COMMISSION OF THE EUROPEAN COMMUNITIES

environment and quality of life

Study into the emission of air pollutants coming from the use of coal within the United Kingdom

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for the Environment and Consumer Protection Service
of the Commission of the European Communities

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CONTENTS (Part I)

SUMMARY

Part I of this study into the emission of air pollutants coming from the use of coal within the U.K. is concerned with the present and future patterns of coal production and consumption and the effect of these on possible future levels of pollutant emissions. Part II of the study will examine the feasibility and economics of pollutant reduction during production and combustion processes.

In this part of the study an examination of historic trends in the emissions of sulphur dioxide and smoke is first presented (Section 2) and the improvement in the U.K. atmospheric environment in recent years clearly shown. Estimates of future coal production and market disposals are then presented (Section 3) and the uncertainty involved in making these projections noted.

The three major pollutants of concern - sulphur dioxide, oxides of nitrogen and particulate matter - are then considered in detail (Section 4) and estimates made of possible future emissions of each pollutant. Separate projections are shown for low, medium and high level emissions. Of the three major pollutants considered, sulphur dioxide is most likely to be dependent upon changes in coal quality. The information presented on this shows that the average sulphur content of U.K. coals is unlikely to change significantly in the foreseeable future. The projections of pollutant emissions are not therefore dependent to any significant extent on the quality of coal reserves; the important considerations are shown to be the estimated total future production of coal and the estimated market breakdown of this total. The projected increases in the high level emissions of all pollutants are a direct consequence of the projected increase in coal burn at power stations. To the extent that the fuel consumption estimates are subject to a substantial degree of uncertainty, so the projected emissions are also uncertain. The medium level emissions of sulphur dioxide are not projected to increase because of the introduction of new plant in the industrial market with significantly lower levels of emission per tonne of fuel consumed. A continuing reduction in the low level emissions of all pollutants is projected because of the progressive implementation of existing legislation in respect of domestic smoke control and a small reduction in the domestic coal burn.

An analysis of trace element concentrations in U.K. coals is presented in Section 5 but no projections of future concentrations are shown since there is no reason to assume that there will be any significant movement in these concentrations during the period with which the study is concerned. A brief description of current coal preparation practice and its effect on sulphur is presented in Section 6 and the principal legislation relating to Air Pollution in the U.K. is summarised in Section 7.

Finally this report concludes that the changes in patterns of fuel usage which have been the major factors in securing the environmental improvements seen in the U.K. during the last 20 years, will continue to be the primary influence in determining ground level concentrations of the pollutants considered. The report indicates that these trends will be such as to ensure that the progressive reduction in ground level concentrations will continue into the foreseeable future. The significance of such developments as fuel desulphurisation, flue gas washing, or fluidised-bed combustion will be among the considerations dealt with in Part II of this study.

CONTENTS (Part II)

LIST OF TABLES

PART 1

1. Introduction

1.1 In February 1977, the National Coal Board was asked by the Environment and Consumer Protection Service of the Commission of the European Communities to undertake a study into the present and possible future release of air pollutants arising from the use of coal within the United Kingdom.

1.2 The pollutants with which the study would mainly be concerned were

(a) SO_2

(b) NOx

(c) Particulate Matter.

Reference would also be made to chlorine, fluorine and certain trace elements (Arsenic, Cadmium, Mercury, Lead and Vanadium).

1.3 In order to arrive at quantified estimates of pollutant release, a considerab amount of scientific data on coal analysis has been collated, together with information on present and possible future patterns of coal production and consumption. This report, which constitutes Part I of the study, summarises this information and in particular shows the estimated emissions of the three major pollutants listed above for the reference year, 1975/76.

Estimates are also made of the position which obtained in 1970/71, and projections are made for 1980, 1985, 1990, and 2000.

1.4 Part II of the study will examine the feasibility and economics of sulphur reduction at the point of production and the reduction and disposal of pollutants during consumption over and above that assumed in this report.

2. Historical Perspective 1956 - 1976

2.1.1 Pattern of U.K. Pollutant Emissions from Coal

The estimated emissions of smoke and oxides of sulphur from the use of coal and other solid smokeless fuels given in Table 1 are taken from the 1976 Yearbook of the National Society for Clean Air and from 'Clean Air', Winter 1977.

Table 1 Emissions of smoke and sulphur oxides from the use of coal

10^6 tonnes p.a.

Year / Pollutant	1956	1960	1964	1968	1971	1976
Smoke	2.29	1.47	1.14	0.84	0.52	0.37
SOx	4.88	4.73	4.65	4.01	2.97	2.36

2.2 Smoke

The marked and progressive reduction in smoke emissions since 1956 has had two main causes:

(i) In 1956, domestic solid fuel consumption was 41 m tonnes. In 1976 not only had this fallen to 14 m tonnes, but due largely to smoke control legislation, the proportion of smokeless fuel had risen from 15% to 37%.

(ii) In 1956 77 m tonnes was supplied to Industrial plant and Railways. By 1976, this market had fallen to 13 m tonnes and this tonnage was also subject to smoke control legislation.

It should be noted that in 1956, 56% of the total smoke emitted in the U.K. came from domestic open fires. In 1976 this proportion had risen to 90% and most of this was in rural areas. Some indication of the environmental effect of these changing patterns of consumption may be obtained from the National Survey of Air Pollution carried out by the Warren Spring Laboratory of the Department of Industry. This showed that between 1959 and 1970 annual average smoke concentrations at ground level in urban areas of the U.K. fell from 170 to 55 $\mu g/m^3$. A more recent communication from the laboratory gives the corresponding figure for 1975/76 as 32 $\mu g/m^3$. (Appendix I briefly describes the method used by the Warren Spring Laboratory to calculate National Average concentrations.)

2.3 Sulphur Oxides

The emission of sulphur oxides follows the pattern of coal consumption during these years. Two points should be noted:

(i) In 1956, power stations accounted for 29% of total coal disposals. By 1976 this figure had risen to 61%, entailing a proportional reduction in the emission of sulphur oxides at medium and low level.

(ii) Total estimated emissions of sulphur oxides from the use of fossil fuels rose from 5.4m tonnes in 1956 to 6.5m tonnes in 1965, and then declined gradually to 5.0m tonnes in 1976. The emissions from the use of coal in the same years were 4.9, 4.6 and 2.9 m. tonnes respectively.

The/

The combined effect of these factors was shown by Warren Spring Laboratory to have resulted in a fall in average SO_2 concentration at ground level in U.K. urban areas from 155 $\mu g/m^3$ in 1959, to 100 $\mu g/m^3$ in 1970.

We are now informed by the Laboratory that the corresponding figure for 1974/75 was 74 $\mu g/m^3$.

3. Coal Production and Market Disposals

Statistics and Projections

3.1 Table 2 shows the tonnages and analyses of coal supplied by the N.C.B. to each of the main market sectors in 1970/71 and 1975/76. It shows that the main changes during this period were a 15% decrease in total disposals, a 10% increase in disposals to power stations, a slight rise in ash and moisture content causing a reduction in calorific value and virtually no change in the sulphur and chlorine content.

3.2 Appendices II and III show regional breakdowns for N.C.B. disposals in the base year, 1975/76, and Appendix IV gives details for imported coals for the same year. No analysis of the coal produced by licensed mines has been presented.

3.3 Table 3 summarises the N.C.B. disposals in 1970/71 and 1975/76 and shows estimates of future disposals by market for 1980, 1985, 1990 and 2000. The estimate for the year 2000 is the mean of the range indicated in "Coal for the Future" (2) and more recently published by the Departmental of Energy in the consultative document "Energy Policy" (3). The estimate for 1985 is that given in "Plan for Coal" (1) and also in "Energy Policy". The estimate for 1990 is an interpolation of those for the years 1985 and 2000. It should be emphasised that these forecasts, and particularly the furthest projections, are subject to a substantial degree of uncertainty. They may be considered to be taken from the ranges:-

1985	126-136	10^6	tonnes
1990	132-160	"	"
2000	137-203	"	"

TABLE 2

NCB DISPOSALS BY MARKET WITH RELATED ANALYTICAL DATA

1970/71

UK Total

Market Sector	10^6 tonnes	Technical Analysis (Actual)				
		Moisture %	Ash %	Cal.Val. kj/kg	Sulphur %	Chlorine %
Power Stations	66.3	11.3	16.2	24,440	1.49	0.23
Carbonisation	24.0	9.0	7.3	29,650	1.17	0.17
Industrial & Misc.	28.1	10.3	9.0	27,690	1.37	0.25
Domestic and manufactured Fuels	19.8	8.4	5.0	29,980	1.23	0.25
Others inc. Export	2.9	10.6	8.3	27,910	1.34	0.26
Total	141.1	10.3	11.5	26,820	1.37	0.23

1975/76

UK Total

Market Sector	10^6 Tonnes	Technical Analysis (Actual)				
		Moisture %	Ash %	Cal.Val kj/kg	Sulphur %	Chlorine %
Power Stations	73.1	11.9	17.1	24,070	1.51	0.23
Carbonisation	17.5	9.4	6.0	30,140	1.15	0.19
Industrial & Misc.	12.1	11.3	9.6	26,860	1.42	0.25
Domestic and manufactured Fuels	15.0	8.6	4.7	30,020	1.20	0.28
Others inc. Exports	1.5	9.9	6.3	29.950	1.07	0.13
Total	119.2	11.1	13.2	25,920	1.41	0.23

TABLE 3

NCB DISPOSALS FOR 1970/71, 1975/76 WITH PROJECTIONS FOR 1980, 1985, 1990 AND 2000

10^6 tonnes p.a.

Year / Market	1970/71		1975/76		1980		1985		1990		2000	
	Value	%	Value	%	Value	%	Value	%	Value	%	Value	%
Power Stations	66.3	47	73.1	61	78.7	63	89.0	65	88.0	60	86.0	50
Carbonisation	24.0	17	17.5	15	17.8	14	19.0	14	20.0	14	23.0	14
Industry & Misc.	28.1	20	12.1	10	12.0	10	12.0	9	20.0	14	41.0	24
Domestic & Manufactured Fuels	19.8	14	15.0	13	9.7	8	8.0	6	18.0	12	20.0	12
Other inc. Export	2.9	2	1.5	1	6.3	5	8.0	6				
TOTAL	141.1	100	119.2	100	124.5	100	136.0	100	146.0	100	170.0	100

Ref. 1, 2, 3

4. Pollutant Emissions : Estimates and Projections

4.1 In this section, emissions of the three major pollutants under consideration are estimated and projected under three headings : high, medium and low level. This division is inevitably somewhat arbitrary, and requires some explanation.

Briefly, all power station emissions are taken as high level, all industrial emissions as medium level, and domestic emissions as low level. It will be clear that this is only one of a variety of approaches which could have been adopted: for example a number of heavy industrial sources could legitimately be regarded as high level. However, the categorisation used is useful for the purpose of demonstrating trends and in distinguishing between low level emissions and medium level emissions, which come mainly from industrial chimneys whose heights are controlled by the Clean Air Acts (see Section 7).

4.2 Sulphur Dioxide

4.2.1 All British coals contain sulphur in a number of forms (see Section 6) and it is the oxidation of this sulphur during the combustion of coal which gives rise to the emission of sulphur dioxide (SO_2). Some sulphur is retained in the coal ash, and a small amount may be emitted in the form of sulphur trioxide (SO_3). For the purposes of this study it will be assumed that 90% of the sulphur in coal is emitted, and that all of this is in the form of SO_2.

4.2.2 The average sulphur content of British coal, increased from around 1.2% in 1938 to 1.4% in 1952 since which time it has remained at broadly the same level. Average sulphur contents vary from coalfield to coalfield. Scottish and Welsh coals are outstandingly low, most containing less than 1.0% whereas Yorkshire coals tend to be higher than the national average with mean values approaching 1.7%. The current overall position by coalfield is as follows:

Coalfield average % S.	Total output %
- 0.5	Nil
0.5 to 1.0	18
1.0 to 1.5	51
1.5 to 2.0	31
+ 2.0	Nil

/all sulphur contents on the as received basis/

Current production plans indicate that the sulphur content of the output from existing pits will remain at the present level for the next ten years. The sulphur content of classified plus unclassified reserves at existing collieries plus Selby, Thorne and Betws new mines is the same as that in present and planned output. However, the sulphur content in the classified portion of those reserves is slightly higher than in the unclassified reserves. To that extent, when these reserves are mined, there may be a tendency for the sulphur content of the output to rise by perhaps 0.1 percentage point.

4.2.3 The sulphur content in opencast output is forecast, on present production plans, to fall initially to 1.5% in 1980 and then rise to 1.6% in 2000.

4.2.4 The plans of the National Coal Board involve a high proportion of output coming by the end of the century from new mines, most of which have not yet been identified. Those which have been identified are likely to have outputs whose sulphur contents are similar to that of current output. These mines would therefore moderate the possible tendency for the sulphur content of existing mines to rise slightly. So far as unidentified new mines are concerned, the best view would appear to be that a high proportion will be in the eastwards extension of the East Pennine coalfield with a few in the other coalfields now being worked.

It is reasonable at this stage to assume that the average sulphur content of output from these sources will be comparable to that of the reserves originally available to existing mines in those coalfields. This is lower than the present average for national output and it is therefore probable that a programme of new mines based on existing coalfields will tend to reduce the sulphur content of U.K. output.

4.2.5 It must be recognised that any large programme of new mines - perhaps above the 150 m.t.p.a. deepmined output in the year 2000 taken as a mid-point in "Coal for the Future" - might well involve new sinkings in Oxfordshire and/or the Cheshire basin, both of which appear to have sulphur contents somewhat higher than the average of classified reserves. But the time when the output from collieries in new coalfields could have perceptible influence on the national average is very distant.

4.2.6 In conclusion, the available evidence points to a tendency towards a slight rise of 0.1% at most in the sulphur content of output from existing mines, and from opencast. This tendency is likely to be moderated or even cancelled out by the relatively low sulphur content expected in output from new mines at least until the end of the century.

4.2.7 Based upon the tonnage data and projections set out in Section 3, and the assumptions made in Section 4.2.1 Table 4 shows the emission of SO_2 from low-level, medium level and high-level sources, with projections to 2000.

4.2.8 In estimating the medium-level emissions of SO_2 it has been necessary to consider the development of fluidised bed combustion between now and the year 2000 in the industrial market. An evaluation of the scope for sulphur reduction by this process will be presented in Part II of the study. In Part I it has been assumed that there will be no addition of limestone for SO_2 control in fluidised bed fired boilers and furnaces.The medium level emissions shown in table 4 includ those from coal carbonisation.

4.3 NOx

4.3.1 During the combustion of coal, oxides of nitrogen are formed, partly by the combination of atmospheric nitrogen and oxygen, and partly by the oxidation of chemically-held nitrogen in the fuel. For the purposes of this study, the term NOx is used to denote the sum of the NO and NO_2; other oxides of nitrogen are not considered.

4.3.2 High level emissions.

The main factors affecting NOx formation and emission in large boiler plants are

(i) flame temperature
(ii) residence time
(iii) Oxygen concentration (excess air)
(iv) Nitrogen content of fuel.

For pulverised fuel power stations operating in the U.K. emissions per tonne of coal burned are taken as:-

5000	grammes of NO
700	grammes of NO_2
5700	grammes of NOx

Since over 95% of the coal burned at power stations in 1975/76 was at pulverised fuel power stations, these rates are assumed to be representative of

the/

TABLE 4

ESTIMATED SO_2 EMISSIONS FROM SOLID FUEL USAGE: U.K. TOTAL

'000 tonnes p.a.

Source	1970/71	1975/76	1980	1985	1990	2000
High Level	1,778	1,957	2,139	2,430	2,403	2,349
Medium Level	884	430	429	437	627	1,027
Low Level	438	324	210	175	175	175
TOTAL	2,909	2,590	2,656	2,917	2,890	2,836

the average for all power stations and have been applied to the estimates of the total power station burns to calculate the high level emissions shown in Table 5.

4.3.3 Medium level emissions.

These will include emissions from industrial process, steam-raising and heating installations, and a wide variety of combustion conditions will be involved. Clearly, any figure of NOx emission for this type of plant can only be an approximation and individual sources will vary widely. For these reasons, it has not proved possible to derive a figure for NOx emissions which could be meaningfully applied across the industrial spectrum. The emissions shown in Table 5, for completeness, are based on the same emission rates as for power stations; it must be emphasised that these figures are merely indicators.

4.3.4 Low level emissions.

Domestic appliances also show a wide variation in NOx emissions, being greatest with the closed appliances of the 'roomheater' type which operate at higher temperatures. Nevertheless, since the contribution of domestic sources to total NOx emission is fairly small, an average figure which can be applied to the domestic market as a whole has been deemed to be sufficiently accurate for the purposes of this study. This is taken as 700 grammes per tonne of coal burned and is shown and projected in Table 5.

4.4 Particulate Matter

4.4.1 High level emissions.

Section 7 sets out the legislation with regard to particulate emissions. It will be clear from this that it is not possible to establish precisely quantified criteria for U.K. installations but, in general, the figure of 0.05 grains/cu.ft. of flue gases may be taken as typical of best practice and will be used as an average figure for power station plant. This approximates to 950 grammes per tonne of coal burned, and this is the figure which is shown and projected in Table 6.

4.4.2 Medium level emissions.

Industrial and commercial installations are subject to the provisions of the Clean Air Acts. Permitted grit and dust emissions are governed by a variety of considerations such as the purpose and location of the plant and therefore precise determination of emission levels is not possible. However, as a first approximation, and using an average excess air usage denoted by 10% CO_2 in flue gases, a figure of 3000 grammes per tonne of coal burned is used. Table 6 has been compiled on this basis.

4.4.3 Low level emissions.

These emanate from two main classes of appliance.

(i) domestic open fires burning coal. Particulate matter emission here has been taken as 35,000 grammes per tonne of coal burned;

(ii) domestic appliances burning smokeless fuel. The maximum emission rate required of a manufactured fuel before it can be classified as smokeless is 5 grammes per hour at a normal burning rate (usually around 1 Kg/hour). On

TABLE 5

ESTIMATED NOx EMISSIONS FROM SOLID FUEL USAGE: UK TOTAL

'000 tonnes p.a.

Year / Source	1970/71	1975/76	1980	1985	1990	2000
High Level	371	410	442	502	496	485
Medium Level	160	70	70	70	110	230
Low Level	14	10	7	6	6	6

TABLE 6

ESTIMATED PARTICULATE MATTER EMISSIONS FROM SOLID FUEL USAGE: UK TOTAL

'000 tonnes p.a.

Year / Source	1970/71	1975/76	1980	1985	1990	2000
High Level	62	68	74	84	83	81
Medium Level	83	36	35	36	48	78
Low Level	429	323	209	176	176	176
TOTAL	574	427	318	296	307	335

> this basis, an average emission rate for smokeless fuels in practice of 2,500 grammes per tonne of fuel burned has been assumed.

There is, in addition, a small tonnage of bituminous coal (about ¼ m.t.p.a.) burned on 'smokeater' appliances. These are designed to operate smokelessly, and for the purposes of this exercise are classified as smokeless fuel burning.

Total domestic consumption in the reference year was 13 million tonnes of which 40% was smokeless fuel. It is expected that this total figure will fall to around 8 million tonnes p.a. by 1985, but projections beyond that date become extremely difficult. It is likely that, with the exhaustion of natural gas reserves, the domestic consumption of solid fuel will rise in the long term, but this is unlikely to become an important factor before the end of the century. In view of the fact that much of the 8 m.t.p.a. forecast for 1985 will be consumed in rural areas where there is no gas supply, it is assumed that this figure for direct domestic consumption will continue until 2000.

Within that figure, the proportion of solid fuel which is burned smokelessly will depend upon a number of factors. Progress with the implementation of smoke control areas will be the main factor tending to increase it in urban areas, this will tend to be balanced by the fact that a substantial proportion of bituminous coal consumption is in rural areas, and this tonnage is less vulnerable to competition from other fuels. It is assumed that the combined effect of these factors will be to increase the smokeless share of the domestic market from its present 40% to 50% by the end of the century.

The implications of these assumptions for low-level particulate emissions are shown in Table 6.

5. Trace Elements

Samples were taken in each of the producing coalfields and analysed for the trace elements shown in Table 7. No projection of these figures has been attempted but there is no reason to suppose that there will be any significant movement in these concentrations during the period with which the study is concerned. Emission of these elements will clearly be dependent largely upon the extent to which they are volatilised during the combustion process. To the extent that they are emitted, the tall stack policy, whilst primarily aimed at SO_2 also ensures the adequate dilution and dispersal of all other emissions, including heavy metals and other trace elements.

TABLE 7

Trace Element Concentrations

	National Average Concentration p.p.m.	Range of Coalfield Averages p.p.m.
Arsenic	18	4–40
Cadmium	0.4	0.3–0.6
Mercury	0.5	0.4–0.6
Lead	38	28–60
Vanadium	76	38–134
Fluorine	114	98–130

6. Coal Preparation and Consumer Requirements

6.1 Coal Preparation Methods

87% of the total output of U.K. coal is subjected to some form of mechanical cleaning process which in general, and with the principal exception of froth flotation, will rely upon specific gravity differences to separate coal from incombustible and inferior materials. The percentages of the total tonnage of prepared coal treated by the various techniques are shown below and brief descriptions of these techniques are given in Appendix V:

	%
Water-Medium:	
Jigs	61.8
Hydrocyclones	0.3
Concentrating Tables	0.3
Dense-Medium:	
Baths	22.0
Cyclones	6.1
Froth Flotation	7.1
Others	2.4

6.2 Of the three main pollutants dealt with in this study, sulphur dioxide is the most directly influenced by the preparation process. This is due to the high specific gravity of iron pyrites (5.0 approx.), as compared with clean coal (1.4 approx.) and shale (2.4 approx.).

6.3 The scope for sulphur removal

Sulphur occurs in British coals in two main forms:

(a) organic sulphur, and
(b) pyritic sulphur.

There may in addition be much smaller quantities present in the form of sulphates, but these will not be considered.

6.4 The organic sulphur content of British coals ranges from 0.4% to 1.5% with a mean of 0.8% (air-dried basis). This sulphur is an integral part of the coal matrix and cannot be removed by physical means.

6.5 Pyritic sulphur, comprising the balance of the sulphur content, averages 0.7% in British coals and ranges from 0.2% to more than 2.0% in exceptional cases. Sulphur in this form can be reduced by conventional specific gravity based coal preparation techniques, to an extent which is determined by the size of the pyritic particles in relation to the size of the coal particles being treated. Clearly the separation of pyrites can only be effected when the coal is of a size at which the pyritic particles are liberated.

6.6 The proportion of pyrites removed will depend upon the extent to which it is disseminated throughout the coal but in some instances - usually where coal is prepared for the coking market - a significantly higher proportion, perhaps up to 50% in total, can be removed by washing at a lower specific gravity than usual. This is accompanied by the production of a high sulphur middlings product which is sold for power generation. The sale of the middlings is an essential feature of this technique, since to discard them would render the process uneconomic. There would in addition be severe difficulties in disposing of them as a refuse due to the likelihood of the spontaneous combustion of the discarded material. The following example.is typical of the sort of additional sulphur removal which is obtainable by low-gravity washing.

Input:	100 tonnes coal floating at 1.6 S.G.,	1.50% S
Output:	(a) 85 tonnes coal floating at 1.4 S.G.,	1.35% S
plus	(b) 15 tonnes middlings 1.4 to 1.6 S.G.	2.35% S

6.7 Further removal of pyrites could be effected to some extent by crushing the coal to minus 0.5 mm and separating on concentrating tables. This process results in a coal product in the form of a fine slurry for which there is no market at present. Moisture content and handleability are vitally important considerations in all sectors of the market and the proportion of fine coal currently incorporated into washed and blended smalls is already approaching the limit of acceptability. This fine coal comes in part from froth flotation plant which is widely used for water clarification and fine coal recovery. The application of this process to sulphur removal involves the use of selective depressants, and its effectiveness is being investigated. It should be noted that all these fine coal processes are associated with a thermal loss which may be as much as 20% of the heat content of the coal before treatment.

6.8 In addition to these processes, there are a number of chemical techniques, some of which claim to have an effect on the organic sulphur in addition to the pyritic component. None of them have yet been put to commercial use, and preliminary estimates suggest that they would result in approximately a doubling of the cost of the raw coal.

6.9 The costs of the principal conventional coal preparation techniques may be summarised as follows:

Baum Jigs:	£1.00 per tonne input
Dense Medium:	£1.20 - £1.30 per tonne input
Froth Flotation:	Up to £3.00 per tonne input depending on method of tailings disposal.

These costs, based on December 1976, are for recently commissioned plant and include interest and depreciation charges at 15%.

6.10 The feasibility and economics of sulphur reduction by the various coal preparation processes and the effects of these processes on the availability and acceptability of the products to the customers will be further considered in Part II of this study.

7. Principal Legislation relating to Air Pollution in the United Kingdom

7.1 The control of atmospheric pollution in Great Britain is effected principally by the Alkali etc. Works Regulation Act 1906 and the Clean Air Acts 1956 and 1968. The Public Health Act 1936, and the Control of Pollution and Health and Safety at Work etc. Acts 1974 also contain provisions dealing with the matter. There are similar provisions for Northern Ireland, but they are not all identical with those for Great Britain.

7.2 Alkali etc. Works Regulation Act 1906

This Act applies to works in a large number of classes listed in a Schedule to the Act, including power stations, coke ovens, chemical process plant and cement works. Additions to the classes may be made by Regulations under the Health and Safety at Work etc. Act 1974. Works to which the 1906 Act applies may not operate unless they are registered and the best practicable means employed to prevent the escape of noxious or offensive gases from them into the atmosphere. Registration is for one year at a time and may be refused if the works do not comply with the above requirement.

7.3 For the purposes of the 1906 Act "gases" includes smoke, grit and dust. A large number of particular gases is specified in a list in the Act as noxious or offensive. Some may contain liquid in the form of droplets. Additions to the list may be made by order of the Secretary of State.

7.4 Clean Air Acts 1956 and 1968

The principal provisions of the Clean Air Acts 1956 and 1968 are those that:-

(a) prohibit the emission of dark smoke,

(b) permit the establishment of smoke control areas in which the emission of any smoke is controlled,

(c) restrict the emission of grit and dust from chimneys,

(d) provide for the measurement of grit and dust from chimneys, and

(e) require chimneys serving furnaces to be of a height approved by the local authority.

7.5 Some of the provisions of the Acts apply only to furnaces used to burn:-

(a) pulverised fuel, or

(b) any other solid matter at a rate of 100 lbs an hour or more, or

(c) any liquid or gas at a rate equivalent to 1¼m Btus an hour or more.

These furnaces are referred to in the following paragraphs as "large furnaces". The Acts do not apply to works that are subject to the 1906 Act unless, in an exceptional case, the Secretary of State provides for them to do so.

/Dark Smoke

7.6 Dark Smoke

The emission of dark smoke from the chimneys of buildings, chimneys serving the furnaces of boilers and industrial plant on land but not in buildings, or otherwise from industrial or trade premises, is prohibited except in certain classes of case prescribed by Regulations; these exceptions provide for lighting-up, soot-blowing, break-down etc.

7.7 Smoke Control Areas

A local authority may make a Smoke Control Order declaring the whole or part of their district to be a smoke control area and the Secretary of State may require them to make such an Order. The confirmation of the Secretary of State is required for any Order. The occupier of a building in such an area commits an offence if smoke is emitted from the chimney of the building unless the smoke is caused by the use of fuel declared by Regulations to be an authorised fuel. The Secretary of State may, however, exempt on such conditions as he may prescribe, fireplaces he is satisfied can be used for burning other fuels without producing any substantial quantity of smoke.

7.8 Grit and Dust

Large furnaces installed on or after 1st October, 1969, are required to be provided with plant approved by the local authority to arrest grit and dust unless an exemption is granted on the grounds that there will be no emission of grit and dust that will be prejudicial to health or a nuisance. The same applied to furnaces installed on or after 1st January 1958 which burned pulverised fuel or, at the rate of one ton per hour or more, solid fuel in any other form, or solid waste.

7.9 The local authority may also require provision to be made for grit and dust from large furnaces to be measured, and for measurements to be taken and recorded, but if the furnace is used to burn solid matter at a rate less than 1 ton an hour, or gas or a liquid at a rate less than 28m Btus an hour, the occupier of the building may require the local authority to make the measurements and keep the records.

7.10 Regulations may prescribe limits on the rate of emission of grit and dust from the chimneys of furnaces other than those designed solely or mainly for domestic purposes and used for heating boilers with outputs of less than 55,000 Btus an hour. The Clean Air (Emission of Grit and Dust from Furnaces) Regulations 1971 and corresponding Regulations for Scotland have been made for this purpose in relation to certain classes of furnace.

7.11 Chimney Heights

Since 1st January 1957, if a new chimney is erected to serve a large furnace, or the combustion space of a large furnace is increased, or a new large furnace is installed to replace a furnace with a similar combustion space, the chimney serving the furnace must, subject to certain exemptions, be of a height approved by the local authority. The height may not be approved for these purposes unless the authority are satisfied that it will be sufficient to prevent so far as is practicable, the smoke, grit, dust, gases or fumes from the chimney becoming prejudicial to health or a nuisance, having regard to:-

(a) the purpose of the chimney,

(b) the position and descriptions of the buildings near it,

(c) the levels of the neighbouring ground, and

(d) any other matters requiring consideration in the circumstances.

/Similar

Similar requirements have applied since 1st April 1969 to the height of other chimneys serving buildings used as residences, shops or offices.

7.12 Control of Pollution Act 1974

The Control of Pollution Act 1974 contains provisions -

(a) to permit Regulations to impose requirements as to the composition of motor fuel and the sulphur content of oil fuel,

(b) to prohibit the burning of insulation from cables to recover metal from them except at works registered under the Alkali etc. Works Regulation Act 1906, and

(c) to permit local authorities:-

  (i) to undertake research relevant to the problem of air pollution,

  (ii) to publish the results, and

  (iii) to require the occupiers of premises other than private dwellings to provide information about the emission of pollutants into the air.

7.13 Under (a) above the Oil Fuel (Sulphur Content of Gas Oil) Regulations 1976, which were passed in order to implement E.E.C. Directive 75/716/EEC on the sulphur content of gas oil, prescribe 0.8% as the limit for gas oil until the 1st October, 1980, and 0.5% as the limit thereafter, but there are some exceptions, e.g. for power stations. Other Regulations have been made relating to motor fuel.

7.14 Under (c) the Control of Atmospheric Pollution (Research and Publicity) Regulations 1977 have been made to govern local authorities in the exercise of their powers. Local authorities using these powers must consult representatives of industry and persons conversant with problems of air pollution or having an interest in local amenity at least twice a year about the way in which they exercise their powers and the extent to which information collected should be made available to the public.

7.15 Miscellaneous

Under the Public Health Act 1936 the local authority may take proceedings to abate statutory nuisances, and such proceedings may be taken in respect of smoke that is a nuisance to the inhabitants of the neighbourhood other than smoke from the chimney of a private dwelling or dark smoke of which the emission is otherwise prohibited (see paragraph 6.6 above).

7.16 The Health and Safety at Work etc. Acts 1974 requires employers and self-employed persons to carry on their undertakings in such a way as to ensure, so far as is reasonably practicable, that persons not in their employment but who may be affected thereby are not thereby exposed to other risks to their health and safety. This could apply to risks resulting from atmospheric pollution.

7.17 Apart from Acts of Parliament, the occupier of premises whose enjoyment of them is materially injured by smoke from other premises may have a right of action for Nuisance at Common Law and be able to obtain an injunction to restrain the nuisance or damages.

8. Conclusions

8.1 This part of the study has been concerned with present and future patterns of coal production and consumption and the effect of these upon possible future levels of pollutant emissions.

8.2 Of the three major pollutants considered, sulphur dioxide is the most dependent upon future changes in coal quality. The information available on this suggests that the average sulphur content of British coal is unlikely to change significantly before the year 2000. There is also no indication that there will be any significant change beyond this period.

8.3 In estimating the levels of pollutant emissions, no account has been taken of the effect of possible technical or legislative changes, with the following exceptions:

(a) It has been assumed that additional industrial coal-burning capacity will be new plants operating with significantly lower levels of emissions than those obtained with older equipment.

(b) Allowance has been made for the progressive implementation of existing legislation in respect of domestic smoke control.

8.4 In making these projections of pollutant emissions at high, medium and low level, it has become clear from the work undertaken for this part of the study that the quality of coal reserves is not likely to be a significant factor. The important considerations have been:

(a) the estimated future total production tonnage, and

(b) the estimated market breakdown of these tonnages.

8.5 These tonnages and market breakdowns are subject to a substantial degree of uncertainty, particularly for the more distant projections. Using mean tonnages taken from the ranges proposed in "Coal for the Future", the study indicates a proportional increase in the emission of pollutants at high level, accompanied by substantial reductions in low-level emissions. The forecast increase in overall SO_2 emissions from coal are a consequence of the projected increase in coal usage. Some of this increased tonnage will be in replacement of imported oil. No attempt has been made to assess the future SO_2 emissions from oil but it should be noted that estimates of SO_2 emissions from coal and fuel oil (the alternative fuel in the major markets) made by the Department of Industry's Warren Spring Laboratory, suggest that on a thermal equivalent basis fuel oil produces approximately 40% more SO_2 emission than coal (see, for example, reference 4).

8.6 In general, it may be concluded that changes in patterns of fuel usage, which have been the major factor in securing the environmental improvements seen in the U.K. during the last 20 years, will continue to be the primary influence in determining future ground level concentrations of the pollutants considered in this study. Indications are that these trends will be such as to ensure that the progressive reduction in ground-level concentrations observed since 1956 will continue for the foreseeable future.

8.7 The significance of such developments as fuel desulphurisation, flue gas washing, or fluidised-bed combustion and their likely environmental impact will be among the considerations dealt with in Part II of this study.

References/

References

1. Plan for Coal. National Coal Board, June 1974

2. Coal for the Future. Department of Energy, 1976

3. Energy Policy. Department of Energy, 1978

4. 'Estimates of Smoke and SO_2 Pollution from Fuel Combustion in the U.K.' Warren Spring Laboratory, 1977 - published in 'Clean Air' - Winter, 1977

APPENDIX I

THE DETERMINATION OF AVERAGE GROUND LEVEL CONCENTRATIONS OF SMOKE AND SULPHUR DIOXIDE BY THE WARREN SPRING LABORATORY. (1)

The total number of sites in the National Survey of Air Pollution, a co-operative survey co-ordinated by the Warren Spring Laboratory (WSL), is about 1200. Of these some have been installed by local and other authorities in response to their own needs for information, whereas others were set up, at the request of WSL, to provide, in conjunction with existing sites, a comprehensive U.K. survey which takes account of population, population density, domestic heating habits, industrial and other activities, etc. Each site is classified according to the National Survey Site Classification system (2) and over 1000 of the sites are classified as being urban (town) sites.

There is a small variation from year to year in the total number of sites available as readings are started at some new sites and ceased at others. The number of sites producing valid monthly or seasonal averages in any particular period is also variable, due to operational difficulties, and is normally lower than the total; typically approximately 75% of the total.

In order to calculate meaningful National Average concentrations for urban areas (over 80% of the U.K. population live in such areas) the following method was adopted:-

(i) The annual tables of smoke and sulphur dioxide were examined for the most recent pair of consecutive years and those sites in urban areas picked out for which annual averages were available for both years (typically there are 500-550 such sites for any given pair of years).

(ii) The overall average for those sites for each of those two years was then calculated, and the difference between them was taken to represent a generally valid difference in concentrations over the whole country between those two years.

(iii) The process was then repeated for each pair of consecutive years and in this way increases or decreases from one year to the next were calculated.

(iv) It was assumed that the pair of years with the most sites would give average values more representative of the true overall National Average than the others. Starting with the values for this pair of years, and using percentage decreases or increases found for other pairs of years, a trend line was drawn covering the whole span of years.

It is reasoned that although the average concentration determined for any one year varies with the number of sites used, the large number of sites involved ensured that these variations are small - only a matter of a few microgrammes per cubic metre.

References:-

1. National Survey of Air Pollution 1961-71, Warren Spring Laboratory, 1972.
2. The Investigation of Air Pollution. Directory - Sites used from the beginning of the Cooperative Investigation, Warren Spring Laboratory.
3. Regions used by the Registrar General for statistical purposes.

APPENDIX II

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/76

Grade Classification

1. Large Coal

Coal which will pass over a screen of stated size (normally 50mm) but which has no upper size limit.

2. Graded Coal

Coal screened between specified ranges of sizes (normally not more than 50mm and not less than 12.5mm).

3. Carbonisation Washed Smalls

Coal with a specified upper size limit (normally below 50mm) and no lower size limit prepared for the coking market - normally coal of Rank 200 - 600 with ash content 5-8%.

4. Industrial Washed Smalls

Coal with a specified upper size limit (normally below 50mm) and no lower size limit prepared for the industrial market - normally coal of Rank 700-900 with ash content 6-10%.

5. Untreated Smalls

Untreated coal with a specified upper size limit (normally below 50mm) and no lower size limit - normally for power station usage.

6. Blended Smalls

A blend of Untreated and Washed Smalls.

7. Slurry

Fine particles (normally below 1mm) recovered from coal preparation, normally containing a substantial proportion of inerts.

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

U.K. Total - All Coals

'000 Tonnes

Market	Power Station	Carbonisation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlori %
Large Coal	20	-	114	7,815	114	8,063	8.7	4.8	32.8	53.7	29,710	1.18	0.31
Graded Coal	619	170	3,808	4,672	357	9,626	8.5	4.9	29.8	56.8	30,000	1.29	0.25
Carb. Wd. Smalls	122	14,974	360	976	24	16,356	9.4	5.8	28.4	56.6	30,170	1.16	0.21
Ind. Wd. Smalls	3,828	1,541	2,846	1,495	668	10,378	12.1	8.1	27.6	52.2	27,450	1.36	0.24
Blended Smalls	41,778	34	3,188	-	-	45,000	11.2	17.4	28.0	43.4	24,180	1.63	0.28
Untreated Smalls	25,729	847	1,530	1	324	28,431	12.5	17.0	25.5	45.0	23,970	1.32	0.14
Other, inc. Slurry	1,094	-	205	20	52	1,371	28.6	20.6	18.1	32.7	16,420	0.82	0.16
TOTAL	73,190	17,466	12,051	14,979	1,539	119,225	11.1	13.2	27.7	48.0	25,920	1.41	0.23

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

U.K. Total - Opencast

'000 Tonnes

Market	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	15	84	3	102	3.5	4.2	11.1	81.2	32,770	1.03	0.06
Graded Coal	20	3	155	549	198	925	4.8	4.2	11.5	79.5	32,290	1.08	0.05
Carb. Wd. Smalls	-	188	-	-	-	188	9.5	7.9	-	-	-	1.10	0.05
Ind. Wd. Smalls	69	44	61	266	462	902	13.0	6.3	10.9	69.6	28,210	0.95	0.06
Blended Smalls	-	-	-	-	-	-	-	-	-	-	-	-	-
Untreated Smalls	4,380	382	745	-	236	5,743	12.0	9.8	30.2	48.	26,620	1.80	0.07
Other, inc. Slurry	198	-	3	-	36	237	31.9	17.3	16.8	34.0	15,650	1.09	-
TOTAL	4,667	617	979	899	935	8,097	11.9	9.2	26.2	52.7	27,030	1.61	0.07

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

U.K. Total - Deepmined

'000 Tonnes

Market	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlori %
Large Coal	20	-	99	7,731	112	7,962	8.7	4.8	33.1	53.4	29,680	1.18	0.31
Graded Coal	599	167	3,653	4,122	160	8,701	8.8	4.9	31.4	54.9	29,810	1.31	0.26
Carb. Wd. Smalls	122	14,686	360	976	24	16,168	9.4	5.8	28.4	56.4	30,170	1.16	0.21
Ind. Wd. Smalls	3,759	1,498	2,785	1,229	205	9,476	12.0	8.3	28.9	50.8	27,400	1.39	0.26
Blended Smalls	41,777	34	3,187	-	-	44,998	11.2	17.4	28.0	43.4	24,180	1.63	0.28
Untreated Smalls	21,349	465	785	1	88	22,688	12.6	18.5	24.3	44.1	23,330	1.21	0.16
Other, inc. Slurry	895	-	203	20	16	1,134	27.5	21.8	18.6	32.1	16,640	0.73	0.16
TOTAL	68,521	16,850	11,072	14,079	605	111,127	11.1	13.5	27.8	47.6	25,850	1.39	0.24

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

Scottish Area - Deepmined

'000 Tonnes

Market Grade	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	7	794	2	803	9.0	5.3	34.3	51.4	29,510	0.76	0.17
Graded Coal	2	3	392	242	22	661	10.5	4.8	33.0	51.7	29,020	0.69	0.18
Carb. Wd. Smalls	-	692	2	-	-	694	10.8	7.7	30.5	51.5	28,630	0.63	0.14
Ind. Wd. Smalls	369	110	428	-	-	907	14.0	6.4	31.1	48.5	26,960	0.74	0.19
Blended Smalls	-	-	-	-	-	-	-	-	-	-	-	-	-
Untreated Smalls	7,578	-	17	-	-	7,595	14.4	22.4	21.3	41.9	22,100	0.54	0.09
Other, inc. Slurry	525	-	6	-	-	531	29.0	21.7	18.7	30.6	15,890	0.61	0.14
TOTAL	8,474	805	852	1,036	24	11,191	14.1	17.9	24.1	43.9	23,580	0.59	0.18

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

North East Area - Deepmined

'000 Tonnes

Market Grade	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	20	-	1	566	-	587	9.3	4.4	34.4	51.9	30,100	1.18	0.12
Graded Coal	175	2	300	909	10	1,396	7.6	4.9	33.9	53.6	30,720	1.34	0.17
Carb. Wd. Smalls	-	3,646	126	-	-	3,772	10.3	5.3	30.2	54.2	30,020	1.12	0.22
Ind. Wd. Smalls	146	98	85	-	3	332	13.5	7.5	30.5	48.5	27,370	1.27	0.15
Blended Smalls	5,466	-	1,091	-	-	6,557	10.6	18.2	28.0	43.2	24,200	1.70	0.20
Untreated Smalls	1,424	384	135	-	-	1,943	8.7	17.8	27.6	46.9	25,400	1.35	0.10
Other, inc. Slurry	13	-	-	-	-	13	17.7	20.6	21.7	40.0	21,050	1.20	0.27
TOTAL	7,244	4,130	1,738	1,475	13	14,600	10.0	12.8	29.4	47.8	26.780	1.44	0.18

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

North Yorks. Area - Deepmined

'000 Tonnes

Market	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	-	295	1	296	-	-	-	-	-	-	-
Graded Coal	81	14	240	242	-	577	8.0	5.9	33.0	53.1	29,790	1.76	0.38
Carb. Wd. Smalls	-	40	10	14	-	64	8.3	5.4	32.7	53.6	30,450	1.56	0.18
Ind. Wd. Smalls	212	13	285	15	-	525	11.3	8.2	30.9	49.0	27,560	1.90	0.33
Blended Smalls	5,232	17	6	-	-	5,255	10.1	19.0	27.5	43.4	24,080	1.94	0.25
Untreated Smalls	1,577	-	-	-	-	1,577	9.3	21.2	26.7	42.0	23,730	1.97	0.34
Other, inc. Slurry	51	-	3	-	-	54	-	-	-	-	-	-	-
TOTAL	7,153	84	544	566	1	8,348	9.9	17.8	27.9	44.4	24,650	1.93	0.28

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

Barnsley Area - Deepmined

'000 Tonnes

Market / Grade	Power Station	Carbonisation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	1	216	1	218	-	-	-	-	-	-	-
Graded Coal	86	2	192	207	43	530	5.4	5.2	33.9	55.5	31,490	1.58	0.16
Carb. Wd. Smalls	-	1,204	9	165	-	1,378	9.0	6.4	30.2	54.4	30,120	1.59	0.14
Ind. Wd. Smalls	553	-	-	31	-	584	9.9	15.6	27.6	46.9	26,900	2.00	0.11
Blended Smalls	3,537	-	5	-	-	3,542	7.1	22.3	26.4	44.2	24,230	1.79	0.15
Untreated Smalls	587	-	2	-	-	589	6.6	23.4	26.3	43.7	23,800	1.74	0.11
Other, inc. Slurry	66	-	1	-	-	67	-	-	-	-	-	-	-
TOTAL	4,829	1,206	210	619	44	6,908	7.6	16.9	27.9	47.8	26,320	1.74	0.14

