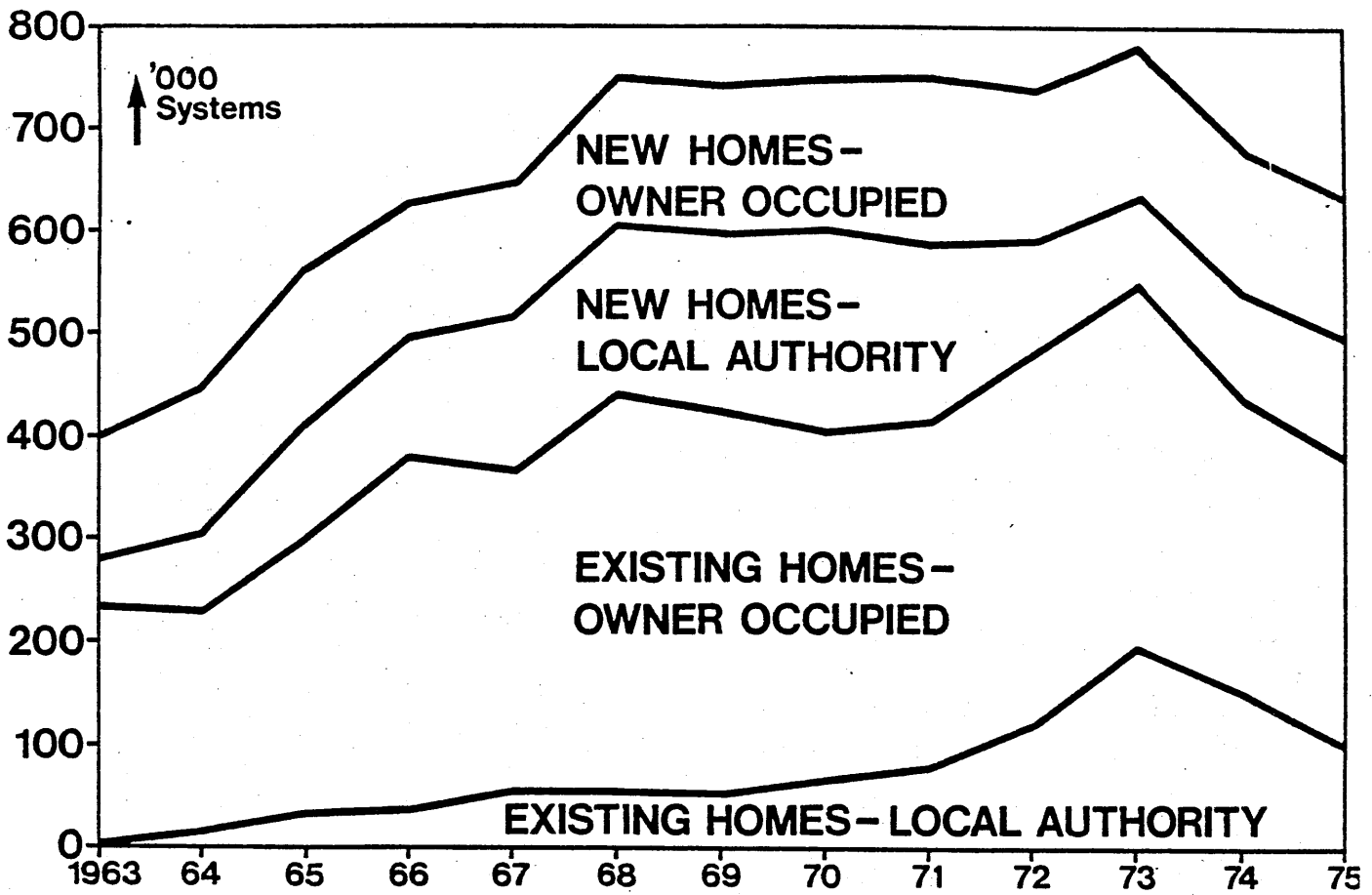


Fig.(1)

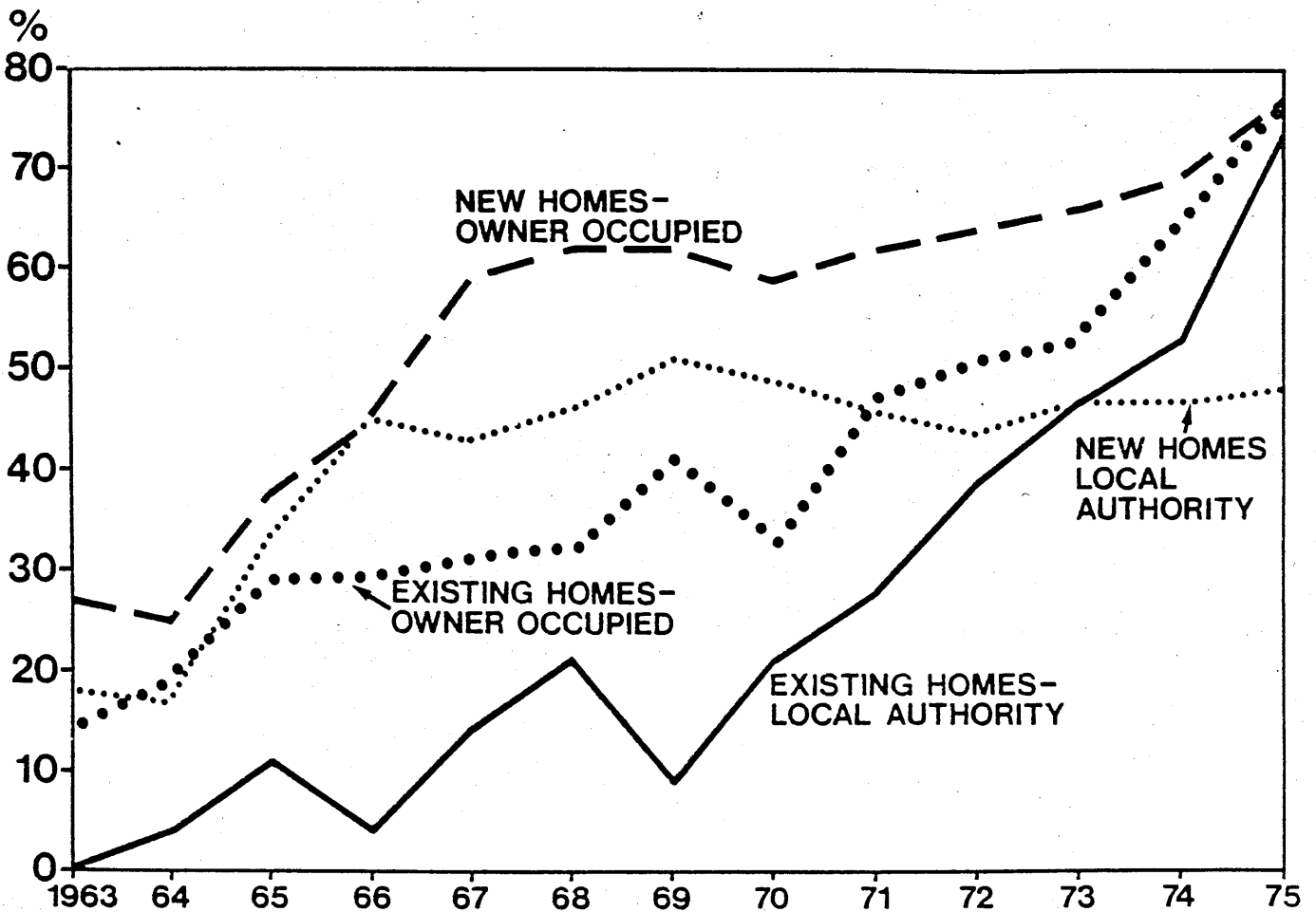


Fig (2)

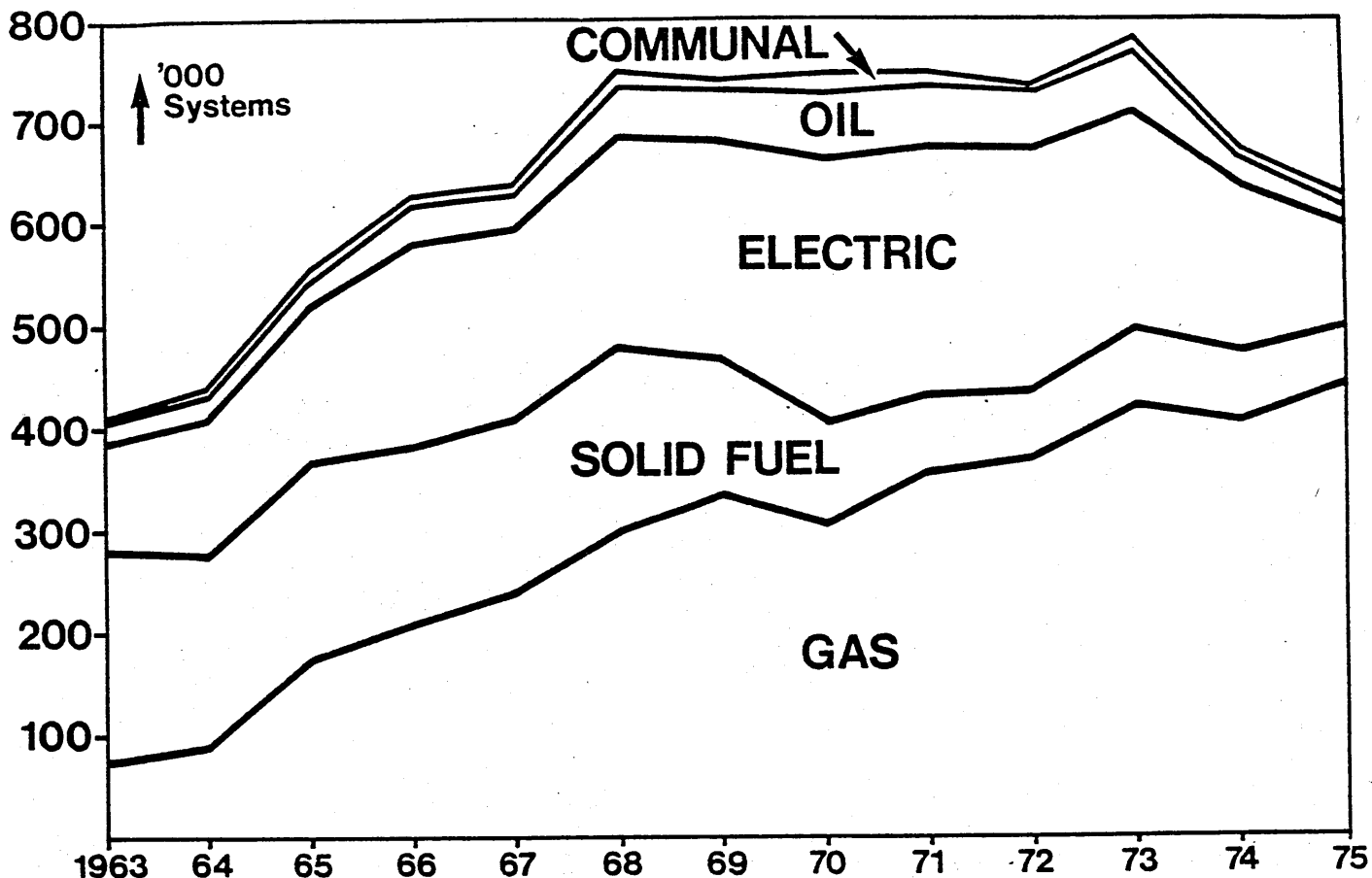


Fig.(3)

1964	82 000
1965	140 000
1966	182 000
1967	184 000
1968	245 000
1969	266 000
1970	291 000
1971	400 000
1972	482 000
1973	517 000
1974	464 000
1975	556 000
1976	590 000

Table 1 Sales of gas central heating systems

POSSIBLE SALES OF REPLACEMENT GAS FIRES
(assuming an average life span of 15 years)

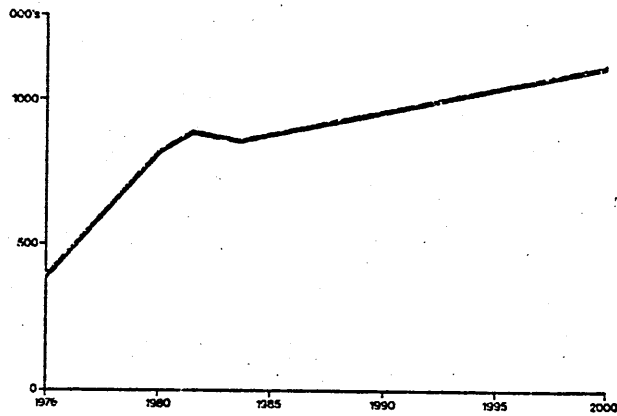


Fig. (4).

