MEDIUM-TERM ASPECTS OF A COAL REVIVAL: TWO CASE STUDIES

REPORT OF THE IIASA COAL TASK FORCE

W. SASSIN, F. HOFFMANN, M. SADNICKI, editors

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PREFACE

Analysis of the energy options open to mankind once cheap oil and gas resources have been exhausted is one of the main areas of research within the IIASA Energy Systems Programs. The known and inferred resources of coal are fairly large compared to present global energy consumption; they would support the present consumption level for several hundred years. Moreover, coal is a well-known traditional source of energy, currently contributing some 35% to the world's primary energy balance. Thus, investigation of the potential of coal became an important topic in the Program.

Because of the long-term viewpoints and the global prospects of a "coal option", IIASA has sought to use the expertise of national groups as a corrective that would help to tie a possible vision of tomorrow to the reality of today. Thanks to the generous support given to this research proposal, IIASA was able to organize an informal working body, a Coal Task Force, to which scientists from different countries and different institutions have contributed.

This report summarizes the collaborative efforts of experts from British and German coal bodies in investigating potentials and problems of a medium-term revival of coal. The two countries were chosen as examples, because coal has played a central role in their industrial development and still possesses a major share in their supply balances.

Based on the results of the two case studies, the ongoing work of the Coal Task Force will concentrate on questions of the future world coal market, on global environmental problems in the truly extensive use of coal, and in particular on the critical role of coal as an option for transition to a non-fossil global energy supply system. The findings, though based on a quite extended time horizon, point up a number of imminent questions with respect to research and development programs and national energy policy decisions.

If further research into a revival of coal were initiated by this report, IIASA would happily consider this as a small compensation for the invaluable confidence and input it has received for its own Program through the Coal Task Force.

Medium-Term Aspects of a Coal Revival

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Medium-Term Aspects of a Coal Revival:
A Summary

1. INTRODUCTION

This report gives preliminary results of the work of the Coal Task Force (CTF).

The CTF was initiated by the International Institute for Applied Systems Analysis (IIASA) and, with respect to the work reported here, consists of members of the following organizations:

- Gesamtverband des Deutschen Steinkohlenbergbaus, FRG (F. Hoffmann)
- IIASA (M. Grenon, W. Sassin)
- National Coal Board, U.K. (A. Baker, M. Sadnicki, R. Ormerod)
- Steinkohlen Bergbauverein, FRG (R. Hildebrandt).

Organizations from other coal-producing nations are also participating in the effort to analyze the prospects of a revival of coal.

The objective of the CTF is to outline a *global coal option* in order to investigate energy economies largely based on coal. The potential, the requirements, and the constraints of such an economy are explored, and possible strategies of transition are described. The comparison of the coal option with other primary energy options (nuclear, solar, etc.) is a further task within the IIASA Energy Project.

2. METHOD OF INVESTIGATION

The design of any global energy system, whether it is based mainly on one form of primary energy or on a mix of various forms, must meet two basic requirements.

- Once achieved, the anticipated system must conform with the assumed long-term demand for final energy, and must not violate global constraints such as limited resources of primary energy, standards for emission of pollutants, availability of capital and manpower, land, materials, etc.

- The future energy system must evolve from the present system. During the transition, additional constraints will apply, further restricting the achievable system.

The present global energy system is essentially an aggregate of regional subsystems with differences both in structure and in intensity of use of scarce resources. A varying but generally large fraction of primary energy is at present supplied in the form of crude oil and natural gas. These forms of energy are unevenly distributed, and most of the fields exploited today will be exhausted within 50 years. The transition phase cannot be considered to be the same process in different countries or regions.

To get some basic information about similarities and possible variances among regions for the introduction of significant additional amounts of coal, which in a global context is a rich resource, we decided to investigate examples covering different national systems with varying coal consumption rates and their possible medium-term development (up to the year 2000 and a little beyond). For long-term development and a world view, other approaches than those to be described may well be more appropriate. These aspects require further study and will be handled later in the program of the CTF.

To analyze a more limited national coal option, we had to select a method that is adapted to the medium-term view and that can be used essentially in the same way in a variety of geographical regions, e.g. within a country, a trading community, or a continent.

There seem to be two general ways to base the method. First, one could explicitly force coal into the *primary* energy market until it provides 50 to 70% of primary energy, by projecting supply limitations for oil and gas and analyzing the economies of a limited list of conversion technologies, starting from coal, nuclear, and solar energy. However, this immediately raises the question of the *forms* of final energy in which coal is to be used. So, instead, we have chosen another approach. We first consider final energy requirements and the possible growth in each energy carrier, and then the applicability of coal as primary fuel input to produce these energy carriers. This approach enables us to focus on consumer choice of energy carrier and on the requirements for coal extraction and conversion processes.

Starting from the consumers' rather than the suppliers' end is the more important the longer the time horizon of our analysis. Compared to the energy substitution processes of the past (Figure 1), we face a unique situation now. The sequence from wood to coal and then, via oil, to natural gas not only provided ever cheaper forms of primary energy; it was paralleled by the availability of final energy forms that were ever cleaner and easier to handle, and to some extent led to technologies that are more attractive to the consumer. In contrast to that development, the driving force to introduce nuclear or solar energy or to revive coal is not technological innovation leading to more attractive technical systems; the driving force for a transition in the future will be a shortage of attractive primary energy sources. No internal trend to substitute coal for liquid and gaseous fuels can be predicted in the final energy spectrum.

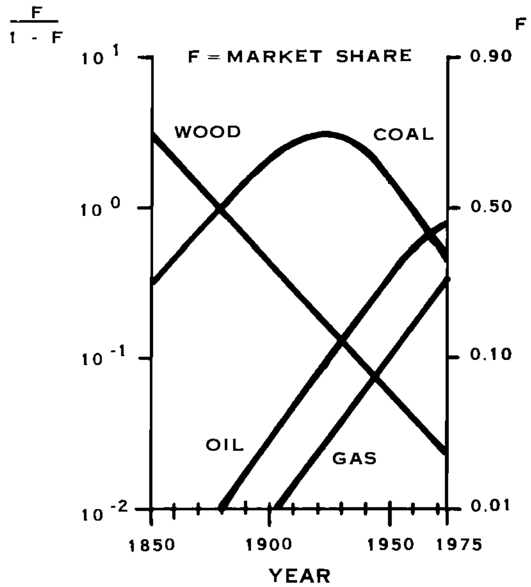

Figure 1. World energy market penetration.
Source: Marchetti, IIASA.

There is, of course, considerable debate about the detailed mechanisms for describing how coal-based processes can best provide an increasing share of final energy. For any region, we are tackling this problem by focusing attention on specific energy markets where coal would most readily substitute for other fuels. The penetration mechanisms of coal into these markets are considered not to be based directly on comparisons of costs of supplying the final energy from alternative sources. Instead, the coal option concentrates on seeing what resources (capital, labor, etc.) would be required, and what environmental consequences would result, if coal were to follow a projected rate of penetration along the most attractive pathways into the market--the rate assumed depending on the nature of the market and the conversion process employed. Subsequent comparison with the resources required by other energy options would provide a means of assessing cost in a more structured way. This comparison would then be expected to alter the assumed penetration rates of coal, so that a fuller analysis would be essentially an iterative procedure.

Similarly, a fuller analysis should feed back into the economic system the resource requirements for a particular demand/supply match so as to revise dynamically the overall level and individual types of demand. At this stage we have not explicitly considered this feedback process, and so the demand/supply/resource projections are *scenarios*, in which changes can subsequently be made to alter assumptions and check consequences.

To provide these scenarios for a region, the approach chosen comprises the following steps.

A. Project final energy requirements in relation to consumer technologies.

B. For each specific energy market (e.g. liquid to industrial sector, electricity to residential/commercial) in turn, identify "attraction potential" for coal-based final energy carriers by reason of:

- Early availability of coal-based technology,
- Existence of a supply infrastructure to handle the energy carrier,
- A possible energy gap in the supply of (indigenous) primary energy to that carrier,
- Anticipated comparability in the possible costs of the coal-based and the alternative-based final energy at the time of substitution.

C. Introduce appropriate coal-based conversion processes into these markets, with penetration rates assessed from the nature of the process and of the market. The choice among different coal technologies will also be influenced by:

- Energy efficiency,
- Types of coal handled.

D. Deduce requirements of coal or coal-based energy to be extracted; consider extraction technologies and their rates of introduction.

