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Kimmeridgian Shales Total Petroleum System of the North Sea Graben Province

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U.S. Department of the Interior
U.S. Geological Survey

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Conversion Factors, Datums, and Other Abbreviations

Multiply	By	To obtain
square kilometer (km^2)	0.3861	square mile
meter (m)	3.281	foot

Datum

Vertical coordinate information is referenced to the North American Vertical Datum of 1988 (NAVD88).

Other abbreviations

AU	Assessment Unit
BBO	Billion barrels of oil
BCF	Billion cubic feet
BTU	British thermal unit
TCF	Trillion cubic feet
TOC	Total organic carbon
TPS	Total Petroleum System
U.K.	United Kingdom
USGS	U.S. Geological Survey
‰	Parts per thousand

Kimmeridgian Shales Total Petroleum System of the North Sea Graben Province

By Donald L. Gautier

Abstract

The North Sea Graben of northwestern Europe, World Energy Project Province 4025, is entirely offshore within the territorial waters of Denmark, Germany, the Netherlands, Norway, and the United Kingdom. Extensional tectonics and failed rifting are fundamental to the distribution of oil and gas in the province. Accordingly, the geologic history and reservoir rocks of the province are considered in the context of their temporal relationship to the principal extension and rifting events. The oil and gas accumulations of the province are considered part of a single petroleum system: the Kimmeridgian Shales Total Petroleum System (TPS). Source rocks of the Kimmeridgian Shales TPS were deposited in Late Jurassic to earliest Cretaceous time during the period of intensive extension and rifting. The Kimmeridgian Shales contain typical “type II” mixed kerogen. Oil and gas generation began locally in the North Sea Graben Province by Cretaceous time and has continued in various places ever since.

Reservoirs are found in strata with ages ranging from Devonian to Eocene. Pre-rift reservoirs are found in fault-block structures activated during rifting and can be of any age prior to the Late Jurassic. Syn-rift reservoirs are restricted to strata actually deposited during maximum extension and include rocks of Late Jurassic to earliest Cretaceous age. Post-rift reservoirs formed after rifting and range in age from Early Cretaceous to Eocene. Seals are diverse, depending upon the structural setting and reservoir age. Pre-rift reservoirs commonly have seals formed by fine-grained, post-rift sedimentary sequences that drape the Late Jurassic to earliest Cretaceous structures. Contemporaneous shales such as the Kimmeridge Clay seal many syn-rift reservoirs. Fields with post-rift reservoirs generally require seals in fine-grained Tertiary rocks. In most of the North Sea Graben, source rocks have been continuously buried since deposition. Structural trap formation has also taken place continuously since Mesozoic time. As a result, oil and gas are present in a wide variety of settings within Province 4025.

Assessment units for the World Energy Project were defined geographically in order to capture regional differences in exploration history, geography, and geological evolution. Three geographic areas were assessed. The Viking Graben, in the northern part of the province, includes both United Kingdom and Norwegian territorial areas. The Moray Firth/Witch Ground in the west-central part of the province is entirely in United Kingdom. waters. The Central Graben in the southern part of the province includes territorial areas of Denmark, Germany, the Netherlands, Norway, and the United Kingdom. The North Sea Graben is estimated to contain between 4.3 and 25.6 billion barrels (BBO) of undiscovered, conventionally recoverable oil. Of that total, the Viking Graben is believed to contain 2.2 to 14.8 BBO of undiscovered oil, the Moray Firth/Witch Ground may contain between 0.3 and 1.9 BBO, and the Central Graben was estimated to contain undiscovered oil resources of 1.7 to 8.8 BBO. Province 4025 was also estimated to hold between 11.8 and 75 trillion cubic feet (TCF) of undiscovered natural gas. Of this total, 6.8 to 44.5 TCF is thought to exist in the Viking Graben, 0.6 to 3.4 TCF is estimated to be in the Moray Firth/Witch Ground, and 4.5 to 27.1 TCF of undiscovered gas is estimated to be in the Central Graben.

Introduction

The U.S. Geological Survey (USGS), for the purposes of conducting its assessment of global oil and gas resources (U.S. Geological Survey World Energy Assessment Team, 2000), has divided the world into 8 regions and 937 provinces, exclusive of the United States. These provinces were ranked according to their discovered petroleum volumes, which are the sum of total cumulative oil and gas production and proved reserves. From this ranked list, the 76 highest ranking provinces were initially selected for assessment. In addition, another 26 “boutique” provinces were selected for assessment on the basis of their regional significance or possible future discoveries of petroleum (Klett and others, 1997).

The North Sea Graben Province of northwestern Europe, the subject of this report, is USGS World Energy Project province number 4025 and is ranked number 8 among the 76 world priority provinces in terms of volumes of discovered oil and gas. The Anglo-Dutch Basin and Northwest German Basin Provinces adjoin the North Sea Graben Province on the south and southeast. Taken together, these three provinces account for the vast majority of oil and gas resources in Western Europe. The location and boundaries of the North Sea Graben Province are shown in figure 1.

In contrast to the adjacent gas-prone Anglo-Dutch and Northwest German Basin Provinces, the North Sea Graben Province is distinctly oil prone. Statfjord, the largest field in Western Europe in terms of recoverable oil, is located in the northern part of the province on the boundary between the Norwegian and United Kingdom sectors of the North Sea (fig. 2). As of 1996, Statfjord was reported to have ultimately recoverable resources of 569.5 million m^3 of oil (3.582 billion barrels of oil) and 56.4 billion m^3 of natural gas (1.991 trillion ft^3 of gas) (Norwegian Petroleum Directorate, 1999).

The Total Petroleum System (TPS) concept (modified from Magoon and Dow, 1994) is the basis for this assessment. A TPS is a natural system that encompasses a petroleum source rock and all genetically related oil and gas and which includes the essential elements and processes that are necessary for the existence of hydrocarbon accumulations. The TPS has definite geographic and stratigraphic boundaries. The minimum petroleum system is a subset of the TPS within which the essential elements and processes have been demonstrated conclusively. An assessment unit (AU) is a mapped volume of rock within a TPS that has sufficiently homogeneous geology, exploration history, and risk characteristics to warrant treatment of its oil and gas accumulations as a single population for the purposes of analysis. A TPS may include one or more AUs, and every AU exists within a TPS.

An eight-digit numeric code is used to uniquely identify each AU with respect to World Energy Project Region, Province, and Total Petroleum System. For example, the Viking Graben Assessment Unit is assigned number 40250101. The first digit is the region number, indicating the AU is in Europe (Region 4). The next three digits uniquely identify the province; in this case, the North Sea Graben is number 025. The following two digits (01) refer to the TPS and the final two digits are the unique AU number (also 01 in this example). Klett and others (1997) established the codes for the regions, provinces, and assessment units. The provinces of Europe, Region 4, are shown and explained in USGS Digital Data Series 60 (DDS–60), which is the primary publication of the World Petroleum Assessment 2000 (U.S. Geological Survey World Energy Assessment Team, 2000).

The North Sea Graben is one of the world's great petroleum provinces. The oil and gas accumulations found there occur in a variety of structural settings and within reservoir rocks of various of ages, but almost all originated from shales that were deposited during a relatively brief stratigraphic interval encompassing Late Jurassic to earliest Cretaceous time. This source-rock interval, herein referred to as the Kimmeridgian shales, is known to have been the source of oil and gas at various times and places in the North Sea Graben (Cornford, 1998). Still, it is of such a distinctive and uniform character as to justify treating all hydrocarbon accumulations derived from it as belonging to a single Total Petroleum System. That single TPS, herein referred to as the Kimmeridgian Shales Total Petroleum System (fig. 3), is the dominant geological construct upon which the World Energy Assessment of the North Sea Graben depends.

The province is located entirely offshore in the North Sea, within the national jurisdictions of Norway, the United Kingdom, Denmark, Germany, and the Netherlands. The province boundaries were established to include the principal geologic features associated with the Mesozoic rift structures of the North Sea Graben and adjacent areas. The North Sea Graben can be conveniently divided into three subbasins (fig. 4). The Viking Graben is a north-northeast-trending structure situated in the northernmost part of the North Sea Graben, located between the East Shetland Platform and the Horda Platform and Fenno-Scandian Shield. The southernmost part of the North Sea Graben system is a southeast-northwest-trending rift complex collectively referred to as the Central Graben. At the juncture of the Central and Viking Grabens, the Moray Firth/Witch Ground structure is a west-trending extensional feature that terminates near the coast of the United Kingdom (fig. 4).

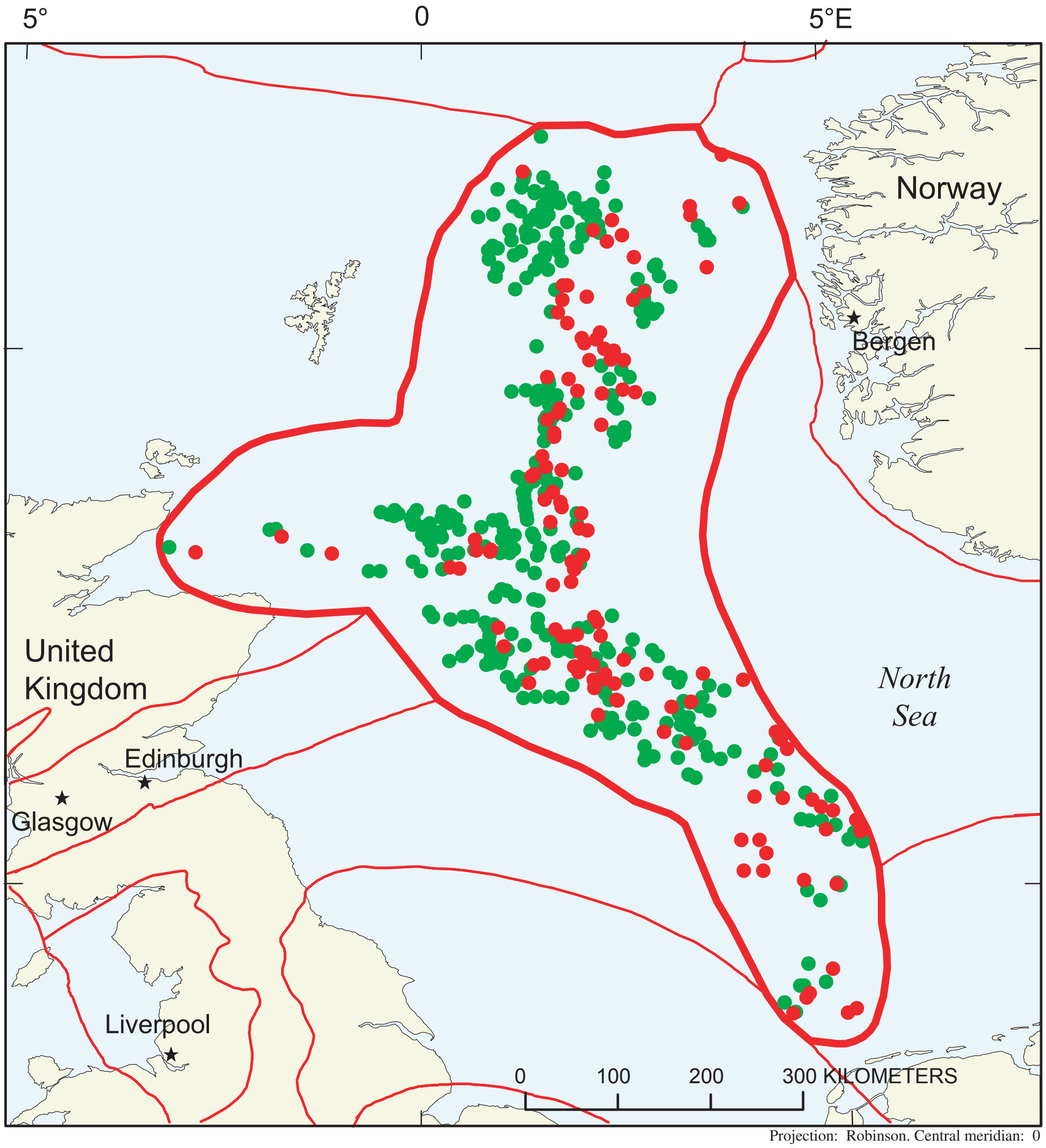
The petroleum of the North Sea has been the subject of many studies and a vast literature (for example, Glennie, 1998a). The Kimmeridgian TPS itself was the subject of a summary, "Mandal-Ekofisk(!) Petroleum System, Central Graben, North Sea" by Chris Cornford, published in Magoon and Dow (1994). The following geologic summary relies upon this extensive literature.

