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PLAY-BASED EXPLORATION AND COMMON RISK SEGMENT ANALYSIS OF THE MAIN CENOZOIC PLAYS IN THE NORWEGIAN NORTH SEA

A master thesis submitted to the Aristotle University of Thessaloniki (coordinating institution) in the fulfillment of the requirement of Inter-University Master of Science in 'Hydrocarbon Exploration and Exploitation'

by

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Submission date February 2019

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M.Sc. in 'Hydrocarbon Exploration and Exploitation'

An enormous thank you to my “unsung heroes”, Π.Μ.Χ.Σ.

PREFACE

The MSc thesis, titled *Play-based exploration and common risk segment analysis of the main Cenozoic plays in the Norwegian North Sea*, was undertaken in partial fulfillment of the interdepartmental Master's degree in "Hydrocarbon Exploration and Exploitation", offered by the Aristotle University of Thessaloniki. The aim of the dissertation is to utilize hydrocarbon probability mapping in order to refine and identify additional petroleum potential in the target area of the thesis, the Norwegian North Sea.

In the context of a petroleum conference in France, I attended a number of thought-provoking talks and observed a number of things that aroused my interest in this subject, which is also of great importance in my country. It should be noted that due to Greece's geographical position and geological structure, hydrocarbon exploration and exploitation have become prominent in recent years.

This project is addressed to anyone who is interested or involved in the exciting field of hydrocarbon exploration and exploitation, either in an academic or a professional capacity. I hope that this work is both factually relevant and academically stimulating.

ACKNOWLEDGEMENTS

Without the presence, support and tolerance of certain valuable persons in my life, I would not have been able to carry out this project. Special thanks are due to my supervisor, Professor Filippos Tsikalas, who is currently employed by Vår Energi (earlier named Eni Norge) as Senior Principal Exploration Advisor and Chief Geologist in Barents Sea. He is also Adjunct Professor at University of Oslo, Norway, a country which is highly advanced in terms of petroleum exploration. I am grateful for the opportunity he has given me to further develop my skills and knowledge in my chosen field of study. I would also like to extend my thanks to my co-supervisor Professor Andreas Georgakopoulos for his continuous scientific, intellectual, and moral support provided to me throughout the process of completing my MSc studies and thesis.

Exprodat (a Getech Group company) is highly acknowledged for providing an academic license to the Inter-University Master of Science Program in 'Hydrocarbon Exploration and Exploitation' for the use of the *Exploration Analyst* software (a plug-in to ESRI's ArcGIS), which made a significant contribution to the study and was the conversion tool in the construction of the play risk element maps. Special thanks go also to Dr. Chris Jepps (Chief Operating Officer at Getech/Exprodat), who was always very kind and made himself available whenever help was needed.

ABSTRACT

The main Cenozoic, i.e. Paleocene and Eocene, plays in the Norwegian and UK parts of the North Sea have been mapped and studied. Play fairway mapping techniques have been initially reviewed and then utilised to construct play chance and common risk segment (CRS) maps for the Paleocene and Eocene plays and their associated play elements. As Paleocene and Eocene fields comprise an important part of the discovered oil and gas fields in the North Sea, assessing these plays in a systematic way could potentially lead to maximizing discoveries. During the Paleocene and Eocene periods, uplift of the basin margins resulted in a series of submarine fans transported from the Shetland Platform towards the east, and provided the reservoir in a series of stratigraphic and combined traps. Concerning, the active petroleum system this is related to the prolific source rock of the Upper Jurassic Kimmeridge Clay/Draupne Formation, and generated and expelled hydrocarbons. The main part of the study included the construction of all associated play elements both for the Paleocene and Eocene plays: (1) reservoir presence and effectiveness; the latter was split into reservoir thickness and burial depth; (2) source rock presence and effectiveness; the latter was split into vertical effectiveness representing maturity and thus generation and expulsion of hydrocarbons, and horizontal effectiveness representing the effectiveness of the carrier system with hydrocarbon migration and charging; and (3) seal presence and effectiveness. A series of maps depicting the various play risk elements have been subsequently constructed utilising *Exprodat's Exploration Analyst* software (a plug-in to ESRI's ArcGIS). In particular, for each play element a proxy conversion table was constructed based on publicly available data and detailed geological reasoning, and the software was utilized as a conversion tool. The final outcome for each play is a single CRS map that derives from the combination (multiplication) of the intermediate combined outcomes. Furthermore, creaming curves have been presented and reviewed for the Paleocene and Eocene plays in the North Sea, together with yet-to-find (YTF) resources for these plays that appear to represent considerable undiscovered resources. The final CRS maps for both the Paleocene and Eocene plays from this study can be used in combination with the available wells to chase further the two plays in a local-scale on available 2D, and mainly 3D seismic reflection data**.** Play-based exploration can contribute significantly in this aspect by addressing the key risk play elements to be considered in the exploration effort.

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1. INTRODUCTION

1. Chapter 1

1. INTRODUCTION

North Sea is a shallow epicontinental sea that comprises the northeastern arm of the Atlantic Ocean. The North Sea is located between the British Isles and the mainland of northwestern Europe and is covering an area of approximately 570,000 sqkm. It is bordered by the island of Great Britain to the southwest and west, the Orkney and Shetland islands to the northwest, Norway to the northeast and Denmark to the east (Fig. 1.1).