E. Consider likely resource requirements for coal extraction and conversion.

F. Perform feedbacks inside the economy by sensitivity analysis on:

- Changing total demand levels and/or energy carrier substitution at step A,
- Changing the "attraction potentials" at step B,
- Choosing different market penetrations for conversion processes at step C,
- Changing the introduction rates of extraction technologies at step D,
- Introducing resource or environmental constraints at step E.

When coal is ultimately compared with other energy options, further steps will be needed. Step G would be to calculate the resources required to meet energy demand at point A by each energy source in turn. Step H would be, by selective mixing of energy sources, to suggest *mixed energy options* that seem good in the medium term by reason of generally lower resource requirements or of flexibility in relation to the obvious uncertainty of future estimates.

3. THE CASE STUDIES

Case studies were made for the FRG and the UK. We again emphasize that the aim of these studies is to demonstrate the *methods*, and to show applicability to many other regions. Therefore, any projections shown are for the purpose of demonstration; they do not necessarily represent the views of the National Coal Board or the Gesamtverband des Deutschen Steinkohlenbergbaus.

Adaptation to the Specific Situation

Both case studies follow the general procedure outlined in Section 2. There are some differences, mainly with respect to the availability of indigenous crude oil and natural gas; these fundamentally influence the timing of the development of primary energy substitutes. Individual steps A to F are treated more or less extensively in the two studies. Important variations in approach are summarized in Table I.

Both studies make extensive use of the technical material presented at the first International Symposium on Gasification and Liquefaction of Coal, which was organized by the UN Economic Commission for Europe (ECE) in January 1976 in Düsseldorf, FRG. A review of the findings of the Symposium is given in Appendix C. The participants could issue no clear statement about the possible part to be played by liquid and gaseous fuels from coal, because of the large uncertainties in estimating future demands and in assessing the competitiveness of various energy sources. By drawing up long-term scenarios for the two regions considered, we have tried to reduce this uncertainty as far as possible. With respect to many questions posed at the Symposium, our method appears to be equally suited to a great number of other regions for improving an assessment of the role of specific coal technologies.

The case studies are briefly reviewed below. Details are given in Appendices A and B.

Table 1. Comparison of the analyses of the two case studies.

Step	Difference in approach, by step FRG	UK
A Final energy projection Energy carrier competition	From EC/FRG energy program More detail on population density	From historical trends More detail on use of energy
B Identification of "attraction potential"	No difference	
C Identification of conversion processes	Project timing of conversion processes; is it sufficient?	Fill the energy carrier requirements. What timing for processes?
D Extraction technology	Project the supply of coal; do we require coal imports?	Supply must equal demand What timing required?
E Resource/environmental requirements	Some quantified	Some quantified
F Sensitivity analysis	Scenario variables chosen to yield lowest market potential for coal	Some sensitivity analyses on step A to E
Time scale	Up to 2000	Up to 2020

Summary of the UK Case Study

The UK case study (described in Appendix A) suggests how coal should develop through alternative final energy carriers to regain a dominant role in the market early in the 21st century. The approach used is to consider possible patterns of demand for five final energy carriers to the residential, industrial, and transport markets. The possible energy carriers were taken to be:

- Centrally generated electricity,
- High Btu gas supplied by grid,
- Liquid fuels,
- Solid fuels (used directly),
- Local distribution schemes (including combined electricity and hot water and medium to low Btu gas).

Within the case study various scenarios are explored. Scenario 1 is built up from assumptions that could be described as "business as usual". Final energy grows at 1.25%, all electricity is centrally generated, oil and gas are increasingly reserved for premium use (as indigenous supplies decline), and the nuclear industry gathers momentum once the next reactor type is proven. The other scenarios examine:

Scenario 2--the increased importance of electricity generation by local combined heat and power schemes;

Scenario 3--the possibility of no further nuclear power stations being built;

Scenario 4--the effect of the different energy sectors growing at different rates.

The results obtained re-emphasize that the coal option cannot mean a total reliance on coal. In fact in *market share* terms (see Table 2), coal use is shown as growing very slowly until the end of the century, but then increasing rapidly with the decline of indigenous fluid fuels and the availability of coal conversion technology.

Table 2. Market share of coal in the UK case study.

Coal share of:	Actual 1974	Range from scenarios 2000	2020
Primary fuel	35%	35% - 40%	50% - 60%
Final energy	26%	30% - 35%	55% - 60%

The figures in Table 2 mask major changes in the markets for coal which are summarized in Table 3.

Table 3. Principal coal uses, actual and in case study.

Year 1974	2000	2020
Central electricity generation	Central electricity generation (fluidized bed)	Replace gas and liquid fuel
	Direct use of solid fuel in industry	Combined heat and power on local basis
	(Substitute fuels and combined heat and power developing but constrained)	Direct use of solid fuel

As new technologies build up, total coal demand is shown in the case study to grow to 160 to 200 million tons p.a. by the year 2000. After 2000, coal requirements increase rapidly to 350 to 450 million tons p.a. If nuclear is not available, a radical shift in national energy policy will be required (either to build up local energy systems or curtail demand, or to speed up the introduction of renewable sources), but the demand for coal will not be affected. Even if nuclear growth is substantial, large coal demands result from the growth in total energy demand.

In summary, the analysis of the UK case study helped us to conclude that the following are the essential facets of the coal option:

- Up to the year 2000, the most important uses of coal will continue to be electricity generation and direct use in industry. Increased R&D in new conversion processes is required.

- Around 2000, the conversion of coal to substitute gas and liquid will become increasingly important. R&D in liquefaction should have the objective of producing the first commercially operating plant by the year 2000.

- Existing methods of mining will support an output of around 200 million tons p.a., provided that there is, first, continuing research to improve conventional mining methods, and, second, a continuing programme of creating capacity in new locations.

- To satisfy the full potential of coal demand, a completely new mining process will be required, to access resources that cannot be recovered by existing methods. A pilot scheme demonstrating such a method would have to be available by 2000.

- The use of resources (labour, capital) in such a coal option seems, on a preliminary assessment, not to be excessive. There will be major organization problems in mobilizing these resources.

The above points would add up to an extremely demanding task for the UK coal industry. The ability to develop new technologies, access new reserves, and mobilize resources of manpower and capital would be the limiting factor of the coal option. Such a task would have to be considered within a national energy strategy that might include shifts in R&D and investment priorities, conservation programmes, and controlled depletion of North Sea oil and gas.

Summary of the FRG Case Study

In the FRG case study (described in Appendix B), we investigated the possibilities and problems that would result in the FRG within the next 25 years if coal consumption were really pushed to its reasonable maximum. The basis for calculating possible future coal demand is a scenario for the development of the demand for final energy. This scenario distinguishes between different consuming sectors and different final energy carriers; the assumptions were consistently chosen in such a way as to yield the lowest realistic potential market which coal and coal products can penetrate. Likely or possible deviations from the reference scenario thus would tend to increase the market potential for coal.

From a large number of technological processes using coal, we selected those which, according to the present state of R&D offer an early and economic possibility for commercial application in important submarkets. Starting from a conservative estimate of when these processes will be available and using market penetration rates typical for each submarket, the overall coal demand was derived as a function of time (Figure 2). Even with these somewhat restricting assumptions, a significant increase in coal consumption is projected for the years after 1990: in 2000, a total of 240 million t.c.e., 200 million of it hard coal.

A large share (60%) of the 200 million t.c.e. hard coal will be used for electricity production. Besides conventional coal-fired power plants, fluidized bed combustion and pressurized gasification are assumed to be in operation by then. Roughly 17% of the coal consumption in 2000 feeds into the production of synthetic natural gas. New technologies (fluidized bed combustion) for supplying industrial process heat require another 13% of the total, the remainder going into steel production and other conventional processes.

In case the assumption that nuclear energy can provide 600 TWh in 2000--corresponding to 120 GW(el) installed nuclear capacity--turns out to be too optimistic, the demand for coal would be more still than the estimated 240 million t.c.e. Another factor increasing coal demand would result from underscoring projected energy conservation objectives.

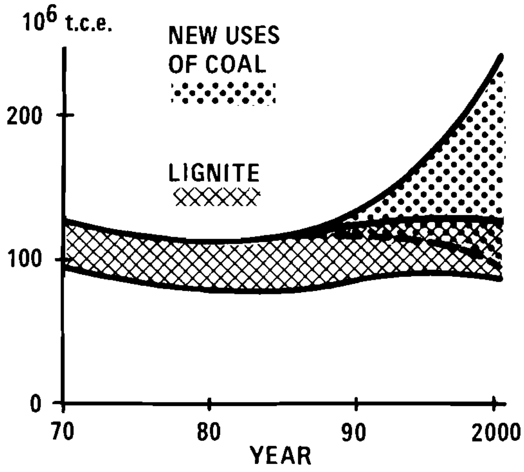

Figure 2. Total coal demand (FRG).

