DEPARTMENT OF ENERGY

Development of the oil and gas resources of the United Kingdom 1983

NATIONAL INSTITUTE OF ECONOMIC AND SOCIAL RESEARCH

HALL

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Throughout the text one thousand million (10^9) is referred to as one billion and one million million (10^{12}) as one trillion.

Useful conversion factors:

1 tonne of crude oil is approximately 7.5 barrels
1 cubic metre = 35.31 cubic feet

The front cover design is based on a British Petroleum PLC photograph of production platform FA (Graythorp 1) in BP's Forties oil field in the North Sea.

Summary

This report describes the development of the oil and gas resources of the United Kingdom in 1982. It gives information about the economic and industrial impact on the UK of oil and gas production and describes the initiatives taken by Government during the year.

Oil and gas production
Total oil production in 1982 was 103.3 million tonnes, compared with 89.4 million tonnes in 1981. Two offshore oil fields — Fulmar and North Cormorant — came on-stream during the year bringing the total number in production to 20. In 1982 production of gas from the UK Continental Shelf (UKCS) was 38.3 billion cubic metres, of which nearly six per cent was contributed by gas from oil fields delivered to shore through the Shell/Esso Far North Liquid and Associated Gas (FLAG) system which began operation in 1982.

Exploration and development
The Alwyn North and Clyde offshore oil fields and the Morecambe gas field were granted development approval in 1982. At the end of the year there were eight offshore oil fields and one gas field under development. Also in 1982 approval in principle was given to the Rough gas storage project.

Exploration activity offshore continued at a high level during the year. 111 exploration and appraisal wells were drilled — the largest number since the record year of 1975 when 116 wells were drilled. Nine significant discoveries were announced.

Licensing
The Eighth Round of licensing was launched in 1982. 184 blocks were put on offer including 15 for cash tender. The main objectives of the Round were to provide new opportunities to explore for gas in the Southern North Sea and to open up exploration in a number of hitherto undrilled areas.

Reserves
After taking account of cumulative oil production to the end of 1982 of 457 million tonnes, the remaining recoverable reserves of oil in present and future discoveries on the UKCS are estimated to be in the range 1550–3750 million tonnes. After deducting cumulative gas production to the end of 1982 of 433 billion cubic metres (bcm), remaining gas reserves are put at 1025–1700 bcm.

Oil and Gas (Enterprise) Act 1982
The Act received Royal Assent in June 1982. Under its enabling provisions the oil and gas exploration and producing business of the British National Oil Corporation (BNOC) was transferred to its subsidiary, Britoil, which was later established as a private sector company. The Act also introduced competition into the supply of gas by removing the purchasing privileges of the British Gas Corporation (BGC) and restricting the Corporation's monopoly in the supply of gas by onshore pipe. The Act will also permit the disposal of assets held by BGC.

Economic benefits
Revenue from the sale of oil produced from the UKCS was £14.3 billion in 1982, compared with £12.3 billion in 1981. Revenue from the sale of gas was £1.0 billion, compared with £0.8 billion in 1981.

Government income from taxes and royalties in the financial year 1982/83 amounted to about £7.8 billion.

Investment
Gross capital investment in the oil and gas exploration and production industry as a whole was estimated to be £3.1 billion in

1982, representing about 25 per cent of total UK industrial investment.

Offshore supplies

In 1982 the total value of orders reported by operators for oil and gas development work on the UKCS was £2.26 billion. The UK share, at 73 per cent, was worth £1.64 billion.

Part 1: Reserves

1.1 Oil reserves

In 1982, a high level of exploration and appraisal activity on the UKCS provided some encouraging drilling results, particularly in the Central North Sea. Estimates of initial recoverable reserves in present discoveries are set out in Table 1(a), together with the equivalent figures derived from the 1982 Brown Book (Development of the oil and gas resources of the United Kingdom 1982. HMSO price £5.50) for comparison. The estimates are calculated by addition of the reserves for individual fields in each category. The total of proven plus probable reserves (1925 million tonnes, rounded to the nearest 25 million tonnes) provides the most meaningful estimate of total initial recoverable reserves. Once cumulative production to the end of 1982 of 457 million tonnes has been taken into account, 1475 million tonnes are left as the estimated remaining recoverable reserves in present discoveries.

A change to the figures in the 1982 Brown Book resulted from the transfer from category 2 to category 1 in Table 1(a) of the reserves of the Clyde and Alwyn North fields, which were approved for development in 1982. Other changes were made

Table 1(a) Initial recoverable oil reserves in present discoveries on the UKCS as at 31 December 1982[1][2][3]

million tonnes

	Proven*	Probable*	Proven plus Probable	Possible*
Category				
1 Fields in production or under development	1375 (1325)	250 (250)	1625 (1575)	225 (225)
2 Other significant discoveries not yet fully appraised	75 (75)	225 (325)	300 (400)	400 (450)
Total initial reserves[4] in present discoveries			1925 (1975)	

* The terms "proven", "probable" and "possible" are given the internationally accepted meanings in this context:

(i) Proven — those reserves which on the available evidence are virtually certain to be technically and economically producible.

(ii) Probable — those reserves which are estimated to have better than a 50 per cent chance of being technically and economically producible.

(iii) Possible — those reserves which at present are estimated to have a significant but less than 50 per cent chance of being technically and economically producible.

(1) As discussed in the 1982 Brown Book, a statistical problem arises in aggregating the estimated ranges of proven, probable and possible recoverable reserves for individual discoveries to provide a statistical range for their total. For this reason the column "Maximum possible" which appeared in the 1982 Brown Book has been omitted.

(2) Figures in brackets are the equivalent figures from the 1982 Brown Book.

(3) Figures are rounded to the nearest 25 million tonnes.

(4) After subtraction of cumulative production to the end of 1982 (457 million tonnes) remaining reserves in present discoveries are estimated to be 1475 million tonnes.

because some reserves which were previously considered as probable in both categories are now classed as proven. The net result of the changes is an increase of 50 million tonnes in the proven reserves in category 1 and an equivalent reduction of 50 million tonnes in the probable reserves in category 2. A further 50 million tonnes has been subtracted from the probable reserves in category 2 as a result of re-assessment. The possible reserves in category 2 also show a reduction of 50 million tonnes because some accumulations, which last year were considered as possible future developments, are now thought unlikely to come forward for development because of unfavourable reservoir characteristics.

Table 1(b) shows estimated ranges of initial recoverable reserves for the whole of the UKCS. The table differs from that of the 1982 Brown Book in that the reserves in future discoveries are attributed to major geological areas, rather than to the licensed and unlicensed parts of the UKCS. In other respects the approach used in 1982 is followed. For the reasons outlined in the 1982 Brown Book, the statistical range of reserves in present discoveries, which was calculated to be 300 million tonnes, is smaller than the difference between proven reserves and the sum of proven, probable and possible reserves.

Table 1(b) Range of initial recoverable oil reserves on the UKCS

million tonnes

	Range		
Reserves in present discoveries[1]	1775	to	2075
Reserves in future discoveries by geological area			
(a) North Sea 56°–62° N	200	to	750
(b) West of Shetland	25	to	350
(c) West of Scotland[2]	0	to	550
(d) Remainder of UKCS[2]	0	to	475

(1) Based on a range of ±150 million tonnes centred on the best estimate of total recoverable reserves (proven plus probable, 1925 million tonnes) given in Table 1(a).

(2) The bottom end of the range is taken as zero because no oil has been proved in these areas to date.

225 -2125

Forecasts of undiscovered reserves are inevitably more speculative than those given for discovered reserves in Table 1(a). They depend on the degree of appraisal in the various areas and because of the greater uncertainty involved the ranges are much wider than for present discoveries. The northern sector of the North Sea is still considered to have the greatest potential for oil discoveries.

The sum of the ranges in Table 1(b) gives a range of initial recoverable reserves on the UKCS of 2000–4200 million tonnes. However, the chance of total reserves falling outside that range is much smaller than the chance of reserves in any individual area falling outside their stated ranges.

1.2 Gas reserves

Gas reserves are defined as the quantities of gas available for consumption obtainable from the sources listed in Table 2(a). Gas which has been or is expected to be flared offshore is not included. Those heavier natural gases which are normally marketed as liquids and condensates (see Appendix 8) are also excluded from the gas reserves assessment but are included in the oil reserves assessment.

Exploration and appraisal of gas prospects increased significantly in 1982 but did not reach the stage of proving significant additional reserves. Some discoveries were made. In addition, appraisal drilling on known discoveries enabled some preliminary development plans to be formulated.

Table 2(a) shows estimates of recoverable gas reserves in present discoveries. It breaks down the reserves into three main categories, dry gas, gas from gas condensate fields and associated gas from oil fields. The commissioning of the FLAG system gas pipeline (which will enable about half of the known associated gas reserves on the UKCS to be landed) has resulted in an increase in the number of oil fields which are able to deliver associated gas to shore. There has therefore been a significant addition to estimated reserves of associated gas in the category of fields currently delivering gas to shore and a corresponding subtraction from the reserves of associated gas in the category of oil fields which have yet to be connected. The 1983

Table 2(a) Estimates of recoverable gas reserves in present discoveries on the UKCS as at 31 December 1982.[1]
Figures in billion cubic metres. Figures in brackets are in trillion cubic feet.

	Proven*	Probable*	Proven plus Probable	Possible*
A Initial recoverable reserves				
Gas from dry gas fields				
1 Fields in production or under development				
(a) Southern Basin	646 (22.8)	31 (1.1)	677 (23.9)	14 (0.5)
(b) Other areas[2]	198 (7.0)	28 (1.0)	226 (8.0)	34 (1.2)
Sub-total	844 (29.8)	59 (2.1)	903 (31.9)	48 (1.7)
2 Other significant discoveries not yet fully appraised				
(a) Southern Basin	48 (1.7)	42 (1.5)	90 (3.2)	51 (1.8)
(b) Other areas	– (–)	– (–)	– (–)	42 (1.5)
Sub-total	48 (1.7)	42 (1.5)	90 (3.2)	93 (3.3)
Total dry gas	892 (31.5)	101 (3.6)	993 (35.1)	141 (5.0)
Gas from gas condensate fields[3]				
1 Fields in production or under development	23 (0.8)	6 (0.2)	29 (1.0)	– (–)
2 Other significant discoveries not yet fully appraised	17 (0.6)	153 (5.4)	170 (6.0)	337 (11.9)
Total gas from gas condensate fields	40 (1.4)	159 (5.6)	994 (7.0)	337 (11.9)
Associated gas from oil fields[3]				
1 Fields in production or under development				
(a) Currently delivering gas to shore	91 (3.2)	3 (0.1)	94 (3.3)	3 (0.1)
(b) Expected to be connected	40 (1.4)	14 (0.5)	54 (1.9)	8 (0.3)
Sub-total	131 (4.6)	17 (0.6)	148 (5.2)	11 (0.4)
2 Other significant discoveries not yet fully appraised	3 (0.1)	31 (1.1)	34 (1.2)	37 (1.3)
Total associated gas	134 (4.7)	48 (1.7)	182 (6.4)	48 (1.7)
Total initial reserves in present discoveries	1066 (37.6)	308 (10.9)	1374 (48.5)	526 (18.6)
B Remaining recoverable reserves				
Cumulative production to the end of 1982[4]				
1 Dry gas				
(a) Southern Basin	395 (14.0)			
(b) Other areas[2]	29 (1.0)			
2 Associated gas from oil fields	9 (0.3)			
Total cumulative production to the end of 1982	433 (15.3)			
Total remaining reserves in present discoveries	633 (22.3)	308 (10.9)	941 (33.2)	

* The terms "proven", "probable" and "possible" have the meanings defined in Table 1(a)
(1) See footnote (1) in Table 1(a)
(2) UK Frigg and Morecambe
(3) All in the Northern sector of the North Sea
(4) Excludes flared gas

Table 2(b) Range of initial recoverable gas reserves on the UKCS

Figures are in billion cubic metres. Figures in brackets are in trillion cubic feet.

1 Reserves in present discoveries	
(a) Dry gas fields	957 (33.8)–1053 (37.2)
(b) Gas condensate fields	125 (4.4)– 314 (11.1)
(c) Gas associated with oil	164 (5.8)– 198 (7.0)
2 Range for 1(a), (b) and (c)	1246 (44.0)–1565 (55.3)
3 Reserves in potential future discoveries	
(a) Gas prospects	60 (2.1)– 575 (20.3)
(b) Gas condensate prospects	unassessable
(c) Gas associated with oil	5 (0.2)– 60 (2.1)
4 Range for 3(a), (b) and (c)	65 (2.3)– 635 (22.4)
5 Statistically aggregated range of initial recoverable reserves on the UKCS (aggregated range for 2 and 4) (rounded)	1450 (51)–2125 (75)

estimate of total remaining recoverable gas reserves in present discoveries is 941 billion cubic metres (bcm) (33.2 trillion cubic feet (tcf)), 66 bcm (2.2 tcf) lower than the 1982 estimate, mainly as a result of a further year's gas production.

Table 2(b) gives estimates of the range of potential gas reserves on the UKCS. As in previous years no allowance has been made for possible accumulations of gas at deeper levels in existing discoveries or for gas in areas which have not yet been drilled.

The statistical methods used in Table 2(b) result in a narrower range for potential reserves in existing discoveries than might be deduced from the figures in Table 2(a). Similar statistical methods have been used to arrive at the range given in Table 2(b) for reserves in potential future discoveries. Since all the reserves are in areas which have been significantly explored, the best estimate of the range of total potential reserves is that given by a statistical aggregation of both categories. This technique, which was not used in the 1982 Brown Book, has had the effect of narrowing the range of initial recoverable reserves on the UKCS from the 1982 assessment of 1350–2250 bcm (48–79 tcf) to 1450–2125 bcm (51–75 tcf). Of these reserves about 430 bcm (15 tcf) have already been produced; the remaining recoverable reserves are therefore estimated to be in the range of 1025–1700 bcm (36–60 tcf).

Part 2: Exploration

2.1 Licensing

(a) Offshore

Proposals for the Eighth Round of offshore licensing were announced on 17 May 1982. They identified the areas in which it was proposed to offer blocks, outlined the general basis on which the Round would be conducted and announced the intention to invite cash tenders for a number of blocks in the mature oil province of the Central North Sea.

Following consultation with a range of interests including the oil industry, fishing and environmental organisations, detailed arrangements for the Round were published in official Gazette Notices of 24 September 1982. 184 blocks were put on offer, including 15 for cash tender. The closing date for applications was 17 January 1983.

The main objectives of the Round were to provide new opportunities to explore for gas in the Southern North Sea and to open up exploration in a number of hitherto undrilled areas.

The award of licences for seven blocks in the cash tender area was announced on 17 February 1983. The total value of the successful tenders was over £32 million. At the time of going to print, applications for other blocks were still being assessed.

Details of each of the eight rounds of licensing are shown in Appendix 1.

(b) Onshore

There are 3 types of onshore licence: the Mining Licence, which is no longer issued; the Exploration Licence, which confers rights to conduct geological surveys and shallow drilling (to a maximum depth of 350 metres) for the sole purpose of obtaining geological information; and the Production Licence, which confers the right to drill deep wells and produce any hydrocarbons found.

The 1982 Petroleum (Production) Regulations introduced a single four year term for Exploration Licences. Production Licences are valid for an initial four year period with an option of a further 20 year period on surrender of at least half of the original licensed area.

All statutory permissions, including planning permission where necessary, and the permission of owners and occupiers of land, must be obtained before any operations are carried out under onshore licences.

At the end of March 1983 some 54,000 sq kms were currently under licence. About 39,000 sq kms were covered by 112 Exploration Licences and 14,500 sq kms by 74 Production Licences. The remainder was covered by 14 Mining Licences.

During 1982, 16 Exploration Licences and 24 Production Licences were awarded. Most were for territory in the established areas of interest in the North East, the Midlands, the South and the South West of England.

2.2 Exploration drilling

(a) Offshore

111 exploration and appraisal wells were commenced during 1982, representing the highest level of activity since the record year of 1975, when 116 wells were drilled.

The number of exploration wells commenced was 68, a considerable increase over the 48 such wells drilled in 1981 and the largest number since 1975 when 79 wells were drilled. The number of appraisal wells drilled reached a peak of 43, compared with 26 in 1981.

Much of the increased activity was concentrated in two main areas, East of Shetland and East of Scotland, and more specifically within these areas in the East Shetland Basin, the Moray Firth and Central North Sea.

Nine new discoveries of oil and gas were announced in 1982. These finds were indicative of the continuing prospectivity of the Central North Sea and the potential for further gas discoveries in the Southern North Sea Basin. In all areas, there was a trend for finds to be made at deeper levels and in older rocks. All significant announced discoveries of hydrocarbons on the UKCS are listed at Appendix 3.

Activity in various areas of the UKCS was as follows:

— Northern North Sea (East Shetland Basin and Unst Basin)

Eleven exploration wells were commenced in 1982. Ten were drilled in blocks awarded in the Seventh Round, of which nine were to evaluate prospects along the margins of the East Shetland Basin and one was to investigate the previously undrilled Unst Basin. Two of the wells proved the extensions of previous discoveries into adjoining blocks, three contained oil shows, four were dry holes and the remaining two were drilled on satellite structures, adjacent to existing accumulations. Eleven appraisal wells were commenced in the area in 1982.

— Moray Firth

1982 saw a burst of drilling activity in this area. This could be attributed to the fulfilment of drilling obligations under production licences and to a revival of interest in the area following the oil discovery made on block 13/29 at the end of 1981. Seventeen exploration wells and nine appraisal wells were begun. Two discoveries were announced and two wells proved extensions of earlier discoveries into new areas.

— Central North Sea

Exploration and appraisal well drilling continued at a high rate in 1982; 19 exploration and 15 appraisal wells were commenced. As in 1981, the majority of exploration wells were on pre-Seventh Round licensed blocks.

Oil and gas condensate have been found at various levels in the area and the evaluation of recent discoveries has led to a large increase in appraisal activity. Four discoveries were announced in 1982.

— Southern North Sea

Nine exploration wells were drilled in 1982, resulting in two discoveries. In addition, eight appraisal wells were drilled to assess the potential of five existing gas discoveries and to evaluate extensions of gas accumulations on the Leman Bank and West Sole gas fields.

— English Channel

No drilling took place in 1982. Seismic surveys continued in preparation for drilling in 1983.

— South Western Approaches

Five wells were drilled in 1982 to fulfil obligations under Sixth Round licences. Results have not so far been encouraging. Evaluation of Seventh Round acreage continued.

— Irish Sea and Celtic Sea

Four exploration wells were drilled in the Irish Sea during 1982. In one of the wells gas was discovered but testing of another was curtailed when some hydrogen sulphide was found to be present in the reservoir. There was no drilling activity in the Celtic Sea.

— West of Shetlands

Three exploration wells were completed during 1982, compared with two in 1981 and four in 1980.

— North of 62° N

No drilling took place during 1982. However, some seismic surveys were made in preparation for the fulfilment of drilling obligations under production licences.

– Rockall Trough

No drilling took place in 1982.

(b) Onshore

Exploration activity during 1982 was concentrated in the Weald and East Midlands. Ten exploration wells were started in 1982. In addition, two exploration wells were on long-term test. A three-well appraisal programme was successfully completed to evaluate the oil discovery at Humbly Grove in Hampshire and gas was encountered in a deeper reservoir. Drilling is planned for 1983 on adjacent structures to the north of Humbly Grove. Preliminary discussions were held with the Department of Energy on the possible development of the field.

2.3 Designation of UKCS

The Regulations under which licences for petroleum exploration or production are granted apply in respect of territorial waters and areas designated under section 1(7) of the Continental Shelf Act 1964.

In July 1982 two new areas, one to the North West of the Shetlands and the other in the English Channel were designated, the latter following the signing on June 24 of a delimitation agreement with France on the Continental Shelf boundary at the Eastern end of the English Channel.

The newly designated areas, totalling 8,400 sq kms (equivalent in area to about 30 blocks), brought the total area of designated Continental Shelf to approximately 651,650 sq kms.

Further areas of the Continental Shelf are expected to be designated in due course, although the scope for doing so is at present restricted pending the outcome of negotiations between the UK and certain neighbouring states in respect of dividing lines.

Part 3: Development

3.1 Development drilling

(a) Offshore

118 development wells were started in 1982, compared with 137 in 1981. There was a marked decrease in drilling activity in the East of Shetland area because the initial development drilling programmes for a number of fields in the area had been completed.

The significant use of mobile rigs for development drilling programmes continued; nine rigs were committed at the end of the year. Eleven of the 36 development wells in the East of Scotland area were drilled by mobile units, and all of the development wells in the East of England area were drilled by jack up drilling units.

Appendix 2 gives details by geographical area for the years 1973–1982 of the number of development wells drilled and of activity by mobile rigs and fixed platforms on the UKCS.

(b) Onshore

Details of the number of exploration and appraisal/development wells drilled and the rig activity for the years 1973–1982 are given in Appendix 2.

3.2 Development and production programmes

Under the terms of petroleum production licences, development work and the production of petroleum may be carried out only with the consent of the Secretary of State for Energy or under a development or production programme approved by him.

(a) Oil

At the end of 1982 all producing oil fields (with the exception of Auk, Beatrice, Buchan, North Cormorant, South Cormorant, Fulmar, Tartan and Wytch Farm) were operating under temporary consents given normally for three or six months at a time. Buchan is operating under a long term consent and Auk has been granted a two year production consent. Beatrice, North and South Cormorant, Fulmar and Tartan are operating under staged approvals designed to give operators a firm base for investment decisions while retaining Government control for the longer term. South Cormorant's staged approval was based on a revised development plan which covered the development of the central part of the Cormorant field through an Underwater Manifold Centre (UMC). The first production well was drilled through the UMC in October 1982.