POSSIBLE SALES OF REPLACEMENT
CENTRAL HEATING SYSTEMS
(assuming an average life span of 15/17/20 years)

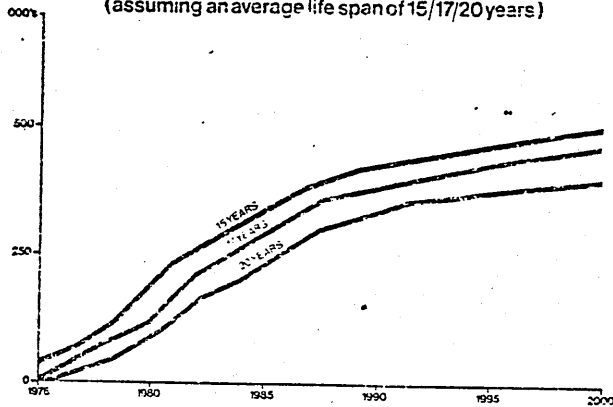
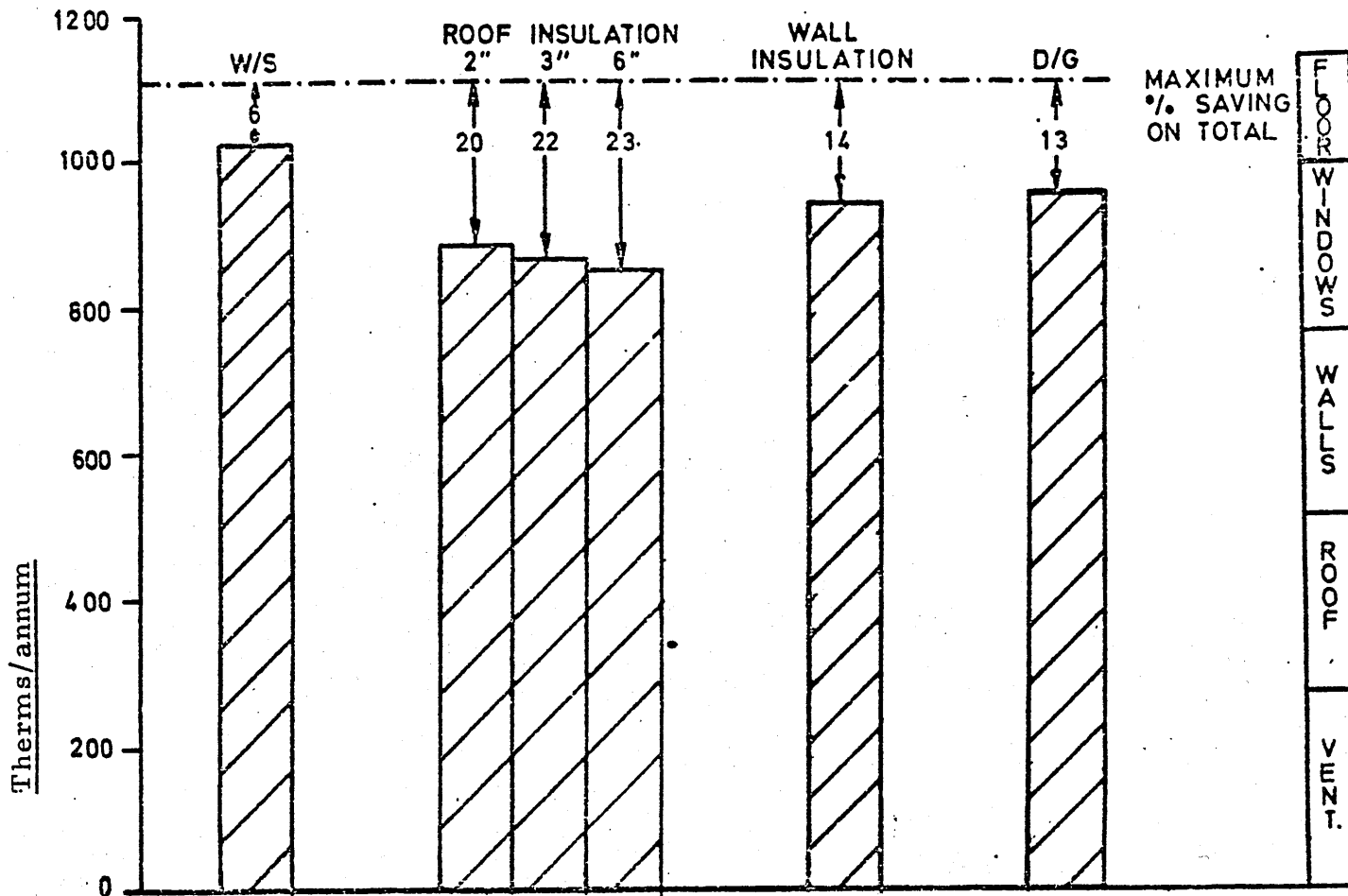


Fig. (5).



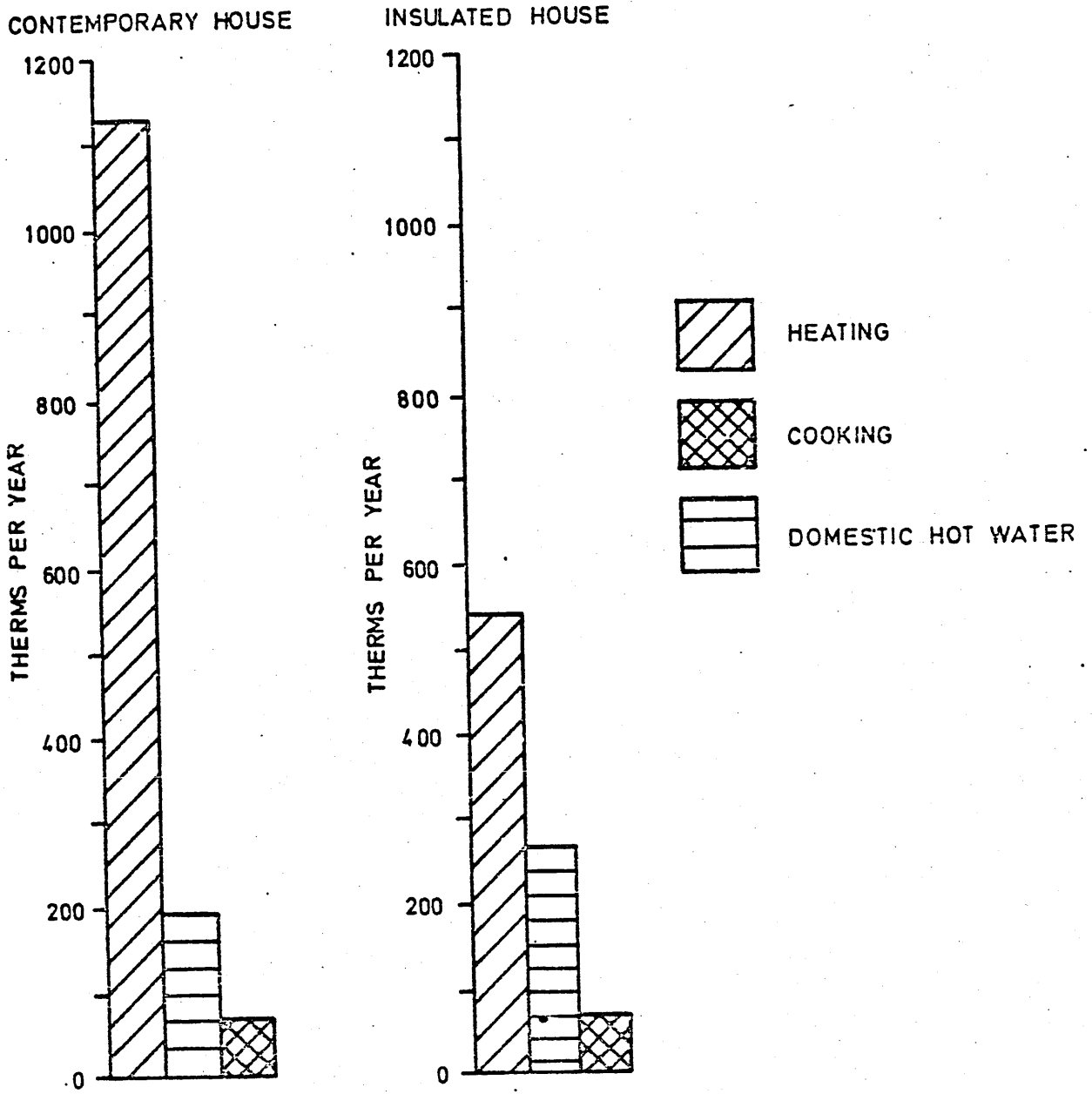
EFFECT OF INSULATION ON TOTAL CONSUMPTION

Fig.(6).

Insulation: Relation between Energy Saving and Cost.

TREATMENT	WEATHER STRIPPING	FIBREGLASS ROOF INSULATION			WALL CAVITY INSULATION	DOUBLE GLAZING
		2"	4"	6"		
COST £	5	20	35	50	100	300
ENERGY SAVING Therm/year (1975)	80	215	240	250	155	140

Table 2.



EFFECT OF INSULATION ON ANNUAL GAS CONSUMPTION

Fig.(7).

APPENDIX I

The increment in total fuel consumption between any two periods is given by $\Delta F_{\tau} = F_{\tau} - F_{\tau-1}$

Here ΔF_{τ} represents the change in total fuel demand between period τ and $(\tau-1)$ but it does not express the total new demand for fuels. The reason is that not all of the demand prevailing in period $(\tau-1)$ is also committed in period τ as some of the installations that existed in period $(\tau-1)$ are retired during the course of the year because of obsolescence.

Let $w_{\tau-1}$ = average stock of appliances in period $(\tau-1)$

Let $\lambda_{\tau-1}$ = rate of utilisation of appliances in period $(\tau-1)$

Then $F_{\tau-1} = \lambda_{\tau-1} w_{\tau-1}$

Of the stock of appliances $w_{\tau-1}$ if the depreciation rate is τ then only $(1-\tau) w_{\tau-1}$ will be present in period τ . If the rate of utilisation is λ_{τ} then the fuel consumption is

$$\lambda_{\tau} (1-\tau) w_{\tau-1}$$

This quantity expresses the position of fuel consumption that in period τ is committed to the stock of appliances already in existence at the start of the period and not yet retired from the market. The new demand for fuel will be the difference between the total demand for fuels and the 'committed' demand for fuels. If F^* is the new demand

$$F_{\tau}^* = \lambda_{\tau} w_{\tau} - (1-\tau_g) \lambda_{\tau} w_{\tau-1}$$

where τ_g is the depreciation rate in the gas market. Since the rate of utilisation is unlikely to vary much with τ over the time period considered

let $\lambda_{\tau} = \lambda_{\tau-1} = \lambda$ thus

$$F_{\tau}^* = F_{\tau} - (1-\tau_g) F_{\tau-1}$$

$$F_{\tau}^* = (F_{\tau} - F_{\tau-1}) + \tau_g F_{\tau-1}$$

Thus the new demand for fuels is greater than the incremental change in fuel consumption $F_{\tau} - F_{\tau-1}$.