Seen from the demand side, a significant increase in coal consumption towards the end of the century seems to be a real possibility, provided new coal-consuming technologies are introduced. Increased development efforts could improve the economics for these technologies, but will not significantly reduce the necessary lead times below 10 to 15 years.

Only rough estimates are possible at this stage of the analysis to quantify the economic resources required to implement such a coal scenario. Capital requirements for new pits, coal conversion, and coal transportation up to the year 2000 would accumulate to more than DM100×10^9 (in constant prices). A large part of that capital will be needed in any case to secure the anticipated increased energy supply, irrespective of the primary energy source chosen.

Massive efforts would be needed to build up--both qualitatively and quantitatively--the labor force for supplying twice the amount of coal used today. Again, part of this effort is a consequence of overall increased energy consumption.

In summary, the case study suggests that within 25 years an important part of the primary energy demand could be based on coal if an early political decision were to favor such a "coal option". This would not rule out other energy sources (Figure 3): on the contrary, nuclear energy as well as crude oil would have to complement coal in comparable amounts to meet the energy demand around 2000. Without a coal revival, an even stronger dependence on crude oil and natural gas than today would be an inevitable consequence.

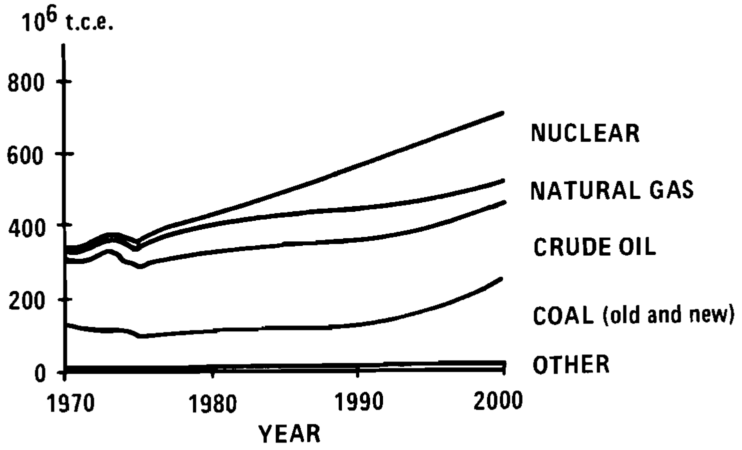

Figure 3. Primary energy consumption (FRG).

4. CONCLUSIONS FROM THE CASE STUDIES

An important purpose of the work described was to develop a methodology for exploring possible demands for coal on the basic assumption that coal will provide the key to the future global energy supply problem. This methodology must take into account both the long-term supply aspects and the energy system that exists today.

We concluded that a methodology for analysing the coal option must start by investigating selected geographical regions; and further, that any such study must first consider both the quantity and the form (solid, liquid, and networked) of energy demanded by the final consumer. The methodology comprises the following steps:

- Projection of final energy carriers;
- Estimation of the "attraction potential" for coal-based technologies;
- Analysis of availability and likely penetration rates of coal technologies;
- Investigation of the coal resource and supply position;
- Analysis of likely general resource requirements and environmental consequences.

The two regions chosen for analysis, the FRG and the UK, both have sizeable existing coal industries, but in the medium term face different strategy choices. This is a result of the differences in their indigenous energy resources, their existing energy systems, and the nature of demand. Hence we have used approaches specific to each country to handle the uncertainties associated with the overall energy consumption growth rate, the development of alternative energy sources and systems, etc.

Starting from the projected development of final energy demand, coal can clearly reverse historical trends and extend its market share in both countries. In the FRG, coal may expect to supply 34% of the market in the year 2000, its share continuing to rise rapidly thereafter. This compares with a falling share of 32% in 1974. The corresponding figures for the UK are 33% in 1974 and 35 to 40% in 2000. In both cases this entails a substantial increase in total coal consumption by the year 2000 (FRG: 240 million tons, UK 160 to 205 million tons p.a.). In both countries we find rapidly increasing demands for coal after the turn of the century.

These results indicate that a coal option must be considered a real possibility in both countries. This statement is based on the assumption that coal concentrates on those channels to the consumer of final energy where the conversion technology has already been demonstrated on the scale of pilot plants, and where plants either are today or will be economically competitive with indigenous coal or imports if they are available.

The analysis quantifies a gradual shift in the uses of coal. In the long run, this shift leads to coal being converted into final energy forms that today are more easily obtained from other primary energy forms (e.g. crude oil and natural gas). The introduction of new conversion technologies is assumed in the two studies to commence when existing R&D programs are expected to achieve successful operation of full-scale commercial demonstration plants.

We stress that in the long run the market share of coal could be increased further by intensifying the R&D effort. This would contribute to shortening the time to commercial introduction of the processes feeding into the channels considered for a medium-term coal revival. It could also extend the use of coal to other channels. (In the FRG, for example, the gasification of coal using the heat of a high temperature reactor is being researched; another example is the use of methanol derived from coal as an additive to gasoline.)

Turning now to the question of how the projected demands can be met, a planned program for expanding the coal supply is obviously necessary. We conclude that the existing R&D programs in both regions should be sufficient to support the initial phase of a coal revival. However, consideration of coal resource to reserve transitions shows that the coal industries in both regions would find it difficult to satisfy continuing increases in demand around and certainly beyond the year 2000. Given the long lead times involved, substantial new R&D effort in new mining techniques is required now.

We are thus discussing preparations for an additional annual 100 million t.c.e. in 2000 or 2010. (In the FRG, this is the order of magnitude to be considered if coal should contribute to stabilizing and even slightly reducing the oil and gas imports towards 2000; it is also the order of magnitude that will have to be added to coal production in the UK by about 2010 in order to replace North Sea gas, which by then will most probably be in short supply.) This means building new mines, new transportation facilities, and harbors for imports, and providing sites for conversion plants--an effort of a similar order of magnitude as today's national nuclear programs. Some figures illustrate the resources required. Drawing on the results of both studies, to extend a national energy system capable of producing and utilizing an additional amount of 100 million tons of coal p.a. would require capital investments in the order of 60 billion US dollars. It is difficult to describe the labor problem simply in job figures. For the mining effort alone, up to 100,000 new, highly skilled workers are indicative; 20 new pits, some in new mining areas, would have to be opened; some 15 sites for large-scale gasification and up to 80 sites for new coal-fired power plants would have to be found. These figures must be put into perspective by comparison with the efforts that will be required to expand and adapt national energy systems in the face of dwindling cheap oil and gas reserves.

Such a comparison should not distract one from the special problem inherent in a coal option, however. A massive effort of coordination and investment must be made at a time when coal consumption is stagnating or even declining. On the other hand, the existing large infrastructure of the coal industry and its supporting industrial partners will form a sound base for expansion.

It is premature to prepare detailed programs for the expansion of coal on the basis of the case studies reported here. Nevertheless we can state that, if coal is to be promoted to the position of an energy policy option, such programs should be investigated in detail as soon as possible. This will facilitate an objective comparison of alternative energy supply options, a step that must be taken at various decision levels. The major advantages and disadvantages of decisions taken today on the basis of the existing energy system can be judged only by taking a sufficiently long view. Coal is no exception: the sooner the full requirements for a coal option are known, the more time will be available to address and adjust institutional constraints connected with the embedding of any new technological system in complex regional development plans. It will be necessary to meet environmental and risk standards, to adjust to socioeconomic goals, and, last but not least, to win public support and the help of the private consumer for the necessary changes.

Appendix A

The Coal Option:
UK Case Study

1. INTRODUCTION

Summarizing the discussion in the main text, we can state that the purpose of this case study is to investigate the following broad questions:

- What might be the demands for coal in a region that follows a coal option, given different levels and patterns of energy demand and different patterns of supply?

- What implications can we draw in terms of required economics and timing of coal processes (extraction or conversion)?

- What implications are there in terms of resource requirements and environmental consequences? Furthermore, if limits on these are imposed, what alternatives are there within this coal-based energy strategy?

The region studied here is the UK. We reemphasize that this is only to give a base for analysis; the intention is to show applicability to any region where a coal option may be relevant. Obviously, therefore, any projections that follow are in no sense the views of either the UK Government or the National Coal Board.