In October 1982 staged approval was given to the development of the Alwyn North field and in December 1982 to the Clyde field. During the year revised development programmes were received for Beatrice, Claymore, Ninian, Fulmar and Heather. Discussions are taking place on the development of the extension to the Forties field and also on the possible development of the Balmoral field. In addition, the Department of Energy are discussing a number of other developments with operators.

(b) Condensate

In the Northern sector, outline proposals were submitted for the development of the North Brae gas condensate area of the Brae field. It is proposed that the gas condensate should be produced by recycling dry gas from North and South Brae. The condensate would then be transported by pipeline into the Brae/Forties system.

(c) Gas

At present all producing gas fields operate under temporary consents given normally for six or 12 months at a time.

In February 1982 approval was granted to the British Gas Corporation's plans to develop the Morecambe gas field as a seasonal supplier. The field will produce at maximum rates during periods of peak demand but will normally be shut-in or produce at minimum rates during the summer months. In March 1982 approval in principle was granted for BGC's Rough project. Formal development approval is dependent on the issue of a gas storage licence by the Crown Estate Commissioners. The Rough reservoir capacity will be developed to store gas produced from other fields during periods of low demand; this gas will then be made available during the months of high demand.

In 1982 outline proposals for the development of the Victor and S E Indefatigable fields in the Southern Basin of the North Sea were submitted to the Department of Energy. Gas from the Victor field would be delivered to shore via the existing facilities of the adjacent Viking field. The S E Indefatigable field would be developed as a seasonal supplier, similar to the Morecambe project. Gas would be delivered to the Bacton terminal via a new pipeline. In addition, preliminary plans for achieving extra production, or for offsetting declining production rates, for a number of existing Southern Basin gas fields have been discussed with the Department.

3.3 Projects for further gas and natural gas liquid supplies

BGC's need for new gas supplies and the freeing of the gas market through the enactment of the Oil and Gas (Enterprise) Act 1982 are likely to lead to an increase in development activity in the gas sector, particularly in the Southern Basin.

In the Northern sector gas is often found in association with oil and is likely to contain, in addition to methane, substantial quantities of natural gas liquids (NGL). NGL consist of ethane, propane, butane and condensate. Propane and butane when condensed are known as Liquefied Petroleum Gases (LPG).

Associated gas from the Brent field, the first major source of such gas to be developed on the UKCS, commenced flowing to St Fergus in Scotland through the Shell/Esso Far North Liquid and Associated Gas (FLAG) system at the end of May 1982. However, for many fields, the volume of associated gas produced is too small to allow individual gas pipelines to be economic, and other methods of carrying the gas ashore have to be considered. In some cases it is possible to use existing pipelines serving larger fields. For example gas from the Piper and Tartan fields flows into the Frigg pipeline system.

From 1987 gas from the Alwyn North field is expected to flow into the Frigg pipeline system via a new 70 mile pipeline. Arrangements have also been made for piping Odin and North East Frigg gas from Norwegian waters to St Fergus via the Frigg system. Gas flow is expected to begin in 1984.

Further North, Shell/Esso's Western Leg pipeline is linked into the FLAG system, providing a route ashore for associated gas from the Ninian and North and South Cormorant producing fields and from the N W Hutton field which is due to begin production this year. Also, the Northern Leg pipeline constructed by Britoil is due to feed into the FLAG system by October 1983, providing the means for associated gas from the Magnus, Murchison and Thistle fields to be brought ashore to St Fergus.

The Department of Energy have held preliminary discussions with Shell/Esso about a possible pipeline from Fulmar to St Fergus which could be in use by 1986. This pipeline would bring ashore associated gas from Fulmar and possibly Clyde and in later years could act as a route to shore for other discoveries in the Central North Sea.

The above projects and plans represent a major step towards ensuring that UKCS gas reserves are developed in accordance with the nation's needs. The Government remain confident that producer companies will continue to come forward with proposals which will provide the means for bringing Britain's North Sea gas ashore in an efficient and economic manner.

Part 4: Production and downstream activities

4.1 The Oil and Gas (Enterprise) Act 1982
The Oil and Gas (Enterprise) Act 1982 (the 1982 Act) received Royal Assent on 28 June 1982. It contains four main provisions affecting the State-owned oil and gas industries.

First, under enabling provisions contained in the 1982 Act, the oil and gas exploration and production business of the British National Oil Corporation (BNOC) was transferred to its subsidiary, Britoil. The shares in Britoil were taken over by the Secretary of State on 1 November 1982. 51 per cent of the shares were then sold to the public, establishing Britoil as a private sector company. BNOC remains in existence, wholly State-owned, principally trading in oil to which it has access through participation agreements.

Secondly, it changed the statutory framework within which the British Gas Corporation (BGC) buys and sells gas. It removed BGC's first offer purchasing privileges, and freed a part of the gas market to allow certain consumers to buy gas from the supplier of their choice, subject in some cases to the consent of the Secretary of State. A diagrammatic representation of the new consent requirements under the Gas Act 1972 (as amended by the 1982 Act) is given at Appendix 17.

Thirdly, it included provisions relating to the use by private suppliers of BGC's onshore pipeline system for the transmission of their gas. The initial course of action for a private supplier wishing to use one of BGC's pipelines will be to negotiate with the Corporation, but, should such negotiations fail, there is provision for the Secretary of State to determine whether the pipeline may be used by the private supplier and on what terms. Private suppliers may transmit gas through non-BGC onshore pipelines following negotiations with the owner and subject to the requirements of the Pipe-lines Act 1962.

Fourthly, provision was made enabling the disposal of assets held by BGC. Using the powers provided, directions (The British Gas Corporation (Disposal of Offshore Oilfield Interests) Directions 1982) were laid before Parliament by the Secretary of State for Energy on 6 August 1982. These required BGC to carry out the preliminary arrangements necessary for the disposal of their interests in six offshore oil fields (Beryl A and Beryl B, Hutton, North West Hutton, Montrose and Fulmar). The Government intend to transfer these interests to the private sector as soon as possible.

4.2 Oil production
In February 1982 two offshore oil fields, Fulmar and North Cormorant, came on-stream, bringing the total number of offshore oil fields in production to 20. Total oil production increased from 89.4 million tonnes in 1981 to 103.3 million tonnes in 1982. This includes 2.4 million tonnes of heavier natural gases, 0.5 million tonnes of condensate and over 0.2 million tonnes of onshore crude oil (of which 160,000 tonnes were produced from the Wytch Farm field and 80,000 tonnes from other land fields in the East Midlands and at Kimmeridge in Dorset). Production from the individual oil fields is given in Appendix 8.

4.3 Oil production forecasts
Forecasts of petroleum production were given by the Minister of State for Energy in reply to a Parliamentary Question on 11 March 1983. The reply is reproduced in Appendix 16.

4.4 Oil depletion
In 1982 the Government redefined their policy on oil depletion. In June 1982 the

Secretary of State for Energy announced the Government's intention not to force oil companies to make cuts in oil production, at least until the end of 1984.

The House of Commons Select Committee on Energy's report on North Sea oil depletion policy was published on 18 May 1982. Its arguments on depletion controls were generally in close accordance with the Government's own views and in reply, given on 29 July 1982, the Government agreed with much of the report and reaffirmed that given all the uncertainties affecting oil supply and demand, and the profile of UKCS production, action in the short term to defer UKCS oil production would not be justified. It was also made clear that the Government see no case for further development delays in the foreseeable future. Reserve powers of intervention will however be retained in case of some specific and overriding requirement to act in the national interest or some radical change in the circumstances relevant to the established pattern of UKCS development. There would be no wanton use of reserve powers in a way which might disrupt company expectations of their prospects on the UKCS; if their use had to be considered seriously, the Government would also consider what assurances might be given in parallel.

The reply also made clear that the Government will continue to use their powers in the national interest to achieve the optimum recovery of oil and gas through good oil field practice and the tight control of gas flaring.

4.5 Oil disposal

Total disposals of UKCS oil in 1982 amounted to 102.3 million tonnes. 40.3 million tonnes were delivered to UK refineries, constituting 52 per cent of the total deliveries of oil to UK refineries. 27.7 million tonnes of foreign crudes were imported during the year, compared with exports of UKCS crude of 60.6 million tonnes. The North Sea crude oil was exported almost entirely to the markets of our partners in the European Community and the International Energy Agency. The remainder went to traditional markets in Finland and the Caribbean. Figures for exports of crude oil by country are given in Table 3.

Table 3 Exports of UKCS crude oil in 1982

Destination[1]	million tonnes (rounded)
	Provisional
Bahamas	0.1
Belgium	0.2
Canada	0.9
Canary Islands	0.1
Denmark	2.1
Federal Republic of Germany	11.1
Finland	0.1
France	4.7
Irish Republic	0.2
Italy	0.5
Netherlands	12.1
Netherlands West Indies	0.3
Norway	1.6
Portugal	0.2
Spain	0.7
Sweden	3.7
Switzerland	0.3
USA	21.5
Virgin Islands	0.2
Total exports	60.6

[1] Some of the exports to the Caribbean area may have been for transhipment to the USA; exports to the Netherlands include oil for transhipment or in transit to other destinations (e.g. Belgium and the Federal Republic of Germany).

4.6 Oil terminals

The four landward oil terminals which receive UKCS crude oil are located at Sullom Voe in the Shetlands, Flotta in the Orkneys, Hound Point on the Firth of Forth (which receives Forties oil via Cruden Bay) and Nigg Bay on the Cromarty Firth. In 1982 these terminals received 84.6 million tonnes of crude oil, some 85 per cent of total UKCS production, the remainder being loaded into tankers offshore. Details of the four terminals are shown in Table 4. A fifth landward oil terminal at Teesside receives oil from the Norwegian Ekofisk field.

4.7 Gas production

In 1982 gas produced from the UKCS amounted to 38.3 billion cubic metres (1.4 trillion cubic feet). Production from individual fields is set out in Appendix 9.

Supplies of UKCS gas to BGC in 1982 were at the same level as in 1981 and accounted for 77 per cent of total gas supplies in 1982, compared with 75 per cent in 1981. This increased contribution resulted from higher

Table 4 Oil terminals receiving UKCS crude oil in 1982.

Terminal	Location	Fields connected	1982 throughput (million tonnes)
1. Sullom Voe	Shetlands	Brent, Thistle, Dunlin, Murchison, North and South Cormorant (BRENT SYSTEM). Ninian and Heather (NINIAN SYSTEM)	45.7
2. Flotta	Orkneys	Piper, Claymore, Tartan	15.2
3. Forties landward	Hound Point	Forties (via Cruden Bay)	22.1
4. Nigg Bay	Cromarty Firth	Beatrice	1.6
			84.6

production of associated gas; deliveries of such gas to shore by the FLAG system accounted for nearly 5 per cent of total supplies (UKCS production plus imports) to BGC in 1982. Gas imports declined in 1982 because of reduced output from the UK/Norwegian Frigg field (60.82 per cent of gas production from this field is deemed to come from Norway under the UK/Norway Intergovernmental Agreement of 1976).

4.8 Gas terminals

There are eight gas terminals in the UK: three at Bacton, two at Easington and one at Theddlethorpe, to receive gas from the Southern Basin fields; and two at St Fergus to serve the Frigg pipeline system and the FLAG system. The Shell/Esso FLAG system terminal was commissioned during the summer of 1982 and inaugurated by HRH the Prince of Wales on 6 October 1982. A ninth terminal is under construction at Westfield Point near Barrow-in-Furness for gas from the Morecambe field.

4.9 Gas flaring

Under the terms of petroleum production licences, gas may be flared only with the consent of the Secretary of State for Energy. Consents for flaring at levels above those necessary to ensure safe operation are given only when there is no technically and economically feasible alternative means of gas disposal.

The average rate of flaring during 1982 was 11.09 million cubic metres per day (392 million cubic feet per day). Although this represents only a slight reduction compared with 1981 levels, oil production increased by 14 per cent during the period. The average rates of oil production and gas flaring at producing oil fields for the years 1976 to 1982 are illustrated in the chart at Appendix 10.

The commissioning of the FLAG system and the Western Leg pipeline during 1982 allowed the Brent, Ninian and North and South Cormorant fields to export associated gas to St Fergus and consequently to reduce flaring offshore.

The commissioning of the gas handling and LPG recovery facilities at Sullom Voe in 1982 allowed all of the producing oil fields in the Brent and Ninian pipeline systems to export live crude oil to the terminal.

The installation of additional processing equipment on the Tartan platform to remove hydrogen sulphide from gas and NGL took place during 1982 and first gas exports commenced in mid-January 1983.

Government policy remains that development plans for new fields will not be approved unless satisfactory proposals are made for the

collection of gas where this is technically and economically feasible.

Further information on gas flaring at oil terminals and producing oil fields is given in Appendix 11.

4.10 Offshore pipelines

The 36 inch FLAG system gas pipeline was commissioned in 1982 to bring associated gas from several fields in the Brent area to St Fergus for processing before entering the national gas transmission network. The Western Leg pipeline was also commissioned to bring gas from South Cormorant, North Cormorant and Ninian to Brent for onward transmission.

The West Sole to Easington gas pipeline, which was laid in 1981, was completed and commissioned during the year. A major construction project in 1982 was the laying of the 20 inch Northern Leg gas pipeline which will eventually link Magnus, Thistle and Murchison to the FLAG system. Commissioning of this system is expected in 1983.

Other construction projects included the laying of two pipelines for BGC. One will link the Rough field to the Easington terminal; the other will run from the Morecambe field to a new terminal near Barrow-in-Furness.

Details of the major offshore pipelines are given in Appendix 13.

The Submarine Pipe-lines Safety Regulations 1982 came into operation on 19 November 1982. They cover such matters as the inspection of offshore pipelines, emergency procedures and anchoring near pipelines.

4.11 Production and disposal of natural gas liquids

The largest part of the UK's NGL resources is contained in oil fields in the Northern sector of the North Sea. In 1982 commissioning of facilities at Sullom Voe and St Fergus provided the potential for the recovery of NGL from these fields in addition to the quantities which have for some years been recovered from the crude oil landed at Flotta and Cruden Bay.

In 1982 output of propane and butane which was separated from oil landed at Sullom Voe through the Ninian and Brent pipeline systems was 600 thousand tonnes. Shell/Esso's St Fergus facilities, which separate NGL from gas brought ashore by the FLAG system, handled over 500 thousand tonnes of NGL during the year. Ethane and propane were transported via pipeline for use as boiler fuel at Peterhead power station; butane and condensate were injected into the Cruden Bay–Grangemouth pipeline for recovery at Kinneil.

When the fractionator and ethylene cracker under construction at Mossmorran in Fife are commissioned, all NGL landed at St Fergus from the FLAG system will be transported via a pipeline also under construction direct to Mossmorran for separation. Propane, butane and condensate from the fractionator will be exported via the associated terminal at Braefoot Bay on the Forth to markets at home and abroad. The ethane is destined for use as feedstock for the ethylene cracker. BP Chemicals are proposing to modify their ethylene cracker at Grangemouth so that it could operate on ethane as well as naphtha feedstock. Initially BP would use the Brent ethane from the Mossmorran fractionator, which would otherwise continue to be used as boiler fuel at Peterhead power station, up to the time when it is required as feedstock for the Mossmorran cracker. Subsequently, BP Chemicals propose to rely on ethane from Forties and Magnus supplemented as necessary by purchases from other producers. The proposal would require the construction of pipeline connections between Grangemouth and Mossmorran.

Part 5: Operational aspects

5.1 Offshore employment

A survey of the workforce employed offshore was conducted by the offshore operators in July 1982, on behalf of the Inland Revenue. The returns indicate a small rise in the total offshore workforce from about 21,000 in July 1981 to about 21,500 in July 1982, of which 84 per cent were UK nationals. The survey covered not only those employed on offshore installations but also construction workers and personnel on mobile drilling rigs, service vessels, support barges and survey teams.

5.2 Training

In 1982, the Health and Safety Commission's Oil Industry Advisory Committee set up a Working Party under the chairmanship of the Department of Energy to consider the adequacy of present safety training for the offshore workforce and what guidance to the industry was required. The Working Party met in December 1982 and is expected to meet regularly in 1983. Matters for discussion will be wide ranging and will include survival training and other aspects of occupational health and safety training.

The Petroleum Industry Training Board changed its name, function and membership on 1 September 1982 to become the Offshore Petroleum Industry Training Board with responsibility primarily for those employed offshore. The Board continued to operate the training centre at Montrose, which specialises in fire and drilling training. Some 3500 personnel attended the various fire training courses and some 1750 personnel attended drilling and production courses. In addition, certificates were issued to 1248 persons who had been examined under the Offshore Installations (Well Control) Regulations 1980.

The employers' offshore training associations, the Petroleum Training Association North Sea (PETANS) and the Scottish Offshore Training Association (SCOTA), reported increased attendances at their courses in 1982. 1750 personnel received training from PETANS, where the majority of courses dealt with offshore survival. 2500 personnel attended SCOTA's courses which ranged from office management to drilling and production technology.

The closure of the Fort William Underwater Training Centre from March 1982 until November resulted in no noticeable shortage of bell divers during the year. The diving school has now reopened under new ownership and does not rely on Government for finance.

5.3 Offshore safety

The Department of Energy continued to enforce health, safety and welfare legislation on and around offshore installations. In 1982, the Inspectorate drew five cases to the attention of the Procurator Fiscal. Three of the cases were heard during the year and resulted in fines of up to £750.

On 1 November 1982 section 24 of the Oil and Gas (Enterprise) Act 1982 came into force, and in so doing, substituted a new section 1 of the Mineral Workings (Offshore Installations) Act 1971 (the 1971 Act) thereby extending the coverage of the 1971 Act to include the storage of gas and the provision of accommodation for persons working on offshore installations. As a consequence, units which provided accommodation facilities were required to possess a Certificate of Fitness as required by the Offshore Installations (Construction and Survey) Regulations 1974 (the 1974 Regulations). Following consultation with the

offshore industry, it was agreed that, where appropriate and subject to adequate safeguards, the Department of Energy would be prepared to consider exempting accommodation units from holding such a certificate for the period 1 November 1982 to 31 October 1983.

On 1 November 1982 there were two mobile accommodation installations on the UKCS; one already complied with the 1974 Regulations. Four applications for exemption from holding a Certificate of Fitness were under consideration at 31 December 1982.

The Offshore Installations (Included Apparatus or Works) Order 1982 also came into effect on 1 November 1982. This order applied the UK offshore safety regime to the pipeline booster platforms on the UKCS which serve the Frigg and Ekofisk fields.

Discussions continued in 1982 on the improvement of braking systems on draw-works (the winching machinery for raising and lowering the drilling equipment). Broad agreement was reached with the oil industry on the standards required. It is expected that monitoring systems will be developed in the early part of 1983.

5.4 Offshore accidents and dangerous occurrences

During 1982, 13 deaths were reported to the Department of Energy under the Offshore Installations (Inspectors and Casualties) Regulations 1973, together with 39 serious injuries and 181 dangerous occurrences. Further information is given in Appendix 15.

The number of deaths increased in 1982, compared with 1981. This is disturbing but does not seem to be attributable to an increase in any particular activity or to have an identifiable trend. Three of the deaths occurred when a bridge which connected a fixed installation to a mobile accommodation unit failed whilst it was being raised. There was a decrease in the number of serious injuries reported to the Department in 1982 but an increase in the number of dangerous occurrences.

In addition two deaths and three serious injuries were reported to the Department under the Submarine Pipe-lines (Inspectors etc) Regulations 1977. One of the deaths occurred during a diving operation at a pipeline and was the first for three years at an offshore diving operation.

Also six people died in a helicopter which crashed when taking a medical team to treat a man who had been injured on a survey vessel.

5.5 Offshore emergency planning

Various amendments to the Department's Offshore Emergencies Handbook were issued during 1982. The Handbook describes the main lines of communication to be used and action to be taken by Government, industry and other organisations in the event of an emergency involving an offshore installation, such as fire, collision or structural failure.

The Department's NOROX series of exercises, which began in 1975, is intended to test lines of communication and co-ordination of response in various offshore emergencies, between offshore operators and organisations such as the police, HM Coastguard and the armed forces. A further exercise in the series was held in May 1982. The exercise simulated an oil tanker losing motive power and drifting towards the Murchison platform in worsening weather conditions. It was divided into two distinct phases: the first covered the threat of a collision between the vessel and the platform and evacuation of the personnel; the second covered the control of oil pollution which resulted from the collision. Responses to enquiries from the press, the broadcasting media and the public were also tested.

The North Sea Sector Club arrangements which apply across median lines and under which mutual assistance is provided between operators in an emergency, were extended during 1982 to cover the entire North Sea area. All oil and gas fields in production in the North Sea are now included in one or other of the six Sector Clubs.

5.6 Protection of installations

Regular surveillance and patrolling of offshore oil and gas installations and pipelines continued to be carried out by RN offshore patrol vessels and RAF Nimrod maritime

patrol aircraft. Other defence resources would be available for deployment in an emergency.

Contingency plans for the protection of installations against terrorist attack were tested in a variety of exercises during the year.

During 1982 a further thirteen 500 metre safety zones, which no unauthorised vessels are allowed to enter or remain in, were established around the following permanent installations: the Magnus and Brae A platforms, the second Beryl Single Point Mooring, the Claymore Template, the South Cormorant Underwater Manifold Centre, the N W Hutton platform, and the seven subsea wellheads in the Hewett, Argyll and South Cormorant fields. Changes in the law relating to safety zones following enactment of the 1982 Act have enabled the safety zones to be completed around three installations in the Frigg gas field sited close to the median line with Norway. At the end of 1982 there were 111 safety zones protecting permanent oil and gas installations on the UKCS. In addition, safety zones were established to protect a number of mobile rigs whilst on location for drilling purposes.