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

Doncaster Area - Deepmined

'000 Tonnes

Market	Power Station	Carbonisation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	-	476	19	495	7.3	4.0	34.0	54.7	30,630	1.26	0.47
Graded Coal	115	-	280	258	28	681	8.7	4.4	33.6	53.3	29,930	1.50	0.45
Carb. Wd. Smalls	24	241	61	279	-	605	8.5	4.9	32.9	53.7	30,260	1.47	0.34
Ind. Wd. Smalls	325	1	138	427	1	892	12.8	4.6	31.6	51.0	28,100	1.32	0.47
Blended Smalls	4,369	-	-	-	-	4,369	10.8	14.9	28.3	46.0	25,400	1.40	0.40
Untreated Smalls	840	-	-	-	-	840	12.8	17.0	29.0	41.2	22,970	1.88	0.24
Other, inc. Slurry	15	-	78	-	-	93	25.4	25.9	-	-	16,070	1.49	-
TOTAL	5,688	242	557	1,440	48	7,975	10.7	11.7	30.0	47.6	26.440	1.45	0.39

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

South Yorkshire Area - Deepmined

'000 Tonnes

Market	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	-	483	5	488	4.5	4.1	34.4	57.0	32,360	1.28	0.25
Graded Coal	62	108	163	93	3	429	4.2	4.1	34.9	56.8	32,600	1.44	0.21
Carb. Wd. Smalls	5	3,524	16	98	-	3,643	9.4	5.2	31.8	53.6	30,340	1.47	0.21
Ind. Wd. Smalls	251	534	75	-	-	860	10.4	7.9	31.6	50.1	28,210	1.59	0.24
Blended Smalls	2,030	34	8	-	-	2,072	10.2	16.3	28.3	45.2	25,150	1.54	0.25
Untreated Smalls	99	-	-	-	-	99	12.1	18.6	27.4	41.9	23,390	1.58	0.22
Other, inc. Slurry	40	-	2	-	-	42	18.8	20.8	20.4	40.0	20.650	1.10	0.21
TOTAL	2,487	4,200	264	674	8	7,633	9.4	8.7	30.9	51.0	28,720	1.49	0.23

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

North Notts. Area - Deepmined

'000 Tonnes

Market	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	11	635	22	668	8.1	4.1	33.0	54.8	30,170	1.15	0.48
Graded Coal	-	-	334	365	1	700	10.0	3.9	33.1	53.0	29,350	1.21	0.48
Carb. Wd. Smalls	84	1,088	118	419	-	1,709	9.9	5.3	32.1	52.7	29,530	1.21	0.37
Ind. Wd. Smalls	635	11	338	1	-	985	13.4	7.2	30.5	48.9	27,010	1.16	0.38
Blended Smalls	4,269	-	1,439	-	-	5,708	11.9	16.7	27.9	43.5	24,200	1.40	0.40
Untreated Smalls	-	-	-	-	-	-	-	-	-	-	-	-	-
Other, inc. Slurry	25	-	28	-	-	53	-	-	-	-	-	-	-
TOTAL	5,013	1,099	2,268	1,420	23	9,823	11.2	11.7	29.7	47.4	26,330	1.31	0.40

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

South Notts. Area - Deepmined

'000 Tonnes

Market Grade	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc: Export	Total	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	3	997	1	1,001	11.0	4.9	33.5	50.6	28,270	1.25	0.32
Graded Coal	-	-	354	326	-	680	12.9	5.2	32.9	49.0	27,370	1.33	0.33
Carb. Wd. Smalls	-	-	-	-	-	-	-	-	-	-	-	-	-
Ind. Wd. Smalls	301	-	340	-	38	679	16.3	9.5	30.0	44.2	24,670	1.01	0.29
Blended Smalls	6,847	-	309	-	-	7,156	13.8	17.0	28.5	40.7	23,110	1.22	0.29
Untreated Smalls	14	-	-	-	-	14	-	-	-	-	-	-	-
Other, inc. Slurry	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	7,162	-	1,006	1,323	39	9,530	13.6	14.4	29.4	42.6	24,040	1.30	0.30

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

North Derbyshire Area - Deepmined

'000 Tonnes

Market / Grade	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	18	366	38	422	8.9	5.8	34.6	54.7	31,150	1.91	0.21
Graded Coal	-	-	142	247	-	389	10.9	5.2	33.3	50.6	28,450	1.52	0.26
Carb. Wd. Smalls	-	-	-	-	-	-	-	-	-	-	-	-	-
Ind. Wd. Smalls	772	158	588	139	1	1,658	11.2	10.1	30.9	47.8	26,830	1.79	0.22
Blended Smalls	4,326	-	3	-	-	4,329	10.3	18.4	28.1	43.2	24,140	1.79	0.21
Untreated Smalls	591	-	2	-	-	593	11.3	17.3	28.8	42.6	23,830	1.83	0.20
Other, inc. Slurry	131	-	35	-	-	166	-	-	-	-	-	-	-
TOTAL	5,820	158	788	752	39	7,557	10.6	15.1	29.1	45.2	25,010	1.78	0.21

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

South Midlands Area - Deepmined

'000 Tonnes

Market	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
Grade							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	4	1,088	-	1,092	12.6	5.6	32.9	45.0	26,960	1.31	0.14
Graded Coal	-	-	666	201	7	874	14.3	5.1	33.8	46.8	26,440	1.24	0.12
Carb. Wd. Smalls	-	-	-	-	-	-	-	-	[illegible]	-	-	-	-
Ind. Wd. Smalls	-	-	140	-	-	140	13.7	6.9	32.5	46.9	26,090	1.97	0.11
Blended Smalls	649	-	40	-	-	689	19.5	13.4	29.2	37.9	21.590	1.41	0.06
Untreated Smalls	4,359	-	393	-	-	4,752	15.3	15.3	28.1	40.3	22,430	1.38	0.12
Other, inc. Slurry	2	-	-	-	-	2	25.3	26.2	-	-	15,000	0.59	0.04
TOTAL	5,010	-	1,243	1,289	7	7,549	15.3	12.7	29.2	41.8	23,360	1.37	0.12

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

Kent Area - Deepmined

'000 Tonnes

Market Grade	Power Station	Carbonisation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	-	4	-	4	2.4	4.4	19.9	73.3	33,900	0.98	0.05
Graded Coal	-	-	3	17	-	20	2.6	6.5	16.8	74.1	33,040	0.98	0.04
Carb. Wd. Smalls	-	593	5	-	-	598	9.0	6.0	16.4	68.6	30,920	0.84	0.04
Ind. Wd. Smalls	-	26	-	-	-	26	12.3	6.9	15.7	65.1	29,470	0.83	0.05
Blended Smalls	-	-	135	-	-	135	13.4	12.5	18.2	55.9	26,740	1.26	0.04
Untreated Smalls	-	-	2	-	-	2	6.1	22.4	19.7	51.8	25,460	1.59	0.04
Other, inc. Slurry	-	-	10	20	-	30	22.3	16.7	12.6	48.4	23,020	0.86	0.04
TOTAL	-	619	155	41	-	815	10.1	7.6	16.5	65.8	29,930	0.91	0.04

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

Western Area - Deepmined

'000 Tonnes

Market Grade	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual)						
							Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	7	1,274	22	1,303	7.6	4.8	34.2	53.4	30,050	1.32	0.51
Graded Coal	76	25	459	77	-	637	8.5	5.0	33.9	52.6	29,610	1.49	0.49
Carb. Wd. Smalls	-	705	3	-	-	708	8.4	6.4	31.1	54.1	29,970	1.26	0.32
Ind. Wd. Smalls	119	240	353	2	-	714	10.2	8.4	30.8	50.6	28,170	1.44	0.37
Blended Smalls	4,944	-	152	-	-	5,096	12.0	15.0	29.0	44.0	24,520	1.85	0.43
Untreated Smalls	2,447	-	227	1	-	2,675	11.4	15.6	29.1	43.9	24,480	1.64	0.40
Other, inc. Slurry	4	-	36	-	-	40	27.4	23.9	18.4	30.3	16,640	0.88	0.26
TOTAL	7,590	970	1,237	1,354	22	11,173	10.8	12.4	30.1	46.7	25,990	1.65	0.43

PRODUCTION SIDE

GRADE AND MARKET DISPOSALS

1975/1976

South Wales Area - Deepmined

'000 Tonnes

Market / Grade	Power Station	Carboni-sation	Industry & Misc.	Domestic Inc. M.F.P.	Others Inc. Export	Total	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Large Coal	-	-	44	540	-	584	2.2	5.1	13.6	79.1	33,680	0.78	0.08
Graded Coal	-	12	128	940	46	1,126	3.3	4.8	10.5	81.4	33,230	0.91	0.07
Carb. Wd. Smalls	9	2,951	9	1	24	2,994	8.1	6.7	17.2	68.0	30,920	0.60	0.09
Ind. Wd. Smalls	73	306	15	634	161	1,189	10.2	6.6	11.5	71.7	29,950	0.96	0.05
Blended Smalls	24	-	-	-	-	24	-	-	-	-	-	-	-
Untreated Smalls	1,834	81	7	-	88	2,010	9.2	16.7	12.2	61.9	26,310	1.40	0.06
Other, inc. Slurry	23	-	4	-	16	43	-	-	-	-	-	-	-
TOTAL	1,963	3,350	207	2,115	335	7,970	7.9	9.5	14.0	68.6	29,760	0.94	0.07

APPENDIX III

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/76

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

All Sales Regions

Total, all Markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	11,171	14.1	17.9	24.1	43.9	23,580	0.59	0.12
Northern	14,626	10.0	12.8	29.4	47.8	26,780	1.44	0.18
Yorkshire	30,933	9.5	13.7	29.2	47.6	26,500	1.65	0.27
Western	11,173	10.8	12.4	30.1	46.7	25,990	1.65	0.43
Midlands	34,442	12.7	13.5	29.4	44.4	24,700	1.42	0.26
South Wales	8,762	8.1	9.3	14.3	68.3	29,770	0.94	0.07
Deep-Mined Total	111,127	11.1	13.5	27.8	47.6	25,850	1.39	0.24
Opencast - Supplying Region								
Scottish	443	22.4	12.9	21.9	42.8	21,170	1.09	-
Northern	1,436	10.4	8.4	29.2	52.0	29,580	1.50	0.07
Yorkshire	1,260	10.1	10.3	29.3	50.3	26,630	1.95	0.04
Western	861	10.8	9.8	31.6	47.8	27,420	2.10	0.16
Midlands	1,951	14.8	10.6	31.0	43.6	24,250	1.87	0.04
South Wales	2,147	8.1	5.5	6.8	80.6	31,480	0.95	0.06
Opencast Total	8,098	11.9	9.2	26.2	52.7	27,030	1.61	0.07
All Coals Total	119,225	11.1	13.2	27.7	48.0	25,920	1.41	0.23

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

All Sales Regions

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	8,478	15.2	21.7	21.5	41.6	21,950	0.56	0.10
Northern	7,261	10.0	18.3	28.1	43.6	24,440	1.60	0.18
Yorkshire	20,223	9.7	17.8	27.7	44.8	24,740	1.73	0.27
Western	7,590	11.8	15.3	29.1	43.8	24,420	1.78	0.43
Midlands	23,006	13.1	16.3	28.4	42.2	23,570	1.49	0.24
South Wales	1,964	9.3	16.4	12.6	61.7	26,340	1.46	0.05
Deep-Mined Total	68,522	11.8	17.5	26.9	43.8	23,970	1.49	0.24
Opencast - Supplying Region								
Scottish	305	27.2	14.8	21.8	36.2	18,620	1.11	-
Northern	890	12.9	8.4	30.1	48.6	28,250	1.52	0.08
Yorkshire	967	10.2	11.0	29.2	49.6	26,300	2.00	0.04
Western	590	12.7	9.1	31.4	46.8	26,790	1.73	0.16
Midlands	1,904	14.8	10.6	31.0	43.6	24,240	1.88	0.04
South Wales	12	6.8	12.0	-	-	-	-	-
Opencast Total	4,668	14.0	10.4	29.9	45.7	25,380	1.76	0.06
All Coals Total	73,190	11.9	17.1	27.1	43.9	24,070	1,51	0.23

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

All Sales Regions

1975/1976

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	805	11.0	7.5	30.2	51.3	28,580	0.63	0.14
Northern	4,138	10.2	5.1	29.9	54.8	30,130	1.11	0.21
Yorkshire	5,733	9.4	5.6	31.5	53.5	30,130	1.51	0.20
Western	970	8.7	6.1	31.1	54.1	29,940	1.25	0.32
Midlands	1,259	9.8	6.0	32.0	52.2	29,260	1.33	0.34
South Wales	3,945	8.2	7.0	16.8	68.0	30,770	0.64	0.08
Deep-Mined Total	16,850	9.4	5.9	28.0	56.7	30,100	1.15	0.19
Opencast - Supplying Region								
Scottish	1	9.6	5.0	33.0	52.4	29,560	0.65	-
Northern	197	4.1	7.6	26.5	61.8	33,440	1.12	0.06
Yorkshire	5	8.4	6.9	29.6	55.1	28.830	1.76	0.04
Western	-	-	-	-	-	-	-	-
Midlands	-	-	-	-	-	-	-	-
South Wales	413	8.9	7.6	6.3	77.2	29,510	1.20	0.05
Opencast Total	616	7.1	7.6	26.4	61.9	33,270	1.17	0.05
All Coals Total	17,466	9.4	6.0	28.0	56.6	30,140	1.15	0.19

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

All Sales Regions

Industry and Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	852	12.6	5.8	31.7	49.9	27,800	0.71	0.17
Northern	1,738	11.7	14.9	28.9	44.5	25,010	1.68	0.12
Yorkshire	1,577	9.1	6.8	32.6	52.5	28,730	1.65	0.32
Western	1,239	9.8	8.5	31.1	50.6	28,100	1.56	0.40
Midlands	5,303	13.0	9.4	30.8	46.8	26,010	1.23	0.28
South Wales	362	7.1	9.8	14.7	68.4	29,630	1.00	0.05
Deep-Mined Total	11,071	11.7	9.6	30.4	48.3	26,700	1.36	0.26
Opencast - Supplying Region								
Scottish	86	15.4	10.4	28.0	46.2	24,690	1.10	-
Northern	184	6.2	9.4	28.0	56.4	31,560	1.70	0.07
Yorkshire	277	10.0	7.9	29.7	52.4	27,660	1.79	0.04
Western	269	6.8	11.4	31.9	49.9	28,760	2.92	0.15
Midlands	48	14.8	10.4	29.8	45.0	24,530	1.55	0.04
South Wales	116	4.9	6.6	7.3	84.2	32,800	0.85	0.07
Opencast Total	980	8.8	9.5	28.9	52.8	28,560	1.99	0.09
All Coals Total	12,051	11.3	9.6	30.3	48.8	26,860	1.42	0.25

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

All Sales Regions

Domestic and M.F.P.S

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	1,032	9.2	5.2	34.0	51.6	29,410	0.74	0.18
Northern	1,474	7.3	4.4	34.5	53.8	31,030	1.31	0.16
Yorkshire	3,298	8.2	4.3	33.4	54.1	30,390	1.39	0.36
Western	1,353	7.7	4.7	34.2	53.4	30,030	1.31	0.51
Midlands	4,767	10.9	5.1	33.0	51.0	28,360	1.26	0.31
South Wales	2,154	5.1	4.8	11.0	79.1	32,690	0.92	0.07
Deep-Mined Total	14,078	8.7	4.8	31.0	55.5	29,910	1.22	0.29
Opencast - Supplying Region								
Scottish	48	4.8	6.0	11.4	77.8	30,870	0.94	-
Northern	-	-	-	-	-	-	-	-
Yorkshire	10	9.0	6.1	31.3	53.6	23,720	2.09	0.04
Western	1	5.6	4.1	34.0	56.3	32,980	1.63	0.12
Midlands	-	-	-	-	-	-	-	-
South Wales	840	6.9	4.1	6.8	82.2	31,770	0.87	0.06
Opencast Total	899	6.8	4.3	7.5	81.4	31,670	0.89	0.06
All Coals Total	14,977	8.6	4.7	29.5	57.2	30,020	1.20	0.28

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

All Sales Regions

1975/1976

Other markets inc. exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	24	9.2	4.9	33.4	52.5	29,440	0.55	0.26
Northern	13	6.5	4.8	33.8	54.9	31,290	1.41	0.19
Yorkshire	102	6.1	4.0	34.5	55.4	31,380	1.35	0.30
Western	21	5.2	6.0	33.6	55.2	30,780	1.42	0.57
Midlands	108	12.3	6.8	31.5	48.4	26,840	1.08	0.34
South Wales	336	11.0	7.2	7.3	74.5	29,250	0.86	0.05
Deep-Mined Total	604	9.7	6.2	21.0	63.1	29,490	1.04	0.20
Opencast - Supplying Region								
Scottish	3	18.0	11.7	28.3	42.0	22,700	1.25	-
Northern	165	9.7	8.9	29.1	52.3	29,820	1.61	0.075
Yorkshire	-	-	-	-	-	-	-	-
Western	-	-	-	-	-	-	-	-
Midlands	-	-	-	-	-	-	-	-
South Wales	767	10.1	5.2	6.9	77.8	30,660	0.85	0.069
Opencast Total	935	10.0	6.4	14.2	69.4	30,340	1.09	0.071
All Coals Total	1,539	9.9	6.3	17.3	66.5	29,950	1.07	0.130

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Scottish Sales Region

Total, all markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	10,598	14.1	18.3	23.8	43.8	23,470	0.58	0.11
Northern	218	7.9	6.2	35.0	50.9	30,130	1.38	0.12
Yorkshire	174	5.7	4.1	34.1	56.1	31,540	1.18	0.37
Western								
Midlands								
South Wales	13	3.9	5.1	8.3	82.7	32,810	1.10	0.05
Deep-Mined Total	11,003	13.9	17.9	24.1	44.1	23,690	0.60	0.12
Opencast - Supplying Region								
Scottish	427	22.9	13.1	22.0	42.0	20,940	1.09	-
Northern								
Yorkshire								
Western	5	6.3	10.8	31.9	51.0	30,210	2.62	0.16
Midlands								
South Wales	11	4.2	3.9	7.0	84.9	33,060	0.91	0.06
Opencast Total	443	22.2	12.9	21.8	43.1	21,330	1.10	0.10
All Coals Total	11,446	14.2	17.7	24.0	44.1	23,600	0.62	0.12

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Scottish Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	7,945	15.2	22.4	21.0	41.4	21,730	0.54	0.10
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	7,945	15.2	22.4	21.0	41.4	21,730	0.54	0.10
Opencast - Supplying Region								
Scottish	298	27.4	14.9	21.6	36.1	18,530	1.10	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	298	27.4	14.9	21.6	36.1	18,530	1.10	-
All Coals Total	8,243	15.7	22.2	21.0	41.1	21,610	0.56	0.10

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Scottish Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	805	11.0	7.5	30.2	51.3	28,570	0.63	0.14
Northern								
Yorkshire								
Western								
Midlands								
South Wales	1	8.0	8.2	22.4	61.4	30,260	0.89	0.07
Deep-Mined Total	806	11.0	7.5	30.2	51.3	28,580	0.63	0.14
Opencast - Supplying Region								
Scottish	1	9.6	8.0	33.0	52.4	29,560	0.65	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	1	9.6	8.0	33.0	52.4	29,560	0.65	-
All Coals Total	807	11.0	7.5	30.2	51.3	28,580	0.63	0.14

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Scottish Sales Region

Industry & Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	792	12.5	5.7	31.7	50.1	27,860	0.69	0.17
Northern	101	7.6	8.8	34.3	49.3	29,250	1.48	0.12
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	893	11.9	6.1	32.0	50.0	28,020	0.78	0.16
Opencast - Supplying Region								
Scottish	86	15.4	10.4	28.0	46.2	24,690	1.10	-
Northern								
Yorkshire								
Western	5	6.3	10.8	31.9	51.0	30,210	2.62	0.16
Midlands								
South Wales	4	5.7	4.4	7.8	82.1	32,940	0.83	0.10
Opencast Total	95	14.6	10.2	27.7	47.5	25,240	1.18	0.14
All Coals Total	988	12.2	6.5	31.6	49.7	27,750	0.82	0.16

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Scottish Sales Region

Domestic inc. MFPS

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	1,032	9.2	5.2	34.0	51.6	29,420	0.74	0.18
Northern	119	8.1	4.0	35.6	52.3	30,890	1.29	0.12
Yorkshire	174	5.7	4.1	34.1	56.1	31,540	1.18	0.37
Western								
Midlands								
South Wales	12	3.6	4.9	7.6	83.8	32,950	1.11	0.05
Deep-Mined Total	1,337	8.8	5.0	33.9	52.3	29,770	0.83	0.19
Opencast - Supplying Region								
Scottish	39	4.8	6.0	11.4	77.8	30,870	0.94	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales	7	3.6	3.7	6.6	86.1	33,100	0.93	0.05
Opencast Total	46	4.7	5.7	10.9	78.7	31,180	0.94	0.05
All Coals Total	1383	8.6	5.0	33.1	53.3	29,820	0.83	0.19

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Scottish Sales Region

Other markets inc. exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	24	9.2	4.9	33.4	52.5	29,440	0.55	0.26
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	24	9.2	4.9	33.4	52.5	29,440	0.55	0.26
Opencast - Supplying Region								
Scottish	3	18.0	11.7	28.3	42.0	22,700	1.25	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	3	13.0	11.7	28.3	42.0	22,700	1.25	-
All Coals Total	27	10.1	5.6	32.9	51.4	28,750	0.62	0.26

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Northern Sales Region

Total, all markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	10,206	10.0	12.1	29.2	48.7	27,140	1.38	0.17
Yorkshire	48	9.1	5.2	32.0	53.7	30,180	1.53	0.26
Western								
Midlands	1	10.0	3.4	31.6	53.0	29,380	1.04	0.45
South Wales	290	8.9	6.1	16.3	68.7	30,940	0.84	0.04
Deep-Mined Total	10,545	10.0	11.9	28.9	49.2	27,250	1.36	0.16
Opencast - Supplying Region								
Scottish								
Northern	777	9.9	8.5	29.1	52.5	29,830	1.51	0.07
Yorkshire	5	7.1	5.5	30.6	56.8	29,960	1.80	0.04
Western								
Midlands								
South Wales	3	4.0	3.5	6.2	86.3	33,010	0.98	0.04
Opencast Total	785	9.9	8.4	29.0	52.7	29,840	1.51	0.07
All Coals Total	11,330	10.0	11.6	28.9	49.5	27,430	1.37	0.16

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Northern Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	3,843	9.9	20.0	27.5	42.6	23,840	1.55	0.12
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	3,843	9.9	20.0	27.5	42.6	23,840	1.55	0.12
Opencast - Supplying Region								
Scottish								
Northern	507	12.7	8.4	30.0	48.9	28,330	1.52	-
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	507	12.7	8.4	30.0	48.9	28,330	1.52	-
All Coals Total	4,350	10.3	18.6	27.8	43.3	24,370	1.55	0.12

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Northern Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	3,988	10.3	5.1	29.9	54.7	30,120	1.10	0.21
Yorkshire	34	9.3	5.1	31.8	53.8	30,340	1.49	0.23
Western								
Midlands	1	10.0	5.4	31.6	53.0	29,380	1.04	0.45
South Wales	281	8.9	6.4	16.3	68.7	30,940	0.84	0.04
Deep-Mined Total	4,304	10.2	5.1	29.0	55.7	30,180	1.09	0.20
Opencast - Supplying Region								
Scottish								
Northern	113	3.3	7.4	26.8	62.5	33,770	1.13	0.06
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	113	3.3	7.4	26.8	62.5	33,770	1.13	0.06
All Coals Total	4,417	10.0	5.2	29.0	55.8	30,270	1.09	0.20

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Northern Sales Region

Industry & Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	1,398	12.4	15.5	28.4	43.7	24,460	1.69	0.12
Yorkshire	5	9.4	7.1	32.0	51.5	28,640	1.98	0.31
Western								
Midlands								
South Wales	2	4.7	5.1	8.0	82.2	32,510	0.77	0.04
Deep-Mined Total	1,405	12.3	15.5	28.4	43.8	24,480	1.69	0.12
Opencast - Supplying Region								
Scottish								
Northern	149	5.5	9.5	27.8	57.2	31,870	1.72	0.07
Yorkshire	5	7.1	5.5	30.6	56.8	29,960	1.80	0.04
Western								
Midlands								
South Wales								
Opencast Total	154	5.6	9.4	27.9	57.1	31,810	1.72	0.07
All Coals Total	1,559	11.7	14.9	28.3	45.1	25,220	1.69	0.11

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Northern Sales Region

Domestic inc. MFPs

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	977	5.8	4.3	34.8	55.1	31,740	1.39	0.19
Yorkshire	10	7.8	3.9	33.5	54.8	30,660	1.33	0.43
Western								
Midlands								
South Wales	4	4.1	3.7	6.5	85.7	33,070	1.04	0.05
Deep-Mined Total	991	5.8	4.3	34.7	55.2	31,740	1.39	0.19
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	3	4.0	3.5	6.2	86.3	33,010	0.98	0.04
Opencast Total	3	4.0	3.5	6.2	86.3	33,010	0.98	0.04
All Coals Total	994	5.8	4.3	34.7	55.2	31,740	1.39	0.19

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Northern Sales Region

Other markets inc. export

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	-	-	-	-	-	-	-	-
Opencast - Supplying Region								
Scottish								
Northern	8	5.5	9.5	27.8	57.2	31,870	1.72	0.07
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	8	5.5	9.5	27.8	57.2	31,870	1.72	0.07
All Coals Total	8	5.5	9.5	27.8	57.2	31,870	1.72	0.07

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Yorkshire Sales Region

Total all Markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	24,817	9.8	13.3	29.3	47.6	26,500	1.63	0.28
Western	64	9.4	5.6	30.9	54.1	29,770	1.16	0.30
Midlands	288	10.5	6.3	32.3	50.9	28,590	1.37	0.29
South Wales	462	8.7	6.7	14.2	70.4	30,750	0.72	0.06
Deep-Mined Total	25,631	9.7	13.1	29.1	48.1	26,590	1.61	0.27
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire	1,216	10.2	10.4	29.3	30.1	26,560	1.90	0.04
Western								
Midlands	106	11.3	11.0	30.0	47.7	26,000	2.07	0.05
South Wales	19	4.1	3.6	6.8	85.5	32,990	0.91	0.06
Opencast Total	1,341	10.2	10.4	29.2	50.2	26,570	1.96	0.04
All Coals Total	26,972	9.8	13.0	29.1	48.1	26,590	1.65	0.26

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Yorkshire Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	15,982	10.1	17.6	27.8	44.5	24,630	1.72	0.29
Western								
Midlands	96	11.9	17.4	28.6	42.1	23,480	1.82	0.20
South Wales								
Deep-Mined Total	16,078	10.1	17.6	27.8	44.5	24,630	1.72	0.29
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire	967	10.2	11.0	29.2	49.6	26,300	2.00	0.04
Western								
Midlands	106	11.3	11.0	30.0	47.7	26,000	2.07	0.05
South Wales								
Opencast Total	1,073	10.3	11.0	29.2	49.5	26,270	2.01	0.04
All Coals Total	17,151	10.1	17.2	27.9	44.8	24,740	1.73	0.28

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Yorkshire Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	5,214	9.4	5.6	31.5	53.5	30,140	1.47	0.19
Western	62	9.4	5.6	30.9	54.1	29,780	1.16	0.30
Midlands	74	9.9	6.8	32.2	51.1	28,910	1.40	0.33
South Wales	444	8.8	6.7	14.3	70.2	30,700	0.72	0.06
Deep-Mined Total	5,794	9.3	5.7	30.4	54.6	30,160	1.41	0.19
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire	5	8.4	6.9	29.6	55.1	28,830	1.76	0.04
Western								
Midlands								
South Wales								
Opencast Total	5	8.4	6.9	29.6	55.1	28,830	1.76	0.04
All Coals Total	5,799	9.3	5.7	30.4	54.6	30,160	1.41	0.19

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Yorkshire Sales Region

Industry & Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	1,275	9.8	6.7	32.6	50.9	28,330	1.63	0.35
Western								
Midlands	92	11.8	6.4	32.0	49.8	27,800	1.38	0.26
South Wales	5	3.7	4.3	7.1	84.9	32,960	1.05	0.04
Deep-Mined Total	1,372	9.9	6.7	32.5	50.9	28,290	1.61	0.34
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire	240	10.2	8.0	29.8	52.0	27,480	1.78	0.04
Western								
Midlands								
South Wales	9	5.0	3.3	7.6	84.1	32,920	0.80	0.07
Opencast Total	249	10.2	7.9	29.5	52.4	27,580	1.76	0.04
All Coals Total	1,621	10.0	6.9	32.0	52.1	28,170	1.63	0.28

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Yorkshire Sales Region

Domestic inc. M.F.P.S.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	2,341	8.4	4.4	33.4	53.8	30,300	1.40	0.35
Western	2	10.0	5.6	30.7	53.7	29,620	1.22	0.28
Midlands	26	6.7	3.7	34.3	56.3	31,500	1.22	0.34
South Wales	13	3.9	4.0	6.7	85.4	33,040	1.05	0.04
Deep-Mined Total	2,382	8.4	4.4	33.3	53.9	30,320	1.40	0.35
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire	5	9.5	6.5	31.8	52.5	28,380	2.19	0.04
Western								
Midlands								
South Wales	9	3.7	3.7	6.3	86.3	33,030	0.97	0.05
Opencast Total	14	5.8	4.8	15.8	73.6	31,290	1.43	0.04
All Coals Total	2,396	8.3	4.4	33.2	54.1	30,320	1.40	0.35

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Yorkshire Sales Region

Others inc. Exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	5	6.4	4.3	34.5	54.8	31,180	1.37	0.37
Western								
Midlands								
South Wales								
Deep-Mined Total	5	6.4	4.3	34.5	54.8	31,180	1.37	0.37
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	-	-	-	-	-	-	-	-
All Coals Total	5	6.4	4.3	34.5	54.8	31,180	13.7	0.37

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Midlands Sales Region

Total: All Markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	1,660	10.2	11.7	29.4	48.7	26,960	1.53	0.30
Western	677	14.4	8.8	31.8	45.0	25,510	1.51	0.40
Midlands	26,304	12.6	14.3	29.2	43.8	24,530	1.45	0.26
South Wales	222	7.7	5.8	14.3	72.2	31.430	0.81	0.05
Deep-Mined Total	28,863	12.4	13.9	29.2	44.5	24,740	1.45	0.27
Opencast - Supplying Region								
Scottish	2	4.8	6.0	11.4	77.8	30,910	0.94	-
Northern								
Yorkshire								
Western	58	17.6	7.6	30.8	44.0	24,870	0.90	0.06
Midlands	1,842	15.0	10.6	31.0	43.4	24,140	1.86	0.04
South Wales	57	3.7	4.8	6.8	85.7	33,090	0.92	0.06
Opencast Total	1,959	14.9	10.4	30.6	44.1	24,330	1.81	0.04
All Coals Total	30,822	12.6	13.7	29.3	44.4	24,720	1.47	0.25

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Midlands Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	905	11.0	16.8	27.8	44.4	24,450	1.31	0.29
Western	295	15.9	13.9	29.6	40.6	22,870	2.00	0.33
Midlands	19,906	12.8	16.7	28.4	42.1	23,580	1.50	0.25
South Wales								
Deep-Mined Total	21,106	12.8	16.6	28.4	42.2	23,600	1.50	0.26
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western	58	17.6	7.6	30.8	44.0	24,180	0.90	0.06
Midlands	1,796	15.0	10.6	31.1	43.3	24,150	1.87	0.04
South Wales								
Opencast Total	1,854	15.1	10.5	31.1	43.3	24,160	1.84	0.04
All Coals Total	22,960	13.0	16.1	28.6	42.3	26,650	1.53	0.24

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Midland, Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	485	9.4	6.0	30.9	53.8	29,540	1.94	0.31
Western	23	9.1	5.7	30.5	54.7	30.080	1.20	0.23
Midlands	1,183	9.8	6.0	32.0	52.2	29,280	1.32	0.34
South Wales	157	8.9	6.0	16.0	69.1	30,980	0.79	0.05
Deep-Mined Total	1,848	9.6	6.0	30.3	54.1	29,610	1.44	0.31
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	7	-	10.3	-	-	-	-	-
Opencast Total	7	-	10.3	-	-	-	-	-
All Coals Total	1,855	9.6	6.0	30.3	54.1	29,610	1.44	0.31

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Midlands **Sales Region**

Industry and Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	142	4.3	6.0	33.1	56.6	31,800	1.73	0.14
Western	156	14.7	5.5	32.8	47.0	26,610	1.26	0.39
Midlands	2,208	13.0	8.0	31.6	47.4	26,460	1.27	0.23
South Wales	8	6.0	7.0	6.8	80.2	31,110	1.03	0.04
Deep-Mined Total	2,514	12.6	7.7	31.7	48.0	26,790	1.30	0.23
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands	46	14.8	10.4	29.8	45.8	24,530	1.55	0.04
South Wales	12	4.9	3.5	7.7	83.9	32,930	0.83	0.08
Opencast Total	58	13.4	9.5	26.8	50.3	25,670	1.45	0.05
All Coals Total	2,572	12.6	7.7	31.6	48.1	26,770	1.30	0.23

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Midlands Sales Region

Domestic inc. M.F.P.s

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	126	13.7	4.0	31.2	51.1	27,960	1.27	0.50
Western	202	12.5	4.0	34.5	49.0	27,980	1.01	0.51
Midlands	2,966	11.2	5.1	32.8	50.9	28,290	1.23	0.32
South Wales	56	3.4	4.6	7.7	84.3	33,150	0.99	0.05
Deep-Mined Total	3,350	11.3	5.0	32.6	51.1	28,290	1.22	0.35
Opencast - Supplying Region								
Scottish	2	4.8	6.0	11.4	77.8	30,910	0.94	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales	39	3.4	3.7	6.6	86.3	33,130	0.94	0.05
Opencast Total	41	3.5	3.9	6.9	85.7	32,970	0.94	0.05
All Coals Total	3,391	11.3	5.0	32.6	51.1	28,290	1.22	0.35

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Midlands Sales Region

Other inc. exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire								
Western								
Midlands	40	15.4	10.2	30.0	44.4	24,750	0.95	0.31
South Wales								
Deep-Mined Total	40	15.4	10.2	30.0	44.4	24,750	0.95	0.31
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total								
All Coals Total	40	15.4	10.2	30.0	44.4	24,750	0.95	0.31

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Western Sales Region

Total, all Markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	45	6.9	6.6	33.8	52.7	30,570	1.44	0.15
Yorkshire	3,687	7.7	17.9	27.9	46.5	25,860	1.88	0.17
Western	10,134	10.7	12.9	29.9	46.5	25,860	1.68	0.43
Midlands	1,710	12.9	11.6	29.7	45.8	25,140	1.29	0.21
South Wales	329	7.7	7.2	15.1	70.0	30,810	0.62	0.12
Deep-Mined Total	15,905	10.2	13.8	29.2	46.8	25,890	1.66	0.34
Opencast - Supplying Region								
Scottish	1	4.8	5.9	11.3	78.0	30,930	0.94	-
Northern								
Yorkshire	35	8.6	7.4	28.9	55.1	28,600	1.85	0.04
Western	714	10.9	9.9	31.6	47.6	27,280	2.13	0.17
Midlands								
South Wales	43	4.0	3.6	6.6	85.8	33,020	0.93	0.05
Opencast Total	793	10.5	9.5	30.5	49.5	27,560	2.08	0.16
All Coals Total	16,698	10.2	13.6	29.2	47.0	25,980	1.68	0.33

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Western Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	7	8.2	13.9	30.0	45.9	26,170	2.00	0.23
Yorkshire	3,129	7.8	19.4	27.2	45.6	25,310	1.93	0.15
Western	7,295	11.7	15.3	29.1	43.9	24,480	1.77	0.43
Midlands	837	13.8	14.1	27.8	42.3	23,770	1.45	0.14
South Wales								
Deep-Mined Total	11,268	10.8	16.4	28.5	44.3	24,660	1.79	0.33
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western	532	12.2	9.2	31.5	47.1	27,000	1.82	0.18
Midlands								
South Wales								
Opencast Total	532	12.2	9.2	31.5	47.1	27,000	1.82	0.18
All Coals Total	11,800	10.8	16.0	28.6	44.6	24,760	1.79	0.32

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Western Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	9	9.8	7.0	30.2	53.0	29,610	1.33	0.13
Yorkshire								
Western	716	8.8	6.4	31.2	53.6	29,820	1.27	0.34
Midlands								
South Wales	267	8.2	7.6	16.1	68.1	30,510	0.56	0.13
Deep-Mined Total	992	8.6	6.7	27.1	57.6	30,010	1.08	0.28
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total								
All Coals Total	992	8.6	6.7	27.1	57.6	30,010	1.08	0.28

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Western Sales Region

Industry & Misc

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	152	8.9	7.8	31.8	51.5	28,840	1.73	0.31
Western	1,082	9.1	8.9	30.8	51.2	28,310	1.60	0.41
Midlands	598	12.9	10.7	30.1	46.3	25,540	1.02	0.27
South Wales	6	2.5	5.6	12.1	79.8	33,300	0.78	0.08
Deep-Mined Total	1,838	10.3	9.4	30.7	49.6	27,470	1.42	0.35
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire	33	8.5	7.5	28.8	55.2	28,600	1.83	0.04
Western	181	7.1	11.8	31.8	49.3	28,060	3.07	0.15
Midlands								
South Wales	12	5.2	3.4	7.5	83.9	32,800	0.82	0.07
Opencast Total	226	7.2	10.9	30.7	51.2	28,470	2.82	0.13
All Coals Total	2,064	10.0	9.6	30.7	49.7	27,550	1.57	0.33

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Western Sales Region

Domestic & M.F.P.S

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	29	5.7	4.2	35.8	54.3	31,970	1.34	0.14
Yorkshire	406	6.2	4.3	33.8	55.7	31,310	1.44	0.38
Western	1,039	7.0	4.9	34.2	53.9	30,310	1.38	0.52
Midlands	274	9.1	4.5	33.8	52.6	29,540	1.46	0.36
South Wales	55	3.5	4.9	7.8	83.8	33,020	1.06	0.05
Deep-Mined Total	1,803	7.1	4.7	33.5	54.7	30,450	1.39	0.46
Opencast - Supplying Region								
Scottish	1	4.8	5.9	11.3	78.0	30,930	0.94	-
Northern								
Yorkshire	2	9.6	6.1	32.0	52.3	28,530	2.19	0.04
Western	1	5.6	4.1	34.0	56.3	32,980	1.63	0.12
Midlands								
South Wales	31	3.6	3.7	6.4	86.3	33,080	0.96	0.04
Opencast Total	35	4.1	3.9	9.4	82.6	32,750	1.06	0.04
All Coals Total	1,838	7.0	4.7	33.1	55.2	30,490	1.38	0.45

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

Western Sales Region

Other Markets inc. Export

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire								
Western	1	7.4	6.3	33.3	53.0	29,660	1.66	0.43
Midlands	1	10.9	4.5	32.3	52.3	28,660	1.11	0.60
South Wales								
Deep-Mined Total	2	8.9	5.5	32.7	52.9	29,250	1.41	0.50
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total								
All Coals Total	2	8.9	5.5	32.7	52.9	29,250	1.41	0.50

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

South Wales Sales Region

Total, all markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	12	15.5	10.2	14.6	67.2	29,440	0.97	0.07
Northern	41	12.1	5.1	32.5	50.3	28,460	1.13	0.16
Yorkshire	65	6.2	3.8	34.2	55.8	31,350	1.31	0.34
Western	224	7.5	5.1	31.7	55.7	30,770	1.22	0.27
Midlands	603	11.7	6.2	32.0	50.1	27,470	1.26	0.26
South Wales	6,651	8.0	10.2	14.6	67.2	29,440	0.97	0.07
Deep-Mined Total	7,596	8.4	9.5	16.7	65.4	29,310	1.01	0.10
Opencast - Supplying Region								
Scottish	1	4.6	5.8	11.4	78.2	31,030	0.94	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales	1,099	9.1	6.3	6.7	78.9	30,870	1.00	0.06
Opencast Total	1,100	9.1	6.3	6.7	78.9	30,870	1.00	0.06
All Coals Total	8,696	8.5	9.1	15.9	66.5	29,430	1.01	0.10

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

South Wales Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	12	15.5	6.6	32.1	45.8	26,480	1.06	0.26
Northern								
Yorkshire								
Western								
Midlands								
South Wales	1,935	9.3	16.4	12.6	61.7	26,350	1.46	0.05
Deep-Mined Total	1,947	9.4	16.4	12.7	61.5	26,350	1.46	0.05
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	12	6.8	12.0	-	-	-	-	-
Opencast Total	12	6.8	12.0	-	-	-	-	-
All Coals Total	1,959	9.4	16.3	12.7	61.6	26,350	1.46	0.05

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

South Wales Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	3	9.7	7.2	30.2	52.9	29,590	1.34	0.12
Yorkshire								
Western	167	8.3	5.4	30.9	55.4	30,470	1.19	0.25
Midlands	1	10.2	5.1	31.5	53.2	29,440	1.27	0.34
South Wales	2,793	8.0	7.1	17.3	67.6	30,780	0.60	0.08
Deep-Mined Total	2,964	8.0	7.0	18.2	66.8	30,750	0.64	0.09
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	405	8.9	7.6	6.3	77.2	29,510	1.20	0.05
Opencast Total	405	8.9	7.6	6.3	77.2	29,510	1.20	0.05
All Coals Total	3,369	8.1	7.1	17.2	67.6	30,710	0.71	0.09

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

South Wales Sales Region

Industry & Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	1	13.9	7.0	31.5	47.6	26,960	1.32	0.12
Yorkshire								
Western								
Midlands	205	12.3	8.0	30.8	48.9	27,030	1.25	0.29
South Wales	161	4.5	6.3	13.3	73.9	32,270	0.83	0.07
Deep-Mined Total	367	10.6	7.5	26.6	55.3	28,290	1.15	0.24
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	58	3.8	8.9	7.0	80.3	33,040	0.92	0.06
Opencast Total	58	3.8	8.9	7.0	80.3	33,040	0.92	0.06
All Coals Total	425	10.3	7.7	25.9	56.1	28,470	1.14	0.23

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

South Wales Sales Region

Domestic inc. MFPs

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	37	12.2	4.9	32.7	50.3	28,434	1.11	0.16
Yorkshire	64	6.3	3.8	34.2	55.7	31,350	1.31	0.32
Western	57	5.2	4.1	34.0	56.7	31,720	1.29	0.33
Midlands	397	11.3	5.2	33.4	50.1	27,740	1.27	0.25
South Wales	1,631	5.4	4.7	11.8	78.1	32,590	0.90	0.07
Deep-Mined Total	2,186	7.2	4.8	17.5	70.5	31,160	1.03	0.14
Opencast - Supplying Region								
Scottish	1	4.6	5.8	11.4	78.2	31,040	0.94	-
Northern								
Yorkshire								
Western								
Midlands								
South Wales	516	8.9	4.4	6.7	80.0	30,930	0.85	0.06
Opencast Total	517	8.9	4.4	6.7	80.0	30,930	0.85	0.06
All Coals Total	2,703	7.6	4.7	14.6	73.1	31,100	0.99	0.12

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

South Wales Sales Region

Other markets inc. exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	132	6.6	11.0	15.7	66.7	29,810	0.51	0.11
Deep-Mined Total	132	6.6	11.0	15.7	66.7	29,810	0.51	0.11
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	108	12.8	8.6	6.1	72.5	29,890	0.88	0.08
Opencast Total	108	12.8	8.6	6.1	72.5	29,890	0.88	0.08
All Coals Total	240	10.9	9.3	9.1	70.7	29,860	0.77	0.09

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

London & Southern Sales Region

Total, all markets

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	267	13.8	12.3	28.8	45.1	24,230	0.56	0.20
Northern	3,809	10.1	15.8	29.0	45.2	25,390	1.63	0.25
Yorkshire	312	7.5	14.4	30.2	47.9	26.980	1.70	0.24
Western								
Midlands	5,183	13.9	11.2	29.7	44.7	24.810	1.34	0.28
South Wales	571	6.9	7.5	11.9	73.7	30,970	1.02	0.06
Deep-Mined Total	10,142	11.8	13.1	28.4	46.7	25.400	1.44	0.25
Opencast - Supplying Region								
Scottish	12	12.5	9.4	21.2	57.0	26,110	1.12	-
Northern	503	11.5	8.3	29.3	50.9	29,120	1.45	0.08
Yorkshire	3	8.1	5.5	30.8	55.6	29,330	1.97	0.04
Western								
Midlands	3	13.5	10.6	29.9	46.0	25,080	1.74	0.04
South Wales	201	3.8	3.7	6.9	85.6	33,080	0.89	0.05
Opencast Total	722	9.7	7.2	24.0	59.1	29,980	1.32	0.07
All Coals Total	10,864	11.6	12.7	28.1	47.4	25,720	1.43	0.24

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

London & Southern Sales Region

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorin %
Scottish	267	13.8	12.3	28.8	45.1	24,230	0.56	0.20
Northern	3,412	10.1	16.4	28.8	44.7	25,100	1.65	0.25
Yorkshire	207	8.2	18.0	28.6	45.2	25,380	1.83	0.22
Western								
Midlands	2,166	15.3	13.4	28.9	42.4	23,480	1.43	0.20
South Wales	29	9.7	16.4	25.5	48.4	25,470	1.92	0.06
Deep-Mined Total	6,081	12.1	15.2	28.8	43.9	24,500	1.53	0.23
Opencast - Supplying Region								
Scottish	7	18.0	11.7	28.3	42.0	22,700	1.25	-
Northern	384	13.1	8.3	30.1	48.5	28,150	1.51	0.08
Yorkshire								
Western								
Midlands	1	11.3	11.0	30.0	47.7	26,000	2.07	0.05
South Wales								
Opencast Total	392	13.2	8.4	30.1	48.3	28,040	1.51	0.08
All Coals Total	6,473	12.1	14.8	28.9	44.2	24,720	1.53	0.23

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

London & Southern Sales Region

Carbonisation

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	139	8.9	5.7	30.5	54.9	30,460	1.17	0.16
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	139	8.9	5.7	30.5	54.9	30,460	1.17	0.16
Opencast - Supplying Region								
Scottish								
Northern	85	5.2	7.7	26.0	61.1	33,000	1.10	0.06
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	85	5.2	7.7	26.0	61.1	33,000	1.10	0.06
All Coals Total	224	7.5	6.5	28.8	57.2	31,420	1.14	0.12

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland **Sales Region**

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	251	14.3	7.6	31.5	46.6	26,640	1.00	0.17
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	251	14.3	7.6	31.5	46.6	26,640	1.00	0.17
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total								
All Coals Total	251	14.3	7.6	31.5	46.6	26,640	1.00	0.17

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

London & Southern Sales Region

Domestic inc. MFPs

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	21	12.0	4.9	32.8	50.3	28,470	1.12	0.18
Yorkshire	103	5.4	4.4	34.8	55.4	31,450	1.34	0.31
Western								
Midlands	809	10.6	5.1	33.4	50.9	28,370	1.27	0.31
South Wales	362	4.9	5.0	10.0	80.1	32,760	0.94	0.06
Deep-Mined Total	1,295	8.7	5.0	24.8	62.5	29,890	1.16	0.23
Opencast - Supplying Region								
Scottish	5	4.9	6.1	11.4	77.6	30,810	0.94	-
Northern								
Yorkshire	3	8.1	5.5	30.8	55.6	29,330	1.97	0.04
Western								
Midlands								
South Wales	184	3.7	3.7	6.9	85.7	33,140	0.89	0.05
Opencast Total	192	3.8	3.8	7.5	84.9	32,980	0.92	0.05
All Coals Total	1,487	8.1	4.9	22.0	66.0	30,330	1.13	0.21

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

London & Southern Sales Region

Other Markets inc. exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire	1	6.7	4.2	34.7	54.4	30,750	1.37	0.43
Western								
Midlands	7	14.4	4.4	33.6	47.6	26,780	1.30	0.11
South Wales	1	3.3	5.4	9.0	82.3	32,890	0.95	0.05
Deep-Mined Total	9	12.3	4.5	32.2	51.0	27,760	1.29	0.16
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	2	3.0	4.2	6.9	85.9	32,870	0.94	0.05
Opencast Total	2	3.0	4.2	6.9	85.9	32,870	0.94	0.05
All Coals Total	11	10.6	4.4	27.6	57.4	28,690	1.14	0.14

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland **Sales Region**

Total All Markets

Deep-Mined - Supplying Region	**Tonnes Per Annum '000**	**Technical Analysis (Actual)**						
		Moisture %	**Ash %**	**Volatile %**	**F. Carbon %**	**Cal. Val. kJ/kg**	**Sulphur %**	**Chlorine %**
Scottish	313	14.3	7.4	31.6	46.7	26,730	0.98	0.18
Northern	292	10.7	4.9	33.3	51.1	29,200	1.09	0.11
Yorkshire	74	4.1	4.3	35.7	55.9	32,120	1.34	0.20
Western	54	6.1	5.0	34.2	54.7	30,660	1.26	0.44
Midlands	295	9.9	4.9	33.4	51.8	28,600	1.31	0.30
South Wales	21	3.2	4.7	8.4	83.7	33,260	0.95	0.07
Deep-Mined Total	1,049	10.9	5.6	32.3	51.2	28,540	1.13	0.20
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western	82	6.3	10.8	31.9	51.0	30,210	2.62	0.16
Midlands								
South Wales	58	3.2	3.5	7.5	85.8	33,560	0.81	0.05
Opencast Total	140	5.4	8.6	24.6	61.4	31,200	2.08	0.13
All Coals Total	1,189	10.3	6.0	31.4	52.3	28,830	1.23	0.19

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland **Sales Region**

Power Stations

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual) Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	251	14.3	7.6	31.5	46.6	26,640	1.00	0.17
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	251	14.3	7.6	31.5	46.6	26,640	1.00	0.17
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total								
All Coals Total	251	14.3	7.6	31.5	46.6	26,640	1.00	0.17

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland **Sales Region**

Carbonization

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total								
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total								
All Coals Total	-	-	-	-	-	-	-	-

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland Sales Region

Industry & Misc.

