The Forties Field*

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The Forties Field is a large oil pool which was discovered in 1970 in the northern part of the British sector of the North Sea some 175 km (110 miles) east of Peterhead, Scotland, in water depths of 91 to 131 metres (300 to 430 ft). The reservoir is a sandstone of Paleocene age occurring at a depth of about 2135 metres (7000 ft) at the base of a thick Cainozoic section, consisting primarily of mudstone. The Paleocene is a sandstone/mudstone sequence and is underlain by Danian and Maastrichtian chalk. The trap is a broad low-relief anticlinal feature with a closed area of about 90 km² (35 sq miles). Maximum gross oil column is 155 metres (509 ft). Recoverable oil is estimated at 1.8 billion barrels from an in-place figure of 4.4 billion.

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Introduction

The Forties Field is located in the British sector of the North Sea. It lies approximately 175 km (110 miles) due east of Peterhead, Scotland (Fig. 1). The major part of the field falls within BP Licence Block 21/10, the eastern end extending into Shell/Esso Block 22/6. Approximate geographical co-ordinates are latitude 57°45'N, longitude 0°45'E. The field is named 'Forties' after the meteorological area in which it was discovered. Weather conditions in this area are severe with frequent gales, particularly in the winter months, and with waves exceeding 5 metres (15 ft) for about one-third of the time.

Water depths across the field vary from 91 metres (300 ft) in the south-east to 131 metres (430 ft) in the northwest. Bottom conditions generally consist of soft clays overlain by a variable thickness of muds.

History of discovery

The Forties Field was discovered in October, 1970, when BP's well 21/10–1 found oil in Paleocene sands at a depth of about 2135 metres (7000 ft). Block 21/10 formed part of a U.K. 2nd Round licence which had been awarded to BP in November, 1965. At that time little was known about the geology of the North Sea, particularly the northern part. Only five marine wells had been drilled in British waters at the time of application for the Forties licence and gas had yet to be discovered in the southern North Sea. It was realised that the North Sea covered a large Tertiary sedimentary basin possibly over-

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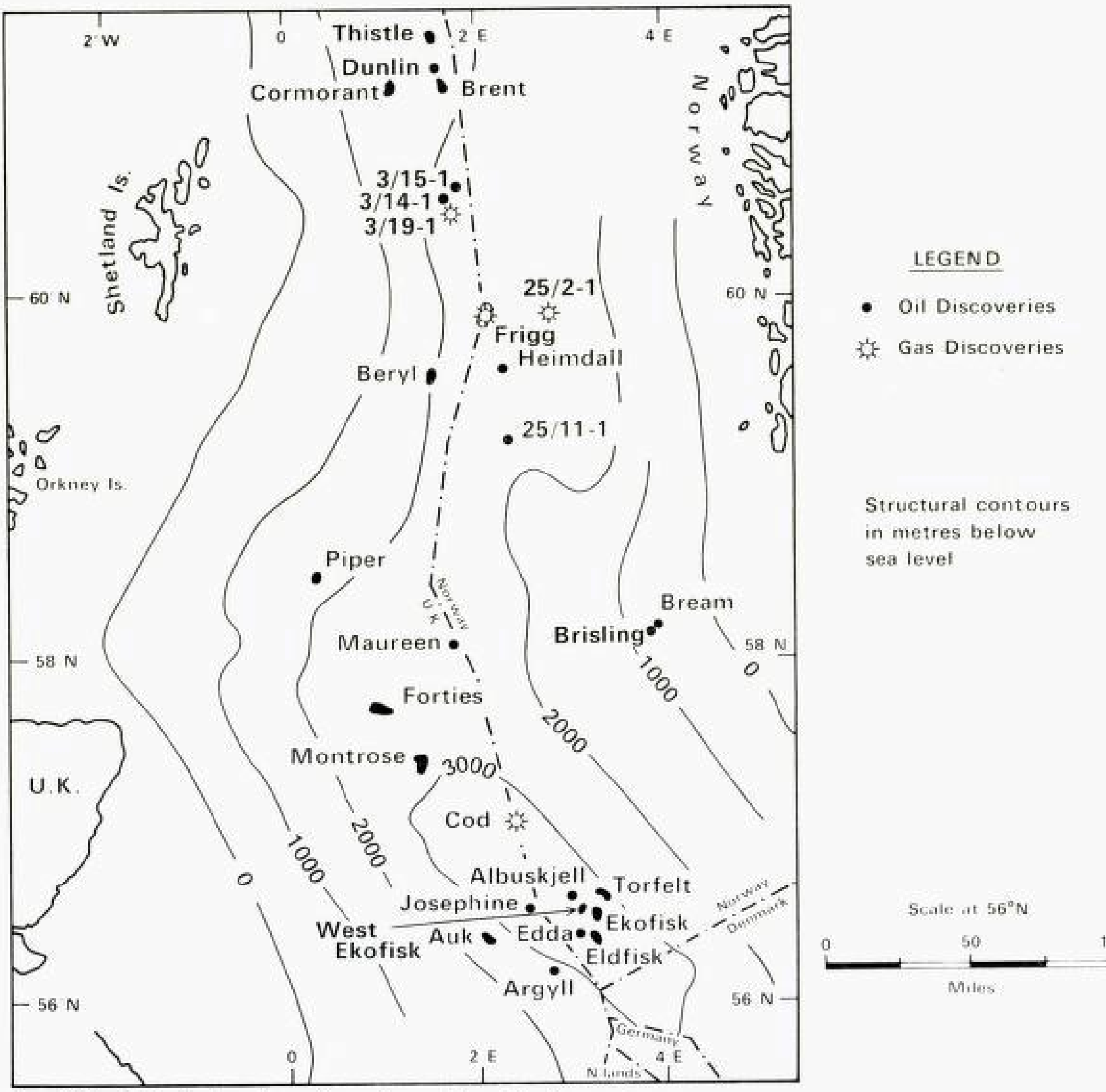


Fig. 1. North Sea hydrocarbon discoveries and base Tertiary contours.

lying in part a thick development of older sediments, but the main interest was centred on the gas area to the south and oil prospects in the northern area were at best thought to be highly speculative. Nevertheless the possibility that oil could occur was recognised as early as 1965, although the subsequent success exceeded all expectations at that time.