5.7 Environmental aspects

Individual operators are responsible for dealing with oil spills at offshore installations and shore terminals and each is required to have plans for such eventualities. Operators engaged in developing oil and gas resources in areas close to shore are required to make special contingency arrangements to ensure a quick and effective response to any pollution incident. The Government's primary role in pollution incidents would be to monitor the operator's activities and offer advice and assistance.

42 oil spills were reported to the Department of Energy in 1982. The total amount of oil involved was approximately 162 tonnes but more than half of this quantity was accounted for by two spills, of 50 tonnes and of 45 tonnes, thus giving an average of under two tonnes each for the remaining 40 spills. A period of favourable weather enabled the operator to recover about half of the 45 tonne spill.

Chemicals continued to be added to the list of products notified under the non-statutory notification scheme for the selection of chemicals for use offshore. Operators, before selecting a chemical for use offshore, are increasingly asking chemical suppliers to show that the product has been notified under the scheme.

The Secretary of State for Energy has the power to exempt operators from certain parts of the Prevention of Oil Pollution Act 1971, as amended, so as to allow them to discharge to the sea treated effluents containing small amounts of oil. The exemptions specify the permitted oil content of the discharge; for production water the oil content must not normally exceed 40 parts per million. A total of some 927 tonnes of oil was permitted to be discharged in this way from 26 installations during 1982.

The increasing use of oil-based drilling fluids has led to concern about the amount of diesel oil contained on the drill cuttings and subsequently discharged into the sea. Accurate estimates of the quantities involved are difficult to make but for 1982 they were probably between 7,000 and 10,000 tonnes, of which about half was thought to be avoidable. For this reason, steps are being taken to introduce regulations to control these discharges since, at present, the discharge of diesel oil is not prohibited under the Prevention of Oil Pollution Act 1971. During 1982 oils which have a much lower acute toxicity to marine life were introduced as an alternative to diesel oils in some oil-based drilling fluids.

Part 6: Economic and industrial aspects

6.1 The economic impact of UKCS oil and gas

In 1982 UKCS oil and gas production accounted for a little under five per cent of UK Gross National Product (GNP) at factor cost. Table 5 shows the contribution to GNP arising within the sector for the years 1978–1982.

Total proceeds from the sale of oil and gas produced on the UKCS in 1982 are estimated to have been £14.3 billion and £1.0 billion respectively. Total tax and royalty receipts attributable to the UKCS are estimated to have been £7.8 billion in the financial year 1982/3. For purposes of comparison, the estimated yield from VAT and income tax in 1982/3 were £13.9 billion and £30.2 billion respectively. Table 6 shows Government receipts from royalties and taxes for each financial year from 1978/9 to 1982/3.

6.2 UKCS fiscal regime

Under the terms of petroleum production licences the Secretary of State may take royalties in kind rather than cash. In 1982 the Government reviewed their policy on royalty in kind. It was decided to continue to take royalty in kind on broadly the same scale but to discontinue taking it from some of the smaller fields. As a result, four of the smaller fields were not required to deliver royalty in kind after the end of 1982; also three other small producing fields have never been required to deliver royalty in kind. BNOC acts as the Secretary of State's agent in handling the royalty oil, which amounted to some 11.1 million tonnes in 1982.

Some changes to the operation of Advance Petroleum Revenue Tax (APRT) were announced in June 1982 and subsequently included in the Finance Act 1982. These included a limitation on the period over which APRT is levied to five years from the date of first payment. Any outstanding APRT payments not offset against Petroleum Revenue Tax (PRT) during this period will then be immediately repayable. (The 1982 Budget statement had proposed no limitation on the period over which APRT would be levied and that repayment of APRT not set off against PRT was to be made at the end of the field life.) Another modification to the 1982 Budget statement was that APRT is now to be allowed as a deduction in computing payback periods.

In his 1983 Budget statement, the Chancellor

Table 5 Income from UKCS oil and gas production — £ billion

	1978	1979	1980	1981	1982 (provisional)
Value of sales and services rendered	3.2	6.3	9.6	13.3	15.4
less purchases of goods and services*	0.5	0.6	1.0	1.4	1.9
Value added by the sector	2.7	5.7	8.6	11.9	13.5
less interest, profits and dividends due abroad	0.7	1.4	2.2	2.4	2.8
GNP arising within the sector	2.0	4.3	6.4	9.5	10.7

* defined as operating plus exploration costs minus employment incomes

Table 6 Taxes and royalties attributable to UKCS oil and gas £ million

Financial year	Royalties	SPD[1]	PRT[2]	Corporation Tax[3]	Total
1978/79	289	–	183	90	562
1979/80	661	–	1436	266	2363
1980/81	992	–	2410	480	3882
1981/82	1387	2025	2390	650	6452
1982/83 (provisional)	1630	2400	3280	500	7810

[1] Supplementary Petroleum Duty.

[2] Petroleum Revenue Tax. Receipts of PRT for 1982/83 include a small amount attributable to Advance Petroleum Revenue Tax (APRT).

[3] The Corporation Tax shown is the estimated proportion of the tax payable which can be attributed to UKCS oil and gas, but before setting off any Advance Corporation Tax (ACT). It is estimated that in 1979/80 £100 million of Corporation Tax was satisfied by setting off ACT; the corresponding amounts in 1980/81, 1981/82 and 1982/83 were £240 million, £220 million and £250 million respectively

of the Exchequer proposed the following main changes in the North Sea fiscal regime:

– Advance payments of Petroleum Revenue Tax (APRT) are to be phased out for all fields by reducing the present rate of 20 per cent to 15 per cent from 1 July 1983, 10 per cent from 1 January 1985 and 5 per cent from 1 January 1986. APRT will be abolished altogether from 1 January 1987.

– Royalties are to be abolished for qualifying fields receiving development consent or approval from the Secretary of State for Energy on or after 1 April 1982 except for onshore fields or those in the Southern Basin. For the same fields, the PRT oil allowance is to be increased from 250,000 to 500,000 tonnes per chargeable period and the cumulative limit from 5 to 10 million tonnes. The Government are ready to discuss with the industry whether there is a need to extend these reliefs to Southern Basin fields. If the case is made out, any extension would be applied to fields developed after 15 March 1983.

– It is proposed to allow relief to be claimed immediately against PRT liabilities on existing developments for expenditure incurred after 15 March 1983 on searching for oil and gas and appraising reserves outside a determined PRT field.

– Finally, following the Consultative Document issued on 7 May 1982 it is proposed to allow full PRT relief for most expenditure on assets with shared use (e.g. pipelines) and to charge related receipts (e.g. pipeline tariffs) to PRT subject to an exempt allowance of 500,000 tonnes per annum in respect of each user field. Any expenditure relief previously clawed back as a result of a sharing agreement will be restored in full and for a five year transitional period the exempt allowance under an agreement made on or before 7 May 1982 will be 750,000 tonnes per annum.

The effect of these changes will be to reduce Government revenues from oil and gas by more than £800m over the four years 1983/84 to 1986/87, and to give a substantial reduction in tax for future fields.

6.3 Costs and investment

Estimates of exploration, development and operating expenditures made by operators and other licensees engaged in exploiting the oil and gas resources of the UKCS during the period 1976 to 1982 are presented in Appendix 14. However, it is becoming increasingly difficult to draw a meaningful distinction between expenditure on oil and on gas fields, since where gas is produced in association with oil, many costs are of a joint nature. Where the costs of associated gas gathering systems for oil fields are separately identifiable, these are included in the figures for gas fields. This difficulty is likely to continue and will become more acute as

significant numbers of associated gas developments are brought forward.

Expenditure on exploration in 1982 totalled £861 million, an increase of £311 million, or about 50 per cent, on the 1981 level. This large increase reflects the high level of exploration drilling which took place during the year.

Expenditure on the construction and installation of platforms and associated equipment and on related pipelines and terminals amounted in 1982 to £2348 million for the development of oil fields and £613 million for the development of gas fields, compared with £2477 million and £280 million for oil and gas fields respectively in 1981.

Operating costs for oil and gas fields in 1982 were £1175 million and £163 million respectively. The increased oil field expenditure in 1982, compared with expenditure of £929 million in 1981, reflected the start-up of the Fulmar and North Cormorant platforms and the build up in oil production during the year.

The cost of producing oil from offshore fields depends on the individual characteristics of the field and therefore varies widely. The average cost of producing oil from fields which began production before the end of 1982 is estimated at $12 per barrel at 1982 prices. The corresponding figure for fields under development at that date is $17 per barrel. These estimates are for the cost of exploration, development and operation over the expected life of the field, but exclude payments of royalties and taxes on oil production and abortive exploration costs not attributable to individual fields. The estimated production cost per barrel of fields under development has risen by $4 compared with last year's figure of $13. This is mainly because of a change in the composition of the fields under development. Other factors such as changes in costs and exchange rates had a smaller influence. The use of capital funds for offshore developments and the time lag between capital expenditure and production is taken into account by assuming a real rate of return on the committed capital which would represent its value in alternative uses. The figures can be interpreted as the average real oil price over the whole life of the field which would be necessary to cover these costs.

The gross capital investment in the exploration and production industry as a whole, including that of drilling contractors and other contractors providing services unique to the industry, is estimated to have been about £3.1 billion in 1982 compared with £2.9 billion in 1981. It formed about 25 per cent of total UK industrial investment and 7 per cent of gross domestic fixed capital formation in 1982. Table 7 shows capital investment in the years 1978–1982.

Total investment in the period 1965 to 1982 inclusive is estimated to have been about £19 billion. In 1982 prices this represents an investment of about £29 billion. In addition there has been exploration expenditure amounting to some £6 billion in 1982 prices over the same period.

Table 7 Capital investment in the oil and gas exploration and production industry

	1978	1979	1980	1981	1982
Gross UK capital investment in the exploration and production industry (£ billion)*	2.2	2.1	2.4	2.9	3.1
— as a percentage of total UK industrial investment	22	19	20	23	25
— as a percentage of gross domestic fixed capital formation	7	6	6	7	7

* Gross Domestic Fixed Capital Formation in Minimum List Heading 104 of the Standard Industrial Classification. It includes development expenditure by operators, licensees, drilling and other contractors and capital expenditure other than on specific fields and allows for the timing of imports to the UKCS.

The main sources of the funds deployed on the UKCS during 1982 were the internally generated resources of companies and loans from UK-based banks. The latter provided approximately one quarter of the total requirement.

6.4 Comparison of UKCS and onshore oil and gas production with consumption in the UK

Table 8 and Figure 1 show the relationship between oil and gas production and total primary fuel consumption.

In 1982 UK oil production was 103.3 million tonnes, while the total UK consumption fell to about 75 million tonnes. Within this overall relationship, however, the UK remained part of the wider world oil market and continued a substantial import and export trade. UK production of oil and gas in 1982 corresponded to about 54 per cent and 17 per cent of total primary fuel consumption respectively.

6.5 Offshore supplies

In 1982 the total value of orders reported by operators for oil and gas development work on the UKCS was £2.26 billion. The UK share was 73 per cent (worth £1.64 billion). Over the last four years the UK can take credit in gaining an average 72 per cent share of orders in an exacting and internationally competitive offshore market.

Further improvement in the penetration of the market by UK industry will depend substantially on the industry's willingness to invest in areas where the UK is weak, such as pipe laying, the provision of drilling rigs and the supply of heavy lifting equipment. It will also be important to maintain the UK's competitiveness in the areas where good results are already being achieved.

In 1982 UK industry won the major share of orders for the Rough, Morecambe and Beatrice B developments. In 1983 UK industry will be competing strongly for orders for the Clyde and Alwyn North oil field developments and for developments in the Southern Basin gas fields.

A main function of the Offshore Supplies Office of the Department of Energy is continuously to monitor procurement to ensure that UK industry is given a full and fair opportunity to bid for contracts. It also assists in the promotion of the UK offshore supplies industry at home and abroad.

Details of the oil production platforms installed on the UKCS and under construction are given in Appendix 12.

Table 9 gives a breakdown of the value of orders placed for different goods and services for oil and gas development work on the

Table 8 UKCS and onshore oil and gas production compared with UK total primary fuel consumption

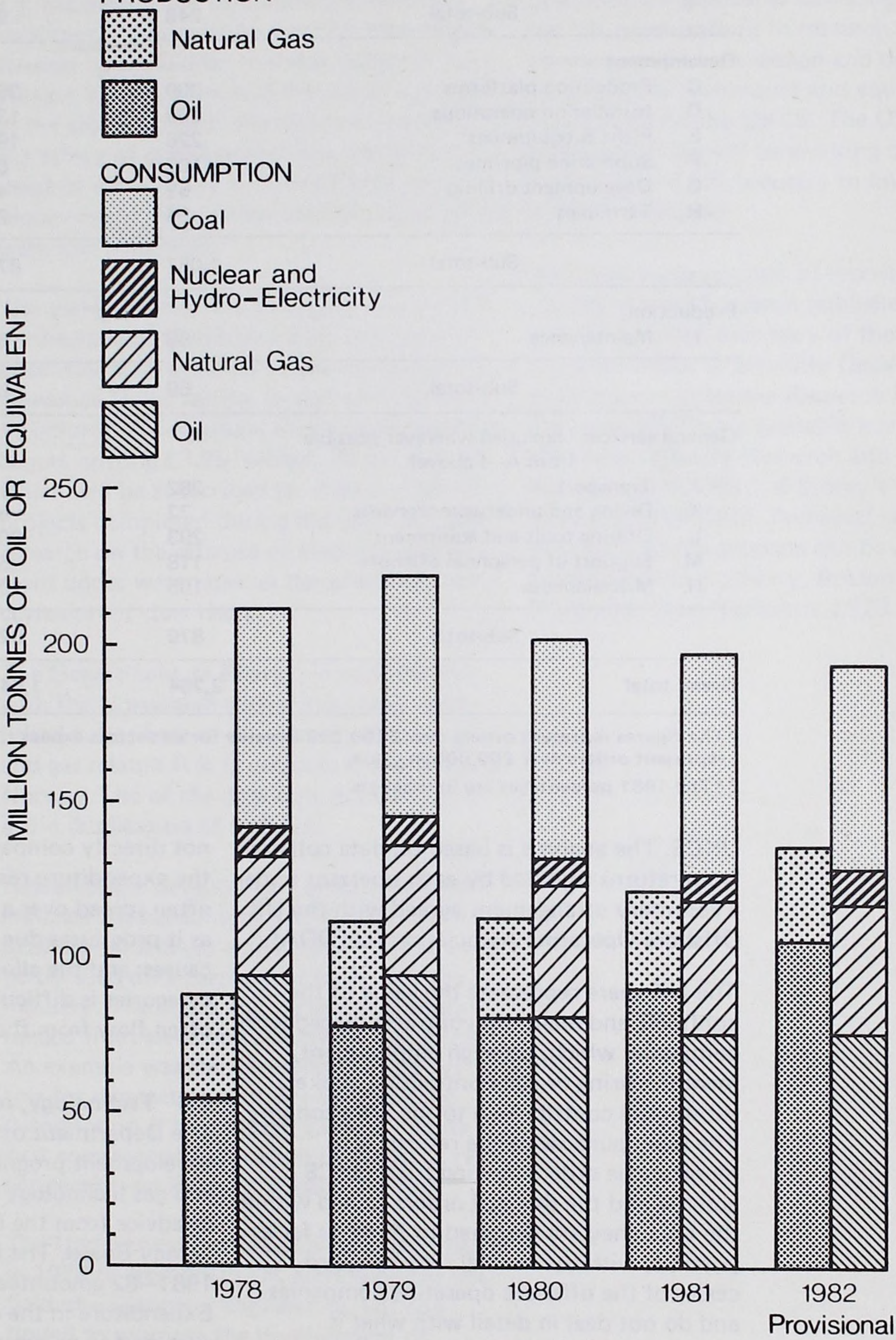
million tonnes of oil or oil equivalent

	Total primary fuel consumption[1]						Oil production[2]	Gas production[3]
	Total	Coal	Petroleum	Natural gas	Nuclear electricity	Hydro electricity		
1978	211.9	70.5	94.0	38.3	7.9	1.2	54.0	33.9
1979	221.4	76.2	94.0	41.8	8.1	1.3	77.9	34.2
1980	202.7	71.1	80.8	41.8	7.8	1.2	80.5	32.0
1981	196.2	69.6	74.8	42.4	8.1	1.3	89.4	32.1
1982 (provisional)	192.6	65.2	75.0	41.6	9.4	1.4	103.3	32.4

(1) Includes oil and gas for non-energy use and marine bunkers.
(2) Crude oil together with condensate and heavier natural gases.
(3) Includes land and colliery methane and associated gas produced and used mainly on Northern sector oil production platforms. Excludes gas flared or reinjected.

Figure 1

UKCS and onshore oil and gas production compared with UK total primary fuel consumption



(Figures are given in Table 8)

Table 9 An analysis of orders placed for goods and services for developments on the UKCS during 1982*

Sector	Value of orders placed £ million		
	Total	UK share	UK%**
Exploration			
A Surveying	45	33	73 (47)
B Exploration and appraisal drilling	203	59	29 (31)
Sub-total	248	92	37 (32)
Development			
C Production platforms	399	350	88 (77)
D Installation operations	208	135	65 (66)
E Plant & equipment	226	194	86 (78)
F Submarine pipelines	103	63	61 (56)
G Development drilling	57	43	75 (71)
H Terminals	94	90	96 (98)
Sub-total	1,087	875	80 (75)
Production			
I Maintenance	59	52	88 (88)
Sub-total	59	52	88 (88)
General services (excluded wherever possible from A–I above)			
J Transport	282	210	74 (73)
K Diving and underwater services	72	54	75 (81)
L Drilling tools and equipment	293	200	68 (69)
M Support of personnel offshore	118	59	50 (51)
N Miscellaneous	105	101	96 (92)
Sub-total	870	624	72 (72)
Grand total	2,264	1,643	73 (67)

*The figures represent orders over £100,000 in value for all sectors except I, Maintenance, where they represent orders over £50,000 in value.

**The 1981 percentages are in brackets.

UKCS. The analysis is based on data collated from returns supplied by each operator under a voluntary arrangement agreed with the UK Offshore Operators Association (UKOOA).

The UK share represents the value of the contracts and main sub-contracts placed with companies which, through employment, manufacturing or sub-contracting, make a substantial contribution to the UK economy. The main purpose of the returns is to monitor the orders flowing from UKCS activity and the share of orders gained within the UK. They are designed to fit in, as far as possible, with the normal recording processes of the offshore operating companies and do not deal in detail with what is imported and what is home produced.

The value of orders and expenditure data are not directly comparable for several reasons: the expenditure resulting from an order is often spread over a number of years, varying as it progresses due to inflation and other causes; and the allocation of orders between categories is difficult because sub-contracts often flow from the main order.

6.6 Technology, research and development

The Department of Energy's research and development programme in the field of oil and gas technology is determined in the light of advice from the Offshore Energy Technology Board. The funds made available in 1981–82 amounted to £21.8 million. Expenditure in the current financial year is expected to be around £18 million. Two advisory groups, consisting of personnel from oil and gas related industries, help the

Department to identify areas in which R & D might be useful. In 1982, increased emphasis was placed on specific aspects of operational safety.

In 1982 various projects associated with the structural safety of offshore installations were supported by the Department of Energy: e.g. the prevention of buckling in offshore structures; the use of foundation piles under tension forces similar to those expected in a tension leg platform; and the use of concrete in the sea. Studies of the improvement of the safety of diving operations, the enhancement of oil recovery from reservoirs and the requirements for containment of fire offshore were also supported.

The completion of the first phase of research on the fatigue of offshore steel enabled the Department to draw up a new section of the Guidance Notes for the Design of Offshore Structures. A new phase of the work has now begun, costing £3.25 million, 70 per cent of which will be subscribed by industry. Other projects completed during the year included research on the safe use of electrical equipment under water and on the prevention of corrosion of steel risers.

The Department of Energy, in conjunction with the Norwegian authorities, have established a data base of all current offshore oil and gas related R & D projects in the UK and Norway. Use of the data base is expected to avoid duplication of research.

Research and development programmes to enhance the capabilities of UK industry in offshore oil and gas activities continued to be pursued on a shared cost basis with the industry. The many and varied programmes ranged from electronics to civil engineering. An example was the development of a system for connecting tubulars by hydraulic deformation (''Hydra-Lok'') which had its first commercial application in making a riser connection on Britoil's Thistle platform.

The Underwater Inititative programme, begun in 1979 to strengthen UK technology in the field of underwater engineering, has continued to promote the development of remotely operated underwater vehicles and related equipment. The work is carried out with the help of the underwater engineering companies, the aerospace and defence industries and the oil industry.

The Department of Energy have recently taken a new initiative to strengthen further the development of UK offshore technology. In the Eighth Round of licensing the co-operation of applicants was sought in involving UK organisations in research into new concepts and in the design and demonstration of associated techniques and equipment for application on the UKCS. The Offshore Supplies Office will be working closely with operators and UK industry to implement the new initiative.

A considerable number of reports on projects already started has been published. Whenever possible, a short summary of these reports is included in the bi-monthly Departmental publication ''Offshore Research Focus'', copies of which are available from the Construction Industry Research and Information Association (CIRIA), 6 Storey's Gate, London SW1P 3AU. Technical reports on non-commercial projects can be obtained from the British Library, Boston Spa, Wetherby, West Yorkshire LS23 7BQ.

