[redacted]

RM 153

## PRICING NORTH SEA NATURAL GAS

### The discovery of gas:

Natural Gas was first extensively discovered in North-Western Europe under the salt beds at Slochteren near Groningen, North-East Holland in 1959. Before that date, there had been considerable speculation among geologists about the possibility of oil or natural gas deposits in this part of Europe since it was an area of marine deposits of a type judged favourable to oil formation. In the U.K. alone over 900 hydrocarbon wells have been drilled since 1914 but they produced only minimal finds - of natural gas at Eskdale in the East Riding in 1937 and south-east of Edinburgh in the same year -and of oil in Nottinghamshire (1939), Lincolnshire (1958) and Dorset (1959). The Groningen discovery itself came after 15 years of drilling, and in its case the reserves were outstanding. By 1969 it was acknowledged as probably the greatest gasfield in the world with agreed reserves of 58 trillion cu. ft. ($58 \times 10^{12}$).

The extent of the discovery at Groningen switched attention to the North Sea. Already in 1958 an International Convention had been set up to settle control of the continental shelf among the countries involved, and provide a framework for national legislation. The Groningen discovery added pressure for the settlement of this convention, and a division was finally agreed on and came into force on 10th July 1964 (see exhibit 3).

Britain was quick to act once this agreement had been reached. The Continental Shelf Act of 1964 declared public sovereignty over mineral resources on or under the Continental Shelf and further provided that any natural gas found there should be offered to an Area Gas Board before being disposed of otherwise than for the sole use of the finder or for chemical purposes. Only if the Board refused gas at a reasonable price, which in the absence of an agreement was to be settled by the Minister of Power, was the finder to be free to offer it for sale directly, and then only to industrial users. Oil, however, could be offered directly to the market. The 1965 Gas Act rectified the omission of the Gas Council from the '64 act, at the same time as it gave the Council powers to distribute gas and sell it to Area Boards.

The British sector in the North Sea covers some 100,000 square miles, and this has been divided into blocks of about 100 square miles each. It was decided that blocks would be allocated to drilling companies or groups of companies, and the first allocations were made in September 1964 of 348 blocs to 22 concerns. In November 1965 a further 122 blocs were allocated in the North Sea, and 5 in the Irish Sea. (See Exhibit 1 and 2).

At the time there was some dissatisfaction at the way the Ministry of Power conducted the allocation. Under the terms of the licence each licensee was to have a right to the original licenced area for six years, at an annual rent of £6,750 (or £25 per sq. km.), with an option thereafter on not more than half the original area for a further 34 years at an annual rent rising from £40 per sq. km. in year 7 by annual jumps of £25 to a maximum of £290 per sq. km. in year 17, (i.e. to about £78,300 p.a. per bloc) Most companies were interested in the blocs which extended from the Schlocteren line (there were as many as 8 applicants to a bloc in this area) as well as those to the East of the Scottish mainland where it was hoped to find oil. Where there was more than one applicant, the Ministry allocated on the basis of 5 criteria, the most important of which was the drilling programme contained in the application In spite of this it was claimed that unfair preference had been given to British companies in the first allocation (30% of the blocs had gone to U.K. companies, but considerably more than 30% of the most sought after blocs) and to drilling concerns which included nationalised industries in the second (both the Coal Board and the Gas Council extended their interests -the Gas Council which had had a 31% share in the Amoco group on the first round raised this to 50% on the second.) Nevertheless, the Ministry of Power appeared to have accomplished its aim of encouraging development. The North Sea operators agreed to spend a minimum of £110 million on exploration, and by 1968 they were claiming that far more than that sum had already been committed for development work.

The drilling platform 'Mr Cap' started work on the first well on Boxing Day 1964. By January 1969 over 170 wells had been drilled in British waters, about half of these being 'wildcats'. Four major fields have been discovered, West Sole, by B.P. in bloc 48/6, Hewett by Arpet and Phillips in blocs 48/29-30, and 52/5, Indefatigable by Amoco in 49/18 and 49/23 and Leman Bank by Shell-Esso and Amoco in 49/26-27. Two further discoveries were announced in May 1968, by the National Coal Board Continental Group in bloc 49/17 (this appears to be a pocket on the edge of the Indefatigable field) and by Gulf in bloc 47/8. It is not yet clear as to the size of these last two finds, but they are both reported to be clearly commercial. (See Exhibit 4). Estimates from the oil industry put total reserves at 2,000 m.c.f.d. by 1975 or 20 trillion c.f. (West Sole 2, Hewett and Indefatigable 4 each, and Leman Bank 10) but this, the industry acknowledges, is a conservative forecast. The Ministry of Power estimates the four fields at 25 trillion c.f., or 3,000 m.c.f.d. with a depletion period of 25 years.[1] These are official estimates. Unofficially David Barran of Shell has said that there will probably be 3,000 m.c.f.d. flowing by 1975, and the Gas Council and Area Boards are basing their investment plans on 4,000 m.c.f.d. by the mid 70's, (the Bacton terminal on the Norfolk coast for example has been planned for a 4,000 m.c.f.d. capacity). Evidently the Gas Council still believe that there is a good possibility of achieving 8,000 m.c.f.d. From international experience it is unusual for an area's reserve potential to be fully discovered in the first four years.

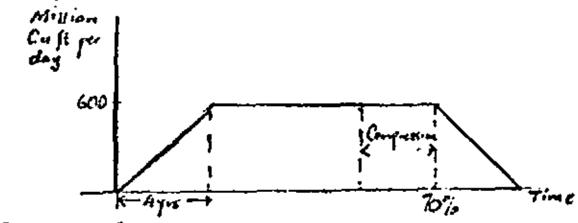
In any case whatever the final reserves discovered, the British part of the North Sea is already acknowledged as one of the major gas fields in the world. (See Exhibit 6. )

Beach-pricing decision:

Of key importance in the development of the North Sea reserves has been the price which the Gas Council and drilling concerns have negotiated for delivery of the gas to the shore. In the case of the B.P. find the Gas Council offered from 2½d. to 4d. per therm depending on quantity and build up, while B.P. argued for a price in the region of 6d. to 7d. The price was finally fixed by the Minister of Power at 5d. a therm.[2] Yet this agreement was reached just after the gas supply breakdown in the West Midlands in the winter 1965/6, and before other gas had been found in the North Sea. As a result of these exceptional circumstances this first settlement was not regarded as a guiding light. Instead, attention shifted to the negotiations which the Gas Council started in December 1966 with its own drilling partner Amoco on the one hand, and Shell/Esso on the other. The Gas Council proposed a price to both of 3d a therm for the first 100 m.c.f. per day. For a field of 500 m.cu. ft. this would have worked out at 1.8d. a therm, and for one of 1,000 m.cu. ft. per day at 1.65d. Both drilling groups rejected the proposal, and were reported to be pressing for a price in the range of 3.5d. - 4d. a therm for all sizes of delivery.

In the talks that followed certain conflicts of principle and fact emerged. The following constitutes a summary of their differences which have been used by the Gas Council and the oil companies, and adds some further considerations which bear on the case from the point of view of the Minister of Power.

1. Normally production from a gas field builds up gradually as initial wells and pipelines are installed, continues on a plateau, and then declines, thus:




The plateau level of production is maintained either by drilling extra holes when the pressures fall, and/or by installing compressors. It is usual to express the depletion period as if the plateau level of production were maintained throughout. Thus a twenty year depletion period would indicate that on the plateau one twentieth of recoverable reserves were being realised, even though the process of recovery might continue for thirty years, and plateau production for only twelve. (See also Exhibit 5).

2. 1 therm equals 100 cubic feet.

The Gas Council Case

The Gas Council's proposals have been based on a cost plus principle. Their aim has been to set a price which would encourage further exploration in the less promising as well as those more promising areas of the North Sea which have been concentrated upon till now. Thus the Council have been aware that a simple cost-plus price taking account only of the actual costs incurred by a particular company in finding and developing the gas it offers for sale would be insufficient. Companies must have an expectation of sufficiently high rewards if exploration and development are to continue.

Accordingly the Council have worked out a price based on discovery, development and operating costs, and including opportunity costs for capital and a risk factor. One independent estimate of these costs has been made by Peter Hinde who himself was connected with the Gas Council. His figures, excluding an opportunity cost for capital, are given in Exhibit 7. The oil companies have agreed with most of the straight figures. They put the cost of a well at £0.75 m. rather than £0.63 m. and production costs of 0.17d. per therm in a small field as against 0.13d. (For the sake of comparison, Appendix I contains some estimates of costs based on conversations with the oil industry). In deriving a cost plus price the main problems at issue have been: (i) the load factor; (ii) the risk factor; (iii) the opportunity cost of capital.

The load factor is defined as the ratio between the average daily take for a year and the maximum daily take expressed as a percentage. Hinde's figures assumed 100% load factor, but the Gas Council were at one time suggesting taking three times as much gas in winter as in summer. The oil companies argued that this could make a considerable difference to the price. Either the Gas Council would have to incorporate the fluctuations into their offered price or maintain a high load factor through selling to industry on an interruptable basis and/or developing extensive underground storage.

As far as risk is concerned, Shell-Esso have consistently emphasised that only one well in 37 is commercially viable on a world scale. This appears to be close to the A.A.P.G. finding that only one in every nine new field wild-cats find anything and only one in 30 or more finds anything worth finding. But this figure refers to both gas and oil and if we take profitability after 6 years as a measure of "commercialness", the A.A.P.G. study estimates that while by 1951-3 only 23% of oil strikes were commercial, the figure for gas was 50%. This would bring the global risk figure for gas down to 1:18. Yet as far as the North Sea is concerned, the Gas Council has argued that the success rate has been more like 1 in 4.

To allow a risk element of 1:18 would thus be greatly over-estimating the possibility of failure. Exhibit 8 gives the rate of success for wild-cats in the North Sea up to mid 1968.

These risks are only the finding risks. Shell-Esso have argued that there are other risks as well. The North Sea weather has already caused the loss of the rigs Sea Gem and Ocean Prince, the evacuation of one of Phillipps rigs, and the drifting off location of a number of semi-submersibles. There is the possibility of structural fracturing if the gas pressure falls away. There are geological and political risks. These, too, it has been argued, should be added in.

Finally, there is the question of the opportunity cost of capital, or profit. The Féderal Power Commission in its regulation of natural gas prices in the United States allow for 12% rate of return after tax and this is considered as roughly equivalent to 16% before tax. In Britain the tax structure is different. The oil companies have to pay royalities of 12½% of the well-head value of the gas, while corporation tax runs in the region of 40%. Esso estimated that about 50% of all profit would go to the British government and both Shell and Esso have accordingly been pressing for the minimum of 15% return on capital.

One attempt to calculate a supply price for natural gas in the North Sea, bearing in mind the above considerations, was made by Messrs. Odell and Thackery and is illustrated in Exhibit 9. They assume a discount rate of 20%, composed of 15% for the cost of capital and 5% for engineering, geological and political risks. They further assume a depletion rate of 3%, a load factor of 100%, probabilities of 1 in 5 and 1 in 10 for finding fields below and above 200 m.cu. ft. per day respectively. They also allow for a three year period of exploration (four years for the large fields) and a further two years before any revenue is received. It can be seen that the supply price falls rapidly as the size of field increases, so that any field over 200 m.cu.ft. per day (with wells of 12 m.c.u. ft. per day located some 50 miles offshore) would have a supply price of under 2d. a therm. The importance of the assumption about the discount rate can be gauged from the fact that if we reduce it to 15%, then the supply price for 100 m.cu. ft. per day becomes 2.7d. per therm rather than 3.6d. and for 1,000 m.cu.ft. per day field the supply price is reduced from 1.1d. to 0.84d.

Apart from the principles and estimates of the Gas Council's proposed prices the two councill negotiators, Sir Henry Jones and A.F. Hetherington, have supported their case by reference to the state of the energy market. If the reserves of gas are as large as the Council hopes they will yield not only gas for the traditional gas market, the public distribution sector, but the base energy market or industrial sector as well. Natural gas would begin to assume the importance it has internationally. (Exhibit 10). Entering into the industrial sector, however, would bring them into competition with fuel oil and coal. At anything below 4d. a therm gas would be a very effective competitor with fuel oil (or below 3d. if the fuel oil tax were removed), and the Electricity industry has even said that if it could buy gas at anywhere near the current 4¾d. a therm equivalent which it pays for its fuel it would do so because of the convenience of gas in comparison with oil or coal. Yet for a price in this range the beach price of natural gas would have to be 2d. a therm, and considerably less than this if it was to compete effectively throughout the base energy market.

The Shell-Esso case:

Shell-Esso have conflicted with the Gas Council on three main points: the supply price which would encourage them to explore throughout their allotted blocs; the principle on which prices should be based; and the market on which the Gas Council should concentrate.

As regards the supply price, we have already mentioned the different assessment of risks put forward by the oil companies and the Gas Council. It addition to this David Barran has argued that any price should include a return for the several hundred million dollars which the oil industry has spent over the last ten years in developing sub-marine exploring techniques, and a return for the experience of companies like Royal Dutch/ Shell who are at the moment exploring shelf regions of the U.S.A., Canada, Nigeria, Alaska, the Caribbean, the Persian Gulf, Borneo, Spain, Australia, New Zealand, East Pakistan, etc. In short the costs of apprenticeship should be recognised and rewarded. (Some idea of the technical difficulties in drilling can be gauged from Exhibit 11). Adding these to his own estimates of costs (15 million on delineation and exploration, £20 million for 2 pipelines from the Leman bank, and £25 million for 50 production wells) Barran estimated that his concern would have invested up to £100 million on the Leman Bank. With a flow of some 800 m.cu.ft. per day by 1973, this would yield a supply price of 3½d. to 4d. a therm.