During the mid 1960's the main exploration activity was in the southern North Sea. The first indication that the northern area might be an oil province occurred in July 1967 when the second well to be drilled in Norwegian waters, Esso 25/11–1, encountered oil shows. One or two small discoveries were made in Danish waters shortly afterwards, and in June 1968 Phillips made a gas/condensate discovery, the Cod Field, in Norwegian Block 7/11. However, none of these fields was large and by the end of 1969, with over 50 exploration well drilled in northern waters, hopes of making economic oil discoveries had begun to dwindle. It was in December 1969 that Phillips made their important Ekofisk discovery in southwest Norwegian waters (Fig. 1). This, together with the simultaneous, but smaller, Montrose discovery by Amoco/Gas Council in UK Block 22/18, revived the interest of the petroleum industry. The tempo of exploration accelerated and further successes followed rapidly. It was in this climate that BP spudded its exploration well 21/10–1 with Sea Quest in August, 1970.

Early reconnaissance seismic work pre–1965 had indicated a large structural nose plunging southeastwards across Block 21/10 towards the deepest part of the North Sea Tertiary Basin. A 5 × 5 km (3 × 3 miles) seismic grid shot in 1967 had defined this feature and had shown, at base Tertiary, 40 km² (16 sq. miles) of closure of low amplitude centred in Block 21/10 upon the axis of the nose. 21/10–1 was drilled upon this feature.

At 2132 metres (6994 ft) below R.T.E. of 34 metres (111 ft) the well entered Paleocene sands, which were indicated to be oil-bearing from mud gas and cuttings analysis. An oil-water contact was clearly established at 2251 metres (7585 ft) b.R.T.E. and subsequent testing produced 37° A.P.I. low sulphur oil at a rate of 4730 bbl/day on a 54/64 in. surface choke. A field of major proportions had been discovered.

A detailed 1.5 × 1.5 km (1 × 1 mile) seismic survey was shot immediately to supplement the 1967 work and the combined data interpreted in the light of the information gained from the discovery well. The new interpretation indicated a larger closed area than had originally been envisaged.

The first appraisal well 21/10–2 was spudded in June 1971 5.5 km (3.4 miles) northwest of the discovery well in order to delineate the field in that direction (Fig. 2). This well found an oil column of 33.5 metres (110 ft) with an oil-water contact at the same depth as that found in 21/10–1. A second appraisal well, 21/10–3, was then spudded 7 km (4.3 miles) west of 21/10–1, but was junked at shallow depth. A replacement well, 21/10–3A, was drilled without incident and found an oil column of 126 metres (413 ft) and once again the same oil-water contact. At the same time Shell/Esso drilled a well in Block 22/6 which was also successful, although the sand development in the upper part of the Paleocene above the oil-water contact showed considerable deterioration compared with the other Forties wells. The same oil-water contact occurred.

By this time plans for the construction of four platforms to develop Forties were well advanced, but some doubts remained as to the structure and sand distribution on the southern flank of the field. In order to select finally a site for the fourth drilling platform a further well, 21/10–5, was drilled 5.5 km (3.5 miles) west-southwest of 21/10–1. This also proved successful and completed the appraisal of the field, (Fig. 2). The first five wells have therefore confirmed the occurrence of a major oil field with an oil column of 155 metres (509 ft) in Paleocene sands, and a closed area of about 90 km² (35 sq. miles).