Part 7: Oil field review

7.1 Oil fields in production

Field (Operator)	Date of production start up	Operator's estimate of (or actual) first year of peak production	Operator's estimated (or actual) peak production (million tonnes per year)	Transport system	Remarks
(a) Offshore					
Argyll (Hamilton)	June 1975	1977	1.1	Tanker loading offshore	Seven wells were on production during 1982. Two infill development wells were completed. A seismic survey of the Argyll/Duncan area was conducted.
Auk (Shell)	Feb 1976	1977	2.3	Tanker loading offshore	One development well was drilled. Good production performance resulted in the extension of predicted field life to 1985.
Beatrice (Britoil)	Sept 1981	1985	2.3	Oil and NGL transported by pipeline to Nigg Bay	Two production and two injection wells were drilled from the 'A' platform, bringing the total number to 16. 10 wells on the 'B' location are shut-in to await installation of the 'B' platform.
Beryl A (Mobil)	June 1976	1980	5	Tanker loading offshore. Gas is being re-injected until a disposal route is available.	Three production wells were drilled to drain peripheral reserves. Pressure in the Upper Beryl reservoir was maintained by gas injection rather than water injection because of uneven water advance. The Lower Beryl reservoir was shut-in and stablilised for testing.
Brent (Shell)	Nov 1976	1984	19.9	Oil and NGL transported by pipeline to Sullom Voe via South Cormorant. Gas and NGL exported to St Fergus via the FLAG system.	Sixteen development wells were drilled from the four platforms. Gas treatment and export systems were commissioned on the platforms.
Buchan (BP)	May 1981	1983	1.7	Tanker loading offshore	Three wells began production in 1982, bringing the total number to eight.
Claymore (Occidental)	Nov 1977	1984	5.9	Oil and NGL transported by pipeline to Flotta	Appraisal of the pre-Jurassic reservoir in the centre of the field continued. Plans to develop the area are being discussed with the Department of Energy. A production well, drilled to a depth of 18,890 feet, was the longest deviated well on the UKCS.

Field (Operator)	Date of production start up	Operator's estimate of (or actual) first year of peak production	Operator's estimated (or actual) peak production (million tonnes per year)	Transport system	Remarks
North Cormorant (Shell)	Feb 1982	1986	7.4	Oil and NGL transported by pipeline to Sullom Voe via South Cormorant. Gas and NGL exported to St Fergus via the Western Leg and the FLAG system.	Three production wells and one water injection well were in operation at the end of the year.
South Cormorant (Shell)	Dec 1979	1984	2.0	Oil and NGL transported by pipeline to Sullom Voe. Gas and NGL exported to St Fergus via the Western Leg and the FLAG system.	Two injection wells and one producing well were drilled in 1982. Production was reduced because of drilling slippages and disappointing water injection rates. The platform was taken off production for two months to allow tie-in of the Underwater Manifold Centre in October.
Dunlin (Shell)	Aug 1978	1979	5.7	Oil and NGL transported by pipeline to Sullom Voe via South Cormorant	Three wells were drilled from the platform in 1982, bringing the total to 23. The problem of high water content continued.
Forties (BP)	Sept 1975	1980	24.6	Oil and NGL transported by pipeline to Cruden Bay	Four wells were drilled in 1982, bringing the total potential to 54 production wells and 14 water injection wells. Options for the development of the extension of the field into block 22/6a are being discussed with the Department of Energy.
Fulmar (Shell)	Feb 1982	1985	7.7	Tanker loading offshore. Gas is being reinjected until it can be exported via the projected pipeline to St Fergus.	Seven development wells were drilled from the platform. Water injection began in late 1982.
Heather (Union)	Oct 1978	1982	1.7	Oil and NGL transported by pipeline to Sullom Voe via Ninian Central platform.	Five development wells were completed. Drilling difficulties were encountered when high pressure water was found above the reservoir horizon. Alternative development options to increase oil recovery are being considered. In 1982 the development plan was revised to include development of an adjacent oil pool.
Montrose (Amoco)	June 1976	1979	1.4	Tanker loading offshore	There were 15 producing wells and four injection wells at the end of 1982. The rate of injection was reduced because of fracturing of the reservoir but this did not affect production rates.

Field (Operator)	Date of production start up	Operator's estimate of (or actual) first year of peak production	Operator's estimated (or actual) peak production (million tonnes per year)	Transport system	Remarks
Murchison (Conoco)	Sept 1980	1982	5.3(1)	Oil and NGL transported by pipeline to Sullom Voe via Dunlin and South Cormorant. Gas and NGL is being reinjected until the Northern Leg of the FLAG system becomes operational in 1983.	Seven wells were drilled from the platform in 1982. Oil production was maintained from 11 wells. Gas was reinjected via two wells and this will continue until such gas can be transported to St Fergus.
Ninian (Chevron)	Dec 1978	1982	15.1	Oil and NGL transported by pipeline to Sullom Voe. Gas and NGL is exported to St Fergus via the Western Leg and FLAG system.	Progress continued with the 96-well development programme. Six wells were drilled from the Southern platform and this is now complete; four wells were drilled on the Central platform; and three wells were drilled on the Northern platform.
Piper (Occidental)	Dec 1976	1979	13	Oil and NGL transported by pipeline to Flotta. Gas is exported to St Fergus via the Frigg pipeline system.	Five development wells were drilled. Work was carried out to plug water production zones and perforate clean oil sands in order to reduce water content. A 3D seismic survey was carried out in 1982.
Statfjord (Conoco)	Nov 1979	1988	28.5(1)	Tanker loading offshore; a pipeline should be in use by 1986. Norwegian gas will be piped to Norway; UK gas will be transported to St Fergus via the Northern Leg gas pipeline and the FLAG system.	The B platform began production during the year. Production from the C platform is due to begin in 1985.
Tartan (Texaco)	Jan 1981	1984	1.4	Oil and NGL transported by pipeline to Flotta via Claymore. Gas export to St Fergus via Piper and the Frigg pipeline system began in 1983.	Eight development wells were drilled, four from the platform and four from semi-submersibles. The gas-sweetening plant to remove hydrogen sulphide from gas and NGL was commissioned in January 1983. The operator has considerably reduced the estimates of reserves (see Appendix 6) and of peak production from the figures given in the 1982 Brown Book.

Field (Operator)	Date of production start up	Operator's estimate of (or actual) first year of peak production	Operator's estimated (or actual) peak production (million tonnes per year)	Transport system	Remarks
Thistle (Britoil)	Feb 1978	1982	6.0	Oil and NGL transported by pipeline to Sullom Voe. Gas and NGL is being reinjected until the Northern Leg of the FLAG system becomes operational in 1983.	Eight production wells were commenced. One was drilled to test a separate structure to the west of the main field. Recovery of oil from the lower parts of the main reservoir was difficult because extreme permeability contrasts were encountered. Polymers were injected in an attempt to reduce water-channelling in the high permeability sands.
(b) Onshore					
Wytch Farm (BGC)	Mar 1979	Not assessed	Not assessed	Oil transported by pipeline to a rail terminal at Furzebrook. Gas is fed locally into the BGC grid.	One well was drilled in the year to complete the current phase of production drilling. There are now 23 wells on the field. Interference tests were carried out to appraise the properties of the reservoir in the Sherwood Sandstone formation.

(1) Including the Norwegian sector of the field.

7.2 Offshore oil fields under development

Field (Operator)	Date of production start up	Operator's estimate of first year of peak production	Operator's estimated peak production (million tonnes per year)	Transport system	Remarks
Alwyn North (Total)	1987	1988	4.2	Oil and NGL will be transported by pipeline to Sullom Voe via Ninian Central. Gas will be exported to St Fergus via the Frigg pipeline system.	The development plan was approved by the Secretary of State for Energy in October 1982.
Beryl B (Mobil)	1984	1985	4.1	Tanker loading offshore using the Beryl A facilities. Gas will be re-injected until a disposal route is available.	The sixth, and final, template well was being drilled at the end of the year. Production continued from a test well, via a subsea completion tied into the Beryl A facilities. A pipeline between Beryl A and Beryl B has been laid.
South Brae (Marathon)	1983	1983	5.3	Oil and NGL will be transported to Cruden Bay via the Forties pipeline. Gas will be re-injected until a disposal route is available.	No drilling took place in 1982. The platform jacket was installed and hook-up of the modules is proceeding.
Clyde (Britoil)	1987	1988	2.4	Oil will be transported by pipeline to Fulmar for loading into tankers offshore. It is expected that gas will be exported by pipeline to Fulmar and then to St Fergus via the projected pipeline.	The development plan was approved by the Secretary of State for Energy in December 1982. A single fixed steel platform will be installed.
Hutton (Conoco)	1985	1985	4.7	Oil and NGL will be transported to Sullom Voe via N W Hutton and South Cormorant.	Six template wells were drilled to complete the programme of ten pre-drilled development wells. Construction problems were encountered with the hull of the Tension Leg Platform.

Field (Operator)	Date of production start up	Operator's estimate of first year of peak production	Operator's estimated peak production (million tonnes per year)	Transport system	Remarks
N W Hutton (Amoco)	1983	1984	5.1	Oil and NGL will be transported by pipeline to Sullom Voe via South Cormorant. Gas and NGL will be exported to St Fergus via the Western Leg pipeline and the FLAG system.	Installation of the modules and their support frame was completed and hook-up is well advanced.
Magnus (BP)	1983	1984	5.8	Oil and NGL will be transported by pipeline to Sullom Voe via Ninian Central. Gas and NGL will be transported to St Fergus via the Northern Leg pipeline and the FLAG system.	Six appraisal wells were recompleted as subsea producers and the flowlines were laid and tied in. The platform jacket was positioned in April 1982 and installation of the modules is complete.
Maureen (Phillips)	1983	1984	3.6	Tanker loading offshore.	Development drilling continued through the subsea template. Eight wells were drilled during the year.

Appendix 1
Licensing

Offshore production and exploration licences are issued under the Petroleum (Production) Act 1934, as extended offshore by the Continental Shelf Act 1964. To date there have been eight rounds of production licensing in 1964, 1965, 1970, 1971/1972, 1976/1977, 1978/1979, 1980/1981 and 1982/1983. Details of each round are given below.

Round	Area under offer	No of blocks on offer	No of applications	No of companies in consortia	No of blocks applied for	Licences		
						No of blocks	No awarded	No of companies
First (1964)	North Sea	960	31	61	394	348	53	51
Second (1965)	North Sea Irish Sea English Channel	1102	21	54	127	127	37	44
Third (1970)	North Sea Irish Sea Orkney/Shetland Basin	157	34	54	117	106	37	61
Fourth (1971/1972)	North Sea Irish Sea Celtic Sea Orkney/Shetland Basin	421 for discretionary award; 15 for cash tender	92 31	228 73	271 15	282	118	213
Fifth (1976/1977)	North Sea Irish Sea Celtic Sea Orkney/Shetland Basin English Channel/South Western Approaches West of Scotland	71	53	133	51	44	28	64
Sixth (1978/1979)	North Sea West Shetland Basin Cardigan Bay/Bristol Channel South Western Approaches	46	55	94	46	42	26	59
Seventh (1980/1981)	North Sea West Shetland Basin Orkney/Shetland Basin English Channel South Western Approaches	Specified area of Northern North Sea; 80 elsewhere	125	204	97	90	90	157
Eighth (1982/1983)	North Sea West Orkney Basin East Shetland Basin Unst Fair Isle Forth Approaches Bristol Channel	169 for discretionary award; 15 for cash tender	40 20	94 47	76 8	No awards yet made 7	 7	 16

Appendix 2
Drilling activity

(A) Exploration drilling; exploration wells started in each geographical area

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
East of England	7	4	2	3	5	—	—	—	1	9
East of Scotland	18	25	49	25	23	20	22	19	37	36
East of Shetland	16	26	23	25	24	11	4	7	7	11
West of England/ Wales	1	4	2	4	4	3	—	—	—	4
West of Shetland	—	8	3	1	11	1	3	6	2	3
Channel and SW Approaches	—	—	—	—	—	2	4	—	1	5
Total all areas	42	67	79	58	67	37	33	32	48	68

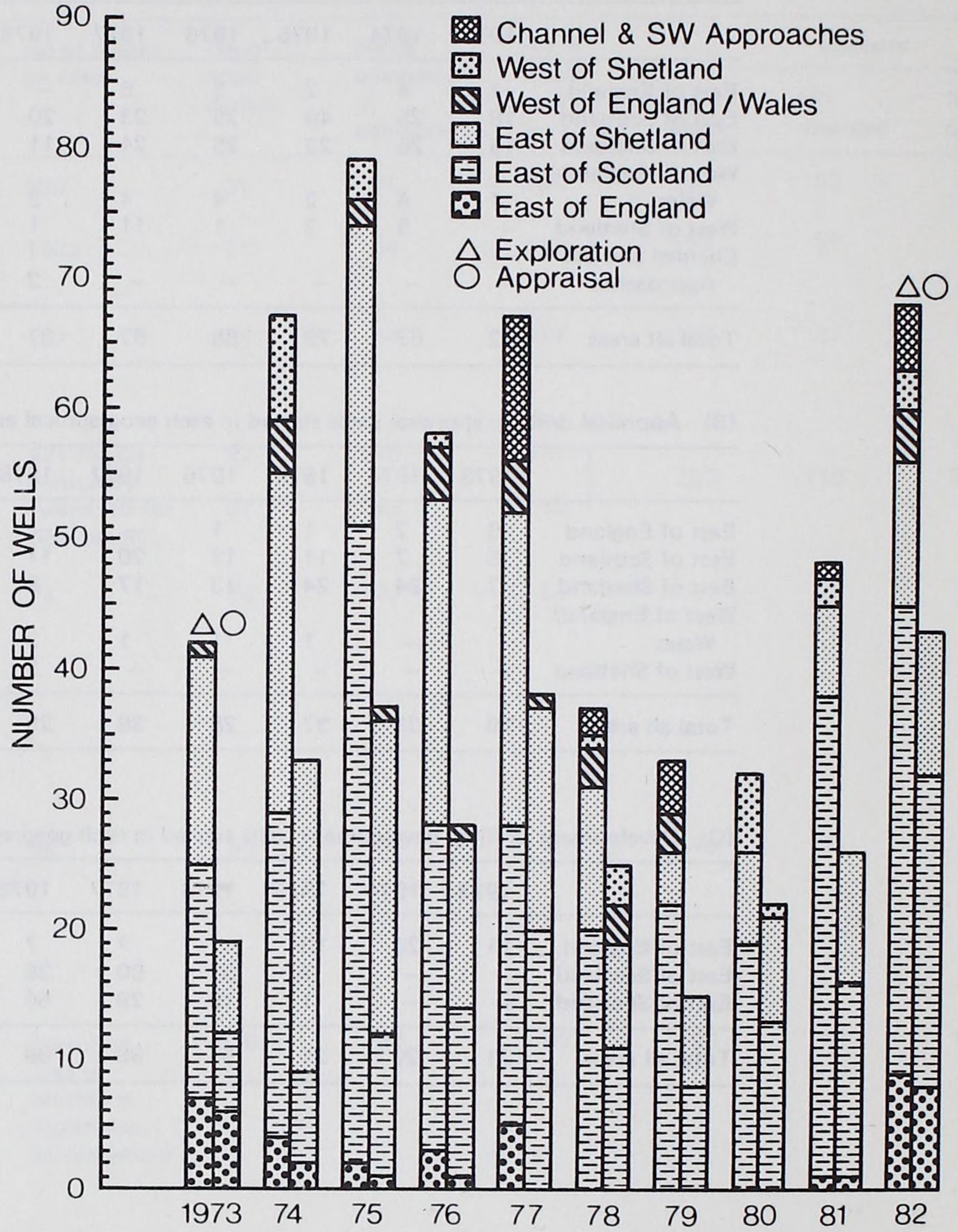
(B) Appraisal drilling; appraisal wells started in each geographical area

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
East of England	6	2	1	1	—	—	—	—	1	8
East of Scotland	6	7	11	13	20	11	8	13	15	24
East of Shetland	7	24	24	13	17	8	7	8	10	11
West of England/ Wales	—	—	1	1	1	3	—	—	—	—
West of Shetland	—	—	—	—	—	3	—	1	—	—
Total all areas	19	33	37	28	38	25	15	22	26	43

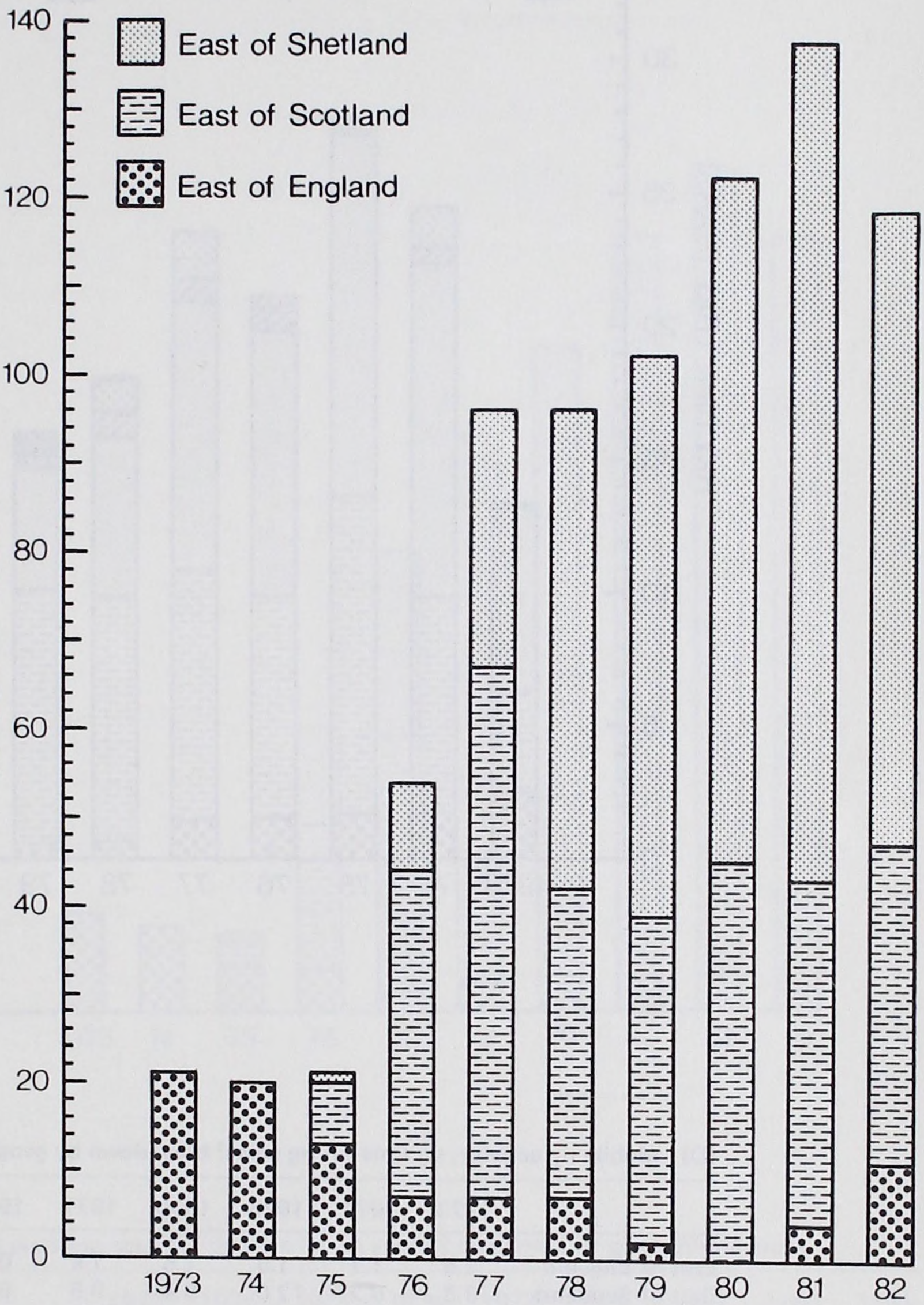
(C) Development drilling; development wells started in each geographical area

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
East of England	21	20	13	7	7	7	2	—	4	11
East of Scotland	—	—	7	37	60	35	37	45	39	36
East of Shetland	—	—	1	10	29	54	63	77	94	71
Total all areas	21	20	21	54	96	96	102	122	137	118

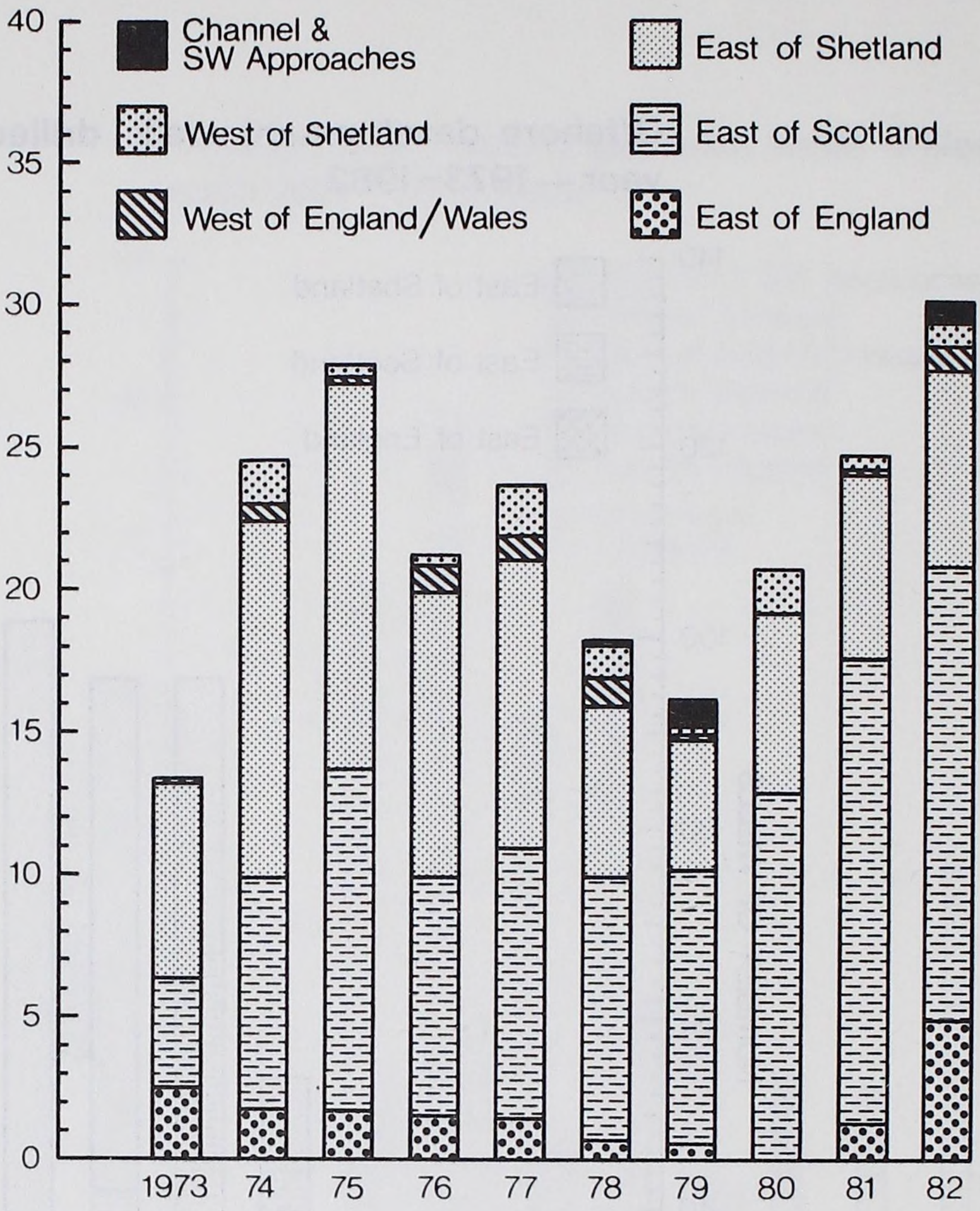
Offshore exploration/appraisal wells drilled each year – 1973-1982



