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Hydrocarbon exploration opportunities in the 21st Century in the United Kingdom[1]

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ABSTRACT

Oil and gas production within the United Kingdom and its offshore designated area has continued to rise through the 1990s, and remains at record levels. This paper charts the developments and major new plays of the last decade, and highlights the opportunities and challenges for the 21st Century.

Through a continuing programme of licensing, the Department of Trade and Industry (DTI) has successfully maintained industry interest in UK exploration and production. This has been despite lower oil prices and continuing competition from other oil and gas provinces in the world. A recent licensing round (17th) that offered acreage in the under-explored basins along the Atlantic Margin to the north-west of Britain attracted many applications, partly because it followed discovery of oil in a Paleocene fan play there in 1992. Similarly, licensing rounds that focused on the mature North Sea basins have proved very encouraging. Improved methods in fault seal analysis have had a significant impact on well success rates in the mature basins. Onshore, exploration activity has increased significantly following the 7th and 8th licensing rounds, with a success ratio of >50% on some plays. The UK's coalbed methane potential continues to be assessed.

The greatest potential for major new discoveries lies along the Atlantic Margin, with significant undiscovered hydrocarbons likely in predominantly Cretaceous and Tertiary reservoirs. Subtle stratigraphic and structural plays will continue to have a key role in the mature North Sea provinces. Focus on older, deeper reservoirs will extend the geographic range of successful plays there.

INTRODUCTION

After 36 years of offshore exploration, the United Kingdom (UK) remains net self-sufficient in both oil and gas. At the end of 1998, the UK had a record number of 204 offshore and 35 onshore fields in production, which comprised 136 oil, 87 gas and 16 condensate fields (DTI, 1999[5]). These fields had produced 0.133 billion tonnes (0.974 billion barrels) of oil and condensate, and 96 billion cubic metres (3.4 trillion cubic feet, tcf) of gas during the year, accounting for 1.7% of the contribution of industry to the UK's National Accounts (Gross Value Added). The total cumulative production to end 1998 was 2.306 billion tonnes (16.9 billion barrels) of oil and condensate and 1,383 billion cubic metres (46.3 tcf) of gas. Maximum remaining discovered reserves are

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estimated to be 1.8 billion tonnes (13.2 billion barrels) of oil and 1,795 billion cubic metres (63.4 tcf) of gas (DTI, 1999). The UK's undiscovered recoverable reserves are currently estimated to lie in the range 0.275-2.55 billion tonnes (2.0-18.7 billion barrels) of oil and 440-1,595 billion cubic metres (15.5-56.3 tcf) of gas (DTI, 1999). UKOOA, the United Kingdom Offshore Operators Association, has conservatively estimated (1996) that there will be a sustained aggregate of 11 to 15 new field developments in the UK offshore designated area per annum until at least 2020. This estimate may need to be revised upwards if sufficient gas discoveries are made in the Atlantic Margin to warrant construction of new gas-gathering infrastructure there.

At the previous Wallace E. Pratt Memorial Conference in 1984, Brooks (1986) reviewed the status of hydrocarbon exploration on the UK Continental Shelf. This paper provides an updated summary of the remaining and future petroleum potential of the United Kingdom and its surrounding designated waters. Some brief historical facts are included here, but Brennand *et al.* (1998) should be consulted for a comprehensive historical review. Although most of the larger oil and gas fields in the UK sector of the North Sea have already been discovered, the rate at which new reserves continue to be found remains remarkably healthy (Brennand *et al.,* 1998). The distribution of oil, gas and condensate fields in the UK and its offshore designated area is illustrated in Fig. 1.

The oil and gas industry in the UK is operated entirely by the private sector in a competitive manner. Exploration has proceeded at a rapid rate, stimulated and controlled to a significant extent by the frequency and regularity of licensing rounds. The Department of Trade and Industry (DTI)'s discretionary award system has elicited a keen response to licence offers, and remains very highly regarded (Brennand *et al*., 1998). Recent offshore licensing rounds have alternated between offering acreage in the frontier areas such as the Atlantic Margin, and blocks within the more mature North Sea area. In the latter area, the main aim of some operators is to locate small satellite oil fields (up to 50 million barrels) that lie close to existing infrastructure. As part of this objective, the 'finder well' concept of drilling a well for minimum possible costs without compromising safety or technical needs may be imperative. Reviews of offshore fallow blocks, in which there has been no drilling for at least six years, were initiated by the DTI in 1996 and 1999. These reviews have proved very successful in encouraging licensees to bring forward exploration plans, or to surrender acreage for relicensing.

Supplementing the private sector's prospect evaluation activity, the Department of Energy (now incorporated into DTI) supported the British Geological Survey in systematic surveying of the UK Continental Shelf between 1967-1990. The resulting series of 328 geological and geophysical maps is complemented by a series of UK Offshore Regional Reports[6], and together these constitute a unique and comprehensive geological dataset and evaluation. This work has provided an invaluable contribution to the successful petroleum exploration of the UK's offshore (Walmsley, 1987).

Weakening oil prices in the 1990s precipitated the CRINE (Cost Reduction Initiative for the New Era) and successor initiatives. Oil and gas industry capital and operating costs have been cut by more than 30% by improving competitiveness, while not compromising safety or environmental standards. An Oil and Gas Industry Task Force, chaired by the Minister for Energy and Competitiveness in Europe, reported in 1999 on new strategies for cost reduction and raising competitiveness of the UK industry. An early by-product of this initiative has been the establishment of Internet based mechanisms for licence trading, as a means of stimulating investment in the UK industry. This is referred to as LIFT[7] (Licence Information For Trading). All of these and future initiatives are designed to maintain the UK's position as a world-class operating environment. The DTI are committed to ensuring that the regulatory regime remains flexible and responsive to the changing needs of the hydrocarbon industry and of the UK.

[6] (web site address – http://www.bgs.ac.uk/bgs/w3/pmgg/pmg_publ.htm)
[7] (web site address – http://www.uklift.co.uk)

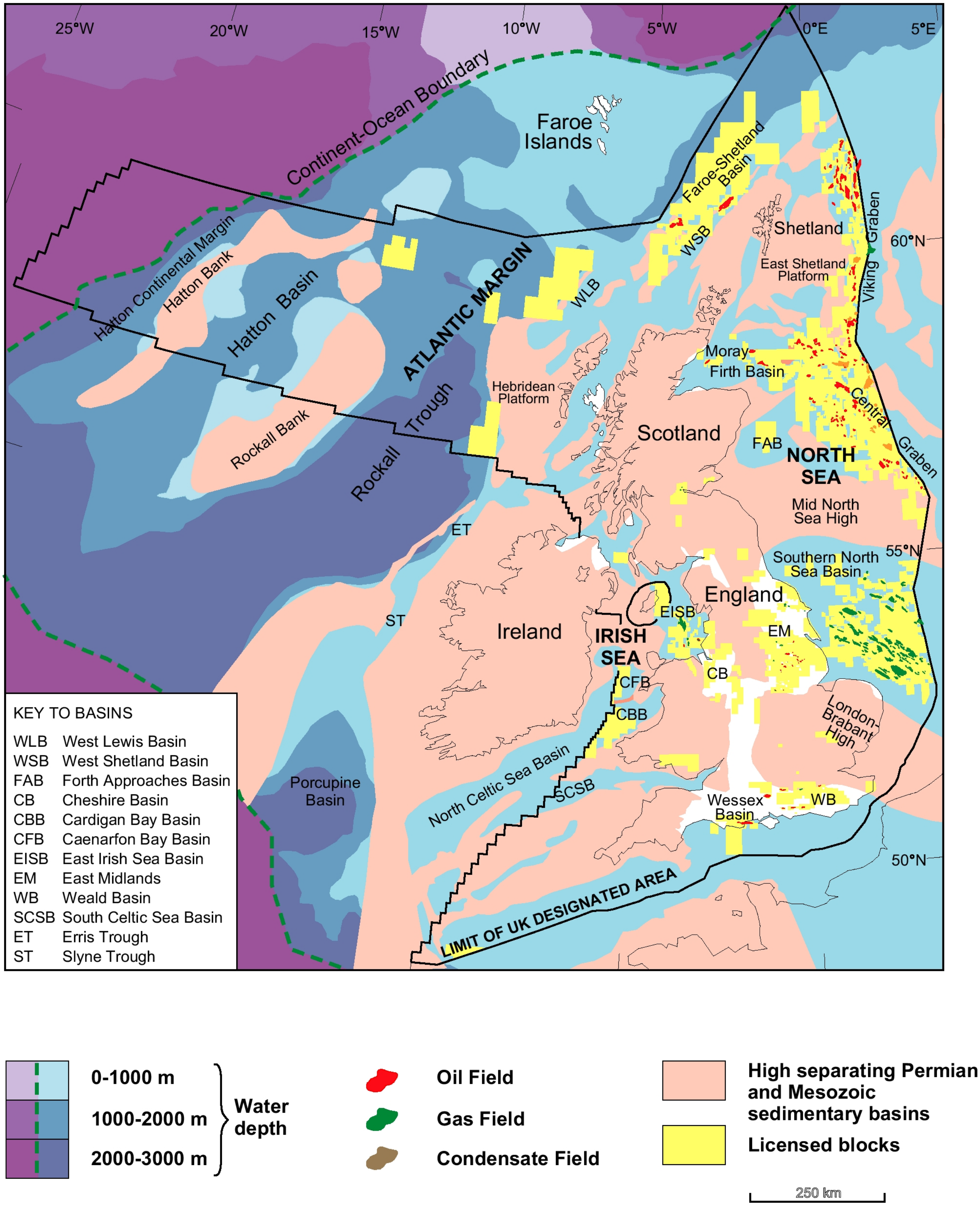

Fig. 1 Location of the hydrocarbon-producing basins and frontier basins of the UK and its designated waters.

The UK oil and gas industry has a good track record in minimizing the environmental impact of its activities. Environmental awareness begins at the licence application stage, when applicants are required to demonstrate that they have considered the sensitivities of the areas they have applied for. They must show that they have environmental management policies in place to ensure that all activity under licence will be carried out under satisfactory standards of care. Legislation introduced in 1997 and enhanced in 1998 requires environmental impact assessments for individual well, development and pipeline projects under both new and existing licences.

The DTI has continued to participate in offshore environmental research and other environmental programmes. For example, it has supported a survey across the Hatton Continental Margin during 1999. The UK Government's contribution towards prevention of climate change is focused mainly on its domestic aim of a 20% reduction in CO_2 emissions by 2020 (DTI, 1999).

EXPLORATION OPPORTUNITIES

North Sea Oil Province

Since the discovery of oil in Paleogene sandstones by well 22/18-1 (now part of the Arbroath Field) in 1969, the North Sea (north of 56° N) has become established as one of the world's major oil-producing regions. Up to end-1998, 133 fields had produced 2.15 billion tonnes (15.8 billion barrels) of oil and condensate and 412 billion cubic metres (14.5 tcf) of gas from the UK sector alone (DTI, 1999). Production is from almost every conceivable clastic and carbonate sedimentary facies, and from strata ranging between Devonian and Eocene in age. Although at a mature stage for exploration, new discoveries are still being made, and the region continues to yield surprises.

The geological history of the oil province was dominated by an episode of crustal extension and accelerated basin subsidence, mainly of late Jurassic age but locally continuing into the earliest Cretaceous, that led to the formation of the Viking Graben, Central Graben and Moray Firth rift systems (Figs. 1, 2). Syn-rift, organic-rich marine sediments (Kimmeridge Clay) are the source interval for virtually all of the region's hydrocarbons. However, it was the post-rift thermal subsidence following early Cretaceous collapse of the rift system that enabled these source rocks to become mature for hydrocarbon generation from Paleogene times onwards along the rift axes (Johnson and Fisher, 1998). Hydrocarbon migration has been essentially vertical, with significant lateral migration restricted to the Upper Jurassic and Tertiary successions. Consequently, most of the producing oil and gas fields lie within the geographical boundary of the mature source rocks (Fig. 3).

Hydrocarbons occur in a range of pre-rift, syn-rift (Upper Jurassic to Lower Cretaceous for the purposes of this paper) and post-rift reservoirs. Note that it was only in the western Moray Firth that rifting continued into early Cretaceous times. Other parts of the oil province entered a mildly compressive tectonic regime around the Jurassic/Cretaceous boundary (Oakman and Partington, 1998). Note also that a precursor episode of Permian to early Triassic rifting may have affected `pre-rift´ subsidence and sedimentation patterns along the axial graben of the North Sea.

PRE-RIFT producing fields of the oil province can be subdivided into three categories, Paleozoic, Triassic to Lower Jurassic, and Middle Jurassic:

(i) Those having reservoirs of Paleozoic (Devonian, Carboniferous or Permian) age (Fig. 2) are concentrated on tilted footwall blocks (e.g. Auk), are adjacent to the major graben-bounding faults, or are on intrabasinal highs (e.g. Buchan). Reservoir quality in these areas is notoriously difficult to predict, but may be enhanced by fracturing during syn-rift footwall uplift, or by leaching, in the case of Upper Permian carbonate reservoirs, beneath a regional base Cretaceous unconformity (Johnson and Fisher, 1998). All of the traps are overlain by Upper Jurassic to Lower Cretaceous mudstones or Upper Cretaceous chalk, providing an effective topseal. The discovery, as recently as 1998, of the Flora Field, with its ?Stephanian[8] reservoir, indicates that the traditional Paleozoic play has not reached maturity yet. Indeed, the reservoir potential of the Carboniferous

[8] European nomenclature is employed for subdivision of the Carboniferous throughout this paper. The Dinantian and basal part of the Namurian subsystems are equivalent to the Mississippian, and the remainder of the Namurian with the Westphalian and Stephanian are equivalent to the Pennsylvanian of American usage (see Fig. 8).

strata remains underexplored, especially since their seismic response strongly resembles that of the equivalent gas-bearing succession of the North Sea Gas Province.

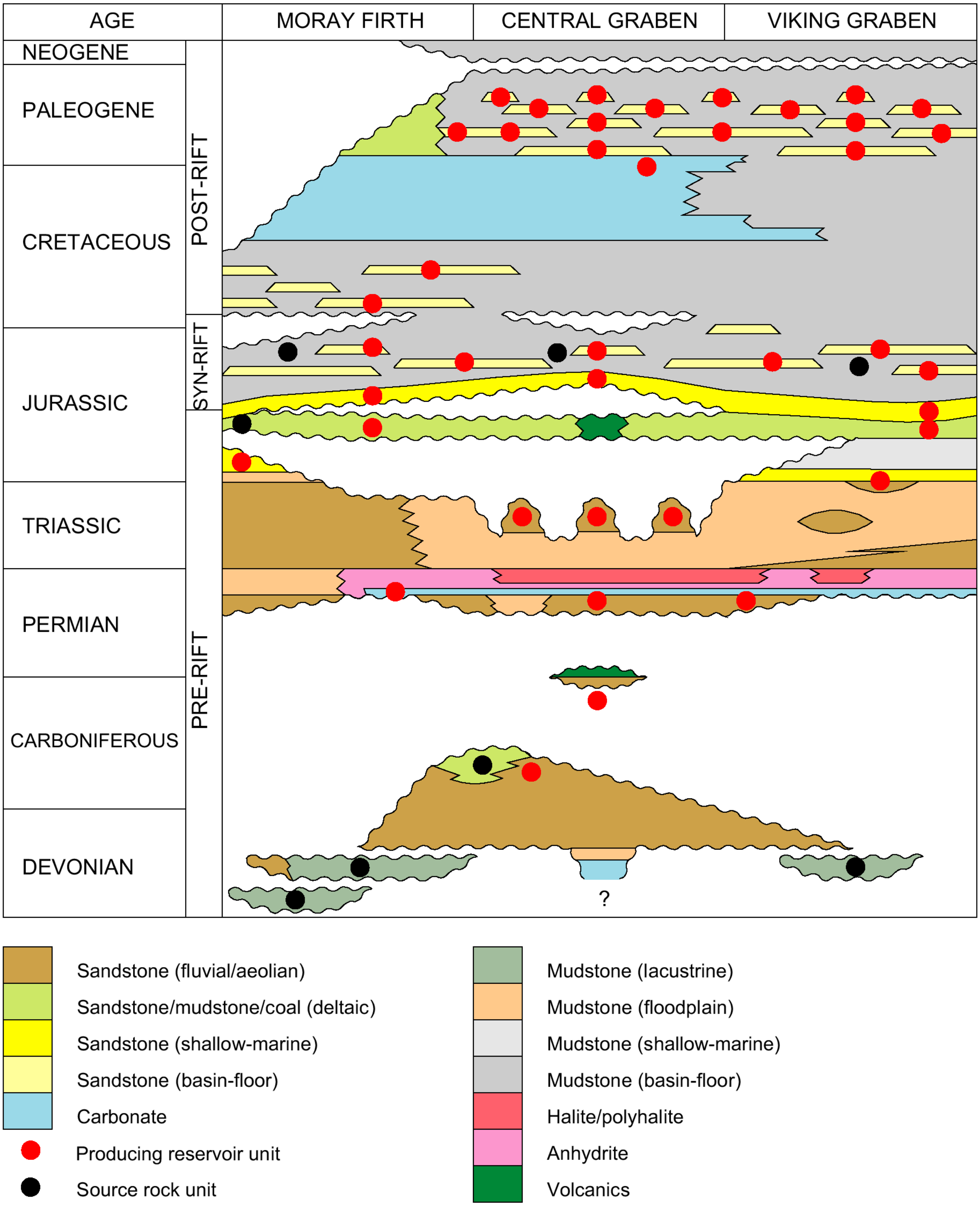

Fig. 2 Simplified table illustrating geographic ranges of the principal lithofacies in the North Sea Oil Province.