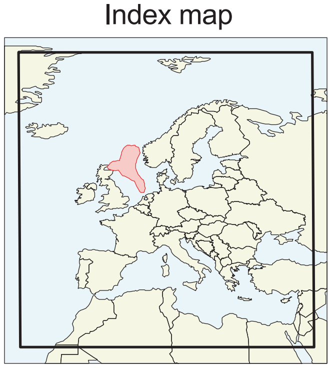
Summary of the Geologic History of the North Sea

The extensional tectonics and failed rifting during the latest Jurassic and earliest Cretaceous are fundamental to understanding oil and gas in the North Sea (Brooks and Glennie, 1987; Pegrum and Spencer, 1990). Accordingly, this discussion of the geologic history is subdivided into three parts with respect to the main episode of rifting. The first section focuses on events and processes prior to rifting (pre-rift). Those events and processes that took place during the rifting events are called syn-rift. Depositional processes and structural events subsequent to the Late Jurassic/earliest Cretaceous are considered post-rift.

Pre-Rift Geologic History

Only a few tens of wells penetrate basement rocks in the vicinity of the North Sea Graben. The wells (Ziegler, 1990) contacted Caledonian (Late Ordovician to earliest Devonian) basement consisting of intrusive igneous rocks and low- to high-grade metamorphic rocks, including metasedimentary sequences. These sparse samples, along with observations from outcrops in the British Isles, northern Europe, and Scandinavia, are evidence that the North Sea was the site of a major

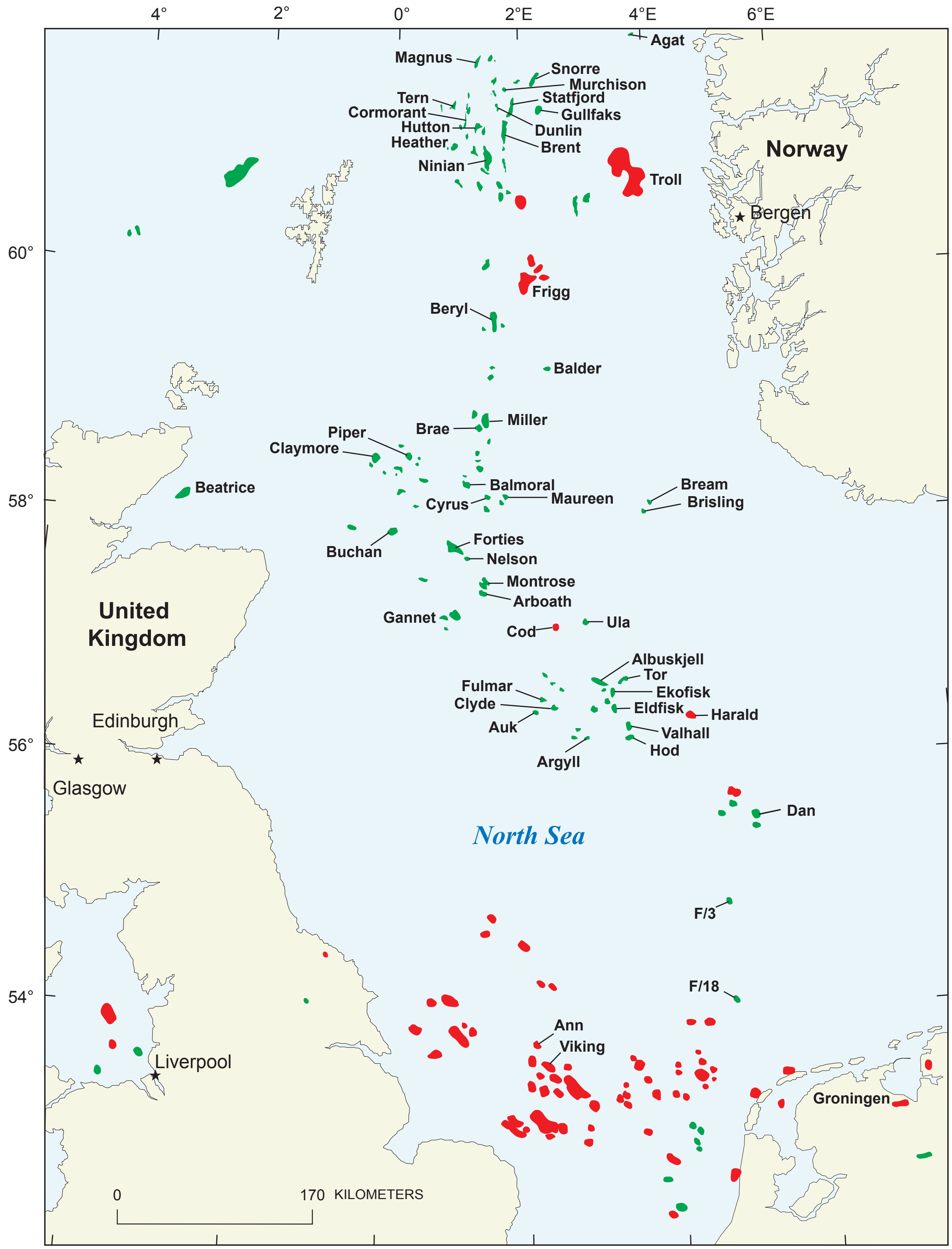




EXPLANATION

- North Sea Graben Province 4025
- Other geologic province boundary
- Gas field centerpoint
- Oil field centerpoint

Figure 1. Location of the North Sea Graben Province (4025), with some nearby province boundaries, coastlines, and cities.



EXPLANATION

Oil field

Gas or gas condensate field

Figure 2. Prominent oil and gas fields of the North Sea (modified from Glennie, 1998a).

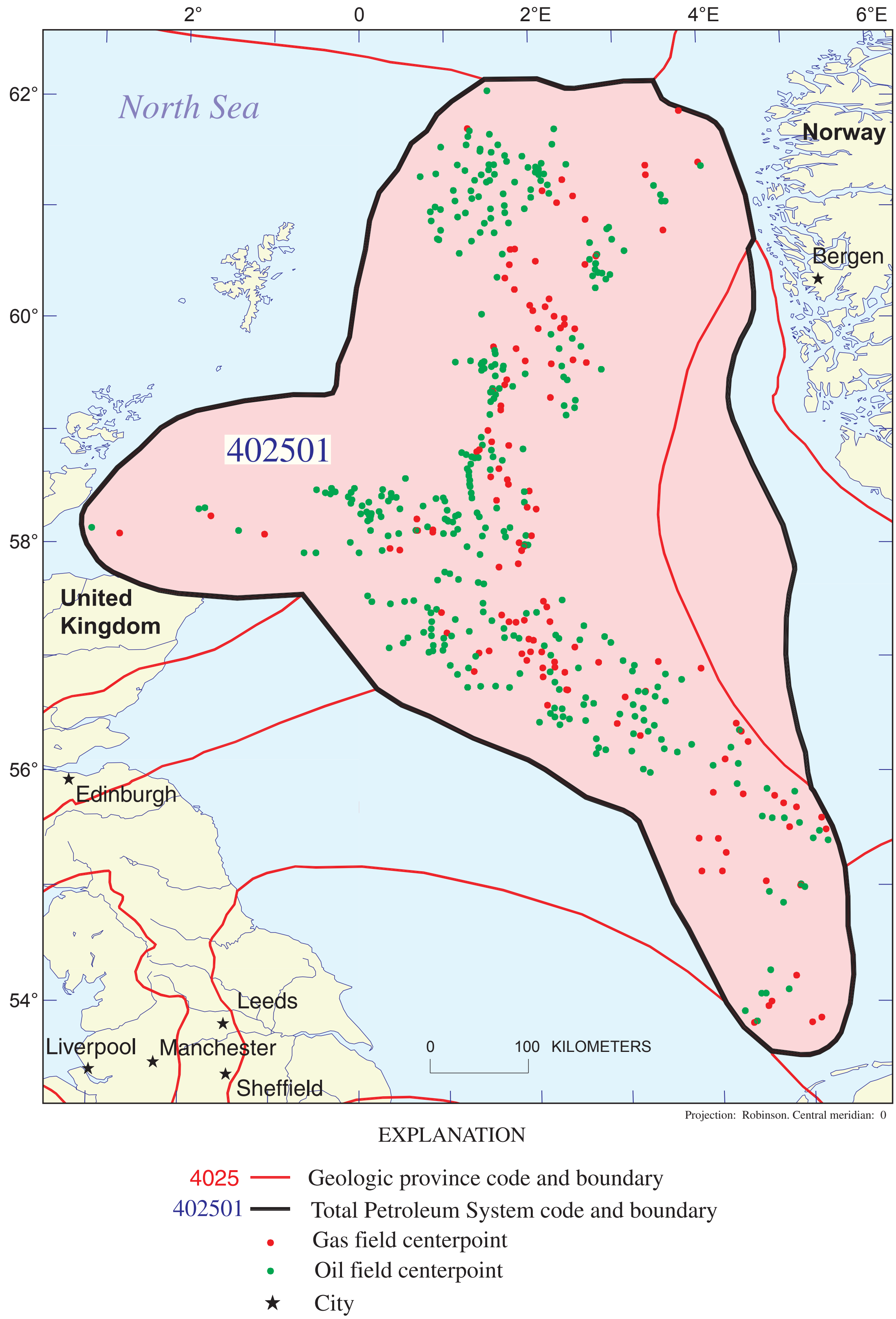


Figure 3. Boundary of the Kimmeridgian Shales Total Petroleum System, with locations of some oil and gas fields.

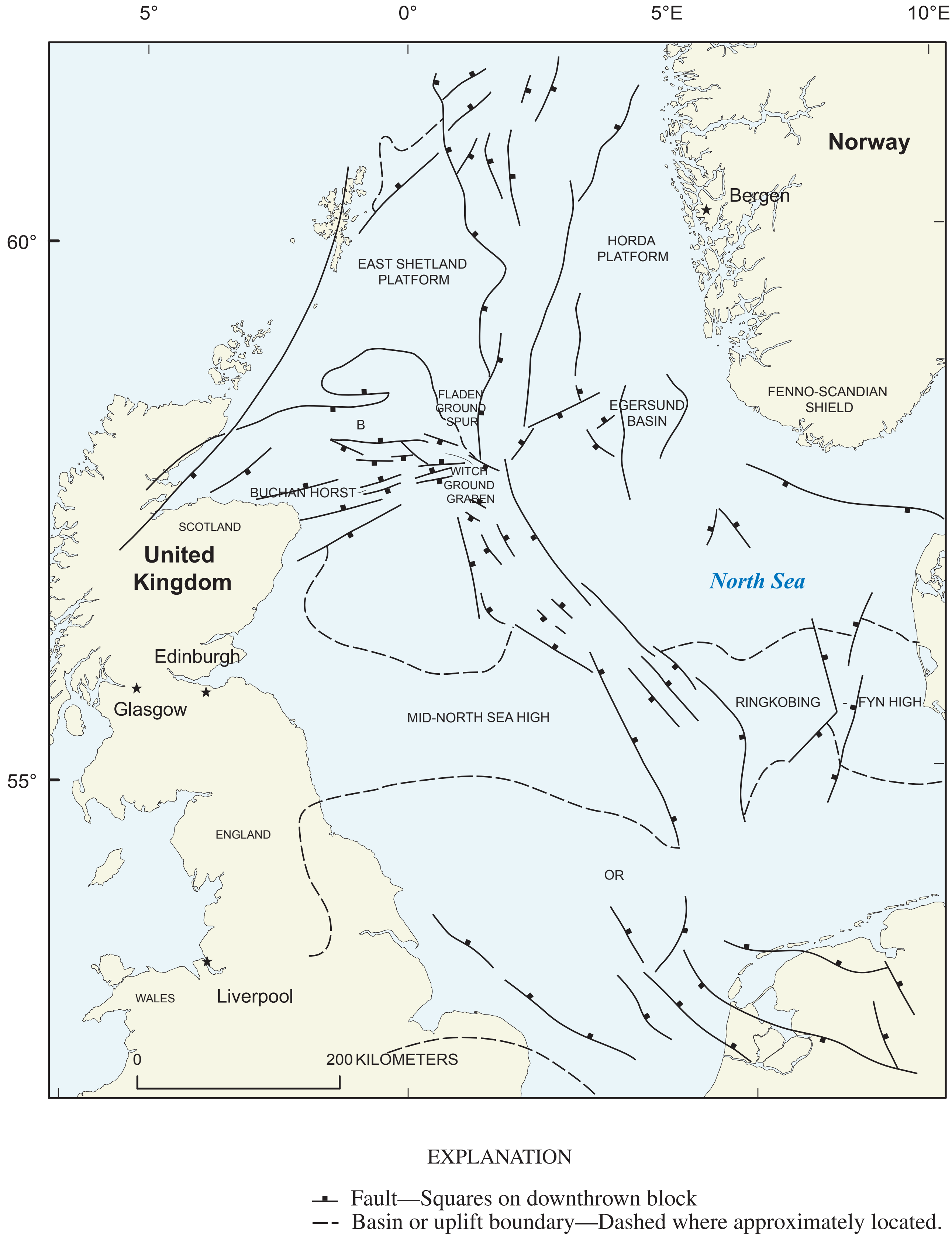


Figure 4. Structural elements of the North Sea (modified from Brown, 1991).

north-south-trending fold belt named the Iapatus Suture. This suture extended from what is now the Arctic, between Greenland and Scandinavia, through the North Sea and onto the European continent in northern Germany and Poland (Glennie and Underhill, 1998; Ziegler, 1990).