This part of the argument has, however, been hard to examine for Shell-Esso have not released detailed figures of their costs. One of the reasons for this is that they have argued throughout that the principle on which prices should be set is not cost-plus but market prices. As Barran said, "The problem is to establish a price at which demand will equal but not exceed ultimate supply potential."

Yet it is one thing to suggest the principle of market pricing for gas, and another to derive actual prices. One method is to calculate the cost of meeting the increase in demand for gas in existing markets when North Sea gas is unavailable. David Barran quoted a current in-holder price of 10d. a therm, but this seems unlikely to hold in the present rapidly changing conditions of gas manufacture.

Traditionally the gas industry was based on coal which until the mid-50's supplied over 95% of the industry's needs (see Exhibit 12); by 1965-6 this had fallen to approximately 50% chiefly because of the steep rises in the price of carbonising coal. Oil refineries, however, were found to present alternative supplies; refinery tail gases were the first to be harnessed, followed by heavy oil, medium oils and liquified petroleum gas. The advantages of the lighter hydrocarbons soon became evident, leading to a swing towards the low-octane light petroleum distillates which were being thrown up as surplus in the refinery production balances. Forecasts suggest that supplies of this particular material may not be unlimited, and accordingly the Gas industry is giving some priority to the development of gas-making processes capable of gasifying crude oil whose supply can be considered unlimited. It should also be noted that the cost of transportation of oil and coal as sources for gas manufacture is lower in the former than the latter case and since we may expect not only the trend to oil from coal in gas manufacture to continue, and also storage costs to fall, it is probably justifiable to forecast a fall of in-holder price of gas in 1975.

A second alternative is to buy natural gas from abroad. Already 10% of current gas supply in the U.K. is derived from liquified natural gas from Algeria. The scheme for transportation, in which the Gas Council have invested £54 million, involved the building of two refrigerated tankers, and delivers gas at about 5½d. a therm. Developments in the technology of transportation could lower this cost, and Hinde has estimated that liquified natural gas could be transported from Venezuala and Nigeria at a delivered price of 4½d. a therm. He also suggests a subsea pipeline delivering gas from Holland at 2d. a therm, but this source has been considered less favourably by the Gas Council both on account of transportation cost (which would imply a higher cost than Hinde estimates) and because some of the Dutch deposits have a high nitrogen content. Indeed for the foreseeable future, the Gas Council have not placed much reliance on alternative natural gas supplies becoming available in Britain at anything below the 5½d. a therm of the Algerian supply.

A precise estimate of the cost of alternative supplies can be derived from Table 2 of Exhibit 12. Here liquified natural gas, liquified petroleum gas, refinery gas and naptha are taken on the basis of present costs or estimates now available, all c.i.f. at port or delivered works. Carbonisation gases have been taken at 8d. a therm. As can be seen, and as Shell/Esso have pointed out, no source offers a supply at a cost per therm of the 4d. they are proposing for natural gas, and this does not take account of the additional efficiency of natural gas over existing processes which would lead to a reduction in distribution and overhead costs per unit of thermal sales. In Barran's own words: "Because natural gas has twice the heat value of town gas, the same volume represents twice the energy, which doubles the capacity of the distribution system, and permits a significant expansion of sales in present areas served with no additional capital expenditure. The natural gas, delivered under high pressure, requires no further compression, and the cost of gas pumping is reduced greatly. As it is free of gum-forming constituents and sulphur servicing the metering costs are lower. Although the thermal leakage may increase temporarily due to higher distribution pressures and the higher heating value, the experience of most companies has been that the newer techniques of detection soon reduce leakage to town gas distribution levels, and the higher pressures further increase the distribution capacity."

To set against this is the cost of conversion of present applicances to those which are able to use natural gas - a process which Barran acknowledges could take from 5-7 years and cost roughly £20 per house, or a total of £500 million including additional pipelines. Even at the Gas Council's figure for conversion cost of up to £30 per household, the gains from conversion appear considerable. To take the North Thames Gas Board as an example, their distribution system including gas-holders has been valued at £160 million for nearly 2 million consumers, that is £80 per consumer as against the £25-30 expenditure on doubling capacity by converting to natural gas.

It is the high cost of alternative supplies, and the savings in distribution and storage, as well as the size of the distribution and storage costs in total cost which led a Sunday Times report to sum up what has been one of the principal arguments of the oil companies in the following way: "Sir Kenneth Hutchinson, the Gas Council Deputy Chairman, has calculated that a 2½ d. landed price for 4,000 million cu. ft. a day of gas would result in an average cost after overheads and distribution of 10½d. a therm. This would mean average prices of 6d. to industry and 1s. 2d. to householders. An extra penny on top of this is of minor importance in gas economics compared with the chance to encourage more intensive exploration." (Sunday Times 18.12.66) (A copy of Hutchinson's original calculations are shown in Exhibit 13 Table 5.)

An alternative method to the opportunity cost approach to market price is to calculate a price at which the market for gas will be cleared, and this leads us to the third point of conflict between Shell/Esso and the Gas Council mentioned above, i.e. the market on which the Gas Council should concentrate. Whereas the Gas Council want to challenge coal and oil in the base energy market, Shell/Esso argue that the 3,000 m.cu. ft. per day of natural gas forecasted for 1975 should be devoted primarily to meeting the growing demand of the public distribution sector.

Total energy demand in the U.K. in 1964 was 286 million tons of coal equivalent. The National Institute of Economic and Social Research, aggregating energy forecasts for individual industries and sectors, have projected that total demand will have risen to 325 - 365 million tons of coal equivalent by 1970, and 370 - 410 m.t.c.e. by 1975. The National Plan assuming a rate of growth of 2.1% p.a. for energy up to 1970 estimated a demand of 324 m.t.c.e. by 1970, and a similar growth rate would bring this figure up to 362 m.t.c.e. by 1975.[1] (See Exhibit 14). One can also use the rough measure of energy coefficients (See Exhibit 15) which allows one to make adjustments to these forecasts to allow for changing growth rates.

The share of gas in total energy in the U.K. is 7%, and this is directed entirely to the public distribution market. A breakdown by regions and sectors of gas production and consumption is given in Exhibit 16. In terms of current sales, 57% goes to residential gas in specialised applications. (The balance of 3% is used by public administration and by the area gas boards for their own purposes). Recent annual percentage increases of the overall public distribution market are given in Exhibit 17.

Residential demand has been growing even faster than this, as the result of the rapid increase in the sale of gas fuelled room heaters, warm air systems, and hot water central heating installations. Some idea of the increase can be gained by looking at Exhibits 18 and 20.

In overall terms, in 1965 the residential sector accounted for 26% of final energy demand, and though by 1975 it will have roughly the same relative position in gross terms, its demand for effective heat will be half as much again.[2]

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1. 1,000 m.c.f.d. of natural gas equals 13.5 m. tons of coal per year (at 270 therms per coal ton) or 8.6 m. tons of oil per year (424 therms per oil ton).

2. Effective heat takes into account the efficiency in use of the various fuels.

To make one further sub-division, we can distinguish four broad groups in the residential demand - cooking, water-heating, refrigeration and space-heating. Of these it is the prospects of space-heating which seem most startling. The Deputy Chairman of the North Thames Gas Board recently forecast that in North London the proportion of homes heated by gas woul rise from 17½% in 1966 to 47% in 1970. He also pointed out two trends encouraging gas consumption in space-heating, firstly the increase of whole-house heating rather than individual room heating, and secondly the tendency for the level of temperature adopted in homes to rise from the current $65^{\circ}$ F to the region of $70^{\circ}$ F current in the U.S. He consequently forecasted a rise of 48% in space-heating in North London by 1970, a rise which would raise the share of gas heating in total gas output in North London from 40% to 76%. The current price of alternative fuels for living room heating is shown in Exhibit 19.

The industrial market is much larger than the domestic one, currently demanding some 25,000 million therms per annum of all fuels. In the United States over half natural gas goes to industry, particularly as industry demand is more stable, and with 200,000 miles of pipeline, constant load factors are particularly important. In the U.K. gas has been confined to the premium markets, those where gas has a special advantage over other fuels either because its temperature can be accurately controlled (in glass melting and brick burning this is particularly important) or because of cleanliness (the food, and pottery industries are examples of this). The total size of this market is 2,500 m. therms per annum or 10% of the industrial market. Currently it is supplied by manufactured gas, liquid petroleum gas, gas oils and in some cases by electricity. Gas oils at 7½d. a therm are the most serious competitors, but it is generally agreed that cost prices of 5d. a therm would allow gas to compete effectively and increase her market share.

The rest of the industrial market buys fuels basically on the value of the heat content. Coal and oil are the basic fuels for this purpose. (See Exhibit 21). Bulk users of heavy oil pay 4½d. - 5d. a therm with some regional variation, and coal is similarly priced to large users. For power stations coal is sold at 4½d. a therm with up to a penny a therm discount for favourable locations. If the distribution costs of natural gas lie between 1½d. and 3d. a therm, clearly the beach price would have to be very low to compete, particularly as oil could probably lower her prices considerably and still make adequate returns. In the U.S. the average price of gas to industrial consumers is about 3d. a therm, and Dutch prices range from 4.2d. to 4.5d. a therm for large users. Shell-Esso have argued however that this market is irrelevent for the gas industry.

If gas demand in the public distribution sector continues to grow at 10 % p.a. (the Gas Council puts the figure at 7½% between 64 and 70) then 2,700 m.cu. ct. per day of natural gas equivalent will be demanded by 1975. Even assuming an 8% growth rate, the total demanded by 1986 would be 4,500 m.cu.ct. per day, and this would require natural gas deposits at least as large as those at Gronigen.

One could add, too, the market for natural gas for non-fuel uses which is estimated to amount to 2,000 m. therms p.a. by 1970. The petro-chemical industry itself consumes the equivalent of 1,400 millions therms p.a. in manufacturing amonia, methyl alcohol, hydrogen cyanide, acetelyne, and methyl chloride. This figure is expected to double in a few years. However, for much of this market delivered prices would have to go below 4d. a therm though North Sea Gas producers could set up their own petro-chemical complexes on the East Coast.

It is on the basis of these considerations that Shell/Esso believe that the public distribution sector can absorb the great majority of the natural gas from the North Sea, and that prices should therefore be set in terms of existing prices in this sector. Prices could be cut in order to achieve the assumed increase of demand in the sector, for as David Barran himself remarked, "Even relatively modest price reductions - of the order of 20-25% would ensure continued expansion of the residential market, with corresponding advances in commercial and premium industrial sales." Having thus established prices to clear the public distribution market, a beach price for natural gas can be obtained by subtracting distribution and overhead costs sustained by the Gas Council. On the basis of current prices (see Exhibit 13) the beach price under this method would come out well in excess of 4d. a therm.

## The Minister of Power:

The Minister of Power imposed a compromise in the case of the B.P. negotiations over West Sole. He clearly played an important though less evident role in later price negotiations. His interventions have had to take into account considerations which were not relevant to either the Gas Council or the oil companies. To begin with the Minister of Power shapes Britain's energy policy and is responsible for four of the five sources of energy supply, coal, electricity, atomic energy and gas. Britain's fuel industries are currently spending over £1,100 million a year to provide extra capacity - that is a sixth of national total capital spending of which the electricity industry alone is spending £700 million on new capacity. Consequently it is of prime importance from the Minister's point of view to avoid any over-capacity. Indeed even before it was known that the North Sea would yield considerable amounts of Gas, the fuel industries were reckoning on selling a total of 337 million tons of coal equivalent by 1970 whereas the Ministry of Power forecast, on the basis of the optimistic 3.8% growth rate of the National Plan, a figure of only 324 million.

The most delicate area of consideration for the Minister is the effect which natural gas will have on the coal industry. In evidence to the Select Committee on Nationalised Industries (see the Committee's Second Report, the volume on "Exploitation of North Sea Gas" no.372 25th July 1968) the Coal Board argued that the effect of the introduction of North Sea Gas into Britain as envisaged in the White Paper on Fuel Policy (Cmnd 3438) would be to reduce demand for coal by some 24 million tons. This would mean that assets to the value of £100 m. would have to be written off, and that there would be a rise in the coal that continued to be produced if overheads could not be reduced fast enough to keep pace with reduced production. On top of this should be added a further £70 - £85 million cost to the Exchequor, if the manpower displaced through the competition of North Sea gas were assisted on the same scale as the social costs of redundancy are at present under the Coal Industry Act 1967. There was an even more serious long term consideration. The power station market is the one market where coal sales were rising (See Exhibit 23). The N.C.B. stated that they were confident that they could produce coal suitable for power station use at a cost of about 3¼d. a therm ex-pit in quantities of 70-80 million tons. (These figures are considerably below the average cost of coal as it stands at present, see Exhibit 22). If the power stations were converted to natural gas, and the low cost general coal could not find an outlet, "it would not be possible to produce the high quality coal which would be available from the same pits, becuase it would not be possible to keep a pit open just to produce the quarter of its production which represented the high quality coal."

These considerations underlay the Minister's public energy decision in October 1968 not to allow Hams Hall power station to convert to natural gas in spite of pressures from both the C.E.G.B. and the Gas Council. They may also lie behind the Minister's refusal to allow drilling in the Irish Sea (outside Gulf's five blocs). Here there is the added political difficulty of piping gas on to Welsh shores. Certainly the 26 mining M.P.s have been one of the strongest pressures in the House of Commons for a high beach price for North Sea Gas.