Pre-rift, Middle Devonian lacustrine sediments, a partial source for oil in the Beatrice Field in the Inner Moray Firth (Fig. 3), are now thought to be widespread beneath the northern half of the oil province (Duncan and Buxton, 1995). This distribution provides a possibility that the geographic range of Paleozoic hydrocarbon reserves may extend far beyond the graben margins onto the underexplored East Shetland Platform in this northern area. Devonian sub-basins that appear to be imaged by potential field data, are likely to provide the focus for initial exploration of this play.

(ii) Pre-rift producing fields with reservoirs of Triassic to Lower Jurassic age have traps either in tilted footwall blocks adjacent to the major graben (e.g. Beryl), as subcrop closures beneath syn-rift or post-rift strata (e.g. Marnock), or in stacked plays beneath producing Middle or Upper Jurassic sandstones (Johnson and Fisher, 1998). These reservoirs are typically thick, highly feldspathic, fluvial channel and sheetflood sandstones. They are fine-grained on the western flank of the Central Graben, where they are partly confined to topographic lows that formed in response to halokinesis of underlying Upper Permian evaporites (Fig. 4). This has led to abrupt reservoir thickness changes, elongate patterns of net sandstone, and poor connectivity between adjacent sand systems. Reservoir properties are highly variable. Not all of the prospective structural or subcrop traps have been drilled as yet, and the potential for traps defined by reservoir pinch-out is underexplored. North of a Triassic watershed at around 58°N, coarse-grained, uppermost Triassic to Lower Jurassic sandstones have excellent reservoir properties, as do the mid-Triassic aeolian sandstones which are important oil reservoirs nearby in the Norwegian sector (Johnson and Fisher, *op. cit.*). However, all but the smallest of prospective structures may have already been drilled in this area.

(iii) The pre-rift, Middle Jurassic tilted fault-block play is one of the most productive in the North Sea (Fig. 3), although creaming curves indicate that it may be almost fully exploited as an exploration target (Johnson and Fisher, 1998). The Middle Jurassic reservoirs were deposited within a diachronous clastic wedge, mainly in coastal or delta-plain environments in the south, and as coastal barrier and wave-dominated deltaic facies in the north. Virtually all of the footwall closures north of 58°N have already been tested, but the potential for economic reserves in hanging wall closures is underexplored, probably because reservoir properties are perceived to deteriorate with increasing depth in this region. The opportunity of discovering untapped reserves may be better in the Central Graben, though reservoir prediction is more difficult here. Nevertheless, there is a likelihood that overpressure has preserved economic porosity and permeability to anomalous depths in the graben. The most attractive prospects may be those stacked below syn-rift drilling targets.

SYN-RIFT

Although most of the syn-rift, Upper Jurassic to Lower Cretaceous producing fields (Fig. 3) occur in small to medium-size traps, this exploration play is currently, and will continue to be, one of the most active in the North Sea (Fig. 5). The play is largely, but not entirely, confined to the syn-rift graben, and it owes its success to the widespread occurrence within these of high-quality sandstones, which directly underlie, interfinger with, or overlie mature source rocks in much of the region. However, the play has not reached maturity yet, because the distribution of reservoir facies is very complex, reflecting the interplay between local tectonic and regional eustatic controls on the rate of creation of accommodation space within each of the graben. Contemporaneous halokinesis is another factor affecting facies distributions in the Central Graben. Later halokinesis is important as a trapping mechanism there.

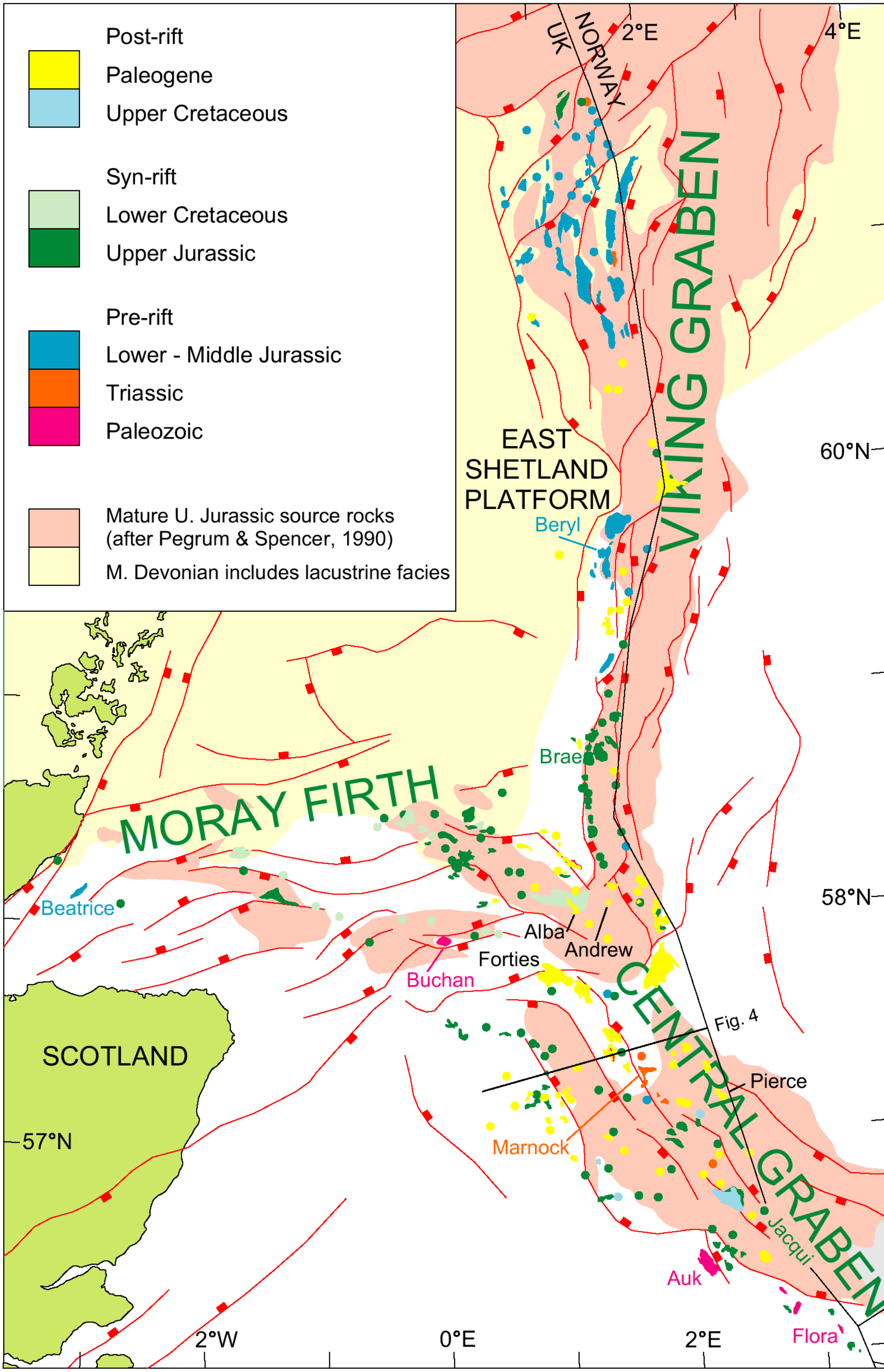

Fig. 3 Principal reservoirs for oil and gas fields in the North Sea Oil Province.

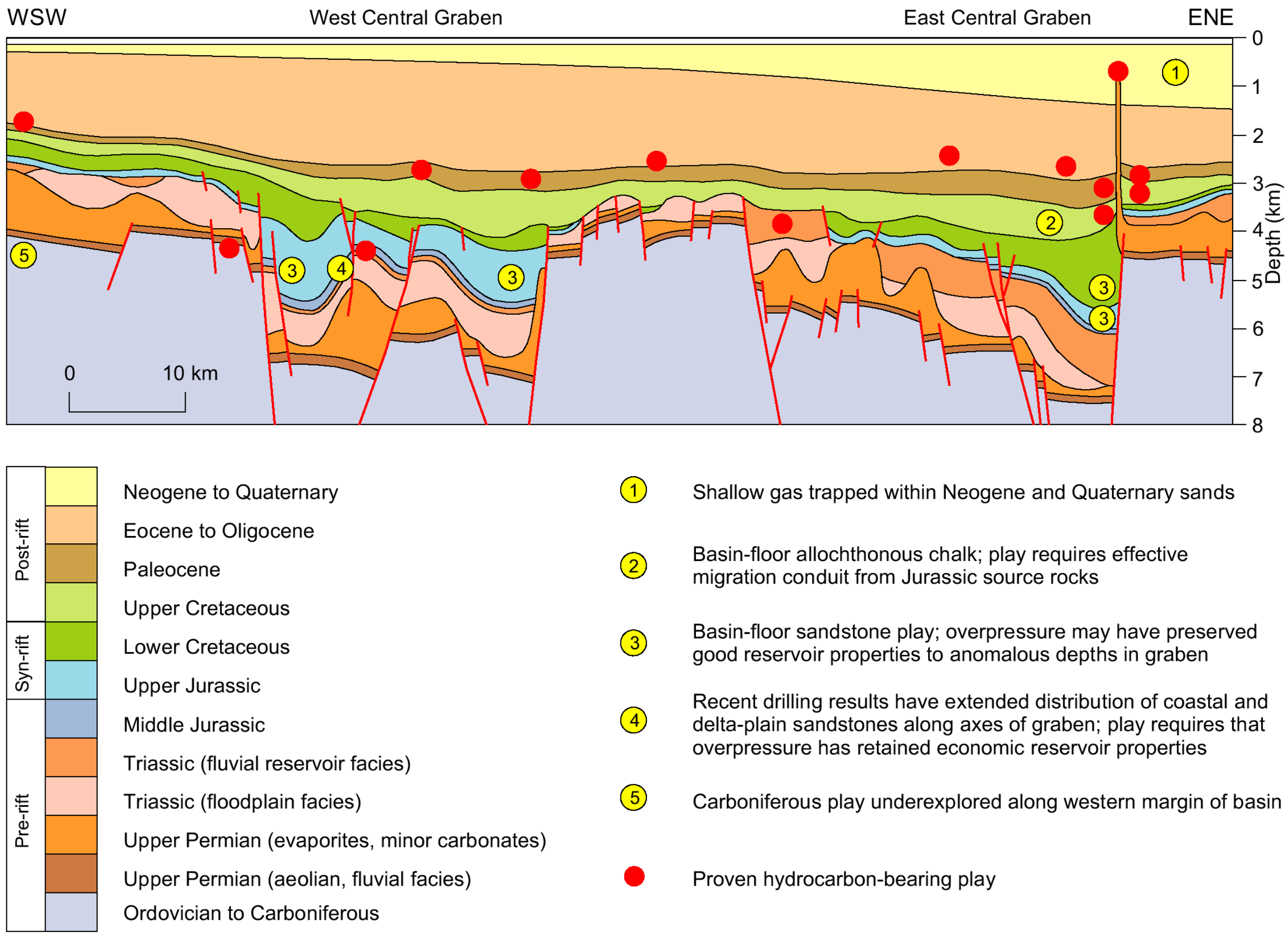

Fig. 4 Schematic section illustrating principal underexplored plays in Central North Sea.

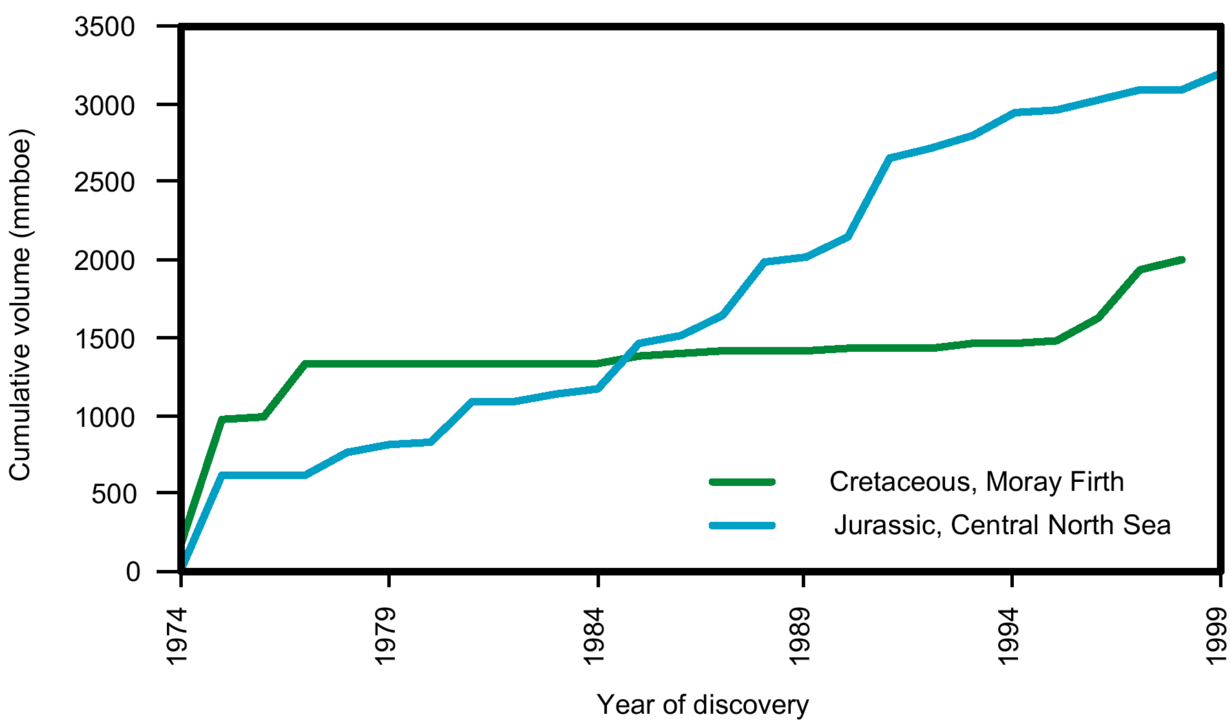

Fig. 5 Creaming curves for the combined Middle and Upper Jurassic plays of the Central North Sea, and Lower Cretaceous play of the Moray Firth (data supplied by Asset Geoscience Ltd.

The producing syn-rift reservoirs include both shallow-marine and deep-marine sandstones. As relative sea level rose rapidly during the early stages of rifting, retrogradational packages of shallow-marine shelf and coastal sands were deposited around the basin margins of the Outer Moray Firth and Central Graben in particular. In parts of the region, these facies continued to be deposited into the early Cretaceous. This excellent reservoir facies passes basinwards into shelf mudstones which provide a good topseal to deeper, pre-rift hydrocarbon accumulations. In selecting shallow-marine drilling targets, the principal challenge is to develop a sequence-stratigraphic framework that assimilates all of the eustatic and local tectonic influences on facies development as a means of determining the preservation potential for the reservoir sandstones (Johnson and Fisher, 1998). Nevertheless, the distribution of shoreline facies is not yet fully understood.

As rifting continued, footwall uplift along the major graben-bounding faults locally exceeded the continuing relative rise in sea level. This led to footwall erosion, and mass transfer of coarse clastic debris into the adjacent, by now sediment-starved, deep-water basins. Where the clastic debris is banked against active faults, it forms small point-sourced accumulations that are often conglomeratic – the reservoir facies for several oilfields in the Viking Graben (e.g. Brae). Where the clastic debris has been transported farther basinwards, it forms larger, lenticular accumulations with a higher proportion of sandstone, often totally encased within basinal mudstone. The locations of the basin-floor accumulations were strongly influenced by contemporary bathymetry.

The syn-rift producing fields display a wide variety of trapping mechanisms, including tilted fault blocks, four-way dip closures, hanging-wall closures, stratigraphic closures, and combined structural-stratigraphic closures (Johnson and Fisher, 1998). Rifting terminated in the Viking Graben and Central Graben during the Late Jurassic. The blanket of post-rift basinal mudstones deposited during the early Cretaceous here provides a regional topseal for many drilling targets.

The majority of syn-rift prospects in the Viking Graben have already been drilled. There are many syn-rift producing fields in the Moray Firth and Central Graben also (Fig. 3), but the basinal parts of these areas remain underexplored. It is largely these areas that contain an estimated syn-rift component comprising 40% of oil and 35% of gas yet to be discovered in the oil province (Johnson and Fisher, 1998). In the Inner Moray Firth, for instance, there has been only limited exploration to date of Upper Jurassic to basal Cretaceous basin-floor sandstones. This may be because it is not widely appreciated that the contemporary source rocks (Kimmeridge Clay) are fully mature for oil generation in the deepest parts of the asymmetrical graben that characterize this area (Oakman and Partington, 1998). Middle Devonian lacustrine sediments in the footwalls of these graben are also likely to be mature for hydrocarbon generation. The most attractive play comprises up-dip, distal pinch-out of sandstone reservoirs, with encasing basinal mudstones providing lateral seal (Fig. 6). It is not known yet whether the reservoir sandstones are widespread along the axes of the graben, or whether they are relatively localized, comprising separate accumulations derived from point sources.