The three-plate convergence of the Caledonian orogeny caused the suturing of the Iapatus Seaway. The Caledonides are unconformably overlain in much of the North Sea Basin by lithologically diverse sedimentary rocks of Devonian age. During the Early Devonian, the northern part of the North Sea Basin received sediment from the Orcadian Basin, while the rest of the North Sea was probably emergent (Ziegler, 1990). When marine waters of the proto-Tethys transgressed the southern and central North Sea Basin from the south during Middle Devonian time, deposition of marine limestone and shale was largely confined to the Central Graben, indicating its structural configuration for the first time (Downie, 1998). The Late Devonian fluvial, alluvial, and lacustrine rocks that are present throughout the rest of the North Sea Basin are appropriately considered part of the Old Red Sandstone (Mykura, 1991) (fig. 5).

During the Carboniferous to Early Permian, the Hercynian orogeny reflected the transition from a three-plate convergence to a two-plate convergence. The future site of the North Sea was well to the north of the active Variscan orogenic belt, where African Gondwanaland was colliding with European Laurasia (Ziegler, 1990). Even so, the Carboniferous strata throughout the North Sea are closely associated with its development (Besly, 1998). Compared to depositional rates in the Variscan foreland of the southern North Sea, the central North Sea Basin experienced relatively slow sedimentation. Marginal-marine conditions persisted until the Late Carboniferous, when deltaic strata with coals and carbonaceous shales were deposited throughout the southern and central North Sea (Collinson and others, 1993). The Carboniferous Coal Measures, which are thick and economically important as natural-gas source rocks in the southern North Sea, are relatively thin and poor in organic matter in the Central Graben and are largely absent in the Viking Graben.

Beginning in the Devonian, northwestern Europe drifted northward. This latitudinal change, coupled with the intensifying orogenic rain shadow of the Variscan Highlands, caused a progressive shift from humid to arid climate and from fluvial/deltaic to desert sedimentation in the area that would become the North Sea Basin (Glennie, 1972, 1997).

Lower Permian rocks in northwestern Europe are mostly referred to as the Rotliegend Group (fig. 5). The Lower Rotliegend, which forms much of the sedimentary section in Germany and Poland, is not prominent north of the Mid-North Sea High (fig. 4). On the other hand, the Upper Rotliegend is present in the northern Permian Basin, which includes the northwestern part of the Central Graben, the Moray Firth/Witch Ground, and the southernmost part of the Viking Graben. The Rotliegend is incompletely known because drilling commonly stops well above the Permian. Glennie (1998b) suggested that facies relationships in the Upper Rotliegend of the northern Permian Basin are similar to those in the large gas fields of the southern North Sea. Thus, he expected mainly desert nonmarine deposits dominated by fluvial, eolian, and lacustrine facies.

The Late Permian Zechstein transgression brought marine waters from the Boreal sea southward, far into northwestern Europe (Kiersnowski and others, 1995). Global sea-level rise at the end of the Permian glaciation triggered rapid advance of the Zechstein Sea. The entry point of Zechstein waters into the area of the North Sea is subject to dispute (Taylor, 1998), but most workers agree that the Boreal waters entered through a restricted passageway and that both the northern and southern Permian basins were well below sea level. The desertification of northern Europe, combined with restricted circulation, caused evaporitic conditions throughout the Zechstein Sea.

Rocks of the Zechstein Group, which include thick evaporites, are found mainly in the two east-west-trending subbasins (the northern and southern Permian basins), separated by the North Sea High (Mid-North Sea High and Ringkobing-Fyn High of fig. 4). The evaporites cover much of the southern North Sea, extending westward through Germany and Poland, through the Netherlands to eastern England. In the northern Permian basin, Zechstein deposits accumulated in what are now the Moray Firth/Witch Ground and the southern Viking Graben. Salt becomes scarce northward, with no halite known north of lat 50°50′N. Throughout most of the Central Graben, Viking Graben, and Moray Firth/Witch Ground, the Zechstein salts are not sufficiently thick to serve as a robust seal. More importantly, except in the Central Graben, the thickness is insufficient to result in major diapiric structures. However, in those areas where salt structures are significant, such as the Danish sector, salt structures control hydrocarbon accumulation.

By earliest Triassic time, the Zechstein Sea had retreated to the Arctic, and a complex rift system had begun to disrupt both the Variscan fold belt and the Permian basins. Triassic rifting was tearing apart the Pangean supercontinent along lines separating Fennosarmatia from Laurentia-Greenland and opening the Tethys rift system (Ziegler, 1990; Glennie, 1998b). Red beds accumulated in discontinuous continental basins formed by the rift system. Despite the structural elements introduced by incipient rifting, the northern and southern Permian basins are recognizable on isopach maps of the Triassic (Ziegler, 1990), and major depositional patterns that originated in the Permian persisted throughout the Triassic. South of the Mid-North Sea High, Triassic sedimentary sequences display great lateral continuity and abundant evaporite facies. Bundsandstein (equivalent to the Bacton Group) red beds formed under a variety of nonmarine desert conditions, but they conformably overlie the Zechstein (Tucker, 1991).

Marine transgression in latest Triassic to earliest Jurassic time established a stable connection from the Boreal Sea to Tethys and effectively ended Triassic sedimentation patterns. Shallow-marine conditions existed over most of the North Sea Basin and much of northern Europe throughout the Early Jurassic. In most areas, Jurassic rocks are marine

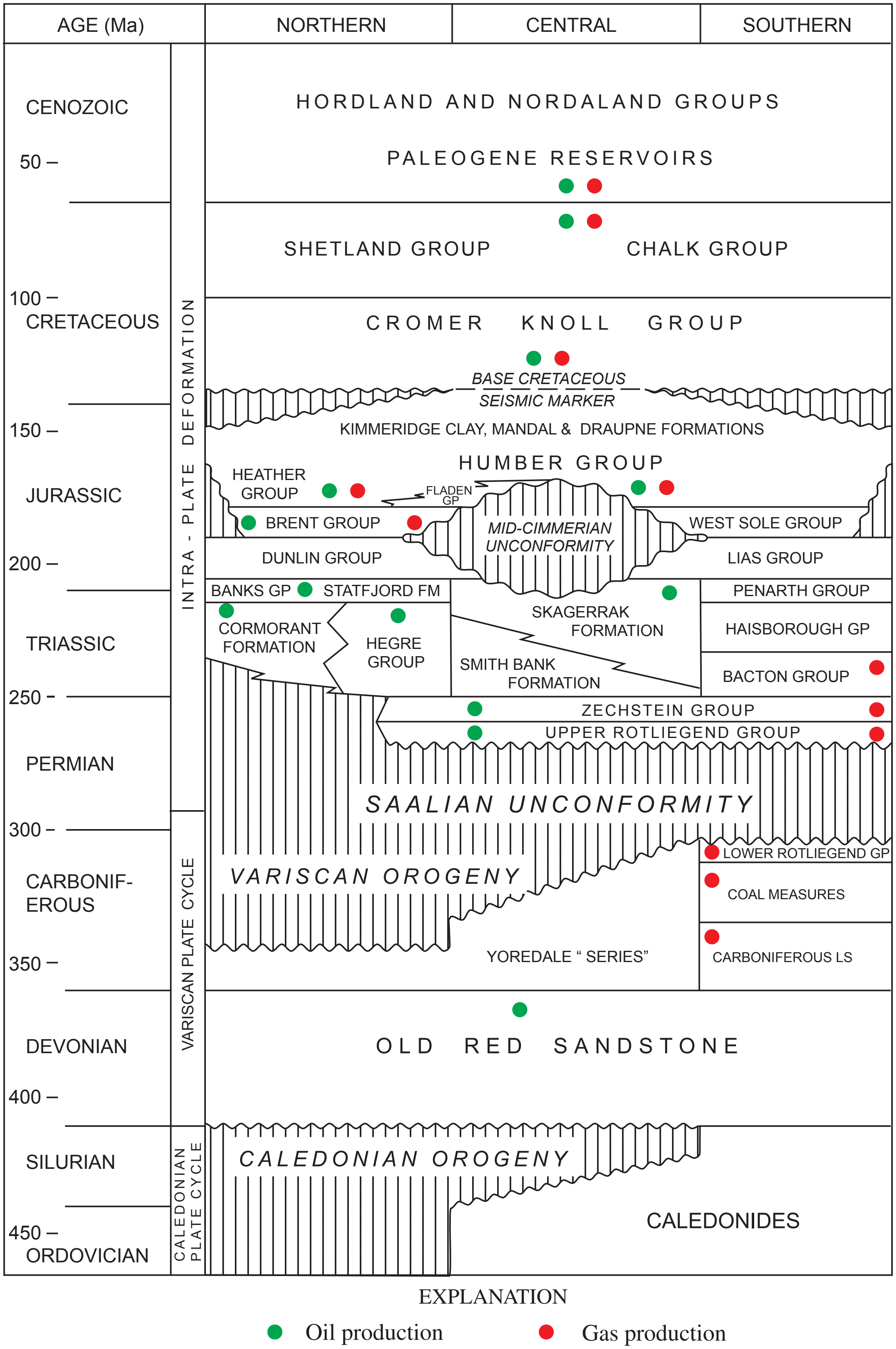


Figure 5. Stratigraphic summary of the North Sea Graben Province (modified from Brennand and others, 1998).

shale sequences containing relatively low percentages of organic matter and little sandstone. But in Germany, uppermost Lower Jurassic (Toarcian) sediments accumulated under near-anoxic conditions, preserving high concentrations of organic matter. As a result, the Toarcian Posidonia shales are petroleum source rocks in Lower Saxony (Kockel and others, 1994). This North Sea–North German shale basin lasted until the Bajocian, when the Central Atlantic rift opened and a rift dome formed in the North Sea.

The North Sea Dome is an extensional uplift covering an area of approximately 700,000 km^2, centered near the junction of the Central Graben, Moray Firth/Witch Ground, and Viking Graben (Ziegler, 1990). The dome, which is represented in the sedimentary section of the North Sea by the mid-Cimmerian unconformity (fig. 5) (Underhill and Partington, 1994), fundamentally altered sedimentation patterns in northwestern Europe, with particular effect in the North Sea Basin. Because Middle Jurassic sedimentary sequences contain prolific reservoirs of oil and gas, this stratigraphic interval has been documented in detail from logs and seismic lines (Morton and others, 1992; Steel and Ryseth, 1990). The rising dome shed sediment to incipient rift basins adjacent to the Moray Firth/Witch Ground and Central Graben, where thin sequences of coal-bearing fluvial sandstone accumulated. In the Central Graben, as much as 1,000 m of nonmarine rocks was deposited, while a clastic wedge advanced southward into the southern North Sea and as far as Lower Saxony. Dome-derived sediments are most important in the Viking Graben, where the Brent Group provides reservoir rocks for some of the largest North Sea oil fields (Pegrum and Spencer, 1990; Johnson and Fisher, 1998). The Brent clastic wedge advanced northward in and adjacent to the Viking Graben, reaching its maximum extent at about lat 62°N. during the early Middle Jurassic (late Bajocian) (fig. 5). The Brent comprises a wide variety of depositional environments, including channel sandstones that form major oil and gas reservoirs and various coastal-barrier and delta-plain sediment packages.