There is also the question of the balance of payments. In 1965 Britain imported 65 million tons of oil and about 36 m.cu.ft. of natural gas. Total expenditure on net oil imports added up to £500 million in the same year and the figure is growing (see Exhibit 24). For every 430 million therms of natural gas, there is a saving of about 1 million tons of crude oil, in money terms from £6-8 million. The threat to the oil industry itself is clear, and this lies behind the suggestion that the solution to the natural gas pricing problem would be a market arrangement whereby the Gas Council could have low beach prices on the condition that they did not challenge the oil industry in the base energy market.

On the other hand, the Minister is also aware that a low gas price in Britain implying a squeezing of the drilling companies, might have adverse effects on Shell and B.P. in the Middle East, causing the Middle East governments to raise their taxation rate, and thus reduce the return flow of profits into the U.K.

Lastly, the Ministry of Power have been pressed to consider both the regional implications of natural gas, and the importance for the British industry as a whole to have cheap energy. The proportion of fuel to total costs varies from almost nothing to 30% in some industries. For manufacturing as a whole the figure is 3½%. A cheap price for natural gas it has been argued would increase the competitivity of British industry. The same argument goes for the cost of living for heat and light account for 5% of the household budget and the figure is growing.

On what principles would you base your estimation of a beach price for natural gas if employed as an advisor by Shell/Esso? Would these principles alter if you were asked the same question by the Gas Council or the Minister of Power? Can you suggest a price in each of these cases, and if not, what further information would you need?

## APPENDIX 1

### THE COSTS OF NORTH SEA GAS PRODUCTION

This appendix isolates the stages in the process of bringing North Sea Gas to the beach, and assigns costs where possible.

1. Seismic research. This may continue say two years prior to drilling. Cost £0.5m. - 1.25 m.

2. Exploration strings. Exploration drilling is of two kinds, 'wildcat' and appraisal after the initial find. Both are done from a floating barge, boat or rig. The annual cost of such a rig is £3 - 3.5m. Exploration wildcats take about 3 months to drill, appraisal wells 2 months, the difference being explained by the fact that with appraisals the drillers already know the nature of the structures through which they are working. Thus it is possible to drill 4 wildcats a year at a cost of £0.75m. each, or 6 appraisals at a cost of £0.5m. each. The production test for a wildcat which has struck gas is over a very limited area. It is usual therefore to drill say half a dozen appraisal wells to judge the extent of the field. One drilling company recently offered gas after only four appraisals, but the government concerned wanted six drilled before any contract.

3. Production wells. These are drilled from a platform whose construction time is 10 months and whose cost is £1m. A derrick is then moved into place. It costs about £0.5m. to move a derrick to a platform from any other platform, and £0.2m. to move the derrick from one side of the platform to the other. A derrick can drill say 5 wells from one position. A well takes 1½-2 months, a good deal depending on the depth of water. The annual cost of drilling over and above the cost of the platform is £2-2½m. The number of wells drilled from a platform is usually in the range 10-15. While drilling is in progress, no wells already drilled by the derrick in that position are used, because of the danger of fire arising from the collar falling down onto the drill head.

   The number of production wells needed for a field depends on the capacity of the wells, rates of breakdown, the load factor and the timing of production. Each well is capable of producing 15-20m.c.f.d. Hinde estimates 15 m.c.f.d., Amoco have said that 20m.c.f.d. is a maximum, Shell estimate rather above this. On top of this, allowance must be made for wells which are out of order. Since it is expensive to move a derrick, the drillers are unwilling to repair every well the moment it breaks down, particularly during the peak of the summer months which are the most suitable months for replacement and repairing. A generous allowance for this would be 25% more wells than total estimated wells.

The load factor refers to the range of flow rates. At a 60% load factor, a company contracting for a rate of 500 m.c.f.d. must be prepared to produce 167% of this at any time and over any period. If the load factor was 80% then the figure would be 125% and so on. Clearly this has to be taken into account in the estimate of the number of wells necessary.

The final factor affecting the cost of production wells is the timing of the drilling. According to one pattern, just under a half the estimated total wells would be drilled in the build-up period, say four years. The derricks would then be removed and brought back again in 2½ years time to add another half. In the 14th and 15th year derricks and platforms might return for replacements, and possibly a few additional wells as the pressure drops.

4. Observation wells. These are to monitor the reservoir in the process of production, check pressure and so on. They take roughly the same time as appraisal wells to drill. It is usual to have two for fields in the range relevant to the North Sea.

5. Compression. Compressors come into operation in the latter part of the life of the well. They require a platform as well as the compressors themselves.

6. Pipeline. B.P. used a 16" pipeline from West Sole because of availability. Since then there have been developments in pipeline production, and Shell/Esso are using a 30" pipe, which is the largest they can obtain. For the larger and now the more common pipe, the main costs would be spread over two years and amount to say £10m. for a field 50 miles out. There would be further costs both in connecting new wells to the main pipeline (£0.5m.), and in cleaning and repairing the existing pipes. These would certainly not exceed the initial costs of the main pipeline. B.P. have had considerable difficulty with their pipeline, and say that they will require a survey before laying the next one. Hinde's figures are acknowledged as too low by all sides, though doubling them would probably be overdoing it.

7. Operating costs. It is wise to allow a 5% p.a. increase in operating costs to cover inflation, and extra costs incurred in increasing pressure.

8. Insurance. In general the oil companies aim to remove the difference between land and sea operations, rather than to insure everything. The insurance of the rig is included in the rental, or estimated running cost. Marine Insurance at first came to about 3.75% of installed capital (excluding pipelines), and covered the loss of the capital and the cost of removal of the wreckage. It did not cover the cost of gas foregone through the wreckage. After the series of mishaps to rigs Lloyds increased their rate on sėmi-submersibles to 9% in 1968. Insurance on installed capital of the pipeline is 1.5%, which covers bursts and breakages. Most equipment of the major oil companies tends to be uninsured, since in effect they act as their own insurers. One estimate has suggested 0.1d. per therm to cover insurance costs of the kind discussed here.

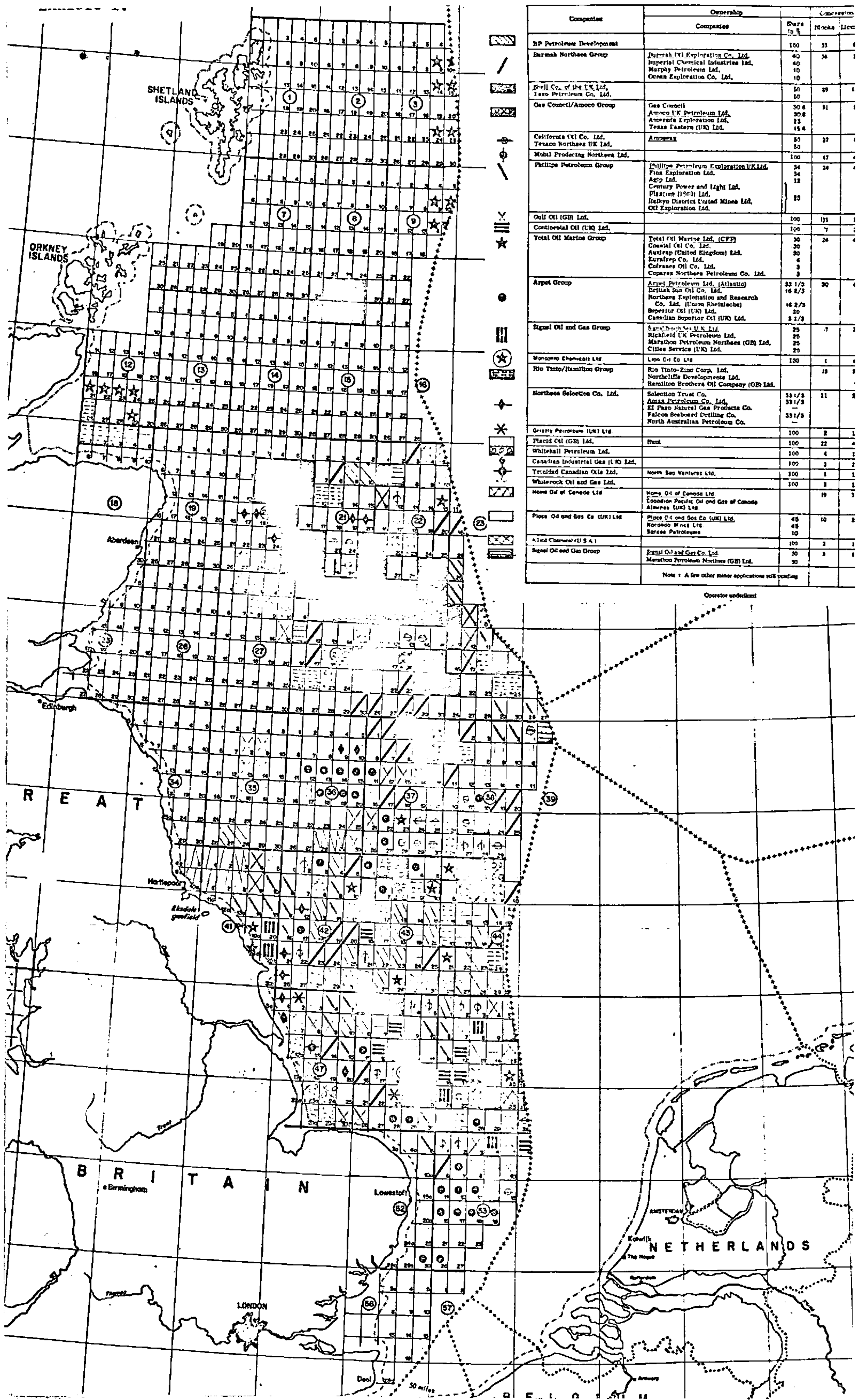
9. General. Very broadly one can weight costs in the following way: exploration 1-2, field facilities (observation and production facilities, not pipelines) 1, pipelines 1, operating costs 1.

10. Tax. Cash investment grants are receivable on all capital at the rate of 20%. Theoretically they should be paid immediately. In fact, there is usually one year's delay. Royalties of 12½% are payable on the well-head value, which equals the beach price minus the transmissions costs. They are regarded as an expense before tax. Profits are subject to corporation tax of 40%.

11. Contract timing. The contract is usually signed after the survey, the wildcats, and appraisal wells. Pipelines are usually post-contract, though in the case of Shell-Esso the protracted negotiations and interim agreements mean that certain of the development wells, and the pipeline are pre-contract.

| Companies | Ownership: Companies | Share in % | Concessions: Blocks | Concessions: Licences |
|---|---|---|---|---|
| BP Petroleum Development | | 100 | 33 | [illegible] |
| Burmah Northsea Group | Burmah Oil Exploration Co. Ltd.<br>Imperial Chemical Industries Ltd.<br>Murphy Petroleum Ltd.<br>Ocean Exploration Co. Ltd. | 40<br>40<br>10<br>10 | 34 | [illegible] |
| Shell Co. of the UK Ltd.<br>Esso Petroleum Co. Ltd. | | 50<br>50 | 89 | [illegible] |
| Gas Council/Amoco Group | Gas Council<br>Amoco UK Petroleum Ltd.<br>Amerada Exploration Ltd.<br>Texas Eastern (UK) Ltd. | 30.8<br>30.8<br>23<br>15.4 | 31 | [illegible] |
| California Oil Co. Ltd.<br>Texaco Northsea UK Ltd. | Amoseas | 50<br>50 | 37 | [illegible] |
| Mobil Producing Northsea Ltd. | | 100 | 17 | [illegible] |
| Phillips Petroleum Group | Phillips Petroleum Exploration UK Ltd.<br>Fina Exploration Ltd.<br>Agip Ltd.<br>Century Power and Light Ltd.<br>Plascom (1909) Ltd.<br>Halkyn District United Mines Ltd.<br>Oil Exploration Ltd. | 34<br>34<br>12<br>20 | 24 | [illegible] |
| Gulf Oil (GB) Ltd. | | 100 | 135 | [illegible] |
| Continental Oil (UK) Ltd. | | 100 | 7 | [illegible] |
| Total Oil Marine Group | Total Oil Marine Ltd. (CFP)<br>Coastal Oil Co. Ltd.<br>Austrap (United Kingdom) Ltd.<br>Eurafrep Co. Ltd.<br>Cofrasea Oil Co. Ltd.<br>Coparex Northsea Petroleum Co. Ltd. | 30<br>30<br>30<br>4<br>3<br>3 | 24 | [illegible] |
| Arpet Group | Arpet Petroleum Ltd. (Atlantic)<br>British Sun Oil Co. Ltd.<br>Northsea Exploitation and Research Co. Ltd. (Union Rheinische)<br>Superior Oil (UK) Ltd.<br>Canadian Superior Oil (UK) Ltd. | 33 1/3<br>16 2/3<br>16 2/3<br>30<br>3 1/3 | 20 | [illegible] |
| Signal Oil and Gas Group | Signal North Sea U.K. Ltd.<br>Richfield UK Petroleum Ltd.<br>Marathon Petroleum Northsea (GB) Ltd.<br>Cities Service (UK) Ltd. | 25<br>25<br>25<br>25 | 7 | [illegible] |
| Monsanto Chemicals Ltd. | Lion Oil Co Ltd | 100 | 1 | [illegible] |
| Rio Tinto/Hamilton Group | Rio Tinto-Zinc Corp. Ltd.<br>Northcliffe Developments Ltd.<br>Hamilton Brothers Oil Company (GB) Ltd. | | 13 | [illegible] |
| Northsea Selection Co. Ltd. | Selection Trust Co.<br>Amax Petroleum Co. Ltd.<br>El Paso Natural Gas Products Co.<br>Falcon Seaboard Drilling Co.<br>North Australian Petroleum Co. | 33 1/3<br>33 1/3<br>—<br>33 1/3<br>— | 11 | [illegible] |
| Grizzly Petroleum (UK) Ltd. | | 100 | 2 | 1 |
| Placid Oil (GB) Ltd. | Hunt | 100 | 22 | [illegible] |
| Whitehall Petroleum Ltd. | | 100 | 4 | [illegible] |
| Canadian Industrial Gas (UK) Ltd. | | 100 | 2 | [illegible] |
| Trinidad Canadian Oils Ltd. | North Sea Ventures Ltd. | 100 | 1 | 1 |
| Whiterock Oil and Gas Ltd. | | 100 | 3 | 1 |
| Home Oil of Canada Ltd | Home Oil of Canada Ltd.<br>Canadian Pacific Oil and Gas of Canada<br>Almeree (UK) Ltd. | | 19 | [illegible] |
| Place Oil and Gas Co (UK) Ltd | Place Oil and Gas Co (UK) Ltd.<br>Noranda Mines Ltd.<br>Sarcee Petroleums | 45<br>45<br>10 | 10 | [illegible] |
| Allied Chemical (U S A ) | | 100 | 2 | 1 |
| Signal Oil and Gas Group | Signal Oil and Gas Co. Ltd.<br>Marathon Petroleum Northsea (GB) Ltd. | 50<br>50 | 3 | [illegible] |
| | Note : A few other minor applications still pending | | | |