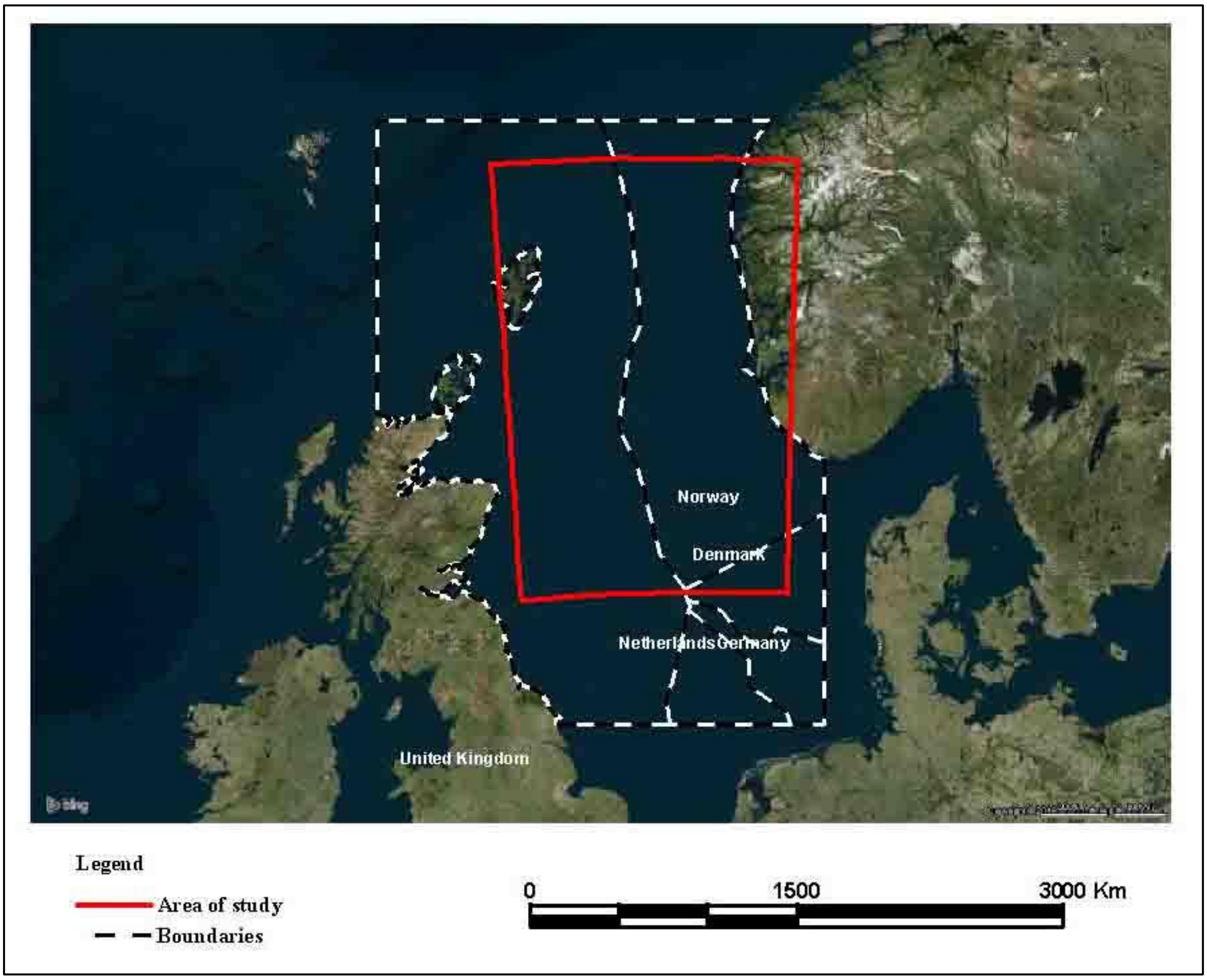


Figure 1.1: North Sea location and study area outlined by red polygon.

The North Sea is connected to the Atlantic by the Strait of Dover and the English Channel and opens directly onto the ocean between the Orkney and Shetland islands and between the

Shetland Islands and Norway. The Skagerrak, an eastward extension of the North Sea between Norway and Denmark, connects the North and Baltic seas via the Kattegat and the Danish straits. The North Sea exhibits water depths, in general, significantly less than 200 m (Fig. 1.2), although glacial erosion has resulted in deeper waters in the extensive Norwegian Channel that leads northwards into the Norwegian Basin. The continental break of slope to the Norwegian Basin is evident only in the far north.