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CHAPTER VIII

MATCHING SUPPLY AND DEMAND FOR GAS

Our present energy system devotes more resources to transporting and distributing energy and to accommodating the time variations in demand (by storage or peaking capacity) than to acquiring primary (1) fuels .

In its marketing policy the BGC has developed a market based on 'interruptible' supplies. To match demand and supply in the winter months, the BGC has taken on a number of customers with the ability to terminate supplies for limited periods. These sales have represented as much as one sixth of all gas sales. Occasionally such outlets will have to be found on a year round basis to accommodate the bringing into production of new fields. Absorption of new supplies from associated oil fields could be a particular problem. However, such marketing solutions to operational problems may be minimised by renegotiation of Southern North Sea gas contracts and by using gas from the development of the Morecambe Bay field as a balancing supply source. Other ways of balancing supply and demand include the use of depleted Southern North Sea gas wells for storage, peaking methods using LPG from oil and SNG from coal and the use of LNG stores could also be increased.

In the late 1960's and early 70's the BGC had little flexibility or control over its level of supplies and its marketing approach had to be supply led. With the development of greater storage facilities and renegotiation of contracts the Corporation can afford to be led to a greater extent than by demand.

(2)
The load curve for gas is shown in Fig.(1). This illustrates the typical demand and supply profile facing the gas industry. A satisfactory elasticity of supply has not been possible because the installed capacity of pipelines etc. limits a maximum offtake at any one time. Also, the gas industry is in most cases buying gas from the North Sea producers and

cannot dictate entirely how much can be produced over any given short time period.

The maximum availability of gas varies during the year, being higher in winter and lower in summer, allowing the North Sea operators to carry out maintenance and repairs when the demand is low. The terms of supply negotiated means that the ACQ (annual contract quantity) is such that BGC need only achieve a 60% load factor. If the maximum seasonal supply levels were taken all the time the load factor would be 80%. The domestic market has a load factor of about 35% and the premium industrial market about 45% (3). To be economic the SNG domestic load factor would have to be much higher.

Storage facilities

Gas can be stored as LNG in insulated tanks or at high pressure in buried nests of pipes or pressure vessels. Alternatively it can be stored in natural aquifers or leached out salt cavities.

The British Gas Corporation has applied for planning permission to create up to six massive storage cavities in salt deposits at Hornsea in Yorkshire. This is for a buffer stock of up to 6000 mcf that could be used for peak demand. Two of these have been completed and a third is in the process of being built (4).

The caverns are formed by solution mining. Sea water is pumped underground under pressure to a depth of about a mile and the cavities are slowly created by dissolving the salt in the sea water. The heavily concentrated brine solution flows back to the surface where it is treated and pumped back out to sea. The increase in storage facilities will enable the BGC to cut back on its interruptible contracts.

A number of LNG tanks are being constructed around the country. Two tanks at Glenmavis have a combined capacity of 2000 mcf of gas and four more are located near Manchester. Other tanks are under construction at the Isle of Grain, at Dynevor Arms in South Wales and at Avonmouth. There is also some storage at the LNG terminal at Canvey Island. The world LNG trade is expected to expand rapidly over the next few years and when North

Sea reserves peak out it is probable that much more than the present 100 mcf/d coming from Algeria will be imported. Worldwide LNG movements amount to about 21 M m³/year but by 1990 this is estimated to reach 150/230 M m³/year (5).

The BGC supply pattern will gain further flexibility in the mid-1980's when the Morecambe field is fully developed. This is held under a 100% BGC production licence. UK gas demand can vary from a low of only 2000 mcf/d in the summer to a peak of 7000 mcf/d in winter. Flexibility in supply is further emphasised by the fact that by 1982/83 production may be about 5.4 billion cfd (6). This compares with the 1978 government 'brown book' which predicts that contracted reserves will be capable of supporting 6 billion cfd production by this time.

Premium uses

It is generally accepted that supplies of gas should be reserved for 'premium' markets. However, the concept of 'premium' is not well defined and the necessity to define it more precisely has been recognised by the Energy Commission (6). The domestic market, petrochemical feedstock sales and certain direct heat applications are regarded as premium. Electricity is specifically non-premium.

In the future it is likely that low priced large volume steam raising applications may be phased out. Supplies may tend to be directed at those market sectors which can afford to pay higher prices and where the inherent qualities of natural gas can be used to the maximum advantage.

Peak Shaving

There will be competition between LNG and SNG peak shaving purposes. If LNG is used for peak shaving then the costs are represented as 1) a charge representing the capital costs of the send out pumps and vaporisers, 2) a charge representing the capital cost of liquefaction and storage, (7) 3) a charge representing the cost of replenishing the store.

With LNG the costs of the send out system are comparatively low, the increase in capital required to double the send out capacity is marginal

compared with the cost of the complete installation. With an SNG plant, provision of send out capacity is the major part of the cost. An SNG plant can only secure throughout the year demand equivalent to its design capacity. An LNG plant, however, with the equivalent of 1000 mcf of gas in store designed to meet a peak demand of say 100 mcf. (i.e., 10 days supply at the full peak shaving rate) could by a modest increase in capital support a send out of 250 mcfd for four days. This may be all that is necessary. The flexibility of LNG means that its contribution to security in the case of an emergency of short duration is greater than that of an SNG installation of equivalent capacity. However, on the other hand SNG may be more effective in meeting emergencies of long duration.

The cost of manufacturing SNG is made up of the two elements of feedstock cost and cost of service. While the cost of service can be predicted over the next few years, this is no longer true for many feedstock prices. Service cost can be expressed either as the total operating cost, less the cost of feedstock, per operating day or in terms of an operating cost per unit thermal unit sent out (P/therm etc.). The latter form should be most useful, since the final cost of the SNG produced simply reduces to service cost plus feedstock cost provided both are expressed in the same units.

The service cost includes both fixed and variable charges. The fixed charges include capital charges such as labour, tax, and insurance, and also operating charges such as depreciation and repairs. The variable charges include the costs of electricity, chemicals, boiler feed water etc.

Gas price P is related to feedstock cost C, service cost S and gasification efficiency E by means of the formula:

$$P = \frac{100C}{E} + S \quad (8)$$

Raw material cost in the case of light distillates and crude oil conversion processes is much higher than the cost of service and so plant load factor is less significant. In the case of coal conversion for SNG production, the cost of service is greater than the feedstock cost and a

lower load factor would lead to a substantial increase in gas price, thus underlying the need for continuous operation of these plants. Thus, while oil based SNG processes are best for peaking purposes, coal based processes are necessary for base load applications.

When comparing SNG from naphtha and SNG from coal, account must be taken of the certainty of future supply contracts. In the case of SNG from liquid petroleum products, there may be uncertainties in the supply and price of naphtha which may lead to an escalation in SNG costs over the life of the project. In the case of SNG from coal projects, coal supply and cost will normally be well defined as a result of the acquisition of sufficient coal reserves for the life of the project.

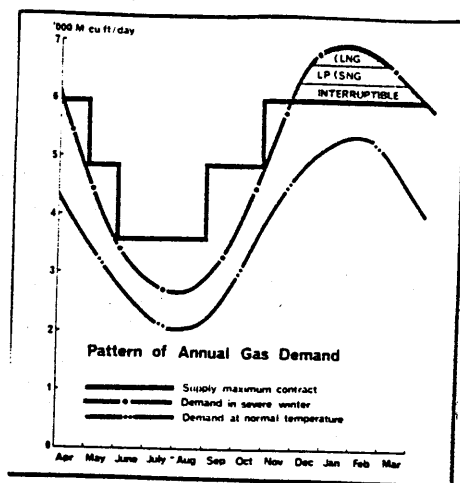


Fig. (1).

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CHAPTER IX

THE EFFECT OF SOME ALTERNATIVE HEATING VECTORS
ON FUTURE GAS DEMAND

In the domestic sector the projection of useful energy demand can be based on the number of dwellings (deduced from population trends etc.) and the likely energy demand per dwelling. The number of dwellings will depend both on the future population and on the rate of construction of dwellings, which in turn depends on the general economic state of the country as a whole. The number of dwellings is starting to saturate (1).

For the useful energy demand per dwelling we must take into account the increasing ownership of central heating, which is largely responsible for the historical increases in useful energy per dwelling. Account needs to be taken also of the improvement in housing stock through the adoption of new building regulations for future houses and extra insulation measures.

It is uncertain what the full effects of these latter measures may be in the future. Consumption in the domestic sector has been about constant over the last 15 years in spite of increases in the standards of comfort. This has been due to improved appliance design and operation and little to do with building insulation (2). Insulation will be less marked on gas consumption than it would be for other fuels. More gas centrally heated homes have some form of insulation (about 68%) than solid fuel and electricity where the figures are 50% and about 43% (3). (Around 70% of houses with gas central heating have some form of loft insulation, although it is another matter whether the degree of insulation is adequate). No more than about 3 to 4% of present dwellings have cavity wall insulation. The figure for roof insulation is much better; approximately 38% of dwellings having acquired it (3). Roof insulation is increasing at the rate of 20% per annum and the new roof insulation grants should increase this rate. Although the Secretary of State for Energy

has indicated plans to increase insulation for over 2 million public sector homes, the poor performance of the nation's houses in acquiring satisfactory insulation was detailed by the Building Group of The (4) Advisory Council for Energy Conservation .

Although the energy saving that has taken place in the past has been more due to good housekeeping and appliance use rather than increasing insulation, future energy conservation measures should seek to improve the acquisition of insulation. An improvement in U value of 40%, which is typical of cavity fill and roof insulation in a normal house, indicates a reduction in energy consumption of some 20%. On the other hand, a change in appliance efficiency of 40% would only realise a saving of 10% (5) in fuel consumption .

General efficiency of appliance use will be also related to controls. New houses probably have controls on their central heating installations and so the realised savings will be near to the theoretical limit. There will still be many houses with central heating and no controls. A reduction of 1° in the internal temperature maintained throughout a heating season can save about 10% of the energy input. Some try to reduce consumption of energy for space heating by heating occupied rooms intermittently instead of lowering temperatures. This tends to cause condensation.

In Chapter VII the implications for installation costs of new central heating in low energy designed houses indicated that the replacement market for gas could be seriously affected in the late 1980's.

The likely level of further domestic gas sales is subject to considerable uncertainty and a major factor will be whether there is significantly increased pressure on people to conserve fuel, because real fuel prices are rising faster than real wealth at a clearly discernible rate.

In addition to savings by application of technology such as boiler design, improved insulation, there are other savings associated with

change of product and market saturation effects.

Parameters used in projection

This estimation is based on a projection of population trends and future house building trends. The average number of persons per household will decline from 2.82 in 1975 to an estimated 2.57 in 1990, 2.55 in 2000 and 2.53 in 2010⁽⁶⁾. Houses and flats are assumed to remain in the same relative proportions as in 1975, 78% of all dwellings being houses and 22% being flats⁽⁷⁾. Total UK dwellings are estimated as 20.35 M in 1975 and 22.9 M in 1990, 24.0 M in 2000, 24.4 M in 2010 (see Appendix 1). The number of UK households or occupied dwellings will be less than the number of UK dwellings. New houses being built will be on average larger than present houses. Present average floor area for houses is 81 m²⁽⁸⁾. For post 1975 houses the average floor area is taken as 95 m². For flats the average floor area is assumed not to change significantly from its present average of 60 m². The height for the average house is taken as 7 m. (It is assumed that by 2000 AD there will be 12.8 M pre-1975 houses and 3.3 M flats, and also 4.8 M post-1975 houses and 1 M flats⁽⁸⁾).