The present conditions (1976) of the region are a wealth in natural gas and oil, a large coal industry, on average competitive with oil, and an uncertainly developed nuclear industry. Figure A1 shows the primary fuel balance for 1974 and probable exploitation curves for indigenous supplies of oil and natural gas. Depending on precise assumptions, demand for liquid fuel and natural gas exceeds indigenous supply from a time somewhere between 1990 and 2000. After 2000 an "energy gap" (at least in security of supply terms) develops very quickly, unless the large indigenous coal resources are exploited--and so the region is a clear case where the coal option is an important one. Our intention here is to focus on the years of transition to new patterns of energy supply (1990-2020), and to attempt to develop smooth strategies of change, based broadly on coal rather than on any other potential long-term primary energy source.

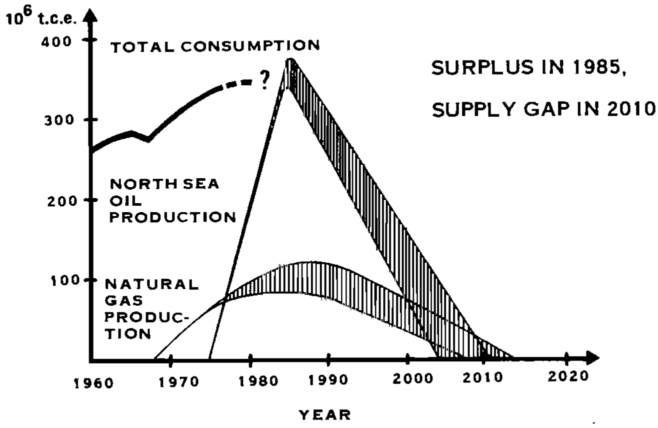

Figure A1. UK primary energy consumption and production.

Section 2 of the main text outlines the methodology employed to construct the demand and supply patterns. This case study follows the steps described there, that is:

A. Total final energy and energy carrier projections,

B. Identification of "attraction potentials" for coal,

C. Identification of conversion processes,

D. Extraction technology,

E. Resource/environmental consequences,

F. Sensitivity analysis.

The following pages contain sections on:

- A general discussion and amplification of the methodology of Steps A to E (p. 15 ff.),

- A first pass through Steps A to E making explicit assumptions (p. 26 ff.),

- A revision of assumptions in Step F, i.e. the sensitivity analysis (p. 36 ff.).

We emphasize that, while the first pass through Steps A to E prepares a scenario, the scenario is intended as a base for further analysis, and in no way constitutes a "central" or "best" projection.

While the general discussion (Section 2) is useful as a background to the scenarios, a reader specifically interested in the regional projections will find that the text from p. 26 onwards is self-contained.

2. DISCUSSION OF METHODOLOGY

Step A: Final Energy Demand

Estimates of future demand should be made in terms of *useful heat* and categorized by the use made of energy. However, our current understanding of the uses of energy is insufficient, especially in the industrial sector. In this study we choose to work in terms of the heat supplied to the users--*final energy*. In 1974 total final energy demand was 59 GTh, rising to 63 GTh* when oil for petrochemical feedstocks are included. Total final energy has been growing at approximately 1.25% p.a. over the last 15 years; but we must bear in mind that this period has witnessed large substitutions of electricity for coal in the residential sector, and this has tended to depress growth.

Table A1 defines categories of demand and of energy carrier that will be used in this study, and gives matrix data for 1974. We use the energy carriers: electricity, central gas, liquid, direct solid and other networked heating. We know that natural gas will penetrate the residential sector to a level of about 60% in 1985 at the peak of indigenous supplies, but beyond this the future division of demand by energy carrier is unclear. The main issues are:

- Will central electricity growth continue at historic rates?

- What will happen to the demand for liquid and central gas as indigenous supplies diminish?

- Will there be a return to direct burning of solid by individual consumers?

- What will be the potential for total and local energy schemes?

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*1 GTh = $(10^{14}\text{Btu}) = 3.6 \times 10^6$ t.c.e.

Table A1. Energy demand: sectors and carriers (percentages of total final energy, 1974).

Source: Estimated from *U.K. Digest of Energy Statistics 1975*. The category "other final consumers" has been split equally between residential and industrial. Total final energy includes non-energy uses of fuel.

		Electricity	High Btu Gas	Liquid	Solid	Other Heating	Total
RESIDENTIAL Space, water, cooking	S	4.5	8	5	9	1.5	28
RESIDENTIAL Lighting, TV, etc.	NS	1.5					1.5
INDUSTRIAL Space, low process heat	S	1.5	6	13.5	5.5	1.5	28
INDUSTRIAL Motive power, high process heat	NS	4		5			9
INDUSTRIAL Chemical feedstock	NS		2	7	4.5		13.5
TRANSPORT	NS			20			20
TOTAL		11.5	16	50.5	19	3	100

S = Substitutable
NS = Non-substitutable

Table A1 gives some guide to which categories of demand are substitutable. (Eventually we would wish to extend these categories as our understanding of the uses of energy improves.) For these substitutable categories the situation is still unclear; price in the market will still be the main determinant, but future economic estimates are very uncertain. Furthermore, even if we assume that a particular energy carrier will penetrate a particular market, there is the problem that widely differing growth rates have been observed in the past.

- 1950-73 Liquid fuel grew at about 10% p.a.
- 1960-73 Electricity grew at about 6% p.a.
- 1967-73 Natural gas grew from nothing to a share of 15% of final energy.
- Up to 73 District heating growth was virtually zero.

The development of market shares in specific energy sectors is correspondingly different for different carriers.

Step B: Attraction Potentials for Coal

We now turn to identifying the potential for coal as a primary fuel input to these energy carriers. This potential will depend on a number of factors, some specifically referring to primary fuel competition, others to the nature of the energy carrier itself (recognizing that a complete separation of Steps A and B would be incorrect). The main factors are:

- Availability of a coal-based technology;

- A possible "gap" in the supply of alternative primary energy to the energy carrier, e.g. scarcity of indigenous hydrocarbons or lack of development of nuclear technology;

- Anticipated comparability of possible costs of the coal-based final energy form and that of the alternative primary energy;

- Existence of a supply infrastructure to handle the coal-based energy carrier;

- Efficiency of the coal conversion technology (including the final efficiency of utilization at the consumer end).

In further work it might be possible to analyse coal-based conversion processes in terms of a "score" obtained for each of these points, arriving at a total score for the potential of the process under the specific assumptions of the scenario. By varying assumptions one might analyse whether particular potentials remained consistently high. For the moment we analyse in broader terms, for each energy carrier, as described below.

Electricity

Possible coal-based routes to electricity are (with approximate conversion efficiencies):

- Conventional pulverized fule combustion (35%),

- Atomospheric fluidized bed combustion (35%),

- Pressurized fluidized bed combustion with combined cycle (40 to 45%),

- Fluid or fixed bed gasification with combined cycle (4o to 45%).

Atmospheric fluidized bed combustion will be available in the early 1980s. It is expected that the viability of combined cycle systems might be demonstrated by 1985, leading to commercial application by 1990.

For electricity generation, coal is competing with the primary fuel nuclear. A coal option *might* consider two possible cases:

(a) The eventual success of breeder and fusion technology by, say, 2020, but with a period of slow nuclear growth in the period from now to 2000.

(b) The complete failure of the nuclear programme. This might arise either through rapidly increasing world uranium prices coupled with worldwide failure to demonstrate the feasibility of breeder or fusion technology, or through a moratorium on nuclear power for environmental reasons.

Both these cases allow nuclear power a smaller role than do many other commentators, but they are a real possibility in the UK, where there is uncertainty in the type of reactor to be used in the next generation of nuclear reactors, and a corresponding weakness in nuclear technology.

The potential for the coal-based route to electricity is:

- In case (a) HIGH in 2000 LOW in 2020;
- In case (b) HIGH in 2000 HIGH in 2020.

Central Gas

Coal routes to central (high Btu) gas include:

- Conventional gasification techniques (Lurgi, Koppers-Totzek, Winkler, with methanation). These are likely to be available on a commercial scale by the early 1980s. Improvements to the processes (such as the slagging Lurgi, being developed at UK Westfield) might be available by the mid-1980s. Overall efficiency will be about 65% with full by-product utilization.
- Advanced gasification techniques including hydrogasification (e.g. Hygas, Bi-gas, CO_2 accepter). These are likely to be available by the mid-1990s. Overall efficiency might be about 75%.
- Gasification with nuclear heat. This process, currently being researched in the FRG in particular, would result in higher efficiencies. It is not likely to be available before 2000, and is not considered in this case study, as it would arise in a coal option only in very particular circumstances.