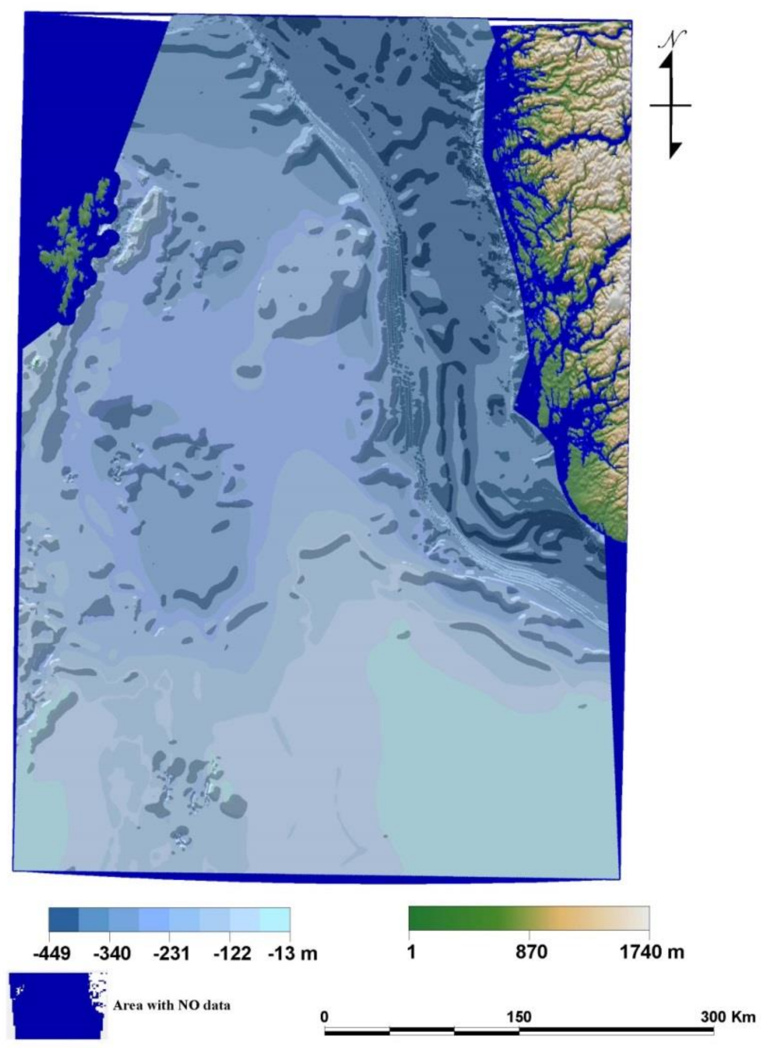


Figure 1.2: Bathymetry of the study area. This map is based on a map by British Geological Survey (1987), and data supplied by Statoil.

Exploration in the North Sea, since 1966, has involved drilling approximately 1750 exploration and appraisal wells and resulted in some 270 discoveries with originally recoverable hydrocarbon reserves and resources of ca. 8.5 x 10^9 Sm^3 oil equivalent (50 x 10^9 bbl). The occurrence of these hydrocarbons is intimately associated with the presence of a complex late Jurassic to early Cretaceous rift system buried beneath a Cretaceous and Tertiary cover. Thick, organic-rich, syn-rift mudstones were laid down throughout most of the rift system and provide the main source rocks. Reservoir rocks, principally sandstones, occur in every system from Devonian to Oligocene, and several geological plays (confirmed or potential) have been mapped in the region. Although North Sea is a mature hydrocarbon province with more than 50 years of exploration, there are still discoveries that are being made. Assessing geological plays in a systematic way and potentially maximizing discoveries is a key priority for the North Sea. In this context, play-based exploration (including play fairway mapping and common risk segment analysis) provides perhaps the most effective way of presenting regional prospectivity analysis without requiring detailed prospect specific knowledge. Play fairway mapping builds and leverages on understanding of the existing basins, petroleum systems and geological plays contained in a region. The creation of a petroleum play utilises its essential elements, namely the source rock, reservoir and sealing lithologies in combination with plausible migration pathways and the maturity of the source rock(s). Considering a systematic play-based exploration approach and common risk segment analysis for key plays can further contribute to better map the various plays and thus lead to further discoveries.

The study area of the thesis comprises the Norwegian and UK parts of the North Sea located between latitudes of 55° 20’N and 62°N. The area extends east-west from close to the Norwegian coast and 6° E to near the coast of the Scottish mainland and a projected line close to the eastern coasts of Orkney and Shetland to the Greenwich Meridian at 62°N (Fig. 1.2). The thesis focuses on the Norwegian North Sea and includes also part of the UK North Sea and deals specifically with the main Cenozoic, Paleocene and Eocene, plays. The main objectives include the following:

- review the main exploration plays in the Norwegian North Sea, and perform updated mapping focussing on the Paleocene and Eocene plays

- utilise modern play fairway mapping (play-based exploration) techniques to construct play chance (Common Risk Segment, CRS) maps for the Paleocene and Eocene plays and their associated play elements
- analyse the basin maturity through construction of basin and play statistics, including field size distributions, exploration success rates and creaming curves focussing specifically on the Cenozoic plays
- review yet-to-find resources with focus on the examined main Cenozoic plays

2. Chapter 2

GEOLOGICAL FRAMEWORK

2. EXPLORATION HISTORY

2.1 Exploration history

It wasn't until the 1960s that exploration in the North Sea really begun, without success in the early years. Geologists estimated that the same rock formations might be found beneath the southern North Sea basin in UK waters. They were right and gas discovered off English East Coast in the 1960s. The first exploration well in the Norwegian sector was Nor 8/3-1. However, the first Norwegian discovery was not drilled until 1967 when the Balder Field well, Nor 25/11-1, found oil in Paleogene sandstones. Twelve exploration wells were drilled in the central or northern part of the UK North Sea before oil was discovered in Eocene and Paleocene sandstones in well UK 21/30-1, now called Gannet Field, in March 1969. Interestingly, this field did not start production for nearly 30 years, when the building of adjacent infrastructure, amongst other factors, made it economic in 1997.