Fortuititious heat gains including passive solar gains

Occupants:

Heat is provided in varying amounts depending on how long the dwelling is occupied during a 24 hour period and how many people occupy it. Brundrett et al⁽⁹⁾ have calculated that for 2 adults and 2 children the sensible heat will be about 5-6 kWh/day for the four persons or about 2000 kWh/year. For three persons this would be 1700 kWh/year. Leach and Romig⁽⁸⁾ have estimated 1100 kWh/year for 2 adults and 1 child. Taking an average value of 1400 kWh/year is equivalent to 5 GJ per year.

Cooking:

In the future it is probable that improved efficiency for cookers will offset increases in cooking. Also, the continued growth in ownership of electrical devices such as electric cookers will not lead to the same large growth in electricity, as there will be a reduction in energy use per

appliance due to improved insulation measures. The energy consumption of a typical electric or gas cooker could be reduced for little extra cost by over 40% from 950 to 540 kWh/year through better insulation of the oven, more responsive controls, better seals on oven doors and minor adjustments to heating elements .

In the case of refrigerators energy use could be greatly reduced by better insulation, door seals and an improved heat pump. Freezers, washing machines, and dishwashers could also be improved. For cooking, allowance needs to be made for opening kitchen windows to let out steam.

Lights and appliances

Theoretically all the electricity used by lights and appliances ends up as heat, but much of this heat will not be provided in occupied areas or during the heating season. Modern future houses are likely to have additional use of lighting due to increased floor areas. Brundrett et al (9)

has estimated about 4 kWh/day which is about 5GJ/year which is a reasonable figure. Because of additional use of lighting in post-1975 houses, this figure is taken as 6GJ/year for these houses.

Passive solar gains:

For pre-1975 houses taking a typical house orientation and average insolation data for Kew, the total yearly solar energy incident is about 56GJ . Transmission reduces this by about 25% and irradiation during the space heating season is 55% of the annual total, while poor room orientation and overshadowing is estimated to reduce by 50% the transmitted irradiation that contributes to space heating . This gives $56 \times .75 \times .55 \times .5 = 11.5\text{GJ}$ per year.

Basnett has estimated that sunlight, both direct and diffuse, contributes 5-6 kWh/day in average winter conditions. Siviour has estimated that this passive solar contribution can fluctuate up to 3 times and down to one third of this value.

For post-1975 houses it is assumed that better use is made of orientation siting and fenestration to maximise solar gains. The gross

annual irradiation will be higher at 80GJ, with an average of say 20 m² facing south, for each house. Of this 52GJ may penetrate the glazing and of this approximately 28GJ occurs during the eight month heating season. It is assumed that two thirds of this energy is available as useful heat giving a final figure of 19GJ. It is unlikely that all of the estimated 4.8 million post-1975 houses by 2000 will be built to take such a maximum use of solar gains. It may be nearer 1985 before the majority of houses are being built to take full use of orientation, siting and fenestration.

Thus for passive solar the estimation is 11.5GJ for one third of post-1975 houses, 15.3GJ for another one third of these houses and 19.0GJ for the remaining third.

Hot water:

It has been shown that some 30-50% of the heat input to the hot water is lost in getting the water to the tap . Brundrett et al has calculated that incidental heat from the hot water system contributes 5-10kWh/day to the house depending on the insulation of the hot water tank. The efficiency of domestic hot water heating takes into account losses in draw off pipes, storage cylinders and flow pipes. It depends not only on the appliance and fuel used, but also on the layout and insulation of the hot water system.

<u>Houses</u>		<u>Flats</u>		<u>GJ/year</u>
<u>Pre-1975</u>	<u>Post-1975</u>	<u>Pre-1975</u>	<u>Post-1975</u>	
4.5	4.5	2.6	2.6	occupants
2.0	2.0	2.0	2.0	cooking
5.0	6.0	3.5	3.0	lights, appliances
3.0	2.8	2.0	2.0	hot water
	1/3 (11.5),		1/3 (2.5),	
11.5	1/3 (15.3),	2.5	1/3 (5.3),	passive solar
	1/3 (19.0)		1/3 (8.0)	
-----	-----	-----	-----	
26.0	26.8,30.6, 34.3	12.6	12.6,14.9, 17.6	
-----	-----	-----	-----	

This gives:

$$(26.0 \times 12.8) + (1.6 \times 26.8 + 1.6 \times 30.6 + 1.6 \times 34.3) + (3.3 \times 12.6) + (.33 \times 12.6 + .33 \times 14.9 + .33 \times 17.6) \times 10^6 \text{GJ/year}$$

$$= 536 \times 10^6 \text{GJ/year by 2000 AD.}$$

Of the estimated 20 million dwellings in the gas supply area by 2000 AD the gas central heating penetration should be almost 75% (ref 9 Chapter VI D), giving about 15 million gas central heating installations. This is 62.5% of the expected 24 million dwellings. Thus contribution to gas heated homes for fortuititious heat gains is approximately

$$\frac{62.5}{100} \times 536 \times 10^6 \text{GJ/year} = \frac{62.5 \times 536 \times 10^6}{100 \times 8 \times 10^9} \times 277.7 \text{MTCE}$$

$$= 11.63 \text{ MTCE (UE). (UE is useful energy).}$$

Ventilation

It is not known how many houses suffer from inadequate ventilation control, as the techniques for measuring air flow in houses are difficult to apply. Ventilation is also dependent on the random opening of windows and doors and on the personal attitudes of householders, some of whom prefer 'fresh air' to the most economical fuel use. Although sometimes designers speak of designing to a mean air change rate of $\frac{3}{4}$ to 1 per hour, in practice this will be affected by many factors such as wind speed, stack effects inside the house, quality of construction, the deterioration of the building with time, the behaviour of the occupants etc. At low wind velocities up to 3m/sec the ventilation rate can be found to be insensitive to the wind, but as the velocity increases the ventilation rates increase in a linear manner (9). The heat loss can be given as:- volume x number of air changes per hour x 0.34 x temperature difference. The factor 0.34 represents the number of watt hours required to heat one cubic metre of air through 1°C (13). If we consider that for an average house of volume 600 m³ the desirable number of air changes per hour is 1½, then the heat loss is:-

$$600 \times 1.5 \times 0.34 \times 10 \text{W assuming a } 10^\circ\text{C winter temperature difference.}$$

This gives 3.06 kW.

Mechanical systems can be designed to supply just the required amount of air when and where it is needed. The total ventilation loss could be substantially reduced by using a mechanical system as opposed to a natural system. The Building Research Establishment have estimated that the heat loss to ventilating air contributes 30% of the space heating load in a fairly well insulated house (14). Mechanical ventilation systems may be expected to reduce the heat loss by ventilation by between 40 and 70%. Against this must be set the energy needed to drive the fan which may amount to 20% of the saving. Preliminary calculations based on meteorological data for the South of England indicate that total ventilation heat loss throughout the heating system could be halved by the use of mechanical ventilation instead of natural ventilation (15).

Built forms can be assessed in terms of surface to volume ratio, which defines the area of building fabric that is exposed to ambient weather conditions per volume of interior space. If all dwellings are divided into five categories (8) from type 1 with the lowest to type 5 with the highest surface to volume ratio, then the division is as follows:-

1. Intermediate single storey flat.
2. Middle terraced houses.
3. Top floor single storey flats.
4. Semi-detached and end terrace houses.
5. Detached houses.

If type 3, a single storey top floor flat is considered as the median case for energy use for space heating, then approximately type 1 can be taken as 50%, type 2 as 85%, type 4 as 120% and type 5 as 150% (8).

Taking about 200 000 as a figure for top floor storey flats in 1977, then by 2000 AD there would be 250 000 with about 190 000 as pre-1975. (8) In 2000 there will be 3.3 M flats which are pre-1975. Thus there are 3.11 M pre-1975 flats which are not top storey and 0.19 M pre-1975 flats which are top storey.

If the floor area for flats is taken as 70 m^2 and the height as 3.5 m,

then the volume is $3.5 \times 70 \text{ m}^3$. Taking $1\frac{1}{2}$ air changes per hour for ventilation then:-

$$\text{Winter heat loss} = 70 \times 3.5 \times 1.5 \times .34 \times 10 = 1250 \text{ W}$$

$$\text{Summer heat loss} = 70 \times 3.5 \times 1.5 \times .34 \times 5 = 625 \text{ W}$$

Taking 200 days for winter and 165 for summer, and assuming there are 30 winter days in which the wind speed is greater than 12 to 15 ms^{-1} in which case the ventilation rate can be assumed to go up to two air changes per hour and the heat loss will be 1.66 kW. Thus assuming an 18 hour/day heating period the total heat loss is:-

$$(1.25 \times 170 \times 18 + 1.66 \times 30 \times 18 + 0.625 \times 165 \times 18) \text{ kWh/year}$$

= 6578 kWh/year. This figure is for each of the 0.19 M pre-1975 flats which are top storey. This gives a total of 1250×10^6 kWh/year for top floor flats pre-1975.

The 3.11 million pre-1975 flats which are not top storey. In this case the heat loss is taken as 50% of the median:-

$$3289 \text{ kWh/year} \times 3.11 \times 10^6 = 10228 \times 10^6 \text{ kWh/year.}$$

The 12.8 million pre-1975 houses in 2000 AD. Taking terraced as 30% (3.84 million), semi detached 31% (3.97 million), detached houses (8) 16% (2.05 million) .

$$\text{Heat loss for terraced houses} \frac{85}{100} \times 6578 \times 3.84 \times 10^6 \text{ kWh} = 21470.6 \times 10^6 \text{ kWh}$$

$$\text{Semi detached} \frac{120}{100} \times 6578 \times 3.97 \times 10^6 \text{ kWh} = 31337.6 \times 10^6 \text{ kWh}$$

$$\text{Detached} \frac{150}{100} \times 6578 \times 2.05 \times 10^6 \text{ kWh} = 20227.4 \times 10^6 \text{ kWh}$$

This gives a total for all pre-1975 dwellings of 83263.6×10^6 kWh.

Post-1975 dwellings in 2000 AD

(8)

Assuming there are 4.8 million houses and 1 million flats . Of the 1 million flats about 60 000 would be top floor and 940 000 intermediate.

Heat loss from top floor flats:-

$$\begin{aligned}
 &= 70 \times 3.5 \times 1 \times .34 \times 10 = 833 \text{ W} && \text{Winter} && 170 \text{ days} \\
 &70 \times 3.5 \times 1.5 \times .34 \times 10 = 1250 \text{ W} && \text{Winter} && 30 \text{ days} \\
 &70 \times 3.5 \times 1 \times .34 \times 5 = 417 \text{ W} && \text{Summer} && 165 \text{ days} \\
 &= (.833 \times 170 \times 18 + .417 \times 165 \times 18 + 1.25 \times 30 \times 18) \text{ kWh/year} \\
 &= 4462 \text{ kWh/year} \\
 &= 4462 \times .06 \times 10^6 \text{ kWh} = 267.7 \times 10^6 \text{ kWh.}
 \end{aligned}$$

For middle intermediate flats then as before the heat loss is taken as 50% of the median case of the top floor flat.

$$\frac{50}{100} \times 4462 \times .94 \times 10^6 \text{ kWh} = 2097.1 \times 10^6 \text{ kWh.}$$

The 4.8 million post-1975 houses in 2000 AD will be subdivided as before. Terraced 30% (1.44 M), semi detached 31% (1.49 M), detached 16% (0.77 M). Also, assume that post-1975 houses have about a 20% increase in volume over pre-1975 houses, (floor area for post-1975 houses is taken as 95 m² compared to 81 m² for pre-1975 houses).