Indigenous supplies of methane will be diminishing by 2000 and be zero by 2020. Therefore, unless security of supply is all-important, the deciding factor will be the costs of the coal process in relation to the costs of imports or oil-based processes. The coal-based processes will probably not be competitive by 2000, but will be in a much stronger position by 2020.

- Overall potential for coal:

  MEDIUM in 2000 HIGH in 2020.

Liquid

Coal routes to liquid include:

- Liquefaction based on liquid extraction. There is one commercial installation today based on mixed-oil input (S. Africa), and several countries plan introducing such plant by the mid-1980s (USSR, Poland). General worldwide commercial availability based solely on coal is likely to be in the 1990s. Overall efficiency will be around 60%.
- Pyrolysis. The efficiency will again be around 60%, and the process will not be available commercially until the 1990s.
- Liquefaction based on supercritical gas extraction. This process, which could take overall efficiency up to 70%, still exists only at laboratory scale.

Indigenous supplies will last longer than those of gas, and the potential for coal is low in 2000. However, even with (a) increased finds, (b) secondary recovery, and (c) reduced exploitation in the period 1985-1995, there will be little or no indigenous production of crude oil by 2020.

The overall potential for coal-based processes is assessed as

LOW in 2000 HIGH in 2020.

Direct Solid

On cost and efficiency grounds it may well be preferable to use coal directly rather than convert to something else. A return to direct use will, however, be limited by rates of housing replacement, taste and convenience factors, and by the need to restrengthen the transport and distribution infrastructure.

The processes involved are diverse:

- Conventional appliances in residential,
- Manufactured solid fuels,
- Conventional coke to iron and steel manufacture,
- Conventional boilers in industry;

plus the new processes:

- New residential appliances,
- Formed coke in iron and steel manufacture,
- Fluidized bed boilers in industry.

Some of these processes involve the conversion of mined coal to another product, but in general we can assume a 1:1 primary to final conversion ratio if we assume full utilization of by-products.

By far the most important of the new processes will be fluidized bed boilers in industry. We have already noted that direct solid will decline in percentage of final energy terms until indigenous natural gas supply has peaked (1985); it will be convenient to consider that any return to direct solid after this time arises through the penetration of fluidized bed boilers into the industrial heating market.

The potential for coal is assessed as

HIGH in 2000   HIGH in 2020.

(Note that here there is no competition of primary fuels for conversion into another energy carrier; we refer to the potential for the energy carrier itself.)

<u>Other Networked Heating</u>

Coal-based processes will include:

- Low Btu gas networks to industry (air gasification),
- Medium Btu gas networks to industry or residential (oxygen gasification or pyrolysis),
- District heating schemes from a central fluid-bed boiler,
- District heating schemes using waste heat from local electricity generation.

Growth of these schemes will be limited by the low level of existing distribution infrastructure.

The potential is assessed as

MEDIUM in 2000 MEDIUM in 2020

Step C: Conversion Technologies--Introduction and Timing

The previous step analysed the potential for coal-based processes in broad terms. We must now be more explicit about how these potentials can be translated to market penetration rules (see also Annex I to Appendix B).

The following parameters must be established for each coal-based process in its particular final energy carrier or market:

- t_1 - the year of introduction of the first plant of commercial scale;
- t_2 - the year when the process achieves a significant proportion (10% of its market);
- p - the allowable penetration rate after t_2;
- s - the saturation level in the market, if one exists.

The time difference between t_1 and t_2 can only be estimated once a particular scenario is established, since we cannot state beforehand the absolute value that 10% of the market represents. However, prior to the preparation of any scenario, we can use the attraction potentials to estimate *either* t_1 or t_2, and we can obtain an estimate of p.

In the coal option the coal potential in central electricity is HIGH in 2000, and a new coal technology could achieve 10% of the market by 1990. However, estimates of the availability of pressurized fluidized bed combustion with combined cycle show that the first plant on a commercial scale should be ready by 1990, and so we take t_1 = 1990. Figure A2 shows past and planned future shares of electricity generating capacity by technology over the period 1950-1985. From this we find that the allowable penetration rate in this market is from 10% to 50% in about 17 years.

For gas, we obtained a coal potential of MEDIUM in 2000, and HIGH in 2020. We take t_2 = 1995, noting that there should be no problems with availability of technology. As a guide to the allowable penetration rate for the coal conversion technology, it is better to take the estimate derived above for the electricity conversion technology, rather than draw parallels with the past penetration of natural gas which has no need of a conversion technology.

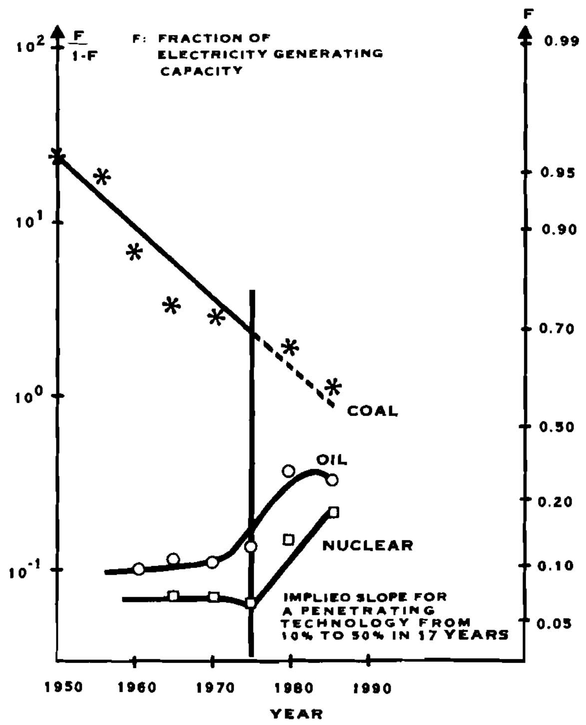

Figure A2. UK electricity generation technologies.

For liquid, we obtained a coal potential of LOW in 2000, and HIGH in 2020. We take t_2 = 2010, and p as above.

For solid the potential was HIGH throughout. As described in Step B, we will analyse the growth in terms of one coal process, fluid bed boilers in industry. This process will be readily available in the 1980s and we take t_2 = 1990. Figure A3 shows the shares of competing fuels in the market of low process heat and space heating in industry over the period 1960-1974. Pre-1973, oil penetrated the market at a rate equivalent to 10% to 50% in 16 years, and this rate is assumed for the new coal process.

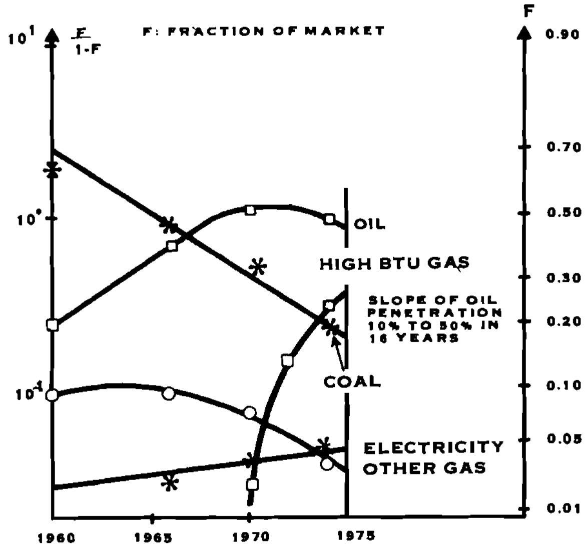

Figure A3. UK competition in the industrial heat market (substitutable. space heating, low process heat, etc.).

For other networked heating, with a potential of MEDIUM throughout, we take t_2 = 2000. In the residential sector, the growth of this form of energy carrier will be limited by the rate of housing replacement, and within this by demand density considerations. We take as a maximum rate of penetration one quarter of the rate of housing replacement. The latter is about 2% p.a., and so a penetration time of 80 years from 10% to 50% of the market is obtained.

Finally, for any local electricity schemes with waste heat utilization, the allowable rates of penetration will be conditioned by the capacity of the specific market to absorb the waste heat. Thus in the residential sector the analysis will be as in other networked heating; and in the industrial as for fluidized bed boilers.

Step D: Coal-Extraction Technologies

We turn to the question of supplying coal in the quantities derived in Step C, and identifying requirements for the contributions of particular coal extraction technologies. Extraction processes are more difficult to analyse than conversion, in that future coal mining may well operate with a continuous spectrum of technological improvement with few discrete changes identifiable in advance. The choice of method of extraction will depend markedly on particular characteristics in specific locations. However, if we identify the most important factors affecting extraction, we can establish a broad list of processes and analyse in average terms for the region.