Operator underlined



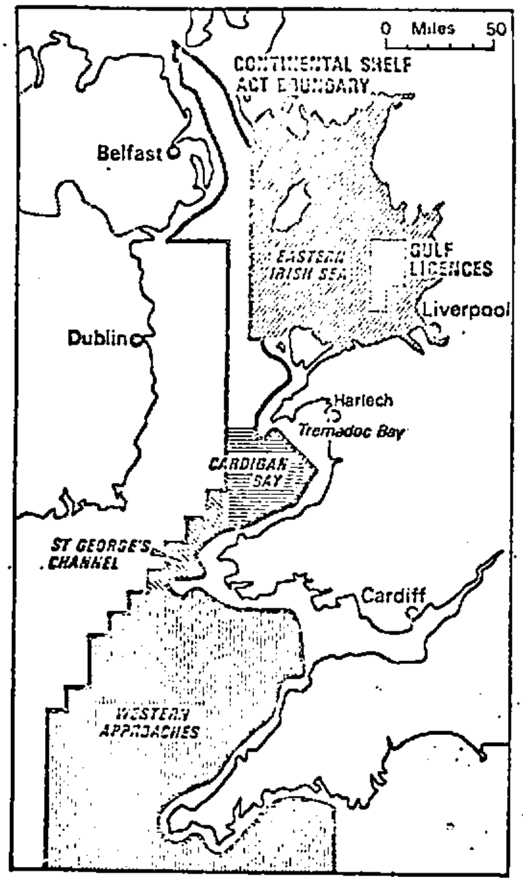



Exhibit 2. British area of the Irish Sea with bloc allocations.

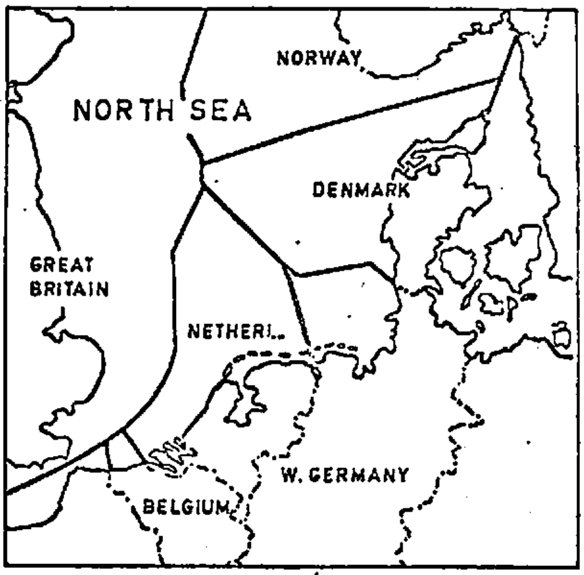
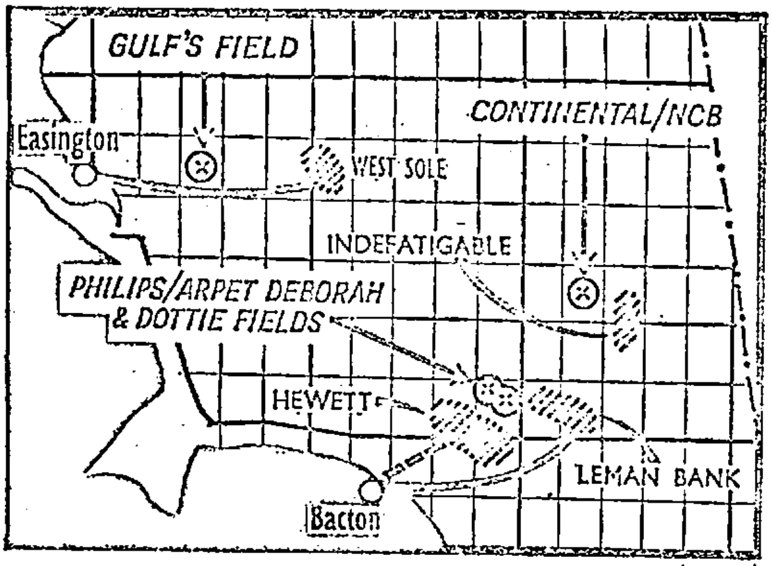
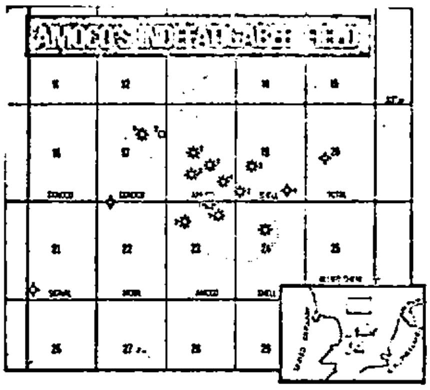



Exhibit 3. Division of the North Sea among the surrounding countries with regard to prospecting for oil and gas.

Exhibit 4.    The Main Fields Discovered in the North Sea.



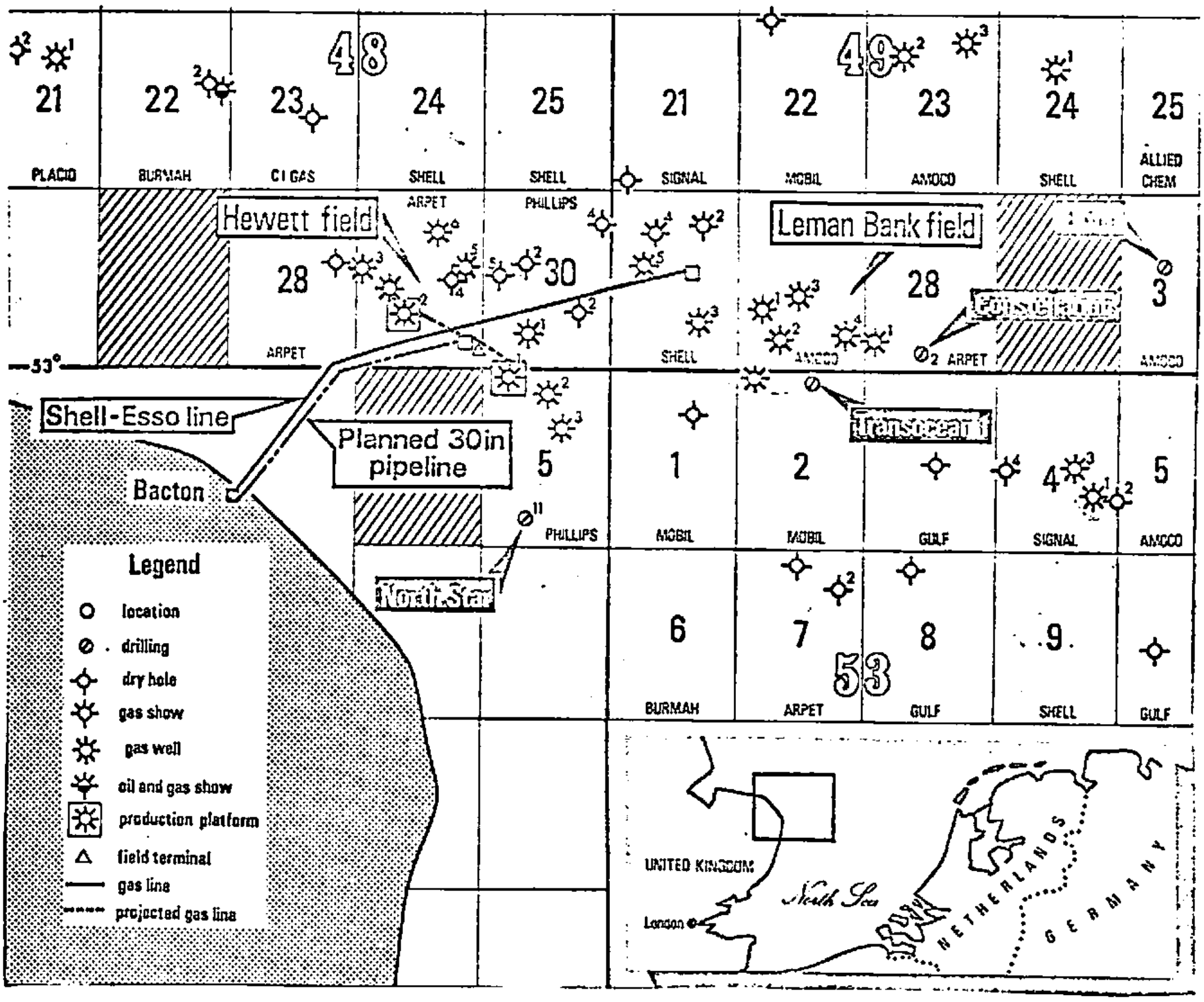


Exhibit 5.

## RESERVES - TO - DAILY TAKE RATIO

1. This ratio is always based on "originally recoverable reserves". It is expressed in terms of 1 million cubic feet per day of contracted take for every "X"000,000,000 cubic feet of originally recoverable reserves. To take an example, a nominal depletion period of sixteen years contains 5840 days: the ratio in this case is 1:5.84 (i.e. 1.0 million cubic feet day for each 5,840,000,000 cubic feet of originally recoverable reserves: the probable economic field life, comprising a build-up period, offtake plateau and tail-off, would be between 20 and 25 years.

2. The following table gives other examples of this relationship between recoverable reserves and contracted daily take:

| Probable Economic Field Life (years) | 20 - 25 | 25 - 30 | 30 - 35 | 35 - 40 |
|---|---|---|---|---|
| Nominal Depletion Period (years) | 16 | 20 | 25 | 30 |
| Reserves: Take Ratio: | 1 : 5.84 | 1 : 7.3 | 1 : 9.2 | 1 : 11 |
| Recoverable Reserves ($Scf \times 10^{12}$) | Daily Take (MMcf/d) | | | |
| 4.0 | 685 | 548 | 435 | 364 |
| 4.5 | 771 | 616 | 489 | 409 |
| 5.0 | 856 | 685 | 543 | 455 |
| 5.5 | 942 | 753 | 598 | 500 |
| 6.0 | 1027 | 822 | 652 | 545 |
| 6.5 | 1113 | 890 | 706 | 591 |
| 7.0 | 1199 | 959 | 761 | 636 |
| 7.5 | 1284 | 1027 | 815 | 682 |
| 8.0 | 1370 | 1096 | 870 | 727 |
| 8.5 | 1455 | 1164 | 924 | 773 |
| 9.0 | 1541 | 1233 | 978 | 818 |
| 9.5 | 1627 | 1301 | 1033 | 864 |
| 10.0 | 1712 | 1370 | 1087 | 909 |

Exhibit 6.

GAS FIELDS - FREE WORLD OUTSIDE NORTH AMERICA

| Maximum field size $10^{12}$ s.c.f. | Number of fields | Total ultimate recovery $10^{12}$ s.c.f. | Average ultimate recovery $10^{12}$ s.c.f. |
|---|---|---|---|
| Up to 0.5 | 295 | 31.8 | 0.1 |
| 0.5 - 1 | 21 | 13.6 | 0.65 |
| 1 - 5 | 17 | 33.1 | 1.95 |
| 5 - 10 | 5 | 35.1 | 7.0 |
| 10+ | 2 | 88.0 | 44.0 |
| TOTAL: | 340 | 201.7 | 0.59 |

Exhibit 7. Estimated Production Costs of North Sea Gas.