Offshore development wells drilled each year — 1973–1982



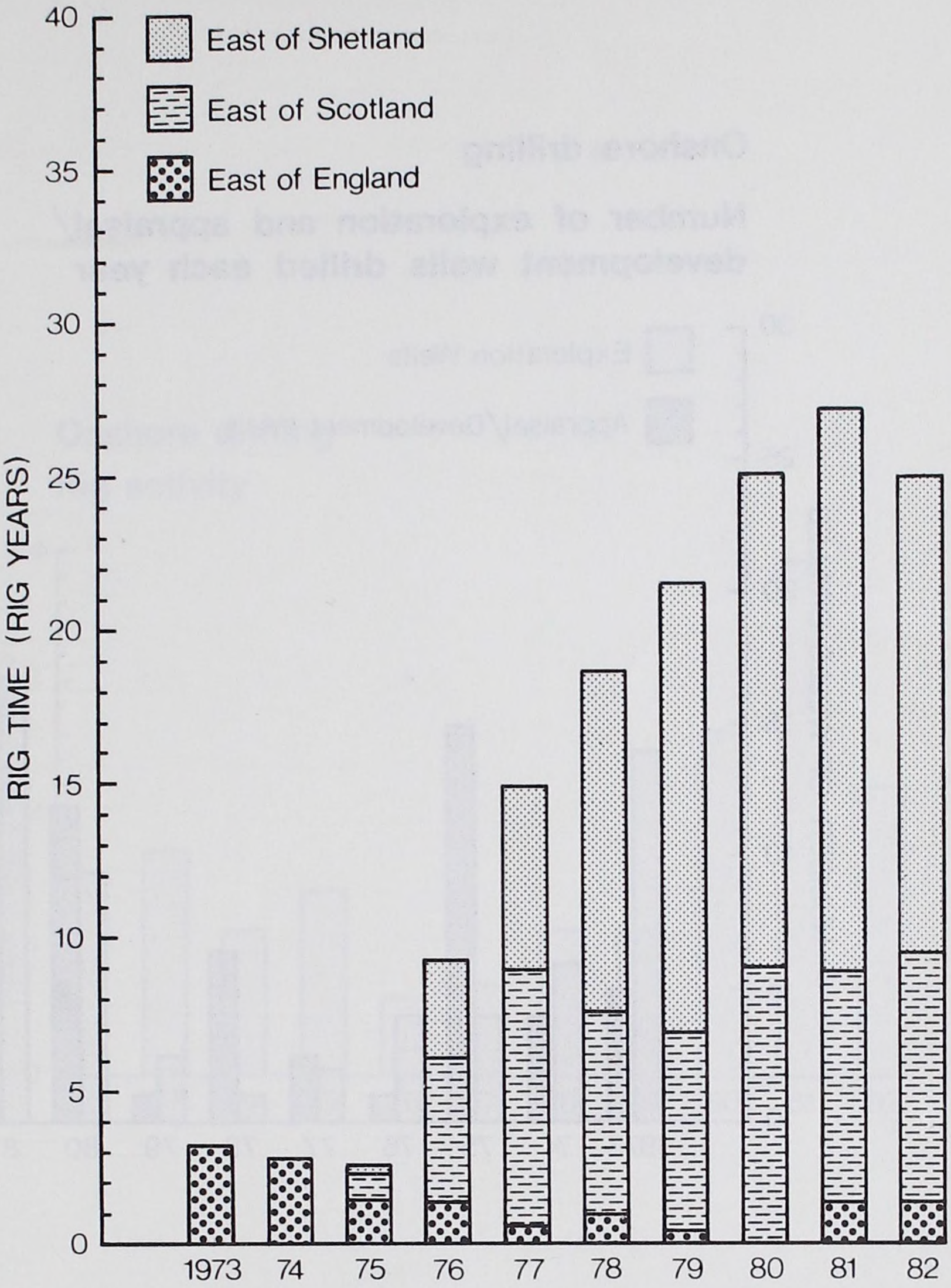
Mobile rig activity
Rig time spent in UK Continental Shelf



(D) Mobile rig activity; rig time (in rig years) breakdown by geographical areas

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
East of England	2.5	1.7	1.6	1.5	1.4	0.6	0.5	–	1.2	4.9
East of Scotland	3.8	8.2	12.0	8.4	9.5	9.3	9.6	12.8	16.3	15.8
East of Shetland	6.9	12.4	13.6	9.9	10.1	5.9	4.5	6.3	6.5	6.9
West of England/ Wales	0.1	0.7	0.2	1.0	0.8	1.1	0.2	–	0.2	0.9
West of Shetland	–	1.5	0.3	0.4	1.8	1.1	0.4	1.5	0.4	0.8
Channel and SW Approaches	–	–	–	–	–	0.1	0.9	–	–	0.8
Total all areas	13.3	24.5	27.7	21.2	23.6	18.1	16.1	20.6	24.6	30.1

Fixed platform activity
Rig time spent in UK Continental Shelf



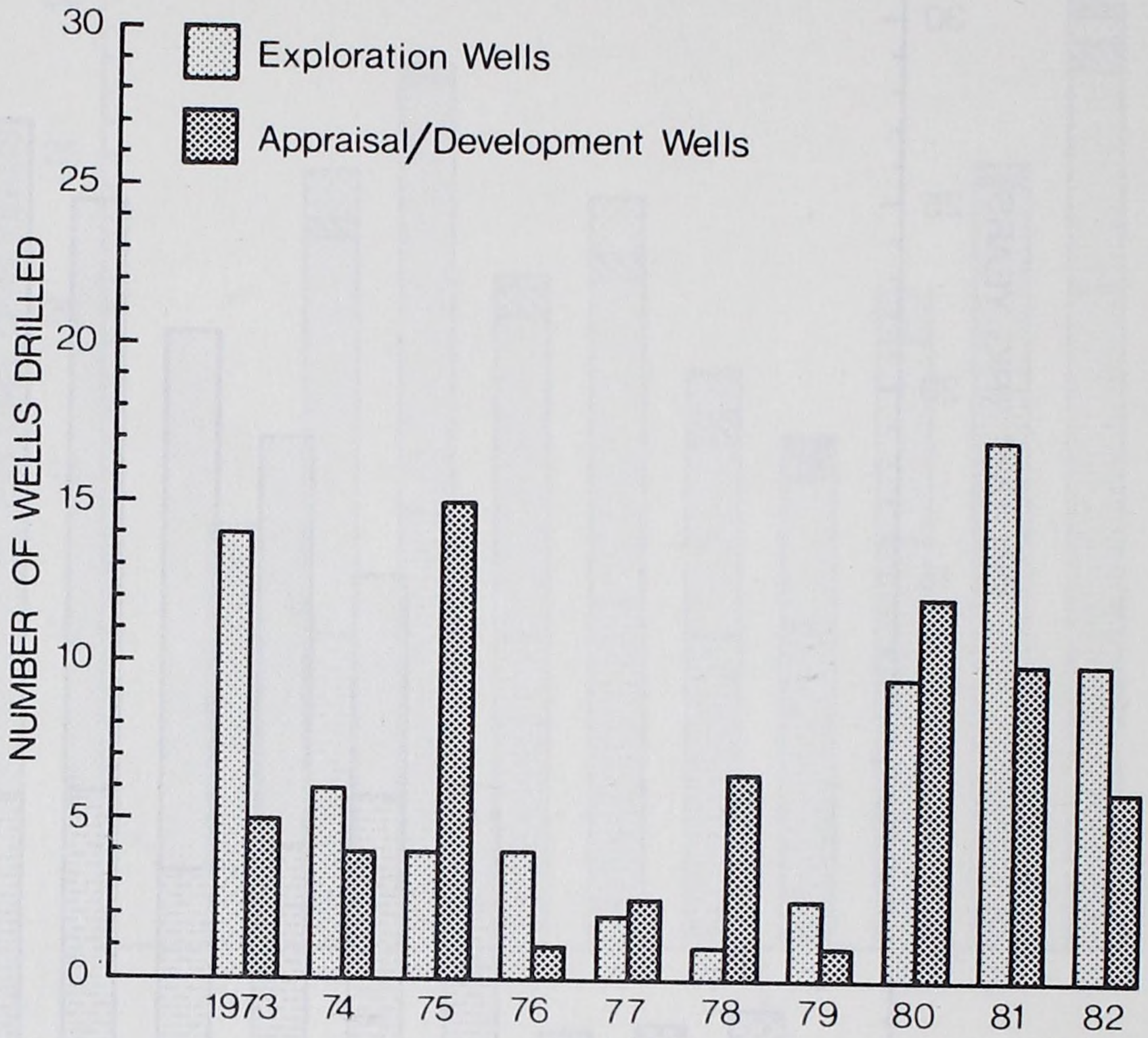
(E) Fixed platform activity; rig time (in rig years) breakdown by geographical areas

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
East of England*	3.2	2.8	1.5	1.4	0.7	1.0	0.5	–	1.4	1.4
East of Scotland	–	–	0.9	4.7	8.2	6.6	6.5	9.0	7.4	8.1
East of Shetland	–	–	0.2	3.2	6.0	11.0	14.5	16.2	18.2	15.5
Total all areas	3.2	2.8	2.6	9.3	14.9	18.6	21.5	25.2	27.0	25.0

*Most of this activity was associated with the development of the Southern Basin gas fields.

Onshore drilling

Number of exploration and appraisal/ development wells drilled each year

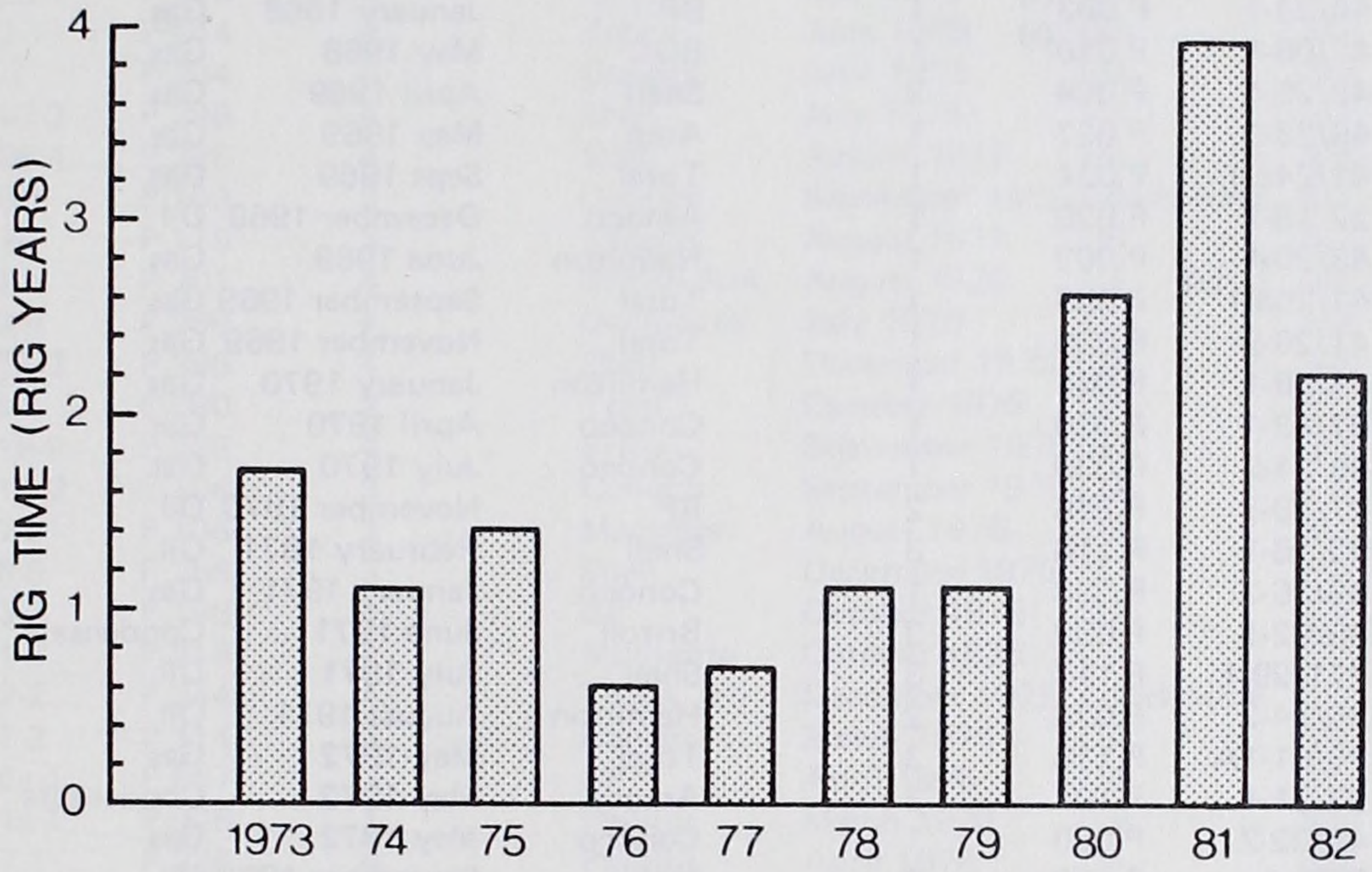


(F) Onshore drilling; number of wells drilled

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Exploration wells	14	6	4	4	2	1	2½	9½	17	10
Appraisal/ Development wells	5	4	15	1	2½	6½	1	12	10	6

NOTE: Where a well was started in one year and completed in the next it has been shown as a half in each year.

Onshore drilling
Rig activity



(G) Onshore drilling; rig activity in rig years

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Activity (rig years)	1.7	1.1	1.4	0.6	0.7	1.1	1.1	2.6	3.9	2.2

Appendix 3
Significant* offshore hydrocarbon discoveries

Announced by the end of 1982. In Department of Energy number order.

Field[1] name	Block and well number	Licence number	Licence round	Operator at the end of 1982	Date discovered	Type	Category[2]	Area[3]
WEST SOLE	48/06-1	P.001	1	BP	December 1965	Gas	FIP	SNSB
VIKING	49/17-1	P.033	1	Conoco	December 1965	Gas	FIP	SNSB
Ann	49/06-1	P.028	1	Phillips	May 1966	Gas	SD	SNSB
LEMAN BANK	49/26-1	P.007	1	Shell	April 1966	Gas	FIP	SNSB
	42/23-1	P.004[4]	1	Burmah	July 1966	Gas	SD	SNSB
INDEFATIGABLE	49/18-1	P.016	1	Amoco	June 1966	Gas	FIP	SNSB
HEWETT	48/29-1	P.037	1	Arco	October 1966	Gas	FIP	SNSB
	48/22-1[5]	P.005	1	Britoil	November 1966	Oil	SD	SNSB
Scram	53/04-1	P.039	1	Arco	July 1967	Gas	SD	SNSB
	48/21-1	P.047	1	Placid	August 1967	Condensate	SD	SNSB
	44/23-1	P.003[4]	1	BP	January 1968	Gas	SD	SNSB
ROUGH	47/08-1	P.030[6]	1	BGC	May 1968	Gas	FIP	SNSB
SE Indefatigable	49/25-1	P.054	2	Shell	April 1969	Gas	SD	SNSB
	49/28-3	P.037	1	Arco	May 1969	Gas	SD	SNSB
	41/24a-1	P.034	1	Total	Sept 1969	Gas	SD	SNSB
MONTROSE	22/18-1	P.020	1	Amoco	December 1969	Oil	FIP	CNSB
	43/20-1	P.002	1	Hamilton	June 1969	Gas	SD	SNSB
	41/25a-1[5]	P.039	1	Total	September 1969	Gas	SD	SNSB
	41/20-2	P.039	1	Total	November 1969	Gas	SD	SNSB
	43/08-1	P.048	1	Hamilton	January 1970	Gas	SD	SNSB
	47/13-1	P.050	1	Conoco	April 1970	Gas	SD	SNSB
Valiant	49/21-2	P.039	1	Conoco	July 1970	Gas	SD	SNSB
FORTIES	21/10-1	P.246	2	BP	November 1970	Oil	FIP	CNSB
AUK	30/16-1	P.116	3	Shell	February 1971	Oil	FIP	CNSB
	49/16-3	P.033	1	Conoco	January 1971	Gas	FIP	SNSB
	30/02-1	P.098	3	Britoil	June 1971	Condensate	SD	CNSB
BRENT	211/29-1	P.117	3	Shell	July 1971	Oil	FIP	ESB
ARGYLL	30/24-2	P.073	2	Hamilton	August 1971	Oil	FIP	CNSB
FRIGG	10/01-1A	P.118	3	Total	May 1972	Gas	FIP	ESB
Lomond	23/21-1	P.101	3	Amoco	May 1972	Condensate	SD	CNSB
Victor	49/22-2	P.025	1	Conoco	May 1972	Gas	SD	SNSB
BERYL A	9/13-1	P.139	4	Mobil	September 1972	Oil	FIP	ESB
	30/13-2	P.079	2	Phillips	September 1972	Oil	SD	CNSB
SOUTH CORMORANT	211/26-1	P.232	4	Shell	September 1972	Oil	FIP	ESB
	211/18-1	P.236	4	Britoil	September 1972	Oil	SD	ESB
Amethyst	47/14a-1	P.005	1	Britoil	October 1972	Gas	SD	SNSB
PIPER	15/17-1A	P.220	4	Occidental	January 1973	Oil	FIP	MFB
MAUREEN	16/29-1	P.110	3	Phillips	February 1973	Oil	FUD	CNSB
	47/15-2	P.133	4	Amoco	March 1973	Gas	SD	SNSB
DUNLIN	211/23-1	P.232	4	Shell	July 1973	Oil	FIP	ESB
THISTLE	211/18-2	P.236	4	Britoil	July 1973	Oil	FIP	ESB
HUTTON	211/28-1A	P.204	4	Conoco	December 1973	Oil	FUD	ESB
	3/14a-1	P.090	2	Total	November 1973	Oil	SD	ESB
HEATHER	2/05-1	P.242	4	Union	December 1973	Oil	FIP	ESB
NINIAN	3/03-1	P.202	4	Chevron	April 1974	Oil	FIP	ESB
'N.W. Dunlin'	211/23-3	P.296	4	Shell	February 1974	Oil	SD	ESB
	15/17-7	P.220	4	Occidental	January 1974	Oil	SD	MFB
Bruce	9/08-1	P.209	4	Hamilton	July 1974	Condensate	SD	ESB
MAGNUS	211/12-1	P.193	4	BP	July 1974	Oil	FUD	ESB
CLAYMORE	14/19-2	P.249	4	Occidental	June 1974	Oil	FIP	MFB
Andrew	16/28-1	P.092	3	BP	June 1974	Oil & Cond.	SD	CNSB
	15/23-1Z	P.324	4	Texaco	October 1974	Oil	SD	MFB
BUCHAN	21/01-1	P.241	4	BP	August 1974	Oil	FIP	MFB
	211/13-1	P.296	4	Shell	November 1974	Condensate	SD	ESB