The amount of exploration drilling in the North Sea since 1964 has fluctuated in response to many factors. These are indicatives of the influence of oil price, which itself may be affected by both political and economic global events. The Norwegian exploration drilling effort, for example, appears to have fluctuated directly with oil prices, but may equally be compared with the licensing rounds or changes in the fiscal regime. In the Danish sector, the frequency of drilling appears to follow a cyclical trend similar to that for Norway. In the UK, the first peak in the number of exploration wells in 1975 could have been in response to the oil price increase due to political instability in the Middle East, but may also be due in part to the success of the 4th licensing Round.

Discoveries of petroleum and natural gas beneath the seafloor began in 1959, when a seaward extension of a major natural gas field in the northeastern part of the Netherlands was identified. Within two decades, natural gas production sites were located along a 160-km band stretching from the Netherlands to eastern England. Farther north, Norway's first offshore oil field went into production in 1971, and the United Kingdom began recovering offshore oil from the North Sea four years later. The two largest producers are Norway and the United Kingdom, and until 1990 the annual yields of the two countries were comparable. By the early 21st century, however, Norway had clearly become the leader of oil and gas production in the North Sea region. Other minor producers include Denmark, the Netherlands, and Germany. New fields are being explored and developed farther north in the Norwegian and Barents seas.

During exploration of the study area from the mid-1960s to today, there have been enormous changes in well-drilling and well-logging technologies. Although such technologies are applied worldwide, many innovations were first made and applied in the North Sea. Basic rig design has not changed substantially since the early days of North Sea exploration, although larger rigs have been employed more recently to cope with the high overpressures in the deeper parts of the Central Graben.

Deviated wells are particularly important for development drilling in all sectors of the study area. In the Danish sector especially, horizontal wells are common in Upper Cretaceous reservoirs where the bit can be geo-steered along particular beds based on information from immediate analysis on the rig of the biostratigraphy or heavy minerals. In order to reduce costs, operators are beginning to look at the possibilities of coiled-tubing drilling and utilizing barges instead of rigs. There has also been wide interest recently in the use of so called slim-hole drilling as a means of reducing costs, while most conventional logging technology is available in devices suited to the narrower boreholes.

2.2 Tectonic setting

The North Sea is an intra-cratonic basin and the crust beneath it has experienced several phases of crustal stretching/thinning with subsequent subsidence, which is necessary for continental basin formation. In this context, Late Carboniferous, Permian-Early Triassic, and Late Jurassic/Lower Cretaceous basins were formed. The Viking Graben rifting accompanied the Late Jurassic/Lower Cretaceous phase, where the rifting partly followed older structures (e.g. Faleide et al., 2008). The major structural elements are shown in Figure 2.1. The Viking Graben and its margins are characterized by large rotated fault blocks, important for forming traps.