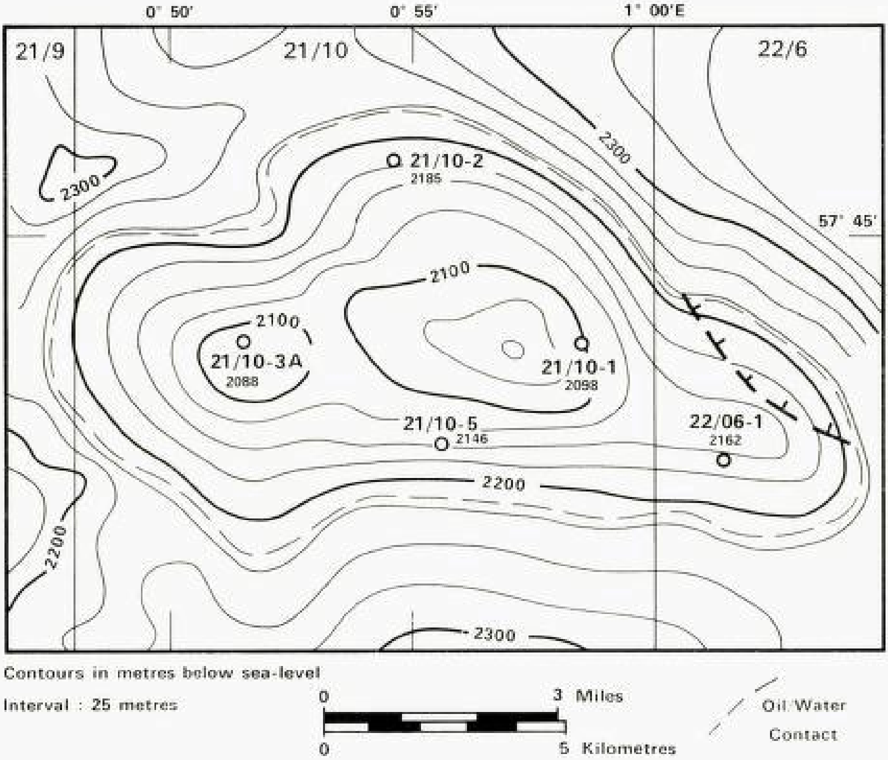


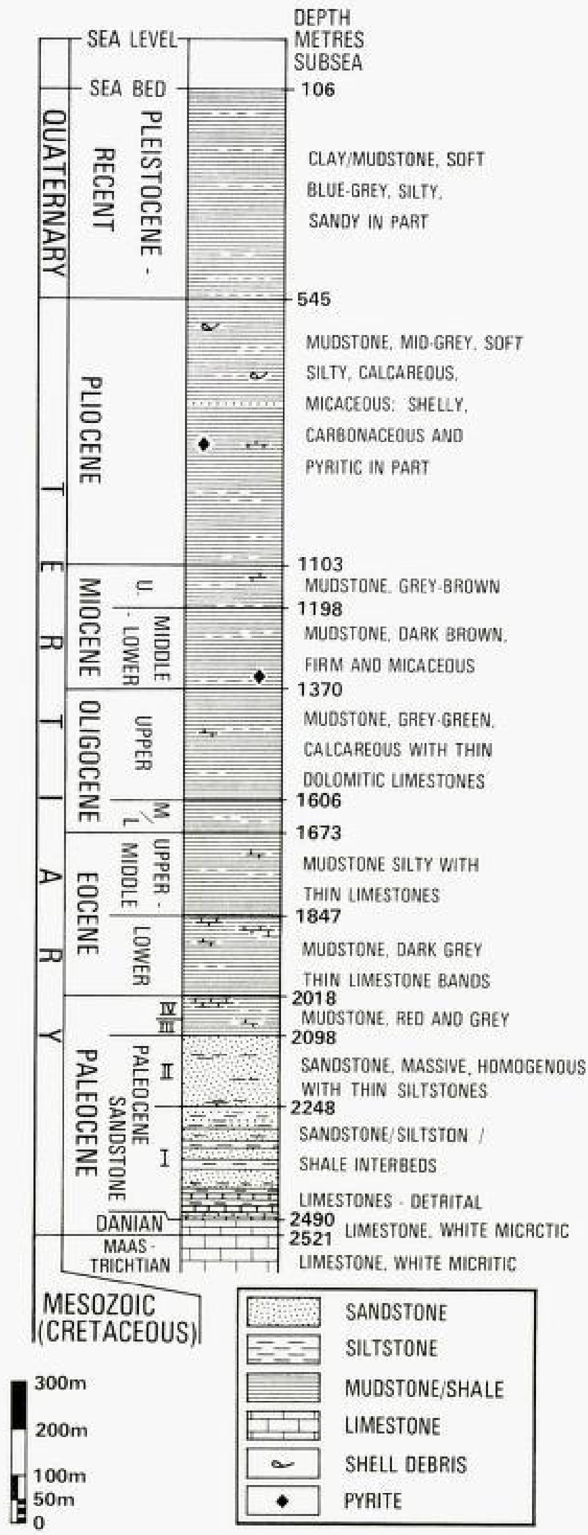
Fig. 2. Structural contours top Paleocene reservoir.

Stratigraphy

The Forties Field lies on the western flank of the North Sea Tertiary basin, the axis of the depositional trough trending approximately north-south along the median line of the continental shelf between the U.K. and Norway (Fig. 1). The Tertiary and Quaternary section within this trough can reach 3500 metres (12,000 ft) in thickness. Apart from the Netherlands and southern England the basin is developed wholly offshore, Tertiary strata being absent from both eastern Scotland and Norway. The Tertiary section in the North Sea basin is almost entirely terrigenous, the predominant lithology being mudstone. Sandstones occur at a number of stratigraphic levels and in some areas can become the major lithotype within the Paleocene and Plio-Pleistocene. Producing sands are primarily of Paleocene age. The Tertiary sequence has been dated using microforaminiferal assemblages.

The central part of the Tertiary Basin overlies a Mesozoic section which also becomes attenuated towards the Scottish coast. The generalised sequence comprises micritic limestones of Upper Cretaceous age underlain by Lower Cretaceous mudstones. The Jurassic, where present, is developed as mudstone with subordinate sands and the Triassic is a distinctive red-brown mudstone. A thin carbonate/anhydrite section, the Zechstein equivalent, occurs at the

Fig. 3. Stratigraphy – Well 21/10–1.



top of the Paleozoic, with salt developed in the central part of the basin. The Zechstein is underlain by the Permian Rotliegendes sandstone.

The stratigraphic column for the Tertiary section of the discovery well in the Forties Field, 21/10–1 is given in Fig. 3. The oil accumulation is in sandstones of Paleocene age, which occur beneath a thick monotonous section of grey to brown variably calcareous and carbonaceous mudstones, ranging from Upper Paleocene to Holocene. Sandstones occur in the Plio-Pleistocene and thin beds of limestone in the Eocene, but the post-Paleocene section is primarily argillaceous. The stratigraphic subdivisions shown for the Tertiary in Fig. 3 are based on micropaleontology. In well 21/10–1 the Paleocene is 502 metres (1647 ft) in thickness. The Eocene/Paleocene boundary is placed on paleontological evidence at 2018 metres (6621 ft) sub-sea, which is close to a prominent peak on the gamma-ray log and a thin limestone band which forms a useful lithological marker. The basal 30 metres (98 ft) of the Paleocene are white to grey micritic limestones of Danian age, but the overlying sequence is predominantly terrigenous. The exact boundary between the Danian and underlying Maastrichtian limestones is not well controlled paleontologically, but is taken at a gamma-ray sonic log marker reflecting a change in limestone character from the clean compact micrites of the Maastrichtian to slightly argillaceous and sandy micrites of the Danian (Fig. 4).

The post-Danian section of Paleocene has been divided by the late Dr. M. J. Wolfe and Mrs. L. Aston of the BP Research Centre at Sunbury into four distinctive lithostratigraphic units, which are shown on the column in Fig. 5. The units are referred to by roman numerals only and no formal terminology is proposed at this stage.

UNIT I 2248–2490 METRES (7375–8169 FT) SUB-SEA

This is divisible into two 'members', the lower (below 2409 metres, or 7903 ft sub-sea) including beds of detrital limestone and the upper comprising argillaceous sandstones interbedded with siltstones and silty shales.

The lower member contains a basal sandstone 4.6 metres (15 ft) thick overlain by a sequence of calcareous sandstones, limestones and mudstones. The unit is characterised paleontologically by reworked Danian and Cretaceous faunas. The limestones are commonly detrital with disseminated quartz of sand grade and indicate contemporaneous erosion of Cretaceous and Danian carbonates following uplift at the end of the Mesozoic. The thickness of the member increases north-westwards across the field, the variations probably reflecting partial infilling of an irregular depositional surface.