Thus heat loss for post-1975 houses:-

$$\text{Terraced } \frac{85}{100} \times 4462 \times 1.44 \times 10^6 \times \frac{6}{5} = 6553.8 \times 10^6 \text{ kWh.}$$

$$\text{Semi detached } \frac{120}{100} \times 4462 \times 1.49 \times 10^6 \times \frac{6}{5} = 9573.7 \times 10^6 \text{ kWh.}$$

$$\text{Detached } \frac{150}{100} \times 4462 \times 0.77 \times 10^6 \times \frac{6}{5} = \frac{6184.3 \times 10^6 \text{ kWh}}{22411.8 \times 10^6 \text{ kWh}}$$

Thus total heat loss from post-1975 dwellings = 24676.6 x 10⁶ kWh.

Thus total ventilation loss:-

$$\begin{aligned}
 &= 83263.6 \times 10^6 \text{ kWh (pre-1975)} + 24676.6 \times 10^6 \text{ kWh (post-1975)} \\
 &= 107940.2 \times 10^6 \text{ kWh} \\
 &= 13.5 \text{ MTCE.}
 \end{aligned}$$

Assuming that by 2000 AD 50% of dwellings have acquired mechanical ventilation, then these will have a reduction of about 30% in heat

(15)
loss . This is $\frac{3}{10} \times 6.8 = 2.04 \text{ MTCE}$. Thus total ventilation loss is

13.5 - 2.04 = 11.46 MTCE. Assuming as before about 15 million dwellings out of 24 million in 2000 AD with gas central heating. If we take 16 million to allow for those dwellings with gas fires but no central heating, then this represents two thirds. Thus total ventilation loss for gas heated homes:-

$$\begin{aligned} &= \frac{2}{3} \times 11.46 \text{ MTCE (UE)} \\ &= 7.64 \text{ MTCE (UE)} \end{aligned}$$

COMBINED HEAT AND POWER (CHP)

The viability of combined heat and power or district heating depends very much on the view that is taken of the likely future rise in fuel prices, and also on discount rate (16). It has been estimated (17) that a total of 4 million dwellings could be connected to simple district heating schemes by 2000 AD. If even 25% of these 4 million dwellings were connected to combined systems rather than simple district heating schemes, about 3 (17) MTCE could be saved.

It would appear that any increase in the relative price of fuel will favour the economics of a CHP scheme for the householder, since the conventional fuel user will have to increase his insulation standards (18) faster than the CHP user in order to maintain parity. However, this situation will change once full insulation is achieved. For the conventional fuel user after he has acquired full insulation, his fuel cost to fixed cost ratio will have decreased somewhat due to a reduction in fuel costs and a rise in fixed costs due to the extra cost of insulation measures. At the same time it is probable that most CHP schemes will be heat metered and so the fuel cost to fixed cost ratio may increase. This is because previously the heating scheme tenant paid a fixed price for his fuel regardless of how much he actually used, but with a heat meter he will have to pay for whatever he uses. Previously when he was not metered and had to pay a fixed price for fuel, the opening of windows for 'airing' while the heating system was still on did not affect his fuel bill. Now, when he is heat metered he will have to be much more energy

conservation conscious in his habits if his fuel bill is not to rise. To maintain his thermal comfort it is therefore probable that his fuel costs will rise.

This convergence of the fuel cost to fixed cost ratio for both CHP and conventional fuel users may mean a less noticeable advantage for a CHP user when compared to a tenant in a conventional well insulated house. Current designs of communal heating schemes use at least 25% more energy (19) (20), and if the heating is not individually metered possibly up to (19) (20) 69% more energy than individual heating systems. It is clear that if the CHP scheme is to have any hope of competing with gas used in modern appliances then it must be heat metered. Evidence for the efficiency of district heating schemes is hard to find, but a recent experiment in Antwerp found that gas consumption in the case of collective heating of a residential building was 50% higher than with individual heating of (21) flats.

Comparing the technologies for supply of heat to a large city, then the annual cost per dwelling is greater for SNG than for CHP for all values (16) of average marginal coal price over the life of the plant. This is not backed up by any conclusive evidence of the operating efficiencies and economics of individual boilers over their service life.

When comparing CHP with SNG development the following points should be taken into account - 1) SNG technology is ready made and can be quickly assembled, whereas CHP technology has to be gradually built up over a number of years, 2) the energy required to manufacture and install the pipe system for the distribution of CHP heat, 3) the mismatch in the life expectancy of housing and power plant for CHP schemes. Since power station plant is not expected to be serviceable for much more than 30 years, then during the lifetime of a house the district heating scheme will require new sources of generation as older plants wear out.

The intermediate size city of 200 000 to 600 000 is the most commonly occurring in the UK and the most applicable to CHP. The last population

census showed that 45 million of the 56 million people in the UK live in conurbations of over 200 000. Thus 80% of the population are accessible (22) for CHP/DH supply and not 25% as suggested in EP20 . Many other countries with lower population densities such as Japan, Germany, France, USA and Sweden all have CHP operating. Also, in view of the government urban renewal programme and city centre redevelopment policy, plus the effects of high transport costs, it is doubtful if there will be any major migration from large conurbations.

Since district heating and combined heat and power must be supplied over a continuous 24 hour period, the plant that supplies such a load must take its place among the base load plant. The presence of this combined plant will displace some of the former base load plant and move it upwards to a lower order of merit operation. With the passage of time it is possible that lower cost base load plant will be installed such as nuclear plant, which could mean the displacement of economic base load plant to an uneconomic placing in the order of merit just to facilitate the CHP plant. The introduction of base load nuclear plants in areas designated for CHP plant development may lead to problems in the order of merit table.

In considering the development of CHP there are some questions whose answers may not be revealed for some considerable time. What is the population distribution likely to be in 15 or 20 years time when more CHP schemes may be operative? Will the present tendency for population drift away from large cities continue? Can a high market penetration for CHP be achieved without restricting consumer choice unacceptably? How easy will it be to solve the technical problems of pipe laying, metering and the conversion of turbines? Can the considerable scepticisms of the electricity and gas industries be overcome?

The existing owner occupier market without central heating is about 3½ million houses and the existing local authority market without central heating is approximately 3 million (3) . Some 50% were built before 1914

and are unlikely to acquire central heating. Thus, from the existing housing market this leaves about $1\frac{3}{4}$ million owner occupier houses and $1\frac{1}{2}$ million local authority as a potential market for CHP. Communal heating of all kinds has reached a plateau of 18% (23). If by 2000 AD this figure becomes 25% then this gives $\frac{1}{4} \times 1\frac{3}{4}$ million owner occupier houses and $\frac{1}{4} \times \frac{3}{2}$ million local authority houses. If at this time there was no CHP or district heating, then the gas share of these houses that would normally have gone to CHP and/or DH would be:-

$$\begin{aligned}
 & 80\% \text{ of } \frac{1}{4} \times 1\frac{3}{4} \text{ million} - \text{owner occupier} \\
 \text{and} & 80\% \text{ of } \frac{1}{4} \times \frac{3}{2} \text{ million} - \text{local authority} \\
 = & \left(\frac{4}{5} \times \frac{1}{4} \times \frac{7}{4} + \frac{4}{5} \times \frac{1}{4} \times \frac{3}{2} \right) \text{ million} \\
 = & \left(\frac{7}{20} + \frac{3}{10} \right) \text{ million} \\
 = & .65 \text{ million}
 \end{aligned}$$

If we assume that of these $\frac{1}{3}$ have standard insulation measures and $\frac{2}{3}$ have extra insulation, then the gas used is:-

$$\begin{aligned}
 & \frac{1}{3} \times .65 \times 10^6 \times 47 \text{ GJ} + \frac{2}{3} \times .65 \times 10^6 \times 27 \text{ GJ} \quad (24) \\
 = & (10.18 \times 11.7) \times 10^6 \text{ GJ (UE)} \\
 = & 21.88 \times 10^6 \text{ GJ (UE)}
 \end{aligned}$$

Slum Clearance

The slum clearance total must be subtracted from this figure. If there are 24 million dwellings in 2000 and 20.35 million in 1975 (25), then the gain is 3.65 million and so the net gain per year is $3.65 \text{ million}/25 = 146 \text{ 000}$ net gain per year. In the public sector there were 135 000 houses built in 1977 and 125 000 in 1978 with 140 000 in the private sector in 1977 and 150 000 in 1978 (26). Thus the annual building rate has been about 125 000 (public sector) and 150 000 (private sector), giving a total of 275 000 per year. In view of the net gain of 146 000/year then the slum clearance rate must be about 125 000/year. This means 3.13 million houses will be knocked down in slum clearance between 1975 and 2000. Many of these, say 50%, will be very old pre-1914 houses with no communal or central heating of any kind. This leaves 1.57 million which will be knocked down

and which will have some sort of central heating. If the communal level of heating is taken as 18% ⁽²³⁾, then this is $\frac{18}{100} \times 1.57 \times 10^6$ houses. If there had been no CHP then the gas share of this market would have been about $\frac{4}{5} \times \frac{18}{100} \times 1.57 \times 10^6$ house installations. Since these are older houses then if they had remained until 2000 most would have had standard insulation (say $\frac{2}{3}$) with $\frac{1}{3}$ having extra insulation. Thus gas use would have been as follows if they had not been knocked down:-

$$\begin{aligned} & \frac{2}{3} \times 47 \times \frac{4}{5} \times \frac{18}{100} \times 1.57 \times 10^6 + \frac{1}{3} \times 27 \times \frac{4}{5} \times \frac{18}{100} \times 1.57 \times 10^6 \\ = & (7.1 + 2.0) \times 10^6 \text{ GJ} \\ = & 9.1 \times 10^6 \text{ GJ (UE)}. \end{aligned}$$

Thus estimation of real gas saving from present housing stock by having communal heating in 2000 AD is:-

$$(21.88 \times 10^6 - 9.1 \times 10^6) \text{ GJ} = \underline{12.78 \times 10^6 \text{ GJ (UE)}}$$

New housing market

Taking, as above, the average yearly rate of building as 125 000/year (public) and 150 000/year (private), then by 2000 AD this gives $(125\ 000 \times 25 + 150\ 000 \times 25)$ new houses from 1975. Assuming communal heating in new public housing as say 25% and communal heating in new private housing as say 10%, then we have:-

$$\left(\frac{1}{4} \times .125 \times 25 \times 10^6 + \frac{1}{10} \times .150 \times 25 \times 10^6 \right) \text{ installations.}$$

If communal heating did not exist then the gas share of this would be:-

$$\begin{aligned} & \frac{4}{5} \times \frac{1}{4} \times .125 \times 25 \times 10^6 + \frac{4}{5} \times \frac{1}{10} \times .150 \times 25 \times 10^6 \\ = & .925 \times 10^6 \text{ installations.} \end{aligned}$$

Thus the gas used, assuming $\frac{1}{3}$ have standard insulation and $\frac{2}{3}$ have extra insulation measures, would be:-

$$\begin{aligned} & \frac{1}{3} \times 47 \times .925 \times 10^6 \text{ GJ} + \frac{2}{3} \times 27 \times .925 \times 10^6 \text{ GJ} \\ = & 31.14 \times 10^6 \text{ GJ (UE)}. \end{aligned}$$

$$\begin{aligned} \text{Thus total gas saving} & = (31.14 \times 10^6 \text{ GJ} + 12.78 \times 10^6 \text{ GJ}) \\ & = \underline{43.92 \times 10^6 \text{ GJ (UE)}} \end{aligned}$$

ACTIVE SOLAR

There have been many estimations of the future potential energy contribution solar energy will make by 2000 AD and after. The UK-ISES branch has suggested that it may be possible to substitute solar space and water heating for existing fuels to the extent of 30 MTCE per annum (27) (31) by 2020 AD if appropriate government assistance was provided.