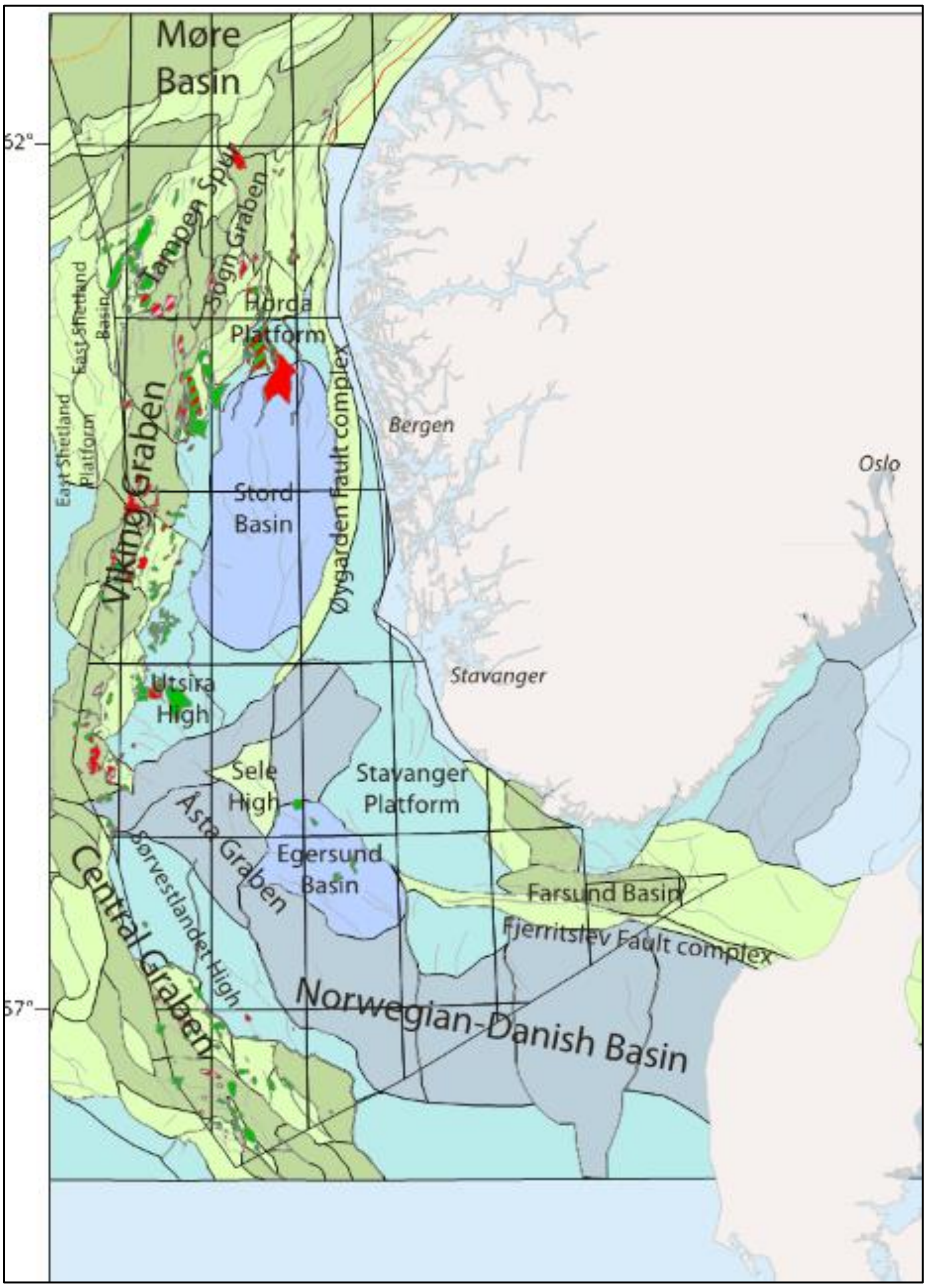


Figure 2.1: Structural elements in the North Sea (NPD, Halland et al., 2011) with major oil- and gas-fields.

The present-day structural configuration of the North Sea has resulted mainly from the Late Jurassic to Early Cretaceous rifting event. The northern North Sea-Moray Firth system is characterized by rigid, faulted-block rotation, whereas the most obvious structures in the central North Sea are dominated by halokinetic deformation. These structural styles have a direct influence on the formation of hydrocarbon traps, and structural traps can be divided into two main categories: syn-rift traps containing mainly pre-rift reservoir rocks, and post-rift traps induced by tectonic inversion and diapirism, and involving mainly post-rift reservoir rocks. The sub-Quaternary outcrop map (Fig. 2.2) shows that the largely Precambrian and Paleozoic rocks of the UK and Norway rarely crop out more than a few kilometers offshore. The only exception lies in the area to the east of Orkney and Shetland, including the East Shetland Platform.