Field[1] name	Block and well number	Licence number	Licence round	Operator at the end of 1982	Date discovered	Type	Category[2]	Area[3]
NORTH CORMORANT	211/21-2	P.232	4	Shell	August 1974	Oil	FIP	ESB
	9/13-4	P.139	4	Mobil	August 1974	Oil & Cond.	SD	ESB
	211/18-6	P.236	4	Britoil	August 1974	Oil	SD	ESB
MORECAMBE	110/02-1	P.153	4	Hydrocarbons GB	September 1974	Gas	FUD	ISB
TARTAN	15/16-1	P.237	1	Texaco	January 1975	Oil	FIP	MFB
Brae N	16/07-1	P.108	3	Marathon	May 1975	Condensate	SD	ESB
	2/05-6	P.242	4	Union	December 1974	Oil	SD	ESB
Mable	16/29-4	P.110	3	Phillips	February 1975	Oil	SD	CNSB
STATFJORD	211/24-4	P.104	3	Conoco	February 1975	Oil	FIP	ESB
N.W. HUTTON	211/27-3	P.184	4	Amoco	April 1975	Oil	FUD	ESB
	3/04-4	P.119	3	Texaco	March 1975	Oil	SD	ESB
	14/20-1	P.294	4	Texaco	February 1975	Oil	SD	MFB
Crawford	9/28-2	P.209	4	Hamilton	April 1975	Oil	SD	ESB
BERYL B (North)	9/13-7	P.139	4	Mobil	May 1975	Oil	FUD	ESB
Tern	210/25-1	P.296	4	Shell	May 1975	Oil	SD	ESB
	21/02-1	P.244	4	Zapex	June 1975	Oil	SD	CNSB
	3/02-1	P.204	4	Conoco	June 1975	Oil	SD	ESB
	211/13-2	P.296	4	Shell	July 1975	Oil	SD	ESB
	211/26-4	P.296	4	Shell	August 1975	Oil	SD	ESB
	15/30-1	P.103	3	Conoco	September 1975	Condensate	SD	MFB
	3/04-6	P.119	3	Texaco	August 1975	Oil	SD	ESB
Balmoral	16/21-1	P.201	4	British Sun	August 1975	Oil	SD	MFB
Scapa	14/19-9	P.250	4	Occidental	July 1975	Oil	SD	MFB
	211/13-3	P.296	4	Shell	December 1975	Oil	SD	ESB
ALWYN NORTH	3/09a-1	P.090	2	Total	October 1975	Oil	FUD	ESB
	211/18-9	P.236	4	Britoil	September 1975	Oil	SD	ESB
MURCHISON	211/19-2	P.104	3	Conoco	September 1975	Oil	FIP	ESB
'West Brae'	16/07-2	P.108	3	Marathon	August 1975	Oil	SD	ESB
FULMAR	30/16-6	P.256	3	Shell	December 1975	Oil	FIP	CNSB
	15/13-2	P.198	4	BP	October 1975	Oil	SD	MFB
	15/21-3	P.218	4	Monsanto	October 1975	Oil	SD	MFB
	21/02-2	P.244	4	Zapex	December 1975	Condensate	SD	CNSB
	23/27-3	P.114	3	Ranger	March 1976	Oil	SD	CNSB
	23/26a-1	P.057	2	BP	April 1976	Oil	SD	CNSB
Audrey	49/11a-1	P.028	1	Phillips	March 1976	Gas	SD	SNSB
	15/27-1	P.226	4	Phillips	April 1976	Oil	SD	MFB
	9/19-2	P.103	3	Conoco	May 1976	Oil & Cond.	SD	ESB
N.W. HUTTON	211/27-6	P.184	4	Amoco	May 1976	Oil	FUD	ESB
'Columba'	3/07-1	P.203	4	Chevron	June 1976	Oil	SD	ESB
	14/20-5	P.324	4	Texaco	April 1976	Oil	SD	MFB
	14/20-6A	P.324	4	Texaco	June 1976	Oil	SD	MFB
	49/29-2	P.105	3	Mobil	June 1976	Gas	SD	SNSB
Eider	211/16-2	P.296	4	Shell	May 1976	Oil	SD	ESB
Toni-Thelma	16/17-1	P.225	4	Phillips	July 1976	Oil	SD	CNSB
	211/18-12	P.236	4	Britoil	July 1976	Oil	SD	ESB
BEATRICE	11/30-1	P.187	4	Britoil	September 1976	Oil	FIP	MFB
	3/07-2	P.203	4	Chevron	November 1976	Oil	SD	ESB
'N.E. Halibut'	211/18-13	P.236	4	Britoil	January 1977	Oil	SD	ESB
	211/19-6	P.104	3	Conoco	January 1977	Oil	SD	ESB
	3/29-2	P.198	4	BP	August 1977	Gas	SD	ESB
	16/22-2	P.240	4	Total	May 1977	Oil	SD	CNSB
	15/23-4	P.324	4	Texaco	August 1977	Oil	SD	MFB
SOUTH BRAE	16/07a-8	P.108	3	Marathon	July 1977	Oil	FUD	ESB
	3/14a-4	P.090	2	Total	August 1977	Condensate	SD	ESB
Clair	206/08-1A	P.165	4	BP	July 1977	Oil	SD	WSB
	16/26-2	P.213	4	Gulf	October 1977	Condensate	SD	CNSB
	210/15-2	P.226	4	Phillips	October 1977	Oil	SD	ESB

Field[1] name	Block and well number	Licence number	Licence round	Operator at the end of 1982	Date discovered	Type	Category[2]	Area[3]
CLYDE	30/17b-2	P.266	5	Britoil	June 1978	Oil	FUD	CNSB
	14/18-1	P.263	5	Occidental	May 1978	Oil	SD	MFB
	2/10a-4	P.234	4	Chevron	May 1978	Oil	SD	ESB
	3/28a-2	P.234	4	Chevron	September 1978	Oil	SD	ESB
	9/18a-3A	P.103	3	Conoco	March 1979	Oil	SD	ESB
	30/17b-5	P.266	5	Britoil	May 1979	Oil	SD	CNSB
Tiffany	16/17-8A	P.225	4	Phillips	July 1979	Oil	SD	CNSB
	9/19-5A	P.103	3	Conoco	July 1979	Gas	SD	ESB
	16/28-4	P.092	3	BP	October 1979	Oil	SD	CNSB
	21/25-1	P.013	1	Shell	September 1979	Oil & Gas	SD	CNSB
	2/05-10	P.242	4	Union	September 1979	Oil	SD	ESB
	21/25-2	P.013	1	Shell	December 1979	Oil	SD	CNSB
N.E. Brae	16/03a-1	P.108	3	Marathon	April 1980	Condensate	SD	ESB
	16/21a-2	P.201	4	British Sun	March 1980	Oil	SD	MFB
	30/12b-2	P.185	4	Amoco	February 1981	Oil	SD	CNSB
	21/19-1A	P.238	4	Shell	April 1981	Oil	SD	CNSB
Duncan	30/24-15	P.073	2	Hamilton	January 1981	Oil	SD	CNSB
	3/14a-7	P.090	2	Total	August 1981	Oil	SD	ESB
	30/07a-1	P.032	1	Phillips	May 1981	Oil	SD	CNSB
	20/02-1	P.317	6	Britoil	April 1981	Oil	SD	CNSB
	9/09b-2	P.276	5	BP	July 1981	Condensate	SD	ESB
	29/05a-1	P.188	4	Arco	September 1981	Oil	SD	CNSB
	3/04-8	P.119	3	Texaco	October 1981	Oil	SD	ESB
	21/15a-2	P.120	3	Conoco	August 1981	Oil	SD	CNSB
	2/15-1	P.327	7	Chevron	October 1981	Oil	SD	ESB
	30/24-17	P.073	2	Hamilton	December 1981	Oil	SD	CNSB
	13/29-1	P.307	6	Ultramar	December 1981	Oil	SD	MFB
	15/17-9	P.220	4	Occidental	March 1982	Oil	SD	MFB
	20/03-2A	P.273	5	Amoco	May 1982	Oil	SD	CNSB
	21/30-4	P.013	1	Shell	June 1982	Oil	SD	CNSB
	43/13a-1	P.002	1	Hamilton	June 1982	Gas	SD	SNSB
	113/26-1	P.287	5	HGB	August 1982	Gas	SD	ISB
	21/30-6A	P.013	1	Shell	September 1982	Oil	SD	CNSB
	22/05b-2	P.356	7	Superior	September 1982	Gas & Cond.	SD	CNSB
'Glamis'	16/21a-6	P.201	4	British Sun	November 1982	Oil	SD	MFB
	49/16-7	P.033	1	Conoco	December 1982	Gas	SD	SNSB

*The description "significant" generally refers to the flow rates achieved in well tests and does not necessarily indicate the potential commerciality of the discovery.

(1) Fields in production or under development are shown in capital letters.

(2) FIP, Fields in Production; FUD, Fields under Development; SD, Significant Discovery.

(3) ESB, East Shetland Basin; WSB, West Shetland Basin; MFB, Moray Firth Basin; CNSB, Central North Sea Basin; SNSB, Southern North Sea Basin; ISB, Irish Sea Basin. The location of the major basins of the UKCS is shown in the map at Appendix 18.

(4) Licence relinquished.

(5) Block relinquished.

(6) P.030 now applies to Block 47/08a operated by Amoco. The Rough field operated by BGC is Block 47/08b, licence P.323.

Appendix 4
Appraisal drilling on significant discoveries

Field name	Block and well number	Licence number	Operator	Type	Activity in 1982
	3/02-1	P.204	Conoco	Oil	No drilling took place in 1982.
S W Ninian/ Columba	3/07-1 3/08a-3	P.203 P.199	Chevron BP	Oil	An appraisal well drilled on block 3/08 gave encouraging results.
	3/14-1	P.090	Total	Oil	No drilling took place in 1982.
	3/27-1 3/28a-1	P.333 P.234	LASMO Chevron	Oil	Drilling confirmed the extension of the heavy oil accumulation onto block 3/27.
Bruce	9/08-1	P.209	Hamilton	Condensate	Two successful appraisal wells were drilled.
	9/12-1 9/13-4	P.254 P.139	Union Mobil	Oil	Evaluation of reserves and development options continued.
	9/19-2 9/19-5a	P.103	Conoco	Oil & Gas	An appraisal well gave disappointing results. Evaluation of the complex structure continued.
	13/29-1	P.307	Ultramar	Oil	Two wells drilled on adjacent block 13/28 indicated a possible extension of the feature. Further drilling is planned for 1983.
Scapa	14/19-9	P.250	Occidental	Oil	A dry hole reduced the estimate of reserves. No further work is planned for 1983.
14/20	14/20-5 14/20-6A	P.324	Texaco	Oil	No wells were drilled in 1982 although approval was given for a further appraisal well.
	15/23-1Z 15/23-4	P.237	Texaco	Oil	No drilling took place in 1982.
	15/30-1 16/26-2	P.103 P.213	Conoco Gulf	Condensate	Two appraisal wells proved to be dry.
N E Brae	16/03a-1	P.108	Marathon	Condensate	No drilling took place in 1982.
	16/07-2	P.108	Marathon	Oil	No drilling took place in 1982.
Toni-Thelma-Tiffany (T-Block)	16/17-1 16/17-8A	P.225	Phillips	Oil	No drilling took place in 1982.
Balmoral	16/21-1 16/21b-4a	P.344 P.201	British Sun Britoil	Oil	Two exploration wells drilled by Britoil on block 16/21b established the extension of the field to the east and to the north west. 16/21a-6 confirmed the existence of a Jurassic reservoir on a feature to the south of the main field to be known as Glamis.
Andrew	16/28-1	P.092	BP	Oil	An exploration well, drilled by Phillips on an adjacent feature on block 16/27a, proved disappointing. A well on the main 16/28 block was re-entered to test a deep horizon, again with poor results.
	21/25-2 21/30-3	P.013	Shell	Oil	Two appraisal wells were drilled on this complex structure in 1982.
Lomond	23/21-1	P.101	Amoco	Condensate	No drilling took place in 1982.
Duncan	30/24-15 30/24-17	P.073	Hamilton	Oil	An extended production test on 30/24-15 was conducted. This led to the initiation of a delineation drilling programme under which three appraisal wells were drilled. A similar test on 30/24-17, east of the main structure, is nearing completion. An appraisal well was drilled on this structure in 1982.

Field name	Block and well number	Licence number	Operator	Type	Activity in 1982
	41/24a-1	P.034	Total	Condensate	No drilling took place in 1982.
Amethyst	47/14a-1	P.005	Britoil	Gas	A further appraisal well was drilled in 1982.
Victor	49/22-2	P.025	Conoco	Gas	A further appraisal well was drilled.
S E Inde-fatigable	49/25-1	P.054	Shell	Gas	A further successful appraisal well was drilled.
Clair	206/8-1	P.165	BP	Oil	No drilling took place in 1982.
Tern	210/25-1	P.296	Shell	Oil	No drilling took place in 1982.
Eider	211/16-2	P.296	Shell	Oil	No drilling took place in 1982.
	211/18-12	P.236	Britoil	Oil	Two successful appraisal wells were completed in 1982.

Appendix 5
Offshore oil fields under development

This table gives information on the eight fields under development at the end of 1982

Field name	Block numbers and licence number	Licensees	Company interest in block (%) at the end of 1982	Extension into other UK blocks		Date of discovery	Operator's estimate of recoverable reserves originally present in the field (million tonnes)[1]
				Block number + licence number	Licensees/Company interest in block (%) at the end of 1982		
Alwyn North	3/9a P.090	Total Oil Marine PLC Elf UK Ltd	33⅓ 66⅔	Part 3/4a P.416	Total Oil Marine PLC/33⅓ Elf UK Ltd/66⅔	Oct 1975	26.25
Beryl B	9/13a P.139	Mobil Producing North Sea Ltd Amerada Exploration Ltd Texas Eastern UK Ltd BGC *BNOC	50 20 20 10 Nil			May 1975	39.9
South Brae	16/7a P.108	Marathon Oil North Sea (GB) Ltd Bow Valley Exploration (UK) Ltd Britoil PLC BCRIC Exploration (UK) Ltd LL & E (UK) Inc BCRIC Oil (UK) Ltd Sovereign Oil and Gas PLC Kerr McGee Oil (UK) Ltd Saga Petroleum (UK) Ltd *BNOC	38 14 20 6.3 6.3 1.4 4 8 2 Nil			July 1977	40
Clyde	30/17b P.266	Britoil PLC Shell UK Ltd Esso Petroleum Company Ltd *BNOC	51.0 24.5 24.5 Nil			June 1978	20.5
Hutton	211/28a P.204	Conoco Ltd Gulf Oil (Great Britain) Ltd Britoil PLC *BNOC	33⅓ 33⅓ 33⅓ Nil	211/27 P.184	Amoco UK Petroleum Ltd/25.77 BGC/25.77 Mobil Producing North Sea Ltd/20 Amerada Exploration Ltd/18.08 Texas Eastern UK Ltd/10.38	Nov 1973	31.8
NW Hutton	211/27 P.184	Amoco UK Petroleum Ltd BGC Amerada Exploration Ltd Texas Eastern UK Ltd Mobil Producing North Sea Ltd	25.77 25.77 18.08 10.38 20			Oct 1975	37.5
Magnus	211/12a P.193	BP Petroleum Development Ltd *BNOC	100 Nil	211/78 P.193	BP Petroleum Development Ltd/100 *BNOC/Nil	July 1974	75

Field name	Block numbers and licence number	Licensees	Company interest in block(%) at the end of 1982	Extension into other UK blocks		Date of discovery	Operator's estimate of recoverable reserves originally present in the field (million tonnes)[1]
				Block number + licence number	Licensees/Company interest in block(%) at the end of 1982		
Maureen	16/29a P.110	Phillips Petroleum Co UK Ltd Fina Exploration AGIP (UK) Ltd Century Power & Light Ltd Ultramar Exploration Ltd The British Electric Traction Co Ltd *BNOC	33.78 28.96 17.26 9 6 5 Nil			Feb 1973	21

[1] The reserves figures quoted may not be precisely comparable with each other or with official figures quoted in this report since differences exist in the procedures and assumptions adopted by different companies and by the Department of Energy.

* BNOC is a co-licensee through its participation agreement.

Appendix 6
Offshore oil fields in production

The table gives information on the 20 fields in production at the end of 1982

Field name	Block numbers and licence number	Licensees	Company interest in block (%) at the end of 1982	Extension into other UK blocks: Block number + licence number	Extension into other UK blocks: Licensees/Company interest in block (%) at the end of 1982	Date of discovery	Operator's estimate of recoverable reserves originally present in the field (million tonnes)[1]
Argyll	30/24	Hamilton Oil	28.8			Aug 1971	7.3
	P.073	Great Britain PLC					
		Hamilton Brothers Petroleum (UK) Ltd	7.2				
		RTZ Oil and Gas Ltd	25				
		Blackfriars Oil Co Ltd	12.5				
		Trans-European Co Ltd	2.5				
		Texaco North Sea UK Ltd	24				
		*BNOC	Nil				
Auk	Part 30/16	Shell UK Ltd	50			Feb 1971	8.8
	P.116	Esso Petroleum Company Ltd	50				
		*BNOC	Nil				
Beatrice	11/30a	Britoil PLC	28			Sept 1976	17
	P.187	Deminex UK Oil and Gas Ltd	22				
		Kerr McGee Oil (UK) Ltd	25				
		Lasmo North Sea Ltd	15				
		Hunt Oil (UK) Ltd	10				
		*BNOC	Nil				
Beryl A	9/13a	Mobil Producing North Sea Ltd	50			Sept 1972	66
	P.139	Amerada Exploration Ltd	20				
		Texas Eastern UK Ltd	20				
		BGC	10				
		*BNOC	Nil				
Brent	211/29a	Shell UK Ltd	50			July 1971	230.4
	P.117	Esso Petroleum Company Ltd	50				
		*BNOC	Nil				
Buchan	21/1a	BP Petroleum Development Ltd	27.1	20/5a	Texaco North Sea UK Ltd/	Aug 1974	7.7
	P.241	Transworld Petroleum (UK) Ltd	14	P.294	100		
		CCP North Sea Ass.PLC	6.35		*BNOC/Nil		
		Goal Petroleum PLC	5				
		Clyde Petroleum PLC	14				
		Sulpetro (UK) Ltd	14				
		St Joe Petroleum (UK) Ltd	14				
		Charterhall Oil Ltd	4.56				
		Lochiel Exploration Ltd	1				
		*BNOC	Nil				
Claymore	14/19a	Occidental Petroleum (Caledonia) Ltd	36.5			June 1974	54
	P.249	Getty Oil (Britain) Ltd	23.5				
		Union Texas Petroleum Ltd	20				
		Thomson North Sea Ltd	20				
		*BNOC	Nil				

Field name	Block numbers and licence number	Licensees	Company interest in block (%) at the end of 1982	Extension into other UK blocks: Block number + licence number	Extension into other UK blocks: Licensees/Company interest in block (%) at the end of 1982	Date of discovery	Operator's estimate of recoverable reserves originally present in the field (million tonnes)[1]
North Cormorant	Part 211/21a P.258	Shell UK Ltd Esso Petroleum Company Ltd *BNOC	50 50 Nil			Aug 1974	53.5
South Cormorant	211/26a P.232	Shell UK Ltd Esso Petroleum Company Ltd *BNOC	50 50 Nil	211/21a P.232	Shell UK Ltd/50 Esso Petroleum Co Ltd/50 *BNOC/Nil	Sept 1972	26.8
Dunlin	211/23a P.232	Shell UK Ltd Esso Petroleum Company Ltd *BNOC	50 50 Nil	211/24a P.104	Conoco Ltd/33⅓ Gulf Oil (Great Britain) Ltd/16⅔ Gulf (UK) Offshore Investments Ltd/16⅔ Britoil PLC/33⅓ *BNOC/Nil	July 1973	41.5
Forties	21/10 P.246	BP Oil Development Ltd *BNOC	100 Nil	22/6a P.084	Shell UK Ltd/50 Esso Petroleum Co Ltd/50 *BNOC/Nil	Nov 1970	261
Fulmar	Part 30/16 P.256	Shell UK Ltd Esso Petroleum Company Ltd *BNOC	50 50 Nil	30/11b P.185	Amoco UK Petroleum Ltd/25.77 BGC/25.77 Amerada Exploration Ltd/18.08 Texas Eastern UK Ltd/10.38 Mobil Producing North Sea Ltd/20	Dec 1975	56.0
Heather	2/5 P.242	Unocal Exploration and Production Co (UK) Ltd Getty Oil Exploration (UK) Ltd Tenneco Great Britain Ltd DNO (Heather Oilfield) Ltd *BNOC	31.25 31.25 31.25 6.25 Nil			Dec 1973	8–12
Montrose	Part 22/17 P.019	Amoco UK Petroleum Ltd BGC Amerada Exploration Ltd Texas Eastern UK Ltd *BNOC	30.77 30.77 23.08 15.38 Nil	Part 22/18 P.020	Amoco UK Petroleum Ltd/30.77 BGC/30.77 Amerada Exploration Ltd/23.08 Texas Eastern UK Ltd/15.38 *BNOC/Nil	Dec 1969	12.1
Murchison (UK)	211/19a P.104	Conoco Ltd Gulf Oil (Great Britain) Ltd Gulf (UK) Offshore Investments Ltd Britoil PLC *BNOC	33⅓ 16⅔ 16⅔ 33⅓ Nil			Sept 1975	42.7[2]
Ninian	3/3 P.202	Chevron Petroleum Co Ltd ICI Petroleum Ltd Murphy Petroleum Ltd Ocean Exploration Ltd Britoil PLC *BNOC	24 26 10 10 30 Nil	3/8a P.199	BP Petroleum Development Ltd/50 Ranger Oil (UK) Ltd/20 Lasmo North Sea Ltd/30 *BNOC/Nil	Apr 1974	143

Field name	Block numbers and licence number	Licensees	Company interest in block(%) at the end of 1982	Extension into other UK blocks: Block number + licence number	Extension into other UK blocks: Licensees/Company interest in block(%) at the end of 1982	Date of discovery	Operator's estimate of recoverable reserves originally present in the field (million tonnes)[1]
Piper	15/17a P.220	Occidental Petroleum (UK) Ltd	36.5			Jan 1973	94
		Getty Oil (Britain) Ltd	23.5				
		Union Texas Petroleum Ltd	20				
		Thomson North Sea Ltd	20				
		*BNOC	Nil				
Statfjord (UK)	211/24 a & b P.104 211/24c P.293	Conoco Ltd	33⅓	211/25a P.104 211/25b P.293	Conoco Ltd/33⅓ Gulf Oil (Great Britain) Ltd/16⅔ Gulf (UK) Offshore Investments Ltd/16⅔ Britoil PLC/33⅓ *BNOC/Nil	April 1974	384[2]
		Gulf Oil (Great Britain) Ltd	16⅔				
		Gulf (UK) Offshore Investments Ltd	16⅔				
		Britoil PLC	33⅓				
		*BNOC	Nil				
Tartan	15/16a and 14/20a P.237	Texaco North Sea UK Ltd	100			Jan 1975	8.2
		*BNOC	Nil				
Thistle[4]	211/18a P.236	Britoil PLC	15.6	211/19a P.104	Conoco Ltd/33⅓ Gulf Oil (Great Britain) Ltd/16⅔ Gulf (UK) Offshore Investments Ltd/16⅔ Britoil PLC/33⅓ *BNOC/Nil	July 1973	60[3]
		Burmah Oil Exploration Ltd	8.4				
		Deminex UK Oil and Gas Ltd	42.5				
		Santa Fe (UK) Ltd	16.875				
		Tricentrol Exploration UK Ltd	10				
		Charterhouse Petroleum Development Ltd	1				
		Charterhouse Oil and Gas Ltd	1.40625				
		Ultramar North Sea Ltd	1.40625				
		Britoil (Alpha) Ltd	2.8125				
		*BNOC	Nil				

(1) The reserves figures quoted may not be precisely comparable with each other or with the official figures in this report since differences exist in the procedures and assumptions adopted by different companies and by the Department of Energy.