ACORD envisages a contribution of 6 MTCE for domestic water heating (28) and 9 MTCE for domestic space heating by 2000. The Energy Policy (29)

Review paper has estimated that solar domestic space heating and water heating may each contribute 3 MTCE giving a total of 6 MTCE.

ETSU has estimated that within 25 years about 2% of Britain's present energy needs could be supplied from the sun. In domestic water and space heating ETSU estimate that saving in primary energy due to solar contributions could be 4.4 MTCE by 2000 and possibly 22 MTCE by 2030 (30).

The House of Commons Select Committee Report on Alternative Energy Sources has estimated that the contribution in the UK from solar space (28) and water heating is likely to be not greater than 15 MTCE by 2000.

In the UK about 3.5GJ of solar radiation are incident in an average (32) year on each square metre of south facing roof. A domestic solar water heating system with 4 square metre of panel area may be expected to operate at an annual efficiency of 35% and so will supply 5GJ of heat over the year. This is about 40% of the domestic hot water requirements of the average household. Against this must be set about 0.5GJ of electricity used annually by the pump. The useful heat supplied is not proportional to the area of the panels because an increase in panel area will lead to the system operating on average at a higher temperature and therefore at a lower collection efficiency.

It is the variation in level, the seasonal mismatch between demand and availability and the low average density of solar radiation which pose the major problems. The ratio, between the June average and the January average, of solar radiation collected, depends critically on angle and

orientation of the collector. For a vertical collector the ratio is 2 : 1 which is optimal for winter, when heat is needed most, and is thus a preferred design .
(33)

Unit prices of collectors are high because of the low volume of present day manufacture. Installation costs are high partly due to insufficient studies of the economic integration into buildings. The extent of penetration in the domestic market depends on overcoming the high capital cost of solar collectors and heat storage systems.

The parameter with the greatest effect on the cost of energy is the area of the collector. The incremental value of heat collected drops off with increasing area as the load factor decreases on each additional element of area .
(34)

In Seattle, Washington, an increase in collector size to allow an increase in load carried by the solar system from 50% to 70% yielded an increase of 33% in unit heat costs . The influence of storage capacity on energy cost seems fairly small. For a Boston house an increase of storage capacity from 50kg/m^2 to 200kg/m^2 increased the proportion of total load carried by the solar system by 16% for an increase in unit energy cost also of about 16% .
(34)

Estimates of the likely cost of solar energy allowing for technical development and economies of scale range from £300/kW of average output for low temperature applications to £1500/kW for high temperature applications . If direct electric heating is used for standby, then it is not permissible to take the system marginal cost as a measure of the cost of standby power . For each kW of standby heating capacity an extra kW of generating capacity must be supplied in the system. The standby power supplied will come from plant with high operating costs. The long run cost of providing standby is at least the cost of the generating capacity (£90/kW) and this needs to be included in evaluating the performance of any solar system if the standby power is direct electric heating .
(35)
(36)

Market penetration of solar water heaters

Development of the market is likely to depend on:-

1. The rate of increase of prices of alternative energy sources.
2. The rate of reduction of capital costs of solar installations.
3. Customer education through practical demonstrations and advertising.

The installation of solar systems should not mean that local authority rates are increased as is the present case on the installation of a central heating system.

Assume that in the new private sector there are 5000 installations per year from 1975 to 1985, 15 000 per year from 1985 to 1990 and 25 000/year from 1990 to 2000. Assume that in the new public sector new units are about one third of those in the private sector. Thus by 2000 the total number of new units in houses built after 1975 will be:-

$$375\ 000\ (\text{Private}) + 125\ 000\ (\text{Public}) = 500\ 000.$$

In the present housing stock of about 19 million at 1975 let us assume there is a rate of installation of 120 000 per year from 1975 to 1985, rising to 160 000 per year from 1985 to 1995 and 200 000 per year 1995 to 2000. This gives a total of 3.8 million in pre-1975 houses.

Thus the estimated total number of solar water heaters by 2000 is 3.8 million + 0.5 million.

In 1975 there were 13.4 million houses with gas out of 16 million in gas supply areas. This represents 83.8%. Assuming that by 2000 there should be 20 million houses in gas supply areas, thus 83.8% of 20 million or 16.8 million houses should have gas. Therefore in a total of 24 million dwellings in 2000 there are 3.8 million pre-1975 houses with solar water heaters. It is necessary to know how many of these are likely to be in gas supply areas.

Thus 3.8 million pre-1975 houses with solar water heaters out of a total of 24 million dwellings in 2000 is equivalent to 2.66 million pre-1975 houses with solar water heaters out of the 16.8 million dwellings with gas. Also, the 0.5 million post-1975 solar water heaters out of 24

million dwellings in 2000 is equivalent to 0.35 million out of the 16.8 million dwellings with gas.

Assuming 52GJ (for space heating) and 18GJ (for water heating) (24), (Table A.1.2), then water heating represents about 25.7%. Future values for space and water heating for a house with standard insulation and one with extra insulation are 47GJ and 27GJ (24), (Table A.1.4). Thus water heating contributes 12.1GJ (standard) and 6.94GJ (extra insulation). Assume that of the total 3.01 million solar water heaters in gas houses by 2000, one third have standard insulation and two thirds have extra insulation. Assume also that the saving by using a water heater is 60%. Thus there will be 1 million houses with solar water heaters having standard insulation and 2.01 million houses with extra insulation. Thus the saving will be:-

$$\begin{aligned} & \frac{60}{100} \times 1.0 \times 10^6 \times 12.1\text{GJ} + \frac{60}{100} \times 2.01 \times 10^6 \times 6.94\text{GJ} \\ & = (7.26 + 8.37) \times 10^6 \text{GJ} \\ & = \underline{15.63 \times 10^6 \text{GJ (useful energy)}} \end{aligned}$$

Solar space heaters

Assume that 10% of new dwellings acquire these from 1990 to 2000 each year in the private sector and the rate of installation in the public sector is one third of this.

Thus in the private sector $\frac{1}{10}$ (150 000) = 15 000 per year from 1990 to 2000 giving 150 000 total. For the public sector $\frac{1}{3}$ (150 000) = 50 000 total.

Assume that the penetration in the present housing stock of 19 million is .05% per year which is 10 000 per year from 1990 to 2000, which gives about 100 000 by 2000. It is assumed that the penetration of solar space heaters before 1990 is negligible.

Thus for present and new housing stock an approximate estimation might be 300 000 installations by 2000 AD. Taking a figure of 70% for gas penetration in the estimated 24 million dwellings by 2000, then for the 100 000 pre-1975 and the 200 000 post-1975 space heating installations

then 70 000 and 140 000 will be in gas homes.

If space heating represents 74.3% ⁽²⁴⁾, (Table A.1.2), then by 2000 space heating will be 34.9GJ (standard) and 20.1GJ (extra insulation).

Thus gas saving:-

$$\left(\frac{1}{3} \times \frac{80}{100} \times .21 \times 10^6 \times 34.9 + \frac{2}{3} \times \frac{80}{100} \times .21 \times 10^6 \times 20.1\right) \text{ GJ}$$

Assuming ¹/₃ have standard insulation and ²/₃ have extra insulation and there is a gas penetration of 80%, this gives:-

$$\begin{aligned} &.8 \times .07 \times 10^6 (34.9 + 40.2) \text{ GJ} \\ &= .056 \times 10^6 (75.1) \text{ GJ} = 4.2 \times 10^6 \text{ GJ.} \end{aligned}$$

Thus total saving for both water and space heating in place of gas is

$$19.83 \times 10^6 \text{ GJ (UE)} = 0.69 \text{ MTCE (UE).}$$

If at the time this displaces gas made from coal with an overall primary to useful energy conversion efficiency of 40%, then the primary energy saved is:-

$$\frac{19.83 \times 100}{40 \times 28.8} \text{ MTCE} = 1.72 \text{ MTCE (PE).}$$

INSULATION

(15)

The BRE report indicates that over the next 10 years home insulation could save 2% of total fuel consumption. However, without intensive government action much less than this will be achieved. Insulation has negligible maintenance and repair costs compared with alternative methods of reducing fuel consumption, and so the application of insulation to existing as well as new houses continues to be the first priority. For existing houses the cost of providing satisfactory insulation is much higher than for new houses, as each house would have to be tackled individually. The potential savings of fuel from insulating older houses without central heating would not be very large. The main fuel saving would be obtained by insulating those houses with central heating, most of which are post-war.

Not all structures are as simple to insulate as traditional houses of cavity brick wall construction. For example, 9" solid brick walls

would have to be battened and lined internally with consequent loss of usable space. About half the present stock of houses consist of dwellings more than 40 years old, and many of these would require non-standard methods of insulation. The cost of insulation for old houses with solid walls would be much higher than for houses of recent construction.

Although some of the benefit of improved insulation is manifest as an improved standard of comfort (14, 37), it is likely that over the next decade the demand for improved comfort will saturate, and improving insulation standards over the next few decades will be more manifest as energy savings.

The number of dwellings in the UK with no cavity walls is 12.5 million (38) with 5.8 million dwellings having no lofts. The 12.5 million dwellings with no cavity walls represent 61.4% of the 20.35 million UK dwellings. (25)

Thus the number of households (occupied houses) with no cavity walls is $\frac{61.4}{100} \times 15.2 = 9.33$ million houses and $\frac{61.4}{100} \times 4.3 = 2.64$ million flats. Also, 5.8 million dwellings with no lofts represents 28.5% of UK dwellings.

For households this is $\frac{28.5}{100} \times 15.2 = 4.33$ million houses and

$\frac{28.5}{100} \times 4.3 = 1.23$ million flats. Thus:-

<u>Total households with no cavity walls:</u>	9.33 million houses
	2.64 million flats
<u>Total households with no lofts:</u>	4.33 million houses
	1.23 million flats

By 2000 there will be 3.65 million new dwellings with 75% or 2.74 million having cavity walls and 25% or 0.91 million without cavity walls. Consider the 0.85 million dwellings not occupied in 1975. (25)

		<u>Houses</u>	<u>Flats</u>
Those with no cavity walls	61.4% of .85 = .52M	.41M(78%)	.11M(22%)
Those with no lofts	28.5% of .85 = .24M	.19M	.05M

Thus the total number of dwellings in 1975 with no cavity walls was

Houses	9.33M + 0.41M = 9.74M
Flats	2.64M + 0.11M = 2.75M

The total number of dwellings in 1975 with no lofts was

Houses 4.33M + .19M = 4.52M

Flats 1.23M + .05M = 1.28M

By 2000 there will be 3.65M extra dwellings of which 2.74M have cavity walls and 0.91M have no cavity walls. Assume that 20% have no lofts, so .73M have no lofts with 2.92M having lofts.