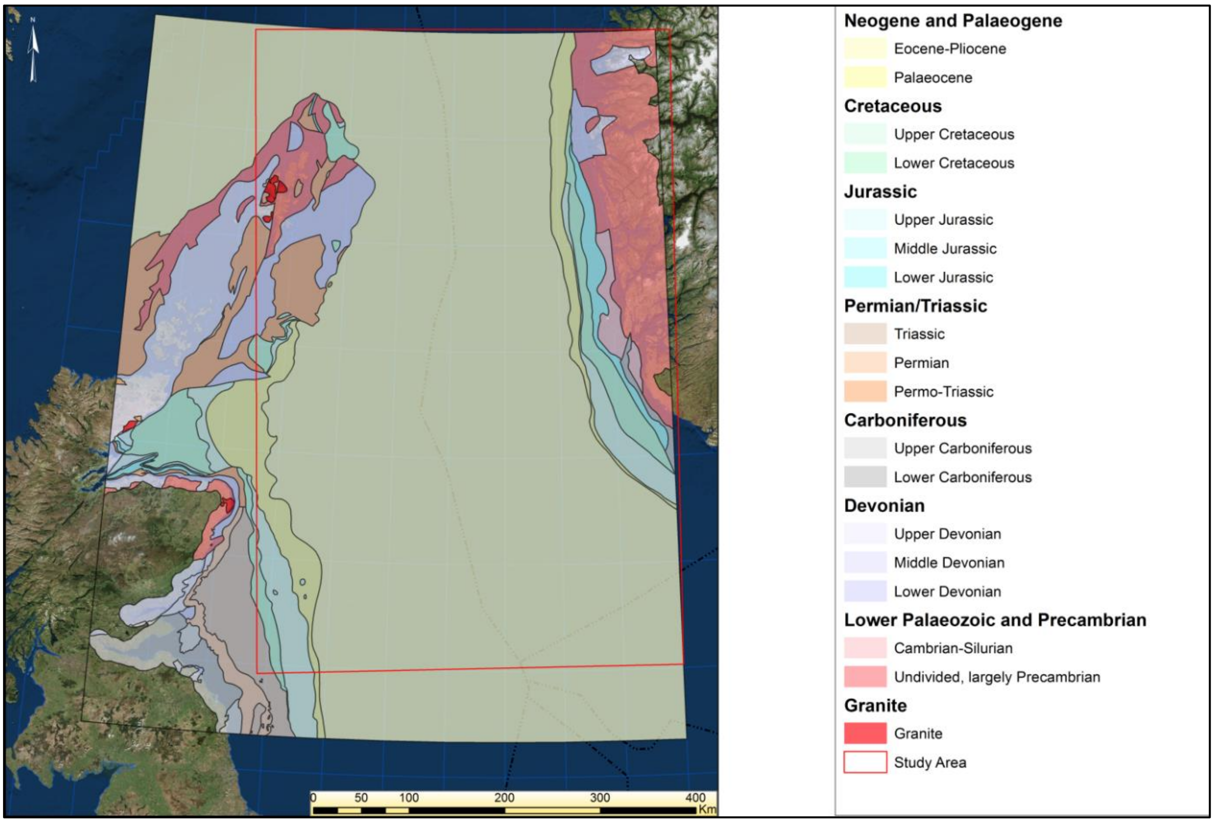


Figure 2.2: Sub-Quaternary subcrop map.

Off the coasts of northern England and Scotland, south of the Moray Fifth, the Permian and Mesozoic outcrops become successively younger away from the shore, with the base-Permo-Triassic outcrop pattern mimicking the coastline. Farther offshore, these strata are overlain by a post-rift blanket of Paleogene and Neogene sediments that thickens towards the graben at the center of the North Sea. Around the Moray Fifth coast, the outcropping Mesozoic strata are commonly in faulted contact with older rocks, and there is an extensive cover of Cretaceous rocks. Off the coast of Norway, the band of Permian to Paleocene outcrop bordering the land is narrow as younger Paleogene and Neogene strata occur relatively close to the coast (Fig. 2.2).

The distribution of the oil- and gas-fields within the study area (Fig. 2.1) shows that these are concentrated along the central zone of the North Sea, with a branch into the Moray Firth region. This is because a three-armed graben system developed, principally during Late Jurassic. This rift structure has controlled many aspects of the petroleum geology of the region. The highly organic Kimmeridge Clay Formation deposited during late Jurassic has provided the source for almost all of the oil and gas, and both the distribution and burial history of this formation has been controlled by the structural developments associated with graben rifting and post-rift subsidence. The structures that hold the hydrocarbons are many and varied, but are generally directly related to the rifting history, particularly the large, faulted-blocks of the Viking Graben that were formed during the main rifting phases. Both the syn- and post-rift development of the basin has been punctuated by important episodes of emplacement of deep water sandstones into the rift, proving many reservoirs that are readily sealed by the deep-water argillaceous rocks that surround them.

Post-rift subsidence has been centered over the main grabens, with over 5 km of post-Jurassic sediments deposited over extensive areas. However, this pattern is not reflected in the present-day bathymetry as the earlier basin configuration has been largely filled with Plio-Pleistocene deposits (Fig. 2.2). Furthermore, Quaternary glaciers have eroded the relatively deep Norwegian Channel, close to the Norwegian coast, that gives a recently acquired asymmetry to the basin topography.

The basic structural framework of the North Sea is mainly the result of Upper Jurassic/Lower Cretaceous rifting, partly controlled by older structural elements. A short description of the main geologic events at various time intervals is given below.

Carboniferous-Permian

Major rifting with extrusion of basic volcanics and deposition of reddish eolian and fluvial sandstones (Rotliegendes Formation) took place at that time interval. Two basins were developed with deposition of thick evaporate sequences (Zechstein Formation). When overlain by a sufficient amount of younger sediments, buoyancy forces caused the salt to move upwards (halokinesis). This is important for the generation of closed structures, including hydrocarbon traps, in the southern part of the North Sea and also as a control on local topography and further sedimentation.

Triassic

Major N-S to NE-SW rifting with thick coarse fluvial sediments deposited along rift margins, grading into finer-grained river and lake deposits in the centre of the basins. The transition between the Triassic and Jurassic is marked by a widespread marine transgression, both from north and south.

Jurassic

The marine transgression was followed by the growth of a volcanic dome centred over the triple point between the Viking Graben, Central Graben and Moray Firth Basin. The doming caused uplift and erosion and was followed by rifting. Large deltaic systems containing sand, shale and coal were developed in the northern North Sea and the Horda Platform (Brent Group). In the Norwegian-Danish Basin and the Stord Basin, the Vestland Group contains similar deltaic sequences overlain by shallow marine/marginal marine sandstones. The most important Jurassic rifting phase in the North Sea area took place during Late Jurassic and lasted into Early Cretaceous. During this tectonic episode, major block faulting caused uplift and tilting and created considerable local topography with erosion and sediment supply. In anoxic basins thick sequences of shale accumulated, producing the most important source rock, the Kimmeridge Clay/Draupne Formation, which acts both as a source rock and an important seal for hyrdocarbon traps in the North Sea area.

Cretaceous

The rifting ceased and was followed by thermal subsidence. The Upper Cretaceous in the North Sea is dominated by two contrasting lithologies. South of 61º N there was deposition of chalk, while to the north the carbonates give way to siliclastic, clay-dominated sediments.