The upper member consists of interbedded sandstones, siltstones and shales. Sandstone is the commonest lithology and is typically grey, fine-grained, argillaceous and poorly indurated. The sonic log is characterised by a rapidly fluctuating trace representing thinly interbedded lithologies. Thin bands of limestone and hard calcite-cemented sandstones occur infrequently throughout.

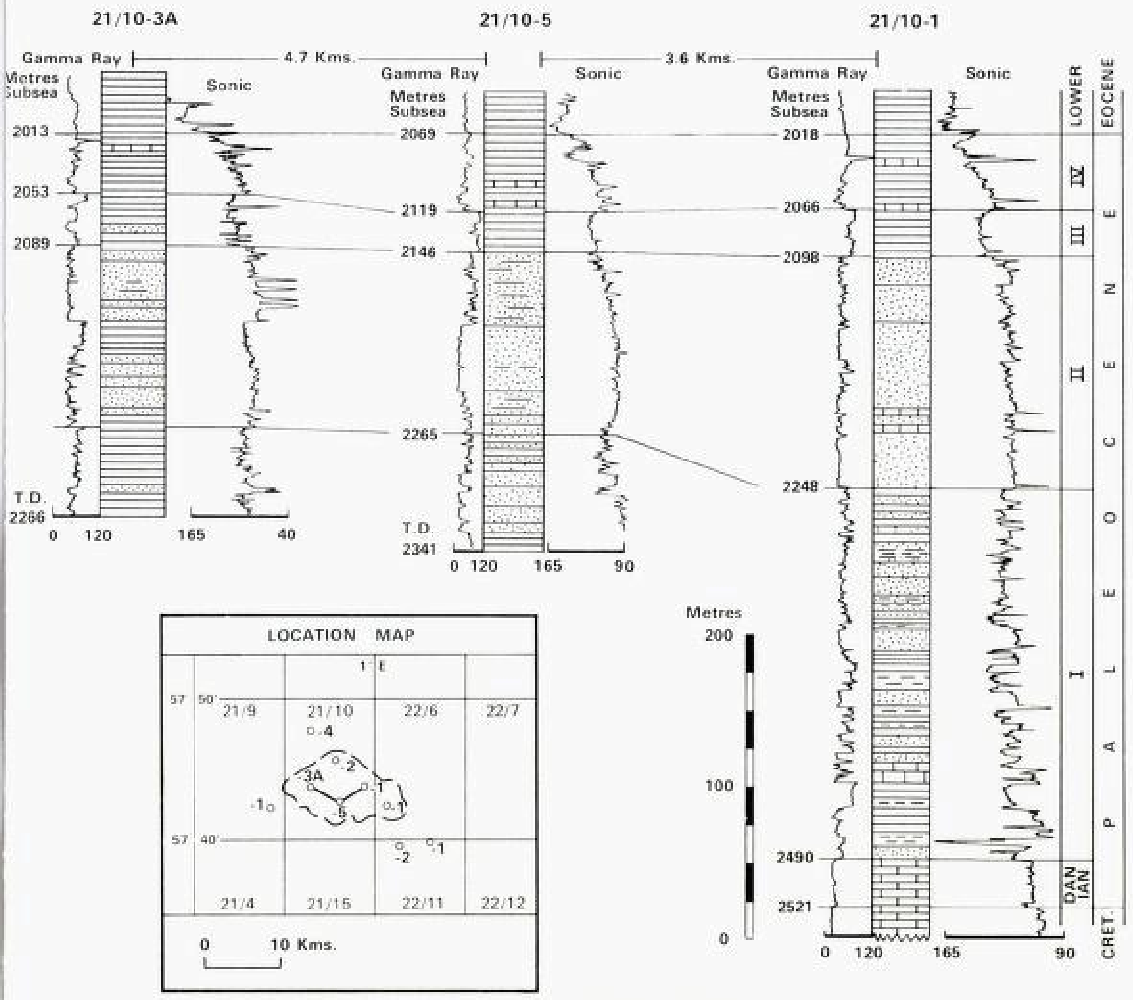


Fig. 4. Well correlation 21/10–3A, 21/10–5, 21/10–1.

UNIT II 2098–2248 METRES (6883–7375 FT) SUB-SEA

Unit II contains all the massive sandstones within the Paleocene and is the producing 'formation' of the Forties Field. It is also productive of oil and wet gas in a number of other structures in the southern part of the northern North Sea. The dominant lithologies are sandstone and mudstone. Studies of core material from wells within the field have allowed the contrasting lithologies to be grouped into four facies, referred to as A, B, C and D.

Facies A is characterised by fine-grained sometimes silty sandstones, frequently with detrital mica and lignite, which are interbedded with laminated siltstones and shales, often as upwards-fining graded units commonly less than 1.5 metres (5 ft) in thickness. The shales are typically kaolinitic and the fauna is sparse. The beds vary from 2 cm to 1.7 metres (5.5 ft) in thickness and the sandstone percentage in the lithofacies varies between 20 and 55%, with the sands having moderate to good reservoir character. Flow and load structures