Syn-Rift Geologic History

By latest Jurassic (Callovian) time, accelerating extension and subsidence caused marine transgression throughout the North Sea Graben, halting the northward advance of the Brent clastic wedge. The principal phase of extension began in Late Jurassic (Middle Oxfordian) time and continued into the earliest Cretaceous (Berriasian). Increased subsidence in all three grabens (Viking, Moray Firth/Witch Ground, and Central Grabens) was accompanied by shoreline retreat and basin deepening. Marine sediments accumulated throughout the graben system, including the site of the North Sea Dome.

Late Jurassic extension formed a series of long, narrow, interconnected basins, open northward to the Boreal sea and southward to Tethys. Except for coarse siliciclastic deposits derived from erosion of local structures, sediment consisted of fine-grained mudstones, commonly laminated and rich in organic matter. Most rapid sedimentation occurred during the Late Jurassic near the major bounding fault systems of the grabens. At places in the western Viking Graben, Kimme ridgian shales are more than 2,000 m thick. In much of the Central Graben, sediment thickness exceeds 1,000 m. In the deepest parts of the Danish Central Graben, Upper Jurassic rocks are more than 4,000 m thick.

Simultaneously with deposition of the early Late Jurassic to earliest Cretaceous (Oxfordian to Berriasian, but mainly Kimmeridgian) shales, uplift and erosion of various structural blocks generated coarse sandstones and conglomerates deposited in fans near the base of the fault blocks (Cornford and Brooks, 1989). Each of the sandstones, being locally derived, displays individual characteristics. For example, the Brae Formation consists of westward-thinning, coarse clastic wedges deposited adjacent to a growth fault on a compacting hanging-wall syncline in the southern Viking Graben. The Piper Formation in the Moray Firth/Witch Ground is a sandstone-rich marine deposit of equivalent age to the Kimmeridge Clay, variously interpreted to be a shallow-marine deltaic deposit or a fluvial system. The Fulmar Formation also comprises a series of shallow-marine shoreline sequences deposited in the Central Graben. Each of the coarse siliciclastic deposits was derived locally and interfingers with the fine-grained, organic-carbon-rich shales of the Kimmeridge Clay and equivalent formations (Cornford, 1998).

In the Viking Graben and the Moray Firth/Witch Ground, extensional structures consist of complex sets of half-grabens arranged more or less symmetrically about the basin axis. Uplift of the footwall and subsidence of the hanging wall characterize most fault-bounded traps, and subaerial erosion of the uplifted footwall blocks provided a sediment supply for accompanying deposition adjacent to the fault on the hanging wall (Glennie, 1998a). In the Viking Graben, relief of 1,500 m can be documented on such structures (Ziegler, 1990). In the Central Graben the structural pattern is different, typically consisting of uplifted horst blocks and intervening basins. The difference in structural style is further complicated by the presence of thick Zechstein evaporites beneath the Central Graben, which have reacted to stresses by differential diapiric flow (Pegrum and Spencer, 1990).

Post-Rift Geologic History

Near the end of the Jurassic, the extensional axis shifted westward to the proto-Atlantic basin. Rifting in the North Sea had largely ceased by the end of Early Cretaceous time (Ziegler, 1990). Steep geothermal gradients associated with the extensional tectonics decayed, and the regional pattern became one of gradual cooling and associated subsidence, especially near the axis of the abandoned rift, where post-rift sediments accumulated to greatest thickness. The only real exception to the tectonic quiescence was in the Moray Firth/Witch Ground, where uplift interrupted the burial history and coarse clastic sediment accumulated to form the reservoirs of a few fields, such as Claymore (Cornford, 1998). To the south, Late Cretaceous to earliest Paleocene post-rift rocks are dominated by fine-grained pelagic carbonates (chalks) (Hancock and Scholle, 1975). Little or no chalk is found north of lat 57°N.

Cretaceous sedimentation subdued the topography, but during the early Tertiary, broad regional subsidence continued as the steep thermal gradient of the rift faded away (Bowman, 1998; Cornford, 1998; Glennie, 1998a; Ziegler, 1990). Post-rift sediments as much as 3,000 m thick accumulated in the Viking Graben. The Tertiary sedimentary sequences are mainly marine mudstones with locally significant submarine fans. Fans deposited during the Paleocene and Eocene are particularly significant (Reynolds, 1994). Subsidence and sedimentation have continued in many areas throughout the Tertiary and Quaternary. The great isostatic differences resulting from erosion of uplifted blocks and accompanying rapid sedimentation in subbasins and half-grabens probably initiated salt tectonics in the Central Graben (Bain, 1993). Salt movement has continued into the Holocene.

History of Exploration and Production

North Sea exploration actually began onshore in 1959 with the discovery of the Groningen gas field in the Netherlands by Shell and Esso. To Shell and Esso geologists, the thick, high-quality Rotliegend reservoirs of Groningen suggested that similar reservoirs might lie offshore (Glennie, 1997). Exploration based on the Groningen geologic model began in German waters, resulting in scientifically successful but economically untenable discoveries of low-BTU gas. The U.K. offshore exploration that began in 1964 discovered some of the largest fields of the southern gas province (Brennand and others, 1998). Within 1 year, more than 20 TCF of gas had been discovered. This volume proved to be enough to glut the U.K. monopoly gas market (Glennie, 1997), at least temporarily.

Discouraged by the local gas market in the U.K., explorationists began looking elsewhere in the offshore. Drill-stem tests detected oil in Danish Danian chalks in 1966 and in chalk reservoirs of similar age in the Valhal field of the Norwegian sector in 1967. In 1969, Phillips found oil in the structure that would be named Ekofisk, the largest field in the Central Graben. Ekofisk provided ample incentive for further exploration, leading to a series of discoveries of additional chalk fields in Danish and Norwegian waters. The following year, Forties, one of the largest North Sea oil fields, with reservoirs in Paleocene marine sandstones, was discovered by British Petroleum in U.K. waters.

Following the discoveries in the Central Graben, intense seismic acquisition around the North Sea allowed identification of numerous buried structures in the Central Graben, Moray Firth/Witch Ground, and Viking Graben. In 1971, Shell/Esso drilled a large buried structure in the Viking Graben and discovered Brent field. Brent reservoirs were a novelty, consisting of mid-Jurassic deltaic sandstones of pre-rift origin. The discovery of Brent field, with 2 billion barrels of recoverable liquids, prompted a new exploration strategy in the North Sea, resulting in numerous discoveries, especially in the Viking Graben. Also in 1971, Argyll field was discovered, demonstrating that Auk field (discovered 1969) was not a unique example of substantial oil reservoirs in Paleozoic rocks. Pursuit of the Brent exploration model, seeking shallow-marine or marginal-marine sandstone reservoirs in fault blocks, resulted in the discovery of 10 major fields during the following 4 or 5 years, including Statfjord, which was discovered by Mobil Corporation in 1974.

During the same period, exploration by Occidental in the somewhat neglected area of the Moray Firth/Witch Ground found Piper and Claymore fields. Piper and Claymore share a pre-rift reservoir age with the large Brent fields of the Viking Graben but, like Magnus field in the far north of the province, have reservoirs of shallow-marine, coastal origin.

In about 1975, the attention of the explorationists turned from the deltaic/shallow-marine sandstones of the pre-rift sequences back to the Upper Jurassic, seeking hard-to-locate, coarse-grained syn-rift reservoirs immediately adjacent to major fault blocks. This effort resulted in the discovery of North Brae field and others in the Viking Graben and in the discovery of Ula and Fulmar fields to the south.

Application of greatly improved seismic geophysics facilitated exploration for more subtle traps. Discovery of the Frigg gas field in the Viking Graben and Beatrice and Buchan fields in the Moray Firth/Witch Ground demonstrated the viability of exploration there. By the early 1980s, however, most of the U.K. Central Graben had been made available for leasing, and it was becoming clear that the sizes of fields being found had declined significantly. Exploration strategy changed somewhat in response, as companies began exploring for smaller fields in the hundreds-of-millions-of-barrels volume range. The strong downward pressure on oil prices in the mid-1980s forced a more cautious strategy as companies became frugal with exploration money. The world oil glut was felt strongly in the North Sea, and producers curtailed production between 1985 and 1990. That this decline was largely due to market conditions was demonstrated in the early 1990s, when rising prices associated with the first Persian Gulf War encouraged increased production in the North Sea oil fields.

Development in the North Sea as a mature petroleum province continues with drilling of development wells, development of satellite pools, and application of enhanced recovery techniques to improve production from older fields. At the same time, explorationists continue to find new (albeit much smaller) oil fields that, together with applications of enhanced oil recovery technology to older fields, help to maintain North Sea oil production.

Total Petroleum System: Kimmeridgian Shales (402501)

The predominance of source rocks of a narrow stratigraphic interval and similar lithologic character leads to the definition of a single petroleum system. The Kimmeridgian Shales Total Petroleum System is defined to include all the oil-prone areas of the North Sea Graben. The single petroleum system includes the Viking Graben, the Moray Firth/Witch Ground, and the Central Graben. The TPS includes as a subset the “Mandal-Ekofisk(!) Petroleum System” as defined and described by Cornford (1994). Much of the following summary of the Kimmeridgian Shales TPS relies on that publication and on other work by Cornford and his colleagues (for example, Cornford, 1998). The decision to treat the entire North Sea Graben system as a single TPS was made for the sake of simplicity—a detailed analysis of source rock/hydrocarbon relationships in the context of local time/temperature exposure is beyond the scope of this paper and of the World Energy Project assessment.

Source Rocks

Upper Jurassic marine shales are important petroleum source rocks worldwide (Ulmishek and Klemme, 1991). Global sea-level rise, coupled with high organic productivity and increasing water depths, resulted in anoxic bottom waters in areas of closed bathymetric basins. The result was thick accumulations of moderately organic carbon-rich shales, with localized areas of highly organic rich sediment preserved in deep basins.

Rifting reached maximum intensity in the North Sea during Late Jurassic and earliest Cretaceous time (Ziegler, 1990). Rapidly deposited marine mudstones, rich in organic matter, accumulated widely throughout the rift basins, with depositional thickness locally exceeding 3,000 m. In the North Sea, shales believed to have served as petroleum source rocks range in age from early Late Jurassic to earliest Cretaceous (Oxfordian to Berriasian), with highly organic-carbon-rich intervals found at various stratigraphic levels (Cornford, 1998). These organic-matter-rich facies contain from 2 to more than 15 weight percent total organic carbon (TOC) and are easily identified from their high gamma-ray values on logs. For this reason these stratigraphic intervals are often called the “Hot Shales” of the North Sea. The formations with “Hot Shales” include the Kimmeridge Clay in the Moray Firth/Witch Ground, the Mandal Formation in the Central Graben, the Draupne Formation in the Viking Graben, and the Tau Formation in the Norwegian-Danish Basin.

Kerogen in the “Hot Shales” is a typical “type II” mixture of degraded terrestrial and planktonic marine origin. Detailed oil/source-rock correlations and related studies have been done on these rocks, such that the oil/source-rock correlation is not in doubt (Cornford, 1994, 1998; Underhill, 1998). The source rocks containing “Hot Shales” vary in lithology and kerogen content. Nevertheless, average source-rock properties have been specified by Cornford (1994) for illustrative and calculation purposes. The average “Hot Shale” contains 5 percent TOC and has a hydrogen:carbon ratio of 0.9–1.2, with a Rock-Eval hydrogen index of 450–600, and a carbon isotopic composition of $\delta^{13}C = -27.6$ to -28.7 o/oo.