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish	62	14.1	6.8	32.0	47.1	27,100	0.91	0.20
Northern								
Yorkshire								
Western								
Midlands	2	12.3	4.3	33.1	50.3	28,210	1.44	0.30
South Wales	1	3.3	4.2	8.0	84.5	33,380	1.00	0.07
Deep-Mined Total	65	13.8	6.7	31.4	48.1	27,280	0.92	0.20
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western	82	6.3	10.8	31.9	51.0	30,210	2.62	0.16
Midlands								
South Wales	6	3.2	3.4	7.6	85.8	33,630	0.78	0.05
Opencast Total	88	6.2	10.5	31.0	52.3	30,330	2.55	0.16
All Coals Total	153	9.4	8.9	31.2	50.5	29,020	1.85	0.18

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland Sales Region

Domestic & MFIS

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern	292	10.7	4.9	33.3	51.1	29,200	1.09	0.11
Yorkshire	74	4.1	4.3	35.7	55.9	32,120	1.34	0.20
Western	54	6.1	5.0	34.2	54.7	30,670	1.26	0.44
Midlands	294	9.9	4.9	33.4	51.8	28,600	1.31	0.30
South Wales	20	3.2	4.7	8.5	83.6	33,250	0.94	0.07
Deep-Mined Total	734	9.4	4.9	32.7	53.0	29,370	1.20	0.21
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales	52	3.2	3.5	7.4	85.9	33,550	0.81	0.05
Opencast Total	52	3.2	3.5	7.4	85.9	33,550	0.81	0.05
All Coals Total	786	9.1	4.8	31.4	54.7	29,570	1.18	0.21

CONSUMPTION SIDE

MAIN MARKET DISPOSALS WITH RELATED ANALYTICAL DATA

1975/1976

N. Ireland **Sales Region**

Other inc. exports

Deep-Mined - Supplying Region	Tonnes Per Annum '000	Technical Analysis (Actual)						
		Moisture %	Ash %	Volatile %	F. Carbon %	Cal. Val. kJ/kg	Sulphur %	Chlorine %
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Deep-Mined Total	-	-	-	-	-	-	-	-
Opencast - Supplying Region								
Scottish								
Northern								
Yorkshire								
Western								
Midlands								
South Wales								
Opencast Total	-	-	-	-	-	-	-	-
All Coals Total	-	-	-	-	-	-	-	-

APPENDIX IV

IMPORTED COAL : 1975/76

Country of Origin	Areas of Consumption	Tonnes ('000s)	Average or Typical Technical Analysis						
			Moisture %	Ash %	Vol. M. %	F. Carbon %	C.V.kJ/kg %	Sulphur %	Chlorine %
Power Stations									
U.S.A.	C.E.G.B., S.W. Region	1,083	5.0	11.0	N/A	N/A	28,500	1.50	0.20
Australia	C.E.G.B., S.E. Region	1,867	8.0	14.0	N/A	N/A	26,800	0.75	0.20
Others		206							
TOTAL		3,156							
Carbonisation									
U.S.A.	S. Wales, Scotland, Tees-side	403	5.0	7.0	25.0	63.0	N/A	0.90	N/A
Australia	S. Wales	342	10.0	8.5	21.0	60.5	N/A	0.65	N/A
Poland	Tees-side	53	9.0	7.5	25.5	58.0	N/A	1.00	N/A
TOTAL		798							
Domestic including Manufactured Fuel									
Belgium/Lux.	) These imported) domestic fuels are) comprised almost) entirely of Anthracite and manufac-) tured ovoids. They) are sold mainly in S.E. England, with smaller tonnages elsewhere in the U.K.	28	3.0	6.0	N/A	N/A	33,000	0.55	0.02
France		72	2.0	5.0	8.6	84.4	32,900	1.00	0.01
North Vietnam		31	3.0	5.2	6.2	85.6	33,500	0.55	N/A
West Germany		46	3.0	7.0	8.0	82.0	32,000	0.65	0.03
South Africa		14	5.0	10.2	10.6	74.2	30,000	0.87	N/A
Morocco		15							
Others		21							
TOTAL		227							

APPENDIX V

THE PRINCIPAL TECHNIQUES OF COAL CLEANING IN THE U.K.

A large number of techniques have been developed for the cleaning of coal. The fundamental purpose of such treatment is the reduction in the proportion of dirt in the saleable product and the separation of coals into homogenous physical sizes. These requirements arise from the demands of the particular customers; for example, domestic users normally require larger sizes of coal than industrial consumers, coke manufacturers require coals with lower ash percentages than power stations, etc.

The principal techniques for coal cleaning, currently used in the U.K. are described below and some indication of their ability to reduce the sulphur content given. Further consideration of these techniques will be included in Part II of the study.

JIGS AND LAUNDERS

The simplest type of coal preparation plant uses the differential settling rates of coal and the heavier shales and pyrites. In a flowing current of water, either upward or horizontal, this will result in solids of different specific gravities being found at different places in the stream. This simple principle led to the use of trough washers using horizontal water flows, upward current washers and combined flow washers. These techniques are not in general modern use, due to relatively high losses of coal in the discard.

Jig washers use a rather more elaborate version of this method, utilising pulsating water currents. In this, stratification of the different density elements is achieved by alternate upward and downward currents of water produced, in modern jigs, by pulses of compressed air.

The Baum jig is a modern example of this technique which is widely used in the U.K. This jig is limited in operation to separating above 1.6 specific gravity and is used to treat a wide size range of coals. It is expected that effective pyrite separation occurs only at densities lower than this and the Baum jig is not normally considered as a method of removing pyrites.

DENSE MEDIUM BATHS

This technique directly uses the different densities of coal and dirt by immersing the raw coal in a liquid with a density intermediate between coal and dirt. The coal then floats and separates from the dirt, which sinks. Although some experiments have been made with heavy organic liquids, all practical methods use solid suspensions in water to achieve the intermediate density. Most U.K. systems use magnetite which has the advantage of being high density, stable and easily recoverable by magnetic methods. It is, however, fairly expensive and the losses of magnetite contribute to the high cost of dense medium systems relative to Baum jigs.

The various dense media baths are all restricted to the cleaning of coarse coals, normally above about 10mm. They are not therefore suitable for sulphur reduction on most coals.

DENSE MEDIUM AND WATER CYCLONES

Cyclones for the separation of coal and dirt are normally used with dense media, the effect being to separate particles as in static dense media baths but with greatly increased settling speeds. This enables fine coal to be treated down to the bottom limit of about 0.5mm, this limit being set not by the limitations of the cyclone but by the difficulties of recovering the

magnetite/

magnetite medium from smaller sizes. The top size suitable for dense-media cyclones is about 50mm.

The dense-medium cyclone enables a cut to be made down to 1.3 specific gravity with a high degree of control. It is gaining favour as a washing technique, despite its high operating costs relative to jigs, due to this virtue and to the rather lower coal losses. The ability to separate low densities make this one of the preferred methods of reducing sulphur content.

Cyclones using a water medium (so called hydrocyclones) which separate particles essentially on the basis of mass are likely to be a good method of separating finely pulverised coal from pyrites though they would be relatively ineffective in removing shale and other dirt. They may therefore be used as an alternative to Tables in multi-stage sulphur reduction techniques.

FROTH FLOTATION

Froth flotation (FF) depends upon rather different effects than those considered above, i.e. upon the surface properties of the different particles. The dirt content tends to be wetted more easily than coal. As a result, air bubbles stick more firmly to coal than dirt. FF uses this by frothing a fine coal slurry and separating off those particles that rise with the froth. These consist mainly of clean coal. FF is useful for cleaning fine coal less than $\frac{1}{2}$mm in size and is normally used as a subsidiary circuit in a coal preparation plant.

Pyrites have similar surface properties to coal and FF cells are not efficient at separation of pyrites in their normal operation. Some separation is observed but this is largely due to the frothing cell acting as a simple gravity separator. Indeed a major part of pyrite separation can be observed to occur in the conditioning tank, often installed before the actual frothing cell to allow enhancement of the surface properties. Separation is effected in the cell by those coal particles with a high proportion of pyritic content being weighed down by the pyrites relative to cleaner coal particles. This distinction is void below 150 µm size when a single air bubble will buoy up a particle irrespective of specific gravity.

The selective rejection of pyrites requires the use of a two-stage process in which, in the first stage, coal is floated and dirt removed and a second stage in which pyrite is floated and coal depressed by the use of a chemical depressant.

This technique has been tested by the US Bureau of Mines and is reported to be efficient at removing pyritic sulphur. It is not yet in commercial operation.

CONCENTRATING TABLES

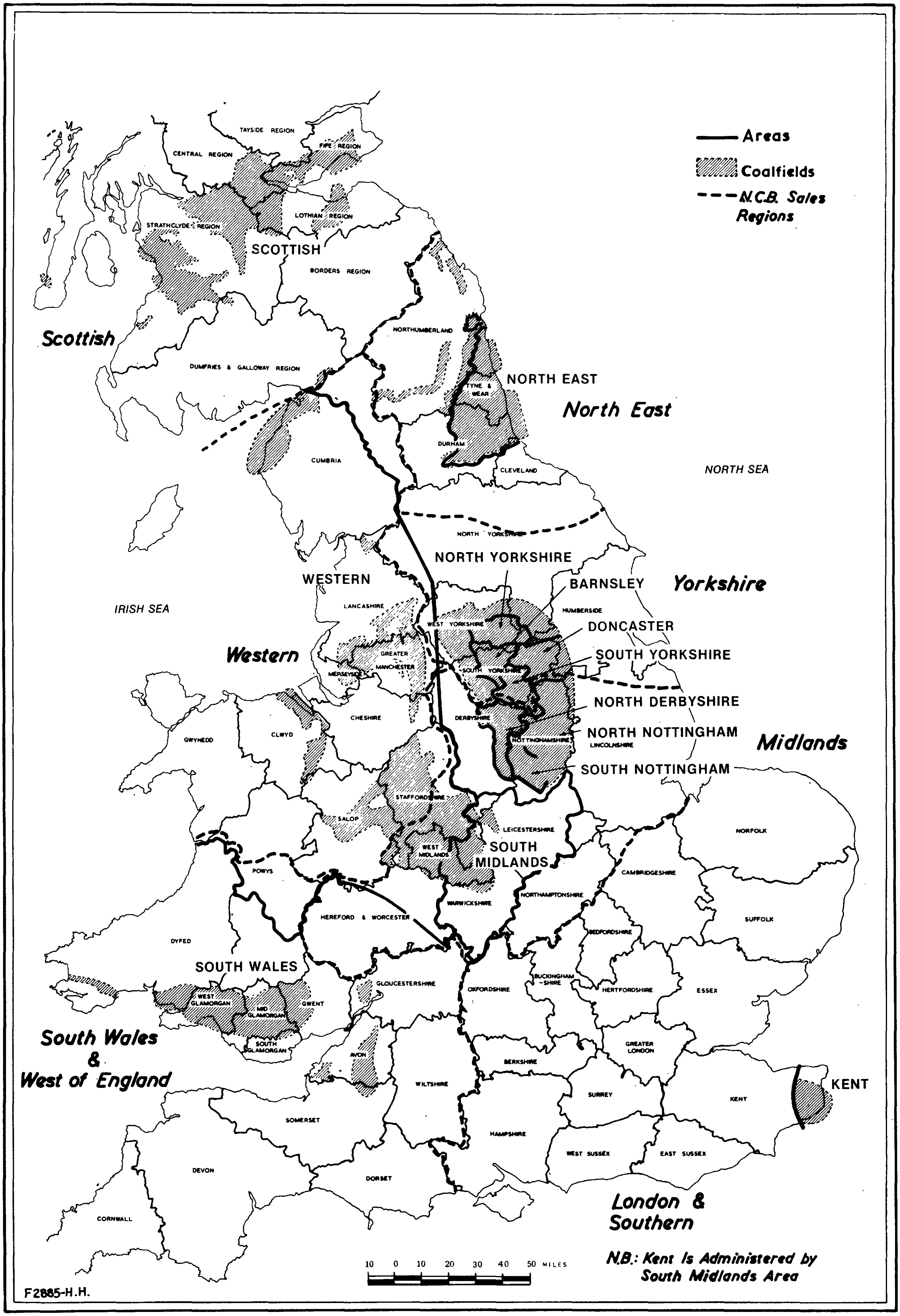
The concentrating table is an alternative of cleaning fine coal, but is not widely used in the U.K. The fine coal is fed on to one corner of a rhombus-shaped table along which run a series of rectangular strips parallel to the long side. The table is agitated in a slightly inclined plane in a differential manner; moving away at a relatively slow speed and returning much faster. Feed water is passed on to the table all along one side. As a result of these motions, the coal and dirt are separated with the clean coal discharging along the long open side and dirt discharging along the short side.

Tables have been used for washing coal up to 10 mm in size but would not be considered for sulphur reduction at such a size. At sizes below 1mm, however, they could be used to remove pyrites, in a multi-stage system.

PNEUMATIC/

PNEUMATIC SEPARATORS

These techniques have been rendered obsolete by the wet nature of present day raw coals. The high cost of pre-drying the coal has ruled out their consideration for sulphur reduction.


Areas
Coalfields
N.C.B. Sales Regions
TAYSIDE REGION
FIFE REGION
CENTRAL REGION
LOTHIAN REGION
STRATHCLYDE REGION
SCOTTISH
BORDERS REGION
Scottish
NORTHUMBERLAND
DUMFRIES & GALLOWAY REGION
NORTH EAST
TYNE & WEAR
North East
DURHAM
CUMBRIA
CLEVELAND
NORTH SEA
NORTH YORKSHIRE
NORTH YORKSHIRE
WESTERN
BARNSLEY
Yorkshire
IRISH SEA
LANCASHIRE
HUMBERSIDE
WEST YORKSHIRE
DONCASTER
Western
GREATER MANCHESTER
SOUTH YORKSHIRE
SOUTH YORKSHIRE
MERSEYSIDE
NORTH DERBYSHIRE
CHESHIRE
DERBYSHIRE
GWYNEDD
CLWYD
NOTTINGHAMSHIRE
NORTH NOTTINGHAM
LINCOLNSHIRE
Midlands
SOUTH NOTTINGHAM
STAFFORDSHIRE
SALOP
LEICESTERSHIRE
NORFOLK
WEST MIDLANDS
SOUTH MIDLANDS
POWYS
CAMBRIDGESHIRE
WARWICKSHIRE
NORTHAMPTONSHIRE
SUFFOLK
HEREFORD & WORCESTER
DYFED
BEDFORDSHIRE
SOUTH WALES
GLOUCESTERSHIRE
OXFORDSHIRE
BUCKINGHAMSHIRE
HERTFORDSHIRE
ESSEX
WEST GLAMORGAN
MID GLAMORGAN
GWENT
SOUTH GLAMORGAN
South Wales & West of England
AVON
GREATER LONDON
BERKSHIRE
WILTSHIRE
KENT
KENT
SURREY
SOMERSET
HAMPSHIRE
WEST SUSSEX
EAST SUSSEX
DEVON
DORSET
London & Southern
CORNWALL
10 0 10 20 30 40 50 MILES
N.B.: Kent Is Administered by South Midlands Area
F2885-H.H.

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PART 2

Technical/economic evaluation of the methods to diminish emissions

D.W. Gill and R.F. Littlejohn
(Appendix 3 by G.F. Morris and R. Abrey)

SUMMARY

The potential air pollutants sulphur dioxide, nitrogen oxides, suspended particulates and trace elements arising from the projected use of coal in the United Kingdom up till the end of the present century are examined in turn, and the present and future environmental impact is estimated, taking into account expected developments in pollution control techniques. The cost and effectiveness of extra pollution control measures in addition to those now used are assessed and also the energy requirements for operation of control measures. Costs of existing anti-pollution measures are not considered. The problems of disposal of solid waste and liquid effluents resulting from air pollution control processes, and the time-scales for availability of processes are also discussed.

Pollution control measures may take the form either of dispersion from high chimneys to reduce ground level concentrations, or of reduction in quantities emitted. It is shown that the operation of the U.K. "tall-stack" policy results generally in adequate dispersal of pollutants from power stations and industrial sources, and the ground-level concentrations of potential pollutants from power generation and from most industrial coal combustion plants governed by the "tall-stack" policy are well below levels that are believed to cause risk of harm to health and the environment. The contribution to ground-level concentrations resulting from these high- and medium-level emitters is small in comparison with those from low-level sources, except for a few areas where there is a high concentration of industry burning coal or fuel oil. Pollution control measures aimed at decrease of emissions can be grouped roughly into those that are applied to the fuel before combustion, those that are applied during combustion, and those applied to the combustion effluent gas. The report attempts to assess the effectiveness of such measures in relation to their financial, energy and environmental costs.

Treatment of coal before combustion would normally be carried out at or close to the colliery, although magnetic separation of pyrites for sulphur removal might more conveniently be performed at power stations on the pulverised coal before it enters the furnace. Using extensions of existing techniques for coal cleaning only a small reduction in sulphur content, of less than 15% on a thermal basis, is predicted, but for more accurate predictions data for a much larger number of coals than the five used for this study would have to be taken. The use of novel physical or chemical coal cleaning processes in the U.K. is unlikely at least until the end of the century, although recent research has suggested that such processes could give much greater sulphur reduction.

Towards the end of the period covered by the study, coal conversion processes may possibly account for a significant market for coal use, with the largest outlet probably being in production of substitute natural gas (SNG) for distribution through the national gas grid to homes, public buildings, offices and factories. SNG would be cleaned so as to contain negligible amounts of sulphur compounds, and its combustion would be relatively non-polluting apart from some nitrogen oxides. Some coal gasification plants supplying local industrial complexes may also be constructed during the period under consideration.

The principal systems for pollution control during combustion are likely to be fluidised-bed combustion with limestone addition in industrial boilers, (up to 90% sulphur retention), and modification of combustion conditions for NO_x reduction in power station boilers. Neither of these is likely to be implemented unless made necessary by the imposition of emission limits. Fluidised bed combustion is expected to be used, with or without limestone addition, for industrial boiler and drier firing, and there is evidence that even without limestone addition, on average 30% of the sulphur in the coal is retained, compared with only 10% retention usual for conventional coal-burning appliances. Combustion control modifications in power station boilers could reduce NO_x emissions by an estimated 20%, or more, depending on existing boiler design.

On the present evidence it is considered that the "tall-stack" policy satisfactorily controls the effects of pollutant emissions from power stations and industrial sources. If, however, in the future legislation were to be introduced making some form of sulphur dioxide emission control necessary, the process most likely to be used initially in the U.K. electricity industry is a regenerative flue gas desulphurisation (FGD) process, which produces only small amounts of solid or liquid wastes, most of the sulphur being recovered in potentially useful form as sulphur or as sulphuric acid. The process costed (Wellman Lord) would add 25 to 30% to generation costs for a reduction in sulphur dioxide emissions from power plant of 90%. It is unlikely that FGD will be used on smaller plants to any great extent. For the long term, coal gasification in association with combined cycle power generation is being studied.

Processes have been developed to the pilot plant stage, mainly in Japan, for the removal of nitrogen oxides from flue gases, but there is little experience of these on gases from coal combustion. Dry processes appear to be more fully proven than wet processes, and some FGD processes could be modified to remove NO_x as well but this could be even more expensive. If the modification were to call for an on-site chlorine dioxide or ozone generator the modification could be an expensive one, and it would also reduce the yield of recovered sulphur.

Improvements in particulate removal techniques are expected. As new power stations are built, highly efficient dust arrestor plant (up to 99.5% removal) will be more widely employed and older, less efficient plant phased out. Some reduction in emissions from other industrial users of coal can be expected as a result of developments in dust removal techniques, and this could make possible the introduction of more stringent emission standards. The introduction of additional smokeless zones is expected to result in a reduction of approximately 50% in low-level emissions in 2000, compared with the estimate given in Part 1 of the study.

Trace elements are emitted to the atmosphere either as vapour (chlorine, as HCl, mercury and selenium) or contained in solid particles which escape collection in the dust arrestors. Some elements become concentrated on the fine particles present in the flue gas, and the extent of this concentration is expressed as an enrichment factor, i.e. the concentration of the element in the fine particles divided by its concentration in the coarse ash particles deposited in the furnace. In many published papers, and in this report an enrichment relative to concentration in the whole coal ash is used.

Measured enrichment factors are used, in conjunction with stack dust loadings and experimental measurements of plume dispersal, to estimate the ground level concentrations of some toxic elements present in airborne particles. Measurements at ground level have shown that the elements considered are all present in much lower concentrations than could give cause for concern.

There are grounds for believing that, if necessary, the content of most trace elements could be substantially reduced by washing of crushed coal at a relative density of 1.6, but no data are available for British coals.

1. Introduction

This report forms the second part of a two-part study carried out by the NCB for the Environmental Directorate of the Commission of the European Communities. Part 1 (1) examined the present and future patterns of coal production and consumption in the United Kingdom and the effects of these on the possible future emissions of atmospheric pollutants without taking into account any reductions in emission factors which might result from technological developments.

In this report, developments in the technology of pollution control are reviewed in relation to the use of coal in the United Kingdom, and estimates are made of the extent to which new control processes might be applied in the U.K. up till the year 2000, and of the cost and effectiveness of such processes. Other adverse environmental effects resulting from measures to reduce atmospheric pollution are also taken into account, but no attempt is made to cost these, except where it is possible to estimate the cost of preventing such secondary environmental effects. Only emissions from the use of coal are dealt with, the large contributions of other fuels, especially oil, being ignored. A great deal of expenditure is already incurred in the removal of particulate matter from coal combustion gases, and this expenditure is not included. Only anticipated technological improvements in particulate removal are considered.

The views expressed and the conclusions reached are solely those of the authors, based on the evidence available at the time of preparation of the report, and should not be regarded as committing the NCB or coal users in any way concerning future action to reduce atmospheric pollution. The extents to which the various processes referred to in the report are likely to be introduced will be influenced by many factors, especially by legislative measures and by future technological and economic changes that may alter the effectiveness and cost of individual processes.

Where costs of pollution control processes have been converted from costs given in prior publications relating to construction and operation of plant in other countries, there are several sources of uncertainty. As far as possible, cost conversion has been done by converting the costs to March 1979 costs in the currency of the country of origin, and then converting to British currency at March 1979 conversion rate. It cannot be stressed too strongly that costs produced in this way do not reflect the changed standards of construction and operation that would be necessary if the plant were to be built in the U.K. The determination of costs to take account of varying requirements (safety, labour, environment, etc.) would have taken far too long to allow it to be done for every process referred to in this report, but where estimates are available for U.K. location these have been included.

Where it has been necessary to estimate the change in capital cost on scaling up a plant, a 2/3 power factor has been used but it is recognised that this may in many cases be an over-simplification. For the up-dating of costs to March 1979 levels, extrapolated Chemical Engineering Plant Cost Indices have been used for USA costs, and a cost of living index for other countries. The conversion factors used to correct to March 1979 costs for six countries are shown in Table 1.

All costs quoted in the report, except where stated otherwise, are at March 1979 values.

Except where stated otherwise, coal quantities refer to the coal as delivered, i.e. with average moisture and ash contents.

TABLE 1

Factors Used for Converting Costs to March 1979 Values

Year(1)	Country					
	Canada(2)	France(3)	W. Germany(3)	Japan(2)	U.K.(4)	U.S.A.(5)
1965	2.70	2.24	1.58	1.80	3.67	2.12
6	2.58	2.19	1.57	1.76	3.58	2.05
7	2.55	2.21	1.58	1.72	3.58	2.02
8	2.50	2.24	1.58	1.72	3.27	1.98
9	2.37	2.02	1.57	1.69	3.17	1.92
70	2.35	1.88	1.49	1.62	3.01	1.84
1	2.33	1.84	1.43	1.63	2.76	1.75
2	2.18	1.76	1.39	1.62	2.62	1.69
3	1.78	1.54	1.31	1.40	2.45	1.61
4	1.46	1.19	1.15	1.07	1.97	1.40
5	1.37	1.26	1.10	1.03	1.61	1.27
6	1.31	1.18	1.06	0.98	1.37	1.20
7	1.21	1.11	1.03	0.96	1.14	1.14
8	1.10	1.06	1.02	0.98	1.05	1.06

Notes

1. Average for calendar year
2. General wholesale price index (W.P.I.)
3. Industrial products W.P.I.
4. Finished goods W.P.I.
5. Based on C.E. Plant Cost Index, 1970-77, otherwise general W.P.I.
6. In March 1979, £1 was worth the following:

   2.39 Canadian dollars; 8.74 French francs; 3.79 Deutschmarks; 420.7 Yen and 2.04 U.S. dollars.

2. Alleviation of the effects of sulphur oxide emissions

2.1 Introduction

The data on market disposals given in Appendices 1 and 2 of Part 1 of the present study(1) use the following groupings: power station, carbonisation, industry and miscellaneous, domestic including coal supplied to manufactured fuel plants, and other disposals including exports.

In this section, the emissions of sulphur oxides, mainly consisting of sulphur dioxide, SO_2, resulting from the use of coal in each of these market sectors will be considered, with particular reference to the need for reduction in sulphur dioxide emissions in order to conform with possible new legislation for protection of the environment, and to the costs and other consequences of sulphur removal processes.

Towards the end of the century, it is likely that in addition to the above uses coal may be beginning to be used for the production of substitute natural gas, as a household fuel. At about the same time, new uses for coal may be arising in the production of feedstocks for chemical manufacture and for liquid fuels mainly for use in transport. These will represent new markets for coal, but the market penetration is not thought likely to be large during the present century, although a substantial research effort is already in progress in the U.K. and in other countries. No account is taken in the calculations in this report of pollutant emissions from these new uses.

The "industry and miscellaneous" sector includes, besides small and medium-sized boiler plant, certain industrial coal-fired furnaces, cement kilns and brickworks. Although oil-firing has to a large extent taken over these former uses for coal, there are prospects of a switch back to coal as reserves of oil become depleted from about 1990 onwards.

Section 2.2 discusses the dispersal of sulphur dioxide by controlling the height of emission, which is the current procedure for all except very small coal and oil using plants in the U.K. The ground level concentrations of sulphur dioxide resulting from the present procedures are examined and conclusions are drawn concerning action which might have to be taken to meet possible future legislation. It is concluded that there are two possible cases, requiring action of different kinds; these two cases relate to implementation of two different standards for ambient air quality laid down in a proposed (but not yet accepted) EEC Directive(2) dealing with sulphur dioxide and suspended particulates. The first case, in which strict limits on ambient concentrations would be involved, would require action in only a small number of heavily polluted areas in order to reduce sulphur dioxide concentrations, and the action taken could include use of a low-sulphur fuel or the removal of sulphur during or after combustion by some industrial users. The second case, to be implemented at the discretion of Member States, would require the attainment of lower ambient concentrations (Guide Values). If these were to be introduced in the U.K., they would require more drastic action by many coal users to reduce emissions of sulphur dioxide by a significant fraction.

This section considers the cost and effectiveness of various measures that could be taken in order to comply with any legislation that might be introduced in the U.K. that would necessitate the control of SO_2 emissions, and compares these with the present tall-stack policy.

Sections 2.3, 2.4, 2.5 and 2.6 deal with various ways in which emission limits could be met, by sulphur removal before, during or after combustion, discussing the extent of sulphur reduction possible, the costs, and possible time-scales for availability. Any adverse environmental effects of their use are also referred to.

The costs of sulphur reduction differ with the initial sulphur content of the coal, and to put the problem into perspective Appendix 1 gives breakdowns of the amounts of coal falling into different ranges of sulphur content. The figures relate to the financial year 1977/78 and are for these markets: power generation, industrial use and domestic heating, including manufactured fuel plants.

2.2 Disposal by controlling height of emission

2.2.1 Current practice

The method used at present in U.K. for controlling the contribution to ground-level concentration (g.l.c.) from electricity generating and other industrial sources(3,4) is to specify the heights of chimneys so that the maximum contribution to g.l.c. of sulphur dioxide does not exceed some target value. Different limits may be applied depending on the type of locality but a maximum hourly average concentration of 0.5 mg/m^3 (17 parts per hundred million by volume, vpphm) is commonly specified. Monitoring of ground level concentrations around UK power stations has shown(5,6) that the maximum g.l.c. resulting from the power station chimney emissions very rarely exceed this value. The regulations on chimney design include recommendations about efflux velocity, gas temperature and measures to prevent downwash of the plume. Statutory Authorities can also require emissions from neighbouring sources, wind eddies around large buildings in the vicinity and other locally important factors to be taken into account when the height of a new chimney is calculated.

The maximum average concentration over any period of time depends on the length of averaging period. It has been estimated(7) that if C is the maximum 3-minute g.l.c. resulting from a large single source, then the maximum hourly concentration will be $C/_2$, the maximum daily concentration $C/_{12}$ and the maximum yearly concentration $C/_{100}$. The maximum daily and yearly averages are therefore $1/_6$ and $1/_{50}$ respectively of the maximum hourly concentration. Lucas(7) does not define "maximum", but it is reasonable to adopt the criterion of the proposed EEC Directive(2), i.e. the value which is exceeded on 2% of occasions. For a typical power station burning 1.5% sulphur coal and emitting stack gases with an initial SO_2 concentration of 2850 mg/Nm^3, the maximum daily average corresponding to the hourly maximum of 0.5 mg/m^3 will be only 0.083 mg/m^3 (83 μg/m^3), and the maximum yearly average will be 0.01 mg/m^3 (10 μg/m^3). This represents respectively a 34,000-fold and a 285,000-fold dilution of the stack gas. These dilution factors have been calculated here because they are useful for estimating maximum g.l.c. of other flue gas constituents.

The present regulations apply to all installations larger than 0.366 MW (Th) (1.25 million Btu/h) with the exception of heating systems for commercial premises constructed before 1968. Domestic housing and other small sources are therefore exempt and it may generally be assumed that high- and medium-level emissions are subject to sulphur dioxide control but low-level emissions are not.

2.2.2 Effectiveness of current practice

The Clean Air Acts of 1956 and 1968 and concomitant regulations have brought about a manifest improvement of air quality in urban areas of the U.K. The ground level concentration of sulphur dioxide fell by 50% and that of smoke by 75% between 1960 and 1975(8). Some indication of the importance of the contribution of high- and medium-level emissions to the present total can be obtained by analysing the daily average SO_2 and smoke concentrations which are published by Warren Spring Laboratory(9). It must be emphasised that this approach can only be considered valid in a broad, qualitative sense.

Appendix 2 shows such an analysis using data for a 12-month period in 1976/77 for three categories (total of 192 sites) out of the fourteen used altogether by W.S.L., in which industrial sources can be expected to contribute substantially to the total atmospheric pollution. The purpose of the analysis was threefold: (a) to distinguish between contributions from domestic sources and those from electricity generation plus industry; (b) to assess changes in ground level concentrations likely to result from the trends predicted in part 1 of this study, assuming no technological change; and (c) to estimate the reduction in SO_2 emission needed, in addition (or as an alternative) to tall-stack policy in order to meet possible EEC legislation.

The distinction between domestic and other sources can be obtained from the long term averages shown in tables A2.2, A2.3 and A2.4. Domestic emissions are seasonal, reaching a maximum in mid-winter and falling to an insignificant level in mid-summer. The magnitude of the difference between the summer and winter averages therefore gives an indication of the relative importance of contributions from low-level sources to the g.l.c.'s at any site, or any group of sites. The data is summarised in Figures 1, 2 and 3.

Changes in the contribution of each type of source to ground-level concentrations will depend mainly on the quantities and sulphur contents of fuel burnt, but also on the rate of replacement of older power stations by new ones. The quantity of SO_2 released from domestic heating sources is predicted(1) on the basis of existing practice to decrease from 324,000 tonnes in 1975/6 to 175,000 tonnes in 1985 and then to remain constant until the end of the century. The corresponding reduction in average ground level concentration would be about 10 $\mu g/m^3$ (but considerably more in densely populated districts).

The change in emissions from electricity generation and industrial usage of coal between 1975/76 and 2000 implied by the trends predicted in Table 3 of Part 1 of this study(1) would be from 2.4 million tpa to 3.4 million tpa. However, it is assumed that all of the increase in the industrial use of coal, except for an annual energy growth(10) of about 1% in the industrial sector is accounted for by conversion from oil to coal firing. The average sulphur content of industrial coal (Table 2 of reference 1) is 0.53 kg/GJ, and that of an average fuel oil is 0.66 kg/GJ, so that the change from oil to coal should result in a 28% decrease in SO_2 emissions per unit of heat release (allowing for a 10% sulphur retention in coal ash). Over the period of years during which conversion from oil to coal is expected to proceed, the reduction in emissions from this cause would approximately counterbalance the increase in emissions due to the energy growth rate, if no new technology were introduced, resulting in a small net decrease.

High-level emissions from coal combustion are expected (Table 4 of reference 1) to increase by 473,000 tonnes of SO_2 per annum between 1975/76 and 1985, and then to fall slightly up till the end of the century. Continuation of the present tall-stack policy would mean that these changes would have little effect on ground level concentrations of sulphur dioxide, apart from the improvement referred to earlier as older power stations go out of service and are replaced by newer ones meeting higher standards.

Taking all the above considerations into account, the ground level concentrations at sites in the three categories studied are expected in the year 2000 to be on average reduced by 12.5% of their 1976 values, if no desulphurisation measures were to be adopted. The main factor effecting this reduction is the change in low-level emissions, but the replacement of oil by coal for industrial use, much of it in fluidised bed firing, also has a small contribution.

2.2.3 Possible future legislation

A proposal for a Directive on ambient air quality has been submitted to the Council of Ministers of the EEC, but has not yet been accepted(2). The standards laid down in the current draft relate to sulphur dioxide and suspended particulate matter; those on sulphur dioxide are as follows, (Annex 1 of Directive):

(i) For the whole year, median of daily means not to exceed:

80 $\mu g/m^3$ if median smoke concentration is more than 40 $\mu g/m^3$,

or 120 $\mu g/m^3$ if median smoke concentration is less than 40 $\mu g/m^3$.

(ii) For October to March, median of daily means not to exceed:

130 $\mu g/m^3$ if median smoke concentration is more than 60 $\mu g/m^3$,

or 180 $\mu g/m^3$ if median smoke concentration is less than 60 $\mu g/m^3$.

(iii) For periods of 24 hours, arithmetic mean SO_2 concentration not to exceed 250 $\mu g/m^3$ on more than 2% of occasions if the smoke concentration at the same site exceeds 100 $\mu g/m^3$ on more than 2% of occasions; and not to exceed 350 $\mu g/m^3$ on more than 2% of occasions if the smoke concentration is less than 100 $\mu g/m^3$ on at least 98% of occasions.

The Directive also allows that certain zones may be chosen by Member States at their discretion, in which more stringent limits, laid down by them, would have to be met. For these more stringent limits, guide values are indicated in Annex II of the draft Directive as follows:

(iv) For the whole year, arithmetic mean of daily values not to exceed 40-60 $\mu g/m^3$.

(v) For 24-hour periods, the arithmetic mean of SO_2 concentrations not to exceed 100-150 $\mu g/m^3$.

It is noted that the proposed limit values in the EEC Directive (Annex 1) refer to the median values of daily means, whereas the Warren Spring data are arithmetical averages of daily means. For the U.K. the typical ratio of arithmetic mean/median for SO_2 is about 1.6, so that whole year averages corresponding to the EEC Directive median values are 93 and 139 $\mu g/m^3$ respectively, depending on whether the average smoke concentration is less than or greater than 46 $\mu g/m^3$. Experience shows that if a site conforms to requirement (i) on annual average, it will probably conform also to requirement (ii) on winter average.

Comparing these proposed limits with present concentrations (Figure 1) shows that at present all B3 sites and most of the C1 and C2 sites have sulphur dioxide annual average concentrations of less than 139 $\mu g/m^3$. Of the sites where 93 $\mu g/m^3$ is exceeded, only four sites have smoke concentrations so high that the lower SO_2 limit of 93 $\mu g/m^3$ is operative. The anticipated reduction in ground level SO_2 concentrations resulting from extension of the number of smoke control areas will mean that only at a very few heavily populated areas, or areas where there is a preponderance of older, heavily polluting industrial plants, will the standards listed in items (i), (ii) and (iii) of the draft EEC Directive be exceeded. Smoke concentrations will drop further during the remaining years of the century, as more smokeless zones are declared, and this will mean that most districts would be subject to the 139 $\mu g/m^3$ annual limit. There is likely to be more difficulty however in meeting the proposed daily limits in some densely populated areas.

If the 40 $\mu g/m^3$ SO2 limit were to be widely applied, however, only about 15% of industrial areas would conform without the introduction of special measures to curb sulphur dioxide emissions from combustion appliances as well as to other SO_2-emitting processes.

2.2.4 Conclusions on effectiveness of tall-stack policy

The following conclusions are drawn:

(i) The emissions from medium- and high-level sources do not at present result in ground level sulphur dioxide concentrations that exceed the levels laid down in Annex I of the proposed EEC Council Directive, except for a small number of heavily industrialised areas (in category C1). As regards these sources the present tall-stack policy may be regarded as generally adequate to meet the limits given in the proposed Directive, although special action may be needed where there is a high density of small energy users burning coal.

(ii) If the contribution of low-level sources is also taken into account, all sites have yearly average SO_2 concentrations lower than the Annex I limits, except for about 10% of the purely industrial districts and about 15% of the mixed industrial/residential districts. The latter percentage is expected to fall steadily as more smokeless zones are introduced. The daily concentration limits would, however, be exceeded in a larger number of urban areas under present conditions, due to a combination of medium and low-level sources, including emissions of particulates from motor vehicles and oil firing in commercial premises.

(iii) If the U.K. were to introduce standards conforming to the guide values given in Annex II of the proposed Directive, a substantially different approach to SO_2 control would have to be adopted in the U.K. It is estimated that emissions of sulphur dioxide from industry would have to be reduced by between 50% and 75%, and some reduction of emissions from certain power stations might also be required in order to meet this standard.

2.2.5 Effects on long range transport of air pollutants

The question of the long range transport of sulphur oxides has not been considered in the preceding discussion. Some knowledge is accumulating about the processes governing the drift of atmospheric pollutants across international boundaries, but there is still very much uncertainty about the magnitude of environmental effects resulting from the phenomenon. Any future legislation on ambient air quality will not directly affect the extent of long range transport of pollution, but it may do so indirectly if it proves necessary to reduce substantially emissions (including those from high-level sources) in order to conform to the legislation.

The tall-stack policy has the effect of reducing high local concentrations of pollutants and distributing them more evenly over the whole country. Thus the background level of pollutants in country areas is increased slightly, and the fraction transported abroad by the atmospheric circulation is also slightly increased when a tall-stack policy is adopted. These increases are small in comparison with the benefits in reduction of ground-level concentrations and deposition rates near the source. A recent OECD study(11) estimated the fraction of U.K. and Ireland sulphur emissions deposited within the countries of origin to be 0.4 with the remainder being transported outside the national boundaries, to be deposited over the sea or in other countries.

Adequate dispersal by the use of'tall-stacks is thus the preferred method of SO_2 disposal from large plants burning fossil fuels in the U.K., but it is nevertheless necessary to evaluate the costs and assess the practicability of emission controls so that the cost-effectiveness of alternative courses of action can be compared.

2.2.6 Costs of tall-stack policy

The only cost incurred in using a tall enough stack to give adequate dispersal of pollutants is that of the excess chimney height over the cost of the chimney that would otherwise be required.