Cenozoic

During the Paleocene and Eocene periods there were major earth movements with the onset of sea floor spreading in the North Atlantic and mountain building in the Alps/Himalaya. In the North Sea, deposition of chalk continued until Early Paleocene. Uplift of basin margins, due to inversion, produced a series of submarine fans transported from the Shetland Platform towards the east. These sands interfinger with marine shales in both the Rogaland and the

Hordaland Groups. In the Miocene, a deltaic system had developed from the Shetland Platform towards the Norwegian sector of the North Sea, and is represented by the Skade and Utsira Formations. Due to major uplift and Quaternary glacial erosion of the Norwegian mainland, thick sequences were deposited into the North Sea during the Neogene. This led to burial of the Jurassic source rocks to depths where hydrocarbons could be generated and the seals were effective.

2.3 Main tectonic events and structural elements

Structures which shaped the central and northern North Sea comprise both those which formed the crustal framework and those that subsequently reworked that framework into the present-day configuration. Structures that formed the pre-Mesozoic tectonic framework include those resulting from:

- Early Devonian and earlier Caledonian deformation that produced some of the major crustal lineaments
- Rifting of Devonian and Carboniferous age that was associated with large strike-slip faults

The main pulses of Mesozoic and Cenozoic deformation that shaped the structural framework of the North Sea were:

- Permian and Triassic rifting
- Thermal uplift and volcanism during Mid-Jurassic
- Late Jurassic rifting
- Latest Jurassic to Early Cretaceous rifting, including a change in rift direction
- Cretaceous to Cenozoic thermal subsidence
- Cretaceous to Cenozoic pulses of tectonic inversion
- Cenozoic uplift of the basin margins

In the area of the North Sea Central Graben there is some form of triple junction between the north-dipping thrust zones of the Southern Uplands, the thin-skinned collisional thrusts of Scandinavia and the south-easterly dipping suture of the Tornquist Sea. Closure of the Tornquist Sea and the lapetus Ocean involved soft docking, with some thin and thick-skinned thrust tectonics and basin inversion on the subducting plates, but no uplift of the obducting crustal material. Late movements along both sutures were strike-slip.

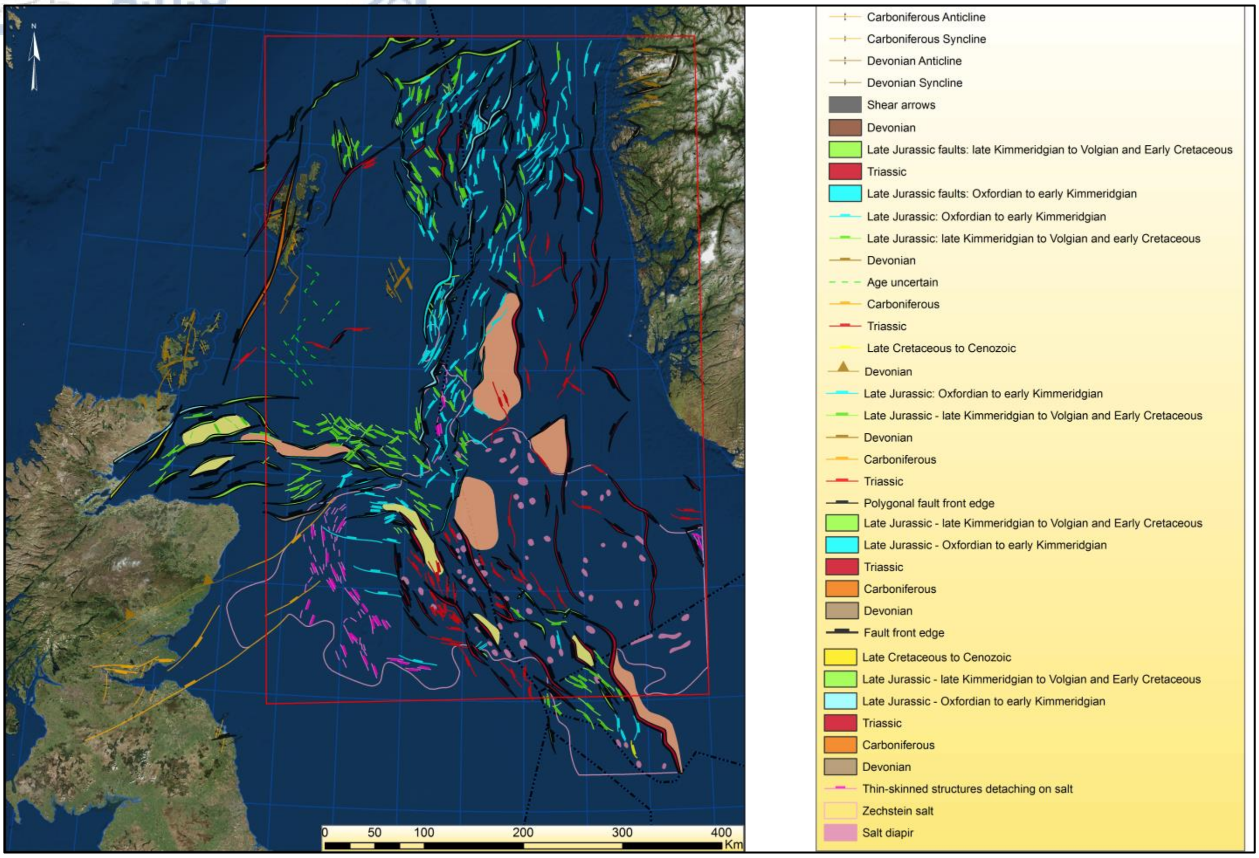


Figure 2.3: Structural framework of the study area.