Currently about 90% of all coal supplied in the region is deep-mined, and of this about 90% is obtained from mechanized longwall coal faces. As coal is extracted, the coal faces become more distant from existing access shafts and drifts, and so the expected increase in "external energy price" up to 2020 does not necessarily mean that further mining is economic. The solutions may include the following:

- Automation might be increased and productivity improved at existing access (the improvement may be increased mechanization of face-end procedures, improved automation of coal clearance, or selective use of a specific technique such as hydraulic cutting of coal).

- New access might be created where there is the possibility of very large productivity improvement through radical changes in the systems of transport of men, materials and coal;

- A further route to economic competitiveness arises through marketability; a fluidized bed process has less stringent coal input requirements, and therefore it may be possible to mine coal reserves previously considered unusable: the mining techniques are the same, but in effect a new extraction process is created *tied to a specific market.*

- The price of productivity improvement has been the drop in in-seam recoverability (90% for a handfilled face, currently around 40% for longwall faces and expected to fall further). However, it may be possible to balance this trend with the development of high recoverability techniques that take isolated parcels of coal rapidly, i.e. low capital shortface technology.

- Another approach to higher recoverability can be opencast mining. As stated above, current opencast output is about 10% of the region's production (12 Mt). This level might be greatly expanded, especially with the adoption of technologies that would extend the present maximum depth of 750 feet to around 1000 feet. The advantages in recoverability and productivity in opencast must be weighed against the obvious disadvantages of environmental disturbance over the life of any opencast site.

- A third method of increased recoverability might be the proved technology of low-pressure underground gasification. However, current indications are that, in virgin deposits of coal, on average it will be more economic to use conventional opencast or deep-mining techniques (whichever is applicable). In the important area of *secondary recovery* of deposits worked once by deep mining, there are problems associated with recovery of the products of gasification of the isolated pockets of coal.

There remain large quantities of coal resources which cannot be extracted by the set of mining techniques described above. A very important constraint is depth; the limit of working of the deep-mining processes described above is in general around 4000 feet. Specific local geological or environmental considerations may also prohibit the application of the above techniques. To overcome these problems, a completely new technology is required. This could be one or a mix of the following:

- High-pressure underground gasification;
- Underground liquefaction;
- Completely automated remote-controlled mining;
- Biological extraction or some entirely new combination of processes.

To build a mix of all the previously mentioned extraction processes into a supply profile is complex, especially as there is little data on how fast extraction technologies can penetrate the industry in a climate of expanding coal production.

Step E: Resource/Environmental Consequences

Eventually the CTF would aim to document coal option energy strategies in terms of the following resource inputs and environmental outputs.

Inputs

- Coal reserves (and requirement for resource to reserve transition)
- Capital
- Labour
- Materials
- Land (area used)
- Water (use of)
- Consumer capital

Outputs

- Air pollutants (CO_2, CO, NO_x, SO_2, particulates), centralized
- Air pollutants as above, decentralized
- Water pollution
- Water--effect on water table
- Radioactive emissions
- Heat dissipation (centralized)
- Heat dissipation (decentralized)
- Solid waste
- Occupational health and safety
- Subsidence.

Such a task is impossible in a preliminary report and is of limited relevance until *all* energy strategies being evaluated are documented similarly. What is far more important is that different coal-producing regions are currently much aware of particular items from this list. It may not be the whole region that is relevant; subsidence may be a particular problem for a particular coal-producing subregion, or alternatively SO_2 emission may be of particular importance to a region with dense coal conversion and direct consumption. Our goal is to quantify these items of particular interest, and identify possible constraints, so as to investigate how the setting of these constraints will affect the supply/demand match.

In the scenarios that follow we will concentrate on three items of particular importance in our region: manpower, coal reserves, and capital.

3. A BASE CASE FOR A UK COAL OPTION

Steps A to E: Scenario 1

This scenario is intended only as a base for further analysis, and in no way represents a "central" or "best" projection. The assumptions are the following:

- Final energy will grow at the historical rate of 1.25% p/a. As described in Step A, the historical rate was artificially depressed, and so the assumption is a conservative one. Total final energy demands of 86 GTh in 2000, and 110 GTh in 2020 are obtained.

- There will be no change in the relative proportions of demand of the total sectors *residential, industry* and *transport*.

- As indigenous supplies decline, demand for liquid and central gas will decrease to "premium use". This is defined as the non-substitutable components of demand, plus some premium use in the substitutable sector of residential (eventually for gas 40% of the sector, i.e. 11% of total final energy, and for liquid 10% of the sector, i.e. 3% of final energy).

- Solid is assumed to penetrate the industrial heating sector as described in Step C, but cannot penetrate more than 50% of the market.

- An exogenous projection of solar input to residential is taken: 1 GTh in 2000, and 8 GTh in 2020.

- Any remaining demand is divided between electricity and other networked heating. The latter cannot grow faster than the rates laid down in Step C.

- All electricity is centrally generated. The potential for coal into central electricity is assessed as HIGH in 2000 and LOW in 2020. As described in Step B, this means that coal plays a major part in electricity production until the breeder (or fusion) technology is sufficiently developed in the region. The assumption here is that the new (post-1990) generation of nuclear reactors will reach 10% of the generating capacity by 2000.

- New coal technologies will penetrate into the electricity, gas, and liquid markets as laid down in Step C.

From these rules the following total demands for energy carriers can be derived (see Table A2 for a complete tabulation on the same format as Table A1):

	Year 2000		Year 2020	
	%	GTh	%	GTh
Central electricity	13.5	11.6	18.5	20.3
Central gas	19	16.3	13	14.3
Liquid	45	38.7	37	40.7
Solid	17.5	15.0	20.5	22.6
Other heating	4	3.4	8.5	9.3
Solar	1	1.0	2.5	2.8
Total	100.0	86.0	100.0	110.0

Table A2. Energy demand: sectors and carriers (Scenario 1).

	Central Electl.	High Btu Gas	Liquid	Solid	Solar	Other heating
RESIDENTIAL Space, water, cooking	5 / 6.5	14 / 11	4 / 2.5	2 / 2	1 / 2.5	2 / 3.5
RESIDENTIAL Lighting, TV, etc.	1.5 / 1.5					
INDUSTRIAL Space, low process heat	3 / 6.5	3 / 0	9 / 2.5	11 / 14		2 / 5
INDUSTRIAL Motive power, high process heat	4 / 4		5 / 5			
INDUSTRIAL Chemical feedstock		2 / 2	7 / 7	4.5 / 4.5		
TRANSPORT			20 / 20			
TOTAL	13.5 / 18.5	19 / 13	45 / 37	17.5 / 20	1 / 2.5	4 / 8.5

2000 / 2020 Percentage of total final energy

Figure A4 plots energy carrier shares on this basis throughout the whole period 1970-2020.

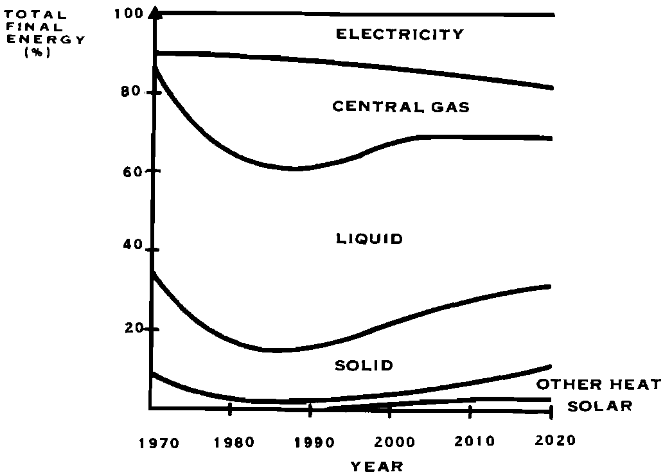

Figure A4. UK energy carriers as a percentage of total final energy (2000 and 2020 as in Scenario 1).

It will be seen that Scenario 1 thus embodies a broad "electricity generation on present principles" view. Scenario 2 contains a contrastingly *low* central electricity view, on radically different principles.

Electricity

In Scenario 1, demand for central electricity is 370 TWh in 2000 and 650 TWh in 2020, after allowing for transmission and distribution losses of 10%. With a total plant safety margin of 20%, this gives total generation capacity requirements of 80 GW in 2000 and 125 GW in 2020. The build of capacity other than coal is broadly as follows.