A new 2000 MW power station would typically have a 200 m high chimney, and if most of the sulphur were removed, the height could be reduced by an estimated 15%(12), typically saving £0.75 million.

The only other reduction in cost is that of capital charges (6½%), reduction in maintenance resulting from the shorter chimney being negligible. For a yearly load factor of 65%, this is equivalent to operating costs of less than 0.004 p/kWh (E), or less than 0.2% of current generating costs for high merit stations.

Energy savings due to use of tall-stacks compared with gas scrubbing are considerable , (see section 2.6.4).

2.3 Sulphur reduction at the point of production

2.3.1 General

The scope for sulphur removal in coal preparation was discussed briefly in Part 1 of this study(1), where it was explained that the customary coal washing techniques used for "dirt" removal also remove a proportion of the pyritic sulphur, but do not reduce the organic sulphur content of the coal. The proportion of pyritic sulphur which it is possible to remove depends on the form in which the pyrites is disseminated throughout the coal, and on the particle size distribution of the coal being washed, and for more complete removal of the pyrites it is necessary to crush the coal to a smaller top-size before washing.

The particles removed by washing contain some carbonaceous matter in addition to inert mineral and pyrites, so the net effect of cleaning is to reduce the total yield of fuel (on a thermal basis) in addition to reducing the ash content of the cleaned coal. When sulphur contents are expressed on a percentage weight basis it is very difficult to get a clear idea of the true sulphur reduction, because of the increase in calorific value of the fuel as a result of washing. In this report, therefore, all sulphur contents will be expressed on a thermal basis.

One way of obtaining a greater sulphur reduction is to wash at a lower density separation, using dense medium baths or dense medium cyclones. This means that the rejected material would contain particles which have a higher carbonaceous content than usual, but contain a higher proportion of the mineral matter present in the run-of-mine coal. Tipping of this material as waste would be environmentally hazardous, especially if it had a high pyrites content, due to risk of spontaneous combustion; it would also make excessive demands on land for disposal and would be very wasteful of energy because of the large amount of combustible matter rejected. For this reason washing at a lower specific gravity would probably only be done in conjunction with a high-density separation at about 1.9 relative density, producing a "middlings" fraction which would have to be treated separately, either by further processing(1,13) or by combustion in an appliance capable of burning a high sulphur, high ash fuel without emitting large amounts of sulphur dioxide.

Little research has been carried out in the U.K. into new physical or chemical processes for coal desulphurisation, although a number of processes have been explored in the laboratory in the U.S.A., and some have been tried out on a larger scale. None is yet approaching the stage of commercial use, but it is considered that there is a distinct possibility that between now and the end of the century at least one of the new processes will be proved sufficiently promising to warrant more extensive testing on a large scale. Until this point is reached it is not possible to make more than very rough estimates of the costs or the time-scale for availability.

Chemical methods have the potential for removing organic sulphur, and can therefore give greater sulphur reduction than physical methods. For example, Battelle's Hydrothermal process (a sodium hydroxide treatment) is reported(14) to take out 70% of the organic sulphur as well as most of the pyritic. They have possible drawbacks however, namely rather expensive treatment plant and secondary effects on combustion of the coal: where sodium hydroxide is used, the coal must be completely freed of residual alkali to avoid corrosion of superheater tubes. Bacterial desulphurisation(15) looks promising, but because the process is very slow, large containment volumes would be needed for the treatment, and disposal of the sulphur-containing product (ferric sulphate solution) would present problems. At present it seems unlikely that any such processes will be in use on a large scale in the U.K. before the year 2000, and therefore they are not included in the detailed cost estimates.

One interesting possibility should, however, be mentioned; that is the development of a physical process which could be applied to the dry, milled coal as prepared at power stations for injection into the furnaces.

This would avoid the difficulty encountered in most wet processes using finely divided coal (as necessary for a good release of pyrites), namely the need for thermal drying in order to make the treated coal easily handleable. Since the coal is normally pulverised at the power station, it makes some sense to insert a desulphurisation stage between milling and firing. Magnetic separation of pyrites(16,17,18) is a possible technique, but up till now most of the development has been with coal slurries. A target figure for sulphur reduction by magnetic separation, applied to a 2% sulphur coal, would on the basis of published data appear to be 30 to 50% reduction in total sulphur. Most development work has been with coal/water slurries, and attempts to separate in air dispersions of coal have been less successful(19).

Rough estimates of the likely operating costs for magnetic separation of pyrites suggest that they could be considerably less than the 100% of the raw coal cost which was estimated for chemical processes, (Section 6.8 in reference 1), and would probably not exceed 10% of the raw coal cost. The true cost will depend to a large extent on the use that can be made of the coal rejected along with the pyrites. The amount of combustible matter rejected is expected to vary widely from one coal to another for a given sulphur reduction, and more precise costing at present is not yet possible.

2.3.2 Processes examined in detail

The modifications to the present coal preparation procedures which have been studied for evaluation of financial and energy costs are the following:

(i) Cleaning of a greater proportion of power station coal, (up to 100% of the coal supplied for electricity generation), which would mean a reduction or cessation of supplies of untreated and blended coals to the CEGB.

(ii) Washing of all power station and industrial coal at a lower specific gravity than at present.

(iii) Washing at two specific gravity separations, with and without further crushing and cleaning of the middlings to produce a clean fraction for combination with the product from the low gravity wash.

Full details of the study are given in Appendix 3, but the following paragraphs contain general discussions of each of these changes in turn.

(i) Cleaning a greater proportion of power station coal

In 1975/76, the coal supplied to the U.K. electricity industry for power generation comprised 5.2% washed smalls, 57.1% blended smalls and 35.1% untreated smalls, the remainder being graded coal, large coal or other types of coal (see Appendix II of reference 1). The reason for the multiplicity of types is that the principal requirement of the electricity industry is for a coal of consistent calorific value and ash content (about 16%), with additional restrictions on ash and coal composition in order to avoid slagging and high-temperature corrosion. Low sulphur content is not at the present time an over-riding consideration, although the cleaning carried out by the NCB does effect a considerable reduction in sulphur content on a thermal basis (see Table 2). The reason why it is necessary to wash or partly wash some coals and not others is because the coals differ in their washability characteristics - whereas washing of one coal might only reduce the ash content to about 16%, the ash content of another may be reduced to as little as 7 or 8%, requiring it to be blended with unwashed coal to give the agreed ash content for power station coal.

TABLE 2

Preparation of power station coal; estimate of present procedure based on a sample of five seams (Appendix 3)

	Seam No.					
	A	B	C	D	E	Average
Tonnes raw coal/t.product	1.45	1.22	1.23	1.30	1.59	1.19[(a)]
Tonnes discard/t.product	0.45	0.22	0.23	0.30	0.59	0.20[(a)]
Energy loss in discard[(b)]	12	2	12	10	16	6.2 (a)
Combustible content of discard,%	22.7	15.2	41.5	27.4	21.5	25.7 (d)
Sulphur in raw coal,g/MJ	0.63	0.67	0.64	0.66	1.35	0.79
Sulphur in product,g/MJ	0.53	0.57	0.47	0.59	1.11	0.65
Sulphur removed, g/MJ[(c)]	0.10	0.10	0.17	0.07	0.24	0.08[(a)]
Sulphur content of discard,%	1.10	1.60	2.81	1.25	2.06	1.76[(d)]

(a) Weighted average for all disposals to electricity industry (see text).

(b) As a percentage of energy in product.

(c) g sulphur per MJ in raw coal minus g sulphur per MJ in product.

(d) Average for discard produced in preparing coal for power stations

Percentages calculated on dry basis.

C.V. of dry coal 27.0 MJ/kg

Table 2 is based on data for 5 coals (full results are given in Appendix 3). One of these coals had an ash content of the desired level after washing, and would therefore be sold as a washed smalls. The other four would be classed as blended smalls. The averages in the final column of Table 2 are weighted averages, calculated from the 1975/76 figures for disposals reported in reference 1, (Appendix II), namely 4.0 million tonnes of washed smalls, 41.8 million tonnes of blended smalls and 25.7 million tonnes of untreated smalls. The figures in the final column therefore refer to the average for all coal supplied to the CEGB, but the variability of the coals is well illustrated by this example, and study of a much larger number of coals will have to be carried out in order to get a reliable estimate of the overall picture.

There appears to be no fundamental reason why the U.K. electricity industry should not be supplied with coals of lower ash content, provided they can be burnt without serious slagging or corrosion of tubes, but this would require careful consideration of each individual case. There would be other incidental benefits such as reduced transport costs, reduced ash disposal costs and possibly less boiler tube erosion, although only the first of these (transport costs) has been taken into account in the costings.

The total reduction of sulphur dioxide emissions, together with financial and energy costs and the additional amount of discard which would have to be disposed of are shown in Table 3. Additional washery capacity would be needed (capital costs), and the production costs include charges on this capital expenditure. The sulphur reduction is not great: only about 4% reduction in sulphur content per unit of energy in the coal.

(ii) Washing all power station and industrial coal at a lower specific gravity than at present

Considerable difficulty is encountered in estimating the effects of this change over the whole range of British coals. As with the case of magnetic separation discussed earlier, different coals will have widely differing characteristics in regard to effectiveness of sulphur removal, loss of combustibles etc., and although some guidance can be obtained by laboratory float and sink tests, the behaviour of a coal in a production washery is not always the same as predicted on the basis of the laboratory test. This is because the latter cannot accurately simulate conditions in the plant; for example, the coal is subject to breakage as it goes through the plant.

For the purpose of the present study, five coals (selected to be as far as possible representative) have been examined, and estimates have been made from the results on these coals of the probable sulphur reduction if all power station and industrial coals were treated similarly. The accuracy of these estimates will therefore depend on the degree to which the coals studied are representative of the average behaviour of all coals.

The coals selected as a basis for the study are described as seams A to E, and are the same coals as those referred to in Table 2.

TABLE 3

Costs and effectiveness of washing all power station coal

(1977 production level)

	Seam Number					
	A	B	C	D	E	Average(a)
Tonnes discard per tonne product	0.54	0.37	0.27	0.39	0.59	0.43
Extra discard per tonne product, t.	0.09	0.15	0.04	0.09	0	0.07
Energy loss in discard(b)	15	6	14	14	16	13
Sulphur in product coal, g/MJ	0.51	0.51	0.45	0.57	1.11	0.63
Extra sulphur removed, g/MJ(c)	0.02	0.06	0.02	0.02	0	0.024
Capital cost of extra plant £$10^{(6)}$	-	-	-	-	-	96
Extra production costs, p/tonne(d)(f)	-	-	-	-	-	25.5
Cost of coal loss, p/tonne(d)(e)	35	49	30	45	0	32
Capital cost to CEGB(g)(h) £$10^{(6)}$	-	-	-	-	-	1.9
Operating cost to CEGB(h) p/kWh	-	-	-	-	-	0.0002
" " " " p/tonne(d)	-	-	-	-	-	0.5
Total additional costs, p/tonne(d)	-	-	-	-	-	26.0
Saving on transport, p/tonne(k)	11	25	3	12	0	10
Net additional costs, p/tonne	-	-	-	-	-	16.0

(a) Arithmetic mean for coals A to E.

(b) As a percentage of energy in product.

(c) g sulphur/MJ in present product less g sulphur/MJ in product from 100% washing.

(d) pence per tonne of all disposals to CEGB.

(e) cost in excess of that incurred by present cleaning, based on a 1979 coal cost of £21/tonne excluding transport.

(f) at 20% of capital cost per annum.

(g) cost of increased electrostatic precipitator capacity.

(h) calculated on sulphur distribution shown in Table A1.1, and assuming a universal sulphur reduction of 0.05% (0.024g/MJ).

(k) assumes an average transport cost of £2.50/tonne.

C.V. of dry ash-free coal 33.5 MJ/kg

Predicted reduction in sulphur dioxide emissions, energy losses and costs are shown in Table 4. Also shown in Table 4 are estimates of the increase in annual production of discard material at washeries, as compared with the annual production of discard if present coal preparation procedures were continued unchanged.

(iii) Washing at two specific gravity separations

This option is basically the same as (ii), but differs in that instead of throwing away all the coal floating between specific gravities of 1.4 and 1.9, this would be separated as a "middlings" fraction, which would be sold for combustion in appliances equipped for sulphur retention, or would be treated further at the washery in order to extract as much sulphur and as little coal substance as possible. This clean component of the middlings would be recombined with the main fraction of clean coal. In order to allow good separation of the pyrites from the middlings it would be necessary to crush them further, and in the study crushing to a top size of 3 mm was assumed, followed by froth flotation or concentrating table treatment. The average sulphur reduction of 0.052 g/MJ represents 8% of the level resulting from present preparation procedure.

The fine, wet, clean component would be difficult to dry sufficiently to make it safe to blend with the clean coal without introducing the risk of handling problems. Thermal drying of the fines may therefore be necessary with many of the coals so treated.

Costs have been estimated for three variations of this process: sales of middlings separately for combustion in special appliances; further treatment of middlings at the coal preparation plant, without thermal drying; and further treatment of middlings with thermal drying. The costs are shown in Tables 5, 6 and 7, along with the increase in amounts of discard produced at the washeries. It is assumed that the middlings would have to be offered at a 30% discount in order to provide an incentive for their non-polluting use. It has been estimated (see Section 2.6.5) that flue gas desulphurisation in a U.K. power station would add 25% to 30% to electricity generation costs.

TABLE 4

Consequences of washing all power station coal[a]

(Data from Appendix 3)

Year	1985	1990	2000
High-level SO_2 emissions, 10^3 tpa	2383	2311	2259
Reduction in emissions by increased washing, 10^3 tpa	47	92	90
Increase in discard production, 10^3tpa	3.9	7.6	7.4
Increase in energy loss[b] %	0.7	1.4	1.4
Extra capital cost, £10^6 [c]	57	113	113
Extra net production cost, £10^6/annum	7.1	14.1	13.8

(a) Assumes that 50% of the extra washery capacity could be installed by 1985, and all of it by 1990.

(b) As a percentage of total energy input to power stations.

(c) Total cost incurred between 1980 and relevant year.

TABLE 5

Three product separation, middlings sold at 30% discount(a) (thermal basis)

	Coal seam No.					
	A	B	C	D	E	Average
Yield of middlings, t/t clean coal	0.255	0.104	0.611	0.250	0.347	0.313
C.V. of middlings, MJ/kg	21.6	23.7	22.1	22.2	23.8	22.7
S content of middlings, g/MJ	0.97	1.04	0.52	0.82	1.89	1.05
C.V. of clean coal, MJ/kg	29.4	30.3	29.2	29.4	28.0	29.3
S content of clean coal, g/MJ	0.46	0.48	0.43	0.54	0.93	0.57
Total coal output, clean coal value(b)	1.14	1.06	1.35	1.19	1.29	1.21
Increased waste, t./t. clean coal value(c)	0	0.027	-0.044	0.003	-0.028	-0.008
Capital cost of extra plant,(g) £10^6	-	-	-	-	-	651
Extra production costs,p/tonne(d)	-	-	-	-	-	234
Increase in clean coal cost, p/GJ(e)	-	-	-	-	-	9.0
Estimated high-level emissions in 1990(f)	-	-	-	-	-	1,780
Estimated high-level emissions in 2000(f)	-	-	-	-	-	1,740

(a) Discount is to offset the higher generating costs with FGD (see section 2.6.5)

(b) Calculated as 1 + yield of middlings x $\frac{\text{C.V. of middlings}}{\text{C.V. of clean coal}}$ x 0.70

(c) Calculated at same C.V. as product of present practice

(d) Per tonne of coal delivered to power stations; includes combined capital charges and maintenance at 20% annually of capital costs

(e) This is the increase in cost per MJ which would be needed to pay for additional cleaning and discount on middlings, compared with present practice. The average cost of power station coal in 1978 was 2079 p/tonne, or 87 p/GJ

(f) Allowing for 90% sulphur retention in firing middlings and 10% retention in firing clean coal

(g) i.e. cost of converting existing plant, or of erecting new plant for 3-product separation (1977/78 output level). The cost of new plant for a single density separation would only be about 90% of this

TABLE 6

Three product separation, with crushing and further cleaning of middlings for recombination with clean coal[(a)]

	Coal seam no.					
	A	B	C	D	E	Average
Thermal recovery of combined product, %[(b)]	101	97	106	101	103	102
Reduction in sulphur, g/MJ[(c)]	0.030	0.065	0.055	0.042	0.069	0.052
Capital cost of extra plant £10^6 (1977 production)	-	-	-	-	-	72
Extra production costs, p/tonne[(d)]	-	-	-	-	-	30
Estimated high-level emissions in 1990[(e)]	-	-	-	-	-	2,205
Estimated high-level emissions in 2000[(e)]	-	-	-	-	-	2,155

(a) See Appendix 3 for assumptions regarding cleaning of middlings.

(b) As a percentage of thermal recovery from same amount of raw coal by present washing practice.

(c) Per MJ in product, compared with present preparation procedure (Table 2).

(d) Per tonne of coal delivered to power stations; combined capital charges and maintenance costs at 18% annually of capital cost.

(e) Units of 10^3 tonnes per annum; assumes that no form of SO_2 reduction is used. Base values (ref.1) are 2,403 x 10^3 for 1990 and 2,349 x 10^3 for 2000.

Note:

The capital cost assumes that the treatment plant will be housed in the new buildings required for 3-product separation, the costs of which have already been included in Table 5. Costs should be added to those shown in Table 5.

TABLE 7

Three product separation, with crushing, further cleaning, and thermal drying of middlings for recombination with clean coal

	Cost	Increase due to thermal drying
Capital cost of new plant, £10^6	788	65
Operating costs, p/tonne(a)	336	72

(a) Per tonne of coal delivered to CEGB; excess over cost of coal cleaning by present procedure.

2.3.3 Effect of low sulphur coal on power station boiler operation

Most large power station boilers, including all U.K. power stations erected since about 1960, are equipped with electrostatic precipitators for particulate removal. The efficiency of these precipitators is affected by the resistivity of the ash which collects on the electrodes, and if the resistivity of the layer of ash exceeds a certain value operation is impaired. Reduction of the sulphur oxide content of gases leaving the boilers is accompanied by an increase in the resistivity of the collected layer of ash, and therefore by a decrease in the efficiency of particulate removal. This has to be compensated for by making the electrostatic precipitators larger and therefore more expensive in order to obtain the required degree of gas cleaning. The additional capital cost of electric precipitator capacity resulting from the use of coals of sulphur content lower than a datum level of 1.4% has been estimated to be of the order of £1 m per 2000 MW station for a 1.2% sulphur coal and £2 m per 2000 MW station for a 1% sulphur coal(20). Operating costs, other than repair and maintenance of the precipitators, would not be significantly affected.

Charges on capital, and repair and maintenance at a total annual rate of 15% of the capital costs have been included in Tables 4 and 5, in the proportion to which coals of moderate sulphur content would be brought into the range of sulphur contents where high ash resistivity becomes a problem.

2.3.4 Domestic heating market

Although not wholly appropriate, this is most conveniently dealt with here. The scale of most domestic and the smaller commercial heating appliances makes flue gas desulphurisation impracticable. Reduction of sulphur dioxide emissions from these sources is therefore limited to a choice of three actions: reduction of solid fuel use; fuel desulphurisation; and sulphur retention during combustion.

For appliances such as the 'smoke-eater', or open fires burning washed large or graded coals and smokeless fuels, scope for reducing sulphur significantly below present levels by changes in coal preparation procedures is small, but it is possible that at some time in the future some physical or chemical desulphurisation technique could be used in the production of manufactured fuels. The commercial availability of this is uncertain, but process development would probably take at least ten to twelve years, and would not be embarked upon unless a market for the undoubtedly expensive fuel were clearly foreseen. No significant market penetration is therefore to be expected before the year 2000.

A much greater probability is the development of a processed fuel incorporating crushed limestone, which on combustion would "fix" part of the sulphur as calcium sulphate. A manufactured fuel of this type has been developed by McDowell-Wellman(21) in conjunction with the Ohio Department of Energy, and it is claimed that the fuel pellets burn smokelessly and with negligible emissions of sulphur dioxide. If an assessment of the process were to recommend in favour of development and a decision were to be taken to build a plant to produce a fuel of this type before 1990, the project could contribute significantly to the reduction of SO_2 concentrations in densely populated areas by the end of the century. The ash resulting from combustion would contain some lime, and could need care in handling for disposal.

2.4 Fuel conversion

The processes which will be considered in this section are: coke-making, coal liquefaction (including the Solvent Refined Coal and other processes), and coal gasification.

(i) Coke making

In coke-making, the sulphur present in the coal finishes up partly in the coke (about 60% of the original sulphur), partly in the gas (about 30%) and partly in the by-products(22). The sulphur in the gas is in the form of hydrogen sulphide and organic sulphur compounds, 90 to 95% being as H_2S. When the gas is to be used for domestic heating purposes, desulphurisation is obligatory, but since conversion of the U.K. gas distribution network to natural gas, nearly all the gas produced by coke ovens is used in industry, and for heating the ovens. Sulphur removal is not at present required for these purposes, except for a few special processes where freedom from sulphur contamination is essential. Only about a tenth of the gas produced is currently desulphurised. Therefore the greater part of the sulphur in the gas after by-products separation is eventually released to the atmosphere as sulphur dioxide. Emissions of sulphur dioxide from coke ovens in 1976 are estimated at 130,000 tonnes (65,000 tonnes as S); the sales of coal for carbonisation were 17,466,000 tonnes at an average sulphur content of 1.15% (reference 1, Appendix III), therefore the estimated emissions represent 32.4% of the sulphur in the coal. National Smokeless Fuels Ltd., who operate a third of the U.K. coking capacity are in the middle of a programme of installing desulphurising plants.

Costs of desulphurising all coke-oven gas by the Stretford process are estimated to be £2.2 per tonne per annum of coal capital cost, and £1.00 per tonne of coal input total costs. Approximately 75 MJ of primary energy equivalent per tonne of coal input is required for gas desulphurisation. Desulphurisation could be operable within 3 years of taking a decision to install the necessary plant. Solid/liquid waste production would be mainly from the discharge of salts in solution resulting from side reactions. These may, if desired, be isolated in fused solid form, but this requires additional fuel. The quantities of waste are very variable, and depend on many factors such as the cyanide content of the raw gas.

(ii) Coal liquefaction

Most coal liquefaction processes are being developed to produce liquid fuels as substitutes for oil-derived fuels used in transport or for chemical feedstocks, although one, Solvent Refined Coal, is not strictly a liquefaction process because the solvent extract is treated to yield a clean, solid fuel. It is to be noted that the time-scale for development of these processes will be longer than for physical coal processing, but probably not chemical processing for sulphur removal.

Because oil-derived fuels have a higher hydrogen/carbon ratio than coal, hydrogenation is an essential step in production, and processes include direct catalytic hydrogenation, solvent extraction followed by hydrogenation, and pyrolysis (COED and Garrett processes). Liquid fuels can also be made by gasification of coal followed by catalytic conversion, but this route is not considered here.

None of these processes is likely to be operational in large tonnages before the end of the century, but rising crude oil prices are likely to speed up development during the 1990's, and at the turn of the century they will be representing a rapidly expanding new market for coal. Environmental problems are expected to be not much different from those currently being satisfactorily dealt with by the oil industry, and the cost of anti-pollution measures will be met as part of the process costing. Some concern has been expressed that the higher proportion of aromatic compounds present in coal as compared with oil might present an additional hazard to operators(23,24); this fact could be reflected in additional cost of extra safety precautions built into the plant, and in provisions for the treatment of solid or liquid effluents that might be contaminated with polycyclic aromatic hydrocarbon compounds, but should not represent an environmental hazard. Coal liquefaction is likely to result in fairly large energy losses, of up to 35% of the heat in the coal.

Hydrogenation treatments reduce the sulphur content of the fuel, whereas pyrolysis usually produces a gas which contains a substantial fraction of the original sulphur in the coal and to make a low sulphur product further treatment is necessary. Speculative conversion efficiencies and product sulphur contents for some coal liquefaction processes operating on high-sulphur coals are as follows:(25,26)

Process	Conversion efficiency[a]	Sulphur content, g/GJ in products
H-Coal	0.70	47
Synthoil	0.75(b)	52
Exxon Donor Solvent	0.60	-
Solvent Refined Coal	0.70	57

Notes: (a) Energy in all saleable products divided by energy in original coal.

(b) Does not take into account some process energy inputs, which result in a lower true conversion efficiency, of about 65%.

(iii) Coal gasification

Coal gasification plants can be designed to meet low levels of pollutant emissions. The main atmospheric emissions arise from coal combustion for auxiliary power and process steam requirements, although these can be avoided by using clean gas for this purpose at the expense of some loss in efficiency.

Two processes need attention: the manufacture of synthetic natural gas (SNG) as a replacement for declining supplies of North Sea Gas, and Low Calorific Value gas, for the firing of combined cycle power generators and some industrial operations.

Gasification of coal on site was widely used up until about 1960 at many works in the metal industries and for firing glass melting tanks, as well as by other industries. The most common type of gasifier was the single-stage, fixed-bed gas producer, and it is quite likely that improved versions of these will once more be adopted. The gas producers in use up till 1960 suffered from a major drawback when using bituminous coals to deliver hot, raw gas to the furnace, namely progressive blockage of the gas delivery pipe with condensed tar. The only practical way of removing this was by burning out, and this normally produced very dense black smoke. It would be expensive to avoid this by installing after-burning equipment, and a more attractive principle is two-stage gasification, in which the coal is carbonised at low temperature in an upper chamber before descending to the lower, gasification chamber. The tar-containing gases from the distillation stage were cooled and passed through electrostatic precipitators which removed the tars and oils in a handleable form suitable for use as a fuel.

Where there is a local concentration of industry, there is a possibility of central gasification plants with private distribution networks to factories within a kilometre or so of the plant. Such a gas would have to be 'clean' (and preferably free of sulphur compounds) and could be burnt in relatively inexpensive boilers or furnaces without generating a significant amount of particulate pollution.

The timescale for the introduction of SNG plants in the U.K. is uncertain, and depends on the rate at which natural gas reserves run out. One estimate(10) is that the first plants could be required during the nineties at the earliest, but may not be until after 2000.

SNG is likely to be produced in the U.K. by upgrading the medium calorific value gas resulting from oxygen/steam gasification, but the optimum size and location of the gasification plants is not yet clear. The existence of the gas grid in the U.K. will favour the adoption of large central SNG plants, probably sited in coal producing areas. Because a high degree of removal of sulphur compounds from the gas is necessary in order to avoid poisoning the methanation catalyst, and would in any case be required for distribution to households, sulphur emissions to the atmosphere would be virtually eliminated. A variety of processes are available for desulphurisation of the gas(27), but all the commercially obtainable ones only operate on the cooled gas, making reheat of the gas necessary for methanation. Most processes produce a saleable sulphur and quantities of other by-products; ammonia, phenols, etc. Various high-temperature sulphur removal processes are under investigation(28), in order to avoid the loss of energy in cooling and reheat, but none has yet reached commercial status. The overall thermal efficiency of a process to make SNG from coal is expected to be about 65%.

Low calorific value gas as a power station boiler fuel is of considerable interest for two reasons: compared with coal it is a clean fuel, meaning a great reduction in tube slagging and corrosion risks in the boiler and reducing air pollution; and its freedom from particulate impurities will introduce the possibility of combined cycle power generation, passing the hot gases from a pressurised combustor through a gas turbine before raising steam from the waste heat. Residual impurities in the gas could still cause problems in the gas turbine. The combined cycle could give up to 7 percentage points higher efficiencies of power generation than are attained in the most efficient stations operating today, if anticipated developments in gas turbine construction are realised, and the emissions of atmospheric pollutants would be greatly reduced.

If sulphur removal from the fuel gas is required, gas cooling will be necessary unless a hot gas desulphurisation process can be developed for use either in the gasifier itself(29,30) or as a separate acid gas clean-up between the gasifier and the combustor. One estimate(31) of the extra energy cost of hot gas desulphurisation over the no sulphur removal case suggests that for various projected processes the amount of energy used will be between 10% and 17% of the energy in the product gas output, for 85% to 96% sulphur removal. All the processes considered utilise an initial H_2S absorption step followed by sulphur recovery (Claus or Allied plants) and tail gas clean-up. It is this clean-up of SO_2 from the sulphur recovery plant tail gases that largely accounts for the high energy consumption.

For cold gas desulphurisation(31) energy requirements for one process (Benfield) is given as 8.5% of the chemical energy content of the make gas (C.V. 6.0 MJ/Nm^3), but this does not include the heat removed from the hot gas before it passes to the desulphurisation plant. This is estimated to be a further 23% of the chemical energy content of the make-gas, and the overall efficiency of clean gas production depends on how well this can be recovered and made use of elsewhere in the plant.

The sulphur could be recovered either as the element or as sulphuric acid. Prediction of future market prices for these materials is very difficult, because widespread introduction of processes for sulphur recovery from combustion processes would soon swamp the market.

Coal gasification processes generate quite large quantities of waste water which is contaminated with suspended solid matter, dissolved salts and organic compounds including oils and phenolic compounds. Processes exist for the treatment of these aqueons wastes by sedimentation, filtration, biological purification, adsorption etc., to render them fit for discharge to water-courses, or for recycling within the plant. The treatment processes are quite expensive, and form an important contribution to the total construction and operating costs of the plant.

It is considered(32) unlikely that power generation from low calorific value gas will be used in the U.K. before the year 2000, although it could be introduced during the first decade of next century if further developments in the process are sufficiently encouraging.

2.5 Sulphur retention during combustion

2.5.1 General

Although some unsuccessful attempts were made in Germany, Japan and the U.S.A. to retain sulphur by injection of finely powdered limestone into pulverised coal fired boilers, these were unsuccessful because of inefficient sulphation of the limestone, and tube fouling. The practical retention of sulphur during coal combustion has more recently been made possible by development of the fluidised bed combustor. This is a vessel containing a bed of inert particulate material, e.g. sand, coal ash, limestone or dolomite, which is fluidised by introduction of the combustion air through a specially constructed distributor plate which forms a support for the bed material when the bed is "slumped", i.e. when the air is shut off.

The coal is introduced into the bed, either by injection in a stream of air to a point or points within the bed, or by dropping it into the bed from a feeder terminating in the freeboard, i.e. the space above the bed. For pneumatic in-bed feeding, the coal must have a top-size roughly the same as that of the largest bed particles, and may be an unwashed coal. For above-bed feeding, the coal may have a top size of up to 50mm, and should normally be washed in order to avoid the accumulation in the bed of oversize ash particles.

It is usual to operate coal-fired fluidised-bed combustors at temperatures between 1070 and 1170 K, in which range the ash does not become sufficiently sticky to cause problems of agglomeration. This also happens to be the temperature range in which lime particles formed by the calcination of limestone can most effectively absorb sulphur dioxide, at atmospheric pressure. Absorption of sulphur dioxide will also occur at elevated pressures, but in this case dolomite (calcium magnesium carbonate) is found to be a much better absorbent, although the magnesium does not form a stable sulphate at bed temperatures. The sulphation reaction is: $CaO + SO_2 + \frac{1}{2}O_2 = CaSO_4$.

Limestones differ in their sulphur-absorbing capacity, and with all stones sulphation of the calcium content is incomplete. It is necessary therefore to add limestone with the coal at a calcium to sulphur molecular ratio considerably in excess of one. Figure 4 shows the relationship between the percentage absorption of sulphur and the Ca:S molecular ratio for limestones of two different reactivities, in a bed at least 0.75 m high and at atmospheric pressure. Figure 5 shows the relationship for a typical dolomite in a combustor operating at 5 atmospheres pressure.

The lower temperature of combustion in fluidised beds allows a greater amount of sulphur to be retained by the coal ash than in most other forms of coal-firing. Results for six British coals burnt in fluidised beds, without limestone addition, show sulphur retentions ranging from 7 to 64%, with an average of 29% (unpublished work by NCB).

The fluidised combustion of coal is likely to be used in the future to some extent in preference to other methods of combustion, especially for industrial boilers and dryers, even if no use is made of its capability for sulphur retention. This is because the output of a given size of fluidised-bed combustor is much higher than than of a conventional coal-fired appliance of the same size. Users attracted to coal by a rise in price of oil or gas would find fluidised-bed firing cheaper than stoker-firing because of this. An additional attraction is that fluidised-bed combustors are more tolerant of variation in fuel quality.

Therefore, the appropriate costs to consider are those resulting only from changes in plant and operating procedure to give sulphur retention, and not the total costs of converting to fluidised bed combustion from other types of appliance. The main differences necessitated for sulphur retention are as follows:

(i) There is need for limestone storage, handling and feeding facilities; and if the limestone delivered is too coarse for feeding to the bed crushers would have to be installed, operated and maintained.

(ii) Handling equipment for solids removed from the bed and separated from the waste gas has to be made larger to cope with the added limestone, part of which is broken down into dust and is elutriated from the bed.

(iii) There is a small reduction in thermal efficiency because of the increased rate of removal of hot solids. For a 1.5% sulphur coal this loss should not exceed 0.4% of the heat input, at 85% sulphur retention. The limestone calcination reaction is endothermic, but this is partly offset by the heat of sulphation, resulting in a net thermal change which is small compared with the sensible heat loss.

(iv) Solid waste disposal costs would be increased. For a 10% ash, 1.5% sulphur coal and 85% sulphur retention, conditioning (water treatment) of the solid waste would be required before disposal (this would hydrate excess lime to the hydroxide), and the quantity of conditioned waste would be 1.6 times as great as the quantity from a combustor without sulphur retention. The anhydrous calcium sulphate formed in the combustor only hydrates slowly, and would not take up water during conditioning.

2.5.2 State of development

(i) Industrial boilers

Several experimental and prototype fluidised-bed fired industrial boilers have been in operation in Britain since 1974, as have a number of hot-gas drying furnaces with heat outputs of up to 5 MW (Th)(33). A 10 MW (Th) heat input boiler is expected to be commissioned during 1979. None of these appliances has been equipped for sulphur retention by limestone addition. Some of them have been converted from other methods of firing, and it would not have been possible to use a fluidised bed sufficiently deep to give good sulphur absorption (0.5 m or more), but the principle of sulphur retention in atmospheric pressure fluidised bed combustion has been demonstrated in a 10MW (Th) experimental boiler burning crushed coal injected pneumatically into the bed. Some more recent experiments on a smaller scale have suggested that sulphur retention is equally effective when coal with a larger top size is fed above the bed.

The use of fluidised bed combustion with limestone addition can therefore be regarded as a proven process, and commercially available as from 1979, although there can be expected to be further developments in the details of boiler design, coal and additive feed, ash removal, etc.

(ii) Boilers for electricity generation

One of the main attractions of fluidised combustion, apart from the capability of sulphur retention, is in their operation under pressure for combined cycle (gas turbine/steam turbine) power generation giving greater total efficiency of electricity generation. Much experimental work has already been carried out on fluidised bed combustion under pressure, and more is planned in order to determine the degree of hot gas cleaning necessary for operating gas turbines on the combustion products. Experiments have shown that sulphur oxides can be readily absorbed by dolomite in the bed(34).

It is thought unlikely that either atmospheric pressure or pressurised fluidised bed combustion for use in power generation will have been developed sufficiently for significant amounts of electricity to be generated by either process before 2000. Beyond this date, there is a possibility that pressurised combustion will begin to contribute, and if the current environmental awareness is maintained it is reasonable to expect that this will utilise sulphur retention, possibly with regeneration of the spent absorbent(35,36) in order to reduce the environmental impacts of stone quarrying and waste disposal.

2.5.3 Costs of fluidised bed combustion with sulphur retention

Limestone prices vary widely from region to region, and from one quality to another in the same region. The properties most beneficial for sulphur retention in fluidised bed combustion are not those which would command a high price for other uses, e.g. road-surfacing or use as an aggregate, where hardness and strength are wanted. Very often, too, quantities of fine material arise in the production of graded stone for other purposes, and these could be a cheap, suitable material for sulphur absorption. Dolomite is generally a little more expensive than limestone although there is a wide overlap of price ranges. The cost estimates in this report are largely based on those given in a recent IEA Coal Research report(37), but they have been adjusted to refer to industrial boiler use, because no significant use of fluidised bed combustion for power generation is anticipated during the present century.

Figure 4 shows that the most efficient use is made of limestone up to about 85% sulphur retention. For higher levels of retention a disproportionately large amount of additional limestone has to be used. When the coal being fired has a calorific value of 25.6 MJ/kg, and contains 1.5% sulphur, 85% sulphur retention gives a sulphur dioxide emission rate of 0.176 g/MJ, which is well below the current EPA New Source Emission Standard of 0.516 g SO_2/MJ (1.2 lb/10^6 Btu)(38).

If, at some future date, emission limits were to be introduced, a standard equal to the current EPA New Source Standard could easily be achieved in the U.K. by fluidised bed combustion, in fact, a lower limit, e.g. half the present EPA New Source Standard, could also be met without too much additional expense save with coals of the highest sulphur content. The limestone usage and quantity of additional solid waste for disposal would be greater for a lower SO_2 emission.

Limestone requirements to reduce SO_2 emissions to 0.5 kg SO_2/GJ heat input, and to 0.25 kg SO_2/GJ for coal of different sulphur content are shown in Table 8, and the additional amounts of waste solids generated are shown in Table 9. The figures refer to a conceptual 15 MW (Th) heat input atmospheric pressure boiler, and the sulphur retention has been calculated for a relatively poorly absorbing limestone (close to the lower line in Figure 4), so the costs quoted will allow for variation in limestone quality, and represent maximum costs.

Additional capital costs resulting from the capability for sulphur retention are shown in Tables 10 and 11 and additional operating costs (including charges on capital at 10%) are given in Tables 12 and 13.

There is uncertainty about the way in which the sulphated limestone will be removed from the combustor. Some stones are relatively easily abraded, and will therefore tend to finish up as dust in the off-gases. Other stones will be less easily degraded, and will be largely removed with run-off of bed material as required for bed height control.

TABLE 8

Limestone feed in atmospheric fluidised bed combustion required for various levels of sulphur control

SO_2 emission standard, kg SO_2/GJ		Sulphur content of coal, % S					
		0.5	1.0	1.5	2.0	2.5	3.0
0.5	limestone, %[(a)]	0	2.9	6.4	10.5	14.4	19.1
	removal eff. %	-	36	57	68	74	79
	Ca/S mol. ratio	0	1.15	1.7	2.1	2.3	2.55
0.25	limestone, %[(a)]	1.4	5.3	9.6	14.5	20.0	25.5
	removal eff. %	36	68	79	84	87	89
	Ca/S mol. ratio	1.15	2.1	2.55	2.9	3.2	3.4

Notes:

(a) % of coal feed rate

Calorific value of coal 25.6 MJ/kg

Moderate to poorly absorbing limestone.

TABLE 9 : Waste products from limestone additive in atmospheric fluidised bed combustion

(Figures are as % of coal feed rate)

SO_2 emission standard kg SO_2/GJ	Product dry or wetted	Sulphur content of coal, % S					
		0.5	1.0	1.5	2.0	2.5	3.0
0.5	Dry	0	2.5	5.7	9.3	12.7	16.6
	Wet	0	3.1	7.0	11.4	15.7	20.6
0.25	Dry	1.2	4.7	8.3	12.3	16.6	21.0
	Wet	1.5	5.8	10.3	15.4	20.9	26.5

Notes:

Calorific value of coal: 25.6 MJ/kg

Limestone is 100% $CaCO_3$; addition rates as in Table 13.

Ash not included

When the product is wetted the calcium oxide is hydrated to calcium hydroxide and it is assumed that a further 10% on weight of solids is added to "condition" the solids in order to prevent dust blowing about during handling and disposal.

TABLE 10: Additional capital costs for sulphur retention capability to meet an emission limit of 0.5g SO_2/MJ: 15 MW (Th) fluidised bed boiler

(Costs in £10^3 at March 1979)

Sulphur in coal, %	0.5	1.0	1.5	2.0	2.5	3.0
Limestone storage, handling and feeding:	0	6.6	11.7	15.9	19.6	23.0
Spent absorbant removal:(a)	0	3.2	5.8	8.7	11.3	14.2
Gas clean-up:(b)	0	7.0	12.6	18.8	24.4	36.6
Total (excluding limestone drying + crushing)	0	16.8	30.1	43.4	55.3	73.8
Limestone drying and crushing (optional)	0	37.1	62.9	87.6	108.2	130.5

TABLE 11: Additional capital costs for sulphur retention capability to meet an emission limit of 0.25g SO_2/MJ: 15 MW (Th) fluidised bed boiler

(Costs in £10^3 at March 1979)

Sulphur in coal, %	0.5	1.0	1.5	2.0	2.5	3.0
Limestone storage, handling and feeding:	4.1	10.0	14.5	18.3	21.8	32.4
Spent absorbant removal:(a)	1.6	4.6	7.5	10.7	14.0	17.2
Gas clean-up(b)	3.4	9.9	16.2	23.0	30.1	37.1
Total (excluding limestone drying + crushing)	9.1	24.5	38.2	52.0	65.9	86.7
Limestone drying and crushing (optional):	22.8	55.5	82.5	108.6	134.6	158.3

Footnotes to Tables 15 and 16:

(a) Includes cost of cyclones and hoppers for primary gas clean-up.

(b) Final gas clean-up to meet particulate emission standards (bag filters or electrostatic precipitators)

Basis: Average to poor limestone absorption properties
Ash content of coal 15%
Calorific value of coal 25.6 MJ/kg.

TABLE 12: Annual costs of sulphur retention to meet an emission limit of 0.5g SO_2/MJ 15 MW (Th) fluidised bed boiler

(Costs in p/GJ)

Sulphur content of coal %	0.5	1.0	1.5	2.0	2.5	3.0
Cost of limestone(a)	0	0.6	1.0	1.6	3.1	4.0
Thermal losses(b)	0	0.2	0.3	0.4	0.6	0.8
Power requirement(c)	0	0.3	0.8	1.3	1.8	2.3
Waste disposal(d)	0	0.6	1.1	1.7	2.3	2.9
Operation and maintenance(e)	0	0.3	0.5	0.7	0.9	1.2
Capital charges(f)	0	0.5	1.0	1.4	1.8	2.4
Total additional costs	0	2.5	4.7	7.1	10.5	13.6
Costs as % of coal costs	0	2.2	4.1	6.2	9.1	11.8
Additional costs for limestone drying and crushing:						
Power requirement	0	0.2	0.3	0.6	0.8	1.0
Operation, maintenance and capital charges	0	1.8	3.1	4.3	5.3	6.4
Total additional costs	0	2.0	3.4	4.7	6.1	7.4
Additional costs as % of coal cost	0	1.7	3.0	4.1	5.3	6.4

(a) Limestone price £5.00/tonne, delivered.

(b) Losses due to increased solids removal.

(c) Electric motors for additional solids handling.

(d) Cost of waste disposal £4.8/tonne.

(e) Taken as 5% of the additional capital costs, per annum.

(f) Taken as 10% of the additional capital costs.

Price of coal: 0.115 p/MJ.

Annual Load factor: 65%

Calorific value of coal: 25.6 MJ/kg

Average to poor reactivity limestone.

TABLE 13: Annual costs of sulphur retention to meet an emission limit of 0.25g SO_2/MJ 15 MW (Th) fluidised bed boiler

(Costs in p/GJ)

Sulphur content of coal %	0.5	1.0	1.5	2.0	2.5	3.0
Cost of limestone(a)	0.2	0.9	1.5	2.3	3.1	4.0
Thermal losses(b)	0.1	0.2	0.4	0.5	0.7	0.9
Power requirement(c)	0.2	0.6	1.2	1.8	2.5	3.1
Waste disposal(d)	0.3	0.8	1.4	2.1	2.8	3.5
Operation and maintenance(e)	0.1	0.4	0.6	0.8	1.1	1.4
Capital charges(f)	0.3	0.8	1.2	1.7	2.1	2.8
Total additional costs	1.2	3.7	6.3	9.2	12.3	15.7
Costs as % of coal cost	1.0	3.2	5.5	8.0	10.7	13.7
Additional costs for limestone drying and crushing:						
Power requirement	0.1	0.3	0.6	0.8	1.1	1.4
Operation, maintenance and capital charges	1.1	2.7	4.0	5.3	6.6	7.7
Total additional costs	1.2	3.0	4.6	6.1	7.7	9.1
Additional costs as % of coal cost	1.0	2.6	4.0	5.3	6.7	7.9

(a) Limestone price £5.00/tonne, delivered.

(b) Losses due to increased solids removal.

(c) Electric motors for additional solids handling

(d) Cost of waste disposal £4.8/tonne.

(e) Taken as 5% of the additional capital costs, per annum.

(f) Taken as 10% of the additional capital costs, per annum.

Price of coal: 0.115p/MJ

Annual load factor: 65%

Calorific value of coal: 25.6 MJ/kg

Average to poor reactivity limestone.