Extra dwellings 1975 - 2000:-

	<u>Houses</u>	<u>Flats</u>
2.74M have cavity walls	2.14M	0.60M
0.91M have no cavity walls	0.71M	0.20M
2.92M have lofts	2.28M	0.64M
0.73M have no lofts	.57M	.16M

Thus by 2000:-

Houses with no cavity walls	9.74M + .71M = 10.45M
Flats with no cavity walls	2.75M + .20M = 2.95M
	<u>Total = 13.40M</u>
Houses with no lofts	4.52M + .57M = 5.09M
Flats with no lofts	1.28M + .16M = 1.44M
	<u>Total = 6.53M</u>

It has already been assessed that 3.13 million dwellings with no cavity walls will be knocked down in slum clearance. Assume that 25% of these have no lofts, i.e., 0.78 million. Thus, allowing for slum clearance:-

Number of dwellings with no cavity walls	= 10.27M	42.8%
Number of dwellings with cavity walls	= 13.73M	57.2%
Number of dwellings with no lofts	= 5.75M	24%
Number of dwellings with lofts	= 18.25M	76%

Applying these percentages to the expected number of houses with gas central heating, then we can use 15 million as a reasonable estimate of the number of houses with gas central heating out of the expected 20 million houses in the gas supply area by 2000. Thus in 2000 for:-

Gas dwellings with no cavity walls	6.42M
Gas dwellings with cavity walls	8.58M

Gas dwellings with no lofts	3.6M
Gas dwellings with lofts	11.4M

Assume that by 2000 the proportion of gas houses with at least some form of insulation has increased from the present level of 68% to about 85% with 15% having no insulation. Thus for gas houses:-

No cavity walls, no insulation	=	.96M
With cavity walls, no insulation	=	1.29M
No cavity walls, with insulation	=	5.46M
With cavity walls, with insulation	=	7.29M

Gas houses with insulation up to new building standards (assume 80% of cavity wall stock with insulation are in this category), then this is 5.83M. (24)
Also assume 50% of solid wall stock which is 2.73M. Thus (Table A.1.3),

	<u>Present</u>	<u>Extra insulation</u>	<u>Saving GJ/dw</u>
5.83M C.W. stock	48	26	22
2.73M solid wall	54	40	14

This leaves 20% of C.W. stock with insulation but not up to new building standards, and 50% of S.W. stock with insulation but not up to new building standards.

1.46M C.W. stock	48	36	12
2.73M S.W. stock	54	46	8

Allowing 4GJ/dw of UE saved for those with no insulation standards, this gives $(1.29M + .96M) \times 4GJ$. Thus total saving:-

$$(5.83M \times 22 + 2.73M \times 14 + 1.46M \times 12 + 2.73M \times 8 + 2.25M \times 4) \text{ GJ} \\ = 214.8 \times 10^6 \text{ GJ(UE)} = 7.46 \text{ MTCE.}$$

A correction must be made for the 3.6 million houses with no lofts. Taking a mean saving per house of 14.3GJ, then assuming a 25% heat loss from the loft this is 3.6GJ. Thus loss is $3.6 \times 10^6 \times 3.6GJ = 12.96 \times 10^6 \text{ GJ}$. Houses with no lofts will still have a heat loss through the roof, although reduced, so this loss may, in real terms, be about $6 \times 10^6 \text{ GJ}$.

Thus total saving is about $209 \times 10^6 \text{ GJ(UE)} = 7.26 \text{ MTCE}$.

INSULATION ON HOMES WITH GAS FIRES
BUT NO CENTRAL HEATING

In 1976 there were 13.4 million homes with gas and 11.4 million gas fires in 9.7 million of these homes (39). We have previously calculated that out of 16.8M homes with gas there will be about 15M gas central heating installations by 2000 AD. So there will be 1.8M homes with no gas central heating, but with at least one gas fire. In 1976 there were 1.7M out of 9.7M homes with a second gas fire. This is 17.5%, and so if we assume about the same percentage in 2000 then this is 17.5% x 1.8M = 0.32M. Thus there will be 1.8M homes with one gas fire and 0.32M homes with a second gas fire. There may be more gas fires than this, but it is likely that they will be in homes with gas central heating which has since been installed and so are unlikely to be used much.

(40)

- 1.8M homes with one MLR fire at 180 Therm/year
- 0.32M homes with a second fire at 75 Therm/year.

Thus there are 1.48 million homes with only one gas fire, and all of these will almost certainly have back up. Assume that 50% of space heating is provided by the gas fire. By 2000 AD space heating needs will be 74.8% (44) of the total, giving 34.9GJ (standard) and 20.1GJ (extra insulation). The gas usage would be 17.5GJ (standard) and 10.1GJ (extra insulation). Assume that of these 1.48 million then $\frac{1}{3}$ are standard and $\frac{2}{3}$ have extra insulation. Thus, assuming that insulation cuts space heating needs by 40%, then gas saving would be:-

$$\frac{1}{3} \times 1.48 \times 10^6 \times \frac{2}{5} \times 17.5\text{GJ} + \frac{2}{3} \times 1.48 \times 10^6 \times \frac{2}{5} \times 10.1\text{GJ} = 7.44 \times 10^6\text{GJ}$$

For the 0.32 million homes with two gas fires in use, then if this supplies 80% of needs gas usage would be:-

$$\frac{4}{5} \times 34.9\text{GJ (standard)} \text{ and } \frac{4}{5} \times 20.1\text{GJ (extra insulation).}$$

Assuming of these 0.32 million that $\frac{1}{3}$ are standard insulation and $\frac{2}{3}$ have extra insulation, and the insulation cuts space heating needs by 25%, then the gas saving is:-

$$0.32 \times 10^6 \times \frac{1}{3} \times \frac{4}{5} \times 34.9 \times \frac{1}{4} \text{ GJ} + 0.32 \times 10^6 \times \frac{2}{3} \times \frac{4}{5} \times 20.1 \times \frac{1}{4} \text{ GJ}$$

$$= 10^6 \left(\frac{.32}{15} \times 34.9 + \frac{.32}{15} \times 40.2 \right) \text{ GJ} = (.75 + .86) \times 10^6 \text{ GJ}$$

$$= 1.61 \times 10^6 \text{ GJ.}$$

Thus total saving = (7.44 + 1.61) x 10⁶GJ

$$= 9.05 \times 10^6 \text{ GJ} = \frac{9.05}{28.8} \text{ MTCE} = \underline{0.31 \text{ MTCE}}$$

HEAT PUMPS

Typical commercial heat pumps at peak design heating conditions have COP, allowing for supplementary resistance heating of as low as 1.2 (Lennox Industries Technical specifications). Although at high ambient temperatures the heat pump may have a COP of 3 or 4, it consumes the bulk of its electricity under conditions when it performs less well, including supplementary resistance heating the average COP over the year could be less than 2. Heat pumps are more likely to be used for centralised heating systems in high rise dwellings and other large buildings, since maintenance costs for individual dwellings may prove prohibitive. Gas powered heat pumps could be at least twice as efficient as electric heat pumps as the gas heat pump could use the exhaust gases from the gas engine to boost the heat output of the heat pump. This permits the heat pump to work across a smaller temperature difference, giving a much better coefficient of performance.

Electric heat pumps using air as the low temperature heat source could affect the seasonal load factor of the national grid. As the outside temperature drops the COP will drop, necessitating topping up with another heating system at the severest loads. The long run cost of providing standby power in place of heat pumps is at least the cost of the generating capacity (41) (90£/kW), which should be included in heat pump costs. In very cold weather when the COP of an electric heat pump drops the efficiency falls, but in the case of a gas heat pump the COP will not be so large and it should maintain its efficiency better at lower temperatures.

According to Marshall SNG heat pumps are cheaper in annual cost up to about (150-200) p/GJ for an average marginal coal price over the life of the plant for densities of 20 dw/acre. This compares with nuclear heat pumps which should be economical at higher marginal coal prices (> 200 p/GJ) and at low housing densities.

Cost comparison of Electric Heat Pump, SNG Boiler System and SNG Heat Pump. (Assuming an average space heating load of 54GJ)

	<u>Heat supplied per year</u>	<u>Primary energy use per year</u>	<u>Cost of energy</u>	<u>Cost/ year</u>
Electric heat Pump (COP = 3)	54GJ	67GJ	2p/kWh (=555.4 p/GJ)	£372
SNG fired Boiler	54GJ	122GJ	20p/Therm (=190 p/GJ) 24p/Therm	£232 £278
SNG heat Pump (COP= 1.45)	54GJ	50.4GJ	190 p/GJ 24p/Therm	£96 £115

The economics of the installation of heat pump systems in new housing, in existing housing receiving central heating for the first time, and in replacing heating systems at the end of their life are more favourable than the replacement of existing gas boiler systems by heat pumps (42)

In the gas saturation market of the 1990's the replacement potential for gas heat pumps could be 500 000 units per year if no one bought gas central heating installations by 1990. Assume one third of these consumers may be attracted to the new lower running costs of gas heat pumps and prefer gas heat pumps rather than installing a second gas central heating installation. This would give a market of say 50 000 (1990), 100 000 (1991), 150 000 (1992), and 165 000 (1993-2000), giving a total of about 1 455 000.

For the pre-1975 existing owner occupier market there are some 40% without central heating, or 3.5 million. Assume 50% of these will

eventually acquire central heating and the gas share of these would be 70%. This gives 1.225 million over 25 years turning to gas central heating. This is $1\,225\,000/25$ per year. If by 1990 one third of these are gas heat pumps, then by 2000 the number of installations will be $\frac{1\,225\,000 \times 10}{3 \times 25} = 163\,300$ (approximately).

For the pre-1975 existing local authority market then those without any central heating will be about 3 million, of which about 50% were built before 1914 and are unlikely ever to acquire central heating. The gas share of those that will acquire central heating will be some 80% or 1.2 million over 25 years. This is $1\,200\,000/25$ per year. Assume that by 1990 two thirds of these may have gas heat pumps, then the number of installations by 2000 would be $\frac{2 \times 1\,200\,000 \times 10}{3 \times 25} = 320\,000$.

In the new owner occupier market the penetration of gas should be around 90% by the 1980's. New installations for all fuels in this market have fallen over the last few years from 145 000 to 111 000 with 25 000 warm air installations. Thus by 1980 the gas share may be 100 000 central heating installations with 20 000 warm air installations. Assume that eventually by 1990 one third of these changed from gas central heating to gas heat pumps, then this would give 33 000 + 6000 or about 40 000 gas installations by 1990. This gives 400 000 installations by 2000.

In the new local authority market central heating installations for all fuels have ranged from 111 000 five years ago to 139 000 at present. (26) With an expected gas share of 85% by the early 1980's this would give about 120 000 new gas installations. If half of these changed to gas heat pumps from 1990 to 1995 and two thirds changed from 1995 to 2000, then the number of installations by 2000 would be $60\,000 \times 5 + 80\,000 \times 5 = 700\,000$. Thus the total potential number of gas heat pumps by 2000:-

Replacement	1 455 000
Existing owner occupier	163 300
Existing local authority	320 000
New owner occupier	400 000
New local authority	700 000
	<hr/>
	3 038 300
	<hr/>

Assuming the standard house at this time uses 38GJ of useful heat (43)
for space heating and 21GJ is used for a house with extra insulation
and that $\frac{1}{3}$ of gas heat pumps are in houses with standard insulation and
 $\frac{2}{3}$ in houses with extra insulation, then this gives:-

$$\frac{1}{3} \times 3038.3 \times 10^3 \times 38 + \frac{2}{3} \times 3038.3 \times 10^3 \times 21 \text{ GJ-}$$

Assuming a gas production efficiency of 70% and a gas heat pump COP
of 2, then the primary energy use for the standard insulation house will
be $\frac{54.3}{2} \text{ GJ} = 27.2\text{GJ}$, and for the house with extra insulation the primary
energy use would be $\frac{30}{2} = 15\text{GJ}$. Thus primary energy use is:-

$$\frac{1}{3} \times 3038.3 \times 10^3 (27.2 + 30)\text{GJ}$$

$$= 2.01 \text{ MTCE.}$$

To calculate the saving then it is necessary to calculate the primary
energy used for space heating if these consumers had not turned to gas heat
pumps but had retained gas central heating installations. This would be:-

$$\left(\frac{10}{7} \times \frac{3038.3 \times 10^3}{3} \times 38 + \frac{2}{3} \times \frac{3038.3 \times 10^3}{7} \times 21 \times 10 \right) \text{ GJ.}$$

$$= \frac{10}{7 \times 3} (3038.3 \times 10^3) (38 + 42) \text{ GJ.}$$

$$= \frac{10}{21} \times \frac{(3038.3 \times 10^3) (80)}{28.8 \times 10^6} \text{ MTCE} = 4.02 \text{ MTCE.}$$

Thus saving in primary energy = 4.02 - 2.01 = 2.01 MTCE (PE).