Rapid sedimentation meant that some of the “Hot Shales” were already deeply buried by Cretaceous time. However, most of the organic-carbon-rich shales became thermally mature with respect to oil generation at various times from the Early Cretaceous to the Neogene (fig. 6). Sediment accumulation has been nearly continuous in most of the North Sea since the Mesozoic, and in many areas the Kimmeridgian shales are presently at their greatest burial depth. Oil generation is thought to have begun in large areas of the North Sea by Eocene time. In the Danish and Norwegian Central Graben and in the Viking Graben, rapid sediment accumulation in Neogene to Holocene time (Cornford, 1986, 1998) accounts for much of the thermal maturity of the Kimmeridgian shales. In the Moray Firth/Witch Ground and southernmost Viking Graben, as well as in the Egersund Basin, uplift since latest Cretaceous time has essentially arrested maturation of the Kimmeridgian kerogen.

Depth of burial of Kimmeridgian “Hot Shales” provides a reasonably good proxy for thermal maturity (Day and others, 1981). Figure 7 shows depth of burial of the base Cretaceous seismic reflector, as well as the diverse burial histories of the

Upper Jurassic source rocks. The Central Graben and the northern Viking Graben, in particular, display significant burial and presumably thermal maturity in Paleogene and Neogene time. The southern Viking Graben/Moray Firth/Witch Ground area is clearly at much shallower burial depths.

Reservoirs

Inasmuch as the entire North Sea Graben system shares a single source-rock interval, the reservoirs of the Kimmeridgian Shales Total Petroleum System include virtually all possible reservoirs of the North Sea. The reservoirs are by no means uniformly distributed in time or space, and their diverse character is responsible for much of the geologic complexity of the petroleum distribution. It is convenient to group the reservoirs temporally with respect to the timing of the major episode of rifting. Accordingly, this paper refers to pre-rift reservoirs, syn-rift reservoirs, and post-rift reservoirs. This usage is compatible with that commonly used by geologists involved with the geologic history and petroleum geology of the area (for example, Johnson and Fisher, 1998; Pegrum and Spencer, 1990).

Pre-Rift Reservoirs of Pre-Jurassic Age

Pre-rift reservoirs of pre-Jurassic age contain a relatively small fraction of North Sea hydrocarbons. In most of the fields that produce from pre-Jurassic reservoirs, pre-Upper Jurassic rocks have been stripped away by erosion on the uplifted footwall. The faulted, eroded reservoirs are in close proximity to thermally mature source rocks, indicating that migration distances in these fault-block reservoirs were short.

Pre-Zechstein sequences including Rotliegend sandstones are reservoirs in Argyll and Auk fields. Buchan field has

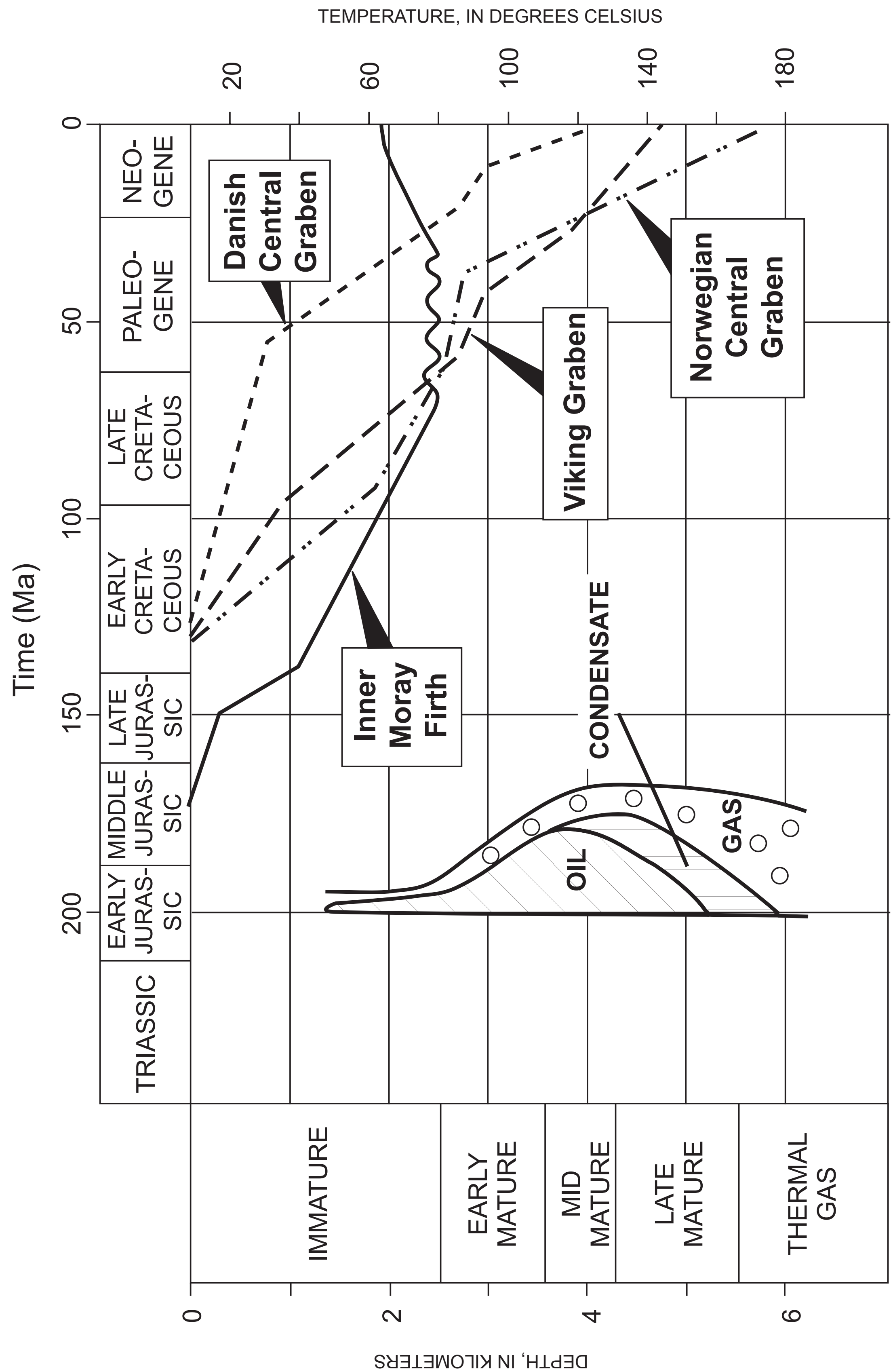


Figure 6. Burial curves for several localities of the northern and central North Sea (modified from Cornford, 1998).

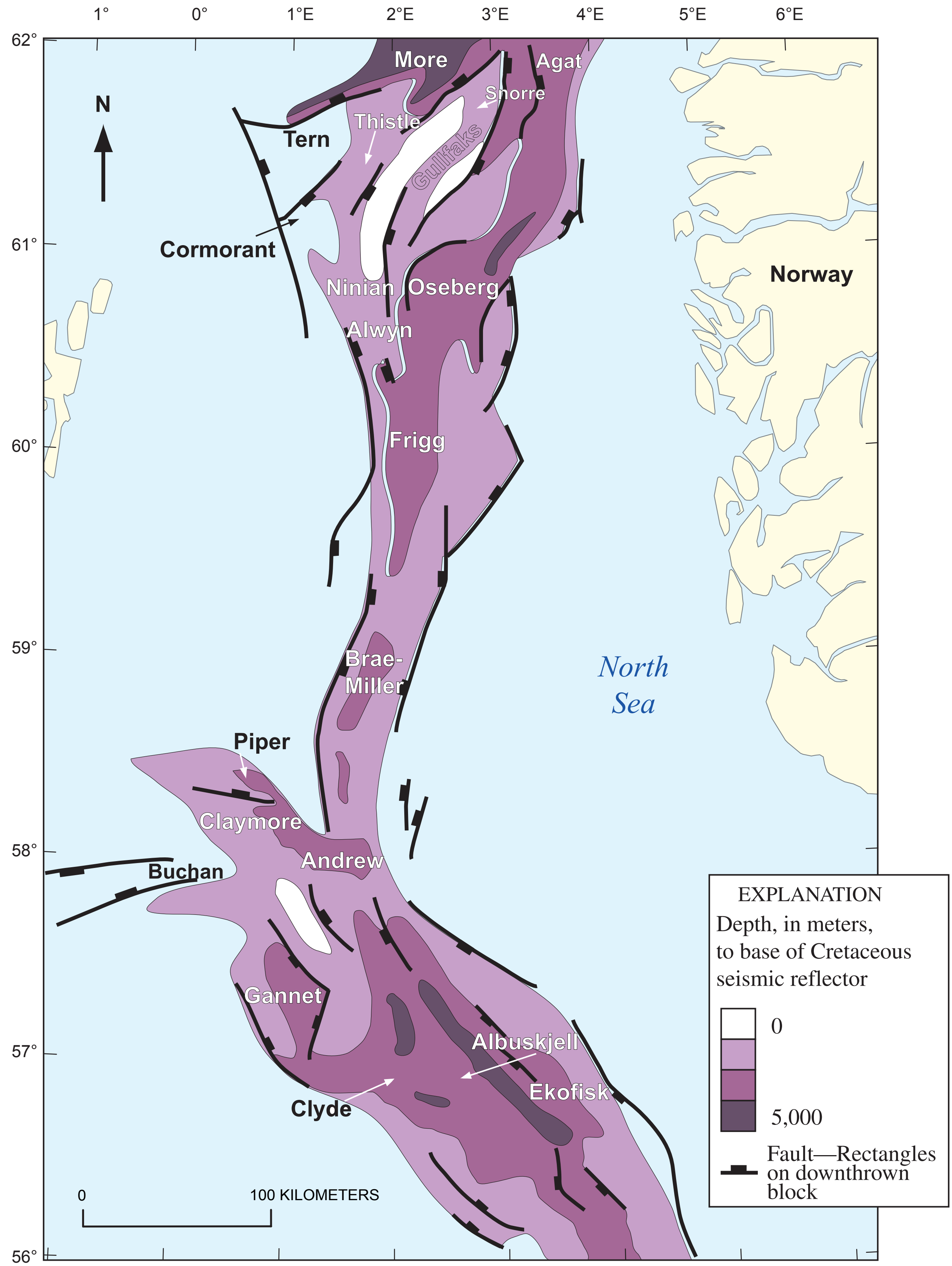


Figure 7. Approximate depth to base of Cretaceous rocks in the Central and Viking Grabens with names and locations of certain oil and gas fields (modified from Day and others, 1981).

reservoirs in Devonian nonmarine red beds. Zechstein carbonates, especially where they are extensively leached and fractured, can also be reservoirs, as in Auk and Argyll. Triassic to Lower Jurassic reservoirs are typically thick fluvial sandstones. According to Brennand and Van Veen (1975), the Zechstein reservoir in Auk field produces from porosity that was enhanced by intensive Early Cretaceous weathering. Argyll field, in addition to carbonate reservoirs, produces from sandstones of the Rotliegend. The largest field in the North Sea that produces from pre-Jurassic reservoirs is Snorre, in the Norwegian sector of the northern Viking Graben. In Snorre, mudstones of Cretaceous age unconformably overlie and seal Triassic reservoir rocks (Hollander, 1987). According to Pegrum and Spencer (1990), Triassic and Lower Jurassic reservoirs in Snorre field are found in tilted fault blocks that expose 1,000 m of strata to a 300-m oil column.

Pre-Rift Reservoirs of Early and Middle Jurassic Age

Pre-rift reservoirs of Early and Middle Jurassic age are considered separately from the pre-Jurassic reservoirs because of their substantial contribution to hydrocarbon accumulations in the Viking Graben. The oldest Jurassic reservoirs are marginal-marine to nonmarine fluvial sediments of the Statfjord Formation. More than 200 m of high-porosity sandstones are present at Statfjord, where they conformably rest on nonmarine red beds of Triassic age. These basal Jurassic sandstones are found throughout the Viking Graben, including at Statfjord and Beryl fields, where they are overlain by marine shales of the Dunlin Group.