Limestone, as delivered, frequently contains a large amount of absorbed water, which must be allowed for in calculation of the rate of addition to give adequate SO_2 reduction. The water does not upset the combustion process, apart from the small reduction in thermal efficiency owing to loss incurred due to the latent heat of evaporation and the sensible heat of the additional water vapour discharged to the atmosphere. It may, however, affect the handling of the stone if it contains a large amount of fine material. If it is necessary to crush the stone before use it may therefore be advisable to dry it before crushing, but as Tables 10 and 11 show, the capital cost of the necessary equipment is high. For small plants it is more economical to buy limestone with the correct top size for feeding to the combustor, and graded stone is usually readily available.

The estimates show that, if limestone drying and crushing on site is not necessary, an emission limit of 0.25 g SO_2/MJ heat input could be met without additional costs of more than 10% of the coal costs, (typically 0.115 p per MJ), for about 95% of the industrial coals supplied (cf. Table A1.3).

2.5.4 Effects on SO_2 emissions and waste solids production of fluidised combustion to meet emission limits

Table 14 shows the projected sulphur dioxide emissions from industrial uses of coal in the U.K. up to the year 2000 if full advantage were to be taken of the potential of fluidised bed combustion for reduction of SO_2 emissions to meet emission standards of 0.5 kg SO_2/GJ and 0.25 kg SO_2/GJ respectively. The table also shows the amounts of solid waste that would be generated by this action (excluding coal ash).

Assumptions made in these calculations are:

(i) All coal used by industry can be fired in fluidised beds except for coal used for cement kiln firing (which results in low sulphur dioxide emissions anyway, because of the nature of the process and charge). In practice, part of the industrial coal is likely to be used in gasifiers, but this has not been allowed for in Table 14. The economics of coal-gas desulphurisation are referred to in section 2.4.

(ii) The proportion of total coal to industry that is used for cement kiln firing will remain the same as in 1977.

(iii) The distribution of sulphur contents in coal disposals to industry will remain the same as in 1977 (Table A1.3).

(iv) All new boiler and dryer installations after 1985 will be fluidised-bed fired.

TABLE 14: SO_2 emissions and waste solids production arising from fluidised-bed combustion with sulphur retention

Industrial sector
(excluding coke ovens)

Emission limit kg SO_2/GJ	Description	Rate, 10^3 tonnes per annum			
		1977	1985	1990	2000
None (Conventional firing)	SO_2 from cement kilns	15	15	20	45
	SO_2 from boilers	240	240	405	827
	Total SO_2	255	255	425	875
None (Fluidised no limestone)	SO_2 from boilers (a),(b)	240	240	355	655
	Total SO_2	255	255	375	700
0.5 (limestone)	SO_2 from boilers (a)	240	240	295	450
	Total SO_2	255	255	315	495
	Waste solids (c)	0	0	500	1735
0.25 (limestone)	SO_2 from boilers (a)	240	240	240	260
	Total SO_2	255	255	260	305
	Waste solids (c)	0	0	795	2750

(a) Includes other uses for which fluidised-bed combustion is applicable.

(b) Assumes 30% sulphur retention by coal ash in fluidised-bed combustion without limestone addition.

(c) Dry weight of $CaSO_4$ and $Ca(OH)_2$, excluding ash.

Rates are given to nearest 5,000 tonnes.

See Section 2.5.4. in text for list of other assumptions.

(v) Existing plants will become obsolete at the rate of 5% of their 1977 capacity each year from 1985 onwards and will be replaced by fluidised-bed fired appliances.

(vi) Future coal disposals to industry will be as shown in Table 3 of Part 1 of this study(1).

(vii) All coal to industry has a calorific value of 25.6 MJ/kg.

2,531,000 tonnes out of a total of 11,926,000 tonnes of coal disposed of to industry in 1977 were to the cement industry; i.e. 0.8 x 2,531,000 tonnes or 2,025,000 tonnes were used for cement kiln firing. This represents 17% of total disposals.

In calculating the figures in the first line of Table 14, for SO_2 emissions from cement kilns, an arbitrary figure (25%) has been taken for the percentage of sulphur in coal emitted to the atmosphere. The value varies widely according to process type, and experimental verification is lacking.

2.5.5 Environmental considerations in disposal of spent absorbent

The only element present in the solutions leached from spent bed and cyclone material which might pose an environmental or health problem is calcium. Other elements investigated by workers at Battelle (Columbus) Laboratories(39) were well below levels of concentration deemed harmful by the U.S.A. Resource Conversation and Recovery Act, in the tests which it was possible to apply. Calcium occurs naturally in significant quantities in many drinking waters, and is an essential component of the diet, so it would not be expected to represent a significant toxic hazard, unless present in high concentrations.

A comprehensive environmental assessment of solid residues is being carried out by Ralph Stone and Company, Inc. in the U.S.A. The first report on this work(40) quoted results of leaching of residues tipped in different environments. When tipped in limestone quarries or the sea, the leachate was highly alkaline (pH 11 to 12), but if tipped in a commercial land-fill tip, the acidic nature of most of the other material tipped served to neutralise the alkalinity of the fluidised-bed residue. The water also contained high concentrations of calcium sulphate.

The report suggests that residues can be used as a conditioner for soils that are acidic, high in heavy metals, or deficient in trace metals on all of which it would have a beneficial effect. It also proposes that substitution of residues in portland cement concrete mixtures could save about $0.50 (£0.35 at March 1979) per kg of equivalent strength concrete, but special precautions might have to be taken in view of the sulphate content of the residues.

2.6 Sulphur removal after combustion: Flue Gas Desulphurisation (FGD)

During the combustion of coal in conventional appliances, such as pulverised-coal fired water-tube boilers, or chain-grate fired shell boilers, the largest part of the sulphur content of the coal is emitted in the flue gases as sulphur dioxide, SO_2, plus a small amount (typically 1 or 2% of the total sulphur oxides) as sulphur trioxide, SO_3.

Not all of the sulphur is emitted with the flue gases; a small amount (roughly 10% on average) is retained by combination with basic constituents of the coal ash. This retention was allowed for in estimation of the SO_2 emissions tabulated in part 1 of this study(1).

The sulphur trioxide content is very important in practice, because cooling of the flue gases allows this to combine with water vapour to form sulphuric acid, H_2SO_4, which will condense at temperatures of between 100° and 150°C, depending on the SO_3 concentration. It is necessary to avoid contact of the flue gas with metal or masonry surfaces below the acid dewpoint temperature, if rapid corrosion and structural deterioration is not to occur.

All FGD processes remove some proportion of sulphur trioxide as well as the dioxide, and solution of the trioxide together with oxidation of the dissolved dioxide result in a build-up of acid in wet gas-scrubbing systems which has to be neutralised at some stage with an alkali. In most processes, the alkali is present at the scrubbing stage.

Allowing for a retention of 10% of sulphur in the coal ash, and assuming 10.6 kg of combustion air per kg of coal, the concentration of sulphur oxides (as SO_2) in the flue gases is given by the following equations:

$$C_s = 2250\ S$$

$$C_s^1 = 770\ S$$

where C_s is SO_2 concentration, mg/Nm^3, in dry stack gas, C_s^1 is SO_2 concentration vppm, in dry stack gas, S is concentration of sulphur in coal,%.

A large number of wet FGD systems have been in operation now for some years, mainly in the U.S.A., U.S.S.R. and Japan, and a large proportion of them on oil-fired boilers. Full scale operation of FGD for coal-fired power station boilers was started in Japan in early 1975, and results of the first three years of operation have shown that the performance has been at least as good as anticipated, although there has proved to be some minor difficulties specific to the use of coal.(41)

Wet scrubbing implies cooling the flue gas, and it is normally necessary to reheat the gas before discharge, in order to avoid blanketing the surrounding ground with the discharged gas under adverse meteorological conditions. A great number of "dry" FGD processes are currently being developed, most of them capable of operating at sufficiently high gas temperatures to avoid the need for reheat. None has yet reached the stage of commercial application in large unit sizes.

The status of currently available processes and processes under development has been reviewed by Rosenberg(42) and by Princiotta(43). All that will be given here is a brief summary of available processes, and comments on potential attractions of some of the more promising emergent processes.

2.6.1 Processes commercially available at the beginning of 1979 for use on coal-fired boilers

These are all wet scrubbing processes and they are divided into processes in which the sulphur absorbed is thrown away with the spent absorbent (once-through processes), and processes in which the reagent is recovered by decomposing the reaction products and the sulphur is recovered in a potentially saleable form - elemental sulphur, sulphuric acid or gypsum) (regenerative processes).

The once-through processes are:

Sea-water or river-water scrubbing.
Limestone-slurry scrubbing.
Lime-slurry scrubbing.
Single alkali process (sodium carbonate/sulphite).
Double alkali process (alkaline sodium sulphite-lime).

The regenerative processes are:

Wellman Lord (alkaline sodium sulphite, thermal regeneration).
MgO process (magnesium oxide slurry, thermal regeneration).
Chiyoda Thoroughbred process (dilute H_2SO_4 + ferric ions).

The Chiyoda Thoroughbred process has been mainly used on oil-fired boilers, but has operated successfully on a 23 MW coal-fired boiler in the U.S.A. It is claimed that with addition of an ozone generator the process can be used also for NO_x removal.(44)

Although plants operating many of the above processes have been in operation for some time now in U.S.A., none has proved trouble-free and some have lost much operating time owing to shut-down for repair and maintenance.

A major drawback of the lime and limestone-slurry processes is risk of scaling resulting from the formation of supersaturated calcium sulphate solutions in the scrubbing water circuit although addition of magnesium compounds reduces this. The double alkali process avoids this by using alkaline sodium sulphite as the absorbent, the spent solution being reacted with a calcium alkali (usually lime) in an external reactor to precipitate a mixture of calcium sulphite and sulphate and regenerate the absorbent.

Another drawback of the lime and limestone slurry processes, shared also by the single and double alkali processes is the difficulty of disposing of the products of reaction. Most of the processes produce a sludge consisting of a mixture of calcium sulphite and sulphate, and water. The sludge is difficult and expensive to dewater to a form suitable for disposal as land-fill, although the waste solids resulting from the double alkali process are reported(45) to be easier to dewater. The single alkali process produces a solution of sodium salts which cannot normally be released to natural watercourses. Most of the existing plants operate in arid regions of the USA, where the natural rate of evaporation is high and exceeds the rate of liquor production plus rainfall. A recent development of the single alkali process(46) uses spray-drying techniques, with sprays of sodium hydroxide or carbonate solution to produce a solid mixture of sodium sulphite and sodium carbonate which, it is proposed, can be used in Kraft or sulphite pulping processes. This avoids the liquid effluent problem.

Water scrubbing has been used by the CEGB at Battersea and Bankside power stations in London, where it relied on the natural alkalinity of Thames water which was used in large quantities, plus waste alkaline sludge from water softening plants, to avoid discharge of strongly acid water into the river.(47) No reheat of stack gases was used and in consequence the plume had a tendency to drop under adverse meteorological conditions although the stack heights were considerably more than those of neighbouring buildings. Although over 95% of the sulphur dioxide was removed by scrubbing, under plume-droop conditions the residual pollutants had a more objectionable effect than if the gas had been discharged hot, without scrubbing.

The Wellman Lord and MgO (magnesium oxide) processes both employ an SO_2 absorption stage and a subequent regeneration stage in which a concentrated stream of sulphur dioxide is produced. The SO_2 is treated in various ways, depending on the facilities available, and the form in which the sulphur is to be ultimately recovered. For example, if the desired end product is elemental sulphur, the dioxide is reduced by a reducing gas such as methane, carbon monoxide, hydrogen or coal gasification products. If the sulphur is to be recovered as sulphuric acid, the dioxide is oxidised in the gas phase over a vanadium pentoxide catalyst to form sulphur trioxide, which reacts with water in sulphuric acid solution. The well-proven Wellman Lord is the preferred process.

Small amounts of other sodium or magnesium salts are formed because of the presence of sulphur trioxide, hydrogen chloride and other compounds in the flue gas. These salts (mainly sulphates and chlorides) are removed by treatment of a purge stream taken from the main scrubbing liquor stream. Coke is used to reduce magnesium sulphate formed in the MgO process.

The Chiyoda Thoroughbred process produces a saleable gypsum, for which there was formerly a greater demand in Japan than there is now, or in the U.K. If efforts were made, outlets for gypsum could possibly be developed in the U.K.; possible uses have been discussed elsewhere(48).

It is almost certain that if a decision were to be taken by the U.K. electricity industry to install FGD on any of its boilers, then a regenerative process would be used (probably Wellman Lord), because of the environmental effects of waste disposal from once-through processes, and the lack of land area for disposal.

2.6.2 Other FGD processes nearing commercial application

A comprehensive list of new processes under development is given in reference 49. Six of the furthest developed of these are reviewed briefly below.

(i) Ammonia process (wet)

Ammonium sulphite solution and/or ammonia gas is injected into the flue gas, and reacts with sulphur dioxide to form ammonium bisulphite. The wash liquor is evaporated to produce gaseous SO_2 and ammonia, and sulphur is formed by reduction as in the Wellman Lord and MgO processes. The sulphur trioxide present in the flue gas forms ammonium sulphate in the scrubber, and this is removed by precipitation with lime.

Status: An experimental plant by Electricite de France was in operation on a 30 MW oil-fired boiler at Champagne-Sur-Oise, France; Institut Francais du Petrol (IFP) and Catalytic Inc. (USA) are associating. Other, independent development is by Mitsubishi (Japan) and by Showa Denko (Japan).

The experimental efficiency of desulphurisation(50) was 90% to 97%, and 99% of the absorbed SO_2 was recovered in the desorption column. About 6% of the ammonia was lost, representing a loss of 10 kg/h of NH_3 for a sulphur dioxide flow rate of 370 Kg/h. It is reported, however,(51) that the ammonia processes suffer from the problem of emission of fumes consisting of ammonium salts, from the chimneys, and that this problem has so far defied all efforts to solve it.

Variations of the process are capable of removing nitrogen oxides.(52,53)

(ii) Saarberg-Hölter process (wet)

Although basically a lime treatment, this process uses formic and hydrochloric acids as additives to produce a high solubility of calcium hydroxide in the wash liquor. There are no reports of scaling or plugging with this process. Unlike many other FGD processes the presence of chloride, resulting from chlorine in the coal, has no adverse effect on the scrubbing process. The calcium sulphite produced in the scrubber is oxidised to sulphate in a special aerator, and the process is reported to produce saleable gypsum. Careful control of the chloride content of the product would be required.

Status: Over 14,000 hours of operation(54) in a 40 MW coal-fired power station boiler at Saarbrücken, and also a plant at a refuse incinerator. Over 90% desulphurisation is claimed, for a low energy consumption. Davy Powergas Inc. is offering the process in U.S.A.

(iii) Citrate process (wet)

Uses a buffered solution (sodium citrate, citric acid and sodium thiosulphate or phosphate) to absorb SO_2, which is then reduced in solution to sulphur by hydrogen sulphide and regenerate the sodium citrate. Developed by the U.S. Bureau of Mines(55), a pilot plant has been built to operate on a 100 MW coal-fired boiler.

(iv) Active carbon processes

Processes have been developed by Bergbau-Forschung/Foster Wheeler, Catalytic/Westvaco, Reinluft and by Sumitomo-Kansai (all dry processes), and Hitachi (wet process).

The dry processes adsorb SO_2 on active carbon at temperatures of about 100°C and release the SO_2 in a concentrated stream by heating to temperatures variously referred to as 400°C and 650°C. The SO_2 is converted to sulphur by anthracite reduction or other means. As in all dry processes, preliminary removal of suspended particulates is essential to avoid fouling the carbon. There is some loss of carbon with each regeneration, probably mainly by oxidation by sulphur trioxide which is formed by catalytic oxidation of SO_2 on the carbon surface(56). This loss of carbon increases the internal surface area of the adsorbent and makes it more reactive, with a consequent risk of spontaneous combustion in the adsorption bed when the flue gas contains appreciable amounts of oxygen. It is reported(53) that the process also removes 40 to 65% of NO_x.

Status of dry processes: Pilot plants have been built and operated in the various countries.

The Hitachi wet process adsorbs the sulphur dioxide on a bed of wet carbon where it is oxidised catalytically to sulphuric acid, which is removed by water washing. A British Patent Specification relating to the Hitachi process(57) gives much scientific information on the kinetics and equilibria of the adsorption process. This Patent refers to a flue gas inlet temperature of 55°C.

Status: A 150 MW Hitachi unit is in operation in Japan.

(v) Cat-Ox process (dry)

In this process, developed by Monsanto (U.S.A.), flue gas at 475°C is first cleaned of particulates in a high-temperature electrostatic precipitator, then passed over a vanadium-based catalyst which converts the sulphur dioxide to trioxide. The gases are cooled in a heat-exchanger, and the SO_3 reacts with moisture in the flue gas to form a sulphuric acid mist which is scrubbed out with recirculating sulphuric acid in a packed tower. 80% sulphuric acid is withdrawn, and the residual acid mist in the gas is removed in a mist eliminator before the gas is discharged at 120°C to 125°C.

In an alternative form of the process, the flue gas may be reheated after cleaning in an electrostatic precipitator operating in the normal temperature range, before the catalytic oxidation.

Status: A test plant was built in the USA, but operational experience appears to have been unsatisfactory. The plant required is rather complex and expensive, and there is a risk that ineffective operation of the mist eliminator will produce a visible and persistent plume at the stack. The process has been dropped, at least for the time being.

(vi) Shell process (dry)

This process uses a fixed bed of copper oxide on alumina to absorb sulphur dioxide and oxygen in the flue gas to form copper sulphate. Regeneration is carried out at the same temperature with hydrogen gas, which produces an SO_2-rich stream for further processing. The operating temperature is below that required in the dry carbon processes for regeneration. 60 to 70% removal of NO_x is reported, in addition to 90% SO_x removal(53).

Status: A pilot plant is in operation on a 0.6 MW slipstream from a coal-fired boiler, and a full scale plant is operating at an oil refinery in Japan.

2.6.3 Discussion of the present state of FGD processes

All the processes commercially available at March 1979 are wet processes; five are 'once-through' processes, requiring large areas of land for disposal of waste products and introducing the risk of pollution of water supplies due to run-off from the tipping areas; and two are 'regenerative processes'. All are capable of installation either on new plants or as 'retrofit' systems on existing plants. There is enough information available to enable rough cost estimates to be made for all these processes, but only one, the Wellman Lord process, has been studied in sufficient detail in relation to special U.K. requirements and operating practices to allow the costs to be regarded as fully realistic. The costs are discussed in section 2.6.5.

FGD has been applied in the USA not only to power station ('utility') boilers, but also to at least 16 industrial boiler plants(58), but it is considered unlikely to be used on industrial boilers in the U.K. because of the high capital cost and the problems of waste disposal. Most plants operating in the USA give flue gas desulphurisation efficiencies ranging from 75% to 90%, and plant availability ranges from poor to moderately good. A recent study(59) by Battelle (Columbus) Research Institute of four FGD installation (including both once-through and regenerative types), operating on high-sulphur coal fired power plants concluded that none of the emissions at any of the four stations met the proposed revised New Source Performance Standards, which would require not more than 0.516 kg SO_2/GJ heat input, plus at least 90% SO_2 removal on a 24-hour averaging basis unless emission was below 0.085 kg SO_2/GJ. Concerning availability, the best that could be said was that the systems limp along from one problem to another.

Referring to the newly-emerging processes described in section 2.6.2, it is possible that one or more of these may be commercial propositions before 1985, and could therefore, if sufficiently attractive, be in operation in the U.K. before the end of the present century. It is not yet possible to predict costs of these processes with any confidence. Three of the processes are wet, two are dry, and one (active carbon) can be either wet or dry. All are regenerative. Dry processes offer the great advantage that gas reheat (which accounts for about 50% of the energy use(60) in once through and for 15 to 30% in regenerative processes) is not needed. An additional attraction of dry processes is that corrosion is less of a problem. Corrosion results from acid liquor, the build-up of chloride ions and physical stress, either operating separately or in concert. It is combated by use of corrosion-resistant metals such as low-carbon stainless steel or special alloys(61). The use of plastic coatings over less expensive metals has also been tried, but these coatings usually offer little resistance to erosion, and the presence of solid particles in the scrubbing liquor will quickly result in the exposure of bare metal which will rapidly corrode. Rubber or ceramic coatings are now reported to be more satisfactory(62). Since coal ash is usually fairly abrasive, removal of particulates before wet scrubbing systems is recommended, although some wet processes remove both particulates and sulphur oxides in a single stage.

2.6.4 Energy requirements of FGD

The most informative way of presenting energy requirements of FGD is as a percentage of input energy to the boiler in the form of coal. Electric power requirements are converted to their input energy equivalents by dividing by the fractional efficiency of power generation for the plant. Since the ultimate objective is to compare the input energies for the same amount of useful output with and without FGD, the value taken for input energy should be the net input energy, i.e. the input energy to the plant less that required for operation of the FGD process.

For the once through processes, the demands for extra energy are in respect of liquid pumping, sludge dewatering and flue gas reheat, but for the regenerative processes additional demands are introduced by the various processes required for regeneration of the absorbant and recovery of the sulphur, and additional fan requirements. Tables 15, 16 and 17 show estimates of the total energy requirements for various FGD processes. The estimates are based on information supplied in references 60 and 63, and where lime is used the energy required for calcination is taken into account.

As remarked earlier, the process of most interest to the electricity industry in the U.K. is the Wellman Lord process. If this were to be applied to all coals supplied to the U.K. electricity industry (using the data of Table A1.1 and the 1975/76 average calorific value of 24.1 GJ/tonne[1]), the total energy required to meet an emission limit of 0.5 kg SO_2/GJ heat input would be 666 TJ per million tonnes of coal, representing 2.8% of the gross heat input. To meet an emission limit of 0.25 kg SO_2/GJ heat input, the energy required for FGD would be 936 TJ per million tonnes of coal, representing 3.9% of the gross heat input.

2.6.5. Costs of FGD

The economics of flue gas desulphurisation are subject to a great deal of uncertainty, but in the light of experience gained in USA and Japan, it is now recognised that early cost estimates were far too low. Capital costs for the lime/limestone slurry treatments are now recognised(64) to be of the order of 25% of the total generating plant costs, and annual costs (including sludge disposal and capital charges) range from approximately 25% of 'no-FGD' generating costs at 80% load factor to 45% at 40% load factor(62). One report is even more pessimistic(59).

Plant for regenerative processes tends to be more complex, but this is compensated for by the lack of waste disposal ponds and operating costs are offset by sale of by-products. A detailed discussion of the possible effect on markets for these if FGD were to be widely adopted is contained in reference 37.

FGD facilities fitted on to existing power stations cost on average about 12% more in capital expenditure than on new power stations, for the same size and desulphurisation capacity. Estimated capital costs for some FGD processes fitted on new 500 MW coal-fired power units are shown in Table 18. The estimates are based on a 1976 TVA survey(65), in conjunction with more recent reports on actual plant costs which have been found to be 50% to 100% higher than the TVA estimates(64,66). Capital costs for limestone slurry scrubbing have been found(62) to be about $138/kW (1977 value) for a 500 MW plant, compared to $53 to $65 (depending on sulphur content of coal) predicted by TVA(37). For the Wellman Lord process, figures are available for a plant installed on an existing 115 MW coal-fired unit burning 3.5% S coal at the Dean Mitchell power station of the North Indiana Public Service Company. Although it has been claimed(67) that the capital cost was $69/kW, it seems quite clear that the final cost of construction was $18 m(67,68) which represents $157/kW. This compared with a TVA estimate of $118/kW for a retrofit Wellman Lord plant on a 200 MW boiler firing 3.5% S coal, with 90% sulphur removal.

TABLE 15

Energy requirements for FGD

Process	Energy requirement GJ/tonne S removed
Once-through processes	
Limestone slurry scrubbing	30
Lime slurry scrubbing	50
Seawater scrubbing	50
Regenerative processes	
Wellman Lord[2]	95
Magnesium oxide[2]	100
Magnesium oxide[3]	60
Active carbon	90
CuO absorption	140
Ammonia (IFP)	85

Notes: See Table 17

TABLE 16

Energy loss by FGD to meet emission standard of 0.5 kg SO_2 per GJ input

Process	Energy loss,[1] % for given coal S content					
	0.5% S	1.0% S	1.5% S	2.0% S	2.5% S	3.0% S
Once-through processes						
Limestone slurry	0	0.3	0.8	1.4	1.9	2.4
Lime slurry	0	0.5	1.4	2.3	3.1	4.0
Seawater scrubbing	0	0.5	1.4	2.3	3.1	4.0
Regenerative processes						
Wellman Lord[2]	0	1.0	2.6	4.3	6.0	7.6
Magnesium oxide[2]	0	1.0	2.8	4.5	6.3	8.0
Magnesium oxide[3]	0	0.6	1.7	2.7	3.8	4.8
Active carbon	0	0.9	2.5	4.1	5.7	7.2
CuO absorption	0	1.4	3.9	6.3	8.8	11.3
Ammonia (IFP)	0	0.9	2.3	3.8	5.3	6.8

Notes: See Table 17

TABLE 17

Energy loss by FGD to meet emission standard of 0.25 kg per GJ input

Process	Energy loss,[1] % for given coal S content					
	0.5% S	1.0% S	1.5% S	2.0% S	2.5% S	3.0% S
Once-through processes						
Limestone slurry	0.2	0.7	1.2	1.7	2.3	2.8
Lime slurry	0.3	1.1	2.0	2.9	3.8	4.6
Seawater	0.3	1.1	2.0	2.9	3.8	4.6
Regenerative processes						
Wellman Lord[2]	0.5	2.2	3.8	5.5	7.2	8.8
Magnesium oxide[2]	0.5	2.3	4.0	5.8	7.5	9.3
Magnesium oxide[3]	0.3	1.4	2.4	3.5	4.5	5.6
Active carbon	0.5	2.0	3.6	5.2	6.8	8.4
CuO absorption	0.7	3.2	5.6	8.1	10.6	13.0
Ammonia (IFP)	0.4	1.9	3.4	4.9	6.4	7.9

Notes to Tables 15, 16 and 17

1. Energy requirement of process as a percentage of input energy to boiler without flue gas desulphurisation.
2. With production of sulphur.
3. With production of sulphuric acid.
For coal of calorific value 25.6 GJ/tonne.
Generation efficiency 11 MJ(Th)/kWh without FGD.
Lime and limestone processes include sludge disposal.
10% sulphur retention by ash is assumed.

TABLE 18

FGD capital costs (USA experience)

($/kW)

Emission limit, kg SO_2/GJ	0.5			0.25		
Sulphur content of coal, % wt.	1	2	3	1	2	3
Limestone or lime	95	101	109	97	105	111
Wellman Lord	220	260	300	238	274	305
Magnesium oxide	144	197	237	166	211	260

500 MW unit; March 1979 costs; U.S.A. location.
Sources: references 59, 62, 64, 65, 66.

TABLE 19

FGD annual costs

New 500 MW unit; 5260 hours operation a year;
90% S removal on 3.5% S coal

Process	Additional generating cost,(a) mils/kWh
Wellman Lord	7.5
Magnesium oxide	6.7
IFP Ammonia	5.5
Bergbau-Forschung	7.1

(a) At March 1979; 1 mil is 1/1000 U.S. dollar
U.S.A. location
Sources: references 13, 37, 43, 67.

To take these facts into account, the TVA estimates have been increased by 75%, and the costs converted to U.S. dollars at March 1979 values, in Table 18.

The costs relating to plant construction and operation in USA cannot be used as a firm indication of costs in the U.K. because of the different constraints which operate in this country. The Central Electricity Generating Board have costed one FGD process - Wellman Lord - for U.K. conditions and have found the anticipated capital costs on the station for installation on a proposed new 3 x 660 MW power station to be as high as £95/kW. A retrofit installation on the same size of station is estimated to cost £105/kW. There are additional capital and operating costs incurred on the rest of the generating system, which are particularly significant for retrofit situations. These costs are not included in the above figures.

Operating costs can vary widely from plant to plant depending on the degree of maintenance and repair required, transport costs for waste disposal, etc. A detailed discussion of operating costs for a number of FGD processes is given in reference 37; because of the limitations on space for waste disposal in the U.K., only the two commercially available regenerative processes, Wellman Lord and Magnesium oxide and two new processes - carbon and IFP ammonia will be considered here. The Chiyoda Thoroughbred process is not dealt with because the produces gypsum, for which future demand in Britain is doubtful. Cost estimates for the less well developed processes are less likely to be accurate than those for an established process such as the Wellman Lord.

Costs can be broken down into raw material costs, energy costs, labour costs, waste disposal costs, maintenance costs and charges on the capital cost. Revenue from sale of the by-products can be set against the operating costs. For regenerative processes the waste disposal costs are small. For the Wellman Lord process up to 1 tonne/hour of solid sodium sulphate is produced from the scrubbing liquor purge for a 500 MW station on high sulphur coal. There might be a market for this, but it is more likely that money would have to be spent to dispose of it without causing environmental harm. (See section 2.6.7).

Operating costs comparisons for the four regenerative processes named are summarised in Table 19. The figures refer to a 500 MW unit with the equivalent of 5260 hours annual operation at full rating, burning 3.5% sulphur coal at 90% sulphur removal,(13,37,43,67) and take into account the fact that capital costs have been found to be higher than those originally estimated. The costings have not been made for the specifically British operating condition, and are of value principally in showing how operating costs of the four processes compared, as judged by the standards of relative prices in the years 1973 to 1976 and in the light of knowledge of the various processes at that time.

Only one process has been costed with particular reference to conditions in the U.K. at the present time, namely the Wellman Lord process. Recent CEGB estimates of operating costs for this on an average power station coal show that it is expected to add between 25 and 30% to the generating cost of electricity. This represents a cost per kWh due to FGD of 0.35 to 0.4 p/kWh, (base generating cost 1.4 to 1.6 p/kWh), which agrees with the level shown in Table 19, which was for a coal of higher sulphur content than average British coal, but a U.S. location.

Energy losses result from requirements of heat to expel absorbed SO_2 and regenerate the absorbent solution, consumption of reducing agent in the production of sulphur, flue gas reheat, and electric power requirements to drive pumps and stirrers and to supply additional fan power. It is estimated that operation of the Wellman Lord process on a typical U.K. coal-fired power station burning coal of an average sulphur content would reduce the overall electricity generation efficiency by four percentage points. There would be an associated, but smaller, de-rating of the station production capacity. The latter could result in additional capital costs in the generating system as a whole, and these have not been taken into account here.

Although the Wellman Lord appears to be the most expensive of the regenerative processes, it is the only really well established one. The one magnesium oxide plant operating in the USA has suffered from serious operational difficulties(69), and plant availability has been only 37%(42). The effectiveness of the recycled MgO and make-up requirements are still not clear.

Cost estimates for the two processes not yet available on a commercial basis are very uncertain.

2.6.6 Possible market penetration in the U.K.

This section considers the essentially practical problems that would limit or determine the rate of installation of FGD systems in coal-fired power stations in the U.K. in a hypothetical situation in which a decision had been taken to equip all plant with FGD as quickly as possible. This decision would have been taken in the light of all evidence for and against such action, including cost, energy losses, and benefits to the environment at home and overseas. At present the picture is far too incomplete for any such decision to be justified or even appear likely to be justifiable.

The extent to which flue gas desulphurisation might be introduced between now and the year 2000 depends on the requirements that might be made to meet any new legislation on ambient air quality or the emission of pollutants from combustion in stationary sources. There would, however, be an upper limit to the rate at which FGD plant could be installed in power stations, because of the need to keep a certain minimum generation capacity operable at all times. Installation of FGD would mean that the plant in question would have to be taken out of service for up to a year. It is estimated that the conversion rate of existing plant would be about 800 MW a year. If necessary, any new coal burning power stations could, of course, be built with FGD, but apart from one 2000 MW station expected to be completed before 1985, no further coal-fired plant is at present anticipated until nearing the end of the century. If it is assumed that the power station to be built during the next five years had to be equipped with FGD, and that FGD giving 90% sulphur retention had to be installed as quickly as is practicable on existing coal-fired plant, the reduced sulphur emissions and the associated costs (March 1979 values) would be as shown in Table 20.

The resultant reduction in SO_2 emissions depends on the amount of coal actually burnt in coal-fired power stations in any year. This depends on various factors, of which the pattern of demand and operational availability are two important ones. Some guidance on possible future average annual loads in coal-fired power stations is gained by studying the statistics for power generation in England and Wales for 1977/78(70).

In this year the CEGB operated about 83 coal-fired stations, many of them old and small, which were only used at times of very high demands for electricity. The total gross coal-fired generating capability was approximately 38,600 MW, and the average load (defined as the annual output of electricity divided by the output which would have resulted if all coal-fired generating capacity operated at full capability throughout the year) was 0.448 (or 44.8%).

TABLE 20

Sulphur dioxide emissions if FGD were to be installed at maximum possible rate in UK power stations, and extra costs which would be incurred

Year	1985	1990	2000
Net generating capability equipped with FGD, MW	6,000	10,000	18,000
SO_2 emission rate in absence of FGD, 10^3 tonnes p.a.	2,430	2,403	2,349
SO_2 emission rate with FGD, 10^3 tonnes p.a.	2,141	1,918	1,482
Total installation cost(a) £10^6	610	1,030	1,870
Annual additional cost £10^6	103	171	308

(a) Cost incurred between 1980 and relevant year.

Costs all at March 1979 values.

Most of the older and smaller stations are in the South of England; the Midlands and North-east England between them hold 66% of the total coal-fired generating capability, and accounted for 75% of the total coal-generated electricity in 1977/78. The average load for these two areas was 51.1%, and it is assumed in Table 20 that this will be the load factor for the stations which would be preferentially equipped with FGD, if it were decided to use FGD in the future. An average thermal efficiency of 34% for the larger, newer stations is also assumed in the calculations for Table 20, leading to a coal usage of 0.44 tonnes per MWh of electricity generated. The basic cost figures used are those estimated by the CEGB.

The value of the sulphur produced by the Wellman Lord process, at March 1979 market price (£275/tonne) would be £75 million per annum in 1985; £125 million per annum in 1990 and £225 million per annum in 2000. There is little prospect that 1979 sulphur prices could be maintained however, if regeneration FGD processes and SNG manufacture were in widespread use, because of the high rate of production of the element which would flood the market. Little or no credit can therefore be allowed for future years.

2.6.7 Disposal of solid products from FGD

Only the products from the Wellman Lord process will be considered. Apart from the main product (sulphur or sulphuric acid), the only material produced in significant quantities is sodium sulphate. It might be possible to sell part of the latter, but if no use can be found for it, care would have to be taken in its disposal because of its high solubility. Disposal at sea is a possibility (it occurs naturally in quite high concentrations in sea water). If it is assumed that 5% of the sulphur removed from the flue gas finishes up as sodium sulphate, the annual rate of production from a 2000 MW power station on 51.1% load factor, and burning an average British coal, would be 10,700 tonnes, as Na_2SO_4. Davy Powergas, who market the Wellman Lord process, are understood to be testing a process modification for the reduction of sulphate to sulphite, which would eliminate this by-product and reduce sodium carbonate consumption, but would increase energy requirements.

The annual production of sulphur (99.5 + % purity) from the same power station would be 45,800 tonnes. If no immediate market exists, sulphur can be stored safely, without deterioration for an indefinite period; if stored underground it would not be expected to present a water-pollution hazard.

3. Oxides of Nitrogen

3.1 Contribution of coal-fired plant to ground-level concentrations

Oxides of nitrogen referred to specifically in this section are nitric oxide, NO and nitrogen dioxide, NO_2. Both are emitted by combustion appliances, but nitric oxide predominates. After emission to the atmosphere, nitric oxide is oxidised to the more toxic dioxide, which is known to reduce resistance to respiratory infections, and if present in sufficiently high concentrations (3000 $\mu g/m^3$ or more) will generally impair respiratory function(71). Nitrogen dioxide is an important contributor to the formation of photochemical smogs, which require also the presence of hydrocarbon vapours and prolonged sunlight. They tend to occur therefore in regions where long periods of anticyclonic weather occur, and where there is a plentiful supply of nitrogen oxides and unburnt hydrocarbon vapours. These conditions are found in various parts of the USA, but only rarely in the U.K. Concentrations of 1000 $\mu g/m^3$ of NO_2 have been measured in photochemical smogs, and these are associated with other highly irritant compounds, mainly peroxides.

Where this type of smog has been prevalent, concern has arisen over NO_x emissions and legislation restricting them has been adopted (Table 21). On present evidence, however, there appears to be little concern in the U.K., where the current standards for flue gas dispersal (i.e. the tall-stack policy) ensure effective dispersal of combustion gases and the climate does not favour prolonged irradiation of the hydrocarbons and NO_x emitted at ground level by cars and lorries.

Most of the published data on NO_x emission from fossil-fuel combustion originates in the USA, and includes results for wet bottom and for dry bottom pulverised coal fired furnaces. Nearly all U.K. power plant uses dry-bottom furnaces which operate at lower temperatures and therefore produce less NO_x. Hence the amount of NO_x emitted by coal-fired boilers in the U.K. will not exceed estimates based on USA experience. Estimates of NO_x emissions from the coal-fired plant operating at the present time are given in Table 5 of Part 1 of this study(1), and these agree broadly with the U.S. published data.

The relative importance of coal as a source of NO_x in the USA in 1976 can be judged from Table 22 which lists the 24 main types of source in order of the quantity that they emit. The four representing coal combustion account for only 19.3% of the total from all man-made sources, or 38.1% of that from stationary sources. The NO_x which comes from transport vehicles results in much higher ambient air concentrations because it is emitted close to ground level. Other combustion of oil also contributes large amounts of NO_x.

Part 1 of this study(1) estimates an increase of about 50% in NO_x emissions from coal use in the U.K. between 1975/76 and 2000, on the basis of continued practice of present combustion technology. An increase of 66% from stationary sources (all fuels) from 1975 to 1985 has been predicted in the USA(72), and a German prediction(73) also foresaw a rapid increase. It can therefore be assumed that in the absence of special action to control NO_x emissions, the upward trend in emission is likely to continue throughout the 1980 s and '90 s, in Britain as elsewhere. This may lead to restrictive legislation which may be applied to stationary sources as well as, or instead of, transport vehicles. However, any benefits from such legislation would be highly doubtful, because it can be shown that the ground level NO_x concentrations arising from the combustion of most of the coal mined in the U.K. are very low.

TABLE 21

NO_x emission standards and projected research objectives for large fossil fuel-fired boilers, U.S.A.

	Present EPA standard (38)		Projected research objectives (71)	
	Lb NO_x/MBtu input to boiler[a]	NO_x, ppm[b]	1980 NO_x, ppm[b]	1985 NO_x, ppm[b]
Gaseous fuel	0.2	150	100	50
Liquid fuel	0.3	225	150	90
Solid fuel	0.7	550	200	100

a. Expressed as NO_2.
b. Calculated at 3% excess O_2, dry basis.

TABLE 22

NO_x emission from stationary sources in U.S.A.[72]

Rank	Source	Mass NO_x metric ton/yr	% emissions, stationary sources	% emissions, all sources
1.	Coal-fired steam utility generators	3,495,000	30.8	15.6
2.	Fuel-burning reciprocating engines	2,132,000	18.8	9.54
3.	Oil-fired industrial/commercial boilers	1,245,000	11.0	5.57
4.	Oil-fired steam utility generators	1,114,000	9.80	4.98
5.	Gas-fired steam utility generators	835,100	7.35	3.74
6.	Coal-fired industrial/commercial boilers	734,600	6.46	3.29
7.	Gas-fired industrial/commercial boilers	491,400	4.32	2.20
8.	Fuel-burning turbine engines	253,300	2.23	1.13
9.	Cement manufacture	91,310	0.803	0.408
10.	Industrial/commercial space heating	80,560	0.709	0.360
11.	Crude distillation of petroleum	69,640	0.613	0.312
12.	Glass manufacture	68,160	0.600	0.305
13.	Catalytic cracking of petroleum	60,730	0.534	0.272
14.	Coal refuse piles (and abandoned mines)	30,590	0.269	0.137
15.	Nitric acid manufacture	27,050	0.238	0.121
16.	Vacuum distillation of petroleum	25,100	0.221	0.112
17.	Ethylene manufacture	24,020	0.211	0.107
18.	Wood-waste incineration	23,960	0.211	0.107
19.	High density polyethylene manufacture	13,930	0.123	0.0623
20.	Propylene manufacture	12,600	0.111	0.0563
21.	Benzene manufacture	10,770	0.0947	0.0482
22.	C_4 hydrocarbons manufacture	10,450	0.0919	0.0467
23.	Brick kilns and dryers	8,680	0.0764	0.0388
24.	Mineral-wood manufacture	8,061	0.0709	0.0361
Others		503,989	4.43	2.25
Total		11,370,000	100.17*	50.85

*because of rounding

Source: Monsanto Research Corp.-Dayton Laboratory (Dayton, Ohio), "Source Assessment Overview Matrix," Sept. 21, 1976: EPA contract no. 68-02-1874

The highest concentration of NO_x in flue gas from an average dry-bottom pulverised-coal fired boiler is about 600 vppm (1.23 g/m^3 as NO_2) (Table 23), and when diluted by the factor derived in Section 2.2.1 for stack gases from power stations, this gives a maximum 24-hour mean g.l.c. of 1.8 vpphm (36 $\mu g/m^3$ as NO_2) and a maximum yearly g.l.c. of 0.2 vpphm (4 $\mu g/m^3$ as NO_2). This is considerably lower than concentrations encountered in photochemical smogs, and lower than the U.S. EPA Air Quality Standard for NO_x, which is 100 $\mu g/m^3$ (measured as NO_2)(38).

It is therefore unlikely that legislation to control NO_x emissions from coal combustion would result in a significant improvement in ambient air quality. However, techniques have been investigated in some countries for the reduction of NO_x emissions, and the remainder of this section considers the reductions that could be achieved and the costs of doing so.

3.2 Methods of reducing NO_x emission

3.2.1 Minimising formation

Both the chemically combined nitrogen in the fuel and the free nitrogen in air can be oxidised during combustion to form nitric oxide or nitrogen dioxide. Oxidation varies with the method of firing (Table 23), and is encouraged by high oxygen concentration, high flame temperature and long residence time at high temperature(75). Concentrations of NO_x formed in the hottest part of the flame are frequently in excess of concentrations for equilibrium at the lower temperatures prevailing at the furnace outlet, and some decomposition of nitrogen oxides may therefore occur downstream of the flame. The decomposition reaction is not rapid, however, and becomes quite slow at temperatures below 1300°C, so that rapid cooling of the furnace gases leads to higher NO_x emissions because the concentrations are "frozen" at their high temperature equilibrium level. Modification of the combustion process to reduce any or all of the factors encouraging high NO_x concentrations was an obvious first approach which could be applied quickly and reasonably cheaply to existing plant.

Much of the work has been done in Japan and the USA on oil-fired boilers, where control of combustion conditions is more easily accomplished because of the ease of controlling and metering the fuel streams to the burners. Extension of the techniques to coal-firing will be more difficult and less rewarding, because of this fact.

Modifications that have been considered for use in conventional boilers, their applicability and their effects, are shown in Table 24,(53) while Table 25(53) shows estimates of NO_x reduction for five practical modifications together with their energy cost in loss of thermal efficiency (if any), and their status with respect to current use and research. In general the improvements are small, 15 to 40% and may be accompanied by loss of efficiency and/or output and, in some cases, by complications such as corrosion and tube wastage. Greater reductions, 50 to 80%, could be achieved by changing from conventional to pressurised fluidised-bed firing for new boilers(76), but as was remarked in Section 2.5.2 fluidised combustion is unlikely to be used for power generation in the U.K. before 2000. The only significant use of this mode of combustion is expected to be in industrial boilers operating at atmospheric pressure, and NO_x emissions from these will only be slightly less than

TABLE 23

Concentration ranges of NO_x from coal fired power plants[74]

Type of firing		Typical NO_x concentration, ppm
PF:	Vertically-fired	225-310
	Horizontally opposed firing	340-375
	Tangential (corner-fired)	420-500
	Front wall fired	390-600
Other:	Cyclone	800-1200
	Spreader stoker	400-470

TABLE 24

Summary of combustion process modification concepts

Combustion conditions	Control concept	Applicable equipment	Effect on thermal NO_x	Effect on fuel NO_x	Primary applicable controls		
					Operational adjustments	Hardware modification	Major redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Boilers, furnaces	Reduces O_2-rich high-NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Boiler, furnaces	Flame cooling and dilution during delayed mix reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/ firebox design
	Increased fuel/ air mixing	Gas turbines	Reduces local hot stoichiometric regions in overall fuel lean combustion	Increases	Improved atomisation		New can design; premix, prevap.
	Primary fuel-rich flame zone	Boilers, furnaces, IC	Flame cooling in low-O_2, low-temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports, stratified charge	Burner/firebox design for two-stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Boilers, furnaces, IC, gas turbines	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/ reduce residence time	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics

Source: Reference 53.