(2) Including the Norwegian sector of the field.

(3) Estimate currently under review.

(4) The interests shown refer to the Thistle field area of block 211/18a only.

* BNOC is a co-licensee through its participation agreements.

Appendix 7
Gas fields in production and under development

The table gives information on the seven fields in production and one under development at the end of 1982

Field name (block number and licence number)	Licensees/Company interest in block at the end of 1982 (%)	Extension into other UK blocks		Date of discovery	Date of production start up
		Block number and licence number	Licensees/Company interest in block at the end of 1982 (%)		
Gas fields in production					
West Sole (48/6) P.001	BP Petroleum Development Ltd/100			Dec 1965	March 1967
Leman Bank (49/26) P.007	Shell UK Ltd (Shell)/50 Esso Petroleum Co Ltd (Esso)/50	49/27 P.016	Amoco UK Petroleum Ltd (Amoco)/30.77 BGC/30.77 Amerada Exploration Ltd (Amerada)/23.08 Texas Eastern (UK) Ltd (Texas Eastern)/15.38	April 1966	Aug 1968
		49/28 P.037	Arpet Petroleum Ltd (Arpet)/33⅓ British Sun Oil Co Ltd/23⅓ Union Rheinische (UK) Ltd/10 Superior Oil (UK) Ltd/20 Canadian Superior Oil (UK) Ltd/33⅓ Sinclair (UK) Oil Ltd/10		
		53/2 P.025 53/1a P.025	Mobil Producing North Sea Ltd/100		
Indefatigable (49/18) P.016	Amoco/30.77 BGC/30.77 Amerada/23.08 Texas Eastern/15.38	49/23 P.016	Amoco/30.77 BGC/30.77 Amerada/23.08 Texas Eastern/15.38	June 1966	Oct 1971
		49/19 P.008	Shell/50 Esso/50		
		49/24 P.007	Shell/50 Esso/50		
Hewett[1] (48/29) P.037	Arpet/33⅓ British Sun Oil Co Ltd/23⅓ Union Rheinische (UK) Ltd/10 Superior Oil (UK) Ltd/20 Canadian Superior Oil (UK) Ltd/3⅓ Sinclair (UK) Oil Co Ltd/10	48/30 P.028	Phillips Petroleum Co UK Ltd/35 Fina Exploration Ltd/30 AGIP (UK) Ltd/15 Century Power & Light Ltd/7.22 Plascom Ltd/4.26 Lasmo North Sea Ltd/8.52	Oct 1966	July 1969
		52/5a P.028	Phillips group as above		

Field name (block number and licence number)	Licensees/Company interest in block at the end of 1982 (%)	Extension into other UK blocks		Date of discovery	Date of production start up
		Block number and licence number	Licensees/Company interest in block at the end of 1982 (%)		
		52/4a P.112	Phillips/19 AGIP (UK) Ltd/8.1 Fina/16.3 Century Power & Light Ltd/3.9 Lasmo North Sea Ltd/4.6 Plascom Ltd/2.3 Arpet/15.3 British Sun Oil Co Ltd/10.7 Union Rheinische (UK) Ltd/4.6 Superior Oil (UK) Ltd/9.1 Canadian Superior Oil (UK) Ltd/1.5 Sinclair (UK) Oil Co Ltd/4.6		
		48/28a P.037	Arpet Group as for Block 48/29		
Viking (49/17) P.033	Conoco Ltd (Conoco)/50 Britoil PLC/50	49/12a P.033	Conoco/50 Britoil PLC/50	Dec 1965	July 1972
		49/16 P.033	Conoco/50 Britoil PLC/50		
Rough[2] (47/8b) P.323	BGC/100	47/3d P.323	BGC/100	May 1968	Oct 1975
Frigg (UK) (10/1) P.118	Total Oil Marine PLC/33 1/3 Elf UK Ltd/66 2/3	9/10a P.090	Total/33 1/3 Elf UK Ltd/66 2/3	May 1972	Sept 1977
		9/5a P.194	BP Petroleum Development Ltd/100		
Gas field under development					
Morecambe (110/2a) P.153	Hydrocarbons Great Britain Ltd/100	110/3a P.251 110/8a P.251 110/7a P.099	Hydrocarbons Great Britain Ltd/100	Sept 1974	1984

(1) The Hewett field includes accumulations formerly known as Dotty and Deborah.

(2) In March 1982 approval in principle was granted to the development of the Rough reservoir capacity to store gas from other fields during periods of low demand; the gas will then be made available during periods of high demand.

Appendix 8
Oil production[1]

million tonnes

	Total from 1975 to end 1976	1977	1978	1979	1980	1981	1982	Cumulative total from 1975
Offshore fields								
Argyll	1.6	0.8	0.7	0.8	0.8	0.5	1.0	6.1
Auk	1.2	2.3	1.3	0.8	0.6	0.6	0.6	7.6
Beatrice						0.2	1.6	1.9
Beryl A	0.4	3.0	2.6	4.7	5.4	4.7	4.4	25.2
Brent	0.1	1.3	3.8	8.8	6.8	11.1	15.4	47.1
Buchan						0.9	1.4	2.3
Claymore		0.3	3.0	4.0	4.4	4.5	4.8	21.2
North Cormorant							1.4	1.4
South Cormorant				0.04	1.1	0.7	0.9	2.7
Dunlin			0.7	5.7	5.2	4.7	3.9	20.1
Forties	9.2	20.1	24.5	24.5	24.6	22.8	22.1	147.8
Fulmar							2.6	2.6
Heather			0.1	0.8	0.7	1.2	1.7	4.6
Montrose	0.1	0.8	1.2	1.3	1.2	1.1	0.9	6.6
Murchison (UK)					0.4	3.1	4.4	7.9
Ninian			0.04	7.7	11.4	14.3	15.0	48.5
Piper	0.1	8.6	12.2	13.2	10.4	9.8	9.8	64.1
Statfjord (UK)				0.04	0.5	1.2	1.8	3.6
Tartan						0.7	0.6	1.3
Thistle			2.6	3.9	5.3	5.5	6.0	23.3
Total stabilised crude oil from offshore fields[2]	12.6	37.3	52.8	76.5	78.7	87.6	100.2	445.8
Stabilised crude oil from onshore fields[2]	0.2	0.1	0.1	0.1	0.2	0.2	0.2	1.1
Liquefied products from oil and gas fields								
Condensates[3]	0.7	0.5	0.4	0.4	0.4	0.4	0.5	3.3
Heavier natural gases[4]	0.1	0.4	0.6	0.8	1.1	1.2	2.4	6.6
Total production	13.7	38.3	54.0	77.9	80.5	89.4	103.3	456.8

(1) All figures are rounded to the nearest 100,000 tonnes except where start up occurred late in the year (Ninian in 1978, South Cormorant and Statfjord UK in 1979). This rounding has created some discrepancies between individual annual field figures and the totals of both UKCS production and of cumulative production for each field.

(2) Includes the condensate and residual dissolved gases present in the disposal of stabilised crude by the industry.

(3) A mixture of pentane and higher hydrocarbons which arise mainly from the treatment of gas from the Frigg and Southern Basin fields.

(4) Ethane, propane and butane produced in the treatment of liquid or gaseous hydrocarbons at pipeline terminals.

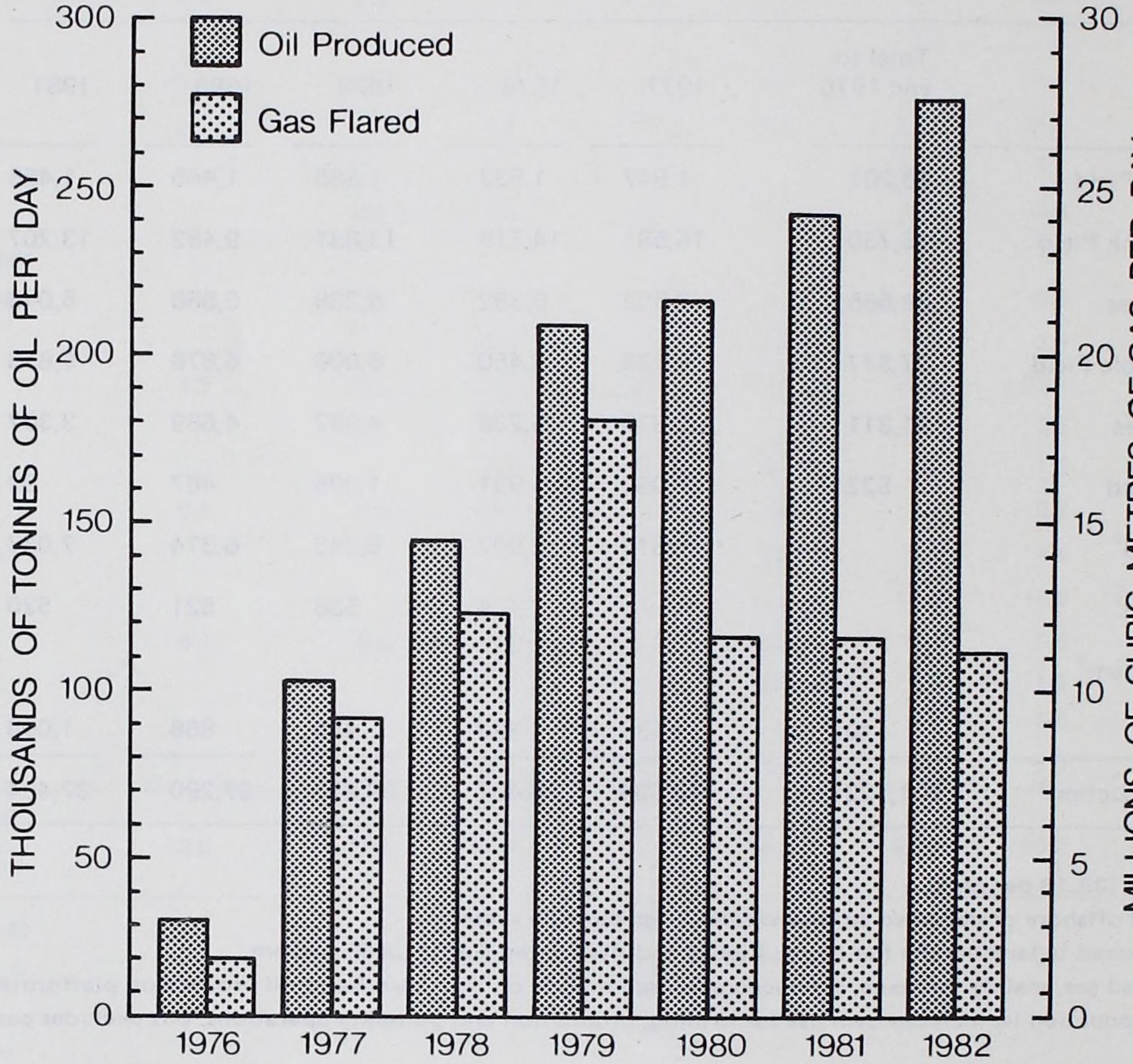
Appendix 9
Gas production

million cubic metres

	Total to end 1976	1977	1978	1979	1980	1981	1982	Cumulative total to end 1982
West Sole Field	16,207	1,947	1,533	1,365	1,445	1,455	1,512	25,464
Leman Bank Field	96,730	15,581	14,719	13,831	9,482	13,207	11,675	175,225
Hewett Area	39,565	7,852	6,392	6,288	6,568	5,048	4,108	75,821
Indefatigable Field	27,377	6,779	6,450	6,006	6,878	5,613	5,720	64,823
Viking Area	21,311	6,330	5,238	4,397	4,689	3,307	4,381	49,653
Rough Field	522	1,063	931	1,005	467	99	101	4,188
Frigg Field[1]		614	2,907	5,345	6,374	7,057	6,569	28,866
Piper Field[2]			4	536	521	520	629	2,210
FLAG system[3]							2,144	2,144
Other[4]	10	138	323	455	866	1,098	1,437	4,327
Total production[5]	201,722	40,304	38,497	39,228	37,290	37,404	38,276	432,721

[1] UK share (39.18 per cent).
[2] Gas used offshore or delivered to land via the Frigg pipeline system.
[3] Gas delivered to land via the Far North Liquid and Associated Gas (FLAG) System.
[4] Associated gas, mainly methane, produced and used mainly on Northern Basin oil production platforms.
[5] Gross production ie. includes own use for drilling, production and pumping operations, but excludes gas flared.

Appendix 10
Oil produced and gas flared at producing oil fields



Appendix 11
Gas flaring at oil terminals and producing oil fields

Field	Average gas flaring rate in 1982 in million cubic metres a day (figures for million cubic feet a day in brackets)	Note of measures taken to reduce flaring.
Oil terminals		
Flotta	0.05 (2)	LPG transported in tankers and specially converted vessels. Methane is used for fuel and supplied to North of Scotland Hydro Electric Board.
Sullom Voe	0.62 (21)	The commissioning of gas handling and LPG recovery facilities resulted in high flaring of gas. The amount should decrease in 1983 as operational experience is gained.
Producing oil fields		
Argyll	0.21 (7)	Small isolated field — no alternative economic outlet for gas.
Auk	0.07 (2)	Small isolated field — no alternative economic outlet for gas.
Beatrice	0.08 (3)	Small amounts flared offshore and at Nigg.
Beryl A	0.29 (10)	High gas reinjection efficiency.
Brent	3.08 (109)	All four platforms began exporting gas through the FLAG system.
Buchan	0.24 (8)	Small isolated field — no alternative economic outlet for gas.
Claymore	0.04 (1)	Small amount flared — no surplus gas.
North Cormorant	0.10 (4)	Flaring was reduced when export of gas by the FLAG system began in mid 1982.
South Cormorant	0.15 (5)	Flaring was reduced when export of gas by the FLAG system began in mid 1982. NGL injected into the oil pipeline to Sullom Voe.
Dunlin	0.26 (9)	NGL injected into the oil pipeline to Sullom Voe.
Forties	2.02 (72)	NGL injected into the oil pipeline to Cruden Bay.
Fulmar	0.79 (28)	Commissioning of gas injection equipment is under way. Gas will be reinjected into the reservoir until a disposal route is available.
Heather	0.30 (11)	No alternative economic outlet for gas. NGL injected into the pipeline to Sullom Voe.
Montrose	0.32 (11)	Small isolated field — no alternative economic outlet for gas.

Field	Average gas flaring rate in 1982 in million cubic metres a day (figures for million cubic feet a day in brackets)	Note of measures taken to reduce flaring.
Murchison (UK)	0.59 (21)	Some gas reinjected into the reservoir. NGL injected into the oil pipeline to Sullom Voe. Flaring will be reduced when export of gas by the Northern Leg and the FLAG system begins in May 1983.
Ninian	0.58 (21)	NGL injected into the pipeline to Sullom Voe. Gas is exported via the Western Leg and the FLAG system.
Piper	0.37 (13)	Gas is exported via the Frigg pipeline system. NGL is transported via the oil pipeline to Flotta.
Statfjord (UK)	0.09 (3)	High gas reinjection efficiency.
Tartan	0.24 (8)	Gas is exported via Piper and the Frigg pipeline system following commissioning of a gas-sweetening plant to remove hydrogen sulphide from gas and NGL.
Thistle	0.60 (21)	Some gas reinjected into the reservoir. NGL injected into the oil pipeline to Sullom Voe. Flaring will be reduced when export of gas via the Northern Leg and the FLAG system begins in October 1983.

Appendix 12
Oil production platforms

Field	Operator	Platform contractor	Site	Platform type	Installation date
PLATFORMS INSTALLED					
Argyll	Hamilton	Converted by Wilson-Walton	Teesside	Converted Drilling Rig	March 1975
Auk	Shell	Redpath Dorman Long	Methil	Steel	July 1974
Beatrice	Britoil	Dragados y Construcciones	Almeria, Spain	Steel	Sept 1979
		Dragados y Construcciones	Almeria, Spain	Steel	June 1980
Beryl	Mobil	Norwegian Contractors	Stavanger, Norway	Concrete	July 1975
Brae	Marathon	McDermott Scotland	Ardersier	Steel	April 1982
Brent A	Shell	Redpath Dorman Long	Methil	Steel	May 1976
B		Norwegian Contractors	Stavanger, Norway	Concrete	August 1975
C		McAlpine/Sea Tank	Ardyne Point	Concrete	June 1978
D		Norwegian Contractors	Stavanger, Norway	Concrete	July 1976
Buchan	BP	Conversion by Lewis Offshore	Stornoway	Converted Drilling Rig	Sept 1980
Claymore	Occidental	Union Industrielle et d'Entreprise	Cherbourg, France	Steel	July 1976
Cormorant (North)	Shell	Redpath de Groot Caledonian Union Industrielle et d'Entreprise	Methil Cherbourg, France	Steel	April 1981
Cormorant (South)	Shell	McAlpine/Sea Tank	Ardyne Point	Concrete	May 1978
Dunlin	Shell	Andoc	Rotterdam, Holland	Concrete	July 1977
Forties FA	BP	Laing Offshore	Teesside	Steel	June 1974
FB		Laing Offshore	Teesside	Steel	June 1975
FC		Highlands Fabricators	Nigg Bay	Steel	August 1974
FD		Highlands Fabricators	Nigg Bay	Steel	June 1975
Fulmar (well-head jacket)	Shell	Redpath de Groot Caledonian	Methil	Steel	July 1979
(platform)		Highlands Fabricators	Nigg Bay	Steel	June 1980
Heather	Unocal	McDermott Scotland	Ardersier	Steel	May 1977
Hutton NW	Amoco	McDermott Scotland	Ardersier	Steel	Sept 1981
Magnus	BP	Highlands Fabricators	Nigg Bay	Steel	April 1982
Montrose	Amoco	Union Industrielle et d'Entreprise	Le Havre, France	Steel	August 1975
Murchison	Conoco	McDermott Scotland	Ardersier	Steel	August 1979
Ninian	Chevron				
Central		Howard Doris	Loch Kishorn	Concrete	May 1978
North		Highlands Fabricators	Nigg Bay	Steel	July 1978
South		Highlands Fabricators	Nigg Bay	Steel	June 1977
Piper	Occidental	McDermott Scotland Union Industrielle et d'Entreprise	Ardersier Le Havre, France	Steel	June 1975
Tartan	Texaco	Redpath de Groot Caledonian Union Industrielle et d'Entreprise	Methil Cherbourg, France	Steel	June 1979
Thistle	Britoil	Laing Offshore	Teesside	Steel	August 1976

Field	Operator	Platform contractor	Site	Platform type	Installation date
PLATFORMS UNDER CONSTRUCTION					
Beatrice B	Britoil	RGC Offshore	Methil	Steel	June 1983
Beryl B	Mobil	Redpath de Groot Caledonian	Methil	Steel	March 1983
Hutton	Conoco	Highlands Fabricators McDermott Scotland	Nigg Bay Ardersier	Steel	Sept 1983
Maureen	Phillips	Ayrshire Marine Constructors HDN Offshore Structures	Hunterston Loch Kishorn	Steel	April 1983

Appendix 13
Major offshore pipelines

Pipelines, from—to	Length (miles)	Diameter (inches)	Material conveyed	Operator	Year commissioned
Operating:					
West Sole—Easington	42	16	Natural Gas	BP	1967
Leman Bank—Bacton	35	30	Natural Gas	Shell/Esso	1968
Hewett—Bacton	20	30	Natural Gas	Phillips/Arpet	1969
Leman Bank—Bacton	38	30	Natural Gas	Amoco	1969
Leman Bank—Bacton	40	30	Natural Gas	Amoco/Shell/Esso	1970
Indefatigable—Leman Bank	25	30	Natural Gas	Amoco/Shell/Esso	1971
Viking—Theddlethorpe	86	28	Natural Gas	Conoco	1972
Hewett—Bacton	20	30	Natural Gas	Phillips/Arpet	1973
Leman Bank—Bacton	36	30	Natural Gas	Amoco/Shell/Esso	1973
Rough—Easington	18	16	Natural Gas	Amoco	1975
Ekofisk—Teesside	220	34	Crude Oil	Phillips	1975
Forties—Cruden Bay	111	32	Crude Oil	BP	1975
Piper—Flotta	124	30	Crude Oil	Occidental	1976
Frigg—St Fergus No. 1	220	32	Natural Gas	Total	1977
Claymore—Piper	8	30	Crude Oil	Occidental	1977
South Cormorant—Sullom Voe	93	36	Crude Oil	Shell/Esso	1978
Piper—Claymore	22	16	Associated Gas	Occidental	1978
Thistle—Dunlin	7	16	Crude Oil	Britoil	1978
Heather—Ninian	22	16	Crude Oil	Union Oil	1978
Piper—Frigg (MCP-01)	33	18	Associated Gas	Occidental	1978
Frigg—St Fergus No. 2	220	32	Natural Gas	Total	1978
Ninian—Sullom Voe	105	36	Crude Oil	BP	1978
Dunlin—South Cormorant	17	24	Crude Oil	Shell	1978
Brent—South Cormorant	22	30	Crude Oil	Shell	1979
Murchison—Dunlin	12	16	Crude Oil	Conoco	1980
Tartan—Claymore	17	24	Crude Oil	Texaco	1980
Beatrice—Nigg Bay	49	16	Crude Oil	Britoil	1981
West Sole—Easington	44	24	Natural Gas	BP	1982
Brent—St Fergus	281	36	Associated Gas	Shell	1982
South Cormorant—Brent	25	16	Associated Gas	Shell	1982
Tartan—Piper	11	18	Associated Gas	Texaco	1983
Awaiting commissioning/ under construction:					
Brae—Forties	73	30	Crude Oil	Marathon	
Magnus—Ninian	57	24	Crude Oil	BP	
Magnus—Brent	49	20	Associated Gas	Britoil	
Morecambe—Westfield Point	23	36	Natural Gas	BGC	
Rough—Easington	18	36	Natural Gas	BGC	