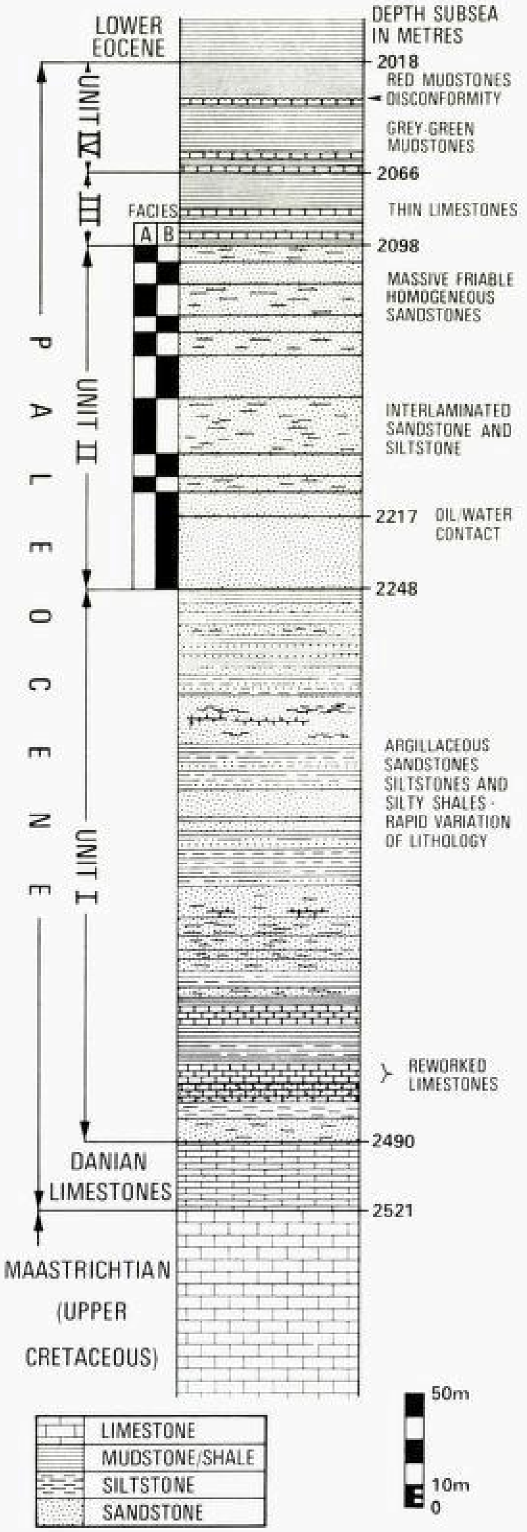


Fig. 5. Paleocene lithostratigraphy Well 21/10–1.

are common, including ripple-drift lamination, load casting, deformed cross bedding, contorted bedding and slump folding, and soft sediment faulting. At a few horizons are intraformational conglomerates with shale clasts up to several centimetres in size.

Facies B comprises the clean homogeneous sandstones. These vary in colour from brown to almost white, in grain-size from fine to coarse grade, and are typically clean and friable. Sorting is poor to moderate, but reservoir properties are excellent. Within thick sequences of sand there are clay laminae and impermeable calcite-cemented zones, and occasional pebbly layers with 50% lithic fragments which are mainly quartzose, phyllite and graphic granite. Fining-upward sections are common, often with convolute and laminar bedding towards the top. Current bedding has not been observed. The sandstones of Facies B in well 21/10–1 vary in thickness up to 35 metres (115 ft), but elsewhere in the field can reach 80 metres (260 ft). The thick sections are believed to be formed of superimposed sand units which are individually about 0.5 to 1.0 metres (1.5 to 3 ft) thick. Fauna is again sparse, as in Facies A.

Facies C is dominated by grey kaolinitic shales and graded siltstone/shale couplets. Occasional thin, dark-brown, fine-grained, sometimes graded sandstone beds occur. The bases of these beds are unusually sharp, erosional and sometimes have sole marks, including rare flute casts. The siltstones show wavy lamination, micro cross-lamination and lenticular bedding. Penecontemporaneous slump structures are common. The shales are rarely bioturbated and fauna is sparse.

Facies D is found only in the eastern part of the field. It is characterised by burrowed green waxy shales which have an abundant marine fauna and flora. Associated with this lithology are purple shales, black limestones, dolomitic mudstones and sideritic concretions.

Over the greater part of the field Unit II is made up of Facies A and B. Facies C occurs in the southern and eastern part of the field and Facies D in the east. The distribution of the four facies appears to be related to thickness variations of Unit II, Facies C occurring within areas of thin development of the Unit and Facies B sands being well represented in areas of thick development. The central part of the field has the highest percentage of clean sands and will have the best production potential.

The change in facies across the field means that a correlation within Unit II is not readily apparent from the logs of the widely spaced step-out wells. The variation in gross lithology is illustrated by the correlation diagram in Fig. 4, which is drawn in a west to east direction from 21/10–3A, through 21/10–5 to 21/10–1. The argillaceous section in the upper part of Unit II in 21/10–5 (Facies C) is probably stratigraphically equivalent to the Facies A and B sands in wells 21/10–1 and 21/10–3A, although an off-lapping relationship could be invoked.

Studies on this and related problems are continuing, but will probably not be resolved until further data from the production wells is obtained. The depositional environment of Unit II is still under study and it will be some time before it is completely elucidated. As additional data become available during the development drilling programme it is expected that critical evidence of the provenance and mode of deposition will be found. At present we consider the most likely source of the sediment to be from Scotland to the west and from locally eroded high areas composed of Upper Cretaceous and Danian chalky limestones. A Scottish provenance for the more arenaceous material is indicated by the predominance of quartzose grains including quartzites and vein quartz, some phyllitic material, hornblende gneiss and pegmatite fragments including much graphic granite, and by the heavy mineral suite consisting predominantly of tourmaline, garnet and zircon, with lesser amounts of staurolite, rutile, sillimanite, hornblende and pyroxene. These features appears to indicate derivation from rocks akin to the Moinian and Lewisian of Scotland.

UNIT III 2066 – 2098 METRES (6778 – 6883 FT) SUB-SEA

Lithostratigraphic Unit III forms the cap rock to the reservoir sands. The contact with Unit II was cored in well 21/10–2 and indicates that the lithological change is transitional. Unit III consists of dark grey, silty, lignitic, shaley mudstones rich in montmorillonite. Thin beds of sand are occasionally developed with the proportion of sandstone increasing westwards. Winnowed pockets of fish remains and several well-preserved skeletons have been found in cores. Planktonic foraminifera are rare, the fauna being dominated by siliceous diatoms and microplankton. The thickness and lithology of Unit III are very constant across the field and the uniformity extends to nearby areas.

UNIT IV 2018 – 2066 METRES (6621 – 6778 FT) SUB-SEA

This is essentially a mudstone unit, the mudstones typically being greenish-grey and slightly calcareous. The upper 10–20 metres (33–66 ft) is, however, red-brown in colour and contains a characteristic red-stained, calcareous, foraminiferal assemblage in which *Globigerina cf. triloculinoides* predominates. These mudstones are separated from the underlying darker coloured beds by a minor unconformity. Several thin, pale-coloured, clay beds with a distinctive mineralogy indicative of degraded volcanic ash are present, together with occasional thin limestone stringers. These lithological features extend beyond the limits of the field and make log markers useful for correlation. The thickness of the unit remains constant across the field and it displays a characteristic sonic log pattern with increase in velocity with depth. This velocity increase serves as a good log correlation feature, and also gives rise to a prominent seismic horizon which is used to map the configuration of the top of the reservoir.