Recent wells in the deepest parts of the Outer Moray Firth and Central Graben have unexpectedly extended the play fairway for thick, Upper Jurassic syn-rift basin-floor sandstones into this area too. Overpressure, caused mainly by high sedimentation rates in the overburden, is expected to have preserved good reservoir quality at anomalous depths relative to present depth in the latter area. It is these sandstones that provide the gas reservoir for the recently discovered Jacqui Field (Fig. 3). Perhaps the greatest challenge will be to convince exploration managers that the best-quality reservoirs may be located in synclinal areas of the graben, rather than the flank areas or intrabasinal highs that have provided the majority of drilling targets until now. Furthermore, recent drilling successes have proven that substantial hydrocarbon reserves still remain to be discovered on the hanging walls of the major faults of the region.

Tectonism continued into the Early Cretaceous in parts of the Moray Firth, where the contemporary basin-floor sandstone fairway (*e.g.* Kopervik play) is proving to be an attractive exploration target. Drilling has established that sea-floor bathymetry had a significant impact on depositional processes here too, with the thickest sandstones being encountered in localized trough areas within under-filled Late Jurassic graben (Oakman and

Partington, 1998). Early successes were in structural traps, but recent discoveries have revealed the potential for significant undiscovered hydrocarbons in stratigraphic traps. Improvements in seismic resolution of the limits of the reservoir sandstones will be required to optimize the potential of this fairway.

Exploration within overpressured parts of the Central Graben has revealed that the basal syn-rift shallow-marine sandstones are more widespread than previously recognized (Cordey, 1993). Location of drilling targets will be more challenging here than around the basin margins, but careful sequence-stratigraphic interpretation of 3D seismic data should yield further successes in this area.

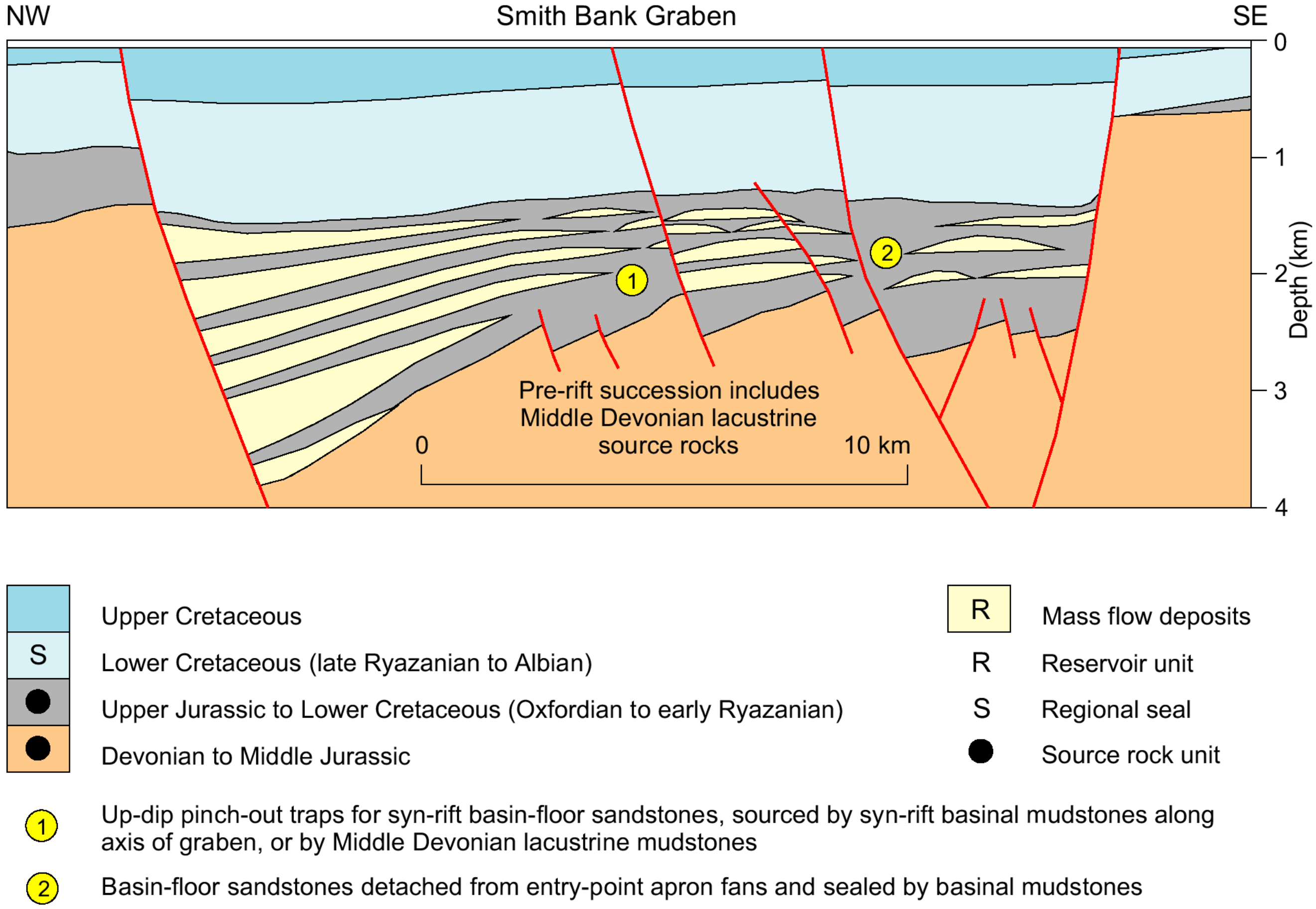

Fig. 6 Schematic play diagram for Upper Jurassic to basal Cretaceous of Inner Moray Firth, North Sea Oil Province.

POST-RIFT

Post-rift thermal subsidence has continued from the cessation of rifting to the present day. Subsidence patterns reflect the continuing influence of the North Sea's graben systems, although they have been modified by late Cretaceous inversion in parts of the Central Graben. Up to 1,000 m of Upper Cretaceous chalk accumulated in the latter area and in the Moray Firth, whereas the contemporary sediments in the Viking Graben are calcareous mudstones with no reservoir potential. The chalk also has generally poor reservoir properties. Exceptions include chalk that has been redeposited by gravity flow processes at the base of oversteepened slopes, for instance around rising salt diapirs and around the graben margins. The potential for stratigraphic entrapment within porous allocthonous chalk encased in non-porous sediment remains underexplored in basinal areas, but requires an effective migration conduit from underlying source rocks. There is also a possibility that chalk porosity has remained anomalously high relative to depth of burial in overpressured areas of the Central Graben. Even where relatively porous, however, it has yet to be proven that significant reserves remain to be discovered from chalk reservoirs in the UK sector of the North Sea. All of the existing fields are in the south-east of the oil province. They are small and only marginally economic, even at $20 per barrel.

Regional patterns of sedimentation changed dramatically in the early Paleocene, with the influx of huge volumes of coarse clastic detritus as debris flows and/or turbidites into the basinal areas of the oil province. This detritus was being shed from the uplands of northern Scotland and from the East Shetland Platform, which were undergoing thermal uplift in response to development of the Iceland plume and opening of the North Atlantic Ocean. The resultant deep-water sandstone reservoirs, of Paleocene to mid Eocene age, contain around 20% of the oil province's proven hydrocarbon reserves (Pegrum and Spencer, 1990).

The Paleogene reservoirs occur in a succession of up to fifteen gently eastward-dipping, overlapping depositional sequences bounded by erosional unconformities. Each of these sequences requires a separate play evaluation (Johnson and Fisher, 1998). This is because the distribution of reservoir sandstones and potentially sealing mudstones within an individual sequence reflects the gross depositional setting of that sequence. Nevertheless, there was a progressive change from the emplacement of laterally extensive sheet sands on the basin floor during the early Paleocene, through the deposition of smaller basin-floor systems during the late Paleocene to early Eocene, to the restriction of sand bodies into narrow, elongate, channels intercalated within mud-dominated slope facies during the mid Eocene. Virtually all of the sand systems become progressively distal towards the east or south-east. Although reservoir quality is generally very good, the overall succession displays a wide range in the thickness, geometry, orientation and architecture of its individual sand bodies.

The Paleogene reservoirs occur in both structural and stratigraphic traps (Bain, 1993). Structural traps are mainly located over pre-Tertiary structural highs (e.g. Forties), or are either flanking or overlying Permian salt diapirs (e.g. Andrew, Pierce); the latter scenario is restricted to the Central Graben. Topseal is provided by regionally extensive mudstone intervals. Stratigraphic traps include mounded closures and sand pinch-outs, which can occur in a wide range of depositional settings. The pinch-out traps have a higher exploration risk of seal failure, although they have only rarely been tested in optimal drilling locations (Bain, *op. cit.*).

Since the first North Sea oil discovery in 1969, exploration of the Paleogene play has led to the discovery of 31 fields having estimated recoverable reserves of 0.72 billion tonnes of oil (5.3 billion barrels) and 151 billion cubic metres (5.3 tcf) of gas and condensate. Nevertheless, the play will remain highly prospective, with the emphasis on locating increasingly subtle stratigraphic traps, and on extending the geographic range of discoveries into basin-marginal areas such as the East Shetland Platform. Depth of burial is relatively shallow in these areas, leading to a preponderance of heavy, biodegraded oils. Nevertheless, experience gained in maximizing production from existing fields of this type in the UK (e.g. Alba) and elsewhere is continuing to improve the economic potential of the many untested prospects in such areas.

The search for subtle traps is benefiting from improvements in seismic acquisition and processing leading to better resolution, increased use of 3D seismic interpretation, AVO and seismic attribute analysis, the application of high-resolution stratigraphic concepts, and improved models for deep-water sandstone depositional processes. Using these and other innovative techniques, the Paleogene play is likely to yield around 45% of future oil and 30% of future gas discoveries in the North Sea's oil province (Johnson and Fisher, 1998). Overlying this play, the shallow gas that occurs within unconsolidated Neogene and Quaternary sands across large parts of the region is widely perceived as a drilling hazard, but may be locally exploitable.

North Sea Gas Province

Since the first gas came ashore from the West Sole Field in 1967, the Southern North Sea had produced around 964 billion cubic metres of gas (34 tcf) from 73 gas fields by the end of 1998 (DTI, 1999). Around 85.5% of this production has been from Lower Permian (Rotliegend) aeolian dune sandstones, and 13% from Triassic fluvial sandstones (Fig. 7). Upper Permian carbonates have contributed minor production from three fields. Remaining production has been from Carboniferous fluvial sandstones.

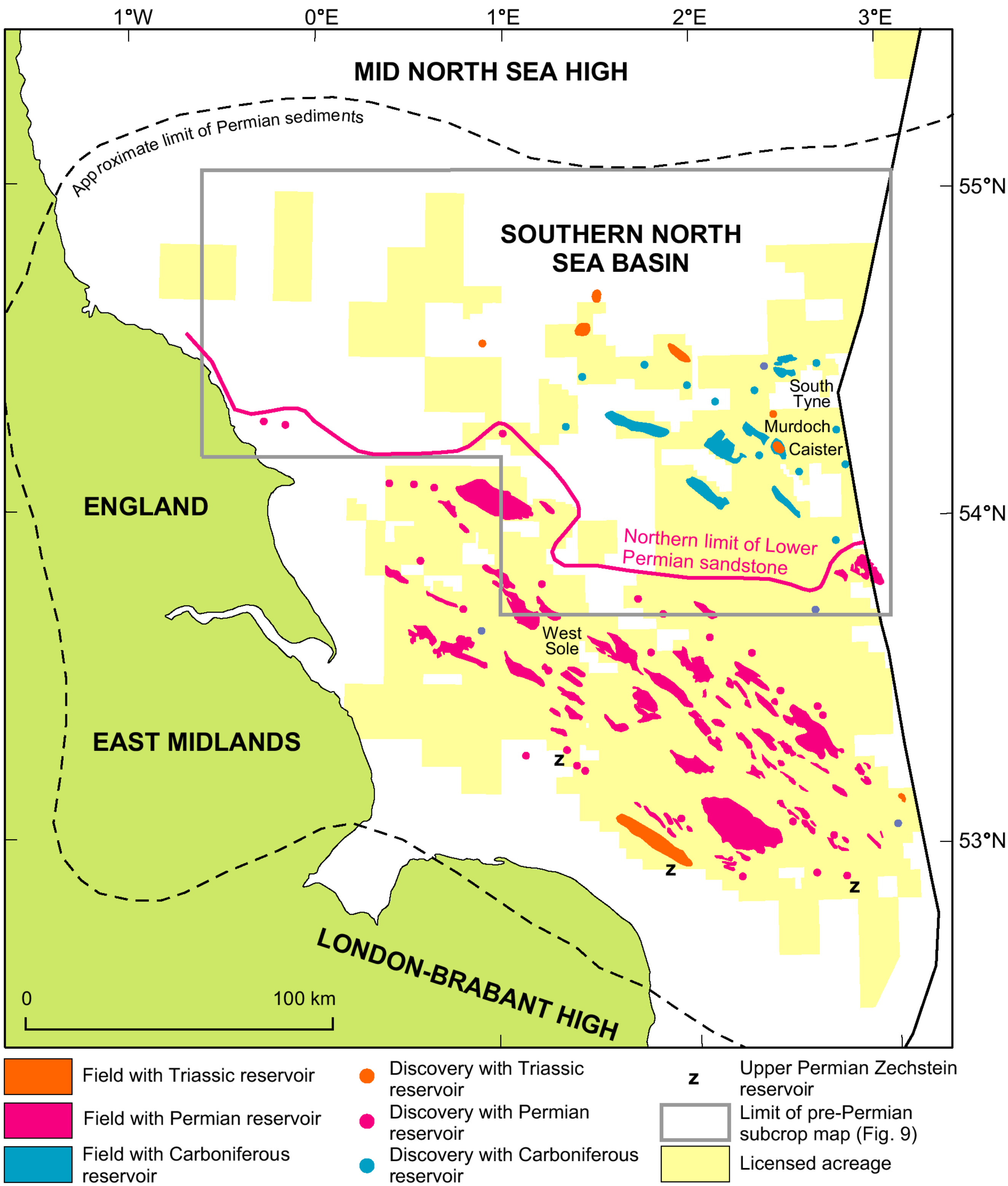

Fig. 7 **Fields and discoveries in the UK North Sea Gas Province.**

The Lower Permian (Leman Sandstone) play is restricted to the southern half of the gas province (Fig. 7), because the reservoir facies passes northwards into contemporary playa lake mudstones and evaporites. Stretching from the UK eastwards to the North German/Polish Plain, this fairway has ultimately recoverable reserves of some 4,500 billion cubic metres (159 tcf) of gas (Glennie, 1998). The Lower Permian play is continuing to evolve by integrating new techniques and technologies with the aim of recognizing ever more subtle traps. Pre-stack depth migration is proving a powerful tool in removing lateral velocity variation effects caused by the widespread presence of diapiric salt in the overburden, hence enabling increasingly accurate depth imaging of drilling targets. Other techniques that are keeping this fairway active include the application of seismic inversion to assess basin-margin plays, the evaluation of diagenetic controls on regional reservoir quality, and careful and detailed fault seal analysis. High resolution sequence stratigraphy is now being applied to map the extent of reservoir units around the margin of the contemporary desert lake, and there may be potential for stratigraphic entrapment of gas in this area.

The Lower Permian reservoir sandstones and lake sediments rest on a regional base Permian unconformity. Folded and faulted Carboniferous strata beneath the unconformity include up to 800 m of Westphalian A-C coal measures, the principal source for gas in the Southern North Sea Basin. Following strong encouragement from the UK Department of Energy (now DTI), exploration drilling to test the fluvial sandstones that are interbedded within the coal measures began during the early 1980s. This has led to the discovery of additional gas reserves in 8 fields and 12 significant discoveries (DTI, 1999) to the north of the established Lower Permian play (Fig. 7). Although these fields are already contributing around 5% of UK annual gas production, exploration of this play is still at the immature stage, with much of the Carboniferous fairway underexplored. Recently published analyses indicate that a significant component of the gas has been generated from pre-Westphalian marine source rocks (Gerling *et al.,* 1999). This should extend the geographic range of exploration farther beyond the erosional limit of the Westphalian coal measures (Fig. 8).