Overlying the Statfjord Formation and the Dunlin Group are strata of the Brent Group, which dominate oil and gas production in the Viking Graben. The Brent rocks are diachronous, transgressing time and prograding from south to north. The basal Brent is typically upper shoreface sandstone overlain by shallow-marine, delta-front sandstones. The best reservoirs of the Brent Group are in barrier-bar and delta-top deposits (Budding and Inglin, 1981). Nonmarine rocks containing carbonaceous shales, coals, and sandstones deposited in various coastal-swamp, alluvial-plain, and back-bay environments overlie these high-quality reservoirs. The uppermost rocks of the Brent are transgressive sandstones that are overlain by Late Jurassic (Callovian and younger) marine shales. The sandstones of the Brent Group are the main producing reservoirs for most fields of the northern Viking Graben, including Alwyn, Brent, Cormorant, Dunlin, Gullfaks, Heather, Hutton, Murchison, Ninian, and Statfjord. In addition, Middle Jurassic sandstones are reservoirs in the southern Viking Graben and elsewhere in the North Sea, as in Bruce, Beryl, and Beatrice in the Moray Firth/Witch Ground, and in Brisling, Bream, Harald, and others in and near the Central Graben.

Syn-Rift Reservoirs

Syn-rift reservoirs are restricted to those reservoir rocks actually deposited during maximum extension. During this time, the depositional mode in the North Sea Graben changed from the progradational depositional systems accumulating outward from the North Sea Dome to that of marine transgression and erosion of local structural relief. Coarse-grained marine sandstones and conglomerates accumulated adjacent to fault blocks. These syn-rift deposits display great variation in thickness, lithology, and reservoir quality and are best developed as reservoirs in the southern Viking Graben, Moray Firth/Witch Ground, and northern Central Graben. For example, in the south Viking Graben, submarine fans of the Brae Formation accumulated adjacent to the Fladen Ground Spur and there provide reservoirs for several fields including Brae and Miller. In the Moray Firth/Witch Ground, shallow-marine transgressive sandstones of the Piper Formation overlie Oxfordian-age deltaic sandstones. These are the reservoirs at Piper and Claymore, the largest fields in the Moray Firth/Witch Ground.

Shallow-marine sandstones of Middle and Late Jurassic (Bathonian to Kimmeridgian) age accumulated outside of the main rift in the area of Troll field, evidently in response to local tectonic uplift in Norway. At Troll, sandstone reservoirs have high porosity and permeability, with net sand reservoir thickness of more than 200 m. At about 1,000-m depth, Troll is the shallowest large field in the North Sea. Shallow marine sandstones of Late Jurassic age also form reservoirs far to the north in Magnus field in the Viking Graben.

Only the lowermost and oldest part of the Cretaceous sequences can be fairly considered syn-rift deposits, and these are largely confined to the Moray Firth/Witch Ground, where Cretaceous sandstones form reservoirs in Scapa and Claymore fields. The sandstone reservoirs were deposited in submarine fans adjacent to rapidly eroding fault blocks.

Post-Rift Reservoirs

Post-rift reservoirs range in age from Early Cretaceous to Eocene. South of approximately lat 57°N., Cretaceous and earliest Paleocene reservoir rocks are mainly chalk. In fact, few reservoirs exist in the Upper Cretaceous except for chalk. The chalks are well known for high initial porosities and low permeabilities and for their steep porosity decline with depth (for example, Scholle, 1977; Taylor and Lapre, 1987). Reservoirs are of acceptable quality where overpressuring, early oil migration, or some other mechanism has preserved porosity. The chalk reservoirs are commonly found in gravity-redeposited settings, such as in slump blocks or debris flows. In many cases, the chalk reservoirs are related to salt structures.

Paleocene sandstone reservoirs are best developed in the northern Central Graben and the southern Viking Graben. In the Central Graben, the provenance of Paleocene sandstones is the Caledonian basement in Scotland, the Shetland Platform, and as yet unspecified western sources. The best reservoirs were deposited as massive, channelized grain-flow deposits. Paleocene sandstones are concentrated in the broad central trough areas of the former rift basins (Milton and others, 1990). A fine example of such reservoirs is Forties field, where permeabilities of 500 millidarcies and porosities of almost 30 percent are reported for reservoirs hundreds of meters thick (Abbotts, 1991). Other well-known fields with Paleocene reservoirs include Maureen, Montrose, Frigg, Heimdal, Balmoral, Gannet, and Arbroath (Abbotts, 1991).

Seals

In contrast to the southern North Sea, where the Zechstein evaporites serve as a regional permeability barrier for all manner of hydrocarbon accumulations, in the central and northern North Sea, the diversity of hydrocarbon accumulations is matched by the wide variety of seals and traps. Oil and gas accumulations in pre-rift reservoirs commonly are found in tilted fault blocks where seals are formed by various fine-grained post-rift sedimentary sequences that drape the Late Jurassic structures. For example, in the Auk and Argyll fields, where Zechstein carbonates and Rotliegend sandstones are reservoirs, traps are sealed by unconformably overlying Cretaceous chalk, by Jurassic claystone, and by low-permeability zones in the Rotliegend as well as by fine-grained Triassic rocks. In the mid-Jurassic Brent reservoirs of the Viking Graben, traps are sealed vertically by unconformably overlying Jurassic and Cretaceous shales. Lateral seals result from the juxtaposition of shales and reservoir sandstones at fault contacts.

In many syn-rift submarine-fan and turbidite reservoirs, such as those of the Brae trend, the seal is temporally equivalent to Kimmeridge Clay. In the Piper and Claymore fields of the Moray Firth/Witch Ground, Kimmeridge Clay overlies the shallow-marine sandstone reservoirs and provides most of the trapping mechanism, although in places fine-grained Cretaceous rocks also overlie the reservoir rocks. Similarly, in the Central Graben, Kimmeridgian shales that are temporally equivalent to the reservoirs seal the Ula and Fulmar fields. In syn-rift reservoirs of earliest Cretaceous age, such as those in Claymore field, the seals are fine-grained Cretaceous mudstones, marls, and chalks.

Fields with post-rift reservoirs require fine-grained facies in the Tertiary for seals. For example, virtually no chalk fields are found where early Tertiary sandstones overlie the chalk. Evidently, the sandstones provide a conduit for oil moving out of the chalks. Likewise, where post-rift reservoirs are Paleocene and Eocene sandstones deposited in submarine channel and fan systems, facies relationships exert primary control on oil entrapment.

Timing of Oil Migration and Entrapment

In most areas of the North Sea Graben, source rocks have undergone almost continuous subsidence and burial since their deposition (Cornford, 1994, 1998; Pegrum and Spencer, 1990). A noteworthy regional exception is in the Moray Firth/Witch Ground, where thick Kimmeridgian shales had only barely reached the oil window before uplift in the Paleogene. In certain restricted areas of greatest subsidence and most rapid sediment accumulation, the Kimmeridgian source rocks attained thermal maturity with respect to oil generation as early as Cretaceous time. By Eocene time, oil generation was widespread. Subsidence and burial of the source rocks continues to this day in most of the North Sea Graben, and, with the exception of the Moray Firth/Witch Ground, source rocks are currently at their maximum temperature and burial depth. In some areas of continuous burial, source rocks have exceeded the temperature range for oil generation and have reached thermal maturity with respect to gas during Neogene to Holocene time.

Rates of subsidence and burial have been nonuniform across the North Sea Graben, with the locus of most rapid deposition trending southward through time. As a result, the reconstructed burial-history curves of the Viking Graben and the Central Graben are somewhat different (fig. 6). Maximum subsidence rates in the northern Viking Graben occurred in the Late Cretaceous, in the southern Viking Graben and Witch Ground during the Early Tertiary, and in the Central Graben during the Neogene and Holocene.

Trap formation in various parts of the North Sea Graben has also occurred continuously from latest Jurassic/earliest Cretaceous time to the present. For example, the chalk-reservoir fields of the southern Central Graben show clear evidence of oil entrapment soon after deposition in the Late Cretaceous (Taylor and Lapre, 1987; Cornford, 1994). However, continuous burial and structural accommodation has yielded an almost continuous supply of newly generated oil to various structures of the North Sea. A continuous generation and migration process by which traps are continually “topped off” with new petroleum generated over a wide span of time has been postulated (Cornford and Brooks, 1989) to be a major factor in the abundance of North Sea oil.

Assessment Units

Serious consideration was given to conducting the assessment of the North Sea Graben Province on the basis of stratigraphically defined AUs (pre-Jurassic reservoirs, post-rift reservoirs, and so forth). As the foregoing discussion shows, in many ways the geologic setting of petroleum is dominated by timing of reservoir deposition with respect to Late Jurassic extensional events. Nevertheless, in the end, the assessment was based on geographically defined AUs. This approach was intended to capture regional differences in exploration history and geography and, in addition, to address the significantly different geologic histories of various parts of the North Sea Graben. As a methodological exercise, the North Sea Graben Province was actually assessed twice—once informally, using stratigraphically defined AUs, and once using geographically defined AUs. However, only the geographically defined AUs are reported in the final publication as the official USGS assessment. The geographically defined AUs are the Viking Graben (40250101), the Moray Firth/Witch Ground (40250102), and the Central Graben (40250103).

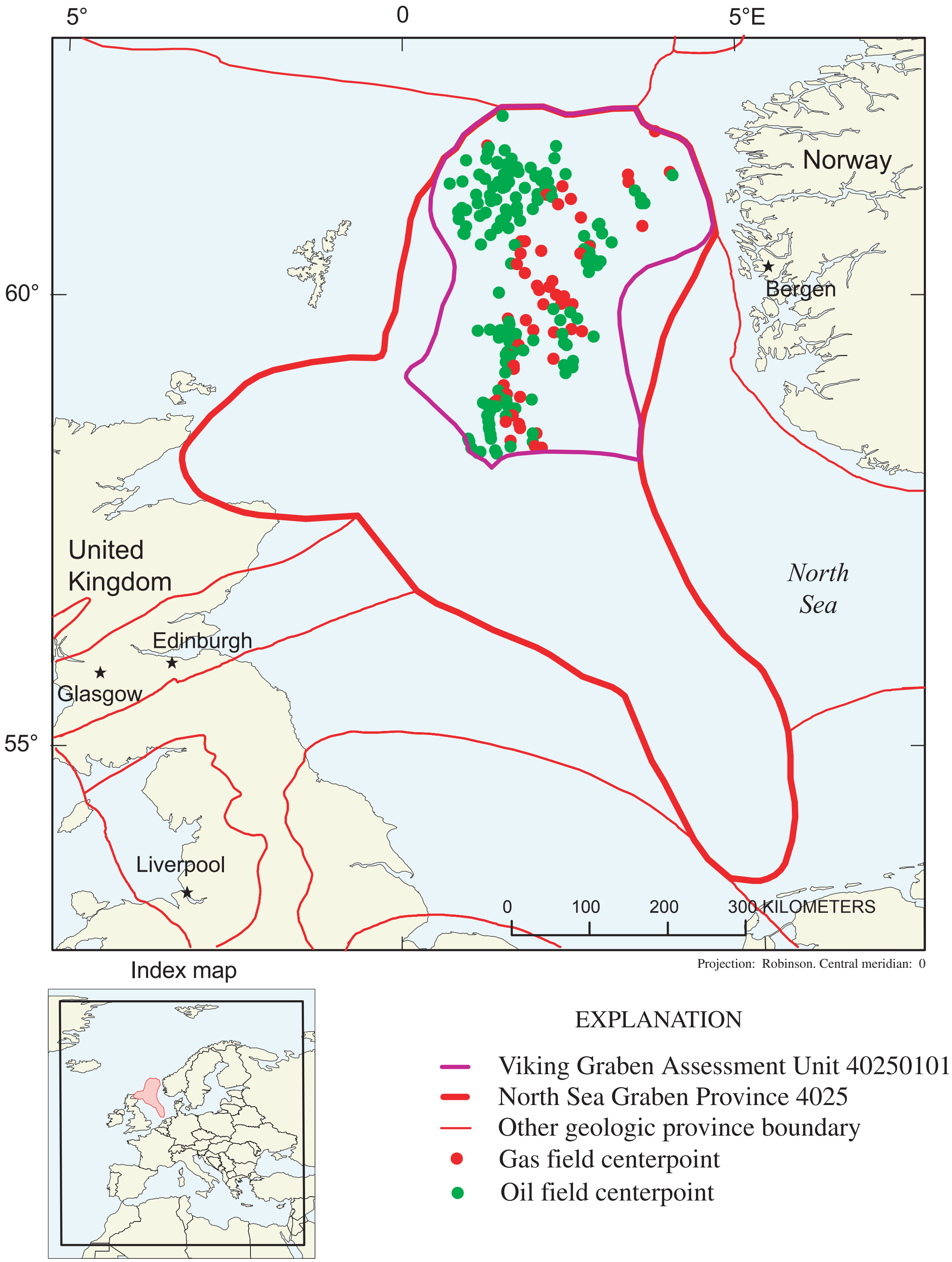


Figure 8. Boundaries of the Viking Graben Assessment Unit (40250101).