Structure

The regional tilt at the base of the Tertiary sequence in the Forties area of the North Sea is down to the east, towards the axis of the Tertiary Basin. In Block

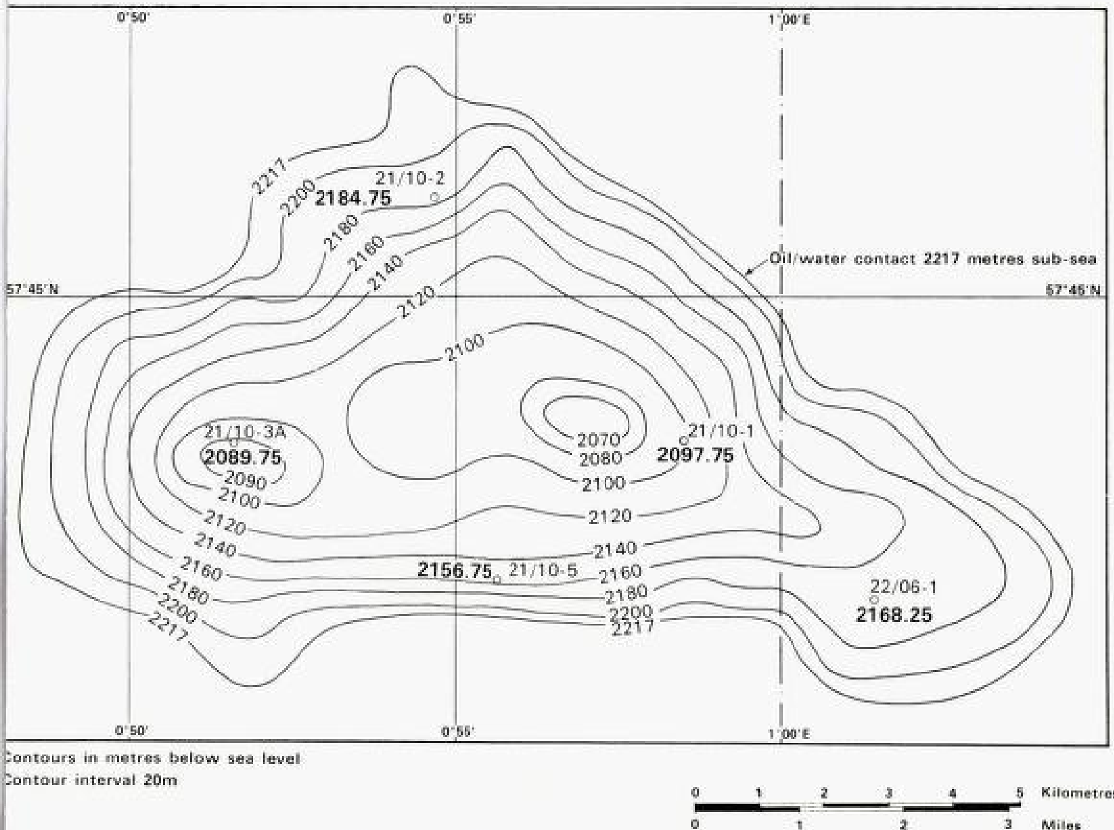


Fig. 6. Isochrons on seismic reflector overlying Paleocene reservoir.

21/10 this regional tilt is interrupted by a large ESE-directed nose which can be followed into Block 22/11. Reversal of dip on this nose provides closure for the hydrocarbon accumulation in the overlying Paleocene sands.

The isochrons on a seismic horizon some 35 metres (115 ft) above the top of the sands are given in Fig. 6, and the depth contours on the top of the reservoir in Fig. 2. A structural cross-section east-west across the field is shown in Fig. 7. Because of horizontal velocity gradients present in the late Tertiary section, the configuration of the structural contours on the top of the reservoir is different from that of the isochrons on the seismic horizon directly above. The velocity gradients are computed from the information from the wells within and adjacent to the field. The most significant change is an increase in closure at the western spill points of the structure, giving an approximate coincidence between structural spill point and the oil water contact at 2217 metres (7274 ft) sub-sea.

The depth contours on the top of the reservoir indicate that the structure is a broad dome elongated east-west with minor faulting affecting only the eastern extremity of the feature. The structure extends 16 km (10 miles) east-

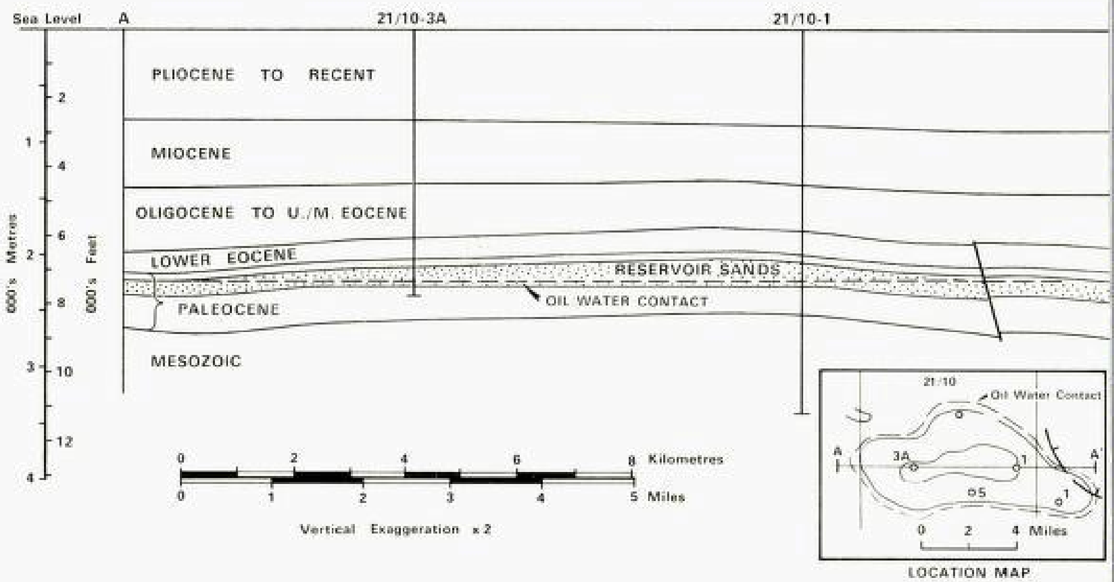


Fig. 7. Structural section E–W across the field.

west by 8 km (5miles) north-south, has a closed area of about 90 km² (35 sq. miles or 22,000 acres) and vertical closure of 155 metres (509 ft).