TABLE 25

Application of combustion modifications to coal-fired boilers

Modification	Equipment/ fuel	Control method/ range	NO_x reduction	Effect on		Extent used	R + D status
				Operation/ maintenance	Efficiency		
Low excess air (EA)	Power station boilers (except cyclone fired) and industrial water-tube boilers	Reduce EA to 20% or less	12.5% reduction in NO_x for each 1% reduction in flue gas O_2 concentration	Flame instability; CO and hydrocarbons may occur in flue gas. Greater surveillance required. Corrosion and slagging possible	0.1% increase for each 1% decrease in excess air	Widely used on USA utility boilers, new and retrofit	Part of all advanced control designs
Staged combustion	Power station and industrial boilers	85-95% of theoretical air supplied to some or all burners; rest of air supplied downstream of primary flame zone	30 to 40%	Load curtailment, flame instability, boiler vibration, excessive CO and smoke emissions all possible with retrofit use. Corrosion and slagging may occur	No effect in new units, possible 1% decrease with retrofit	Included in most new US utility boilers; only prototype in industrial boiler	Evaluation of corrosion potential. Evaluation of industrial boiler use
Flue gas recirculation	Power station boilers	15 to 20% or more recirculation to wind-box; used with LEA	Up to 15%	Smoking, vibration, flame instability at high recirc. rates	Small decrease (fan requirement)	Negligible	Inactive
Load reduction	Power station boilers	Existing units: decrease fuel and air to all burners by up to 50% or inactivate some burners. New units: increase furnace size by up to 30%	10 to 25%	Increased soot deposition, more difficult to control steam temp. at reduced load	Decrease in efficiency	Enlarged furnace routine for new units. Not used in industrial boilers	Evaluation of optimum heat release rate
Burner modification	Power station boilers	Control mixing rate to reduce flame temp. Internal recirculation of combustion products	35% in field test on multi-burner furnace	Risk of flame impingement on walls; soot emission possible at low excess air	In association with LEA gives higher efficiency	Included in new unit design; limited retrofit use	Burner development for new units

Source: Reference 53.

for conventional firing methods, unless special consideration is given in the design of fluidised-bed fired boilers of the need to lower NO_x emissions. This could be done, for example, by supplying the bed with less than the theoretical amount of air to burn all the coal, and completing the combustion in an overbed combustion zone with a secondary air supply. Most of the NO_x produced in fluidised combustion of coal is formed by oxidation of the nitrogen-containing compounds in the fuel, and the two-stage combustion process would disfavour the formation of NO_x in the bed from fuel nitrogen. It would also, unfortunately, reduce the efficiency of sulphur retention by limestone in the bed, because oxygen is needed for the formation of calcium sulphate (see Section 2.5.1).

3.2.2 Flue gas treatment

Since combustion modification alone cannot usually reduce emissions to the level required by the US. EPA, and because the close control of combustion conditions necessary is difficult to accomplish when burning coal, attention has turned towards the removal of NO_x from flue gas. Many processes are being developed in USA and Japan; Table 26 lists fifteen wet processes and Table 27 twenty five dry processes according to their stage of development. These tables are based on information supplied in reference 75, which also lists disadvantages of the various processes. The most recurrent disadvantages are, for wet processes, that they require significant amounts of energy for the regeneration step, that they have not been operated continuously for a long period, that they use large amounts of stainless steel or other expensive materials for process equipment, and that they require flue gas reheat. Disadvantages of a large number of the dry processes are that they require previous removal of particulates, and they require an auxiliary heater to control the reaction temperature. Most processes, both wet and dry have the drawback that they have not been tested on coal-fired flue gas.

Principles applied in the various processes include absorption and reduction (AR), oxidation and absorption followed by reduction(OAR), oxidation and absorption (OA), absorption followed by oxidation (AO), radiation (R), selective catalytic reduction (SCR), selective non-catalytic reduction (SNR), adsorption (AD) and nonselective catalytic reduction (NCR).

In AR processes the nitric oxide is absorbed by a water-soluble ferrous-chelating compound after which it is fairly readily reduced by SO_2 which is also absorbed. High liquid to gas ratios are required, and equipment is expensive. OAR processes employ an initial gas phase oxidation stage to convert NO to the more soluble NO_2, after which conventional FGD scrubbers (but not lime or limestone) can be used, in which NO_2-SO_2 reduction-oxidation occurs. The gas phase oxidants (O_3 or ClO_2) are expensive and must be generated on-site, but scrubbing with an oxidant solution such as permanganate or dilute sodium hypochlorite solution(77) has been claimed to be both cheap and effective (AO process). OA processes involve a gas phase oxidation followed by straight absorption without reduction, and are for this reason less relevant to coal combustion gases which usually contain SO_2. The oxidation processes all produce soluble nitrates in the wash liquors, which are difficult to remove and prohibit discharge as a wastewater stream.

TABLE 26

Advantages of wet processes for NO_x removal

Name	Type[(a)]	Remove both NO_x and SO_2	>90% NO_x removal	>95% SO_2 removal	Saleable product				Pilot plant or larger scale tests on coal-firing	Commercial use on oil-firing	Modification of commercial FGD process	No need for prior removal of particulates	Needs partial removal of particulates	No need for gas reheat
					S	H_2SO_4	Gypsum	Other						
Asahi	AR	X		X			X	X[(b)]				X		
Chisso	AR	X		X				X[(c)]				X		
Chiyoda	OAR	X		X			X				X	X		
Ishikawajima	OAR	X					X				X	X		
Kawasaki	OA			X			X		X			X		
Kobe Steel	AO													
Kureha	AR	X		X			X				X	X		
Mitsubishi H.I.	OAR	X		X			X				X	X		
Mitsui Eng.	AR	X		X				X[(d)]				X		
Mon Alkali	AO		X					X[(b)]				X		
Moretana Ca	OAR	X		X							X	X		
Moretana Na	OAR	X		X				X[(b)]			X	X		
Nissan	AO													
Pensys[(e)]	AR	X			X				X			X		
Tokyo Electric	OA		X											

Source: Reference 77.

An X denotes process has this feature.

(a) See text (section 3.2.2) for explanation of abbreviations.
(b) Sodium sulphate (sales potential dubious).
(c) Ammonium sulphate.
(d) Concentrated SO_2.
(e) Pittsburgh Environmental and Energy Systems.

TABLE 27

Advantages of dry processes for NO_x removal

Name	Type[a]	Remove both NO_x and SO_2	>90% NO_x removal	>95% SO_2 removal	Saleable product				Pilot plant or larger scale tests on coal-firing	Commercial use on oil-firing	Modification of commercial FGD process	No need for prior removal of particulates	Needs partial removal of particulates	No need for gas reheat
					S	H_2SO_4	Gypsum	Other						
Ebara-Jaeri	R	X	X											X
Eneron	SCR													
Exxon (thermal)	SNR									X		X		
Foster Wheeler	AD	X		X	X				X					X
Hitachi	SCR		X							X[b]				
Hitachi Zosen	SCR		X							X		X		
JGC Paranox[c]	SCR		X											
Kobe Steel	SCR		X											
Kurabo Knorca	SCR		X										X	
Kureha	SCR		X											X
Mitsubishi H.I.	SCR		X							X				
Mitsubishi K.K.	SCR		X											
Mitsubishi Petro	SCR		X											
Mitsui E & S	SCR		X											
Mitsui Toatsu	SCR		X											
Ralph M. Parsons	NCR	X			X									
Sumitomo Chemical	SCR		X							X				
Sumitomo H.I.	SCR	X		X		X					X			
Sumitomo H.I.	SCR[d]		X											
Takeda	SCR	X	X			X								
Ube	SCR		X											
Unitika	SCR	X	X			X								
Unitika	SCR[d]		X											
U.O.P.[e]	SCR	X	X		X	X				X	X	X		
U.O.P.[e]	SCR[d]		X							X	X	X		

Source: Reference 77.

An X denotes process has this feature.

(a) See text (section 3.2.2) for explanation of abbreviations
(b) Use on coke-oven plant.
(c) Japan Gasoline Company.
(d) Form of process for NO_x removal only.
(e) Universal oil products development of Shell CuO process.

Of the dry processes, SCR is the most tested and advanced. Ammonia gas is used as a reductant, and is injected into the flue gas after the economiser. The resultant mixture is passed over a proprietary base metal catalyst. The product of the reaction is gaseous nitrogen which is discharged from the stack with the flue gas. The catalysts are sensitive to contamination by particulates in the flue gas, and development work to minimise the problems in coal-firing is in progress. A further problem is the formation of ammonium bisulphate downstream from the reactor. This can deposit and cause fouling of the air-heater, or result in a visible plume from the stack. Many SCR processes claim reduction to less than 10 ppm NO_x.

NCR processes involve the injection of a reducing gas into the radiant zone of the boiler to remove excess oxygen and therefore to minimise SO_x and NO_x formation, after which the flue gas containing some SO_2 and NO_x is passed over a catalyst when hydrogen sulphide and nitrogen are formed. The H_2S is removed in a conventional Stretford unit, to produce elemental sulphur as a marketable by-product. Disadvantages are the expense of the reducing gas and the possibility of increased corrosion in the boiler.

In the SNR processes the ammonia is injected directly into the upper part of the boiler to selectively reduce NO_x to nitrogen. It requires a high ammonia to NO_x ratio, operates in a very narrow temperature range, and only gives a low NO_x removal and is not well placed to compete with the other dry processes.

The adsorption processes are based on the use of active carbon, which is regenerated at high temperature to desorb both SO_2 and nitrogen gas which was adsorbed as NO_x. Efficiency of removal of NO_x is not high, and there is a large carbon loss (see Section 2.6.2). The radiation process is somewhat different from all the others; the flue gas is bombarded with an electron beam which converts the particulates, SO_2 and NO_x into a dry powder which is removed in an electrostatic precipitator. Capital investment requirement is high, and SO_2 removal is only about 80%, although NO_x removal is good. A further attraction is that no chemicals are required for the treatment.

Only five processes have reached the commercial stage (Table 28), and experience on flue gas from coal-fired boilers is very scarce. Capital and operating cost can therefore only be roughly estimated; most estimates which have been published are probably optimistic.

3.3 Costs of reducing NO_x emission

None of the costs presented here have been calculated for British location of plant, and should therefore be regarded as rough guides only.

3.3.1 Minimising formation

Estimates of capital costs for two of the proposed combustion modifications and operating costs for one process are shown in Tables 29 and 30. Operating cost estimates are also shown in Table 31, which covers a wider range of modifications but does not refer exclusively to coal firing. Moreover, the way the costs are expressed in Table 31 does not allow easy comparison with the other tables, and it is included

TABLE 28

Current status of NO_x removal processes, November 1977

Stage of development	Size, MW	Number of processes
Commercial	≥ 50	5
Prototype	5 to 50	10
Pilot plant	0.5 to 5	14
Bench scale	<0.5	8
Conceptual	-	4

Source: Reference 77.

TABLE 29

Estimated investment costs for low excess air firing on existing coal-fired boilers needing modifications

Unit Size (Electrical Output) (MW)	Investment Cost ($/kW)
1000	0.67
750	0.71
500	0.77
250	0.90
120	1.02

Source: Reference 53.
March 1979 costs (corrected from estimates for 1974)
U.S.A. location.

TABLE 30

Differential operating costs of OFA on new and existing tangential coal-fired utility boilers (Net heat rate 10.0 MJ/kWh)

1975 costs

	New Plant Without Overfire Air	New Plant With Overfire Air	Recent Existing With added Overfire Air	Older Existing Without Overfire Air	Older Existing With added Overfire Air
Capital Costs $/kw	500.00	500.20	500.70	250.00	250.70
Annual Cap. Cost $	40,000,000[a]	40,016,000	40,056,000	20,000,000[b]	20,056,000
Annual Fuel Cost $	18,000,000[c]	18,000,000	18,000,000	9,000,000[d]	9,000,000
Labor & Maint.[e] $	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000
Total Annual Cost[f] $	66,100,000	66,116,000	66,156,000	37,100,000	37,156,000
Electricity Cost[g] mils/kWhr	24,481	24,487	24,502	13,741	13,762
Increase - %	-	0.024	0.086	-	0.153
Increase - mils/kWhr[f]	-	0.006	0.021	-	0.021

Based on: [a] Annual fixed charge rate of 16% x 500 $/kW x 500,000 kW

[b] 16% x 250 $/kW x 500,000 kW

[c] 0.70 $/$10^6$ Btu coal cost x 5,400 hr/yr x 500,000 kW x 9,500 Btu/kWhr

[d] 0.35 $/10 Btu coal cost x 5,400 hr/yr x 500,000 kW x 9,500 Btu/kWhr

[e] Labor and maintenance cost of 3.0 mils/kWhr

[f] 5,400 hr/yr at 500 MW - 2,700 GWhr/yr

[g] Cost at plant bus bar; transmission and distribution not included

Conversion factor: $1 (1975) ≡ £0.62 (1979)

Source: reference 53

TABLE 31

Costs of NO_x control by combustion modification

(Units of £/Ton NO_2 prevented)			
Control Option \ Firing Rate MW(Th)	2.93	29.3	293
Low excess air (-10%)	1060	175	-175
Staged Combustion (25%)	590	175	60
Flue Gas Recirculation (20%)	1350	530	410
Reduced Air preheat (-100 °F)	970	930	880
Water injection (1 lb/lb)	1470	1295	1175
Ammonia injection (90%)	590	230	220
Reburnering - Low NO_x burners	470-590	265-325	120-175

Source: Reference 79: Converted to March 1979 costs mainly as a guide to the ratios of costs of various methods in various sizes of boiler. Table 30 shows that capital costs are small, very much less than 1% of the total cost of the plant, even for retrofitting on an old plant. This estimate assumes that there will be no adverse effects on plant efficiency, availability or maintenance requirements which, in consideration of the information in Table 25 is a dubious assumption.

3.3.2 NO_x removal by flue gas treatment

Table 32 summarises the development status, NO_x removal efficiency and costs of selective catalytic reduction processes, and Table 33 gives what information there is for other dry removal processes. At about the same time the report was published which presented these estimates, opinions were being expressed that actual installation and operating costs would be much higher. For the Hitachi process, for example, an estimate of £75/kW capital cost and 0.45 p/kWh differential operating costs on a 125 MW coal-fired boiler in the USA was reported(80). These are much higher than indicated in Table 32.

Tables 34 and 35 give similar data for wet absorption-reduction processes and oxidation-absorption-reduction processes respectively. Operating costs for the wet processes, estimated even at this early stage of development when costs tend to be optimistic, are high compared with the dry removal processes and represent nearly 40% of present total generating costs in the U.K. However, it should be pointed out that most of the wet processes remove SO_2 in addition to NO_x, and the dry processes that are suitable for SO_2 removal are considerably more expensive than those that are not (Table 32).

3.4 Probable market penetration of NO_x reduction processes in U.K.

Because of the lack of operating experience, especially on coal-fired boilers, and because of the small benefits likely to result in ambient air quality, it is not considered that the flue gas treatments will prove attractive in the U.K., unless there are unexpected developments in our understanding of the environmental effects of low concentrations of nitrogen oxides. However, if the Wellman Lord process is adopted for flue gas desulphurisation, and if modifications to the process in order to make it suitable for NO_x removal are found to be relatively inexpensive and trouble-free, then it is possible that such a modified Wellman Lord process will be used in the U.K., at least for electricity-generating boilers. At present, it cannot be said that the prospects for this are encouraging.

Combustion modifications, on the other hand, require much less in the way of capital investment, and additional operating costs should be quite small provided there is no loss of thermal efficiency or additional corrosion as a result of the modifications. It is probable that NO_x emissions from power stations could be reduced by up to about 20% for an increase in generation costs of not more than 4%. The increase is larger than suggested in Table 30, because much more complicated and expensive instrumentation would be needed to ensure adequate control of feed to the burners in order to avoid risks of inefficient combustion and corrosion.

TABLE 32

Status and economics of dry selective catalytic reduction

NO_x removal processes

(Japanese location except where noted)

Process	Development status		Removal efficiency %		capital cost £/kW	Reported revenue requirement p/kWh
	Scale	MW equiv.	NO_x	SO_2		
Eneron	Pilot	1.5	65 (oil)	-	7(d)	0.012(d)
Exxon(a)	Bench	0.003	70-95	90-95	-	-
Hitachi	Commercial	170	>90	-	31.0	-
Hitachi Zosen(b)	Commercial	275	>90	-	11	0.10
JGC Paranox	Prototype	23	>95	-	18.5	-
Kobe	Bench	0.3	90	-	8-14.5	0.09-0.12
Kurabo	Prototype	10	>90	-	24	0.10
Kureha	Pilot	1.6	90	-	-	-
Mitsubishi H.I.	Pilot	1.3	90	-	-	-
Mitsubishi K.K.	Pilot	4.7	>90	-	25	0.12
Mitsui E+S	Commercial	67	90	-	7	-
Mitsui Toatsu	Prototype	30	>90	-	34	0.11
Sumitomo Chem	Commercial	100	90	-	75	0.11
Sumitomo H.I.(c)	Bench	0.5	>90	-	21	0.16
Sumitomo H.I.	Pilot	3.3	85-90	95	32	0.41
Takeda	Pilot	3.3	90	80	62	0.045
Ube	Pilot	3.3	90	-	-	-
Unitika(c)	Bench	0.07	>90	-	17	0.15
Unitika	Pilot	1.5	>90	>90	41	0.47
UOP	Prototype	40	>80	90	73(d)	0.28(d)
UOP(c)	Prototype	40	>90	-	17(d)	0.08(d)

(a) Exxon has also studied removal of NO_x only.
(b) Also being studied on a 0.07 MW equivalent coal-fired unit.
(c) Units designed for NO_x removal only.
(d) U.S.A. location

Source: Reference 77; all costs adjusted to March, 1979 values, using appropriate Japanese or U.S. inflation factors.

TABLE 33

Status and economics of other dry NO_x removal processes

Process	Type	Development status		Removal efficiency %		Reported capital cost, £/kW	Reported revenue requirement p/kWh
		Scale	MW equiv.	NO_x	SO_x		
Ralph M. Parsons	NCR	Not tested	-	-	-	17	0.08
Exxon	SNR	Commercial	53	60-70	-	-	0.04-0.09
Foster Wheeler	AD	Prototype	20	40-60	80-95	23-51	0.06-0.13
Ebara JAERI	R	Pilot plant	1.0	90	80	610	-

Source: Reference 77. All U.S.A. location apart from Ebara JAERI (Japanese location)

TABLE 34

Status and economics of absorption - reduction processes

Process	Development status		Removal efficiency %		Reported capital cost, £/kW	Reported revenue requirement p/kWh
	Scale	MW equiv.	NO_x	SO_x		
Asahi Chemical	Bench scale	0.02	80-85 (a)	95+	72	0.42 (d)
Chisso	Bench scale	0.1	70-80 (b)	95+	60	0.40 (e)
Kureha	Pilot plant	1.6	80-85 (b)	95+	37	0.27 (f)
Mitsui	Bench scale	0.05	85	95+	-	-
PENSYS	Pilot plant	1.0	60 (c)	90	71	0.03 (g)

(a) For an inlet NO_x concentration of 150-250 vppm
(b) For an inlet NO_x concentration of 200 vppm
(c) For an inlet NO_x concentration of 400-900 vppm

Source: Reference 77.

(d) 500 MW coal-fired boiler; U.S.A. location
(e) 50 MW oil-fired boiler; Japanese location
(f) 500 MW oil-fired boiler; Japanese location
(g) 100 MW coal-fired boiler; U.S.A. location

TABLE 35

Status and economics of oxidation - absorption-reduction processes

Process	Development status		Removal efficiency, %		capital cost, £/kW	Reported revenue requirement, p/kWh
	Scale	MW equiv.	NO_x	SO_x		
Chiyoda Thoroughbred 102	Bench scale	0.3	80(a)	95	61	0.38(e)
I.H.H.I.(b)	Pilot plant	1.6	80(c)	90+	51	0.41(f)
Mitsubishi H.I.	Pilot plant	0.6	80-90(a)	95+	-	-
Moretana Calcium	Prototype	8.3	90(d)	95+	-	-
Moretana Sodium	Prototype	10-40	90(d)	95+	82	0.55(g)

(a) For an inlet NO_x concentration of 150 vpm.

(b) Ishikawajima - Harima Heavy Industries.

(c) For an inlet NO_x concentration of 180 vpm.

(d) For an inlet NO_x concentration of 200 vpm.

(e) 250 MW oil-fired boiler; Japanese location. Costs include ozone generator.

(f) 167 MW oil-fired boiler; Japanese location.

(g) 30 MW oil-fired boiler; Japanese location.

Source: Reference 77.

3.5 Projected emissions of NO_x up till the year 2000

Table 36 shows the anticipated NO_x emissions, total, integrated, capital costs, and annual operating costs (including charges on capital, and maintenance at an estimated annual 20% of capital costs). The figures in Table 36 are based on the following assumptions:

(i) There is no technology which is likely to become available for the reduction of low-level emissions.

(ii) The adoption of fluidised bed firing for industrial boilers and other furnaces will not make any significant change in NO_x emission factors.

(iii) High level emissions can be reduced by 20% by appropriate measures at existing and new coal-fired power stations between 1980 and 1990. These measures are most likely to be the staged introduction of combustion air, flue gas recirculation and/or low excess air.

TABLE 36

Probable NO_x emissions from coal combustion and costs of control measures

(Combustion modification)

	1980	1985	1990	2000
High-level sources[a]	442	452	397	388
Medium-level sources[a]	70	70	110	230
Low-level sources[a]	7	6	6	6
Capital cost, £ million[b]	0	28	55	55
Extra annual costs, p/kWh[c]	0	0.0028	0.0056	0.0056

(a) Thousands of tonnes per annum.
(b) Between 1980 and the year referred to, at March, 1979 values.
(c) Includes capital charges and maintenance costs estimated together as 20% annually of capital cost- March, 1979 values. Per kWh total electricity generated from coal.

4. Suspended particulate matter

4.1 Present position

Standards for the removal of particulate matter are constantly being improved, resulting in progressively lower rates of emission per unit of heat input as coal. In the domestic sector, most of the particulates emitted take the form of soot or tar fog, due to incomplete combustion of the volatile matter from the coal. In smokeless zones, the combustion of bituminous coal is not permitted except in appliances specially designed to avoid smoke emission such as the NCB "Smoke-eater", and permitted fuels must, on test, not generate more than 5 grams per hour at a normal burning rate (usually about 1 kg/hour).

As the number of smokeless zones in the country grows, total emissions from domestic fires may be expected to go on decreasing. It was mentioned in section 2.2.2 that the ground level concentration of smoke in urban areas of the U.K. fell by 75% between 1960 and 1975, due mainly to the introduction of smokeless zones.

The second class of emitters of particulate matter is the industrial sector. Coal fired appliances here fall into two main groups, first appliances such as boilers where coal is the sole source of particulates, and second special furnaces and kilns where the charge being heated contributes to the emissions. The present emission standards for boilers were set by the Clean Air Act of 1968 and subsequent legislation, particularly the Clean Air (Emission of Grit and Dust from Furnaces) Regulations 1971 (Statutory Instrument 1971 No. 162). The gist of these laws was outlined in Part 1 of this study(1). A Working Party has since then considered the position regarding furnaces where the charge contributes to the emission,(81) and legislation is expected to be based on the recommendations of the working party, but has not yet been introduced. Many of the coal-fired appliances of this type are at works which come under the surveillance of the Alkali Inspectorate, and rates of particulate emission are then limited to a level which is agreed with the local Alkali Inspector. For cement kilns for example, the agreement states that in older kilns (installed before 1975), for outputs up to 1500 tonnes per day the emission shall not exceed 460 mg/Nm^3; for outputs above 3000 tonnes per day the emission shall not exceed 230 mg/Nm^3; and between 1500 and 3000 tonnes per day the emission shall fall on a sliding scale in proportion to output. New kilns installed since 1975 must all conform to a limit of 230 mg/Nm^3 regardless of output, and a recent agreement (which has not yet been confirmed) will reduce this limit still further, to 100 mg/Nm^3. While it is obvious that in the case of cement manufacture, the fuel contributes very little to the emissions, this represents a good example of the way in which consultation between the Alkali Inspectorate and manufacturers results in a progressive improvement in pollution control.

A similar form of agreement applies to the emissions from U.K. power stations, and the level of particulate concentrations currently agreed with the Alkali Inspectorate for new plant is 115 mg/Nm^3, representing about 99.3% efficiency for combustion of a 16% ash coal for which 15% of the ash is retained in the furnace. Current specifications now design for 99.5% efficiency in order to ensure that long-term average emissions do not exceed the agreed level.

4.2 Possibilities for future reductions of particulate emissions

Each fresh reduction in stack gas concentration of particulates is more difficult and more expensive to make than the last, when the same physical principle of removal is being applied. Occasionally, however, development of a fundamentally new concept of dust-removal will result in a large improvement for relatively small additional expense. Such "breakthroughs" are rare, on the whole, and although various improved devices are currently being tested, especially in the USA(82-85) it is too early yet to say whether one of them will provide such a breakthrough. The figures given in this section are only speculative, and are based upon an extrapolation of past trends in combination with a recognition of physical barriers and the law of dimishing returns.

4.2.1 Low-level sources

"Smokeless zones", i.e. areas covered by Smoke Control Orders, have been introduced progressively in the U.K. since the late 1950 s. 212,000 extra premises were brought into smokeless zones in 1977/78, and approximately 40% of all homes (50% of all homes in urban areas) are now affected by Smoke Control Orders. For the purposes of this study, it is assumed that 50,000 households burning coal non-smokelessly will convert to smokeless operation each year between now and the end of the century. Using the emission factors given in section 4.4.3 of Part 1 of this study, a reduction of 0.0325 tonne of particulates is predicted for each tonne of coal burnt, on going "smokeless". The resultant reductions in particulate emissions (which are only speculative), are shown in Table 37. The reductions are dependent on positive action being maintained in the form of subsidies for conversion to the smokeless use of solid fuels.

4.2.2 Medium-level sources

Any boiler or furnace which is fired with coal, and which utilises fans for supplying forced draught or induced draught will produce gas velocities in the bed which are great enough to entrain small particles of coal and ash. The gas velocities in a fluidised-bed are not greatly in excess of the average velocities in a fixed bed; in fact local gas velocities in parts of a fixed bed are probably well in excess of those in most fluidised beds. In conventionally fired boilers, especially of the travelling grate type, the free moisture content of the coal (up to 12%)(86) helps to prevent the particles being blown out of the bed before the ignition plane reaches them. Sprinkler stokers, in which the coal is thrown on to the surface of the bed tend to result in high solids entrainment if used for firing a 'smalls' coal.

The cyclone, or multicylcone is at present the most popular form of gas cleaner for use with industrial boilers. For large boiler plants, an electrostatic precipitator or bag-filter house may be economically justifiable, and either of these will give a much more efficient removal of particulates. For small plants, the most important considerations are low capital cost and low pressure drop. Wet scrubbers are sometimes used, particularly where the scrubbed gases can be mixed with a stream of clean, hot gas from other parts of the process before discharge to atmosphere, but corrosion and/or erosion can lead to high maintenance costs.

TABLE 37

Projected emissions of particulates from the use of coal in the U.K. allowing for improvements in gas cleaning techniques

(Emissions in thousands of tonnes per annum)

Year	1980	1985	1990	2000
Particulates from high-level sources (a)	74+	84+	83	64
Particulates from high-level sources (b)	74+	73	62	48
Particulates from medium-level sources	35	30	33	54
Particulates from low-level sources	205	149	127	87
Total (a)	314+	263+	243	205
Total (b)	314+	252+	222	189

(a) Assuming 16% ash in coal supplied for power generation.

(b) Assuming only 12% ash in coal supplied for power generation from 1990 onward. 12% ash in 50% of coal supplied in 1985.

If all boiler plants larger than 1 MW (Th) were obliged to install single-stage electrostatic precipitators or bag filters, particulate emissions from medium-level sources could be reduced by between 50% and 75% at a capital cost of the order of £16 per tonne per annum capacity converted.

New processes which might possibly provide a more attractive form of particulate removal for small plants, but which are not yet commercial propositions are the gravel-bed filter(87) and the centrifugal dust collector(88), because these have prospects of meeting the requirements outlined above for use on small plants. While it is not yet possible to estimate costs, there are good prospects that they should both be less than electrostatic precipitators or bag-houses.

4.2.3 High-level sources

The most usual method of particulate removal practiced by the U.K. electricity industry is electrostatic precipitation. A large, modern power station will typically have two or more parallel systems each of three-stage electrostatic precipitators. At any time, the total volume flow of flue gas can be handled by one fewer than the number of installed systems, allowing maintenance to be carried out on one system at a time.

There are various newly-developed types of particulate-removal device which are claimed to have a higher removal efficiency than the electrostatic precipitators currently used. The CEGB is carrying out a technical appraisal of these, and is doing experimental studies of some of them. Those in particular which show some promise are : bag filters; a low-turbulence, high-efficiency electrostatic precipitator, which could be installed in place of the third stage in existing plants; the "Foamator" wet gas scrubber, which utilises a filter medium of foam; and the ionising wet scrubber.

If a wet SO_2 - removal process, such as the Wellman Lord process, is adopted at power stations in the future, this will probably be installed after the normal electrostatic precipitators, and will therefore contribute an additional particulate removal stage. However, the efficiecny of this in respect of that size of particles which is most difficult to remove (i.e. 0.2 to 2 μm), is not expected to be high, and therefore any reduction in particulate emissions from this cause is likely to be marginal.

It is assumed therefore, for the purposes of estimating particulate emissions from high-level sources up to the end of the century, that the steady technological progress in particulate removal will be maintained, resulting in a gas-cleaning efficiency of 99.3% at all stations by the year 1990 and of 99.5% in 75% of generating capacity by the year 2000. There are no firm grounds for this assumption, but it is reasonable to assume that a steady improvement in standards of particulate removal will be sustained and will result in further reductions in particle emissions.

4.3 Probable effect of application of new technology on particulate emissions

There are two classes of new technology which have to be considered here : new developments in the removal of particulates from combustion gases, and new modes of combustion. The position with regard to the first of these has been discussed in section 4.2, but it is necessary to consider also the impact that new methods of coal combustion used by industry might have on particulate emissions to the atmosphere.

Two modes of use are of particular interest ; fluidised bed combustion and gasification. The latter might be performed in small gasifiers operated on site by individual factories, or it might be done in centralised gasification plants such as those operated by the Area Gas Boards in the U.K. In the latter case, it would be possible to estimate a maximum price level for gas that would be attractive to users, by considering the costs of a gas-fired boiler in relation to those of a coal-fired boiler equipped for pollution control.

4.3.1. Industrial boilers and Fluidised-bed combustion

In most fluidised-bed fired industrial boilers, the fuel is likely to be a washed graded coal or a washed 'smalls', fed above the bed. Unlike the sprinkler or spreader stoker, it is not necessary to distribute the fuel uniformly over the bed surface, and entrainment of fine particles is therefore less serious than with these appliances. Nevertheless, the coal entering the bed is rapidly dispersed and dried, and there is therefore ample opportunity for fine particles to be elutriated from the bed before they have been burnt. Combustion of these particles continues in the freeboard and many of them burn away to ash before leaving the hot zone. A specially designed baffle is usually placed in the freeboard zone to create patterns of gas flow which assist the return of the larger particles to the bed.

The concentration of particles in the flue gas entering the primary gas cleaner in a fluidised-bed fired boiler will depend on the proportion of the coal feed which consists of particles small enough to be elutriated, plus the small particles that are formed in the bed by the processes of rapid heating, combustion, and mechanical attrition. The initial fines content, and the number of small particles produced by the burning away of larger particles are both dependent on the size distribution of the coal feed, and are a minimum for a graded coal, which contains nominally no fines. These two sources of fines are a maximum for a crushed coal, such as is suitable for pneumatic feeding into the bed.

Typical top sizes of particles elutriated from fluidised-bed coal combustors, and reaching the primary gas cleaner are as follows :

Fluidising velocity,m/s	Top size of particles elutriated µm
0.5	250
1.0	370
1.5	470
2.0	540
2.5	600

It cannot be assumed that all particles smaller than the critical size for elutriation will be elutriated immediately the coal enters the combustor. Experience has shown that a proportion of them remains in the bed long enough for devolatilisation and partial combustion of the residual char to occur.

Because the particles elutriated from the bed contain some unburnt carbon, some of the collected particulate material may be refired to the bed, and if this is done, rates of solid particles entering the cyclone may be much greater than would be calculated from the coal ash content of elutriable size, because ash particles may pass through the bed more than once.

The consequence of these various factors is that the cost of gas cleaning to meet existing U.K. legislation on the emission of particulates is likely to be somewhat higher than would be required on a travelling grate-fired boiler of equal rating, unless a graded coal were used to fire the fluidised-bed boiler.

4.3.2 Gasification

Gasification of coal for distribution via the national gas grid has been discussed in section 2.4, and little need be said here other than to state that a properly adjusted boiler, when fired on SNG, will generate no airborne particulates, and no form of gas cleaning is required. The capital cost of the boiler will be lower for this reason, and also because the expensive solids handling machinery for coal (and possibly limestone) and bed removal will not be needed, and storage bunkers and supply hoppers will also be unnecessary. On the other hand, some gas storage capacity may be beneficial, to accommodate fluctuation in demand. Operating costs will be reduced by up to one man per shift, who would on a solid fuel fired boiler be needed to look after the coal and solids handling machinery, to ensure delivery of coal from stock to the boiler, and to check that the gas cleaners were emptying properly. Maintenance costs of solids handling machinery tend to be high, and therefore maintenance of a gas-fired boiler would be very much cheaper than that of a coal-fired boiler.

4.4 Summary of prospects for particulate emissions

Based on the considerations outlined in the above sub-sections, the probable emissions of particulate matter from high-, medium- and low level sources are shown in Table 37. The plus signs in columns 2 and 3 of the table denote that not all of the plant at present operated by the U.K. electricity supply industry is equipped to meet the current agreed levels for new plant. This old plant, mostly built before 1958, is expected to go out of service in the next few years. The reference to reduced ash in coal (case b) covers the possibility of more thorough coal cleaning to reduce the sulphur content (see Section 2.3.2).

The estimates of medium-level emissions represent a 'middle-of-the-road' policy, in which factories which are the largest individual coal users (representing 50% of total industrial coal use) are assumed to install more expensive gas cleaning equipment, while the smaller users are exempted.

No information is available concerning the probable capital and operating costs of the improvements shown in Table 37.

5. Trace elements

In addition to the chief elements comprising the combustible "coal" matter, namely carbon, hydrogen, oxygen, nitrogen and sulphur, coal as mined and as delivered to coal users contains a very wide range of elements present in very wide ranges of concentration(89). The majority of these elements are metals but there are also non-metallic elements such as chlorine, silicon, phosphorus, fluorine, bromine, iodine, arsenic, boron, selenium and tellurium. It has been shown(90) that in general, coal ashes, fly ashes, shale and soils have similar contents of several trace elements, and therefore it is to be expected that the dispersal of coal ash in the environment is not likely to have harmful effects. Selenium is reportedly enriched in coals(91).

The trace and minor elements in coal are usually associated either with sulphur, as sulphides, with the aluminosilicate material, or are present as carbonates. In the sulphide group are iron, zinc, cadmium, mercury, copper, lead, arsenic and antimony (selenium is usually also associated with the sulphide minerals). The aluminosilicate group contains titanium, potassium, sodium, zirconium, beryllium and yttrium amongst many others; and the carbonate group includes magnesium, iron and manganese. Some elements, e.g. calcium and magnesium occur in more than one group, while a few elements are present in significant amounts in the form of inherent mineral matter, i.e. derived from compounds of these elements which were present in the plants from which the coal was formed. They are disseminated throughout the coal and may still be chemically bonded to the organic coal structure. These elements include beryllium, gallium, germanium, vanadium, titanium and boron.

5.1 Emissions from high-level sources

Since 1973 studies of the particulates collected by and escaping electrostatic precipitators in power station boilers have shown quite clearly that some elements are present in the very small particles in concentrations very much greater than is found in the "bottom ash", i.e. the large ash particles which fall to the bottom of the furnace. It is found that the smaller the particles, the higher is the concentration of these elements, which include arsenic, cadmium, copper, gallium, molybdenum, lead, thallium, antimony and selenium(92,93). More recently it has been shown that boron can be added to this list(94). The extent of enrichment is usually denoted by an "enrichment factor", defined as the ratio of the concentration of the element to the concentration of aluminium in the dust sample, divided by the corresponding ratio in the original coal.

Some elements are present in the flue gas exclusively, or partly, as gaseous elements or compounds. Those that are evolved almost completely as gases in the chimney are chlorine, as HCl, bromine, as HBr, and mercury, as the element. Other elements that occur partly as vapour are selenium and iodine.

The enrichment of certain elements in the fine particles is almost certainly the result of volatilisation of the element or one of its compounds at the flame temperature, followed by condensation (which occurs preferentially on solid surfaces) as the gases are cooled. Elements which do not volatilise at the flame temperature do not show this enrichment on small particles, and they include Al, Ba, Ca, Ce, Co, Eu, Fe, Hf, K, La, Mg, Mn, Rb, Sc, Si, Sm, Sr, Ta, Th, Ti, Zr and the rare earths. Another group of elements shows erratic behaviour, sometimes enriched on small particles but in other cases showing no enrichment. This group includes Cr, Cs, Na, Ni, U, V and Zn(93,95).

This selective enrichment is important, because even if concentrations of toxic elements in the undifferentiated coal ash are sufficiently low not to represent a toxic hazard, their concentrations in the very finest fly ash particles may be for some elements, e.g. arsenic and selenium, up to fifty times as great, although for average stack particles it is considerably less than this. Also contributing to some anxiety about these elements is the fact that the particles containing the high concentrations are of a size to be absorbed into the body through the lungs.

It is believed that the electrostatic precipitators used in present day power stations are able to remove about 97% of particles in the range 0.2 to 2 µm, and the tall stack policy ensures a wide dispersal of the remaining 3% with very low ground-level concentrations. Of the 115 mg/m^3 maximum dust loading in the stack gases, only 17 mg is of respirable size (smaller than 5 µm), and about 45 mg is below 10 µm in size.

5.1.1 Estimation of ground level concentrations

Arsenic is one of the elements which appears to represent a risk to health from this combination of concentration enrichment and relatively low collection efficiency for fine particles, and therefore it is useful to try to calculate the ground level concentrations which are likely to result from burning a coal of arsenic content in the upper part of the range encountered in British coalfields, i.e. 40 ppm (Table 7 in reference 1). The range of enrichment factors quoted by various workers for particles of the size range found in stack gases is 3 to 14, with an average of 7.7(93–97). For a coal of ash content 16%, and 15% ash retention in the boiler, the fly-ash flow into the electrostatic precipitator per kg of coal fired to the boiler is 0.16 x 0.85, or 0.136 kg. Assuming a precipitator collection efficiency of 99.3%, the emission of particulates from the stack is 0.00095 kg per kg of coal fired. Without any enrichment, the concentration of arsenic in the ash would be 40/0.16 or 250 ppm, and allowing for 7.7-fold enrichment, the concentration would be 1925 ppm of arsenic. Hence, 1 kg of coal fired gives rise to 0.00095 x 1925 mg or 1.83 mg of arsenic contained in the solids borne out of the top of the chimney. The volume of dry flue gas resulting from the combustion of 1 kg of coal at 20% excess air is approximately 8.5 Nm^3, so that the concentration of arsenic in the (dry) gas emerging from the chimney is 0.215 mg/Nm^3.

It was shown in section 2.2.1 that maximum daily g.l.c.'s are lower than stack gas concentrations by a factor of 34,000 and annual g.l.c.'s by a factor of 285,000. Therefore it can be deduced that the highest contribution to daily g.l.c. of arsenic which is likely to be experienced when burning a high-arsenic coal is 0.0063 µg/m^3, and the maximum contribution to annual average g.l.c. will not exceed 0.75 ng/m^3. These figures are for a high-arsenic coal (40 ppm). The national average arsenic content is 18 ppm, and the concentration of arsenic in stack solids corresponding to this would be 865 ppm, with maximum contributions to daily and annual average g.l.c.'s of respectively 0.0028 µg/m^3 and 0.34 ng/m^3. Actual measurements on and in the vicinity of U.K. power stations show that these estimates are in excess of actual concentrations, because the concentration of arsenic in stack solids is found to range from 174 to 680 ppm, and the average contribution to g.l.c. is 0.12 ng/m^3. For comparison, measured values for arsenic in air at 133 locations in the USA are up to 0.8 µg/m^3, with an average daily concentration of 0.02 µg/m^3 (97).

The American Conference of Governmental Industrial Hygienists (ACGIH) Threshold Limit Values(98) (TLV) provide an indication of the relative toxicities of various substances when present in the form of airborne particulate matter. The Health and Safety Executive have formulated a guidance principal that for continuous exposure of people outside a place of work, the average concentration of the pollutant should not exceed one thirtieth (1/30) of the TLV expressed as time-weighted average for a normal 40-hour work-week. The CEGB state that they have adopted the criterion of 1/80 of the TLV as a safe environmental level.

The TLV currently proposed for a trial 2-year operation for arsenic as As_2O_3 is 0.05 mg/m^3 (as As). One eightieth of this is 0.675 μg/m^3, which is approximately a hundred times the maximum daily g.l.c. (calculated above) expected to result from burning a high-arsenic U.K. coal in a modern power station.

Similar calculations can be performed for the other elements for which data are given in Part 1 of this study. The results of these calculations are summarised in Table 38, which also gives the acceptable concentrations, based on 1/80 of the TLV. For all the elements considered except fluorine, the maximum daily average is less than one percent of the acceptable level. The fluorine concentrations may be greatly over-estimated because no allowance has been made for any fluorine in particles removed by the electrostatic precipitators. It is therefore concluded that trace element emissions from the combustion of coal in U.K. power station chimneys do not give cause for concern by this mode of introduction into the human body. It has to be noted that coal-firing is not the only contributor to environmental trace elements: oil combustion, combustion of leaded petrol in internal combustion engines, and the operations of smelting works are other major contributors, while lead in drinking water is a problem in some areas which have soft water in contact with lead pipes.

5.1.2 The wet deposition of trace elements

In section 5.1.1 only one route of introduction to the human body was considered, i.e. the lungs. It is possible that deposition of trace elements from coal combustion may occur close to the source in rainfall ('rain-out'), and that this may result in unacceptably high concentrations of these elements in the soil.

Rainfall is known to be a much more rapid means of removing gaseous and particulate pollutants from an airmass than is dry deposition. This is because the rain falls to the ground much more quickly than turbulent diffusion can bring the pollutants into contact with the ground. Soluble gases, such as sulphur dioxide are removed more efficiently than particles in the size range 0.2 to 2 μm. This is because the rate of gas diffusion to the water droplet is much more rapid than the rate of movement of a fine particle towards the surface of the droplet. The falling rain-drop displaces air as it falls, and the pollutant particles are moved away from the trajectory of the raindrop by these air currents. The collection efficiency for a 2 μm particle has been estimated to be less than 5% in a gravity spray tower(99). The knowledge available is insufficient to estimate how much of the particulate matter in a chimney plume is actually removed by rain of a given intensity and droplet size distribution, but such evidence as there is suggests that it will not be so rapid that complete removal will occur within a few miles of the chimney.

TABLE 38

Estimated maximum ground-level concentrations of trace elements resulting from coal combustion in U.K. power stations

Element[a]	Enrichment factor:[b] Average (Range)	Concentration, ng/m^3 of air[c]				
		Maximum daily g.l.c.		Maximum yearly g.l.c.		1/80 of TLV[d]
		Average coal	High-value coal	Average coal	High-value coal	
Arsenic	7.7 (3-14)	2.8	6.3	0.34	0.75	625
Cadmium	15	0.12	0.18	0.015	0.022	625
Mercury	(e)	2.1	2.5	0.25	0.30	625
Lead	8.3 (4-20)	6.5	10.2	0.77	1.2	1875
Vanadium	3.2 (0.75-6)	5.0	8.8	0.60	1.05	625[f]
Fluorine	(e)	395	450	47	54	3125

Notes

(a) Present either as the element, the oxide, or other stable compound.

(b) From references 93-97.

(c) Weight in ng of the element (not weight of its compounds) in 1 m^3 of air at 273 K and 1.012 bar.

(d) Threshold Limit Value (reference 98).

(e) It is assumed that all the mercury and fluorine in the coal appears in the stack gas, either as vapour or in suspended particles. If a significant proportion occurs in particles the emission will be overestimated here because no allowance is made for removal of particles in the electrostatic precipitators.