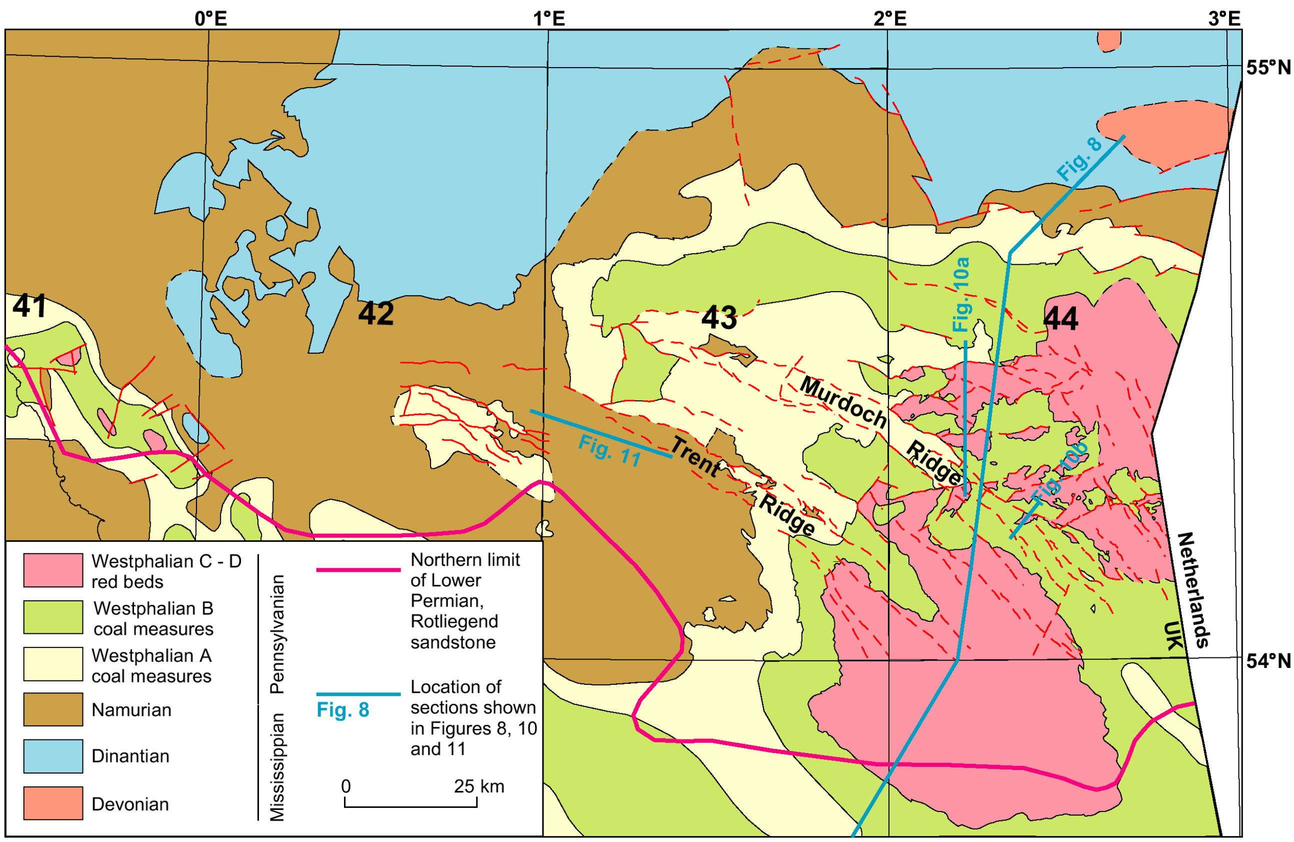

Fig. 8 Subcrop of pre-Permian strata in the northern part of the North Sea Gas Province.

The structure and stratigraphy of the Carboniferous in the northern part of the Southern North Sea Basin are summarized in Figure 9. The deep structure of the basin is conjectural, because seismic resolution is generally limited to within 2 km below the base Permian unconformity. Nevertheless, it is believed that, as in the onshore UK, late Devonian to Dinantian rifting established a block and basin deep structure and palaeogeography (Leeder and Hardman, 1990) across the region. Significantly different interpretations exist for the locations of the syn-rift blocks and basins (e.g. Collinson *et al*., 1993; Cameron and Ziegler, 1997; Besly, 1998). Rift-related subsidence evolved to thermal sag during the early Namurian, and deltas prograding from the north filled the basin. The remainder of the Carboniferous interval is characterized by a succession of alluvial and lacustrine beds (Westphalian A to C), passing upward into alluvial red bed facies (Westphalian C to D). The hydrocarbon source and reservoir potential of the Carboniferous succession in the Southern North Sea Basin are summarized in Table 1.

Carboniferous interval	Source rocks	Reservoirs
Westphalian C-D red beds	None.	Porosity in the range 7-19%. The most sand-prone proximal succession occurs towards the north-east.
Westphalian A-B coal measures	Coal beds make up 5-8% of the succession, and constitute the principal gas source rocks within the North Sea Gas Province. Local oil-prone potential recorded.	Laterally continuous braided channel sandstones are up to 50 m thick, and have porosity of 3-19% and permeability of 0.1-11mD.
Namurian basinal mudstones, prodelta and deltaic sediments	Basinal mudstones provide good to excellent oil-prone source rock potential, now mature for gas generation.	Fluvio-deltaic sandstones have an average porosity of 12-22%, with permeability greatest in tidally-reworked units. Turbidite and debris flow sandstones are poorly sampled, and have low porosity and permeability where deeply-buried beneath the Permian (e.g. 43/17-2).
Dinantian syn-rift deposits	Coal measures preserved along the northern margin of the basin are mostly immature for gas generation.	Porosity up to 25% in braided river and fluvio-deltaic sandstones on the flank of the Mid North Sea High.

Table 1. Source and reservoir potential of the Carboniferous in the North Sea Gas Province.

The majority of the Carboniferous drilling targets tested so far have been defined by structural closure on the base Permian unconformity. Resting on this unconformity, the Lower Permian playa lake sediments and overlying thick Upper Permian evaporites provide an excellent regional seal. The earliest drilling targets were major NW-SE trending 'pop-up' horst blocks bounded by reverse faults (Fig. 9), such as the Murdoch and Trent ridges (Fig. 8). This phase of exploration led to the discovery of most of the fields that are now in production or under development. It established that potentially productive fluvial sandstone reservoirs are widespread in the Westphalian C-D red beds, and at specific intervals within the late Namurian to Westphalian C coal measures and deltaic sediments (Table 1). Quirk (1997) showed that at least the upper part of the succession can be regarded as a stacked series of fluvio-deltaic sequences, with reservoir-quality sandstones being deposited mainly during periods of fluvial aggradation during the early stages of regional rise in lake level across the basin. Challenges for the future will include extending the stratigraphic range of this sequence-stratigraphic approach to reservoir correlation, and the accurate prediction of the thickness and geometry of individual sand bodies. Quirk and Aitken (1997) have emphasized that it is all too easy to miss a gas-bearing Carboniferous reservoir within a structural closure, unless a rigorous structural and stratigraphic interpretation has been carried out to delimit the subcrop limit of the target interval.

The potential for stratigraphic plays within the Carboniferous has been poorly addressed so far, mainly due to the limitations of available seismic data to resolve such plays, and the need for a better understanding of the distribution and geometry of intraformational seals. The South Tyne field (Fig. 7) is a success story for the combined structural and stratigraphic trap found at the erosional limit of the late Westphalian C-D alluvial red beds. As 3D seismic coverage has extended across the region, isolated wedges of the red beds have been resolved as outliers on the hanging walls of E-W to ENE-WSW oriented faults in central Quadrant 44 (Fig. 8). Furthermore, the 3D data has resolved a much greater complexity of faulting within the Carboniferous interval than previously recognized from 2D data (Oudmeyer and de Jager 1993). In almost all cases, the wedges of red beds do not occur within a structural closure of the base Permian unconformity, and hence they require lateral fault seal (Fig. 10). Numerous stratigraphic traps of a similar wedge-like geometry are anticipated for older Westphalian reservoirs as they rise to pre-Permian subcrop (Fig. 6). Successful identification of such drilling targets requires detailed mapping on 3D seismic data, and careful fault seal analysis.

Figure 10 illustrates one of the many undrilled prospects in the Carboniferous fairway. This prospect lies between the Murdoch and Caister gas fields, in which the productive reservoir is basal Westphalian B in age. The prospect comprises an isolated wedge of younger Westphalian C-D alluvial red beds that is preserved on the Murdoch Ridge between the gas fields, and contains reservoir-quality sandstone beds elsewhere in the region. Perhaps this wedge has not been drilled yet because, although it lies within the large closure on the base Permian unconformity that encloses both of the gas fields, it maps as occurring within a structural low at the established reservoir level.

Deeper Carboniferous plays remain speculative, since the geology of the Dinantian to Namurian succession is poorly constrained across much of the southern North Sea. Few wells have penetrated more than a few hundred metres of this section. A notable exception is well 43/17-2, which proved 2454 m of mudstone-dominated late Dinantian to early Namurian sediments from within a deep syn-rift basin (Besly, 1998). Laterally equivalent basinal mudstones are the source rocks onshore for the East Midlands oil province, but have reached maturity for gas generation offshore. Basin-floor fan sandstones, which make up at least 10% of the succession in this well, have excellent reservoir potential for structural and stratigraphic entrapment (Fig. 11).

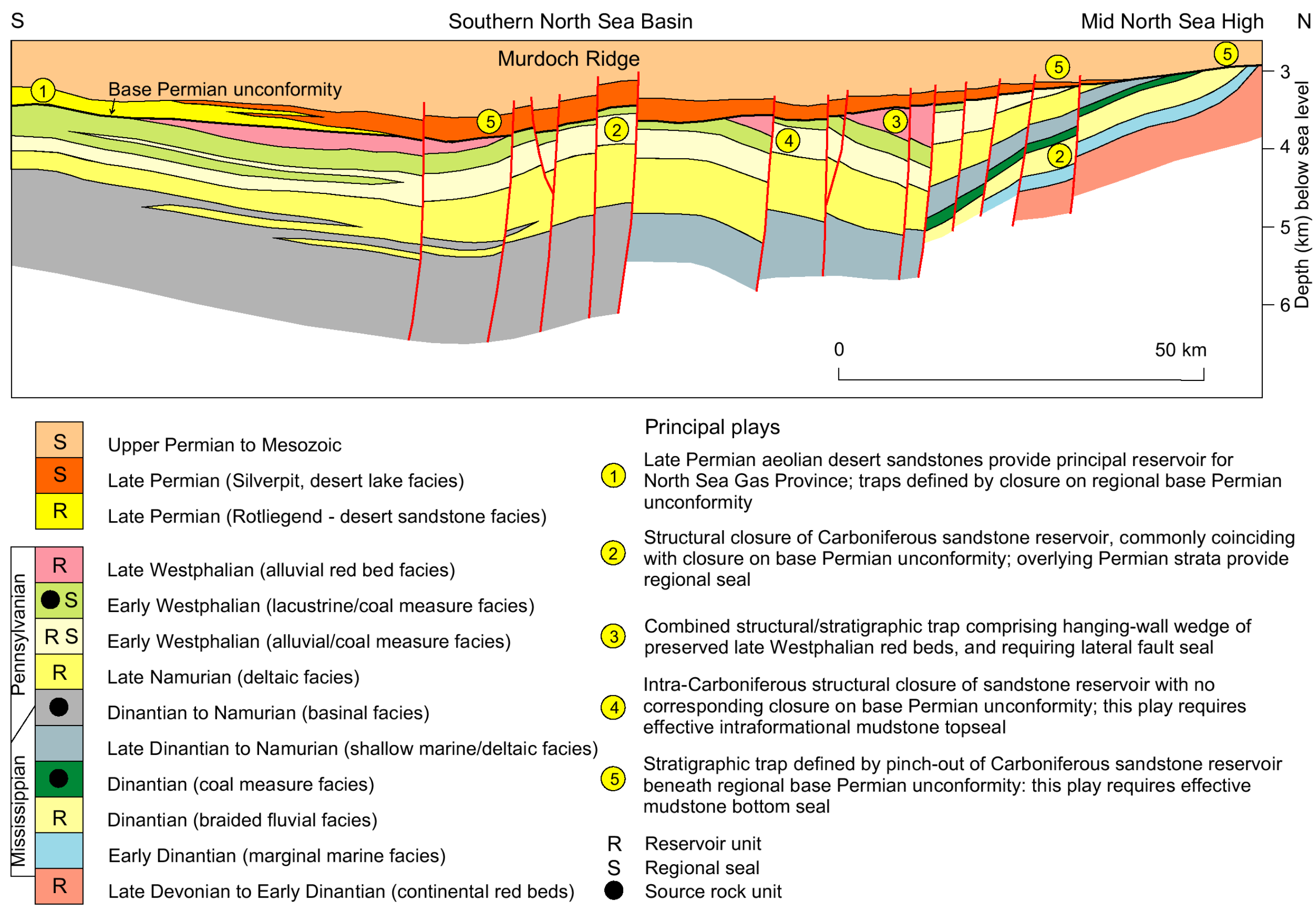

Fig. 9 Schematic section summarizing principal Carboniferous plays in the North Sea Gas Province.

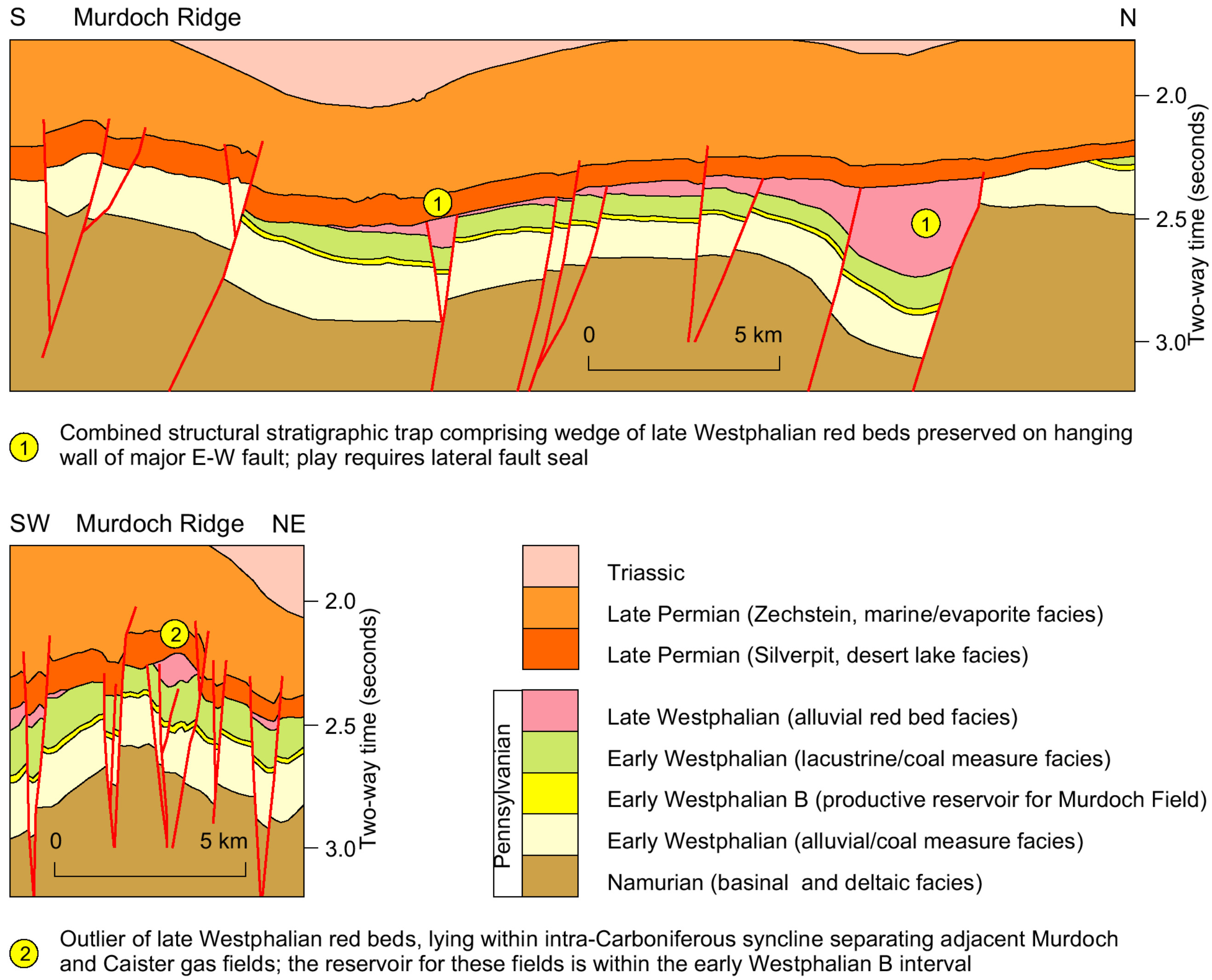

Fig. 10 Geoseismic sections illustrating examples of under-explored Upper Carboniferous plays, North Sea Gas Province.

Cameron and Ziegler (1997) have suggested that significant new opportunities remain in the largely untested basal part of the Carboniferous section. In particular they highlighted a progradational wedge play of Dinantian detrital carbonates, derived from an adjacent platform succession in UK Quadrant 42 (Fig. 11). Carbonate shelf-margin facies recorded from the UK onshore include carbonate shoals, build-ups, talus, debris flows and turbidites (Fraser and Gawthorpe, 1990), and secondary porosities of up to 30% characterize carbonate debris flows where dolomitized (Gawthorpe, 1987).

Another play envisaged by Cameron and Ziegler (1997) relies on the possibility that the normally gas-prone Westphalian coal measures could have generated significant volumes of oil along the southern margin of the North Sea Basin. Their play has oil migrating from these coal measures into conventional structural traps with potentially stacked Devonian to Westphalian reservoirs.

Onshore Basins

Oil production in the UK commenced in 1919 from the Hardstoft Field in the East Midlands of England (Fig. 12). Petroleum exploration onshore has proceeded in a cyclical fashion since then (Evans, 1990), affected by political factors and by improvements in exploratory techniques. With thirty-five fields currently producing around 5.2 million tonnes of oil (38.2 million barrels) and 0.34 billion cubic metres (0.012 tcf) of gas *per annum* (DTI, 1999), all of the onshore area could be perceived to have been at a mature stage of exploration for many years. Nevertheless, significant discoveries are still being made, the coalbed methane extraction industry is in its infancy, and there is no reason to consider that innovative thinking will not yield further discoveries for many years to come.