COST OF AN EXPLORATION WELL
One Mobile Rig Operation
(Three 12,000 ft wells per annum)

| | Exploration Well Unsuccessful | Exploration Well Successful |
|---|---|---|
| | £ | £ |
| *Contractors' Costs* .. .. .. .. | 380,000 | 380,000 |
| *Operating Costs* | | |
| Mud .. .. .. .. .. | 27,000 | 32,000 |
| Casing .. .. .. .. .. | 35,000 | 46,000 |
| Tubing .. .. .. .. .. | — | 7,000 |
| Cementing .. .. .. .. | 15,000 | 18,000 |
| Well equipment .. .. .. | 2,000 | 15,000 |
| Other .. .. .. .. .. | 34,000 | 37,000 |
| *Base and Service Costs* | | |
| Base .. .. .. .. .. | 20,000 | 20,000 |
| Ships .. .. .. .. .. | 73,000 | 73,000 |
| Helicopter .. .. .. .. | 44,000 | 44,000 |
| TOTAL COST | 630,000 | 672,000 |

LIKELY AVERAGE COSTS OF NORTH SEA GAS
(15-year contract)

| | 100 million cubic feet per day | 200 million cubic feet per day | 500 million cubic feet per day |
|---|---|---|---|
| | £000's | £000's | £'s |
| *Exploration Costs* | | | |
| Survey and exploration licence .. | 500[a] | 500[a] | 500[a] |
| Exploration wells: | | | |
| Nine dry wells (at £630,000) .. | 5,670 | 5,670 | 5,670 |
| One successful well .. .. | 670 | 670 | 670 |
| Sub Total | 6,840 | 6,840 | 6,840 |
| *Development Costs* | | | |
| Step-out wells (2@£670,000) .. | 1,340 | 1,340 | 1,340 |
| Observation wells (2@£500,000) .. | 1,000 | 1,000 | 1,000 |
| Observation and step-out platforms.. | 400 | 400 | 400 |
| Production: platforms .. .. | 1,000 | 2,000 | 3,000 |
| wells .. .. .. | 3,500 | 7,000 | 17,500 |
| Dehydration .. .. .. .. | 40 | 80 | 200 |
| Separation .. .. .. .. | 60 | 120 | 300 |
| Instruments .. .. .. .. | 40 | 80 | 100 |
| Sub total | 7,380 | 12,020 | 23,840 |
| *Pipeline and Compressor Costs* .. .. | 6,500 | 7,000 | 9,500 |
| TOTAL CAPITAL COST | 20,720 | 25,860 | 40,180 |
| Annual sales (million therms) .. | 365 | 730 | 1,825 |
| Capital cost per therm[b] .. .. | 0.73d | 0.46d | 0.30d |
| *Production Costs* (per therm) .. .. | 0.13d | 0.12d | 0·10d |
| TOTAL COST PER THERM | 0.86d | 0.58d | 0.40d |

NOTES: (a) Half of total area costs
(b) With 20% cash investment grants.

100 cubic feet of natural gas contain about 1 therm of heat.

Source: P. Hinde. Fortune in the North Sea. London 1966. pp.163-5.

Exhibit 8

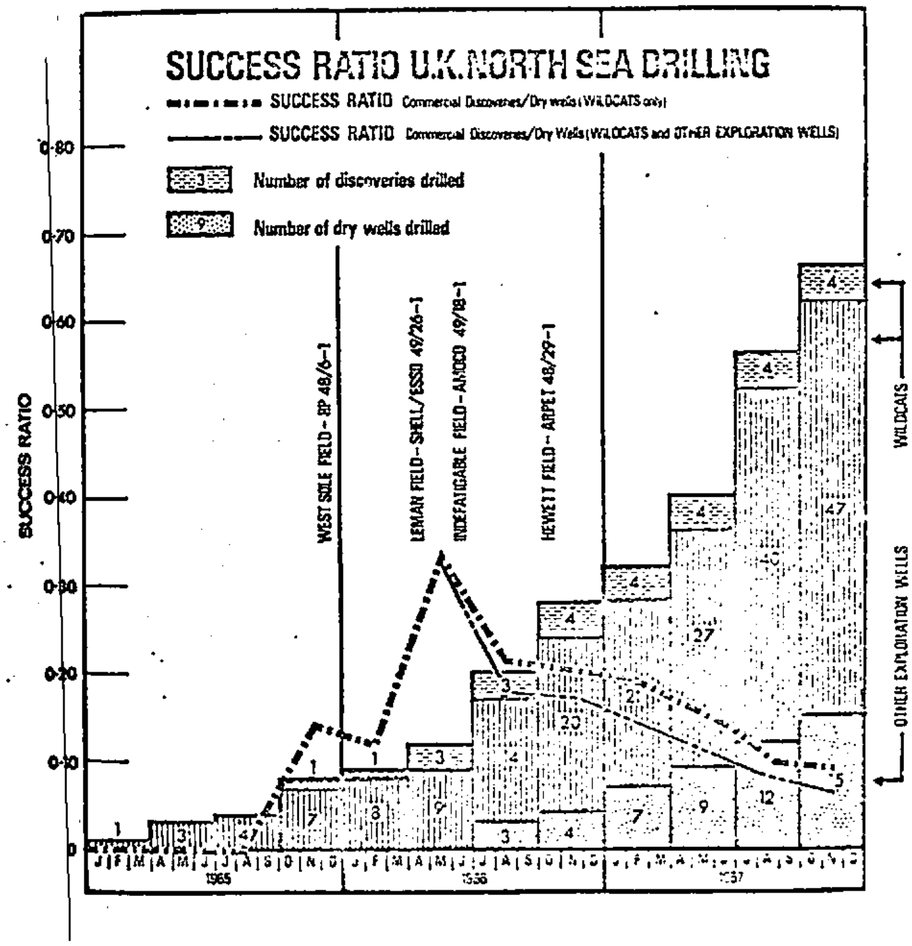



Exhibit 9.

Cost schedule for the supply of natural gas.

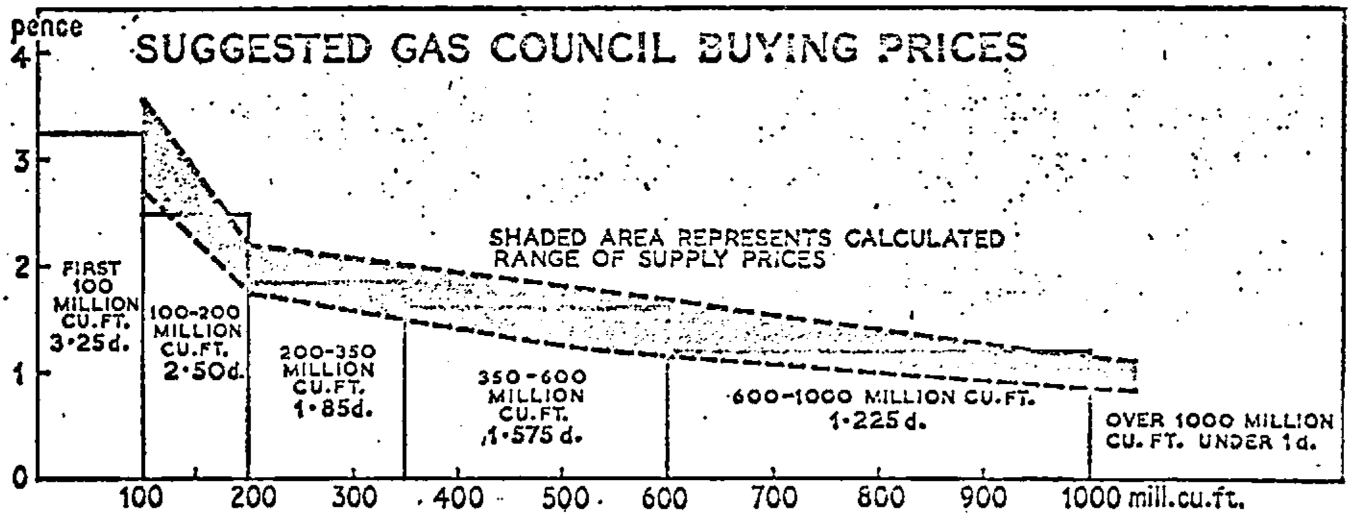


Exhibit 10. International Comparisons of Natural Gas Consumption.

CONSUMPTION OF NATURAL GAS – 1964

| | Net Gas Available | Gas used in Reforming and mixing | Gas Distributed Directly | |
|---|---|---|---|---|
| | | | Domestic | Industrial |
| | mill. therms | % | % | % |
| U.S.A. .. .. | 128,884 | 1·2 | 30·4 | 57·4 |
| U.S.S.R. .. | 38,475 | 0·9 | 3·7 | 86·8 |
| Canada .. | 5,045 | — | 32·4 | 51·0 |
| Italy .. .. | 2,720 | 4·3 | 15·3 | 78·8 |
| France .. .. | 1,883 | 26·0 | 8·6 | 64·4 |
| Germany (F.R.) | 698 | 50·4 | — | 49·6 |
| Austria .. | 620 | 21·5 | 1·2 | 76·9 |
| Poland .. .. | 503 | 2·4 | 7·6 | 87·3 |
| Hungary .. | 297 | 8·6 | 3·1 | 87·1 |
| Czechoslovakia.. | 273 | — | 4·1 | 93·2 |
| Netherlands .. | 186 | 22·6 | 26·4 | 46·4 |

SOURCES:
1. Annual Bulletin of Gas Statistics for Europe – U.N.
2. Gas Facts – American Gas Association

Natural Gas as Proportion of Total Energy Consumption *1964*

| | % |
|---|---|
| U.S.A. ... ... ... | 33 |
| U.S.S.R. ... ... ... | 17 |
| Canada ... ... ... | 16 |
| Italy ... ... ... | 10½ |
| France ... ... ... | 4½ |
| Netherlands .... ... | 2½ |
| W. Germany ... ... | 1 |
| U.K. ... .... ... | * |
| Belgium ... ... ... | * |

* less than ½%

DIRECT INDUSTRIAL SALES OF NATURAL GAS – 1964
(Percentages)

| | Austria | France | Italy | Poland | USSR | USA(a) |
|---|---|---|---|---|---|---|
| Electricity generation .. .. .. | 34 | 31 | 14 | 26 | 35 | 35 |
| Iron and steel .. .. .. .. | 21 | 7 | 14 | 32 | 18(b) | 9 |
| Chemicals .. .. .. .. .. | 7 | 43 | 39 | 22 | 11 | 13 |
| Glass, ceramics .. .. .. .. | 2 | 7 | 8 | 7 | 6 | 6 |
| Cement .. .. .. .. .. | 10 | 4 | 4 | — | 7 | 3 |
| Food and drink .. .. .. .. | 3 | — | 4 | — | 4 | 4 |
| Other .. .. .. .. .. | 23 | 8 | 17 | 13 | 19 | 30 |
| | 100 | 100 | 100 | 100 | 100 | 100 |

NOTES: (a) Utility sales – large users only
(b) Including non-ferrous metals

Source: P. Hinde. op. cit. pp. 167-173.

Exhibit 11.

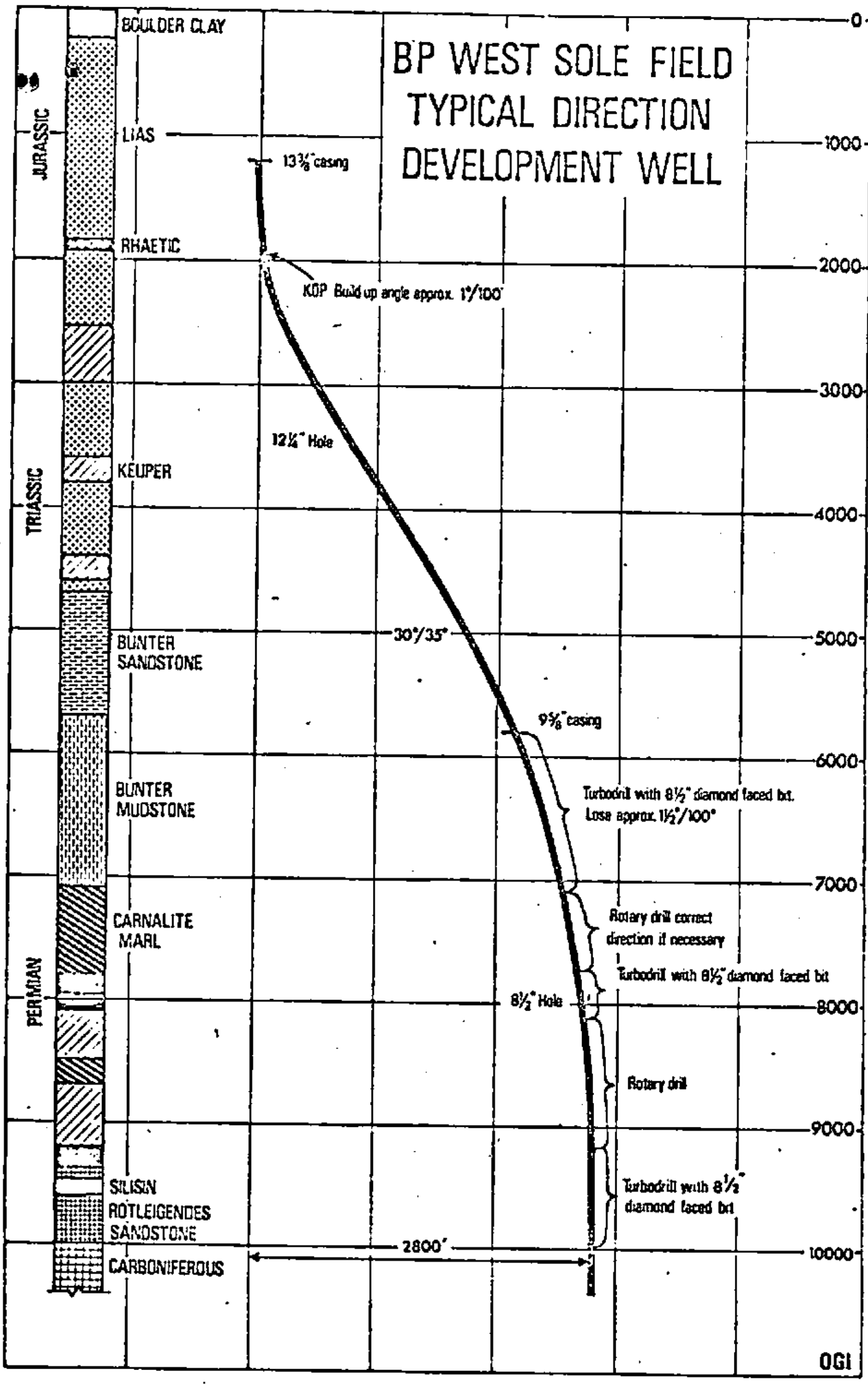



Exhibit 12.