The Paleocene structure overlies a faulted high at the base Cretaceous level. Seismic penetration below the Cretaceous is poor, but it does not appear likely that the structure in the deeper Mesozioc or Paleozoic is directly related to the base Cretaceous uplift over which the Paleocene feature lies. The base Cretaceous unconformity is a very pronounced widespread regional event affecting the whole of the North Sea basin. The late Jurassic movements which preceded this unconformity were typified by block faulting and a complex uplift of this type underlies the Forties Field. Thickness variations in the Cretaceous and Lower Tertiary indicate that the area of the field remained relatively positive during late Mesozoic and early Cainozoic times, a favourable factor for early migration of hydrocarbons, although at present insufficient data are available to assess the organic diagenesis of the Cretaceous and Paleocene shales. Structural expression above the Paleocene diminishes progressively. Turnover on the nose does not persist above the Lower Miocene and at the base Pliocene level the beds dip uniformly south-eastwards across the field. Hence structural growth was terminated in late Miocene times. Uplift on the Mesozoic block fault may however have ceased during the early Tertiary, with differential compaction allowing structural expression to persist through the Miocene section.

Reservoir characteristics and reserves

Well 21/10–1 was tested over the interval 2108.5–2113 metres (6918–6933 ft) sub-sea and produced 37° API oil at a rate of 4730 bbl/day on a 54/64 inch surface choke with an estimated solution gas-oil ratio of 250 scf/bbl. The crude was low sulphur (0.3%) and medium wax at 8.5%. 21/10–3A was tested over the interval 2092–2137.5 metres (6865–7013 ft) sub-sea at rates up to 3260 bbl/day, the production being limited to this rate by equipment restrictions. Bottom hole PVT samples during the test established the GOR at 330 scf/bbl.

Core analysis of the five wells, particularly 21/10–5, where extensive coring of the reservoir was carried out, indicates high porosities and permeabilities. Average well porosities range from 25 to 30% and permeabilities vary up to 3900 md. With the exception of the tight calcite cemented layers the permeability in Facies B varies from 1000 m to 3900 md. In Facies A and C the sandy layers have a spread of permeabilities from 0.1 to 1000 md with the most common permeability measurements lying in the range of 100–200 md.

Analysis of the flow test indicates that 21/10–1 and 21/10–3a are capable of producing rates in excess of 15,000 bbl/day. Both wells were, however, drilled in the crestal position where virtually the full oil column is present. An initial average well rate of 8000 bbl/day for development wells has been assumed. The initial reservoir pressure is about 3200 p.s.i. and with the oil being undersaturated there is no original gas cap.

Oil-in-place and recoverable oil calculations are based on the whole accumulation including that part which falls in Shell/Esso Block 22/6. The calculations yield an average oil-in-place figure of about 1400 bbl/acre ft which in turn leads to a figure of about 4.4×10^9 bbl stock tank oil initially in place. A recovery of 40% would yield a figure of about 1.8×10^9 bbl recoverable oil.

Production plans

Development drilling will take place from four fixed platforms which will also serve as production platforms. The design of each platform allows for 36 drilling slots, although only 27 wells can be completed from each on the required spacing. It is planned to drill wells with a horizontal displacement of up to 2195 metres (7200 ft), at a maximum of 55° from the vertical.

120 acres has been selected as the maximum spacing required to ensure full recovery of the reserves over a 20–25-year period for an initial well rate of 8000 bbl/day. Drilling is to take place over those parts of the field which are 100 ft above the oil-water contact, i.e. within an area of 15,500 acres. On this basis the field can be drilled by 106 wells deviated from the four platforms (Fig. 8).

The field will be developed as follows: the initial phase includes the emplacement of two drilling platforms with ancillary production equipment, a 32 in. submarine pipeline to Cruden Bay near Peterhead, a 36 in. land line from Cruden Bay to a gas separation plant at Kerse of Kinneil adjacent to BP's Grangemouth refinery where about half the production will be refined, and a marine terminal on the Firth of Forth for export of the balance. Fifty-four wells will be drilled from the first two platforms and it is estimated that this will lead to a peak production rate of 250,000 bbl/day. The emplacement of

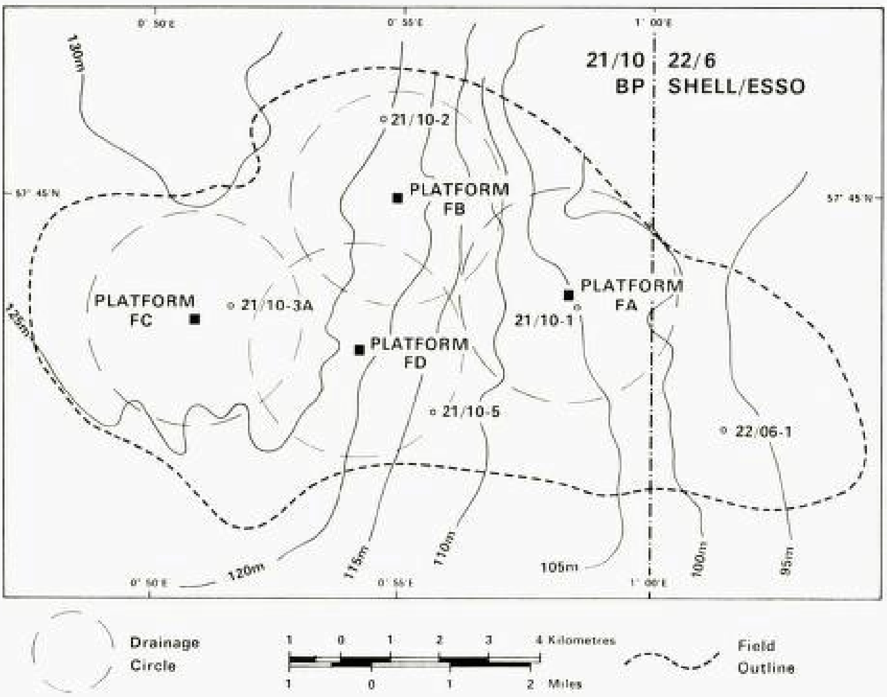


Fig. 8. Platform locations and bathymetry.

two additional platforms and the extension of the storage capacity at the Firth of Forth will follow. Fifty-two wells will be drilled from the third and fourth platforms increasing the production from the field to an average rate of 400,000 bbl/day.