(f) Value for V_2O_5 fume.

The rate of wet deposition will be much faster when the chimney plume enters a cloud where condensation of water vapour is occurring. In these circumstances the particle can provide a nucleus for condensation, and the droplet, incorporating the particle, grows rapidly and links with other droplets to form a rain drop.

For a very rough calculation of the amounts of trace elements deposited by wet deposition near to a 2000 MW power station on 65% load factor the following assumptions have been made :

(i) The coal contains maximum coal field averages of each element.

(ii) Rain falls during one tenth of each year.

(iii) Rain results in deposition of all suspended particulates within 20 km of the chimney, concentrated in a semicircle on the lee-side of the chimney according to the prevailing wind.

(iv) Deposition rate is taken to be insignificant if the deposition in one year is less than 1% of the quantity of the element in the top 0.25 m of soil, using average soil concentrations of the element.

Results of the calculation are shown in Table 39, and it is seen that only mercury has a significant deposition rate. This assumes however that the mercury vapour is sufficiently soluble in rainwater to be washed out close to the source. Some indication that this may not be the case is offered by a study of seventy soil samples taken in the area surrounding a large power station in the USA(103). Although the plant had short stacks (less than 100 m), the mercury emitted by several years of combustion of coal containing 0.1 to 0.4 ppm of mercury showed no signs of accumulation in the soil around the plant.

5.2 Emissions from medium- and low-level sources

Since medium-level sources are mainly subject to the regulations referred to as "tall-stack policy", the general picture in regard to the behaviour of trace elements liberated by coal combustion is similar to that for power stations. There are two differences: because the combustion temperature is probably somewhat lower than in a large pulverised-coal fired boiler, volatilisation of certain elements will be less and therefore the enrichment factors for these elements on fine ash particles are less. Against this is the second difference, namely that these smaller plants are usually equipped with less efficient particulate removal devices, and they therefore emit more particulates per tonne of coal fired.

Very little ash is discharged through the chimney in low-level sources (domestic fires), because these appliances operate on unassisted draught. The particulates consist largely of soot and incompletely burnt hydrocarbons, and their main threat to health is from their possible content of polynuclear aromatic hydrocarbons, and as a vehicle for conveying adsorbed pollutants deep into the lungs. Some of the more volatile elements in coal might be expected to volatilise in the combustion zone, later to condense on the chimney wall or on soot or smoke particles in the flue gas, but no practical investigations have been reported to confirm or refute this possibility.

TABLE 39

Approximate estimate of the wet deposition of trace elements from coal combustion in a 2000 MW U.K. coal-fired power station

(For highest coalfield-average content of each element)

Element	Deposition rate, mg/m^2 year	Average soil concentration ug/g	Weight of element in top 0.25m of soil mg/m^2	column 2 ÷ column 4
Arsenic	1.4	5 (a)	1635	0.0009
Cadmium	0.04	0.55 (b)	180	0.0002
Mercury	0.46	0.008 (b)	2.6	0.18
Lead	2.3	12 (b)	3925	0.0006
Vanadium	2.0	40 (b)	13,000	0.00015
Fluorine	88	650 (c)	212,550	0.0004

(a) Ref.100; crustal concentration (average concentration in earth's crust)

(b) Ref.101.

(c) Ref.102 , crustal concentration, soil concentrations vary very widely.

5.3 Effect of new technological developments on trace element emissions

There are three developments to be considered here : more thorough coal washing, improved particulate removal from flue gases, and the adoption of fluidised combustion techniques.

5.3.1 Improvements in coal washing

The trace elements in coal show different affinities. Some tend to be associated more with the coal substance than with the mineral impurities, and in this class are germanium, beryllium and boron. Other elements, including mercury, zirconium, zinc, arsenic, cadmium, lead, manganese and molybdenum, are generally inorganically combined in the coal: while phosphorus, gallium, tin, titanium and vanadium are associated largely with the organic constituents and to a lesser extent with the inorganic constituents, and cobalt, nickel, selenium, chromium and copper are mainly associated with the inorganic constituents but also to a lesser extent with the organics(104).

When the mineral matter is reduced by coal washing the elements which tend to inorganic affinities are removed in preference to those with organic affinities. Tables 40 to 43 show how mercury, fluorine, chromium, copper, nickel, manganese, lead and cadmium were distributed in different density fractions in some U.S. coals(105). While it is obvious that the results obtained for a few U.S. coals cannot be applied directly to predict what would be the total effect for all British coals, it is reasonable to draw the general conclusion that washing at S.G. of 1.60 probably removes between 25% and 50% of the mercury, chromium, copper, nickel, manganese and lead content of the coal, provided the coal is crushed to a top-size of 1170 µm. For a larger top-size, removal would be less. Washing at a specific gravity separation of 1.40 would give a still greater removal of the heavy metals, but would result in a high loss of combustible matter also.

5.3.2 Improved particulate removal

The prospects for future improvements in standards of flue gas cleaning were discussed in section 4. In the case of high-level sources, many of the particles emitted are very fine, and in the size range showing the largest enrichment factor. The postulated future improvement in particulate removal efficiency from 99.3% to 99.5% will therefore bring about a significant reduction in trace elements emission from the stacks.

For medium-level souces, any future reduction in emissions is likely to be of medium-sized particles rather than very fine ones. The particles removed will be those having lower enrichment factors than those still escaping from the stack, and therefore the reduction in trace element emissions from medium-level sources will not be in proportion to the improvement in gas cleaning efficiency. Instead of a 30% estimated reduction in 2000 (Table 37), the reduction in the emission of trace elements with high enrichment factors might be only 10 to 15%.

Low-level emissions of trace elements from coal combustion are probably already insignificant in total quantity, as explained above in section 5.2 and there is little scope for further reduction.

TABLE 40

Partition of mercury in four density fractions of three U.S. coals (-1170 µm particles)

S.G. fraction	Coal A		Coal B		Coal C	
	% Weight	Hg conc. µg/g	% Weight	Hg conc. µg/g	% Weight	Hg conc. µg/g
Head coal	100	0.28 ± .02	100	0.13	100	0.26
Float 1.30	37.6	0.08 ± .02	42.6	0.09 ± .03	20	0.16
1.30 - 1.40	36.7	0.16 ± .03	36.3	0.08 ± .03	28.1	0.23
1.40 - 1.60	10.3	0.56 ± .06	13.7	0.15 ± .03	24.8	0.19
Sink 1.60	15.4	1.13 ± .03	7.4	0.59 ± .05	27.1	0.43

Reductions in mercury concentration on removing 1.60 sinks :

Coal A : 47%; Coal B : 28%; Coal C : 24%

Reductions in sulphur concentration on removing 1.60 sinks :

Coal A : 42%; Coal B : 42%; Coal C : 23%

Source : reference 105.

TABLE 41

Partition of fluorine in four density fractions of three U.S. coals (-1170 µm particles)

S.G. fraction	Coal C		Coal D		Coal E	
	% Weight	F.conc.µg/g	% Weight	F conc.µg/g.	% Weight	F conc.µg/g
Head coal	100	137	100	100	100	71
Float 1.30	20.1	30	20.5	65	30.6	8
1.30 - 1.40	30.3	56	30.3	85	34.0	44
1.40 - 1.60	24.0	123	22.0	114	18.9	123
Sink 1.60	25.6	270	27.2	110	16.5	155

Reductions in fluorine concentration on removal of 1.60 sinks :

Coal C : 42%; Coal D : 6%; Coal E : 31%

Reductions in sulphur concentration on removal of 1.60 sinks :

Coal C : 23%; Coal D : 50%; Coal E : -7%

Source : reference 105.

TABLE 42

Partition of chromium, copper, nickel and manganese in density fractions of -1170 μm particles of one U.S. coal (Coal A).

S.G. fraction	% Weight	Conc. of metal, μg/g			
		Cr	Cu	Ni	Mn
Head coal	100	27	16	16	13
Float 1.30	37.6	13	7.0	8.1	2.5
1.30-1.40	36.7	23	8.8	9.2	6.5
1.40-1.60	10.3	34	24	26	23
Sink 1.60	15.4	73	58	38	51

Reductions in concentration on removal of 1.60 sinks :

Chromium	:	29%
Copper	:	43%
Nickel	:	28%
Manganese	:	50%
Sulphur	:	42%

Source : reference 105

TABLE 43

Partition of chromium, copper, nickel, manganese, cadmium and lead in density fractions of -1170 μm particles of a U.S.coal (Coal F)

S.G. fraction	% Weight	Conc. of metal, μg/g					
		Cr	Cu	Ni	Mn	Cd	Pb
Head coal	100	26	28	18	263	0.12	14
Float 1.30	51.0	6	13	10	30	0.08	4
1.30-1.40	16.9	11	26	15	89	0.20	10
1.40-1.60	9.2	33	55	28	240	0.24	25
Sink 1.60	22.9	73	66	38	967	0.10	40

Reductions in concentration on removal of 1.60 sinks :

Chromium	:	56%
Copper	:	29%
Nickel	:	30%
Manganese	:	75%
Cadmium	:	0%
Lead	:	56%
Sulphur	:	18%

Source : reference 105

5.3.3 Fluidised-bed combustion

The combustion temperature in fluidised beds is lower than in pulverised-coal fired boilers and most other conventional types of combustor. Usual combustion temperatures are 800 to 900°C in fluidised beds, compared with 1600 to 1700°C in a pulverised coal furnace. This fact would be expected to reduce the volatilisation of trace elements, and therefore to lower their emission rates. Against the lower temperature however is the fact that the burning coal particles have a longer residence time at a high temperature in a fluidised bed, allowing more time for volatilisation to occur. Any elements which do not form volatile compounds, or are not themselves volatile at temperatures below 1000°C would not be expected to exhibit enrichment in the fine fly ash particles, even if they do in a pulverised-coal fired boiler.

When limestone or dolomite is added for sulphur retention, any trace elements contained in this absorbent may also be volatilised, and contribute to the enrichment of the fine particles. Also, the removal of sulphur from the gas phase may affect the volatility of some elements. A theoretical appraisal of the behaviour of four trace elements : lead, beryllium, mercury and fluorine has been reported by workers of Westinghouse Research and Development Centre, Pittsburgh(106). Preliminary experimental results which generally confirm the theoretical predictions are also reported. Some measurements have also been made on a 0.56 m^2 bed area combustor operating at a pressure of about 6 bars, in England,(107) and others on a bench-scale combustor by Argonne National Laboratories.

The most stable volatile forms at 1200 K of the four elements studied in the Westinghouse work are hydrogen fluoride, beryllium hydroxide, mercury and lead tetrachloride. At atmospheric pressure, lead dichloride is also fairly stable, and this (but not the tetrachloride) is expected to condense as the gases are cooled. The presence of significant amounts of gaseous lead was noted in the U.K. work, but there was also appreciable enrichment of lead in the fine particles. In the case of a low-chlorine coal, lead monoxide, PbO is expected to be the predominant lead compound. This is just volatile at atmospheric pressure, but only slightly volatile at elevated pressure. In the Argonne work, however, which was on a pressurised system, almost complete retention of lead in the solid particles was found, and there was no enrichment on the finer fly ash particles. This result is in direct contradiction to the U.K. results, and it must be concluded that the small scale operation, or some other factor such as chlorine content resulted in different behaviour in the Argonne combustor.

There were tendencies for slight enrichment of barium, cobalt, lanthanum, antimony, scandium and tantalum on fine particles in the Argonne work, amounting to a ratio of between 1.5 and 2.0 between concentrations on a back-up filter and in primary cyclone fines.

The results obtained from the U.K. pressurised combustion, using dolomite addition for up to 90% sulphur retention, are shown in Table 44, together with figures for enrichment factors measured in pulverised coal fired furnaces. The enrichment factors have been calculated for the fine dust from the secondary cyclone (medium size 2.5 µm). Little enrichment occurred, and in some cases there is actually a depletion of the element.

TABLE 44

Comparison of trace element enrichment factors in fluidised-bed firing at 6 bars pressure and in pulverised coal firing

Element	Enrichment factors		
	Fluidised-bed[a]		Pulverised coal
Mercury	0.15	(1.6)	1-10[b]
Arsenic	0.8	(1.1)	3-14[c]
Lead	1.3	(1.4)	4-20[c]
Cadmium	1.6	(6.3)	15[c]
Beryllium	1.0	(1.0)	(d)
Antimony	> 1.5	(> 1.5)	3-15[e]

(a) Ref. 107 (U.K. data); figures in brackets are calculated on the assumption that element in vapour form at the sampling point would condense on the dust particles before discharge to atmosphere.

(b) CEGB (U.K. data)

(c) From Table 38 (U.S. data).

(d) No data found

(e) Refs. 93, 95, 96 and 97 (U.S. data).

This may be because the gases were at high temperature when sampled and the element may still have been in the form of vapour. Concentrations of elements in the vapour phase were measured, and if these are added to the portion present in the particles, as if condensation had occurred, then none of the enrichment factors is less than one (figures in brackets in Table 44). Enrichment factors for pulverised coal firing have been calculated as described in section 5.1.

In the pressurised fluidised combustor, the amounts of mercury, selenium, arsenic and lead found in the gas phase in some cases represented a significant fraction of the input quantities. The concentrations measured, and the percentages represented by them of the input rates of the elements, are shown in Table 45.

TABLE 45

Pressurised fluidised-bed combustion : Flue gas burden of elements in vapour form

(Reference 104)

Element(a)	Hg	Se	As	Pb	Cd
Concentration(b) as vapour	3.77	21	1.5	1.3	1.0
Output flow rate as vapour,ug/s	2.85	15.9	1.14	0.99	0.76
Input rate, ug/s(c)	8.1	48	105	440	5.3
Output as vapour/Input, %	36	33	1.1	0.2	14
Vapour/total in flue gas(d)	92	99	20	7	77

(a) Tellurium, beryllium and antimony not detected in gases passing through filter.

(b) Parts weight per 10^9 parts weight of flue gas.

(c) In coal plus dolomite.

(d) Weight of element present as vapour in the flue gas as a percentage of the total weight of element present.

6. Maximum possible reduction in pollutant emissions

This section aims to summarise the greatest possible reduction in emissions, and the costs (financial and energy) of so doing, if neither of these forms of cost were to constitute a barrier to the introduction of control measures. Only processes proven to operate satisfactorily for coal firing are considered.

6.1 Sulphur dioxide emissions

At the present state of knowledge regarding coal desulphurisation, it is not possible to say with certainty that a process can be developed which will remove more than 75% of the coal sulphur. Much higher percentages of sulphur removal can be obtained by flue gas desulphurisation or by fluidised bed combustion, than by coal cleaning, and it cannot be regarded as sensible to install costly plant to reduce the coal sulphur content by small amounts if other expensive processing will be used at a later stage to remove sulphur.

Since we are here concerned only with the maximum possible reduction in SO_2 emissions, improvements in coal preparation are ruled out. Also, since we are only concerned with the period between now and the year 2000, fluidised-bed combustion and coal conversion are ruled out in respect of high-level sources (power station chimneys), and for these sources only FGD is relevant. The reduction in sulphur emissions and costs are as shown in Table 20, and the energy cost is obtained from Table 15.

For medium level sources, it is assumed that control is by use of fluidised bed combustion with limestone addition in sufficient quantity to reduce emissions to 0.25 kg SO_2 per GJ heat input to the boiler. The maximum rate of boiler conversion to fluidised-bed combustion is taken to be that used in Table 14, and energy costs are obtained from Table 13, assuming electrical power is generated at 33.3% efficiency. Full desulphurisation of coke-oven gas from 1985 onwards is also assumed. No SO_2 reduction from low-level sources is anticipated. Table 46 shows the maximum possible SO_2 reductions and the costs of doing so. The total energy cost of 89,400 TJ/annum in 2000 represents approximately 2% of the thermal value of the anticipated U.K. coal production in 2000.

6.2. Nitrogen oxide emissions

There is insufficient knowledge yet about the operability of gas scrubbing systems for NO_x removal in flue gas from coal combustion to allow this to be regarded as a strong contender for use in the U.K. in the time-scale covered by this study. The only possible exception is that of modifications to the Wellman-Lord FGD process to enable it to remove NO_x also. References to the possibility of this were noted in section 2.6.1, but details of such modifications have not been traced in the literature. The most likely form of modification would be the injection of ozone or chlorine dioxide to oxidise NO to NO_2 which would then react with SO_2 in solution to form sulphate ion and gaseous nitrogen. An undesirable effect would be reduction in the sulphur yield and an increase in sodium sulphate production.

TABLE 46

Maximum possible reduction in SO_2 emissions, and associated costs

		1985	1990	2000
High-level sources	SO_2 emissions, 10^3t/annum	2141	1918	1482
	SO_2 reduction, 10^3t/annum	289	485	867
	Energy cost, TJ/annum	27500	46100	82400
	Capital cost,(a) £10^6	610	1030	1870
	Total annual cost, £10^6	100	170	310
Medium-level sources(c)	SO_2 emissions, 10^3t/annum	261	266	312
	SO_2 reduction, 10^3t/annum	176	357	715
	Energy cost, TJ/annum	1420	3000	7000
	Capital cost(a)(b),£10^6	35	70	125
	Total annual cost, £10^6	20	35	75
All sources(d)	SO_2 emissions, 10^3t/annum	2577	2359	1969
	SO_2 reduction, 10^3t/annum	465	842	1582
	Energy cost, TJ/annum	28900	49100	89400
	Capital cost(a) £10^6	645	1100	1995
	Total annual cost, £10^6	120	205	385

(a) Cost between now and relevant year.

(b) Assuming no need for limestone preparation on site of fluidised-bed combustors.

(c) Including coke oven gas combustion.

(d) Including low-level sources.

Because of the uncertainty regarding the future of gas scrubbing for NO_x removal, combustion modifications are selected here as giving the best prospects for reduction of NO_x emissions. No action is assumed for industrial boilers, because this would conflict with the requirements for SO_2 reduction in fluidised-bed firing (see section 3.2.1). No reduction techniques are feasible for low-level sources.

The reductions possible are the same as shown in Table 36, and they are reproduced in Table 47 in a slightly different form, together with the anticipated energy costs. One possibility that has not been allowed for here is that by reducing the combustion efficiency, NO_x reduction modifications may increase the burden of suspended particulates in the gases entering the electrostatic precipitator, and there might in consequence be a need to install more expensive precipitators to meet the same particulate emission standards.

6.3 Particulate emissions

The main difference between the maximum possible reduction and that shown in Table 37 is in medium-level and low-level emissions. In section 4 it was assumed that only the largest firms representing 50% of the industrial coal market would install highly efficient bag filter or electrostatic precipitator gas cleaners. A maximum reduction is achieved by requiring all industrial users to install high efficiency gas cleaners (this might not be possible without some form of subsidy to the small coal users).

Emission rates and costs for maximum reduction of particulate emissions are shown in Table 48. If a 'breakthrough' in gas cleaning technology occurs, allowing a much higher particulate removal efficiency to be achieved for only a small increase in cost, then the cost estimates shown in Table 48 will be higher than those actually needed.

Since it has not been possible to estimate costs of particulate removal improvements, it has been assumed that expenditure on control of high-level sources will continue at about the same level as in the past,(109) in real value, and that 75% of the total relates to coal-firing. For medium-level sources the cost given in section 4.2.2 is adopted.

The major contribution to particulate emissions is from low-level sources. The future use of coal and coal-derived solid smokeless fuels for house-heating is uncertain, but many householders, either through personal preference or non-availability of alternative fuels will continue to use solid fuels. In part 1 it was assumed that the consumption of coal by this market would remain more or less constant between 1985 and 2000. An anticipated increase in the number of smokeless zones in the U.K. means that an increasing number of households at present burning bituminous coal in smoky appliances, will either have to turn to smokeless fuel, or will have to install appliances such as the "Smoke-Eater" fire, which are capable of burning bituminous coal smokelessly. It is not expected that the proportion of smokeless households will increase as rapidly as in the past, however.

TABLE 47

Maximum possible reduction in NO_x emissions, and associated costs (all sources)

	1985	1990	2000
NO_x emissions, 10^3t,/annum	528	513	624
NO_x reduction, 10^3t./annum	50	99	97
Energy cost, TJ/annum(a)	10700	21200	20700
Capital cost(b) £10^6	28	55	55
Annual cost, £10^6	6	11	11

(a) Worst case, assuming one percentage point reduction in combustion efficiency.

(b) Between now and the relevant year.

TABLE 48

Maximum possible reduction in particulate emissions, and associated costs

		1985	1990	2000
High level sources	Particulate emissions, 10^3t./annum	84+	83	64
	Reduction, 10^3 t./annum	0	0	17
	Energy cost(a) TJ/annum	3900	3840	3750
	Capital cost(b) £10^6	102	187	357
	Annual cost £10^6	34	34	34
Medium-level sources	Particulate emissions, 10^3t./annum	25	18	29
	Reduction, 10^3t./annum	11	30	49
	Energy cost(a) TJ/annum	775	1290	2650
	Capital cost(b) £10^6	100	320	650
	Annual cost (c) £10^6	3	9	18
Low-level sources	Particulate emissions, 10^3t./annum	149	127	87
	Reduction, 10^3 t/annum	27	49	89
	Energy cost (c)	-	-	-
	Capital cost(b) £10^6	84	153	294
	Annual cost (c)	-	-	-
All sources	Particulate emissions, 10^3t./annum	258+	228	180
	Reduction, 10^3 t./annum	38	79	155
	Energy cost, TJ/annum(c)	4675	5130	6400
	Capital cost,(b) £10^6	286	660	1300
	Annual cost (c) £10^6	37	43	52

(a) TJ (thermal); from reference 110; assumes 33.3% efficiency of power generation.

(b) Cost between now and relevant year.

(c) TJ (thermal); excludes operating and energy cost of smokeless fuel plants.

A quite arbitrary split between those householders installing 'Smoke-Eaters' and those electing to burn smokeless fuel has been made, and 45,000 extra households a year will be assumed to burn smokeless fuel while only 5000 a year convert to the 'Smoke-Eater'. The total number represents a maintenace of the approximate current rate of conversions to smokeless firing, allowing for the fact that many premises in new smoke control zones are already non-smoke-emitting.

Installation costs of the 'Smoke-Eater' are roughly £300 per household, and additional capital costs for construction of extra smokeless fuel plant capacity is taken to be £100 per ton per annum of coal throughput. This figure is probably not unreasonable allowing for the high cost of pollution control now necessary on this type of plant, and may even be low for a plant required to be erected on a "green field" site.

Operating and energy costs are difficult to estimate, but should both be negative for the 'Smoke-Eater' because of its better combustion efficiency. Table 48 does not include energy losses and operating costs of smokeless fuel plants.

6.4 Trace element emissions

There is insufficient reliable information to predict the future reduction in emissions and costs of control measures. The literature reviewed in section 5 of this report shows that improvements in the control of particle emissions will also reduce emissions to the atmosphere of most of the trace elements in coal. Exceptions are the halogens, selenium and mercury, for which a smaller reduction would result from any reduction in emissions of total particulates, the extent of reduction depending on factors such as plant design and coal ash composition.

Tables 40 to 43 show that coal cleaning removes substantial amounts of trace elements, especially those which are usually to be found associated with the discrete particles of mineral matter in the coal.

Future uses of coal, e.g. liquefaction, may be expected to bring a greater degree of separation of the trace elements. As an example of the fraction of total trace elements which might be removed, Table 49 shows the average of two estimates of the percentage reduction of a range of elements which results on converting coal to Solvent Refined Coal(111).

The results given in Table 44 suggest that any combustion of coal in fluidised beds will produce much lower emissions of some trace elements to the atmosphere, because there is less enrichment of these elements in the fine particles suspended in the combustion gases.

TABLE 49

Trace element reduction in Solvent Refined Coal compared to the parent coal

Element	Symbol	% reduction	Element	Symbol	% reduction
Aluminium	Al	97.5	Lanthanum	La	98.5
Antimony	Sb	94	Magnesium	Mg	92
Arsenic	As	88.5	Manganese	Mn	50
Barium	Ba	89	Mercury	Hg	62
Bromine	Br	-51.5	Potassium	K	100
Caesium	Cs	97	Rubidium	Rb	98
Calcium	Ca	78	Samarium	Sm	91
Cerium	Ce	98	Scandium	Sc	81.5
Chlorine	Cl	52.5	Selenium	Se	95.5
Chromium	Cr	75.5	Sodium	Na	96.5
Cobalt	Co	95.5	Tantalum	Ta	66
Copper	Cu	91	Terbium	Tb	89.5
Europium	Eu	82.5	Thorium	Th	89.5
Gallium	Ga	65.5	Titanium	Ti	14
Hafnium	Hf	86	Vanadium	V	69
Iron	Fe	99	Zirconium	Zr	83.5

Note:

All values except for those for barium, caesium, magnesium and rubidium are the average of two estimates.
Bromine shows an increase.
Source: reference 111.

7. Abbreviations and symbols (other than S.I. units)

ACGIH	American Conference of Governmental Industrial Hygienists
Btu	British thermal unit
CV	calorific value
Chemical elements	symbols listed in Table 49
d.a.f.	dry, ash-free
d.m.m.f.	dry, mineral-matter-free
E	electrical
EEC	European Economic Community
EPA	Environmental Protection Agency (U.S.)
F.B.C.	fluidised-bed combustion
FGD	flue gas desulphurisation
g.l.c.	ground-level concentration
NO	nitric oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
OAR	oxidation-absorption-reduction
ppm	parts per million by weight
P.S.F.	power station fuel
R.D.	relative density (same as specific gravity, S.G.)
SCR	selective catalytic reduction
SO_2	sulphur dioxide
SO_3	sulphur trioxide
SO_x	sulphur oxides
SRC	Solvent Refined Coal
Th	thermal
U.K.	United Kingdom
U.S. (A.)	United States (of America)
vpphm	parts per hundred million by volume
vppm	parts per million by volume

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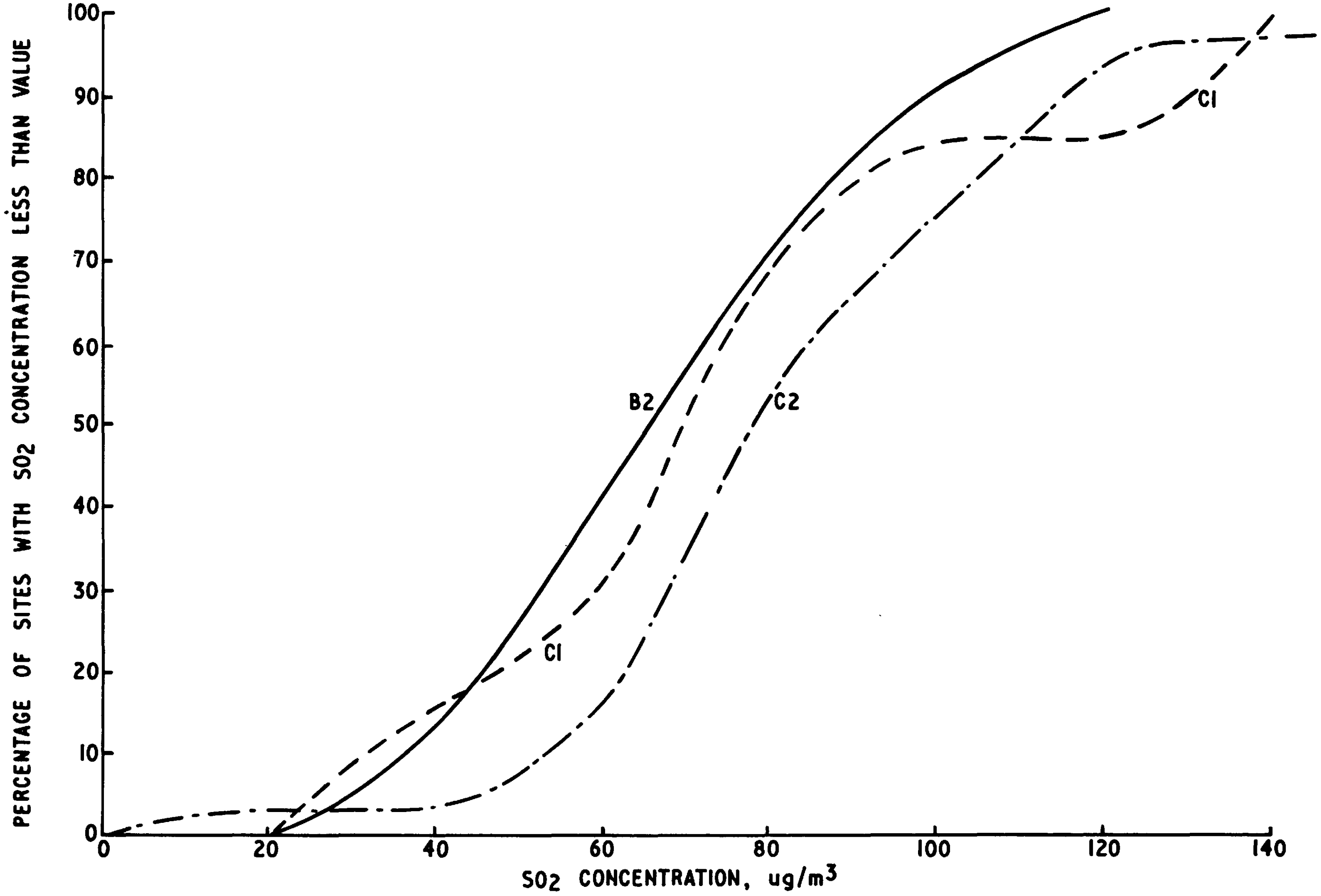

FIGURE I. DISTRIBUTION OF WHOLE YEAR SO_2 CONCENTRATIONS, 1976/77

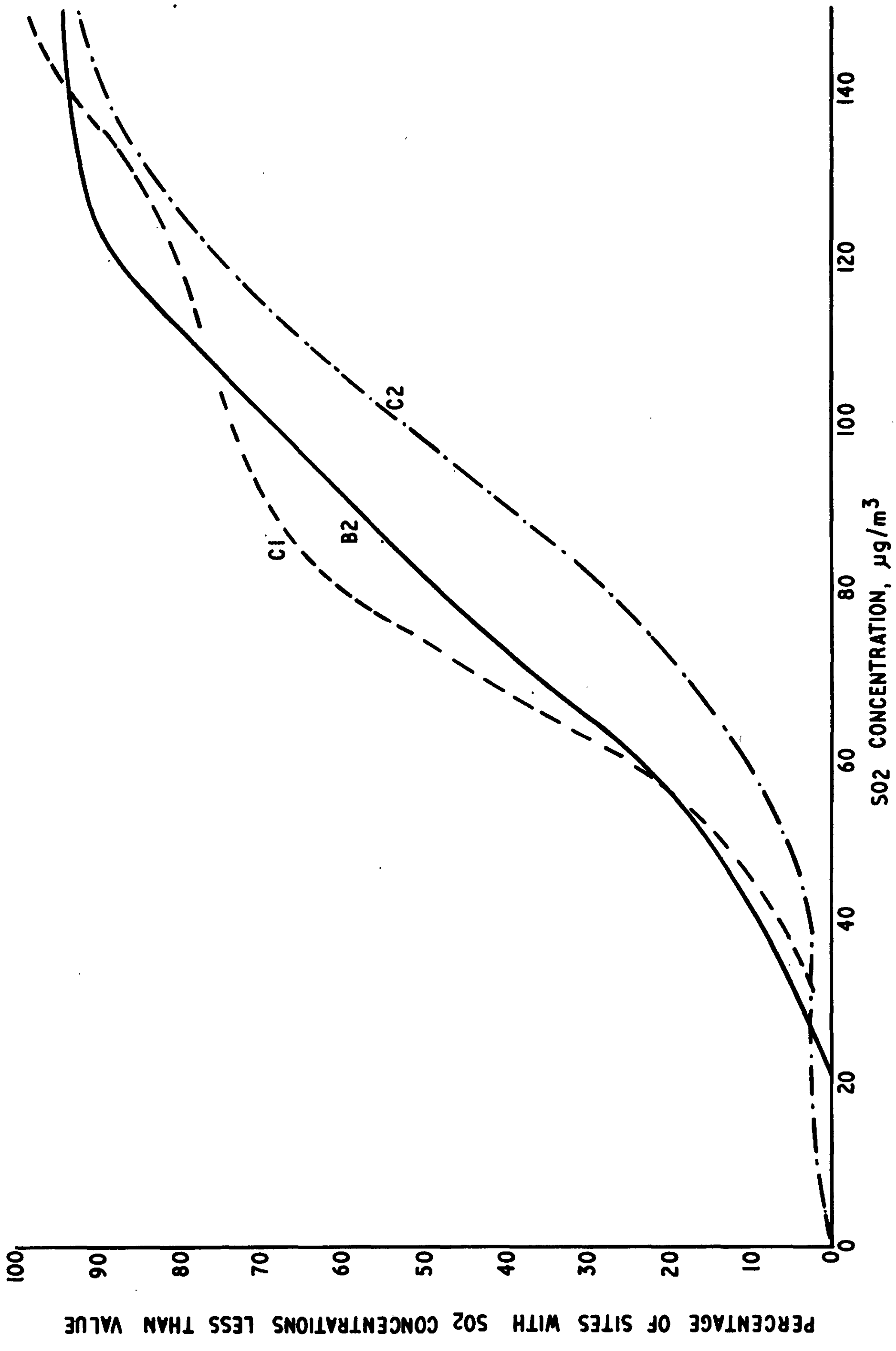

FIGURE 2. DISTRIBUTION OF WINTER SO2 CONCENTRATIONS, 1976/77

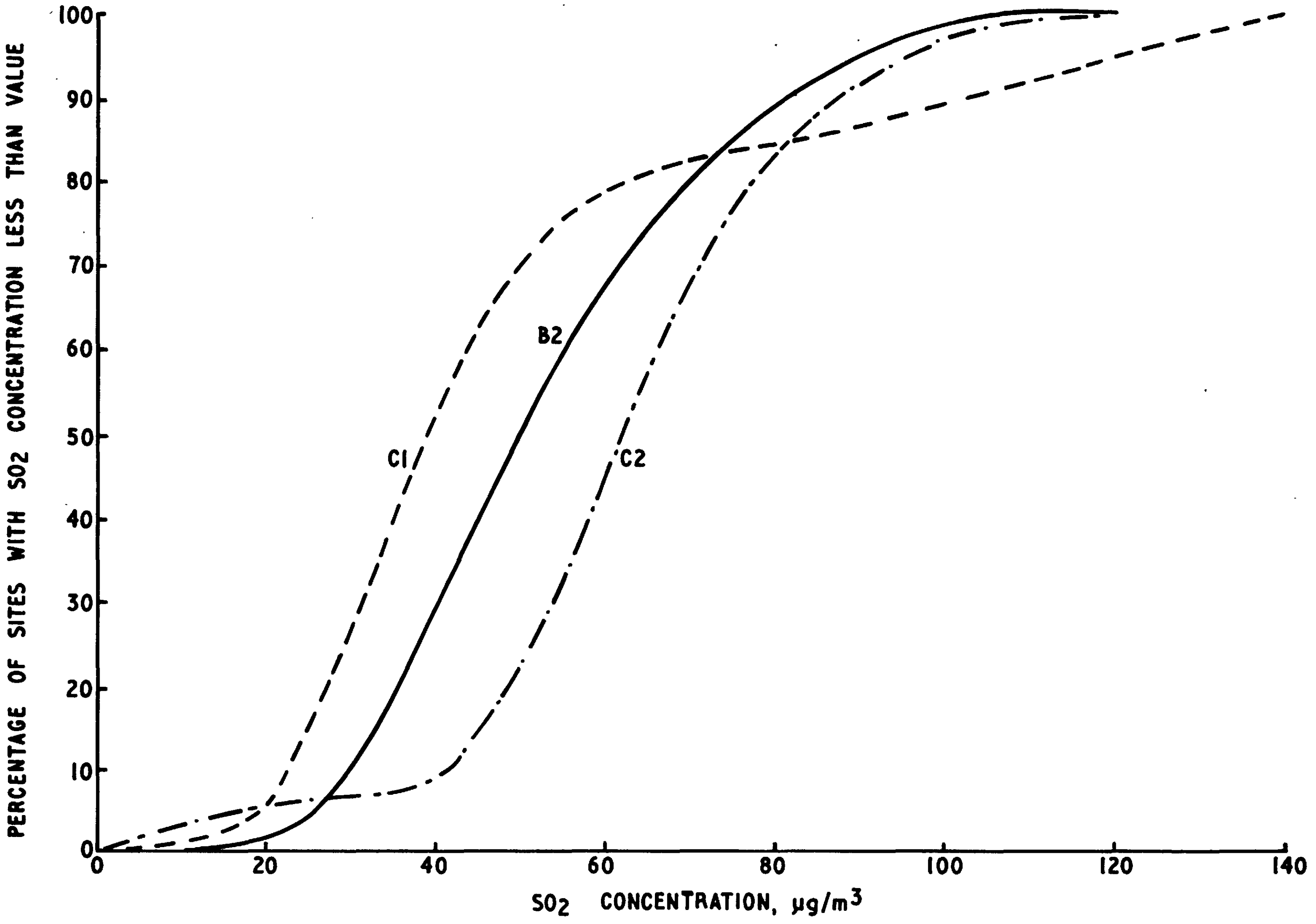

FIGURE 3. DISTRIBUTION OF SUMMER SO2 CONCENTRATIONS, 1976

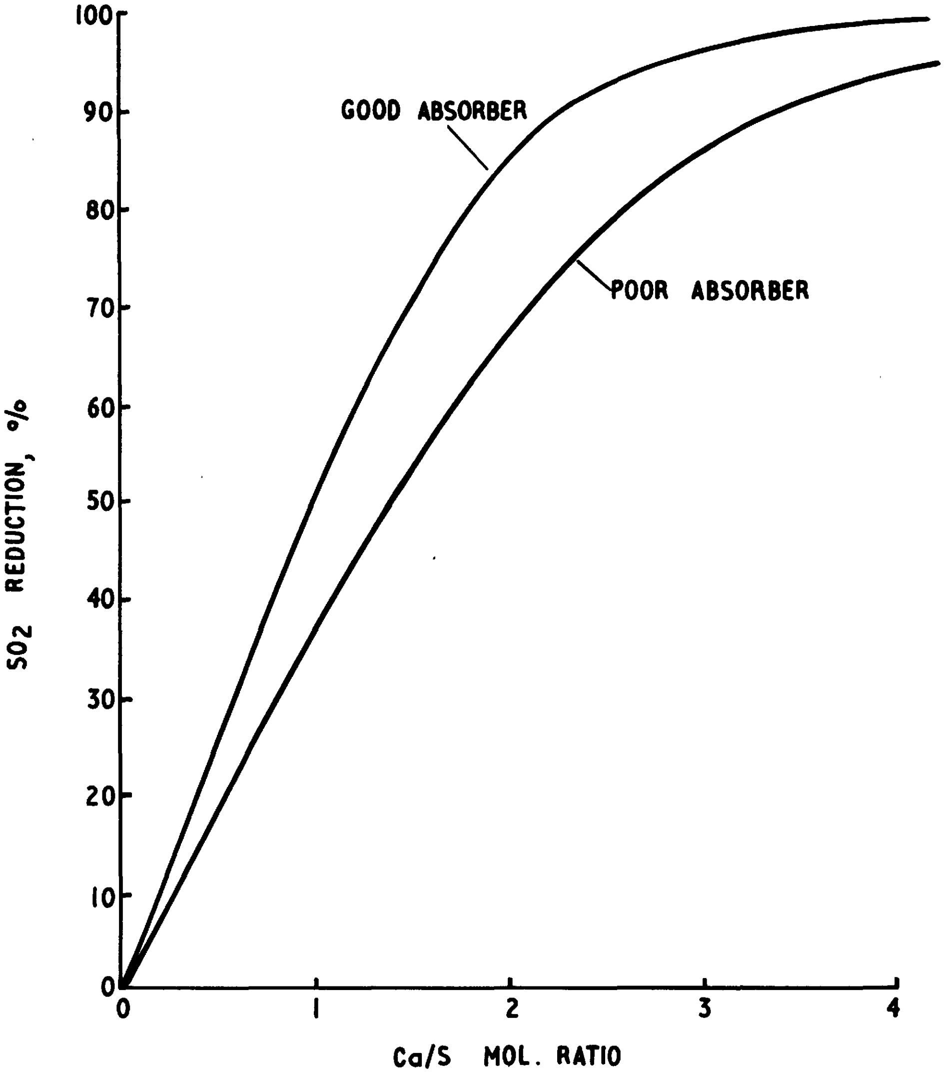

FIGURE 4. TYPICAL SO_2 REDUCTION CURVE FOR LIMESTONE ADDITION, COAL-FIRED FLUIDISED BED COMBUSTION (ATMOSPHERIC PRESSURE)

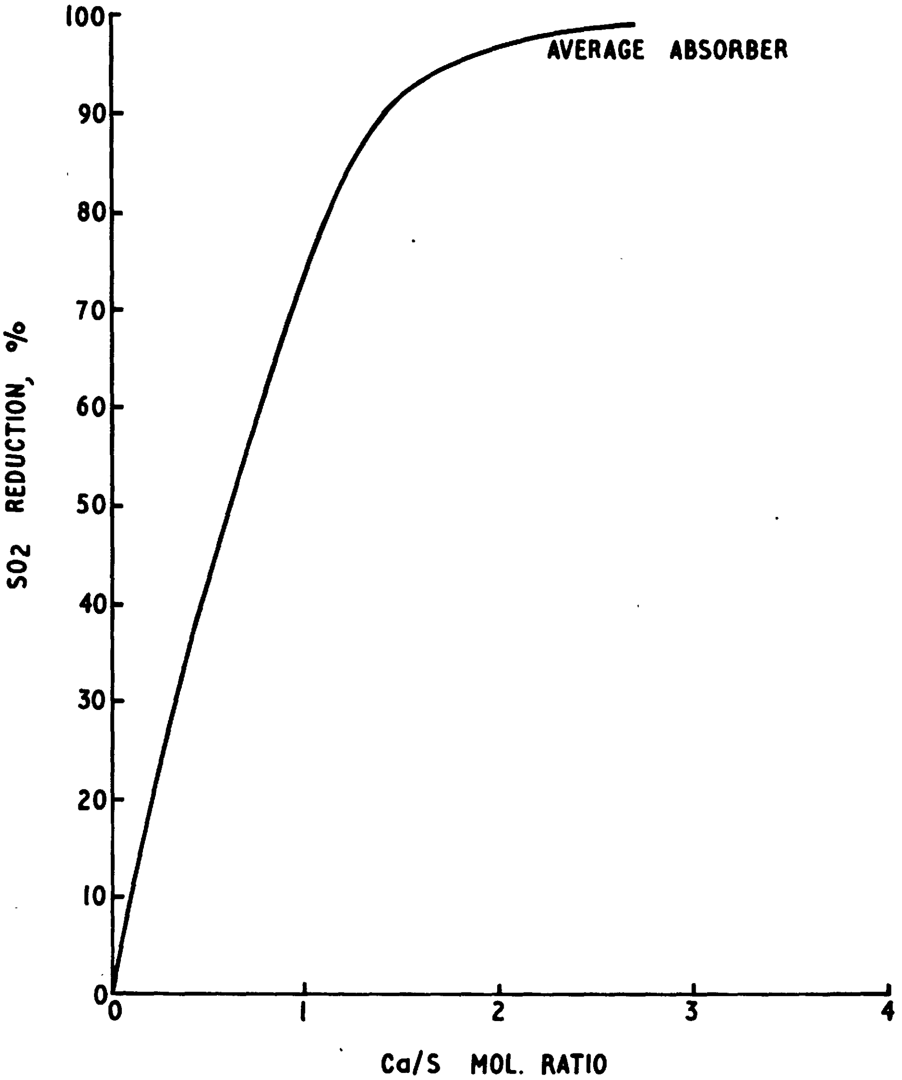

FIGURE 5. TYPICAL SO2 REDUCTION CURVE FOR DOLOMITE ADDITION, PRESSURISED COAL-FIRED FLUIDISED-BED COMBUSTION (5 ATMOSPHERES)

APPENDIX 1

Tables 1, 3 and 5 show the amounts of coal in various ranges of coal sulphur content (on as-received basis) supplied respectively for power generation, industry, and the domestic market (including manufactured fuel plants) in 1977/78.

Tables 2, 4 and 6 show the amount of sulphur supplied in coal in various ranges of coal sulphur content for the same three markets.