**PROPORTION OF GAS AVAILABLE**
**COAL BASED AND OIL BASED**

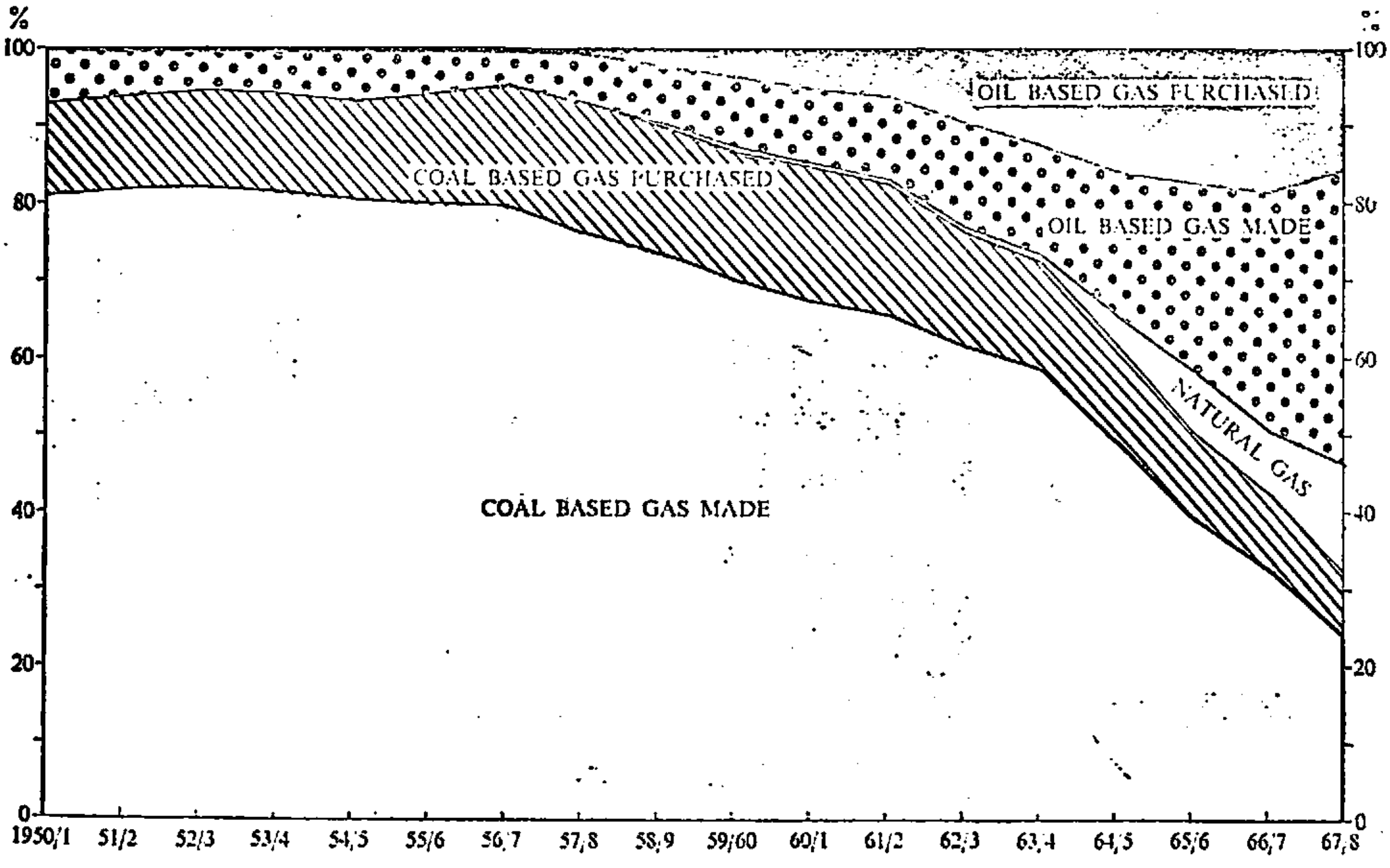


Exhibit 13. Two forecasts by the Gas Council of the demand and supply of gas at an unspecified date.

1st study.

| Types of Utilisation | Annual Consumption (therm/a) | | | Demand (therm/d) | | |
|---|---|---|---|---|---|---|
| | Number | Rate | Total | Peak Rate | Total Winter | Total Summer |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 |
| | Mill. | Mill. | Mill. | | Mill. | Mill. |
| Central Heating (Including Hot Water) | 2 | 1,000 | 2,000 | 8 | 16 | 1·0 |
| Air Heating .. .. | 2 | 450 | 900 | 4 | 8 | — |
| [illegible] .. .. | 4 | 250 | 1,000 | 1·8 | 7·2 | — |
| Small Users .. .. (mainly cookers) | 4 | 100 | 400 | 0·3 | 1·2 | 1·2 |
| Other Cookers .. | 3 | 70 | 200 | 0·2 | 0·6 | 0·6 |
| Other Water Heaters | 2 | 150 | 300 | 0·5 | 1·0 | 1·0 |
| Total Domestic .. | 12 | 400 | 4,800 | | 34·0 | 3·8 |
| Commercial .. / Industrial .. | (2:1) | | (1,000) (1,600) | | 10·0 | 5·0 |
| TOTAL GAS .. .. | | | 7,600 | | 44·0 | 8·8 |

Table 1. Annual load and seasonal variation in demand.

| Raw Materials | Quantity and Price | £ mill. | Mill. Therms Gas/a |
|---|---|---|---|
| 1 | 2 | 3 | 4 |
| North Sea .. | 3,600 mill therm @ 3·25d. | 49 | 3,600 |
| L.N.G. .. | 720 mill. therm @ 5·5d. | 16·5 | 720 |
| L.P.G. .. | 360 mill. therm @ 6d. | 9 | 360 |
| Refinery Gas | 360 mill. therm @ 5d. | 7·5 | 360 |
| Other Gas | 360 mill. therm @ 8d. | 12 | 360 |
| Naphtha .. | 6 mill. ton @ £7 | 42 | 2,200 |
| | | 136 | 7,600 |

Table 2. Cost of gas and feedstock.

| | | £ mill. | £ mill. |
|---|---|---|---|
| 1 | | 2 | 3 |
| Existing Assets (1964) .. | | 600 *less* 40% written off | 360 |
| *Production and Storage* | | | |
| 6,000 mill. ft³/d Reformers | 420 | | |
| 900,000 ton Liquid Storage | 45 | | |
| Underground Storage .. | 20 | 485 *less* 32% written-off | 330 |
| *Distribution and Transmission* 10 years @ £60 mill./a .. | | 600 *less* 12½% written off | 525 |
| *Other Services* 10 years at £15 mill/a .. | | 150 *less* 12½% written off | 131 |
| TOTAL .. .. .. | | | 1,346 |
| Int. Depreciation, Profit, @ 12% | | | 162/a |
| Current Assets £180 mill. @ 8% | | | 14 |
| TOTAL | | | 176/a |

Table 3. Capital requirements.

| Gas Sold and Accounted-for .. .. .. 7,600 mill. therm | £ mill | £ mill | d./therm |
|---|---|---|---|
| Cost of Gas and Feedstock .. .. .. | 136 | 186 | 5·9 |
| Manufacturing Costs .. .. .. .. | 50 | | |
| Distribution .. .. .. .. .. | 50 | 50 | 1·6 |
| Consumer Service .. .. .. .. | 25 | | |
| Collection and Administration .. .. .. | 25 | 65 | 2·1 |
| Welfare .. .. .. .. .. | 15 | | |
| Rates .. .. .. .. .. | 8 | 8 | 0·25 |
| Conversion to Natural Gas .. .. .. | 18 | 18 | 0·4 |
| Depreciation, Interest and Profit .. .. | 176 | 176 | 5·4 |
| TOTAL .. .. .. .. .. .. | | 503 | 15·9 |
| *Add* 6% for unaccounted gas .. .. .. | | 30 | |
| | | 533 | |
| *Revenue* | | £ mill. | |
| Domestic. 4,800 mill. therm @ 20d. .. .. | | 400 | |
| Commercial. 1,000 mill. therm @ 16d. .. .. | | 67 | |
| Industrial. 1,800 mill. therm @ 10d. .. .. | | 75 | |
| TOTAL .. .. .. .. .. .. .. .. | | 542 | |

Table 4. Revenue Account.

Here manufacturing costs are assumed to remain at the present level (twice as much gas and half as costly to produce); distribution costs have been doubled to take account of transferring to natural gas; consumer service, collection and welfare are assumed to remain the same; conversion costs are estimated on the basis of £30 per consumer.

## 2nd study.

| 1 | Alt. (a) (£ mill.) 2 | Alt. (b) (£ mill.) 3 |
|---|---|---|
| Existing Assets £1,346 *less* 25% .. .. .. | 1,010 | 1,010 |
| Distribution 7·5 mill. @ £100 *less* 12½% | 656 | |
| or 15 mill. @ £100 *less* 12½% .. .. .. | | 1,313 |
| Transmission 120 mill. therm/d @ £5 = £600; *less* 12½% .. .. .. .. .. | 525 | 525 |
| TOTAL .. .. .. .. .. | 2,191 | 2,848 |
| Depreciation, Interest and Profit @ 12% .. | 262 | 342 |
| Current Assets £360 mill. @ 8% .. .. | 29 | 29 |
| TOTAL .. .. .. .. .. | 291 | 371 |

Table 5. Capital Requirements.

in (a) it is assumed that half the distribution network has been renewed or replaced at a cost of £100 per consumer.
in (b) assumed that the whole system has been replaced.

**Cost of Gas and Materials:**

| | Mill. therm | d./therm | £ mill. |
|---|---|---|---|
| North Sea .. | 14,400 | 2·5 | 150 |
| L.N.G... .. | 720 | 5·5 | 16·5 |
| L.P.G. .. | 360 | 6 | 9 |
| Refinery Gas .. | 360 | 5 | 7·5 |
| Naphtha .. | (6 mill. ton) | £7 | 42 |

| | £ mill. (a) | £ mill. (b) | Per therm (d.) (a) | Per therm (d.) (b) |
|---|---|---|---|---|
| Total Gas, and Materials (18,000 mill. therm) .. .. .. .. .. | 225 | | | |
| Cost of Manufacture (including storage) .. | 25 | | 3·3 | |
| Distribution .. .. .. .. .. | 100 | | 1·3 | |
| Consumer Service, Collection, [Adm]inistration, Welfare | 82 | | 1·1 | |
| [...]s (as now) .. .. .. .. | 19 | | 0·25 | |
| Depreciation, Interest and Profit at 12% .. | 291 *or* | 371 | 3·9 *or* | 4·9 |
| Total Cost of Gas Available .. .. | 742 | 822 | 9·9 | 10·9 |
| ÷ 6% Loss .. .. .. .. | 786 | 871 | 10·5*d.* | 11·6*d.* |

| *Revenue* | Mill therm. | | £ Mill. |
|---|---|---|---|
| Domestic .. | 8,700 | @ 14*d.* | 507 |
| Commercial .. | 4,000 | @ 12*d.* | 200 |
| Industrial .. | 5,300 | @ 6*d.* | 132 |
| TOTAL .. | 18,000 | | 839 |

Table 6. Revenue Account.

assumed that all appliances have been converted to natural gas.
assumed also that residential demand has doubled as the result of lower prices.

### Exhibit 14

**Forecasts of inland energy demand in the United Kingdom for 1970 and 1975**

*million tons coal equivalent*

| | Actual 1960 | Actual 1964 | Plan forecast 1970 | National Institute's forecast: Interpolation for 1970 | National Institute's forecast: 1975 |
|---|---|---|---|---|---|
| Iron and Steel .. .. | 34.8 | 36.1 | 37.0 | 40-45 | 45-50 |
| General Industry .. .. | 77.2 | 83.8 | 98.0 | 90-100 | 100-110 |
| Railways .. .. .. | 11.0 | 7.2 | 4.5 | 8 | 7-8 |
| Other Transport .. .. | 22.5 | 29.1 | 38.5 | 36-39 | 44-51 |
| Domestic .. .. .. | 71.5 | 78.7 | 86.0 | 90-105 | 110-125 |
| Other inland .. .. .. | 46.7 | 50.4 | 59.0 | 58-68 | 70-80 |
| Total .. .. .. | 263.7 | 285.3 | 323.0 | 325-365 | 370-410 |
| Stock changes and exports coke, etc. .. .. .. | 1.2 | 0.6 | 1.0 | | |
| Total inland demand .. | 264.9 | 285.9 | 324.0 | | |
| Adjusted for normal temperature .. .. .. | 265.4 | 285.4 | | | |

* At 1960 conversion factors for electricity and gas.
Sources: *National Plan* and NIESR.