	Year 2000 (GW)	Year 2020 (GW)
New (post-1990) nuclear 10% in 2000, leading to 60% in 2020	8	75
Existing nuclear	10.5	-
Oil	16	-
Others	5.5	5
Total	40	80

The coal option is to fill the gap with pressurized fluidized bed with combined cycle as fast as possible, for reasons of overall efficiency, fuel flexibility, SO_2 control, etc. Step C gave 1990 as the earliest possible date for the first 2 GW plant, and it could take up to 1996 to install further plant to cross the 10% penetration level. By 2000, with the penetration rules established, there will be 12 GW of capacity of this type, and the process can easily grow to provide the total of 45 GW required by 2020. The capacity requirement from other coal processes (e.g. pulverized fuel or atmospheric fluidbed combustion) is thus 28 GW in 2000. This might just be handled by delayed decommissioning of existing coal-fired plant, but would probably necessitate a new round of conventional coalfired commissioning in the 1980s.

- In 2000, at 50% load factor and 36% efficiency, coal burn is 70×10^6 t.c.e.
- In 2020, at 40% load factor and 40% efficiency, coal burn is 55×10^6 t.c.e.

Gas

Allowing for 5% distribution losses, demand for gas is 17.1 GTh in 2000 and 15.0 GTh in 2020. The figure for 2000 compares with indigenous production in the range 7 to 17 GTh from Figure A1. Step C dictates that the coal-based process provides 10% of the market by 1995, which allows a growth to 17% of the market by 2000, and to 75% by 2020. Thus:

- To provide 2.9 GTh in 2000 at 65% efficiency requires 20 Mt;

- To provide 11.25 GTh in 2020 at 70% efficiency nearly 65 Mt.

The figure for 1995 constitutes approximately two commercially-sized plants of output 250×10^6 ft^3/d and this confirms that there will be no problem with timing of technology.

Liquid

Allowing for *10% distribution losses*, demand for liquid is 43 GTh in 2010, and 45 GTh in 2020. Step C dictates that coal-based processes provide 10% of the market by 2010, which allows penetration to 30% by 2020. Thus:

- At 60% efficiency, 90 Mt of coal are required in 2020.

The 10% penetration for 2010 constitutes five commercial-scale plants of 7 Mt p.a. coal-processing capacity operating at 80% load factor. Thus one plant must be installed by 2000, using 5 to 6 Mt of coal p.a.

Direct Solid

The demand for solid follows direct from the final energy assumptions and is 60 Mt in 2000 and 95 Mt in 2020.

Other Networked Heating

This also follows from the final energy assumptions, if we take an 80% efficiency. The ensuing coal demand is 20 Mt in 2000 and 50 Mt in 2020. Thus the total coal option demands for coal are:

	Year 2000	Year 2020
	(Mt)	
Electricity	70	55
Gas	20	65
Liquid	5	90
Direct solid	60	95
Other heating	20	50
Total	175	355

Figure A5 plots coal inputs to different energy carriers throughout the whole period 1970-2020. For 2000 and 2020 the inputs of coal are compared to the other inputs of primary energy in Table A3.

In Figure A6 we build up a supply profile consistent with the demands calculated above. Again, it must be emphasized that this is a preliminary scenario from which we obtain a basis for further analysis. Beyond 1985, it in no sense represents either a forecast of, or plans for, the coal production from the region under consideration. In general, this supply mix can be regarded as a "high-level technology, low recoverability" mix; there are other possibilities which would aim at a higher overall recoverability.

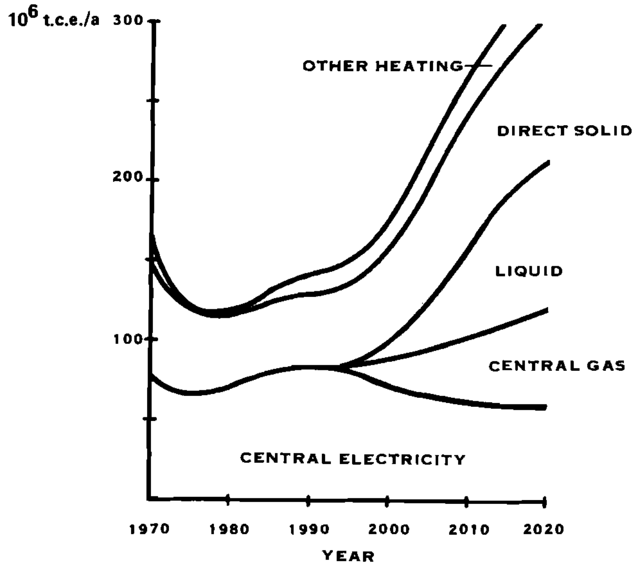

Figure A5. UK: The uses of coal 1975-2020 (Scenario 1).

Table A3. Primary fuel inputs (Scenario 1).

	Year 2000	Year 2020
	(10^6 t.c.e.)	
Coal	175	355
Indigenous gas	50	-
Imported gas	5	15
Indigenous oil	120	-
Imported oil	70	125
Nuclear	45	190
Solar	5	10
Total	470	695
Coal %	37%	51%
Coal-based energy as % of final energy	32%	54%

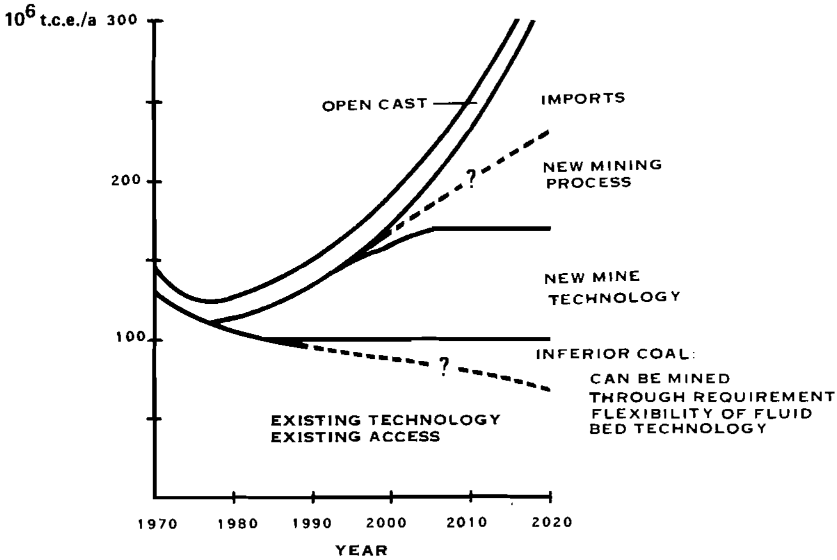

Figure A6. UK coal supply (Scenario 1).

The assumptions contained in Figure A6 together with the associated outputs are listed in Table A4.

Table A4. Production of coal for Scenario 1.

	Production (Mt coal)	
	2000	2020
Opencast builds up to 15 Mt p.a., and is then constant	15	15
Conventional mining, existing access: productivity improvements are assumed to be such that this method of extraction continues to support 100 Mt p.a. for the time period covered. (Some of this output will arise through the use of fluid-bed technology in the electricity and heat markets. However, we cannot as yet quantify what effect the increased flexibility of this market will have on reserves.)	100	100
New pit technology: as planned up to 1985; after that a doubling time of ten years, but saturating at 70 Mt p.a. Productivity improvements maintain output at this level.	55	70
New mining process (or mix of processes): assumed to take the residual demand. In a "low recoverability" scenario this may be remote-controlled mining at depth greater than average.	5	170
Total	175	375

Thus, a pilot mine demonstrating the new mining process must be available by the late 1990s, and the new mining process must expand to an industry of 170 Mt output by 2020. Alternatively, imports would be required to support this coal option scenario.

Implications of the Base Case

We now investigate how Scenario 1 has used three resources.

Coal Reserves

From Figure A6 can be derived the requirement for additions to reserves over the period 1975-2020. In this period the cumulative amount deep-mined is about 8 Gt. To convert this to a reserves requirement we must estimate the average recoverability, withing the context of the "high-level" technology, low-recoverability assumptions.

As quoted previously, the current estimate of recoverability is 40%. Further automation can be expected to give a downward trend to this figure, but other technological improvements (e.g. shield supports to allow the taking of more roof coal) will pull in the opposite direction. For the moment we take 40% as an average recoverability for the industry for all periods, this giving a cumulative reserve requirement of 20 Gt by 2020. If we now direct that all reserves must be demonstrated at least 20 years before extraction, we obtain a geological exploration programme such that 20 Gt of coal are located and appraised as reserves in the next 25 years. These are split roughly as follows:

- 11.3 Gt attached to existing access, including an unknown percentage of "inferior" reserves;
- "inferior" reserves at existing access that should become economic with fluid-bed technology;
- 5 Gt at new mine locations;
- 3.7 Gt at geological locations e.g. at depth greater than 4000 feet, suitable for the new technology.