Assessment Unit 1: The Viking Graben (40250101)

The Viking Graben is a north-northeast-trending rift system that is north of about lat 58°N. and east of long 1°E. (fig. 8). Its southern terminus is at its junction with the Central Graben and the Moray Firth/Witch Ground (fig. 4). The Viking Graben as such extends northward to north of lat 62°N. The AU boundary extends beyond the structural extent of the Viking Graben to include areas of production or prospective production that are genetically related to the accumulations of the Viking Graben (fig. 2). Thus, the Viking Graben Assessment Unit extends eastward to near the Norwegian coastline and includes the Troll field and adjacent areas.

It is helpful to consider the resources of the Viking Graben in terms of reservoir age relative to Late Jurassic rifting, with respect to the relationship of the known and expected undiscovered fields to timing of structural deformation, and to the timing of oil expulsion, migration, and entrapment. This stratigraphic basis for analysis follows the usage and strategy of many explorationists and authors working in the area, including Fjaeran and Spencer (1991), Johnson and Fisher (1998), and Pegrum and Spencer (1990).

In the Viking Graben, pre-Jurassic reservoirs are a minor part of the petroleum system, with only a few notable fields. In contrast, pre-rift rocks of Early to Middle Jurassic age are of major significance. The oldest reservoir rocks, such as the nonmarine to marginal-marine sandstone reservoirs in the Statfjord field, are in the Statfjord Formation. Rocks deposited as part of the so-called Brent Delta in Middle Jurassic time, however, dominate the reservoirs of the Viking Graben (Morton and others, 1992; Abbotts, 1991). The diachronous prograding sandstones of the Brent Group are involved in the large tilted and rotated fault blocks formed during Late Jurassic extension, with westward-dipping blocks on the western side of the graben and eastward-dipping blocks on the eastern side. Syn-rift Kimmeridgian source rocks, the Draupne Formation, reached maturity immediately overlying Brent Group carrier beds, from which oil migrated updip to traps at the crests of the structures. Early-formed oils migrated into these carrier beds to accumulate updip, away from the graben axis.

Syn-rift hydrocarbon accumulations in the Viking Graben are perhaps best known from the Brae trend in the southern Viking Graben, where oil migrated short distances at high expulsion efficiencies. The oil expelled from Kimmeridgian shales accumulated nearby in coarse-grained syn-rift submarine-fan and turbidite reservoirs. Late-stage gas generation from stratigraphically similar source rocks migrated much farther up the flanks of the graben, accumulating in syn-rift sandstone reservoirs that in some cases lie outside the graben boundaries, as in the Troll field.

All known accumulations in post-rift reservoirs also are sourced from the Kimmeridgian. Such accumulations are relatively less significant in the Viking Graben than in the Central Graben; nevertheless, a few significant fields exist in post-rift reservoirs. Examples include Balder and Frigg fields. In most cases, syn-rift accumulations lie near faults, which are invoked as near-vertical migration pathways for fields with post-rift reservoirs.

Assessment Unit 2: The Moray Firth/Witch Ground (40250102)

The Moray Firth/Witch Ground Assessment Unit includes that part of the North Sea rift system that is oriented approximately east-west, between the northeastern coast of Scotland and the middle of the North Sea. The defined AU extends well beyond the boundaries of the Mesozoic rift system itself but is still entirely offshore. The rift system is between approximately long 1°E. and long 3°W., lying between lat 57°40′N. and lat 58°40′N. (fig. 9). Included within this AU are the structures known as the Moray Firth Basin, the Buchan Horst, and the Witch Ground Graben. Throughout this text, the area including these structures is collectively referred to as the Moray Firth/Witch Ground.

The Moray Firth/Witch Ground trends west from the junction of the Viking, Central, and Witch Ground Grabens that coincided with the central location of the North Sea Dome. Rapid subsidence following the doming occurred during the Callovian (late Middle Jurassic) to Kimmeridgian. This initial subsidence was accompanied by the marine transgression that deposited both shallow-marine sandstones that later were to serve as reservoir rocks and the Upper Jurassic shales that are the principal source rocks for hydrocarbons throughout the North Sea Graben Province. Early Cretaceous marine sands with provenance in the Scottish Highlands and adjacent Shetland Platform largely filled the graben.

Sedimentation in the Moray Firth/Witch Ground was similar to the Central Graben and the southern Viking Graben during most of its pre-Tertiary history. However, uplift of the Moray Firth/Witch Ground beginning in the Late Cretaceous and Paleocene truncated the sedimentary record and abbreviated the time-temperature history. As a consequence, Jurassic source rocks in the Moray Firth/Witch Ground are only marginally mature with respect to oil generation in a very limited area, and they never achieved thermal maturity with respect to oil or gas generation over a wide part of the AU. The continuous deposition and accommodation observed elsewhere in the North Sea Graben Province was interrupted after the Cretaceous. The organic-carbon-rich shales of the Jurassic are not as rich, and they have not achieved the same level of thermal maturity as shales elsewhere in the North Sea. This abbreviated time-temperature history is probably responsible for the diminished sizes and number of hydrocarbon accumulations found in the Moray Firth/Witch Ground as compared to the geologically similar Viking Graben and Central Graben.

Beatrice field is in the Inner Moray Firth, distant from any possible mature Upper Jurassic source rock. Beatrice is believed to have had a different source rock than most fields of the North Sea, with Middle Jurassic shales or even Devonian source rocks postulated by Cornford (1986). If this

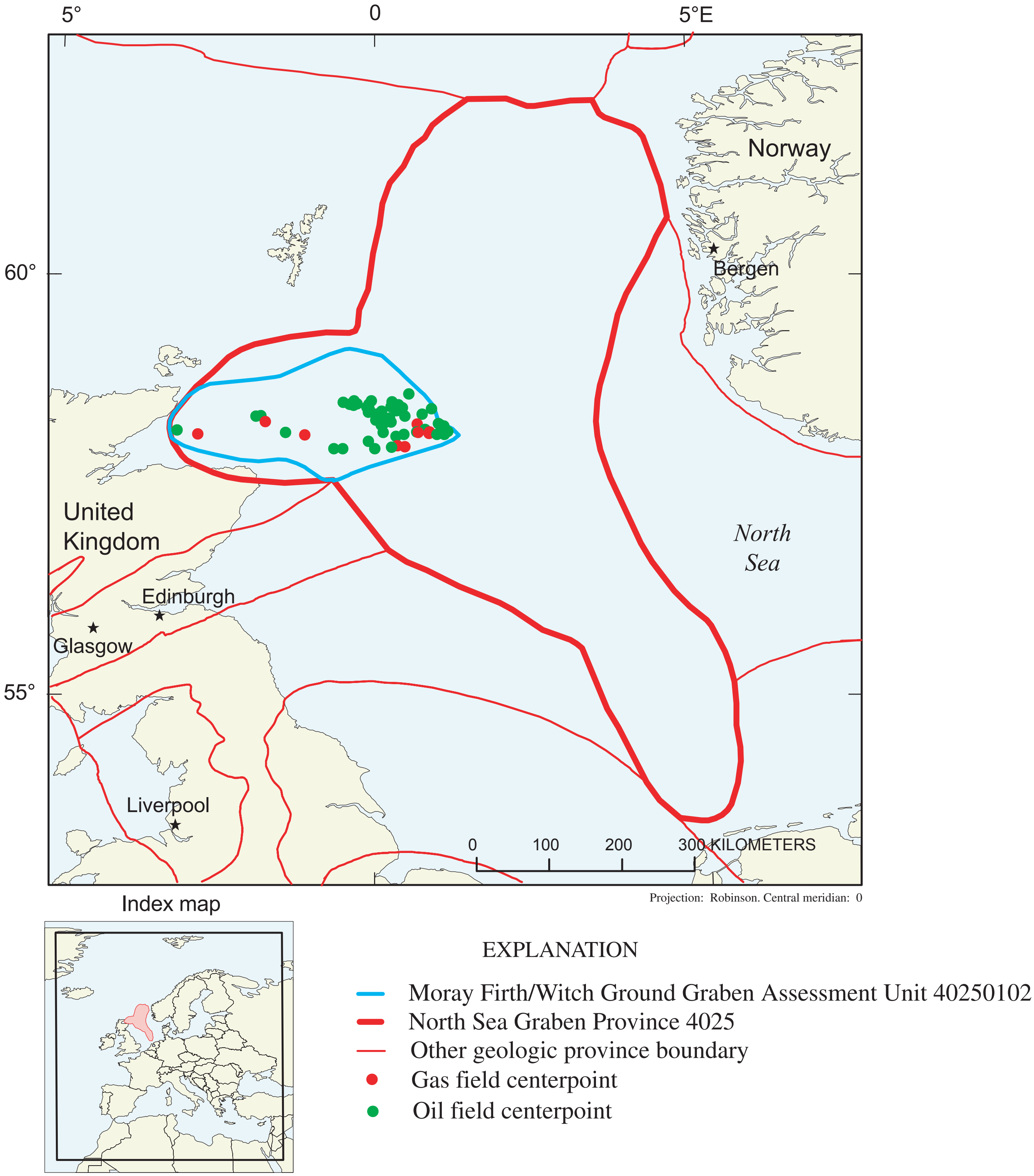


Figure 9. Boundaries of the Moray Firth/Witch Ground Assessment Unit (40250102).

is correct, Beatrice properly should be considered part of another petroleum system. The other fields in the AU are clustered near the junction with the Viking and Central Grabens, where marginally mature Jurassic shales are present. Typical of the Moray Firth/Witch Ground fields are Buchan and Claymore. Buchan field, on the edge of the Witch Ground, produces from Old Red Sandstone. The sandstone reservoirs are on the crest of a tilted and eroded fault block. Jurassic source rocks have evidently provided the charge at Buchan but are only marginally mature near the field. Claymore field, on the southwest margin of the Witch Ground, produces from Upper Jurassic sandstones of the Piper and Sgiath Formations. In addition to these Jurassic sandstones, production also comes from overlying Cretaceous sandstones, from unconformably underlying Carboniferous sandstones, and from Permian carbonate rocks. Kimmeridgian mudstones provide the cap rock for most of the reservoirs. At Piper field, the reservoir is mainly in the shallow-marine and deltaic sandstones of the Heather Group (Sgiath and Piper Formations). The trapping structure is a major northwest-southeast fault zone, with dip closures on the northeast. The Kimmeridge Clay provides the lateral and top seals, and the trap consists of several tilted fault blocks.

Assessment Unit 3: The Central Graben (40250103)

The Central Graben is that part of the North Sea Graben system that extends in a northwest-southeast trend between about long 5°E. and the Prime Meridian, and between about lat 52°N. and lat 58°N. (fig. 10). The AU is entirely offshore. Its boundaries extend well beyond the Late Jurassic extensional structures. Politically, the Central Graben is located in the Norwegian, United Kingdom, and Danish sectors of the North Sea.

In the Central Graben, source rocks are confined to the Mandal Formation, also called the Farsund Formation in the Tail End Graben (Cornford, 1994), which is equivalent to the upper part of the Kimmeridge Clay and Draupne Formation to the north. The Mandal, which reportedly contains an average of 8 weight percent TOC, is now thermally mature with respect to oil generation over a wide area of the Central Graben. In contrast to the Viking Graben, burial has tended to increase later in the history of the Central Graben. In addition, extensive evaporite deposits of the Zechstein Group underlie the Central Graben. Therefore, in addition to the rift-related structures that predominate in the Viking Graben and Moray Firth/Witch Ground, halokinetic structures have strongly influenced migration pathways in the Central Graben.

Three broad categories of reservoir and migration pathway are recognized. The first contains fields with reservoirs of Jurassic or pre-Jurassic age. The second category is that of the chalk reservoirs. The third contains fields reservoired in sandstones of submarine fan complexes or related turbidite systems.