Assuming an efficiency of 70% this is equivalent to about 1.4 MTCE (UE).

Incineration of domestic refuse

By 1985 incineration is likely to be used for the disposal of 30% of
(17)
the 21 million tons of domestic waste . If we assume that by 2000 AD
incineration may be used to dispose of 50% of an estimated 24 million tons
of domestic waste, then tonnage for incineration = 12×10^6 tons. For
solid organic wastes 10^8 tons will yield about 1 tcf of gas. This gives

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0.12×10^{12} scf or about 5 MTCE/year. Allowance needs to be made for the fact that not all solid wastes will be organic, so if about half is assumed organic then this gives 2.5 MTCE /year. Assuming 70% of this heat energy is used for domestic heating and the gas share is 55% of this, then the gas saving would be $\frac{55}{100} \times \frac{70}{100} \times 2.5 \text{ MTCE} = .96 \text{ MTCE}$.

Biogas and geothermal heat

No detailed analysis of the contribution of these sources is given, but a combined figure of 0.5 MTCE for gas saving by 2000 is taken. It is possible that 5-10% of cooking needs could be supplied by biogas if a suitable collection procedure was adopted. Energy Paper No.22. estimates a geothermal contribution to total energy demand by 2000 of 4 MTCE.

Off-peak electricity

Off-peak electricity is mostly purchased to cope with winter heating demand and occurs at loads between 15-32GW ⁽⁴⁴⁾. The effect of off-peak sales is to improve the load factor of stations switched into the grid at loads of 20-30GW ⁽⁴⁴⁾. Thus the argument that off-peak heating improves the cost effectiveness of nuclear power is only valid if nuclear power stations account for at least 20GW of total generating capacity. This will not happen until about 1990 at the earliest. If off-peak sales were discontinued then the case for building up the nuclear component would disappear, as the load factor between 25 and 30 GW without off-peak sales is the region where coal is most effective ⁽⁴⁴⁾. Thus until at least 1990 winter off-peak electricity will be produced by coal fired power stations. The costs of producing off-peak electricity will be directly related to the price of coal.

If at some time in the future most base load power stations were nuclear, then since nuclear stations are capital intensive and have low fuel costs, the costs of producing off-peak power would be very low. If the off-peak was sold at a profit then this could be used to help cover the large capital costs of nuclear stations.

Saturation effects in consumer ownership in the domestic market will have a considerable effect on off-peak sales as will the continued growth in central heating installations, especially gas which should double its market over the next 10 years.

As the marginal costs of producing off-peak electricity will be directly related to the price of coal, so the relative price between gas and coal will be a significant factor in determining the future competition between off-peak electricity and SNG. About 75% of the cost of SNG is due to coal (45) and so over the next 10 years it would appear that off-peak electricity sales will be more affected by coal price rises than will SNG. In the gas replacement market of the late 1980's, if there is a fast nuclear build up then cheap off-peak nuclear electricity could be in competition with gas or SNG. For a housing density of 20 dw/acre the annual cost of off-peak electricity from nuclear plant is about £100/dw which compares with £250/dw for a nuclear electric heat pump and £270/dw for CHP and district heating (16). If the nuclear build up is slow, then the gas replacement market of the late 1980's could be faced with either SNG or off-peak electricity with SNG being less dependent on coal price rises than off-peak electricity. Because the production cost-based prices of gas will be much higher than coal (46), the choice between SNG or off-peak electricity may be more inducive than another natural gas system. This comparison does not include the merits of other domestic heating vectors such as heat pumps and district heating.

Solid fuel

The sales of gas fires will continue to compete strongly with solid fuel in the domestic market. Part of the sales drive for gas fires is built on the replacement of solid fuel fires. Solid fuel is now used in less than 25% of main living rooms (47). If current rates of sale of gas fires continue, then the market will be 2/3 saturated by 1983 and there will be few solid fires left to replace. The potential for selling more

gas fires is enormous as 8 million houses in the gas supply area have no gas fire, being heated by either an electric fire, a solid fuel appliance or a paraffin or lpg heater.

Solid fuel central heating installations may come out favourably when compared with gas, particularly in parts of the UK where anthracite is cheapest, but when labour costs involved in burning solid fuel are taken into account the comparison will be much less favourable.

Improvements in the efficiency of solid fuel appliances have taken place recently. In 1975 solid fuel appliances had efficiencies of 0.46, but new space heating appliances, taking into account chimney and flue gains, may be 85% in the 1980's⁽⁸⁾. Whole house heating efficiencies, taking into account chimney heat gain, above 80% can be maintained down to at least 20% of design output for a room heater with a high output back boiler⁽⁹⁾. Recent developments of high output boiler models have included design features which limit the amount of air which is drawn up the chimney and this shows that savings in whole house heating⁽⁴⁸⁾ of up to 10% can be achieved by this means⁽⁴⁹⁾.

Energy Commission Paper 5. forecasts that solid fuel should represent 15% of delivered fuels by 1990, being about 0.7 B Therms of heat supplied out of 16B Therms in 2000 which would be about 4.5%. This is in line with the continuing inroads being made into the domestic solid fuel market by the sales drive for gas fires.

Summary

The British Gas Corporation has made impressive inroads into the UK fuel market. It now accounts for more than 44% of the domestic fuel market and meets 28% of industrial demand on a heat supplied basis. Overall it is currently providing about 25% of all the heat supplied in the UK and is meeting some 19% of primary energy demand (50). British Gas is proposing to boost sales to 18 000 million therms a year by 1982-3, compared with 15 000 million therms a year in 1977-78. Allowing for the Shell/Esso Brent field reserves of about 3 tcf, the Morecambe field also of about 3 tcf and associated gas, then total sales could easily be boosted to 21 000 million therms or 6500 mcf.

Assuming a median case rate of growth of 2.5% per annum GDP then the projected useful energy demand by 2000 is $1350 \times 10^{15} \text{ J}$ (43). Assuming about a $\frac{2}{3}$ maximum gas penetration by then this gives 31.24 MTCE (UE) or 8.4 B Therms (UE).

The savings estimated are:-

Fortuitous heat gains	11.63 MTCE (UE)
(Assume $\frac{1}{3}$ taken up as extra comfort heat)	
Fortuitous heat gains	7.75 MTCE (UE)
Combined heat and power	1.53 MTCE (UE)
Active solar	0.69 MTCE (UE)
Insulation	7.26 MTCE (UE)
Insulation of houses with gas fires only	0.31 MTCE (UE)
Gas heat pumps	1.40 MTCE (UE)
Domestic refuse	0.96 MTCE (UE)
Biogas, Geothermal etc.	0.50 MTCE (UE)
	<hr/>
	20.40 MTCE (UE)
Less ventilation loss	7.64
	<hr/>
	12.76 MTCE (UE)
	= 3.43 B Therms

This gives a final useful energy demand for gas of 18.48 MTCE or 4.97 B Therms.

Assuming an overall efficiency of gas use of 60%, then this gives 30.8 MTCE or 8.28 B Therms of delivered energy. This compares with a figure of 9.7 B Therms for Demont et al (3), 7.6 B Therms for The Transport Report (43), and 7.0 B Therms for Energy Commission Paper 5 (49).

Gas demand with conservation measures for 2000 AD:-

Above analysis	8.28 B Therms (DE)
Demont et al	9.7 B Therms (DE)
Transport Report	7.6 B Therms (DE)
Energy Commission Paper 5.	7.0 B Therms (DE)

APPENDIX I

	<u>1975</u>	<u>1990</u>	<u>2000</u>	<u>2010</u>
UK Population	56M	56.6M	57.5M	57.7M
Persons/House	2.82	2.57	2.55	2.53
<u>Total UK Dwellings</u>	20.35M	22.9M	24.0M	24.4M
Houses	15.87	17.85	18.68	18.95
Flats	4.48	5.05	5.32	5.45
<u>Total UK Households</u>	19.5M	21.6M	22.2M	22.4M
Houses	15.2	16.8	17.3	17.5
Flats	4.3	4.0	4.9	4.9
Excess Dwellings over Households	.85	1.3	1.8	2.0

(Social Trends 1975, Table 9.2)

APPENDIX II

Average pithead price of Midlands coal = 21.78 £/Tonne
(as at 1.4.1878)

Average calorific value of Midlands coal = 24 190 kJ/kg
(as at 1.4.1978)

= 6719 kWh/Tonne

(Data obtained through personal communication with NCB, Coal House, Harrow).

Thus total works cost p/kWh

Fuel cost 2178/6719 = 0.32 p/kWh

Capital charges (10% p.a.) = .23 p/kWh (see ref.43)

Other works charges = .065 p/kWh

.62 p/kWh

.62p = 1.43 kWh (t) Primary Fuel

1 kWh (t) = .62/1.43 = .43p (Primary Fuel).

This gives 6719 x $\frac{.43}{100}$ £/Tonne

= 28.9 £/Tonne

Pithead coal price = 21.78 £/Tonne

Thus $\frac{21.78}{28.9}$ = 75% of cost of SNG is due to coal.

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CONCLUSION

If 'Plan for Coal' and 'Coal 2000' are to be fully implemented over the next 20 years, it is clear that the main problem will not be producing the coal but finding suitable markets. The great potential of the coal industry to overcome the inevitable future supply problems of both the oil and gas industries in the UK can only be fully realised if new markets are developed for coal. The coal industry is already finding great difficulty in getting suitable outlets to fully market its product. Chapter VI 'World Coal Trade and Markets for Coal' has gone into this problem in some detail and it is clear that to avoid excessive contraction of the coal industry new outlets need to be found soon. Coal gasification offers a way out of this problem. Even if there is some increase in present known natural gas reserves, this will not alter the future supply problems of the gas industry. Chapter IX has shown that even if other domestic heating technologies such as heat pumps, CHP, district heating, off-peak electricity, are more fully developed, they will be unable to take over the role of gas in the domestic market and their impact on gas demand by 2000 will be limited.

It is important therefore that the gas industry finds another source of supply for its product besides the North Sea. The task of developing a future source of supply for the gas industry and future markets for the coal industry should be dovetailed together to the mutual benefit of both industries. A greater emphasis on the use of coal for coal gasification rather than increasing its use in coal-fired electricity stations would also benefit the nuclear industry.

The gap between supply and demand which will build up in the coal industry in the early to mid-1980's should be used to fuel coal gasification plants. The gas industry and the nation as a whole cannot afford to wait in the hope that further as yet undiscovered gas reserves will be revealed. Britain leads the world in coal gasification technology and full use of this expertise should be made without delay. If coal gasification plants

are built now they will be ready to take the excess coal which will be produced after coal demand has been satisfied in the 1980's. Underground coal gasification technology as well as surface gasification needs to be constantly reviewed. The advantages of coal gasification, including the increased efficiency, the decrease in capital requirements and the reduction in environmental impact when compared with fossil fuel plants has been fully documented in Chapter II.

The coal industry represents Britain's lifeline in the event of inevitable future energy supply problems, and coal gasification technology represents the means by which the lifeline may be fired.

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Visits

During the course of this work I undertook several visits to research centres and institutions throughout the United Kingdom. These included a visit to The London Research Centre of The British Gas Corporation in December 1977, and a visit to the National Coal Board's research centre

at Coal House, Harrow in January 1978. I also visited The House of Commons on several occasions for consultations with Mr. A. Palmer, MP, the Chairman of The House of Commons Select Committee. I visited the British Gas Headquarters at Bryanston Street, London in July 1977 for discussions with Mr. R.S. Hackett, Assistant Director of Engineering at British Gas.

Finally I was fortunate to have visited The Westfield Research Centre in Fife of British Gas in March 1978, where I was given a detailed run down on the working of the Lurgi gasifier and the newly designed slagging gasifier.

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