Appendix 14
Expenditure by operators and other production licensees upon exploration, development and operating activities

TOTAL EXPLORATION EXPENDITURE

£ million

	Q1	Q2	Q3	Q4	Year
1976	69.7	70.5	70.8	90.4	301.4
1977	70.4	96.5	103.4	104.5	374.8
1978	65.2	65.6	61.5	68.9	261.2
1979	57.1	48.8	59.2	75.7	240.8
1980	67.4	87.7	109.0	114.7	378.8
1981	90.2	132.6	161.7	165.7	550.2
1982	185.2	217.7	206.5	251.5P	860.9P

DEVELOPMENT EXPENDITURE[1]

£ million

	Total	Platform structures	Modules and equipment	Offshore loading systems	Pipelines	Terminals	Production wells[2]	Appraisal wells[2]	Other expenditure
Oil fields									
1976	1507.1	566.4	569.6	38.6	141.7	71.4	95.5	17.7	6.2
1977	1555.6	462.0	691.9	10.7	64.8	139.9	155.9	8.3	22.1
1978	1690.4	245.2	828.8	14.8	68.4	260.8	242.5	12.9	17.0
1979	1841.1	242.2	838.9	25.7	89.7	278.7	337.2	7.4	21.3
1980	2163.0	282.1	955.9	34.3	92.6	346.8	415.2	23.1	13.0
1981 Q1	541.8	106.2	219.9	4.7	19.8	77.2	103.4	7.7	2.9
Q2	673.2	113.8	243.6	11.0	68.0	85.9	130.5	17.9	2.5
Q3	637.8	102.4	250.5	16.7	62.0	63.4	129.4	10.6	2.8
Q4	624.2	114.3	268.3	6.3	31.4	38.2	151.5	10.1	4.1
Year	2477.0	436.7	982.3	38.7	181.2	264.7	514.8	46.3	12.3
1982 Q1	523.8	89.8	241.0	6.5	11.9	34.0	136.0	–	4.6
Q2	623.8	117.2	302.4	4.9	36.6	34.6	121.2	–	6.9
Q3	626.5	98.5	291.2	9.6	41.6	39.7	139.1	–	6.8
Q4 P	574.3	116.9	255.7	3.2	12.5	36.6	146.4	–	3.0
Year P	2348.4	422.4	1090.3	24.2	102.6	144.9	542.7	–	21.3
Gas fields[3]									
1976	373.5	144.6	81.8	–	102.6	22.2	22.3	–	–
1977	344.3	51.6	65.2	–	178.0	26.9	22.6	–	–
1978	282.9	13.2	50.6	–	147.4	47.2	24.5	–	–
1979	191.3	2.6	77.5	–	41.1	52.4	17.7	–	–
1980	216.8	4.7	81.3	–	38.3	90.6	1.9	–	–
1981 Q1	48.1	3.7	13.2	–	4.3	26.7	0.2	–	–
Q2	72.2	10.9	13.5	–	11.3	31.3	5.2	–	–
Q3	87.7	9.9	10.8	–	15.8	44.7	6.5	–	–
Q4	71.5	15.2	8.3	–	11.5	35.0	1.5	–	–
Year	279.5	39.7	45.8	–	42.9	137.7	13.4	–	–
1982 Q1	100.4	22.1	7.6	–	26.9	37.1	6.7	–	–
Q2	144.3	33.1	15.9	–	31.2	53.1	11.0	–	–
Q3	189.5	34.5	25.6	–	76.6	42.6	10.2	–	–
Q4 P	178.3	56.5	12.9	–	55.2	42.8	10.9	–	–
Year P	612.5	146.2	62.0	–	189.9	175.6	38.8	–	–

TOTAL OPERATING EXPENDITURE

£ million

	Q1	Q2	Q3	Q4	Year
Oil fields					
1976	11.6	16.5	22.5	30.7	81.3
1977	35.9	38.7	41.2	43.1	158.9
1978	45.9	56.1	66.3	89.9	258.2
1979	80.1	97.9	120.3	128.3	426.6
1980	129.1	162.3	148.4	178.7	618.5
1981	202.8	220.2	249.7	256.1	928.8
1982	250.6	275.2	296.6	352.8P	1175.2P
Gas fields(3)					
1976	7.5	15.5	12.2	13.3	48.5
1977	8.5	10.7	12.7	15.8	47.7
1978	15.0	18.3	22.8	31.6	87.7
1979	20.9	22.2	23.0	26.6	92.7
1980	26.3	26.1	30.6	24.5	107.5
1981	24.2	29.8	35.7	34.3	124.0
1982	32.7	36.1	45.8	47.9P	162.5P

P Indicates provisional figures.

(1) The Frigg gas field's reserves were subject to an adjustment of the UK and Norwegian shares effective from 15 April 1977 and the development of the Murchison oil field was subject to a unitisation agreement with the Norwegian licensees of the adjacent Norwegian block on 5 April 1979, resulting in reimbursement of the UK licensees by the Norwegian licensees of a proportion of the expenditure incurred for the development of these fields prior to these dates. These settlements have been treated as sales of fixed assets to Norway in the balance of payments and in the capital formation item of the National Accounts and in Table 7 but they have not been deducted from the expenditure figures.

(2) For oil fields in 1982, and for gas fields throughout, expenditure on appraisal wells has been combined with expenditure on production wells to avoid the risk of disclosing figures for individual fields.

(3) Expenditure on gas fields includes that on the Brent field associated gas (FLAG) system and the other associated gas gathering pipelines.

Appendix 15
Accident statistics

Year	Mobile drilling activity (rig years)	Fixed platform drilling activity (rig years)	Fixed platforms[1]	Estimated numbers employed on installations	Number of fatal accidents		Number of serious accidents	
					Installations	Vessels	Installations	Vessels
1973	13.3	3.2	19	2,430	2	1	22	0
1974	24.5	2.8	23	4,030	9	3	19	6
1975	27.7	2.6	29	6,300	9	1	46	4
1976	21.2	9.4	39	9,200	16	1	50	7
1977	23.6	14.9	50	12,100	10	1	35	5
1978	18.1	18.6	55	12,500	0	4	33	7
1979	16.1	21.5	58	10,500	7	3	39	4
1980	20.6	25.2	60	22,000[2]	1	3	42	3
1981	24.6	27.0	64	21,000[2]	4	2	54	5
1982	30.1	25.0	67	21,500[2]	11	2	37	2

[1] For the purposes of this Table, "Fixed platforms" refers to oil and gas platforms which are on location either drilling, producing or under construction.

[2] The estimated number employed includes construction workers and the personnel of mobile drilling rigs, service vessels, support barges and survey teams, and is not directly comparable with numbers shown for previous years.

Deaths, serious accidents and dangerous occurrences by activity

	Deaths											Serious accidents											Dangerous Occurrences		
	Pre 73	73	74	75	76	77	78	79	80	81	82	Pre 73	73	74	75	76	77	78	79	80	81	82	80	81	82
Construction				2	4			5			3	2			5	12	4	5	4	2	1	1	4	11	
Drilling	20*		5	2	2	2		1		3	3	64*	10	13	26	21	20	10	16	15	24	13	25	23	40
Production												2		1	2	4	2	4	2	3	2	1	11	14	15
Maintenance	2				1	4				1	1	5	1	3	6	4	1	5	13	13	22	11	21	26	31
Diving	3	1	3	3+	6	2	2	3				7	1			2	5	5	1	4	3	7	2	7	8
Helicopters					1			1								4						1	3	1	1
Boats	6	1	3	1	1	1	2		3	2	2	2		2	4	7	5	7	3	3	5	2	19	22	23
Cranes	4	1	1	2	2	2			1			20	5	6	7	3	3	4	3	4	1	3	32	29	50
Domestic Structures[1]											1								1	1	1		1	2	6
Unallocated[2]											3														7
												26	5												
Total	35	3	12	10	17	11	4	10	4	6	13	128	22	25	50	57	40	40	43	45	59	39	118	135	181

* Sea Gem accounts for 13 of the Pre 1973 fatal accidents and six serious accidents.

\+ One further diver died from natural causes while diving from an offshore installation.

(1) Incidents in this category resulted from the failure of part of an installation or from damage to the structure owing to bad weather.

(2) Up to 1973 the statistics included a group of accidents from slips, falls etc which were unassociated with working operations. Only the fatal accidents in this group have been re-classified under the other headings.

Appendix 16
Oil production forecasts

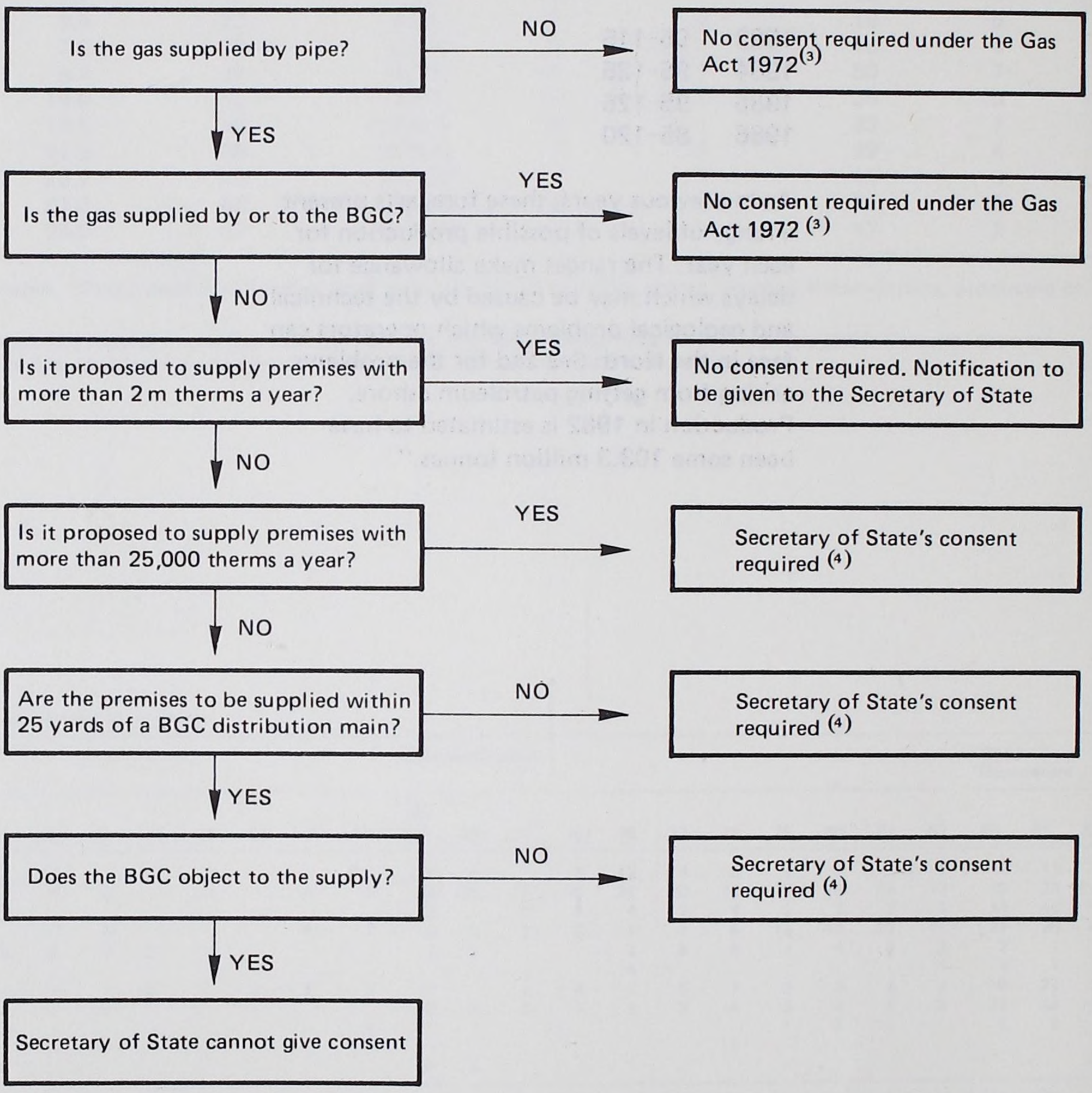
The Minister of State for Energy gave the following reply to a Parliamentary Question on 11 March 1983:

"The latest forecasts for United Kingdom petroleum production in the years 1983, 1984, 1985 and 1986 are as follows:

	million tonnes
1983	95–115
1984	95–125
1985	95–125
1986	85–120

As in previous years, these forecasts present a range of levels of possible production for each year. The ranges make allowance for delays which may be caused by the technical and geological problems which operators can face in the North Sea and for the problems arising from getting petroleum ashore. Production in 1982 is estimated to have been some 103.3 million tonnes."

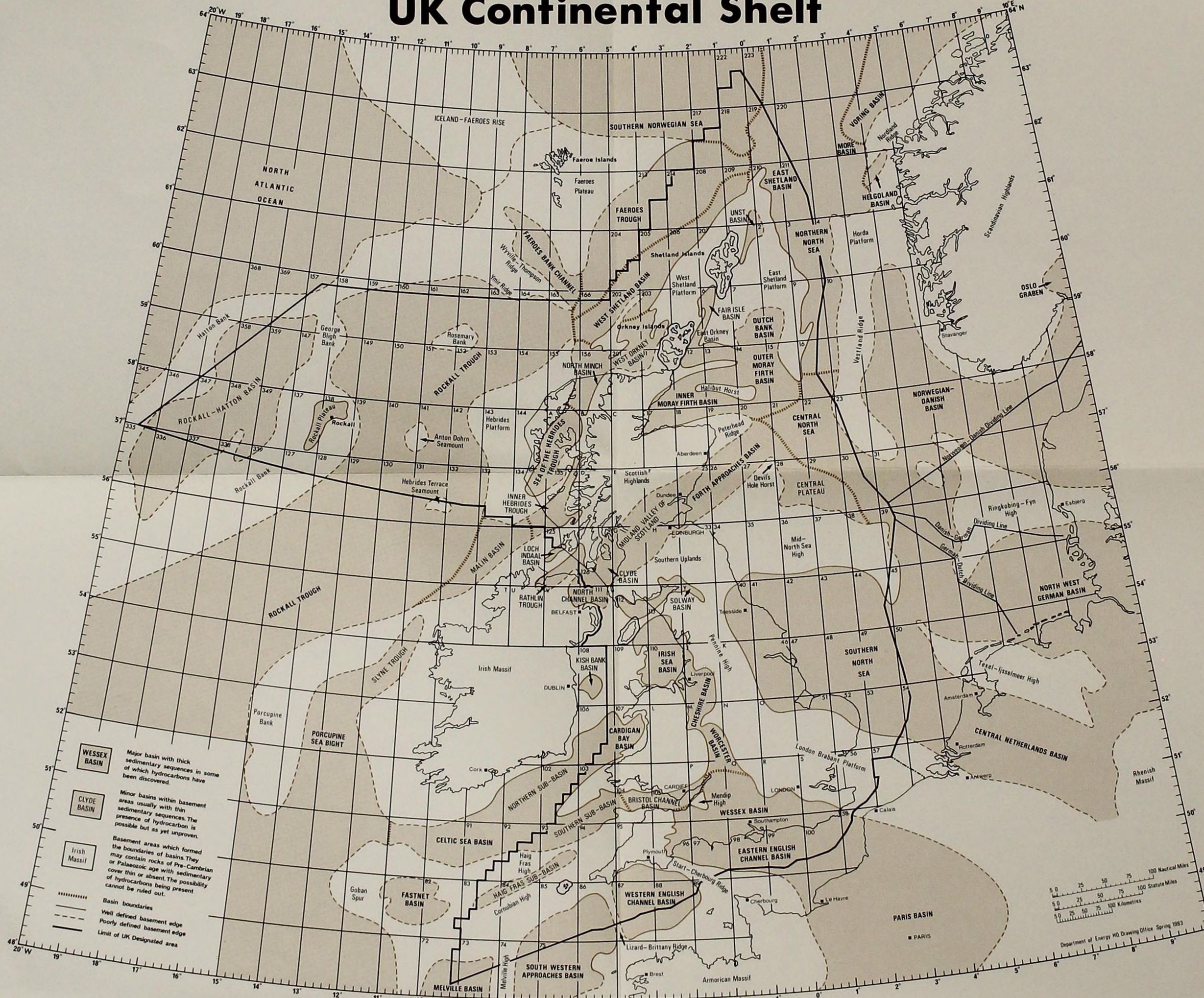
Appendix 17
Diagrammatic representation of procedure for consent to supply gas[1] under ss 29 and 29A of Gas Act 1972[2] (as amended by the Oil and Gas (Enterprise) Act 1982)



(1) See paragraph 17(b) of Schedule 3 to the Oil and Gas (Enterprise) Act 1982 for the definition of 'gas'.
(2) 'Supply' in this context means 'supply to a single set of premises'.
(3) Other legislation (e.g. Health and Safety at Work etc Act 1974, Pipe-lines Act 1962) may be relevant.
(4) The Secretary of State for Energy has said that he would envisage granting consent in all cases where he was satisfied that the safety arrangements proposed were adequate.

Appendix 18
Location of sedimentary basins in and around the UK

LOCATION OF SEDIMENTARY BASINS
UK Continental Shelf



Appendix 19
Map of the U.K. Continental Shelf (as at April 1983)

Printed in the UK for HMSO Dd718650 C50 4/83 398/1

UK CONTINENTAL SHELF

Spring 1983

SEE INSET

Faeroe Islands

Shetland Islands

Orkney Islands

Norwegian

Danish

Dutch

German

French

ROCKALL

Clair

Sullom Voe

Flotta

Nigg Bay

Ardersier

Loch Kishorn

St Fergus

Cruden Bay

Lomond

ULA

Cod

Methil

Grangemouth

Dalmeny

EDINBURGH

Hunterston

Teesside

Morecambe

BELFAST

CARDIFF

LONDON

Rough

Easington

Amethyst

Theddlethorpe

Bacton

Crawford

Scapa

Balmoral

Andrew

Tiffany

Toni/Thelma

North Brae

Fyndre

Ekofisk

Eldfisk

Valhall

Tor

S.E.Tor

Edda

Hod

Auk

Clyde

Fulmar

Albuskjell

Argyll

Roar

Tyra

Gorm

Skjold

Dan

F2-3

P6

Helder

Helm

L4-A

L7-B

L7-C

L10-AE

K15-FB

K15-FA

K7

K8

K10

K13

K14

K17

Indefatigable

S.E. Inde

Viking

Victor

Leman Bank

Hewett

West Sole

Odin

N.E.Frigg

E.Frigg

S.E.Frigg

Frigg

Heimdal

Bruce

Beryl A

Beryl B

Beryl

Crawford

Claymore

Beatrice

Buchan

Magnus

Eider

Thistle

Tern

Cormorant N

Cormorant S

Dunlin

Beta

Delta

Murchison

Alpha

Statfjord

Brent

NW Hutton

Hutton

Heather

Ninian

N Alwyn

Alwyn

Piper

Tartan

Brae

Maureen

Forties

Montrose

0 25 MILES

Miles 50 0 25 50 75 100

Kilometres 50 25 50 75 100

LEGEND

	OIL	GAS	GAS CONDENSATE
Terminal			
Terminal (under construction)			
Pipeline			
Pipeline (constructed, but not "on line")			
Fields (fields in production or under development shown in capital letters)			
Other discoveries (dots are not an indication of size)			

Concrete platform site

Steel platform site

Areas under licence

Offshore areas previously under licence

Eighth round: Blocks awarded in Auction

Blocks put on offer

Hatfield Moors No.1 well

Southampton borehole

Quadrants extend on land and are given letters: see Sedimentary Basin map

Landward fields:-

Producing	Discoveries
1. Corringham	13. Bletchingley
2. Gainsborough	14. Wareham
3. Glentworth	15. Humbly Grove
4. South Leverton	
5. Egmanton	
6. Bothamsall	
7. Caunton	
8. Eakring	
9. Kelham	
10. Kimmeridge	
11. Wytch Farm	
12. Beckingham	

Additional field information in Norwegian, Danish and Dutch sectors courtesy of the Norwegian Petroleum Directorate, Geological Survey of Denmark and Royal Dutch Geological Survey

Key to block Nos

1	2	3	4	5
6	7	8	9	10
11	12	13	14	15
16	17	18	19	20
21	22	23	24	25
26	27	28	29	30

This annual report to Parliament by the Secretary of State for Energy describes the development of the oil and gas resources of the United Kingdom in 1982. It contains the Department of Energy's estimates of oil and gas reserves on the UK Continental Shelf and facts and figures on oil and gas exploration, development, production and operational activities. It also includes financial and economic information about the impact of oil and gas production on the UK.

A series of useful appendices covers specific aspects of oil and gas development such as licences issued, wells drilled, significant discoveries, oil and gas fields in production and under development, production statistics and expenditure by operators.

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