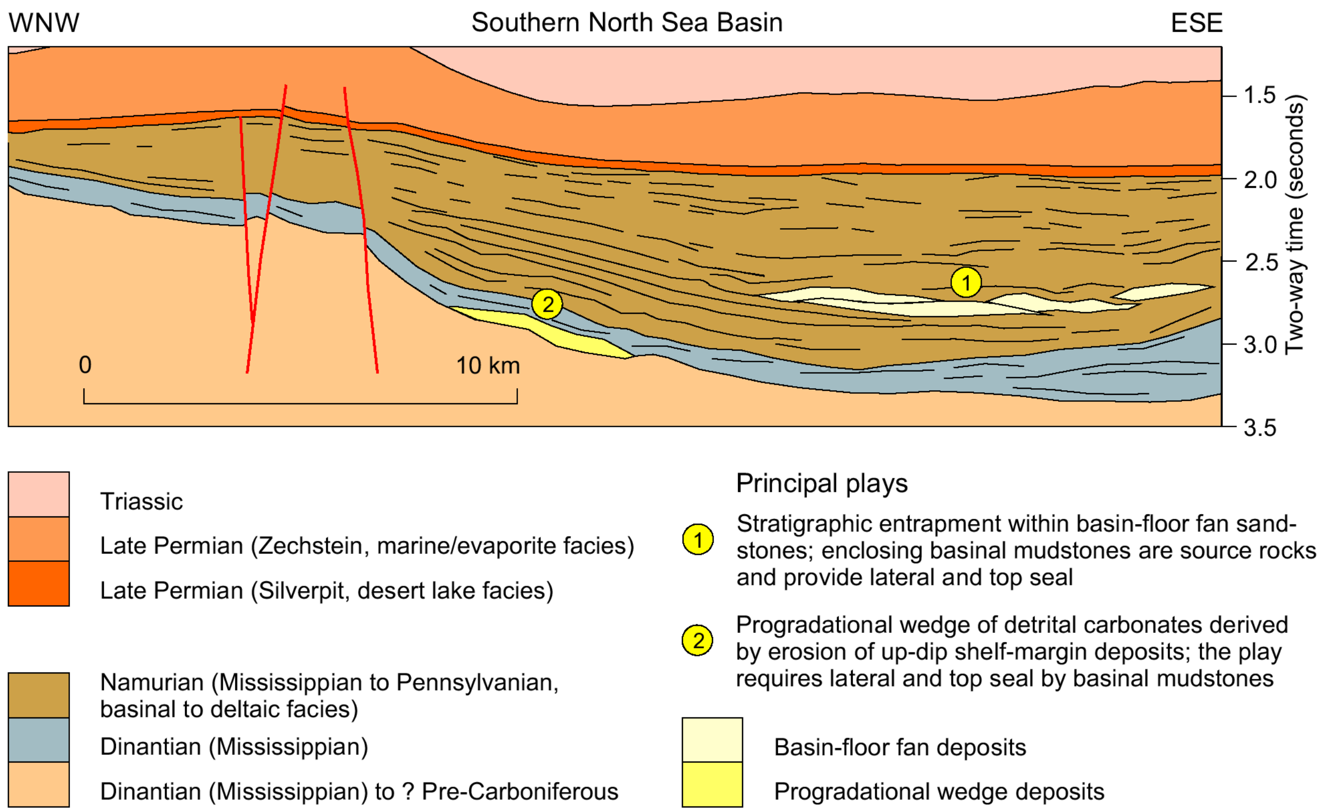

Fig. 11 Geoseismic section illustrating undrilled Lower Carboniferous plays, North Sea Gas Province (adapted from Cameron and Ziegler, 1997).

The oil and gas fields are mainly in three geographic areas. In southern England, petroleum production is from the Weald and Wessex Basins (Fig. 12), and from a range of Triassic (Sherwood Sandstone), Middle Jurassic, Upper Jurassic and Lower Cretaceous reservoirs sourced by Lower Jurassic (Lias) oil-prone mudstones. Around 90% of UK onshore oil production is from the Wytch Farm Field in the Wessex Basin (Fig. 12), aided by extended reach wells that include the 10.7 km current world record for “horizontal” stepout. The key to exploration success in southern England will continue to hinge on unravelling the relationship between the structural development of drilling targets, the timing of hydrocarbon migration into these targets, and the prediction of reservoir facies development, particularly for the Middle Jurassic oolitic limestone play.

Eastern England contains the oil province of the East Midlands (Fig. 12), in which hydrocarbons sourced from late early Namurian basinal mudstones have migrated partly into Dinantian shelf-margin limestones, but mostly into younger Carboniferous sandstones. The oil of early discoveries was mainly trapped in inverted roll-over anticlines. Fraser and Gawthorpe (1990) demonstrated that the hydrocarbon system includes a wider range of plays, whose distribution is strongly influenced by the Dinantian rift-related tectono-stratigraphic development of the region. Not all of these plays have been fully explored as yet. Recent discoveries of oil and gas have extended the East Midlands province eastwards to the North Sea coastline (Fig. 12), and mapping of residual Bouguer gravity anomalies has proved invaluable in delineating the primary drilling targets there. The recent successes in this area have been from late Namurian to basal Westphalian fluvio-deltaic sandstones. Now that 3D seismic coverage is extending across the region, there will be opportunities for defining the structural traps more clearly, and for assessing the potential for stratigraphic entrapment, especially for pinch-out of basal Namurian sandstones onto the regional Dinantian structural highs.

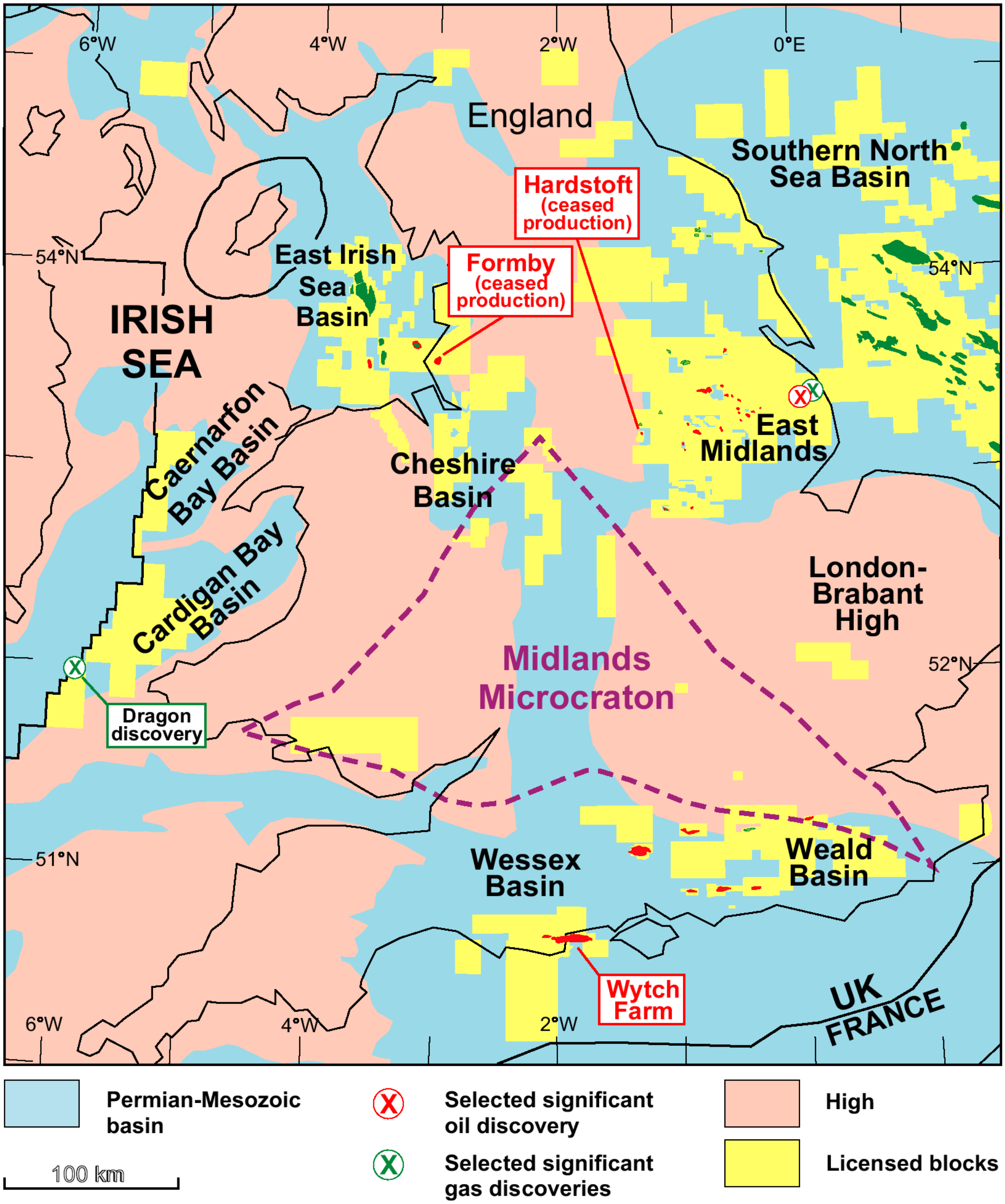

Fig. 12 Hydrocarbon fields and selected hydrocarbon discoveries in the UK onshore and Irish Sea basins.

Farther north in eastern England, there has been limited production of gas from late Permian carbonate reservoirs. Further exploitation of gas reserves here will depend on improvements in production technology. In north-west England, Carboniferous-sourced oil has been produced from the Lower Triassic (Sherwood Sandstone) reservoir at the Formby Field (Fig. 12), topsealed there by Pleistocene boulder clay. Gas is being produced from an Upper Permian sandstone reservoir nearby, and there remain a number of undrilled leads in tilted fault block plays, similar to those offshore in the East Irish Sea Basin.

The Cheshire Basin of north-west England and the Midlands Microcraton of central England have the best potential for expanding the geographic range of the UK's onshore petroleum provinces (Fig. 12). The Cheshire Basin is a Permo-Triassic half-graben, partly underlain by mature, gas-prone Westphalian coal measures. Successful hydrocarbon exploration will depend on locating migration routes from these source rocks into structural traps containing reservoir-quality Lower Triassic sandstone that is itself topsealed by younger Triassic mudstones and evaporites (Mikkelsen and Floodpage, 1997). The Midlands Microcraton is a triangular Lower Paleozoic foreland that was bypassed by the mid-Paleozoic (Caledonian) orogenic deformation which is ubiquitous to the north-east and north-west. It also lies beyond the later Paleozoic (Variscan) deformation front that traces across southern England. Relatively few exploration wells have been drilled on the microcraton, but some of these have encountered sub-commercial shows of oil and gas, mainly in overlying Upper Paleozoic and Mesozoic strata. Silurian marine mudstones are currently within the oil window here, whereas Cambrian to early Ordovician source rocks are mature for gas generation (Smith, 1993). Untested hydrocarbon leads in the Upper Paleozoic section include pinch-out of Namurian and Westphalian sandstones onto regional highs, and four-way dip and tilt-block closures. Additional prospects in the Lower Paleozoic include Silurian and Lower Cambrian marine sandstones in tilt-block traps, in particular where the hanging walls of these traps include early Ordovician basinal mudstone source rocks.

Coalbed methane is already being produced in limited volumes from abandoned mines as vent gas, but there remains greater long-term potential for UK production from virgin coal seams. Though extraction has not been adequately tested on a commercial scale as yet, Creedy (1999) has estimated potentially recoverable UK reserves of 0.3 billion cubic metres (0.01 tcf). If there is to be significant production, it will be from Westphalian seams in England and Wales and from Namurian seams in central Scotland. The principal limitation on development at present is the generally low permeability of the UK coal seams. Until technical solutions are established for stimulating production from such rocks, the best initial prospects are in areas where mining may have already led to fracturing and enhanced permeability of the coal seams, or in structural traps. With successful resolution of this problem, unpublished data suggest that coalbed methane could account for as much as 1-2% of UK gas production by the year 2020.

Irish Sea Basins

With 200 billion cubic metres (7.1 tcf) of gas and 20 million tonnes (147 million barrels) of oil estimated as initially recoverable reserves from six producing fields (DTI, 1999), the East Irish Sea Basin (Fig. 12) is at a mature exploration phase. Early Namurian basinal shales are the source rocks for these hydrocarbons. Production from all fields is from fault-bounded traps of Lower Triassic, principally aeolian Sherwood Sandstone reservoir, top-sealed by younger Triassic continental mudstones and evaporites. Future exploration will initially concentrate on extending this play, but there remains largely untested potential also for gas and oil within widespread Carboniferous fluvial sandstone reservoirs. This play requires intraformational mudstone seal units to be present, as there is no top-seal for reservoirs subcropping the regional base Permian unconformity in the east of the basin, and Carboniferous strata crop out at the sea bed in the west.

The Caernarfon Bay Basin (Fig. 12) contains up to 7 km of Permian and Triassic syn-rift sediments in an asymmetrical graben that is bounded to the north and south by Lower Paleozoic massifs. Only two exploration wells have been drilled so far, and there remain numerous undrilled targets in tilted fault block plays (Fig. 13). As in the East Irish Sea Basin, the principal target reservoir is the Lower Triassic, Sherwood Sandstone, top-sealed by younger Triassic mudstones and evaporites. Wells in the Irish Sector to the west (Fig. 12) have proved that pre-rift, Westphalian coal measures are excellent hydrocarbon source rocks, and are at peak maturity for gas generation there (Maddox *et al.,* 1995). Seismic profiles clearly image these strata continuing beneath a basal Permian unconformity into at least the western part of the Caernarfon Bay Basin. The timing of gas generation presents the greatest exploration risk. Maximum burial of, and primary gas migration from the source rocks could have terminated as early as the Jurassic, whereas many of the tilted fault blocks were reactivated or created during early Tertiary inversion of the basin. However, it is also possible that a secondary gas charge occurred during regional heating associated with intrusion of Paleogene dykes, such as those that crop out nearby on the coastline of north Wales. Floodpage *et al.* (1999) have invoked this second phase of Paleogene hydrocarbon generation as an important factor in the charging of the East Irish Sea Basin's oil and gas fields. It is not clear as yet whether aeromagnetic anomalies in the south-east of Caernarfon Bay are imaging a continuation of the dyke swarm into this area too, or whether they are instead associated with deeply buried Permian syn-rift volcanics. Alternatively, the fault block traps could have been recharged by exsolution of methane from formation brines as a direct result of the Tertiary uplift (*cf.* Doré and Jensen, 1996).

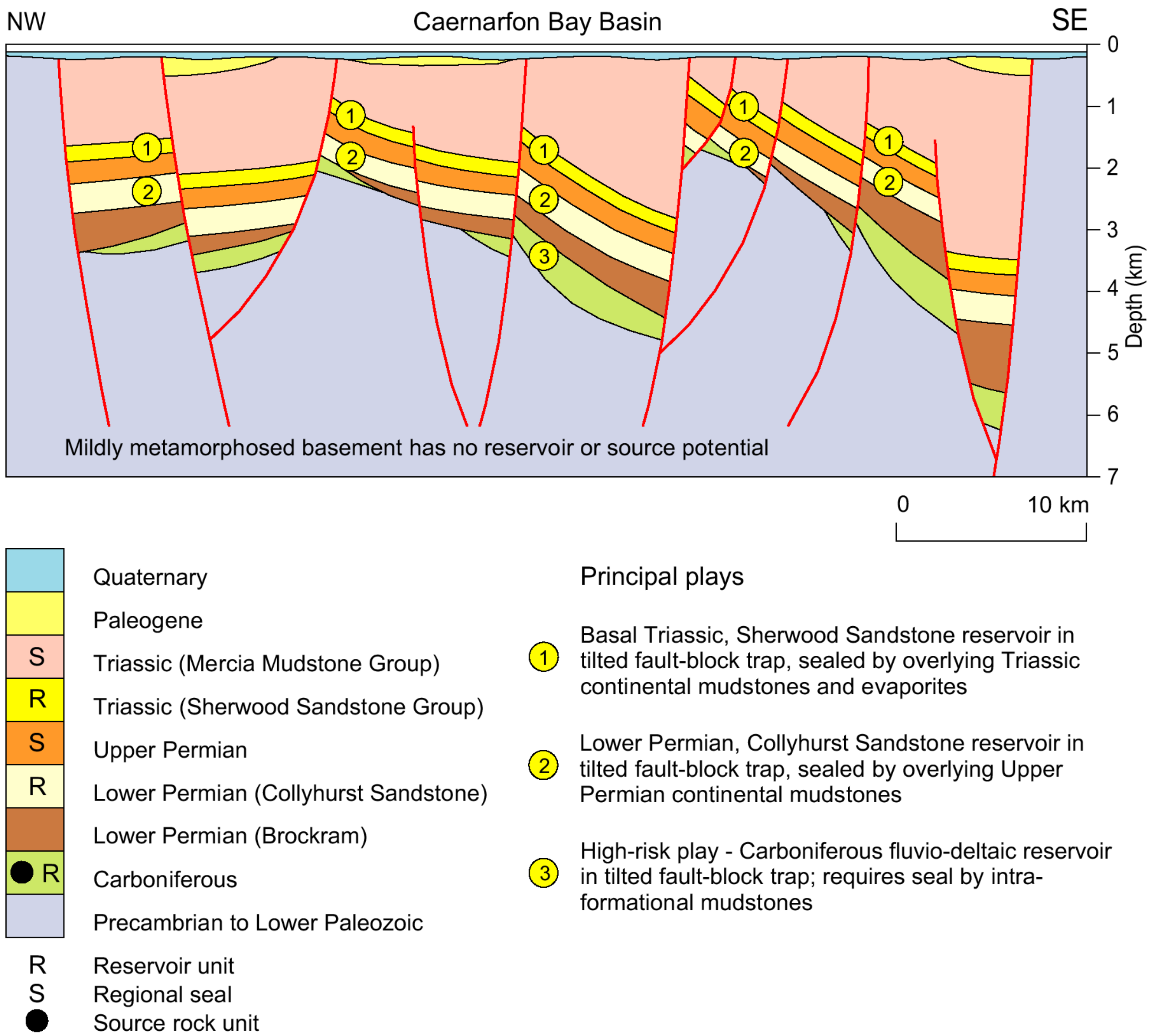

Fig. 13   Schematic play diagram for Caernarfon Bay Basin, Irish Sea.