These figures can be set in the context of published proved reserves for the region of 4 Gt, although that figure is to some extent corrected for recoverability. Total reserves of coal mineable by current methods (less than 4000 feet, greater than 2 feet thick) are about 100 Gt in known locations, and rise to about 160 Gt if inferred reserves are included.

Manpower

Current deep-mined productivity in the region is an average 500 t manyear, although individual collieries vary appreciably. We assume the following broad estimates in order to derive labour requirements.

Existing methods, existing access	1.5 × current in 2000, 2 × current in 2020
Existing methods, new access	4 × current
New technologies	4 × current
Opencast	4 × current deep mined.

This leads to manpower requirements of:

190,000 in 2000   225,000 in 2020

compared with the current level of 240,000 men.

This initial analysis must be extended in two ways:

- Type of work: By 2020 a large proportion of the workforce consists of skilled engineers at or near the surface.

- Location of work: Hidden in the temporary decline of the workforce of men in the years 1975-2000 are major relocations of manpower as increased investment is made in new areas of mining. For example, for the new pits by the year 2000, under the productivity assumptions above, 27,500 are working at new locations. This presents severe problems if the men are either relocated from existing pits (new towns, social infrastructure) or attracted from local employment (disruption of local industries, e.g. agriculture). This problem may exert a stronger influence on constraining production by 2000 than will "type of work" on production by 2020.

Capital

Estimates of the use of this resource are even more uncertain than for the two cases above. However, we can establish the order of magnitude of capital invested in the coal option by looking at the six main processes involved. (All figures are approximate late 1975 prices.)

Process	Assumptions	Total capital invested during Scenario 1	Total investment requirement up to 2000
		(10^9 £)	
Combined cycle FB power stations	£170/kw	6.8	2
Gasification	£75/annual ton coal processed	4.5	1.2
Liquefaction	£75/annual ton coal processed	6.8	0.4
Mining, existing access	£25/annual ton; natural decline rate without investment 2.5 Mt p.a., 30-year life	3.1	1.25
Mining, new capacity	£35/annual ton, 30-year life	3.5	2.1
Mining, new technology (no imports)	£50/annual ton	8.5	0.25
	Total	33.2	7.0

4. ALTERNATIVE CASES FOR A COAL OPTION: A SENSITIVITY ANALYSIS

Step F: Scenario 2--Local Electricity Generation

Scenario 1 analysed possible demands for coal in the context of patterns of energy supply that were broadly conventional. In a region following a coal option we must pose two questions:

- Should electricity increase in market share terms?

- Should all electricity be centrally generated?

In this scenario the implications of answering these questions in the negative are analysed by making the following assumptions:

- Total electricity share of final energy demand is held at 1974 percentage (11.5%).

- Local electricity generation is introduced as fast as as the market will absorb the accompanying waste heat.

- In the residential heating sector, the 10% significance level is reached by the year 2000, and the penetration rate thereafter is from 10% to 50% in 80 years.

- In the industrial heating sector, the 10% significance level is reached by the year 1990, and the penetration rate thereafter is from 10% to 50% in 16 years, subject to a maximum penetration of 50%.

- Typically the ratio of heat output to electricity output will be 2:1. However, from load factor considerations, central electricity generation must always be at least half of total generation. Thus, especially in industry, the schemes will be predominantly for heat production.

- In this respect they are akin to the "direct solid" use considered in Scenario 1; thus in Scenario 2, direct solid cannot also penetrate in the industrial heating market.

- At 2:1 heat to electricity ratio, the *electricity efficiency* is taken to be 25%; at 3:1 20%, and at 5:1 14%.

- The above rules mean that central gas and liquid do not decline in the residential and industrial sectors as fast as in Scenario 1.

- Finally, the *levels* of nuclear reactor building used in Scenario 1 are retained in this Scenario.

- All other assumptions are as in Scenario 1.

Table A5 shows the results of following through these assumptions in percentage of final energy terms. The essentials are summarized below:

	Year 2000		Year 2020	
	% of final energy	GTh	% of final energy	GTh
Central electricity	7.25	6.2	6.0	6.5
High Btu gas	19.5	16.8	15.5	17.0
Liquid	47.5	40.8	41.0	45.1
Direct solid	10.0	8.6	10.0	11.0
Solar	1.0	1.0	2.5	2.8
Local electricity	4.25	3.6	5.5	6.1
(Waste heat)	10.5	9.0	19.5	21.5
Total	100.0	86.0	100.0	110.0

The coal demands by market are:

	Year 2000	Year 2020
	(Mt)	
Central electricity	25	-
High Btu gas	20	80
Liquid	10	100
Solid	35	45
Local schemes		
- Residential	20	50
- Industrial	50	90
Total	160	365

Apart from the introduction of the local schemes, the main change from Scenario 1 arises in central electricity. The generating capacity requirements, assuming a 10% safety margin, are 50 GW in both 2000 and 2020.

Table A5. Energy demand: secotrs and carriers (Scenario 2).

	Central Electricity	High Btu Gas	Liquid	Solid	Solar	Local Electricity	Waste Energy
RESIDENTIAL Space, water, cooking	3 / 2	13.5 / 10.5	4 / 3	2 / 2	1 / 2.5	1.5 / 2	3 / 5.5
RESIDENTIAL Lighting, TV, etc.	1.5 / 0.75					/ 0.75	
INDUSTRIAL Space, low process heat	0.75 / 0.75	4 / 3	11.5 / 6	3.5 / 3.5		0.75 / 0.75	7.5 / 14
INDUSTRIAL Motive power, high process heat	2 / 2		5 / 5			2 / 2	
INDUSTRIAL Chemical feedstock		2 / 2	7 / 7	4.5 / 4.5			
TRANSPORT			20 / 20				
TOTAL	7.25 / 6	19.5 / 15.5	47.5 / 41	10 / 10	1 / 2.5	4.25 / 5.5	10.5 / 19.5

2000 / 2020 Percentage of total final energy

Given the same *levels* of nuclear building as before, we obtain:

Generating capacity	Year 2000	Year 2020
	(GW)	
New (post-1990) generation nuclear	8	45
2nd or 3rd generation nuclear	10.5	-
Oil	16	-
Others	5.5	5
Total	40	50

Thus only 10 GW of coal-fired capacity is required centrally, and this is easily provided by existing capacity without any new coal-fired stations. The above calculation of burn assumes 60% load factor and an average 30% efficiency. Table A6 lists the primary fuel inputs for Scenario 2.

Table A6. Primary fuel inputs (Scenario 2).

	Year 2000	Year 2020
	(10^6 t.c.e.)	
Coal	160	365
Indigenous gas	50	-
Imported gas	10	20
Indigenous oil	120	-
Imported oil	75	140
Nuclear	45	115
Solar	5	10
Total	465	650
Coal %	34%	56%
Coal-based energy as % of final energy	31%	59%

Step F: Scenario 3--No Nuclear

Scenario 2 demonstrates a demand for coal of 160 Mt in 2000 and 365 Mt in 2020 in the following context:

- A significant proportion of electricity is generated locally with waste-heat utilization.
- The demand for electricity as a percentage of total final energy does not increase over its 1974 value of 11.5%.
- There is a consequent low rate of growth of the "post-1990" nuclear reactor technology: 8 GW is required in 2000 and 45 GW in 2020.
- There is no requirement for high-efficiency coal-fired generating plant such as pressurized fluidized bed with combined cycle.

We now turn to the analysis of potentials in Step B where the potential for coal to electricity was HIGH in 2000 and in 2020, i.e. no nuclear capacity was built after 1990 *either* because of a failure to develop breeder technology *or* through increased opposition to nuclear on environmental grounds.

The requirements of 8 GW in 2000 and 45 GW in 2020 can easily be met by the technology of pressurized fluid bed with combined cycle, given the previous estimate of availability of the first commercial plant by 1990. Therefore, if there is no nuclear reactor building after 1990, the demands for coal, using Scenario 2 as a base, become:

	Year 2000	Year 2020
	(10^6 t.c.e.)	
Central electricity	40	100
High Btu gas	20	80
Liquid	10	100
Solid	35	45
Local schemes		
- Residential	20	50
- Industrial	50	90
Total	185	465

Thus two broad conclusions are:

- If no new nuclear reactor stations are built after 1990, coal can easily fulfill the requirements for centrally generated electricity, while also meeting the demands arising from potentials in other energy carriers.
- By 2020, there are large requirements for production from a new mining technology, or from imports of coal