## Exhibit 15.

Energy co-efficients (i.e. per cent rise in energy consumption for each 1 per cent rise in GDP) for industrial countries

| | Average 1950-60 | Official Forecasts 1960-70 |
|---|---|---|
| Germany | 0.6 | 0.8 |
| Belgium | 0.5 | 0.6 |
| France | 0.9 | 0.9 |
| Italy | 1.5 | 1.3 |
| Netherlands | 0.8 | 1.0 |
| Total, European Economic Community | 0.8 | 0.9 |
| United States | 0.84 | 0.75 |
| United Kingdom | 0.43 | 0.55 |

Sources: *Long-Term Perspectives for Energy*, ECSC, 1962.
*Energy in the Future*, S. Schurr and B. Netschert. Resources for the Future, Washington, 1962.
*The National Plan*, Cmnd. 2764, 1965.

Energy consumption and economic growth, 1951-64

| | *Average rise in GDP* | *Average rise in energy use* | *Energy/ GDP co-efficient* |
|---|---|---|---|
| | | *per cent* | |
| 1951-55 | 2.8 | 1.8 | 0.68 |
| 1955-59 | 1.8 | 0.1 | 0.05 |
| 1959-63 | 3.5 | 2.8 | 0.80 |
| 1959-64 | 3.7 | 2.7 | 0.73 |
| (1963-64) | 5.4 | 2.6 | 0.48 |

Source: P.E.P.
A Fuel Policy for Britain 1966

## Exhibit 16.

*British Gas Industry at 31st March, 1965.*

| Board | Area ([illegible] miles) | Number of Domestic Consumers | Number of Works | Miles of Main | Output of Gas (mill. therm/a) | Fixed Assets (£ mil.) |
|---|---|---|---|---|---|---|
| Scottish .. .. .. | [illegible] | 925,562 | 52 | 8,428 | 255·1 | 46 |
| Northern .. .. | [illegible] | 658,884 | 14 | 6,546 | 200·4 | 27 |
| North Western .. | [illegible] | 1,660,669 | 35 | 14,182 | 427·8 | 76 |
| North Eastern .. | [illegible] | 759,533 | 24 | 8,119 | 195·2 | 30 |
| East Midlands .. | [illegible] | 1,200,725 | 22 | 11,062 | 436·5 | 72 |
| West Midlands .. | [illegible] | 1,123,629 | 16 | 9,558 | 452·7 | 65 |
| Wales .. .. | 8,000 | 484,947 | 8 | 5,078 | 146·9 | 34 |
| Eastern .. .. | 7,160 | 799,960 | 22 | 7,449 | 198·1 | 43 |
| North Thames .. | 1,050 | 1,791,195 | 15 | 10,293 | 519·1 | 96 |
| South Eastern .. | 3,300 | 1,570,687 | 13 | 11,622 | 399·2 | 70 |
| Southern .. | 5,200 | 636,073 | 8 | 6,663 | 155·8 | 38 |
| South Western .. | 8,250 | 581,392 | 17 | 6,632 | 133·8 | 38 |
| TOTAL .. | 88,750 | 12,133,196 | 246 | 105,632 | 3,520·6 | 635 |

| Gas Sold 1964-65 | Mill. therm | At price *d.*/therm |
|---|---|---|
| Domestic .. .. .. | 1,726 | 26·4 |
| Commercial .. .. .. | 526 | 21·7 |
| Industrial .. .. .. | 915 | 16·0 |
| TOTAL .. .. .. | 3,167 | 22·6 |

## Exhibit 17.

### Growth of Demand for Gas, Actual and Forecast.

**Percentage Increase in Annual Demand for Gas Over Previous Year**

| Year | Domestic | Industrial | Commercial and Other | Total |
|---|---|---|---|---|
| | % | % | % | % |
| *Actual* | | | | |
| 1963–64 ... ... | 4·1 | 1·1 | −2·6 | 1·9 (5) |
| 1964–65 ... ... | 11·1 | 6·3 | −3·0 | 7·0 (8) |
| 1965–66 ... ... | 16·2 | 1·4 | 4·4 | 9·9 (9) |
| 1966–67 ... ... | 13·0 | −2·2 | 5·1 | 7·7 (9) |
| *Forecast* | | | | |
| 1967–68 ... ... | 16·2 | −0·4 | 6·5 | 10·6 |
| 1968–69 ... ... | 12·4 | 11·1 | 4·1 | 10·8 |
| 1969–70 ... ... | 12·8 | 81·5 | 5·1 | 26·6 |
| 1970–71 ... ... | 11·9 | 43·2 | 5·4 | 21·1 |
| 1971–72 ... ... | 10·9 | 19·4 | 6·1 | 13·6 |
| 1972–73 ... ... | 9·7 | 12·0 | 5·6 | 10·2 |

( ) Temperature corrected.

## Exhibit 18.

*Percentage of New Houses equipped with Gas Appliances.*

| Year Ended December | Cookers (%) | Water Heaters* (%) | Wash Boilers (%) | Refrigerators (%) | Gas Heating: Gas Fires (%) | Gas Heating: Central Heating: Water (%) | Gas Heating: Central Heating: Warm Air (%) | Gas Heating: All Forms of Gas Heating (%) | Gas Consumption per Consumer (Therms) | Solid Fuel Grates (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1955 | 82·7 | 16·1 | 24·3 | 2·1 | 2·7 | — | — | 2·7 | 103 | 43·1 |
| 1956 | 79·6 | 15·4 | 21·2 | 1·8 | 3·0 | — | — | 3·0 | 98 | 40·4 |
| 1957 | 80·1 | 13·4 | 20·2 | 1·8 | 1·1 | — | — | 1·1 | 95 | 41·1 |
| 1958 | 79·0 | 13·2 | 17·3 | 2·1 | 1·4 | — | — | 1·4 | 95 | 38·9 |
| 1959 | 75·6 | 11·3 | 12·5 | 2·5 | 1·8 | — | — | 1·8 | 92 | 35·1 |
| 1960 | 74·9 | 11·9 | 9·5 | 2·5 | 1·5 | 1·9 | 1·7 | 5·1 | 120 | 33·1 |
| 1961 | 74·4 | 11·8 | 10·0 | 3·0 | 1·7 | 3·6 | 2·5 | 7·8 | 133 | 29·5 |
| 1962 | 76·5 | 14·6 | 8·2 | 3·2 | 3·7 | 4·8 | 5·2 | 13·7 | 168 | 31·5 |
| 1963 | 76·6 | 16·8 | 7·8 | 2·8 | 4·2 | 6·5 | 10·6 | 21·3 | 213 | 20·8 |
| 1964 | 78·2 | 14·9 | 5·4 | 3·2 | 4·3 | 10·4 | 15·4 | 30·1 | 265 | 16·3 |
| 1965 | 77·7 | 17·4 | 5·3 | 3·5 | 5·9 | 13·8 | 18·5 | 38·2 | 298 | 10·7 |

* Includes sink water heaters plus single and multipoint water heaters plus circulators.

## Exhibit 19.

*Domestic Living-room Heating Cost per Useful Therm of Alternative fuels.*
*Winter Prices (from 1st December, 1965)*

| Fuel | Price/cwt. | Cost/therm | Cost per Useful Therm (d.): Old-type Open Grate | Gas-coke Grate | Convector | Closed Stove* | Portable Appliance |
|---|---|---|---|---|---|---|---|
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
| | s. d. | d. | | | | | |
| Coal (Gp. 1) .. .. .. | 13 7 | 11·19 | 56·0 | 44·8 | 32·0 | — | — |
| Coal (Gp. 3) .. .. .. | 12 1 | 10·15 | 50·8 | 40·6 | 29·0 | — | — |
| Coal (Gp. 5) .. .. .. | 11 0 | 9·43 | 47·2 | 37·7 | 27·0 | — | — |
| Cleanglow .. .. .. .. | 16 9 | 14·08 | 56·3 | 38·1 | 31·3 | 21·7 | — |
| Coalite .. .. .. .. | 16 3 | 13·65 | 54·6 | 36·9 | 30·3 | 21·0 | — |
| Rexco .. .. .. .. | 17 3 | 14·49 | 58·0 | 39·1 | 32·2 | 22·3 | — |
| Homefire .. .. .. .. | 18 6 | 15·55 | 62·2 | 42·0 | 34·6 | 23·9 | — |
| Gloco .. .. .. .. | 14 3 | 12·21 | — | 33·0 | 27·1 | — | — |
| Selected Nuts .. .. .. | 13 2 | 11·51 | — | — | — | 17·7 | — |
| Sunbrite .. .. .. .. | 13 9 | 12·03 | — | — | — | 18·5 | — |
| Phurnacite .. .. .. .. | 17 10 | 14·36 | — | — | — | 22·1 | — |
| †Gas (General Two-part rate) .. | — | 20·00* | — | — | 29·9 | — | 22·2 |
| †Gas (Standard rate) .. .. | — | 27·00 | — | — | 40·3 | — | 30·0 |
| †Electricity | per unit | | | | | | |
| (a) Standard rate .. .. .. | 1·8d. | 52·75 | — | — | 52·8 | — | 52·8 |
| (b) Storage heater rate .. .. | 0·95d. | 27·84 | — | — | 27·8 | — | — |
| Paraffin Oil .. .. .. | per gal. 2s. 4d. | 18·30 | — | — | — | — | 20·3 |

* Note—The economy of this appliance permits continuous use at roughly the same weekly cost as smokeless fuels used intermittently on a simple modern appliance.

† Excluding Primary and Standing Charges:—

*Gas:*

| | Quarterly |
|---|---|
| General Two-Part Rate | 36s. 0d. |
| Standard Rate | 10s. 3d. |

* The commodity charge for the Heating and Hot Water Two-Part Rate is 16d./therm.

*Electricity:*

| | | Quarterly |
|---|---|---|
| Standing Charge according to area of residence not exceeding | 800 ft² | £1 6s. 0d. |
| Ditto | 1,000 ft² | £1 10s. 4d. |
| Ditto | 1,200 ft² | £1 13s. 7d. |
| Ditto | 1,400 ft² | £1 17s. 11d. |
| Ditto | 1,600 ft² | £2 2s. 3d. |

Storage Heaters 10s. 0d. extra.

Exhibit 20.