The Cardigan Bay Basin forms a continuation of Ireland's North Celtic Sea Basin (Fig. 1), which has two producing gas fields, into UK waters. Describing a south-easterly deepening half-graben near the Welsh coastline, its internal structure becomes increasingly complex towards the south-west. Its Permian to Triassic, syn-rift sediments are less than 3 km thick, but they are overlain by up to 4 km of Jurassic strata, and locally also by up to 2 km of Paleogene fluvio-deltaic sediments. The basin has a proven petroleum system, with potentially producible gas reserves at the Dragon discovery near the UK/Eire median line (Fig. 12), and oil shows in a further three wells.

The Cardigan Bay Basin contains multiple reservoir targets (Fig. 14), that include the Lower Triassic, Sherwood Sandstone, Middle Jurassic shallow-marine sandstones and limestone (Great Oolite), and Upper Jurassic fluvial sandstone, the reservoir for the Dragon discovery. The most likely hydrocarbon source rocks are early Jurassic marine mudstones (Lias Group). These are fully mature for oil generation in the west of the UK sector, and are mature for gas generation nearby in the Irish sector. Gas-prone, Westphalian pre-rift coal measures may also be present at depth locally. The Cardigan Bay Basin was subjected to two Tertiary phases of compressive uplift, whereas maximum burial that terminated primary hydrocarbon generation was probably around the end of the Cretaceous, or earlier if Cretaceous strata, now missing, were never deposited in the basin. Despite its Tertiary structuration, the Dragon discovery has proved that potentially commercial volumes of hydrocarbons were retained at least locally in Cardigan Bay. In addition to undrilled structural traps, the basin contains untested potential for stratigraphic entrapment of hydrocarbons near synsedimentary faults, especially in the Middle Jurassic section.

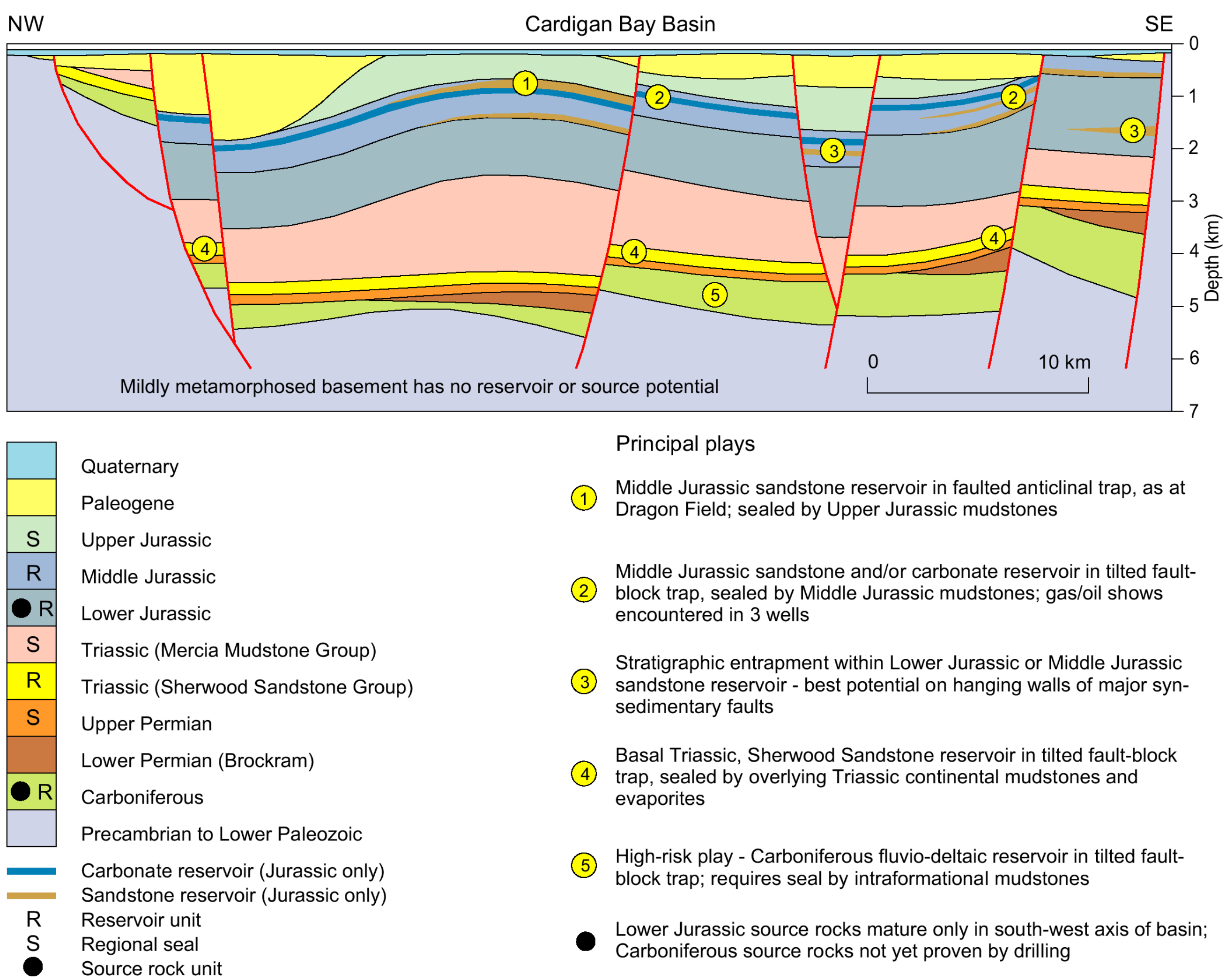

Fig. 14 Schematic play diagram for Cardigan Bay Basin, Irish Sea.

Atlantic Margin

UK designated waters north-west of Britain lie on the north-east Atlantic Margin. They include the Faroe-Shetland Basin, with parts of the relatively unexplored Rockall Trough, Hatton Basin and Hatton Continental

Margin (Fig. 15). Water depths in these areas locally exceed 2 km. Theoretically, this province may contain a large gas hydrate resource, but exploitation of this resource is unlikely in the first decades of the 21st century. The Faroe-Shetland Basin has been the main focus of conventional hydrocarbon exploration along the Atlantic Margin to date.

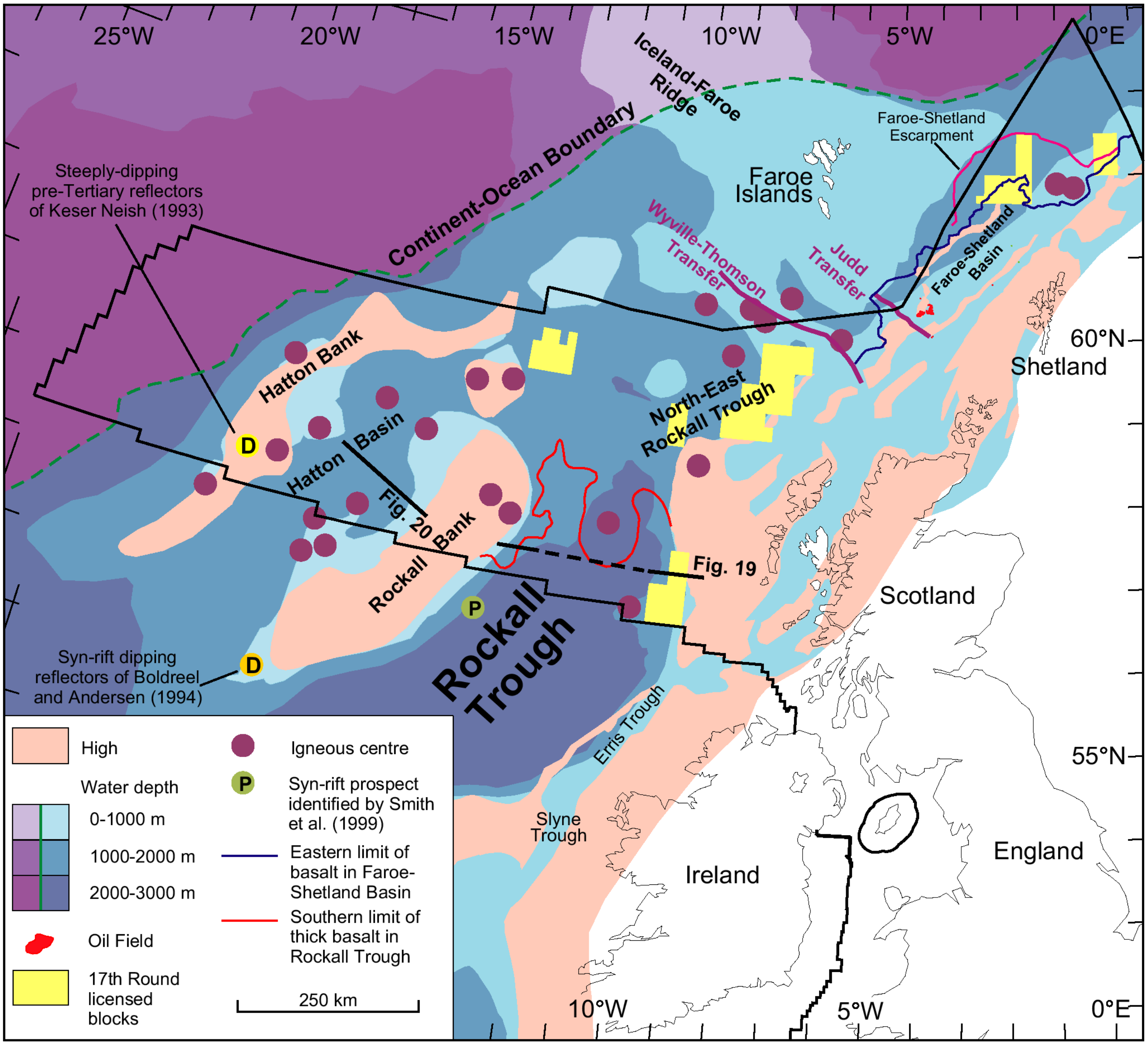

Fig. 15 Location of the hydrocarbon-producing basins and frontier basins of the Atlantic Margin.

The opening of the North Atlantic between Greenland and north-west Europe was accompanied by Paleogene basaltic shield volcanism across an area some 2000 km in diameter. The igneous activity is generally believed to have resulted from the development of the Iceland mantle plume shortly before continental break-up (White, 1989). Present across much of the Atlantic Margin acreage, lavas and sills within the section severely attenuate and disperse the seismic signal, degrading the seismic response at depth. This has significantly hindered our understanding of the pre-Tertiary geological history of the region, and considerable effort is being expended into developing a means of detailed sub-basalt imaging. Seismic refraction profiles and wide-angle seismic reflection data have both been collected to enable models to be constructed for the crustal structure along the Atlantic Margin (e.g. Joppen and White, 1990; Keser Neish, 1993; Shannon *et al.,* 1994). Recent developments in seismic techniques are enabling more refined sub-basalt imaging (e.g. Richardson *et al.,* 1999, White *et al.,* 1999).

As in the Oil Province of the North Sea, play fairways along the Atlantic Margin fall into Upper Paleozoic to Middle Jurassic pre-rift, Upper Jurassic to Lower Cretaceous syn-rift, and Upper Cretaceous to Tertiary post-rift categories (Pegrum and Spencer, 1990; Knott *et al.,* 1993). Tertiary inversion structures are regionally widespread (*e.g.* Doré *et al.,* 1997), presenting multiple opportunities for structural entrapment. Late Jurassic, organic-rich basinal-marine mudstones (Kimmeridge Clay) are the principal oil-prone source rocks in the Faroe-Shetland Basin, but they have not been proven yet in the Rockall Trough and adjacent Rockall Plateau. Scotchman and Broks (1999) have shown that rich oil-prone early Jurassic and Middle Jurassic source rocks also occur in the Atlantic Margin province, and that oil in the Foinaven and Schiehallion fields (Fig. 16) can be correlated to these sources. A viable petroleum system has yet to be established in the Rockall Trough and adjacent Rockall Plateau. These areas contain the last truly frontier acreage in the UK designated waters.

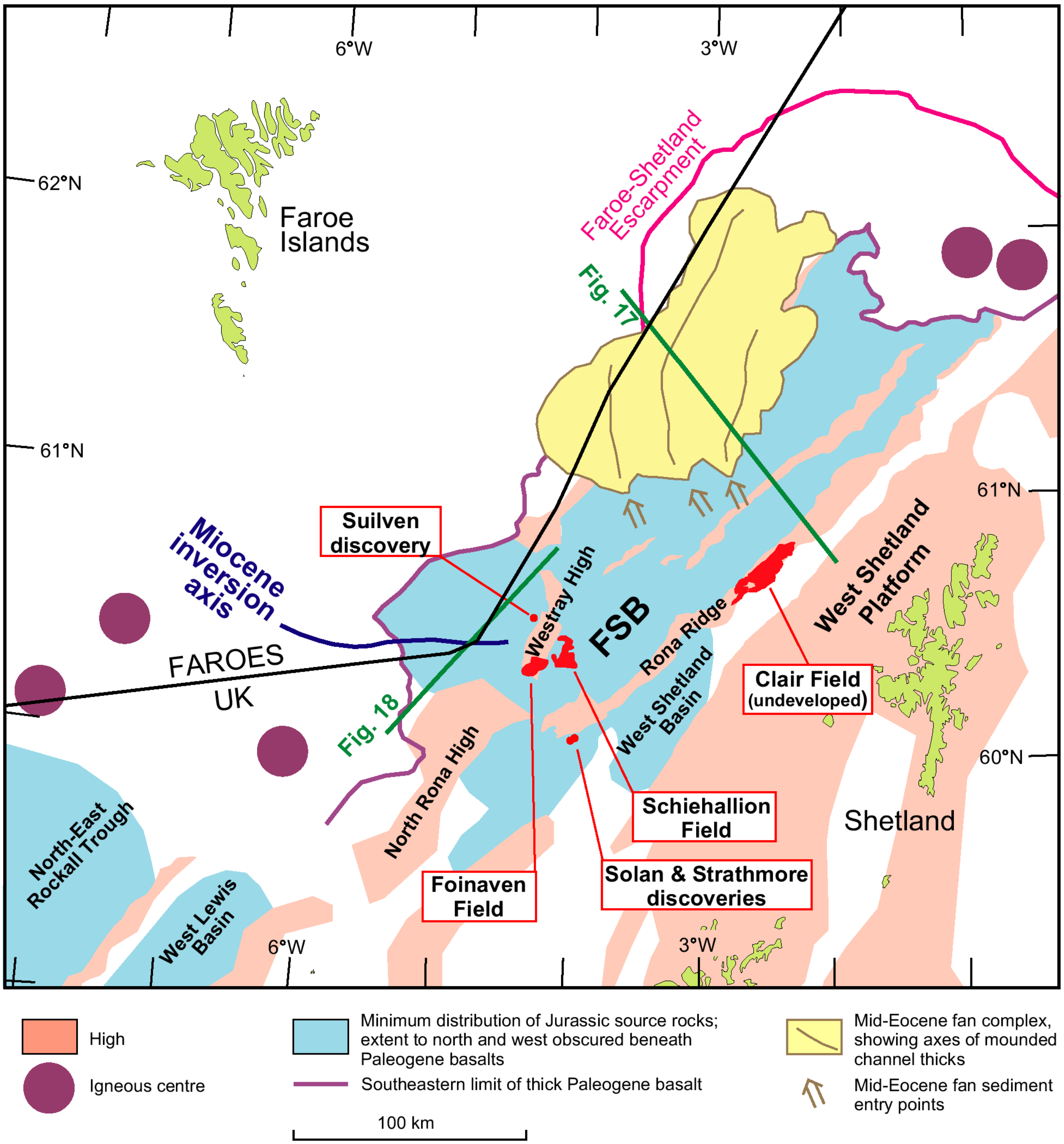

Fig. 16 Location of mid-Eocene fan complex, Faroe-Shetland Basin (FSB).

Faroe-Shetland Basin

Although oil was found on the eastern flank of the Faroe-Shetland Basin as early as 1974, it was not until 1992 that economically viable reserves were discovered in the Foinaven Field (Fig. 16). Recoverable oil reserves in this and the adjacent Schiehallion Field are estimated at 34.4 and 79.87 million tonnes (252 and 586 million barrels) respectively (DTI, 1999). Both of these fields are utilizing floating production systems with offshore loading, as there is no existing infrastructure in the region. Much greater volumes of oil have been proved in the Clair Field (Fig. 16), the largest oilfield offshore of north-west Europe. Mainly because of its very low recovery factor of 7%, the field has not proceeded to full-scale production as yet (Brennand *et al.*, 1998).