In category one, pre-rift or syn-rift reservoir rocks are involved in tilted fault blocks. Examples include the Argyll and Auk fields, where hydrocarbons are trapped in southwestward-dipping, tilted fault blocks. Reservoirs in Argyll are Zechstein Group carbonates with fractures and vugular porosity formed during postdepositional uplift, Rotliegend eolianite sandstones, and Devonian fluvial sandstones. In nearby Auk field, reservoirs include a Zechstein dolomite, which is the most volumetrically important reservoir of the field, the Rotliegend, which produces from eolian and fluvial facies, and various Cretaceous carbonate rocks. The trap is mainly stratigraphic but within a tilted horst block, with erosional truncation of Zechstein carbonates, Rotliegend sandstones, and Lower Cretaceous breccias beneath a subchalk unconformity.

Chalk Group reservoirs, the second reservoir category, predominate in the southern part of the Central Graben, mainly in the Norwegian and Danish sectors. In productive fields, chalk reservoirs have retained high porosities as a result of early oil migration and the development of overpressuring. Chalk fields occur in traps with four-way closure, commonly resulting from the effects of salt diapirism and structural inversion. Migration into these traps probably occurred during or shortly after deposition of the Paleocene mudstone seal. The significance of the Paleocene seals is demonstrated by the fact that the chalk play is limited to areas where Paleogene sandstones are absent. Some of the most important fields in the North Sea have chalk reservoirs. The largest of these is Ekofisk, where slumping of calcareous pelagic ooze contributed to the preservation of high porosity and establishment of a discrete structure/seal pair. Most chalk fields are found where salt diapirs, piercements, and pillows have provided local structures and where fine-grained Paleogene mudstones form an effective seal. Prominent chalk fields include Edda, Ekofisk, Eldfisk, Hod, Dan, and Albuskjell.

Post-rift sandstone reservoirs are the third major reservoir type. Most of these reservoirs were deposited within submarine-fan complexes in comparatively deep water. The largest fields and best reservoirs, such as Forties, Montrose, and Cod, are concentrated in fans deposited near the axis of the Central Graben rift system, although significant fields also exist in laterally accumulated submarine fans, such as those at Gannet field complex. Reservoir porosities of 25–30 percent are common in these sandstones, consistent with relatively shallow burial at the time of hydrocarbon entry into the reservoir. Seals are provided by overlying and laterally equivalent mudstones of Tertiary age. For example, Forties field has a trap that is an anticline with four-way dip closure. Reservoirs are massive sandstones deposited by turbidity currents. The sandstones are stacked and amalgamated, with little or no evidence of the fine-grained facies common to submarine fan systems (Bowman, 1998). In addition to Forties, large fields with Paleogene sandstone reservoirs include Montrose, Lomond, Cod, Maureen, Arbroath, and Balder. Although the Upper Jurassic Mandal Formation is generally agreed to be the source rock for these oil accumulations, several major fields are not underlain by thermally mature Upper Jurassic strata, indicating significant lateral hydrocarbon migration into these traps (Cornford, 1998). This category of field is limited on the eastern side of

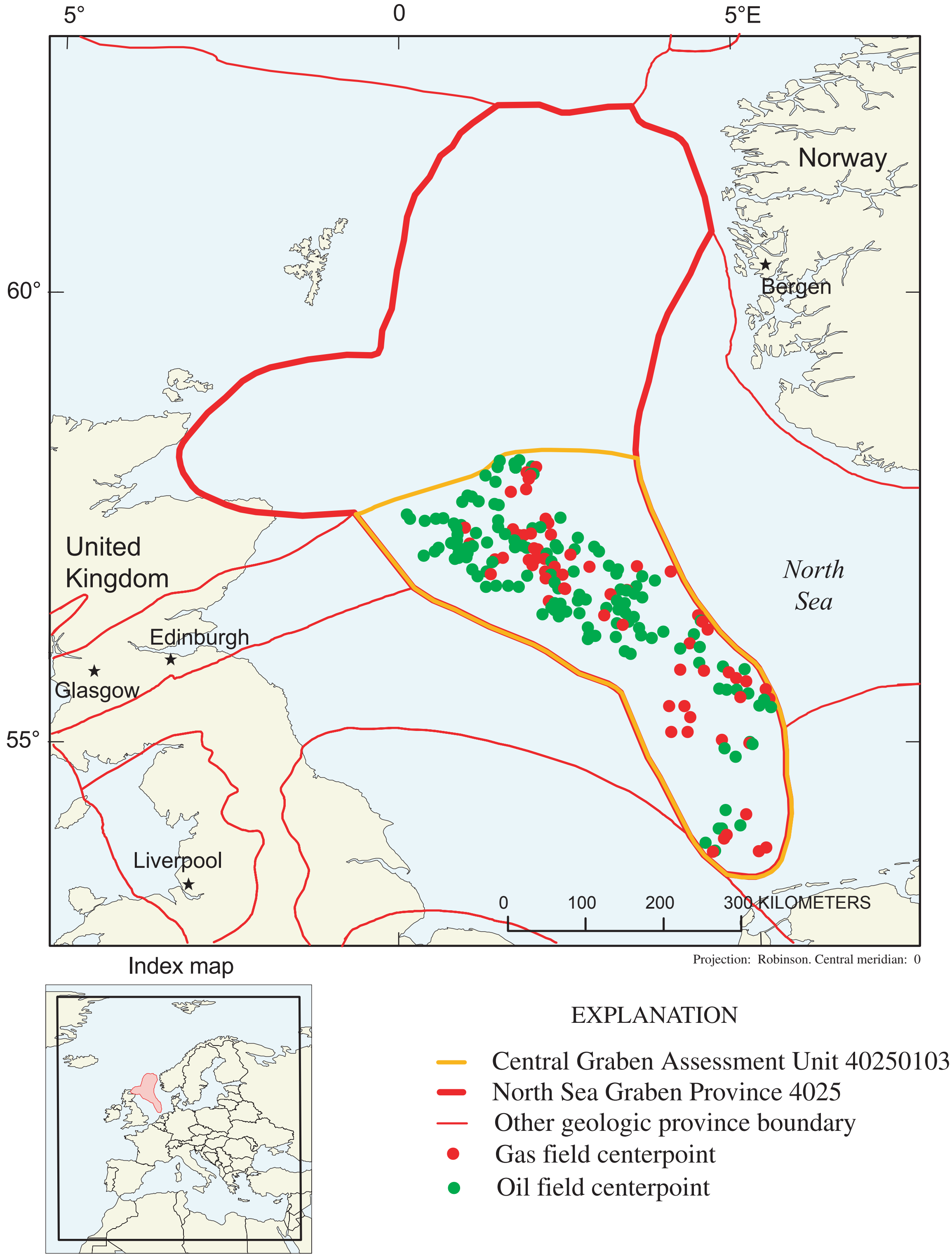


Figure 10. Boundaries of the Central Graben Assessment Unit (40250103).

Table 1. Assessment results summary for the Kimmeridgian Shales Total Petroleum System 402501, including results for three assessment units.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. MFS, minimum field size assessed (MMBO or BCFG). Prob., probability (including both geologic and accessibility probabilities) of at least one field equal to or greater than the MFS. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95-percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. Shading indicates not applicable]

Code and field type	MFS	Prob. (0-1)	Undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
40250101	Viking Graben Assessment Unit													
Oil fields	2	1.00	2,256	6,730	14,804	7,412	2,090	6,513	15,741	7,419	116	380	991	445
Gas fields	12						4,700	13,513	28,785	14,773	173	528	1,226	592
Total		1.00	2,256	6,730	14,804	7,412	6,790	20,027	44,527	22,192	289	908	2,216	1,036
40250102	Moray Firth/Witch Ground Assessment Unit													
Oil fields	2	1.00	269	857	1,923	947	199	666	1,633	758	11	39	102	45
Gas fields	12						356	963	1,732	994	16	47	93	50
Total		1.00	269	857	1,923	947	555	1,629	3,365	1,752	28	85	196	95
40250103	Central Graben Assessment Unit													
Oil fields	2	1.00	1,726	4,391	8,833	4,740	1,259	3,424	7,555	3,791	69	201	478	227
Gas fields	12						3,231	9,169	19,523	10,011	148	445	1,034	500
Total		1.00	1,726	4,391	8,833	4,740	4,490	12,594	27,079	13,801	218	646	1,512	728
402501	**Total: Kimmeridgian Shales Total Petroleum System**													
Oil fields		1.00	4,251	11,978	25,560	13,098	3,548	10,603	24,930	11,967	197	620	1,571	717
Gas fields							8,287	23,646	50,041	25,778	338	1,019	2,354	1,142
Total		1.00	4,251	11,978	25,560	13,098	11,835	34,250	74,971	37,745	534	1,639	3,924	1,859

the basin by the absence of Paleogene sandstones but is not clearly limited on the western side of the basin.

Undiscovered Resources of the North Sea Graben

The principal purpose of the USGS World Petroleum Assessment 2000 was to develop a set of consistent, scientifically grounded estimates of potential additions to reserves of oil and gas in the most important petroleum provinces of the world. In the North Sea Graben Province, this assessment was based upon the evaluation of undiscovered oil and gas resources in the three assessment units (Viking Graben, Moray Firth/Witch Ground, and Central Graben) of the Kimmeridgian Shales Total Petroleum System.

Probabilistic evaluations were made of the sizes, numbers, and properties of accumulations of oil, gas, and natural gas liquids within each AU. Additional information concerning the history of exploration and production within each AU was also provided. Details of the input data and results of the World Petroleum Assessment 2000, as well as extensive documentation of methodology and background information used in the work, are provided in the four-CD publication U.S. Geological Survey Digital Data Series DDS–60, "U.S. Geological Survey World Petroleum Assessment 2000—Description and Results" (U.S. Geological Survey World Energy Assessment Team, 2000).

Important as methodological considerations are, the World Petroleum Assessment 2000, at its core, is based upon considerations of the local petroleum geology and the history of exploration, discovery, and production. The central and northern North Sea has been the site of intensive application of sophisticated technology since development began in the 1960s. Because of the extensive literature and detailed public data available, this exploration history was highly influential in the assessment process.

In the course of developing preliminary information in advance of the formal assessment, several approaches to resource analysis in the North Sea were attempted. For example, a numerically based discovery process model was applied to the data, with interesting results, some of which have been published separately from the World Petroleum Assessment 2000 report (Drew and Schuenemeyer, 1997).

As reported in the World Petroleum Assessment 2000 report (table 1), undiscovered oil resources in the North Sea Graben Province as a whole were estimated to range from 4.3 to 25.6 billion barrels of oil (BBO), with a mean estimate of about 13 BBO. In addition to these quantities of undiscovered conventional oil and associated and nonassociated natural gas, the North Sea Graben Province probably contains significant additional amounts of natural gas liquids in both oil and gas accumulations.

Of this province-level total, the Viking Graben was believed to contain 2.3 to 14.8 BBO, with a mean estimate of 7.4 BBO. The Moray Firth/Witch Ground was thought to have about 0.3 to 1.9 BBO and a mean value of slightly less than 1 BBO of undiscovered oil. The Central Graben was estimated to have undiscovered oil resources of 1.7 to 8.8 BBO, with a mean value of 4.7 billion barrels.

It was also estimated that the province contains 11.8 to 75.0 trillion cubic feet (TCF) of undiscovered associated and nonassociated natural gas in fields larger than 12 billion cubic feet (BCF), with a mean estimate of 37.7 TCF. The Viking Graben was estimated to contain the most undiscovered natural gas, with a range of 6.8 to 44.5 TCF undiscovered and a mean value of 22.2 TCF. The Moray Firth/Witch Ground was thought to have between 0.6 and 3.4 TCF of undiscovered conventional natural gas in fields larger than 12 BCF and a mean undiscovered gas resource of about 1.8 TCF. The Central Graben was estimated to hold between 4.5 and 27.1 TCF of undiscovered gas with a mean estimate of 13.8 TCF in fields larger than 12 BCF.

During the previous USGS world assessment, published by Masters and others (1997), an assessment was made of "the Central North Sea" of the United Kingdom and Norway, an area similar to the North Sea Graben Province of the World Petroleum Assessment 2000. In that study, which used different methods, data, and people, undiscovered oil resources were estimated to be about 10 BBO, and undiscovered gas resources were estimated to be about 40 TCF, provincewide. Thus, the mean values of undiscovered oil and gas resources in the present study are similar to those of the previous study, with the current study reporting slightly more undiscovered oil and slightly less undiscovered gas.

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