CENTRAL HEATING AND SPACE HEATERS

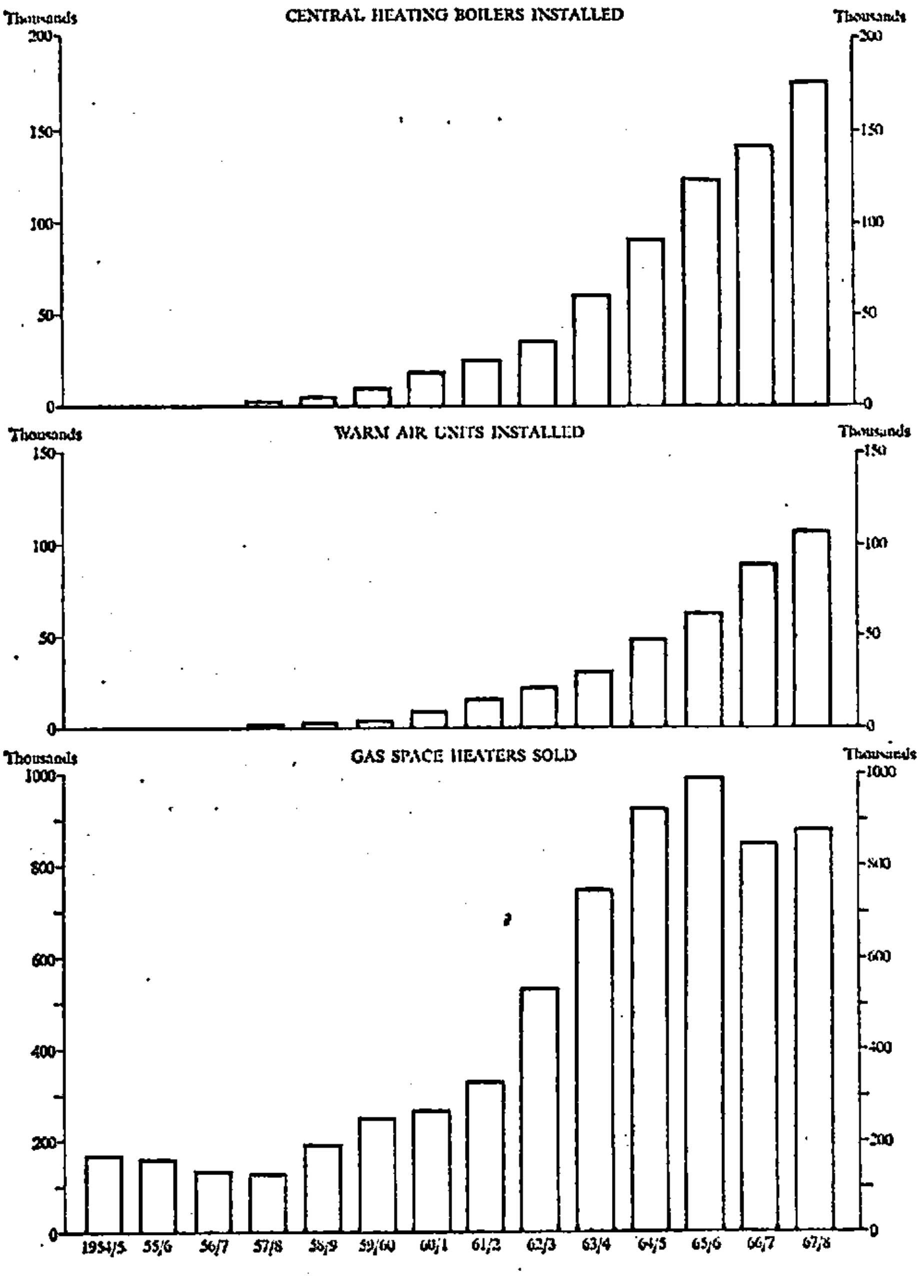


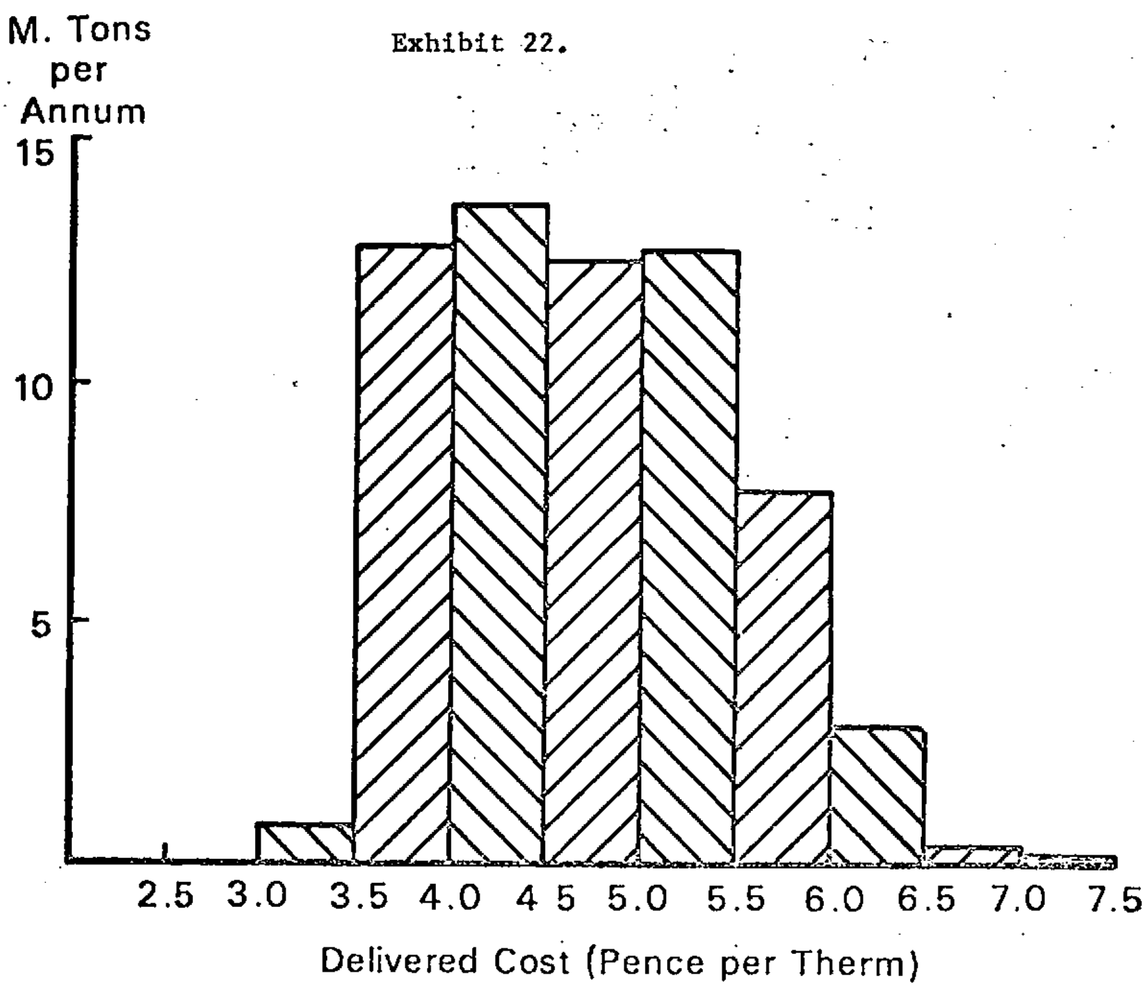
Exhibit 21.

Fuel consumption in the UK by sector and type of fuel, 1950-64

| | | Percentage of total consumption | | | | Total consumption (a) |
|---|---|---|---|---|---|---|
| | | Coal, coke and other solid fuel | Gas | Electricity | Oil | |
| *Collieries* | 1950 | 87.6 | 0.8 | 11.6 | — | 12.1 |
| | 1955 | 79.1 | 0.9 | 20.0 | — | 11.0 |
| | 1960 | 62.8 | 1.3 | 35.9 | — | 7.8 |
| | 1964 | 54.5 | 1.5 | 43.9 | — | 6.6 |
| *Refineries:* | 1950 | — | — | 8.3 | 91.7 | 1.2 |
| | 1955 | — | — | 5.4 | 94.6 | 3.7 |
| | 1960 | — | — | 6.6 | 93.4 | 6.1 |
| | 1964 | — | — | 8.1 | 91.9 | 7.4 |
| *Iron and steel:* | 1950 | 78.1 | 7.2 | 8.2 | 6.5 | 29.2 |
| | 1955 | 72.3 | 8.6 | 9.2 | 9.8 | 32.5 |
| | 1960 | 64.1 | 9.5 | 11.2 | 15.2 | 34.8 |
| | 1964 | 54.0 | 9.1 | 14.1 | 22.7 | 36.1 |
| *Other industry:* | 1950 | 65.0 | 5.9 | 21.5 | 7.6 | 62.8 |
| | 1955 | 60.0 | 6.0 | 24.5 | 9.5 | 73.0 |
| | 1960 | 44.8 | 6.0 | 31.1 | 18.1 | 77.2 |
| | 1964 | 33.9 | 5.4 | 32.8 | 27.9 | 83.8 |
| *Railways:* | 1950 | 93.0 | — | 7.0 | — | 15.8 |
| | 1955 | 93.6 | — | 6.4 | — | 14.0 |
| | 1960 | 86.4 | — | 10.0 | 3.6 | 11.0 |
| | 1964 | 59.7 | — | 18.1 | 22.2 | 7.2 |
| *Other transport:* | 1950 | 9.4 | — | 5.1 | 85.5 | 13.8 |
| | 1955 | 5.4 | — | 2.7 | 91.9 | 18.6 |
| | 1960 | 1.8 | — | 1.3 | 96.9 | 22.5 |
| | 1964 | 1.0 | — | 0.3 | 98.6 | 29.1 |
| *Domestic:* | 1950 | 65.9 | 16.0 | 16.8 | 1.3 | 63.6 |
| | 1955 | 64.1 | 14.2 | 20.1 | 1.7 | 66.3 |
| | 1960 | 56.4 | 11.0 | 29.0 | 3.6 | 71.5 |
| | 1964 | 44.5 | 12.3 | 38.8 | 4.4 | 78.7 |
| *Misc* (b) | 1950 | 59.1 | 11.7 | 20.2 | 8.9 | 25.7 |
| | 1955 | 52.2 | 11.0 | 25.1 | 10.7 | 29.9 |
| | 1960 | 36.6 | 8.8 | 34.5 | 20.1 | 32.8 |
| | 1964 | 26.9 | 8.5 | 42.6 | 22.0 | 36.4 |
| *Total* | 1950 | 65.7 | 8.5 | 15.7 | 10.1 | 224.2 |
| | 1955 | 59.5 | 8.0 | 18.4 | 14.1 | 249.0 |
| | 1960 | 47.0 | 7.1 | 24.5 | 21.4 | 263.7 |
| | 1964 | 35.4 | 7.2 | 29.3 | 28.1 | 285.3 |

Source: *Ministry of Power Statistical Digest, 1964.*
(a) Million tons of coal equivalent.
(b) Public administration, agriculture and miscellaneous.

Exhibit 22.




**Analysis of Delivered Coal Costs Based on Current Requirements (1966/67)**

Exhibit 23.

INLAND COAL CONSUMPTION BY SECTORS AND EXPORTS FROM THE UNITED KINGDOM

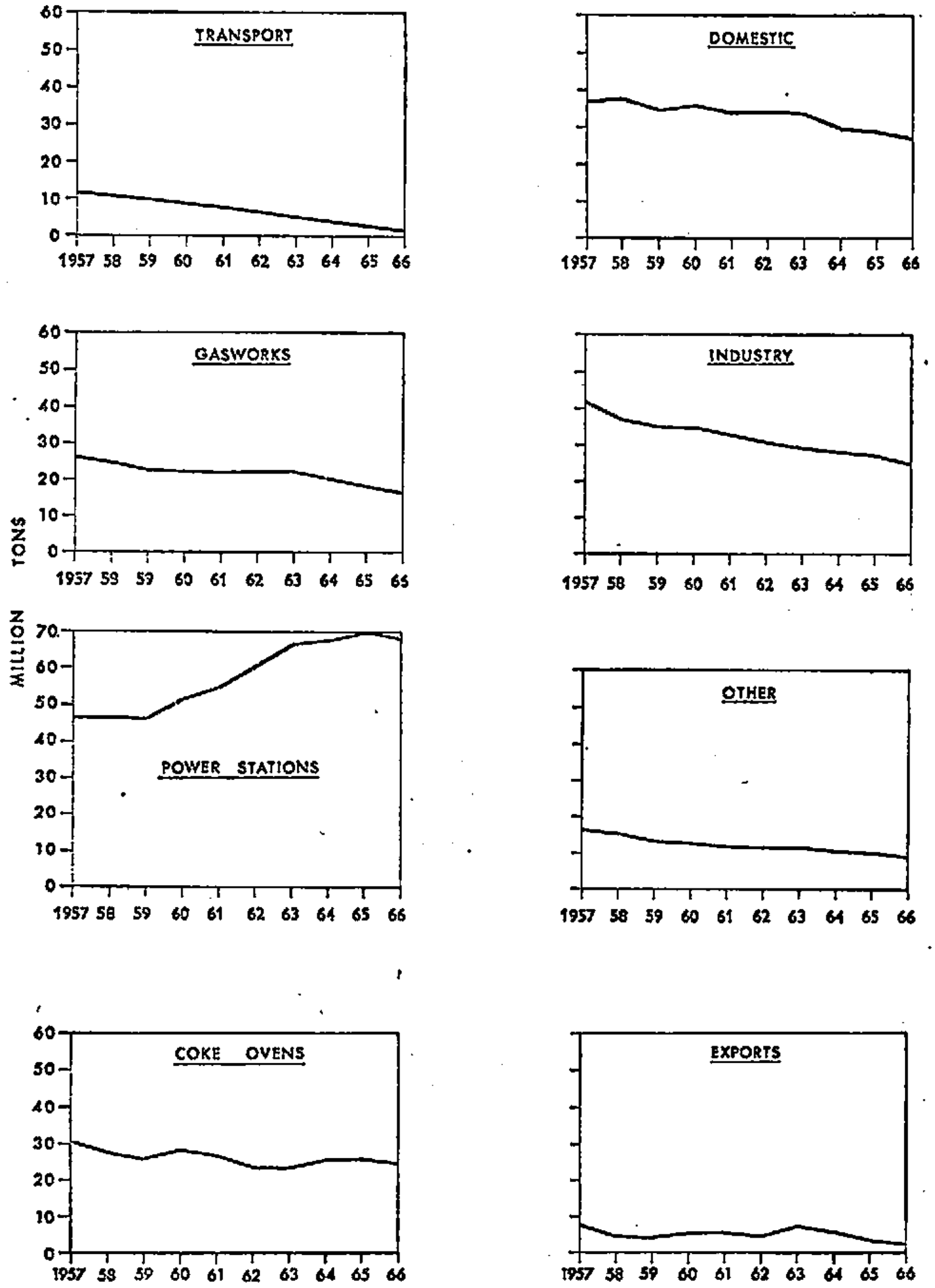



Exhibit 24.

**UK visible trade balance in fuel, 1951-64**

| | Solid fuel: net exports | | Oil: Net imports (—) or exports (+) | | | Net import value all fuels |
|---|---|---|---|---|---|---|
| | | | Crude | Products | All oil | |
| | million tons | £ million | million tons | million tons | £ million | £ million |
| 1951 | 11.8 | 27.7 | −16.6 | −2.1 | −271.4 | −243.7 |
| 1952 | 16.7 | 66.8 | −22.7 | +4.1 | −279.3 | −212.5 |
| 1953 | 18.0 | 70.4 | −25.7 | +5.8 | −234.8 | −164.4 |
| 1954 | 15.1 | 53.8 | −28.0 | +6.1 | −227.8 | −174.0 |
| 1955 | 4.8 | − 7.6 | −27.7 | +3.3 | −256.7 | −264.3 |
| 1956 | 7.4 | 21.8 | −28.4 | +3.4 | −268.8 | −247.0 |
| 1957 | 8.4 | 38.9 | −28.4 | +0.2 | −348.4 | −309.5 |
| 1958 | 5.8 | 27.9 | −33.6 | +2.0 | −328.7 | −300.5 |
| 1959 | 5.5 | 24.7 | −39.0 | +0.8 | −367.3 | −342.6 |
| 1960 | 7.1 | 30.1 | −44.7 | +0.7 | −375.3 | −345.2 |
| 1961 | 7.2 | 30.4 | −48.9 | +1.3 | −387.9 | −357.5 |
| 1962 | 6.6 | 32.7 | −52.5 | +0.2 | −417.5 | −385.0 |
| 1963 | 10.0 | 50.4 | −53.5 | −2.1 | −441.4 | −391.1 |
| 1964 | 7.4 | 39.0 | −59.2 | −3.6 | −484.4 | −445.1 |

Source: *Ministry of Power Statistical Digest, 1964.*