Much of the acreage along the axis and in the east of the Faroe-Shetland Basin is currently licensed, although some of this is due for statutory relinquishment in 2000. In the west of the basin, the recent (1999) agreement on a median line between the UK and the Faroes will provide a major stimulus to exploration, because of proximity of the newly designated acreage to proven hydrocarbon systems at the Foinaven and Schiehallion Fields. Paleocene and Eocene basin-floor fan reservoirs are the principal targets within the newly designated area. Pre-rift and syn-rift plays are also likely to be present here (Fig. 17), and are relatively shallow, but individual prospects are currently difficult to image. This is because the Upper Cretaceous to Lower Paleocene section along the north-western flank of the Faroe-Shetland Basin is extensively intruded by Paleogene sills which hamper seismic interpretation. Furthermore, Paleogene basalts are also present in parts of this area (Fig. 16). Where they occur, wide-angle seismic data suggest that the thickness of sub-basalt sediments varies between 1.25 – 3.75 km, with the greatest thickness in the north (Richardson *et al.* 1999).

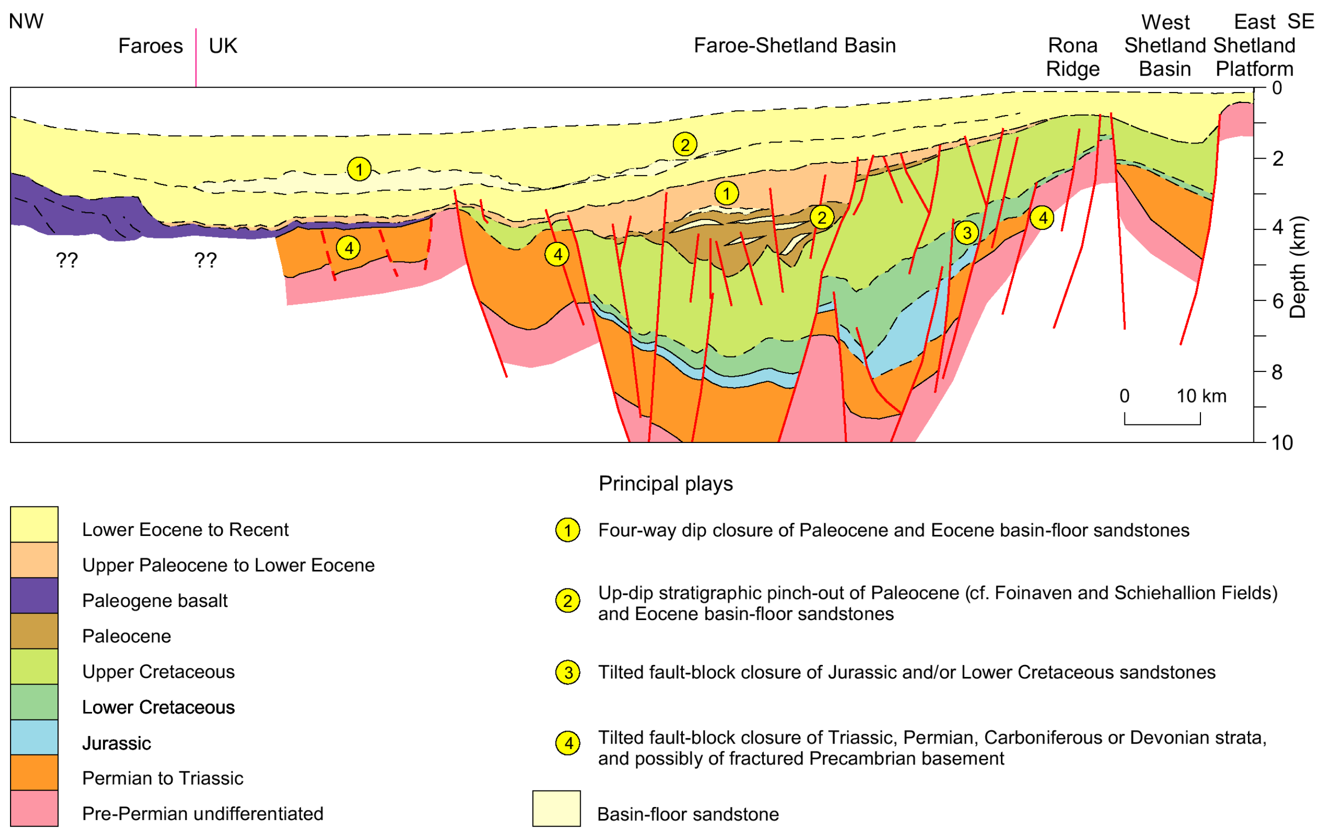

Fig. 17 Schematic play diagram for the Faroe-Shetland Basin.

Pre-rift strata are too deeply buried to be prospective along the axis of the Faroe-Shetland Basin. The Clair Field sits on the Rona Ridge which forms the eastern margin of the basin (Fig. 16), and its oil reservoir is provided by fractured Precambrian to Devono-Carboniferous rocks. Oil and gas/condensate shows have been recorded in other wells along this ridge, and also on the North Rona High (Fig. 16) that forms the southern margin of the basin. Middle Jurassic sandstones preserved on a fault terrace flanking the Rona Ridge have yielded oil and gas shows. South-east of the Faroe-Shetland Basin, the Solan/Strathmore discovery (Fig. 16) contains oil in overlapping Jurassic and Triassic reservoirs within the contiguous West Shetland Basin. Pre-rift prospects in both basins are topsealed by Upper Jurassic, Cretaceous or Paleocene mudstones

Syn-rift plays are relatively lightly explored, though at least twelve wells have encountered oil or gas shows in Upper Jurassic or Lower Cretaceous sandstones within or bordering the Faroe-Shetland Basin. Two currently uneconomic gas discoveries on the eastern margin of the basin have Lower Cretaceous, syn-rift apron fan and basin-floor sandstone as their reservoirs. Underlying Upper Jurassic sandstones are encased in Kimmeridge Clay source rocks to provide drilling targets in combined structural/stratigraphic traps. In the south-west, Lower Cretaceous shallow-marine sandstones penetrated on the Westray High constitute a syn-rift retrogradational shelf play (Fig. 17), although in well 204/19-1 they are overlain by deep-water sandstone facies (Ritchie *et al.,* 1996) and may thus locally lack a topseal. Along the axis of the Faroe-Shetland Basin, depth of burial is a prohibitive factor for syn-rift plays. Upper Cretaceous mudstones locally exceed 3800 m in thickness to provide an excellent topseal throughout the region.

Post-rift, Upper Cretaceous slope-apron sandstones, of Cenomanian to Turonian age, are locally up to 327 m thick along the eastern flank of the Faroe-Shetland Basin, where they are stacked against the Rona Fault. Oil shows have been recorded from these sandstones, though doubts remain about the seal integrity of their boundary fault. Grant (*et al.,* 1999) speculated that if there are detached fan complexes down-dip, these may offer more attractive drilling targets.

The discovery of oil in the Foinaven Field has completely revitalized the post-rift, Paleocene fan play in the region. This discovery has been followed up by the nearby Schiehallion Field and Suilven discoveries (Fig. 16). However, the play is quite subtle, requiring accurate definition of stratigraphic pinchout by 3D mapping, in combination with structural closure in a zone of monoclinal basinward dip. The occurrence of an intraformational mudstone seal is also critical; those mudstones associated with regional flooding surfaces have proved to be the most effective. The Paleocene interval reaches a maximum thickness of almost 3.5 km, and it contains excellent quality sandstone reservoirs within basin-floor fan, slope fan and shelfal facies. Porosities in excess of 25% and permeabilities of greater than 100 mD can be anticipated where the sandstones are buried less than 2.5 km below sea bed (Ebdon *et al.,* 1995). Equivalent reservoirs that occur at greater depth in the north of the Faroe-Shetland Basin are of much lower quality (Johnson and Fisher, 1998), and have yielded only gas shows. Ebdon *et al.* (1995) recognized eight seismically-resolvable sequences within the Paleocene, whereas Mitchell *et al.* (1993) identified nine sequences within the same interval. The relationship between these two interpretations is complicated, because Ebdon *et al.* (1995) used maximum flooding surfaces to divide their sequences, while Mitchell *et al.* (1993) based their work on identifying Type 1 unconformities (*cf.* Mitchum, 1977). Both authors have mapped distinct shelf, slope and basinal systems, and compiled generalized depositional environment maps for each sequence. Their approach is a vital step towards identifying potential stratigraphic targets. Mapping of seismic attributes and AVO analyses have played a critical role in current discoveries, but have yet to be applied on a regional scale.

There is a particularly high potential for success in Paleocene prospects near the Foinaven Field, within the newly designated acreage adjacent to the UK/Faroes median line. The crest of a major E-W trending Oligocene-Miocene inversion axis traces across this area, and numerous stacked potential reservoir targets can be anticipated in four-way dip closures (Fig. 18). As in much of the Faroe-Shetland Basin, aggradational basin floor sandstones characterize the lower part of the Paleocene here, and are likely to be sealed by both lowstand and highstand mudstones. Overlying Upper Paleocene to Lower Eocene sandstones include a greater proportion of shelfal and deltaic deposits, with a potentially higher risk of imperfect seals. Vertical and lateral migration vector determination is of key importance in this area due to local overpressuring, and a complex basin evolution (Illiffe *et al.,* 1999).

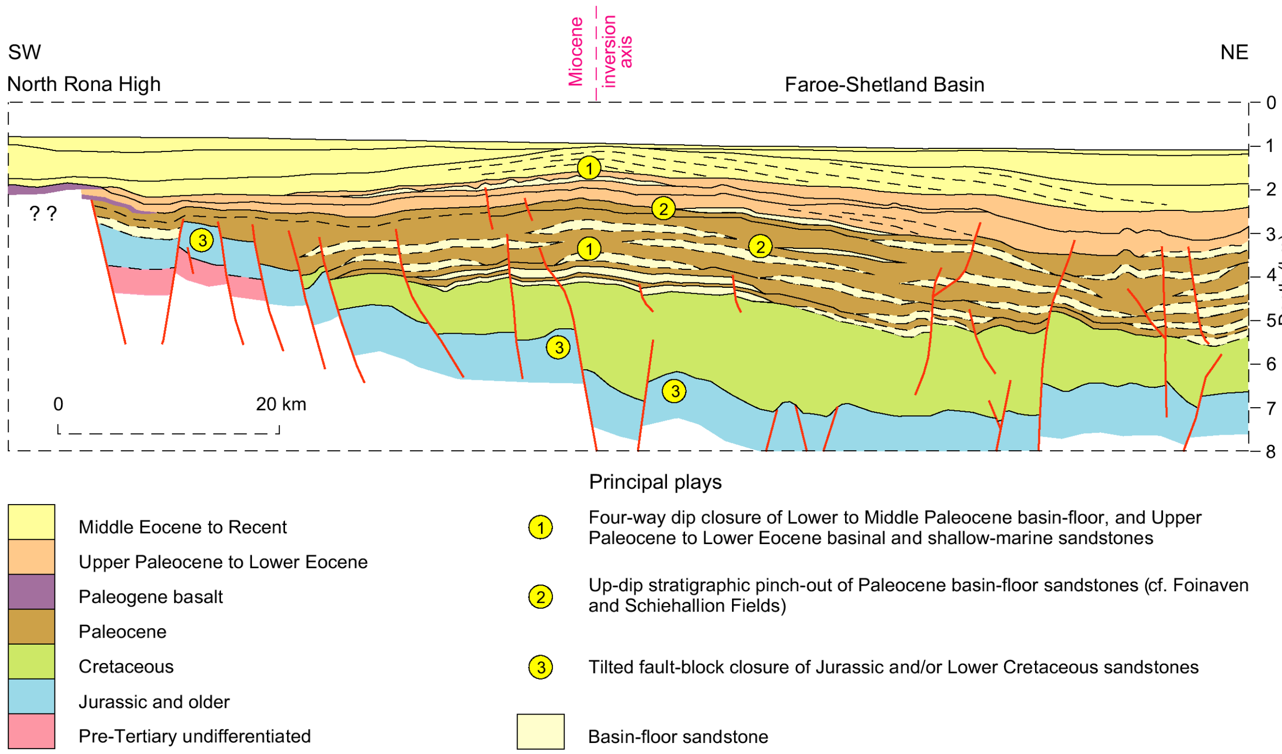

Fig. 18 Schematic play diagram for newly designated acreage in the Faroe-Shetland Basin.

Overlapping, linear basin floors fans of probable mid-Eocene age trace across the north-western part of the Faroe-Shetland Basin, and extend into the Faroes sector (Fig. 16). Three principal submarine canyon entry points have been identified on the margin of the broadly NE-SW trending paleo-shelf, and the fan deposits appear to have flowed across the basin floor in a northerly to north-easterly direction. The fan complex is more than 100 km long and over 50 km wide, and it attains a maximum thickness of 550 m. Internal geometry of the fans is complex, with zones of high-amplitude, layered seismic facies bordered and underlain, sometimes erosively, by relatively high-amplitude chaotic reflections. The principal exploration risks for this play include a risk of biodegradation due to the shallow depth of burial (*ca.* 1,000 m below sea bed) of the basin floor fans, and uncertainty as to the validity of migration routes through the underlying Paleocene section.

Rockall Trough

More than 80% of the Rockall Trough has never been licensed for hydrocarbon exploration, although numerous tranches of blocks were awarded in the 1997 UK 17th Round of Offshore Licensing (Fig. 15). A considerable quantity of new 2D and 3D seismic data has been acquired, but only one well has been drilled on the 17th Round acreage to date. Results from this well will not be released into the public domain until 2003. Of two older wells drilled in the area, one terminated within a thick Paleocene volcanic interval, and the other drilled a Lower Cretaceous syn-rift section on the south-eastern margin of the Rockall Trough (Musgrove and Mitchener, 1996). Three wells were drilled between 1988-1991 on the eastern-flanking basement horst, and within an adjacent Triassic/Jurassic rift basin on the Hebridean Platform (Fig. 15).

The Rockall Trough is a failed rift formed during the opening of the North Atlantic. Some authors (*e.g.* Tate *et al.,* 1999) suggest it may be separated from the Faroe-Shetland Basin by the Wyville-Thomson Transfer Zone, although Doré *et al.* (1997) argued that the Judd Transfer farther north (Fig. 15) is the more likely boundary. Numerous WNW-ESE to NW-SE oriented lineaments traverse the Rockall Trough and offset its eastern margin, and these have been linked to boundaries of pre-Caledonian basement terranes (*e.g.* Musgrove and Mitchener, 1996). The initiation of rifting in the Trough has been variously ascribed to late Carboniferous, Permian, Triassic, Jurassic or Cretaceous (*e.g.* Smythe, 1989, Knott *et al.,* 1993, Musgrove and Mitchener, 1996).

Critically, if the Rockall Trough was not initiated until Cretaceous times, then there is no potential for Jurassic source rocks, and Cretaceous to Tertiary organic-rich basinal marine mudstones are required to be mature for a working petroleum system. If instead, a proto-Rockall Trough developed as a contiguous late Jurassic to early Cretaceous rift with the Faroe-Shetland Basin, there may be Jurassic source rocks within one or more pre-Cretacecous basins beneath the Rockall Trough, but these basins must be of limited extent and connectivity. This is because all paleomagnetic reconstructions for the Atlantic Margin indicate that the pre-Cretaceous seaway was very narrow in the Rockall area (Ziegler, 1988; Knott *et al.*, 1993; Doré *et al.,* 1999). An alternative model presented by Brown and Beach (1999) provides some scope for significant Jurassic deposition in the region under a transtensional regime. Cole and Peachey (1999) and Nadin *et al.* (1999) have each modelled the crustal evolution of the Rockall Trough area, and concluded that an earlier pre-Cretaceous rift basin is located beneath the present-day Rockall Trough.

The western margin of the Rockall Trough comprises a series of tilted fault blocks throwing down to the east (Joppen and White, 1990), but the nature of the eastern margin is contentious because it is masked by the early Paleogene volcanics of the Hebridean Escarpment. According to Musgrove and Mitchener (1996), the syn-rift succession in the trough has a westerly-thickening geometry, thus implying asymmetric rifting accommodated through a series of easterly-dipping faults across the entire trough. The deep seismic reflection profile WESTLINE provides evidence for such easterly-facing syn-rift faults on the eastern margin of the Trough (England and Hobbs, 1997).

Hydrocarbon exploration of the Rockall Trough is driven to a considerable extent by the recognition that Upper Paleozoic and Mesozoic sections with source rocks occur in adjacent, parallel half-graben basins, such as the West Lewis Basin and Erris/Slyne Trough (Fig. 15). British Geological Survey boreholes on the flanks of the West Lewis Basin have proved organic-rich Middle Jurassic mudstones with excellent oil-prone source potential there (Hitchen and Stoker, 1993). Rich, oil-prone Lower Jurassic source rocks have been proved in the Slyne Trough (Scotchman and Thomas, 1995). The recent Corrib gas discovery in Irish waters proves that Carboniferous coal measures also have source potential in the Slyne Trough region (Spencer and McTiernan, 1999). This discovery increases the possibility that Carboniferous source rocks occur beneath parts of the Rockall Trough too.

Figure 19 shows a range of possible exploration plays in the Rockall Trough. Lower Cretaceous syn-rift and Paleocene-Eocene post-rift plays are generally thought to offer the best potential for significant quantities of undiscovered hydrocarbons. The potential for pre-rift Carboniferous to Jurassic plays is highly speculative, and such plays may be of severely limited distribution within the Rockall Trough. The south-eastern part of UK designated waters may contain Westphalian, Permo-Triassic and Middle-Upper Jurassic pre-rift plays, as well as Paleocene-Eocene plays similar to those described by Nolan *et al.* (1999) from across the median line in the Irish sector. In that area, the upper part of the pre-Cretaceous section is modelled as being within the mid to late oil window at the present day.