It is hoped that this ambitious programme can be achieved by 1977 when the field should be on full production. Based on the well potentials assumed, this peak production of 400,000 bbl/day can be maintained for about three to four years before decline sets in.

Because of the under-saturated nature of the crude, pressure maintenance at about 2500 p.s.i. will be effected in order to maintain well efficiency. This will be commenced early in the life of the field in order to delay the need for artifical lift as water cuts increase.

Initially the oil and gas will be separated on the platforms at a pressure of 125 p.s.i.g. and about a third of the solution gas will be piped ashore dissolved in the oil. Some 20–25% of the remainder will be required as fuel on the platforms and thus, at peak throughputs, about 15–20 mmscf/day will remain for disposal from each of the first two platforms. During the drilling phase this must of necessity be flared, but subsequently it will be refrigerated for the recovery of natural gas liquids which will be shipped to shore mixed with the crude. The gas balance at this stage indicates that about one half of the total gas will be recovered, some 20% used as fuel and the remaining 30% flared. Of the gas recovered about 50% will be in the form of dry gas and the balance will comprise condensed liquids in the C_3–C_5 range.

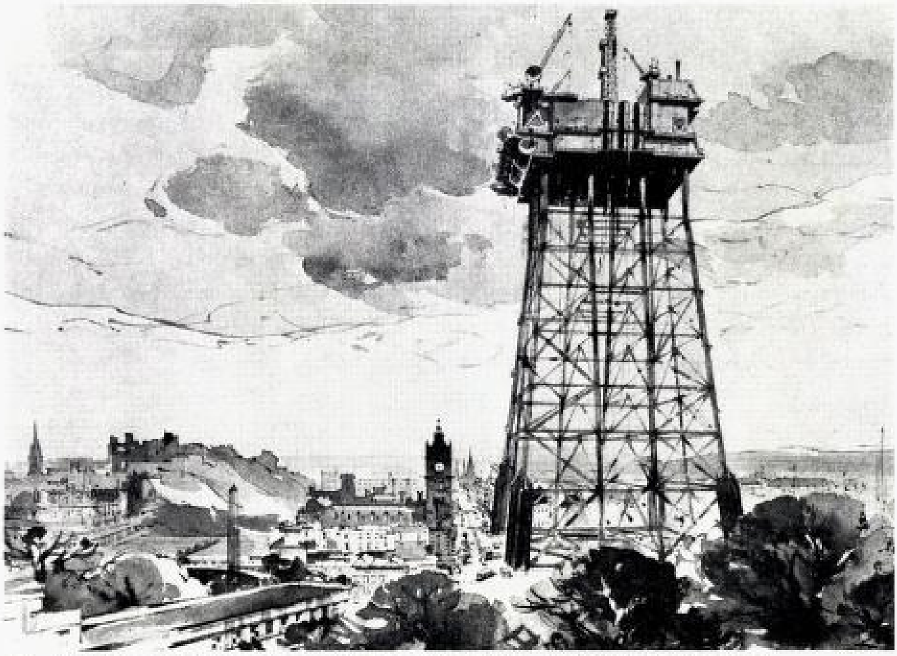


Fig. 9. Forties platform, as it would appear if standing in Edinburgh, Scotland.

The first two platforms are currently under construction, one at Nigg Bay on the Cromarty Firth, and the other at Middlesborough in Yorkshire. These mammoth structures will be larger and in greater water depths than any presently installed anywhere in the world. Conventional jacket templates will be floated to location, righted by controlled flooding and pinned to the sea bed with piles. The largest, which is to be installed in 128 metres (420 ft) of water will be 146 metres (480 ft) high, 61 × 76 metres (200 × 250 ft) in plan and will weigh 17,000 tons. Each template will be topped by a three level deck unit to accommodate drilling and production equipment. These will measure 43 × 52 metres (140 × 170 ft) and each weigh 15,000 tons (Fig. 9).

The North Sea is notorious for its severe weather conditions and design criteria have to cater for possible wind speeds of 114 knots and wave height of 29 metres (94 ft). The 32″ submarine pipeline to Cruden Bay will be about 175 km (110 miles) long and, apart from the shoreward 24 km (15 miles) will be laid in water depths of 91–130 metres (300–425 ft). The pipe will have a protective wrapping of fibreglass and coal tar enamel and an overall coating of 2½″ reinforced concrete. It will be laid from a conventional lay barge during 1973/1974 and subsequently buried by removing the sea bed from under the pipe with high pressure water jets. At Cruden Bay the oil will enter a sealine receiver trap and then pass directly into the land line. An emergency flow tank will be provided in case of shutdowns.

The 36 in. land line will be 203 km (127 miles) long from Cruden Bay to the gas separation plant at Kerse of Kinneil. Here the crude will be split, part going to BP Grangemouth Refinery and part going to the Firth of Forth terminal for export.

The foregoing account describes the discovery in 1970 by BP of the first major oil field in the British sector of the North Sea. The British regulations do not provide for the early release of well data and it is therefore not possible to make public technical inofrmation without prejudice to one's competitive position in the industry. In this respect the authors' wish to apologise for the lack of discussion of certain aspects of the geology of the Forties Field. Nevertheless we hope that this general review will prove to be a useful contribution to the understanding of this new and exciting petroleum province and stimulate others to release information for the benefit of all.

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