TABLE A1.1 ANALYSIS OF SULPHUR CONTENT, 1977/78

DISPOSALS TO POWER STATIONS: BREAKDOWN BY TONNAGE OF COAL

Source of coal	Sulphur Range[1] (% S in coal)														Average sulphur, %	Total disposals, 10^3 tonnes
	0.26-0.50	0.51-0.75	0.76-1.00	1.01-1.25	1.26-1.50	1.51-1.75	1.76-2.00	2.01-2.25	2.26-2.50	2.51-2.75	2.76-3.00	3.01-3.25	3.26-3.50	Over 3.50		
NCB Deep-mined																
Scotland	65	25	7	3											0.53	8,081
North East			14	7	17	34	21	7							1.54	6,150
North Yorkshire					2	22	30	31	9		6	<0.5			1.96	6,877
Doncaster				10	30	42	18								1.50	5,418
Barnsley				4	25	33	8	6	24						1.78	5,860
South Yorkshire			12	3	21	16	36	6	3		2			1	1.63	2,833
North Derbyshire			<0.5	8	29	10	52				<0.5				1.69	5,732
North Notts.			5	36	24	35									1.35	6,264
South Notts.		23	7	16	17	12	17	8							1.30	7,362
South Midlands			1		62	18	5	6	7						1.55	5,841
Western		2	1	23	22	8	14	<0.5	18			1	10		1.78	7,571
South Wales		9	6	10	20	25	30								1.45	2,255
Total deep-mined	7	6	4	11	21	20	17	6	5		1	<0.5	1	<0.5	1.47	70,244
Opencast																
Scotland		16	48	36											0.89	356
Northern				22	43	24	11								1.46	1,648
Central-West			62				21		17						1.35	805
Central-East				1	1	24	51	19	1			3			1.89	4,025
South West			17	52	30										1.15	110
Total opencast		1	10	8	11	19	35	11	3			2			1.67	6,944
Total NCB[2]	7	5	5	10	20	20	19	6	5		1	<0.5	1	<0.5	1.48	77,188

1. Figures shown against each range are percentages of total disposals from each source falling in each sulphur range.

2. NCB accounts for 99.4% of coal supplied to power stations in U.K.

TABLE A1.2 ANALYSIS OF SULPHUR CONTENT, 1977/78

DISPOSALS TO POWER STATIONS: BREAKDOWN BY TONNAGE OF SULPHUR

Source of coal	Sulphur Range[1] (% S in coal)														Total Sulphur, 10^3 tonnes
	0.26-0.50	0.51-0.75	0.76-1.00	1.01-1.25	1.26-1.50	1.51-1.75	1.76-2.00	2.01-2.25	2.26-2.50	2.51-2.75	2.76-3.00	3.01-3.25	3.26-3.50	Over 3.50	
NCB Deep-mined															
Scotland	50	31	12	7											43
North East			8	5	15	36	26	10							95
North Yorkshire					1	18	28	33	11		9	<0.5			135
Doncaster				7	27	44	22								81
Barnsley				3	19	30	8	7	32						104
South Yorkshire			6	2	17	16	41	8	4		3			2	46
North Derbyshire			<0.5	5	24	10	60				1				97
North Notts.			3	30	24	42									85
South Notts.		11	5	14	18	15	24	13							96
South Midlands			1		55	19	6	8	11						91
Western		1	1	15	17	7	15	< 0.5	23			2	19		135
South Wales		4	4	8	19	28	38								33
Total deep-mined	2	2	2	8	20	22	22	8	9		1	1	2		1030
Opencast															
Scotland		11	45	44											3
Northern				17	41	27	15								24
Central-West			41				29		30						11
Central-East				1	1	21	50	21	1			5			76
South West			13	51	36										1
total opencast		1	5	6	9	19	39	14	4			3			116
Total NCB[2]	2	2	3	8	19	22	24	9	8		1	1	2	<0.5	1146

1. Figures shown against each range are percentages of total sulphur from each source falling in each sulphur range.

2. NCB accounts for 99.4% of coal supplied to power stations in U.K.

TABLE A1.3 ANALYSIS OF SULPHUR CONTENT, 1977/78

DISPOSALS TO INDUSTRY: BREAKDOWN BY TONNAGE OF COAL

Source of coal	Sulphur Range[1] (% S in coal)														Average sulphur %	Total disposals, 10^3 tonnes
	0.26-0.50	0.51-0.75	0.76-1.00	1.01-1.25	1.26-1.50	1.51-1.75	1.76-2.00	2.01-2.25	2.26-2.50	2.51-2.75	2.76-3.00	3.01-3.25	3.26-3.50	3.51 3.75		
NCB Deep-mined																
Scotland	26	42	28	4											0.66	832
North East			9	7	16	64	4								1.50	1650
North Yorkshire					1	13	4	82							2.05	544
Doncaster				15	32	53									1.48	430
Barnsley				32	18	6	30	1	13						1.61	196
South Yorkshire				2	8	1	86		1		1				1.81	219
North Derbyshire				25	19	21	35								1.55	780
North Notts.			4	91	2	3									1.14	2185
South Notts.		22	32	31	2		2	10	1						1.07	874
South Midlands			18	9	43	14		15	1						1.43	1432
Western		4	4	26	14	20	10	4	17	<0.5			<0.5		1.57	1153
South Wales		12	49	29	10										0.97	205
Total deep-mined	2	6	11	31	14	20	7	7	2	<0.5	<0.5		<0.5		1.35	10502
Opencast																
Scotland			81	19											0.89	92
Northern				11	62	8	19								1.46	619
Central-West							96	4							1.88	104
Central-East					27	52		9	11						1.69	341
South West		2	95	3											0.89	129
Total opencast		<0.5	15	7	37	17	17	3	3						1.46	1286
Total NCB[2]	2	5	11	28	17	19	8	7	2	<0.5	<0.5		<0.5		1.36	11788

1. Figure shown against each range are percentages of total disposals from each source falling in each sulphur range.

2. NCB accounts for 98.8% of coal supplied to industry in U.K.

TABLE A1.4 ANALYSIS OF SULPHUR CONTENT, 1977/78

DISPOSALS TO INDUSTRY: BREAKDOWN BY TONNAGE OF SULPHUR

Source of coal	Sulphur Range[1] (% S in coal)														Total sulphur, 10^3 tonnes
	0.26-0.50	0.51-0.75	0.76-1.00	1.01-1.25	1.26-1.50	1.51-1.75	1.76-2.00	2.01-2.25	2.26-2.50	2.51-2.75	2.76-3.00	3.01-3.25	3.26 3.50	Over 3.50	
NCB Deep-mined															
Scotland	15	40	38	7											5
North East			5	5	15	70	5								25
North Yorkshire					1	10	4	85							11
Doncaster				11	30	59									6
Barnsley				23	15	6	35	1	19						3
South Yorkshire				1	6	1	89		1		2				4
North Derbyshire				18	17	22	43								12
North Notts.			3	90	2	4									25
South Notts.		13	26	33	3		4	20	2						9
South Midlands			11	7	42	16		22	2						20
Western		2	2	19	12	21	12	5	26	<0.5			1		18
South Wales		8	44	34	14										2
Total deep-mined	1	3	7	26	14	23	10	12	4	<0.5	<0.5		<0.5		142
Opencast															
Scotland			77	23											1
Northern				8	58	9	24								9
Central-West							96	4							2
Central-East					22	51		11	16						6
South West		1	95	4											1
Total opencast		<0.5	34	7	16	12	24	3	3						19
Total NCB[2]	1	2	8	24	16	23	11	11	4	<0.5	<0.5		<0.5		161

1. Figures shown against each range are percentages of total sulphur from each source falling in each sulphur range.

2. NCB accounts for 98.8% of coal supplied to industry in U.K.

TABLE A1.5 ANALYSIS OF SULPHUR CONTENT, 1977/78

DISPOSALS TO DOMESTIC AND MFP[1]: BREAKDOWN BY TONNAGE OF COAL

Source of coal	Sulphur Range[2] (% S in coal)														Average sulphur %	Total disposals 10^3 tonnes
	0.26-0.50	0.51-0.75	0.76-1.00	1.01-1.25	1.26-1.50	1.51-1.75	1.76-2.00	2.01-2.25	2.26-2.50	2.51-2.75	2.76 3.00	3.01-3.25	3.26-3.50	Over 3.50		
NCB Deep-mined																
Scotland	30	37	12	21											0.69	886
North East			12	58	9	10	11								1.25	1362
North Yorkshire					16	6	53	24			<0.5				1.84	559
Doncaster			1	27	56	16									1.35	1180
Barnsley				15	52	18	1	12	2						1.50	525
South Yorkshire			10	31	54	1	4	<0.5							1.27	610
North Derbyshire				12	36	37	14								1.51	693
North Notts.				74	26										1.20	1308
South Notts.		11	17	34	11	11	2	8	5	1					1.30	1098
South Midlands			9	15	40	26	1	1	8						1.46	1233
Western			20	56	3	3	13	1	3					1	1.27	1170
South Wales		23	25	51	1										0.95	1712
Total deep-mined	2	7	11	38	22	10	6	2	2	<0.5	<0.5			<0.5	1.25	12336
Opencast																
Scotland		34	66												0.76	77
Northern					100										1.45	7
Central-West																0
Central-East					18	41	31	9							1.70	152
South West		8	87	5											0.87	861
Total opencast		8	73	4	3	6	4	1							0.99	1097
Total NCB	2	7	16	35	20	10	6	2	1	<0.5	<0.5			<0.5	1.23	13434

1. Manufactured fuels plants.
2. Figures shown against each range are percentages of total disposals from each source falling in each sulphur range.
3. NCB accounts for 99.0% of coal supplied to domestic and MFP in U.K.

TABLE A1.6 ANALYSIS OF SULPHUR CONTENT, 1977/78

DISPOSALS TO DOMESTIC AND MFP[1]: BREAKDOWN BY TONNAGE OF SULPHUR

Source of coal	Sulphur Range[2] (% S in coal)														Total Sulphur 10^3 tonnes
	0.26-0.50	0.51-0.75	0.76-1.00	1.01-1.25	1.26-1.50	1.51-1.75	1.76-2.00	2.01-2.25	2.26-2.50	2.51-2.75	2.76-3.00	3.01-3.25	3.26-3.50	Over 3.50	
NCB Deep-mined															
Scotland	17	34	15	34											6
North East			8	52	10	13	16								17
North Yorkshire					12	5	55	28							10
Doncaster			1	23	57	19									16
Barnsley				11	48	19	1	17	3						8
South Yorkshire			7	27	58	1	6	<0.5							8
North Derbyshire				9	33	40	18								10
North Notts.				70	30										16
South Notts.		5	12	30	12	14	3	13	9	2					14
South Midlands			5	12	38	29	1	1	13						18
Western			14	50	3	4	19	2	6					3	15
South Wales		15	23	60	1										16
Total deep-mined	1	4	7	34	24	14	9	4	1	<0.5				<0.5	154
Opencast															
Scotland		27	73												1
Northern					100										0.5
Central-West															0
Central-East					15	40	34	11							3
South West		6	88	6											7
Total opencast		5	66	5	4	10	8	2							11
Total NCB[3]	1	4	11	33	23	14	9	4	1	<0.5				<0.5	165

1. Manufactured fuels plants
2. Figures shown against each range are percentages of total sulphur from each source falling in each sulphur range.
3. NCB accounts for 99.0% of coal supplied to domestic and MFP in U.K.

APPENDIX 2

Analysis of Warren Spring Data

The measurements for sites in categories B2, C1 and C2 in the Warren Spring Laboratory, National Survey of Smoke and Sulphur Dioxide, April 1976 to March 1977[8] have been extracted and are shown in Table A1.1. The Warren Spring report also gives average concentrations for individual months, and the highest daily concentrations in each month; these are not included in Table A2.1.

Monthly average figures are not calculated if 6 or more consecutive daily results are missing, nor where less than 21 daily results are available in a four week period, or less than 27 daily results in a five week period. The summer and winter means are the arithmetic means of all daily concentrations obtained during the appropriate six months. These means are not calculated if over fourteen consecutive days' readings are missing, nor where less than 110 days' readings are available out of a seasonal total. The mean for the whole year is the arithmetic mean of all daily concentrations obtained during the twelve months, and is only calculated when both summer and winter means can also be calculated.

The periods referred to as months are 4 or 5 week periods, approximating to the calendar months, and the summer and winter periods are respectively 30th March 1976 to 27th September 1976, and 28 September 1976 to 28 March 1977.

When records are incomplete, the highest monthly and daily readings shown in Table A2.1 are the highest readings recorded, provided monthly averages are available for at least four months during the year.

Tables A2.2, A2.3 and A2.4 show, for each category of site, the numbers of sites in various SO_2 concentration ranges, the mean smoke concentrations of the sites in each SO_2 concentration range, and the overall average SO_2 and smoke concentrations for the year and half years. This information is summarised in Figures 1, 2 and 3 of the main report.

Descriptions of the three site categories studied here are as follows:-

B2: predominantly residential areas with medium density housing (typically an inner suburb or housing estate), surrounded by other built-up areas and interspersed with some industrial undertakings.

C1: industrial areas without domestic premises.

C2: industrial areas interspersed with domestic premises of high density or in multiple occupation.

TABLE A2.1

SO_2 and Smoke Concentrations, 1976/77, Site Categories B2, C1 and C2 (E denotes Smokeless Zone)

Name of site	Category	SO_2 concentration, $\mu g/m^3$						Smoke concentration, $\mu g/m^3$			
		Summer mean	Winter mean	Year mean	Highest month	Highest day	Summer mean	Winter mean	Year mean	Highest month	Highest day
Abercarn 1	B2	34	40	37	53	115	13	32	23	56	153
Abertillery 1	B2	-	-	-	63	130	-	-	-	54	153
Acton 12	C1	72	-	-	130	274	14	-	-	37	85
Acton 13	C1	-	-	-	-	-	-	-	-	-	-
Barnard Castle 4	B2	-	59	-	71	184	-	50	-	61	173
Barry 1	B2	35	47	41	73	168	14	35	25	59	120
Bath 5	C2	42	61	51	71	157	9	26	17	43	198
Bedford 5	C2	49	97	74	110	208	19	39	29	45	139
Bedford 7	B2	65	88	77	95	229	16	37	27	48	166
Beeston + Stapleford 1	B2/E	80	130	104	157	298	18	52	34	80	311
Belfast 33	C2	53	88	71	119	288	34	137	88	221	922
Billingham 26	C1	48	36	42	80	221	18	18	18	28	84
Billingham 27	B2/E	39	32	36	45	127	14	13	13	20	87
Billingham 28	C1	47	-	-	55	141	16	-	-	21	68
Birmingham 19	C2/E	53	63	58	108	216	23	42	33	57	137
Birmingham 20	C2/E	57	-	-	112	204	27	-	-	53	167
Birmingham 22	B2/E	81	104	93	150	312	13	31	22	42	131
Birmingham 24	B2/E	85	132	109	164	300	15	34	25	50	160
Birmingham 25	B2/E	74	85	79	113	330	12	23	18	33	118
Birtley 6	B2	49	91	72	119	270	18	49	35	95	315
Blackpool 2	B2	45	-	-	52	120	18	-	-	30	66
Blackpool 4	B2	-	70	-	87	207	-	62	-	95	198
Blackpool 5	B2	-	70	-	89	208	-	52	-	86	240
Bradford 16	B2/E	48	99	74	136	341	16	41	29	50	151
Bradford 17	B2/E	40	77	59	96	258	11	35	23	44	145
Bradford 19	B2/E	44	121	83	143	407	12	55	34	68	248
Bradford 21	C2	66	110	88	136	386	19	55	37	65	194
Broxburn 2	B2	27	41	34	60	149	15	47	31	79	257
Burnley 11	B2/E	-	-	-	66	162	-	-	-	19	73
Bury 2	B2	65	68	67	115	329	24	55	40	82	445
Camberley 1	B2	-	-	-	-	-	51	65	58	83	173
Cannock 17	B2	55	101	79	122	332	31	106	70	126	325
Cardiff 9	C2	74	76	75	108	241	30	70	50	123	329
Carlisle 11	B2	41	-	-	71	232	37	-	-	87	497

TABLE A2.1 (Continued)

Name of site	Category	SO$_2$ concentration, $\mu g/m^3$					Smoke concentration, $\mu g/m^3$				
		Summer mean	Winter mean	Year mean	Highest month	Highest day	Summer mean	Winter mean	Year mean	Highest month	Highest day
Castleford 9	C2	64	162	112	196	479	44	133	88	184	516
Castlereagh 1	B2	50	78	65	107	251	14	37	26	68	270
Chesterfield 18	C2	45	94	70	112	314	26	86	56	116	301
Clacton 2	B2	41	57	50	75	152	11	26	19	51	117
Clydebank 6	B2/E	37	38	38	42	88	10	37	23	47	241
Coalville 1	B2	77	-	-	115	268	23	-	-	62	162
Coatbridge 4	B2/E	-	-	-	215	709	-	-	-	36	109
Coleraine 1	B2	33	38	36	44	87	17	45	31	51	340
Consett 12	B2	-	-	-	-	-	-	-	-	-	-
Darlaston 3	B2	58	94	76	119	278	20	47	34	62	211
Darton 1	B2	59	114	85	114	253	48	135	89	143	336
Deptford 3	C2	90	112	101	161	426	21	29	25	36	152
Derby 18	B2/E	68	117	92	167	324	18	51	34	82	375
Doncaster 19	B2/E	-	111	-	137	328	-	53	-	84	364
Dronfield 5	C2/E	-	-	-	56	142	-	-	-	27	95
Dundee 14	B2/E	-	-	-	71	186	-	15	-	16	67
Dundee 15	B2/E	-	-	-	86	192	-	-	-	36	143
Dunstable 2	B2	40	78	59	100	248	9	24	16	34	79
East Kilbride 16	B2/E	-	39	-	50	144	-	24	-	40	192
East Kilbride 18	B2/E	-	-	-	-	-	-	-	-	-	-
Eccles 6	B2/E	58	154	105	233	435	27	75	51	127	269
Edinburgh 12	B2	39	66	52	92	253	21	52	36	84	212
Ellesmere Port 4	C1	58	84	71	118	358	23	35	29	51	146
Ellesmere Port 5	C1	120	134	127	178	806	18	28	23	42	96
Ellesmere Port 8	C1	70	54	62	91	363	22	33	28	58	152
Enfield 12	C1	61	-	-	76	443	13	-	-	15	75
Erith 3	B2	88	110	99	145	628	36	43	39	53	167
Falkirk 5	B2/E	31	67	49	77	207	12	40	26	47	150
Falkirk 6	B2/E	39	61	50	88	219	11	39	25	64	228
Gainsborough 2	C2	55	66	61	84	143	14	33	23	53	202
Glasgow 66	B2/E	54	88	71	119	435	14	41	28	60	182
Glasgow 68	C2	65	103	83	133	598	18	70	43	115	388
Glasgow 70	B2/E	53	88	71	124	770	19	50	35	91	441
Glasgow 73	C2	53	91	72	122	478	17	56	37	104	421
Glasgow 80	C2	-	74	-	105	367	-	72	-	132	352
Glenrothes 3	B2/E	-	-	-	37	112	-	-	-	33	110
Grangemouth 7	B2	-	43	-	50	182	-	35	-	52	145

TABLE A2.1 (Continued)

Name of site	Category	SO_2 concentration, $\mu g/m^3$					Smoke concentration, $\mu g/m^3$				
		Summer mean	Winter mean	Year mean	Highest month	Highest day	Summer mean	Winter mean	Year mean	Highest month	Highest day
Grangetown 1	B2	34	50	42	71	167	18	36	27	49	186
Halesowen 7	B2	67	93	80	121	302	16	24	20	40	121
Halifax 14	C2/E	-	103	-	134	409	-	34	-	52	181
Hammersmith 5	C2/E	-	-	-	133	227	-	-	-	35	89
Hartlepool 6	B2/E	28	76	52	112	350	12	30	21	45	176
Hartlepool 16	B2/E	30	69	50	87	202	13	38	26	56	219
Hartlepool 18	B2	29	68	49	77	215	9	30	19	59	194
Hatfield 3	B2	-	87	-	112	288	-	33	-	47	124
Healing 1	B2	41	37	39	46	125	8	26	17	40	134
Hereford 5	C2	18	-	-	27	88	14	-	-	20	45
Hinckley 4	C1	55	80	67	112	221	39	91	65	124	232
Huddersfield 15	B2	-	83	-	113	312	-	50	-	66	279
Huddersfield 17	C1	-	-	-	37	129	-	-	-	13	29
Immingham 3	B2	38	-	-	64	167	12	-	-	43	95
Inverkip 2	B2	36	-	-	63	204	17	-	-	51	153
Irlam 7	B2/E	43	67	55	108	567	19	46	33	94	273
Ironbridge 13	B2	35	-	-	40	127	12	-	-	18	58
Ironbridge 18	C2	-	49	-	64	167	-	27	-	36	96
Keighley 10	B2/E	53	106	80	114	269	14	41	28	62	124
Kew 1	B2/E	55	74	65	125	330	11	20	15	20	143
Kingston-u-Hull 16	C1	17	42	29	59	152	11	43	27	63	254
Kirkby 5	C1	26	50	38	65	166	11	28	19	46	149
Kirkintilloch 3	C2	51	95	72	113	341	24	88	55	109	550
Kirkintilloch 5	B2	-	-	-	124	385	-	-	-	222	696
Kirkwall 4	C2	10	13	12	18	33	3	7	5	10	38
Knottingley 1	B2/E	72	86	79	114	420	27	96	62	169	1556
Lanarkshire 15	B2/E	-	63	-	94	386	-	57	-	105	478
Leeds 24	C2	74	130	102	165	353	21	58	39	81	252
Leeds 31	B2/E	64	114	89	134	333	19	49	34	62	257
Leeds 32	C2/E	70	143	106	185	385	18	69	44	95	268
Leeds 34	C2/E	72	122	99	137	325	17	51	34	70	269
Leeds 35	C2/E	79	128	103	151	300	24	60	42	87	220
Leicester 17	C2/E	47	82	65	118	213	14	33	24	52	119
Leigh 1	B2	83	114	99	169	440	26	89	57	148	390
Lewisham 10	B2/E	-	51	-	66	131	-	29	-	49	177
Leyland 1	B2	-	-	-	-	-	-	-	-	-	-

TABLE A2.1 (Continued)

Name of site	Category	SO_2 concentration, μg/m^3					Smoke concentration, μg/m^3				
		Summer mean	Winter mean	Year mean	Highest month	Highest day	Summer mean	Winter mean	Year mean	Highest month	Highest day
Leyland 2	B2	-	105	-	109	266	-	57	-	69	235
Lincoln 12	C1	44	68	56	85	158	13	34	24	51	104
Liverpool 22	B2	-	151	-	206	659	-	98	-	143	427
Llanelli 2	B2	-	-	-	67	201	-	-	-	21	88
Lymm 2	B2	54	80	67	108	470	22	50	36	76	231
Manchester 15	C2	117	186	152	201	515	30	80	56	109	309
Manchester 21	B2	-	161	-	218	639	10	42	27	80	234
Mansfield 5	B2/E	50	89	70	129	258	14	40	27	66	221
Middlesbrough 29	B2	34	56	45	69	131	23	61	42	81	285
Middlesbrough 33	C2	39	69	54	83	152	18	64	41	88	193
Motherwell 5	B2	-	-	-	55	201	-	-	-	12	43
Motherwell 7	B2	36	104	73	230	508	16	49	33	76	195
Motherwell 10	B2	-	40	-	79	161	-	39	-	60	167
Motherwell 11	B2	-	132	-	245	653	-	36	-	45	265
Motherwell 12	B2	43	-	-	236	700	18	-	-	82	206
Neath 3	B2	47	66	56	86	122	14	31	22	45	115
Newcastle-u-Lyme 10	B2	67	113	90	142	381	33	99	66	137	571
Newcastle-u-Lyme 11	B2	61	96	79	120	351	25	73	50	109	461
Newcastle-u-Lyme 12	B2	63	106	84	133	379	17	61	39	91	296
Newcastle-u-Lyme 14	B2	69	104	86	142	399	26	92	58	118	511
Newcastle-u-Tyne 24	B2	84	144	114	182	516	24	73	48	93	357
Newcastle-u-Tyne 31	C2	83	121	102	151	331	22	64	43	85	353
Newport Mon. 23	B2	-	-	-	82	187	-	-	-	46	177
Northampton 7	B2	32	41	36	50	140	12	28	20	45	128
Norwich 6	C2	42	80	60	129	248	12	28	20	43	256
Norwich 10	B2/E	37	55	46	82	242	8	20	14	26	152
Nottingham 4	C2	58	96	77	122	330	22	67	45	129	293
Oldham 13	C2	91	151	120	252	476	24	58	41	99	210
Oxford 19	C1	-	73	-	89	243	-	24	-	32	97
Pontypool 12	B2	-	-	-	-	-	-	-	-	-	-
Poole 22	B2	25	37	31	44	135	9	24	16	34	96
Port Talbot 15	C2	44	52	48	62	227	10	22	16	37	85
Redcar 12	B2	41	58	40	70	201	33	38	36	94	228
Renfrew 3	B2	50	70	60	98	284	16	41	28	72	343
Risley Lancs. 1	C1	47	-	-	151	309	22	-	-	75	185
Risley Lancs. 2	C1	-	-	-	151	364	-	-	-	76	185

TABLE A2.1 (Continued)

Name of site	Category	SO_2 concentration, $\mu g/m^3$					Smoke concentration, $\mu g/m^3$				
		Summer mean	Winter mean	Year mean	Highest month	Highest day	Summer mean	Winter mean	Year mean	Highest month	Highest day
Rogerstone 11	C1	-	-	-	-	-	-	-	-	-	-
Rogerstone 12	B2	49	-	-	100	212	14	-	-	49	121
Romford 4	C1/E	64	109	87	130	551	14	31	23	35	214
Rowley Regis 2	B2	71	67	69	87	220	23	33	28	49	117
St. Helens 12	C1	85	-	-	178	448	23	59	41	93	321
St. Helens 33	C2	80	-	-	150	418	20	58	39	80	233
St. Helens 37	B2	51	100	75	155	474	16	50	33	78	270
Sale 7	B2/E	-	66	-	103	662	-	40	-	58	194
Scunthorpe 14	C1	77	67	72	98	430	20	51	35	70	230
Sheffield 39	C2/E	85	-	-	91	222	23	-	-	32	119
Sheffield 48	C1	56	121	90	152	301	30	63	47	76	311
Southall 10	C2/E	61	95	77	127	334	22	33	27	44	168
Southampton 35	C1	-	62	-	74	179	-	20	-	27	133
Southwick 5	B2	-	-	-	100	149	-	-	-	32	107
Stepney 5	B2/E	93	145	118	157	500	32	50	41	58	233
Stockport 10	C2/E	69	113	91	140	463	21	41	31	65	155
Stocksbridge 11	C1	59	72	65	89	247	23	34	28	46	395
Stocksbridge 12	C2	60	71	66	84	225	20	40	31	52	385
Stockton-on-Tees 6	B2	41	41	41	56	138	14	16	15	23	63
Stoke Newington 5	B2/E	114	-	-	219	482	34	-	-	58	131
Stoke-on-Trent 3	C2	73	113	93	143	364	26	75	50	102	345
Stoke-on-Trent 11	B2/E	88	112	100	148	460	23	55	39	79	298
Stoke-on-Trent 18	C1	-	-	-	143	380	-	-	-	81	292
Stornoway 3	C1	-	-	-	-	-	-	-	-	-	-
Stretford 8	B2/E	78	119	99	177	845	24	50	37	71	272
Sutton Coldfield 6	B2	63	-	-	92	176	13	-	-	39	137
Swansea 18	B2	59	-	-	90	280	21	-	-	50	98
Swansea 20	B2	59	56	57	93	191	13	28	21	47	124
Swansea 22	C2	55	49	52	79	188	13	27	20	44	117
Swindon 2	B2	59	71	65	80	164	11	34	22	56	141
Tamworth 10	B2	-	67	-	84	193	-	44	-	60	151
Tilbury + Thurrock 26	B2	45	-	-	62	184	13	-	-	22	76
Treeton 2	B2	-	142	-	168	318	-	113	-	156	380
Urmston 9	B2/E	57	97	77	162	798	26	49	37	76	200
Wallasey 6	C2/E	60	120	91	168	365	13	40	27	67	162
Walsall 13	B2	52	84	68	108	312	29	62	45	82	235

TABLE A2.1 (Continued)

Name of site	Category	SO_2 concentration, $\mu g/m^3$					Smoke concentration, $\mu g/m^3$				
		Summer mean	Winter mean	Year mean	Highest month	Highest day	Summer mean	Winter mean	Year mean	Highest month	Highest day
Walsall 17	C2	-	111	-	143	338	-	49	-	65	169
Warrington 9	B2/E	62	103	82	126	423	24	54	39	84	223
Warrington 19	B2/E	63	91	77	123	535	23	60	41	81	216
Welwyn G. City 2	C1	57	-	-	115	256	12	-	-	31	114
W. Bromwich 13	C2	64	110	87	137	308	26	51	39	73	166
Weston-s-Mare 1	B2	24	32	28	40	99	12	31	22	36	137
Whiston 2	B2	31	63	47	86	216	15	39	27	66	177
Widnes 2	B2/E	56	-	-	132	357	15	-	-	37	174
Witney 1	B2/E	16	-	-	52	115	10	-	-	37	89
Wombwell 1	B2	-	-	-	-	-	-	-	-	-	-
Worksop 9	B2/E	93	-	-	105	369	7	-	-	38	161
Worsbrough Bridge 1	B2	62	122	93	139	343	29	123	77	155	615
Worthing 5	B2	27	27	27	35	79	17	15	11	22	62

TABLE A2.2: B2 Sites: Classification by Mean SO_2 Concentration

SO_2 Concentration range, $\mu g/m^3$		<20	20-39	40-59	60-79	80-99	100-119	120-139	>139
Whole year: Mean SO_2 = 67.8 Mean smoke = 33.2	No. of sites	0	10	19	24	15	7	0	0
	Average smoke concentration $\mu g/m^3$	-	20.7	24.9	33.7	44.9	47.3	-	-
Summer: Mean SO_2 = 52.8 Mean smoke = 18.1	No. of sites	1	25	35	18	9	1	0	0
	Average smoke concentration $\mu g/m^3$	10	13.3	18.4	21.8	21.6	34.0	-	-
Winter: Mean SO_2 = 83.3 Mean smoke = 47.8	No. of sites	0	8	14	22	18	18	5	6
	Average smoke concentration $\mu g/m^3$	-	26.9	34.6	40.0	47.4	64.7	60.0	75.1

TABLE A2.3: C1 Sites: Classification by Mean SO_2 Concentration

SO_2 Concentration range, $\mu g/m^3$		<20	20-39	40-59	60-79	80-99	100-119	120-139	>139
Whole year: Mean SO_2 = 71.8 Mean smoke = 31.8	No. of sites	0	2	2	5	2	0	2	0
	Average smoke concentration $\mu g/m^3$	-	23.0	21.0	37.0	35.0	-	35.5	-
Summer: Mean SO_2 = 61.4 Mean smoke = 19.5	No. of sites	1	1	9	5	1	1	1	0
	Average smoke concentration $\mu g/m^3$	11.0	11.0	21.8	16.6	23.0	29.0	18.0	-
Winter: Mean SO_2 = 80.3 Mean smoke = 40.0	No. of sites	0	1	3	5	2	1	2	1
	Average smoke Concentration $\mu g/m^3$	-	18.0	34.7	54.3	63.0	31.0	45.5	67.0

TABLE A2.4: C2 Sites: Classification by Mean SO_2 Concentration

SO_2 Concentration range, µg/m^3		<20	20-39	40-59	60-79	80-99	100-119	120-139	>139
Whole year: Mean SO_2 = 80.2 Mean smoke = 38.0	No. of sites	1	0	5	12	7	6	1	1
	Average smoke concentration µg/m^3	5.0	-	25.4	40.4	37.3	46.8	41.0	56.0
Summer: Mean SO_2 = 61.3 Mean smoke = 20.5	No. of sites	2	1	14	14	5	1	0	0
	Average smoke concentration ug/m^3	8.5	18.0	18.8	22.8	22.0	30.0	-	-
Winter: Mean SO_2 = 97.3 Mean Smoke = 54.6	No. of sites	1	0	3	7	9	8	5	4
	Average smoke concentration µg/m^3	12.0	-	25.3	49.6	63.0	50.5	54.7	85.0

APPENDIX 3

REDUCTION OF SULPHUR IN CLEANED COALS

PART 1: THE USE OF CONVENTIONAL COAL PREPARATION TECHNIQUES

A3.1 Five Seams A to E, selected at random have been examined with the aid of a computer model. All calculations have been done on "dry basis" figures because:

(a) although inherent moisture is a property of the coal, the variations between seams could make direct comparison of cleaning techniques difficult,

(b) free moisture varies with plant operation and can be said to be under the control of the operator, i.e. it is a process variable not a coal property.

Two terms have been introduced, Thermal Recovery and Thermal Value per tonne of sulphur. These define the energy potential of the cleaned coal as a percentage of that in the raw coal, and the energy potential of the weight of cleaned coal containing 1 tonne of sulphur. They have been calculated as follows:

$$\text{Thermal Recovery} = \frac{\text{CV of cleaned coal x yield}}{\text{CV of raw coal}} \; \%$$

$$\text{Thermal Value/tonne sulphur} = \frac{\text{CV of cleaned coal x 100}}{\text{\% sulphur}}$$

If the CV (calorific value) is in MJ/t the result is conveniently expressed as TJ/t sulphur.

Since we are interested in reducing the amount of sulphur sent out with the coal with the minimum loss of heat a comparison of relative increases in the Thermal Value/t sulphur with Thermal Recovery give a measure of the effectiveness of any particular operation.

In order to make comparison between coals easier a common dry ash-free (d.a.f.) CV of 33,500 kJ/kg has been assumed and,

$$\text{Calculated CV} = \frac{33{,}500\ (100 - \%\ \text{ash})}{100} \; \text{kJ/kg}$$

with the result rounded to the nearest 100 kJ.

A3.2 Table A3.1 shows the basic properties of the five raw coals examined (25 mm - 0 size fraction in all cases).

Seam A is relatively low in sulphur and reasonably easy to clean.

Seam B, C and D are all "average" in sulphur content but differ widely in washability characteristics.

Seam E, high in sulphur but not difficult to clean.

The three 'average' seams were included in the hope that they would endorse the belief (based on general experience) that all seams will eventually have to be examined individually in order to provide reasonably reliable predictions of the results of additional coal cleaning.

The table also shows the analytical and calculated values for an average power station fuel (P.S.F.) (25 mm - 0) prepared from these five coals.

The average analysis for P.S.F. in 1977/78 on an as received basis was:

Ash	17.0%
Total moisture	12.0%
CV	24,000 kJ/kg

On a dry basis this becomes:

Ash	19.3%
CV	27,000 kJ/kg (to the nearest 100 kJ)

The method of preparation, which follows normal practice, was as follows:

(a) Partial washing in a Baum jig separating at a particle density of 1.70, it being assumed that no cleaning was done on the -0.5 mm fraction.

(b) The -0.5 mm fines were then added back and the resulting mix blended with raw coal to produce the results shown, i.e. an average power station fuel.

(c) In the case of seam E, which is not only high in sulphur but also high in ash the washed coal/fines mixture was so close to the target ash of 19.3% that further blending was not practicable.

On their own, at this stage Thermal Recovery and Thermal Value/t sulphur have little value. Their usefulness lies in comparisons made later.

These results are taken as the standard against which alternative methods of preparation are compared.

A3.3 Table A3.1A extends present practice in that it shows what could be expected if all coal above 0.5 mm was cleaned in a Baum jig and the slurry added back to the cleaned coal.

The results tend to confirm the suspicion that every coal will have to be examined in some detail. The reduction in ash content varies from marginal (C) to substantial (B). Loss of vend bears no relationship to Thermal Recovery, nor does the reduction in sulphur content in any way relate to the increase in Thermal Value per tonne of sulphur.

The increase in amount of discard to be tipped (loss of vend) varies widely and again appears to be unrelated to the reduction in the sulphur content of the cleaned coal.

A3.4 Table A3.2 shows the results from small coal cleaning by dense medium cyclone at densities ranging from 1.9 down to 1.4. In many ways it reinforces the observations made on Table A3.1A. At the higher densities the sulphur content is usually higher than that obtained by jig washing although ash content is always lower. This is to be expected where the high ash high density fractions are low in sulphur. The cyclone gives a much sharper separation than a Baum jig and so any "benefits" from these low sulphur fractions is lost.

Below 1.70 R.D. the Thermal Recovery tends to fall of quite markedly. No figures for Thermal Value/tonne Sulphur are given but they could be produced.

A3.5 Table A3.3 is the logical consequence of Table A3.2, i.e. high density separation to achieve maximum recovery coupled with a low density separation to produce a middlings for further treatment and a primary cleaned product which could be expected to have the lowest possible sulphur content. (Note: The middlings from Seam C have a lower sulphur content than the cleaned coal).

The predicted results for "de-sulphurisation" of the middlings are based on several important assumptions:

(a) The ratio of organic to pyritic sulphur has been taken as 1:1. This is an arbitrary ratio because nothing is known about this relationship in middlings; the ratios quoted from time to time apply either to a seam section or a cleaned coal product as a whole. It may be that the organic sulphur tends to concentrate in the lowest density fractions and the pyritic in the higher density fractions or middlings - it seems that nobody has any evidence. Work will have to be done on this if three-product separation is to be seriously considered for sulphur reduction.

(b) The percentage of pyritic sulphur which can be removed, having been released by crushing say to 3 mm, is taken as 50%. This figure is based on work done in Germany but obviously depends on the degree to which pyrite can be released. Negligible loss of coal is also assumed.

(c) It is assumed that some form of gravity separation is applied to the crushed middlings (see later note about froth flotation) and crushing to below 3 mm has been assumed because the "de-sulphurised" product could then be dewatered in the centrifuge along with the washed smalls.

(d) Thermal recovery is assumed to be the same as for a separation at 1.90 R.D. (i.e. negligible loss in the middlings retreatment).

The reduction in sulphur which might be achieved by this method again varies widely. Nevertheless in terms of Thermal Value/tonne sulphur there is a noticeable improvement in all cases.

A3.6 The use of froth flotation has not been considered, since when used conventionally the coal concentrate almost invariably contains a proportion of free pyrite which would not be present in the product from a gravity separation. The sulphur content is therefore higher than one would normally expect. The results from the use of depressants are uncertain and appear to require an increase in flotation time beyond that normally catered for. Two-stage selective flotation is not a conventional coal preparation technique and it should probably only be considered as a last resort. The density of pyrites (5.0) is so much higher than that of coal that the logical approach to fines treatment must be to look first at techniques which make use of the density differential, e.g. cyclones and concentrating tables.

A3.7 The only definite conclusions one can draw from this investigation are:

(a) Reductions in the tonnage of sulphur, of the order of up to 10% may be possible in some cases, but most will be much lower than this. On a thermal basis, sulphur reductions are a little greater (bottom line in Table A3.3).

(b) Every seam must be looked at individually, since even a marginal reduction in a "middle" sulphur seam may be important if high outputs are obtained from that seam.

In connection with (b) a breakdown of coals supplied to C.E.G.B. by source (i.e. seam) would seem to be needed as a first step.

TABLE A3.1

RAW COAL - STANDARD PREPARATION

		Seam A	Seam B	Seam C	Seam D	Seam E
Raw Coal Properties						
Ash	%	37.1	31.4	26.8	31.7	41.4
Sulphur	%	1.33	1.54	1.57	1.52	2.64
Calculated C.V.	kJ/kg	21,000	23,000	24,500	22,900	19,600
Middlings R.D. 1.6 - 1.8	%	3.9	1.0	12.1	4.5	5.5
Ease of cleaning		Mod. Easy	Very Easy	Difficult	Mod. Easy	Mod. Easy
Summery of Results for Preparation of Power Station Fuel						
Ash	%	19.3	19.3	19.3	19.3	19.3
Sulphur	%	1.43	1.53	1.28	1.60	2.99
Calculated C.V.	kJ/kg	27,000	27,000	27,000	27,000	27,000
Yield of product*	%	69	82	81	77	63
Thermal Recovery	%	89	96	89	90	86
Thermal Value/tonne sulphur	TJ	1.888	1.765	2.109	1.688	0.904

* Standard preparation - Cleaning of plus 0.5 mm in a Baum jig (particle density separation 1.7), all raw coal below 0.5 mm added to cleaned coal. Resulting product then blended with raw coal to give required ash content. In the case of Seam 'E' the mixture of washed coal and raw fines does not permit blending (i.e. ash content is already very close to 19.3%).

TABLE A3.1A

TOTAL CLEANING OF POWER STATION COAL IN BAUM JIGS Dp 1.7
(with raw fines added to cleaned coal)

		Seam A	Seam B	Seam C	Seam D	Seam E
Saleable Product						
Ash	%	15.8	11.3	18.4	15.4	19.3
Sulphur	%	1.45	1.52	1.24	1.62	2.99
Calculated CV	kJ/kg	28,200	29,700	27,300	28,300	27,000
Yield of Product	%	65	73	79	72	63
Thermal Recovery	%	87	94	88	89	86

TABLE A3.2

SUMMARY OF RESULTS FOR CLEANING OF +½ mm BY DENSE MEDIUM CYCLONE

(with Raw Fines added to Float Product)

		Seam A	Seam B	Seam C	Seam D	Seam E
At Density 1.90						
Ash	%	16.9	11.4	20.9	16.4	19.6
Sulphur	%	1.49	1.54	1.22	1.63	3.08
Calculated CV	kJ/kg	27,800	29,700	26,500	28,000	26,900
Yield of Product	%	68	74	87	74	65
Thermal Recovery	%	90	95	94	91	89
At Density 1.80						
Ash	%	15.3	10.7	19.4	15.4	18.5
Sulphur	%	1.48	1.53	1.23	1.63	3.07
Calculated CV	kJ/kg	28,400	29,900	27,000	28,300	27,300
Yield of Product	%	66	72	83	73	63
Thermal Recovery	%	89	94	92	90	88
At Density 1.70						
Ash	%	14.2	10.2	17.8	14.5	17.8
Sulphur	%	1.47	1.52	1.22	1.63	3.04
Calculated CV	kJ/kg	28,700	30,100	27,500	28,600	27,500
Yield of Product	%	64	72	79	71	62
Thermal Recovery	%	87	94	89	89	86
At Density 1.60						
Ash	%	13.3	10.0	16.1	13.6	17.0
Sulphur	%	1.44	1.51	1.23	1.62	2.96
Calculated CV	kJ/kg	29,000	30,200	28,100	28,900	27,800
Yield of Product	%	62	71	73	68	59
Thermal Recovery	%	85	93	84	86	84
At Density 1.50						
Ash	%	12.6	9.7	14.3	12.7	16.4
Sulphur	%	1.40	1.48	1.24	1.61	2.82
Calculated CV	kJ/kg	29,300	30,300	28,700	29,200	28,000
Yield of Product	%	60	70	65	64	56
Thermal Recovery	%	83	92	76	82	79
At Density 1.40						
Ash	%	12.3	9.6	12.8	12.3	16.4
Sulphur	%	1.34	1.45	1.26	1.58	2.59
Calculated CV	kJ/kg	29,400	30,300	29,200	29,400	28,000
Yield of Product	%	55	67	54	60	49
Thermal Recovery	%	76	88	64	77	69

TABLE A3.3

THREE-PRODUCT SEPARATION DENSITIES 1.40 - 1.90

		Seam A	Seam B	Seam C	Seam D	Seam E
Product at Density 1.40 (including Raw Fines)						
Ash	%	12.3	9.6	12.8	12.3	16.4
Sulphur	%	1.34	1.45	1.26	1.58	2.59
Calculated CV	kJ/kg	29,400	30,300	29,200	29,400	28,000
Yield of Product	%	55	67	54	60	49
Thermal Recovery	%	76	88	64	77	69
Middlings 1.40 - 1.90						
Ash	%	35.5	29.4	34.0	33.6	28.9
Sulphur	%	2.10	2.47	1.16	1.82	4.50
Calculated CV	%	21,600	23,700	22,100	22,200	23,800
Yield of middlings	%	14	7	33	15	17
Thermal Recovery	%	14	7	30	15	20
Middlings treatment at washery						
Sulphur in middlings become	%	1.58	1.85	0.87	1.37	3.38
Sulphur in middlings plus cleaned coal	%	1.39	1.49	1.11	1.54	2.79
Sulphur in cleaned coal (Dp 1.9)	%	1.49	1.54	1.22	1.63	3.08
Reduction in sulphur	%	0.10	0.05	0.11	0.09	0.29
Reduction in sulphur below that of standard P.S.F.	%	0.04	0.04	0.17	0.06	0.20
Thermal Value/tonne sulphur	TJ	2.000	1.993	2.387	1.818	0.9642
Increase over standard P.S.F.	TJ	0.112	0.228	0.278	0.130	0.060
	%	6	13	13	8	7

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