The south-west of UK designated waters has potential for prospects in large pre-rift tilted fault blocks, similar to that described by Smith *et al.* (1999) from the Irish sector nearby. The age and nature of the reservoir, source and seal rocks for such prospects remain entirely speculative. However, if the geological history bears comparison with the Slyne and Erris troughs to the south-east, then Triassic to Middle Jurassic reservoirs can be anticipated, with a Jurassic, or possibly Carboniferous source. There may also be potential for syn-rift prospects in Lower Cretaceous basin-floor sandstones here. This play requires that significant volumes of coarse clastic debris were shed into this part of the Rockall Trough during contemporary footwall uplift and erosion of Rockall Bank.

The distribution of Paleocene basin-floor sandstones within the Rockall Trough is poorly known. Knott *et al.* (1993) speculated that such sandstones are confined to the north-eastern corner of the Rockall Trough, and that contemporary retrogradational shelf deposits occur locally along its south-eastern margin. These authors also predicted Eocene basin-floor sandstones along the eastern margin of the Rockall Trough, bordered to the east by a wide belt of shelf deposits. Both Paleocene and Lower Eocene slump masses and basin-floor mounds have been observed on seismic profiles from the south-eastern and western margins of the Rockall Trough, and these are presumed to be sealed by basinal mudstones.

Rockall Plateau: Hatton Basin and Hatton Continental Margin

The Hatton Basin is a NE-SW trending, intra-continental basin situated within the Rockall Plateau, on the westernmost part of the UK designated area. Bounded to the west and east by Hatton Bank and Rockall Bank respectively, water depths across the basin are mostly between 1000 and 1300 metres (Fig. 15). Seismic data coverage across the Rockall Plateau remains very sparse, and much of the data was acquired during the 1970s. Accordingly, the geological history of the basin remains speculative. Recent paleogeographic reconstructions (*e.g.* Doré *et al.,* 1999) suggest that the Hatton Basin was possibly initiated during the Cretaceous. However, studies of wide-angle seismic data suggest that a Carboniferous-Jurassic layer up to 3 km thick underlies the basin nearby in the Irish sector (Jacob *et al*., 1995; Shannon *et al*., 1995). Two opposing syn-rift half-graben have been modelled there, separated by an intra-basinal high. Seismic profiles show a mounded slope-apron interval bordering the volcanic escarpment on the western margin of the basin (Fig. 19). By analogy with the Faroe-Shetland Escarpment to the north-east, this interval can be interpreted as late Paleocene to early Eocene in age.

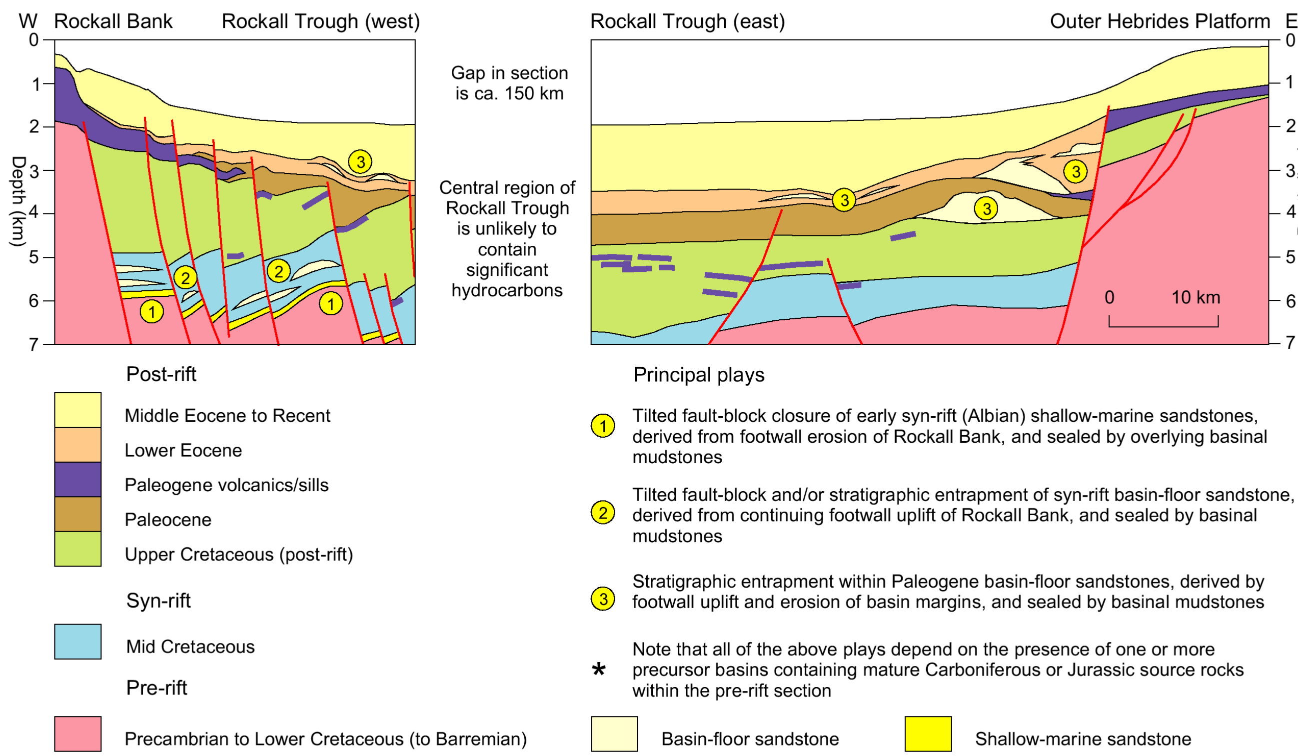

Fig. 19 Schematic play diagram for the Rockall Trough.

On those parts of the Hatton Bank where Paleogene volcanic rocks are thin or absent, a series of steeply-dipping, tilted fault blocks has been imaged on seismic profiles (Keser Neish, 1993). These structures may continue westwards to underlie the Hatton Continental margin. Similar steeply-dipping reflector packages have been identified in the Irish sector, from the south-eastern part of the Hatton Basin (Boldreel and Andersen, 1994). The age of these pre-Tertiary dipping strata remains open to speculation. Prograding Eocene strata penetrated by a British Geological Survey shallow borehole on the eastern flank of Rockall Bank contain

Carboniferous and Jurassic/Cretaceous palynomorphs that may have derived by reworking from Upper Paleozoic and Mesozoic rocks within the Rockall Plateau area (Stoker and Hitchen, pers. comm.).

The Hatton Continental Margin is the westernmost sedimentary basin within UK designated waters, lying adjacent to the Continent-Ocean Boundary (Fig. 15). Shannon *et al*. (1995) modelled the basin as comprising 0.5 km to 1.3 km of heavily intruded Cretaceous sediments. O'Reilly and Readman (1999) suggested that a Triassic to Jurassic age is also plausible for these sediments. The basin is unconformably overlain by a thin post-rift Eocene to Recent succession.

Pre-rift and syn-rift plays remain highly speculative across the Hatton Basin to Hatton Continental Margin area. If underlain by Carboniferous-Jurassic strata, the Hatton Basin has arguably the best potential for source rocks, and the presence of tilted fault blocks along its margins may provide opportunities for structural closure (Fig. 20). However, Cretaceous post-rift mudstones are either thin or absent, reducing the potential for effective topseal in this play. Tertiary slope-apron and basin-floor fans are likely to be present in the Hatton Basin, but their derivation from a hinterland dominated by volcanic rocks may reduce their reservoir potential.

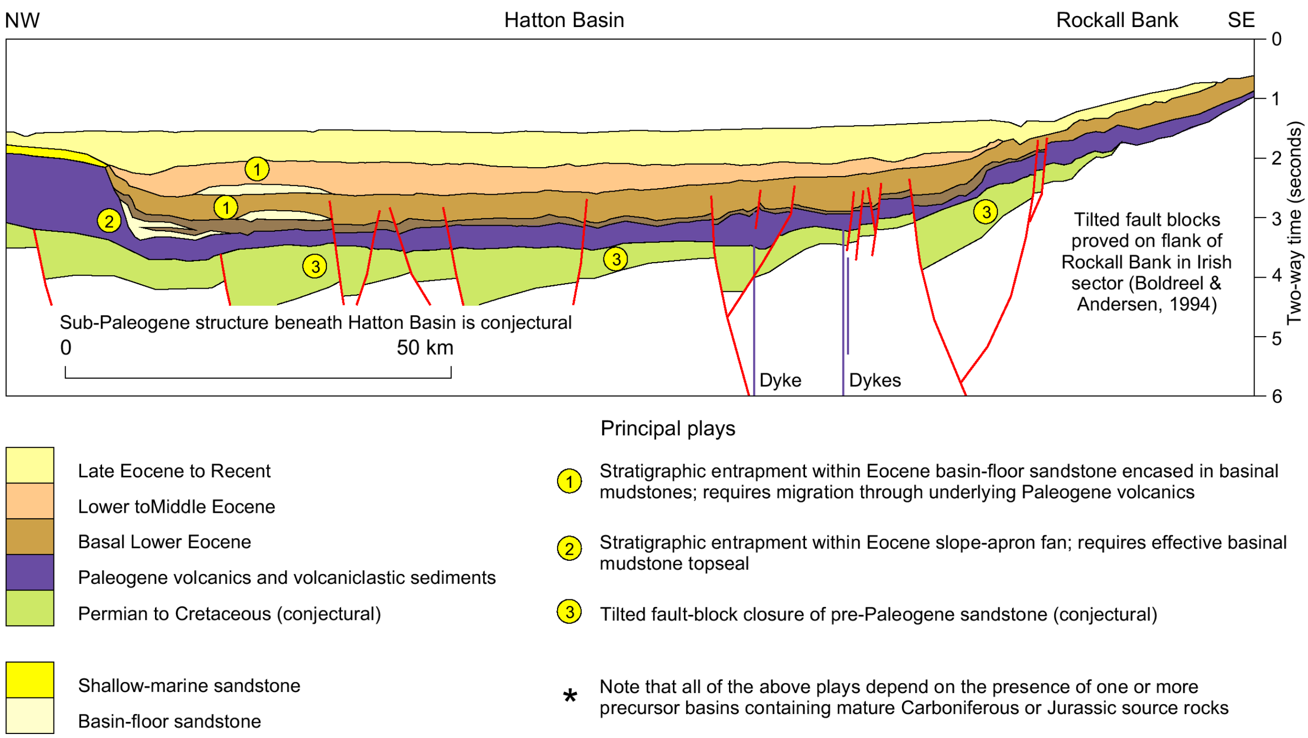

Fig. 20 Schematic play diagram for the Hatton Basin.

SUMMARY OF OPPORTUNITIES AND CHALLENGES

The UK and its designated waters contain a plethora of mature, lightly explored, and frontier sedimentary basins. Historical predictions of oil and gas production have consistently underestimated the long-term resource base in the UK (Fig. 21). Partly this is because recovery factors in producing fields are continually improving, and partly it reflects an increase in the geographic range of production. However, the most significant additions to the resource base have been from the mature producing basins. This paper has demonstrated that the UK's resource base will continue to increase, by locating further reserves in these basins, and potentially by extending production into the frontier basins of the Atlantic Margin.

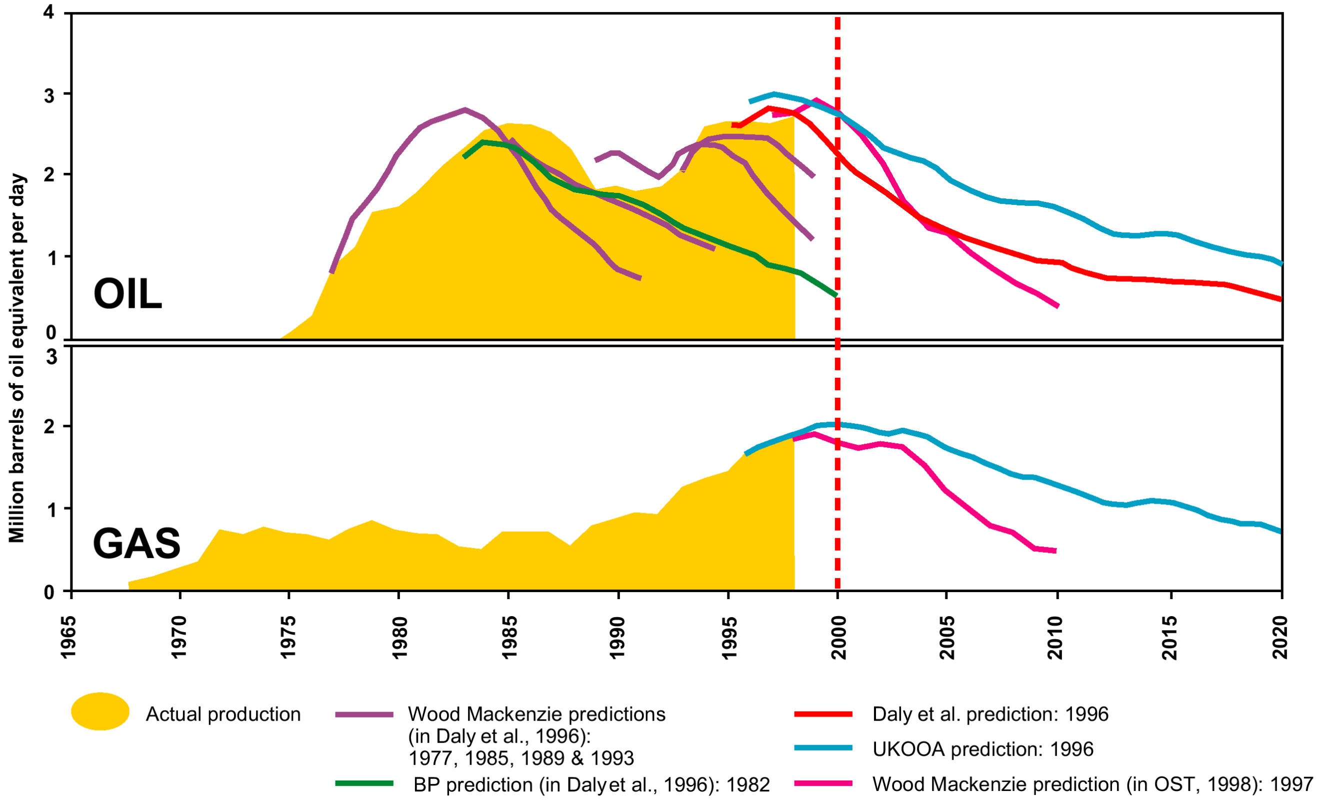

Fig. 21 Past prediction and future potential of UK oil and gas production (all predictions are optimum case).

It is now believed that sufficient proven and undiscovered reserves remain in the mature basins of the North Sea and onshore in England to maintain the UK's position as a leading hydrocarbon producing nation into the early decades of the 21st century. Specifically, the Oil and Gas Industry Task Force predict that, by minimizing discovery costs, UK production can be maintained at above 3 million barrels of oil equivalent per day up to the year 2010, partly by making an additional 5.6 million barrels of discovered oil economic to recover. Initiatives that are being introduced to achieve this, and to reduce the burdens on industry, include a commitment to have one onshore and one offshore licensing round per year, with all open acreage available every two years, and a relaxation on work commitments on current licences.

The Task Force predicts that over two thirds of the UK's undiscovered oil and gas reserves lie within 50 km of existing infrastructure, which provides a window of opportunity for development of marginally economic reserves. In the North Sea Oil Province, the majority of these reserves are likely to be found in syn-rift, Upper Jurassic to Lower Cretaceous shallow-marine and basin-floor sandstone plays, and in post-rift, Paleogene basin-floor sandstone reservoirs. However, a significant component of discoveries will continue to be made from pre-rift, Paleozoic, Triassic to Lower Jurassic, and Middle Jurassic plays. In the North Sea Gas Province, the greatest exploration challenge will be to increase the proportion of production from Carboniferous reservoirs. This will be achieved by extending the geographic range of existing discoveries, by targeting subcrop of proven reservoirs beneath the regional base Permian unconformity, and by testing hanging-wall wedges of these strata adjacent to the major intra-Carboniferous faults.

Nevertheless, it is the frontier basins of the Atlantic Margin that may have the greatest potential to replace existing UK hydrocarbon production by the discovery of major new oil and gas fields. The last decade of the 20th century has seen the Faroe-Shetland Basin established as an oil-producing province, and opportunities remain for further discoveries of oil, both in the established Paleogene basin-floor sandstone play, and in syn-rift and pre-rift plays along the margins of the basin. The 1990s have also seen the discovery of potentially economic gas reserves in the Faroe-Shetland Basin. A realistic target for the first decade of the 21st century will be to discover sufficient additional reserves of gas here to encourage construction of a new gas-gathering infrastructure for the region.

The greatest remaining challenge in the Atlantic Margin, however, will be to establish a viable petroleum system for the Rockall Trough, and perhaps also for the Hatton Basin and Hatton Continental Margin. Initial exploration of these basins has led to the discovery of potentially attractive tilted fault-block plays. Viable source rocks remain to be proven, although their presence in contiguous basins to the north and south gives grounds for optimism. If economic reserves were to be discovered here, they have the potential to maintain the UK's position as a net exporter of hydrocarbons beyond the first decade of the 21st century.

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