Figure 2.3 shows the main tectonic elements of the Jurassic to Early Cretaceous rift system, as well as the main Triassic basins (Stord Basin, Unst Basin and Sogn Graben) and older faults. Colour coding on the faults corresponds to their principal age of movement; significant reactivation of faults is marked by the addition of subordinate colour. Three orders of faults related to their amplitude of throw are represented, showing the variably symmetric and asymmetric geometry of the rift system. Small faults with throws of less than 100 m are not represented. The limit of Zechstein salt and the locations of the main salt diapirs are shown and the movement of Zechstein salt has been a major factor controlling the style of deformation and hydrocarbon trapping in the central North Sea.

Central Graben

In the Central Graben area rifting took place during Permian-Early Triassic and Middle-Late Jurassic times, and Zechstein salt was deposited north of the Mid-North Sea High. When this area was first drilled, the target was the Permian sandstones beneath the salt. It was by accident that oil was discovered in the Upper Cretaceous rocks (Chalk). Ekofisk was the first field to be discovered, but now there is a string of fields with Upper Cretaceous reservoirs, both on the Norwegian side and in the Danish Sector.

There are other sandstone reservoirs too, such as those of Upper Jurassic age in the Ula and Gyda fields. These fields are found south of the Brent delta, which excluded the Brent Group from forming reservoir rocks there. The area was uplifted and Middle Jurassic sediments are mostly absent. Later, oil has been found in Upper Paleozoic reservoir rocks which had been the original prospecting target in the area. In the Embla Field, the reservoir rock is a sandstone believed to be of Devonian age.

The Ekofisk Field, discovered in 1969, was the first large oil-field in Europe. The Chalk in the Ekofisk reservoir is of the same type as we have onshore in Denmark and eastern England in stratigraphic levels approaching the Cretaceous/Cenozoic boundary (Maastrichtian and Danian). Chalk lithologies had previously been assumed to be far too fine-grained to be reservoir rocks, and Ekofisk was the first large oil-field of this type. The Austin Chalk in Texas is one of the few other occurrences where Chalk forms a reservoir rock, but the fields there are fairly small by comparison.

2.3.1 Paleozoic continental collision and plate accretion

Devonian: West Viking Graben

Devonian basins were probably much more widespread than is evident today. Grabens occur both onshore and offshore southern Norway, and a large pre-Permian, probably Devonian, basin developed in the northern North Sea. This basin was possibly formed by gravitational collapse of the thickened crust, but also by pull-apart development. This pull-apart system was bounded by the Great Glen-Møre-Trøndelag fault zone in the north-west and by the Midland Valley-Solund fault systems in the south-east. An analogous pull-apart system may have developed south of the Files/Vestfjorden fault zone. Paleomagnetic data (Torsvik et al., 1996) confirm that Baltica and Laurentia were moving laterally relative to each other at this time.

Roberts et al. (1999) argued that the basal thin-skinned extensional detachments of western Norway link with inclined structures in the middle and lower crust that were associated with the lapetus suture. This thin-skinned extension probably involved at least 200-300 km of normal fault movement to achieve vertical uplift and denudation of about 60 km, as evidenced by Caledonian eclogites unconformably overlain by Devonian sediments in western Norway. According to Coward (1993), the pull-apart basin in the northern North Sea was deep, forming the proto-Viking Graben. It may account for much of the crustal thinning in the Viking Graben and the northern North Sea, and for the initiation of faults and sub-basins that were subsequently reactivated during the Mesozoic (Coward, 1993; Chauvet and Serrane, 1994).

Seismic data from the East Shetland Platform show a thick sedimentary sequence infilling approximately north-westerly trending grabens. These grabens were subsequently inverted with the development of north-westerly trending folds and reverse faults prior to Mesozoic sedimentation, and the structures can be traced onshore in eastern Shetland (Serrane, 1992). The Devonian basins of west Norway were folded by east-west compressional folds that become lighter northwards towards the Møre-Trøndelag fault zone and contain a weak post-folding magnetic overprint of Late Devonian to Early Carboniferous age. It is considered here that these structures record local transpressional zones within the strike-slip systems (Fig. 2.4).

Late Carboniferous

During the mid to Late Carboniferous there was reversal in the sense of displacement on the original Devonian and Late Carboniferous strike-slip and normal faults in Scotland and the northern North Sea, causing tectonic inversion (Coward et al., 1989; Roberts et al., 1999). Large inversion-related fold structures were formed in eastern Shetland and on the East Shetland Platform at this time (Serrane, 1992), and right-lateral displacement occurred along the line of the Great Glen Fault and in the Midland Valley of Scotland. In the Midland Valley, the folds are arranged en-echelon and cross the region with a right lateral offset, and thinning of sediments across the folds demonstrates growth in the mid to Late Carboniferous (Fig. 2.5).

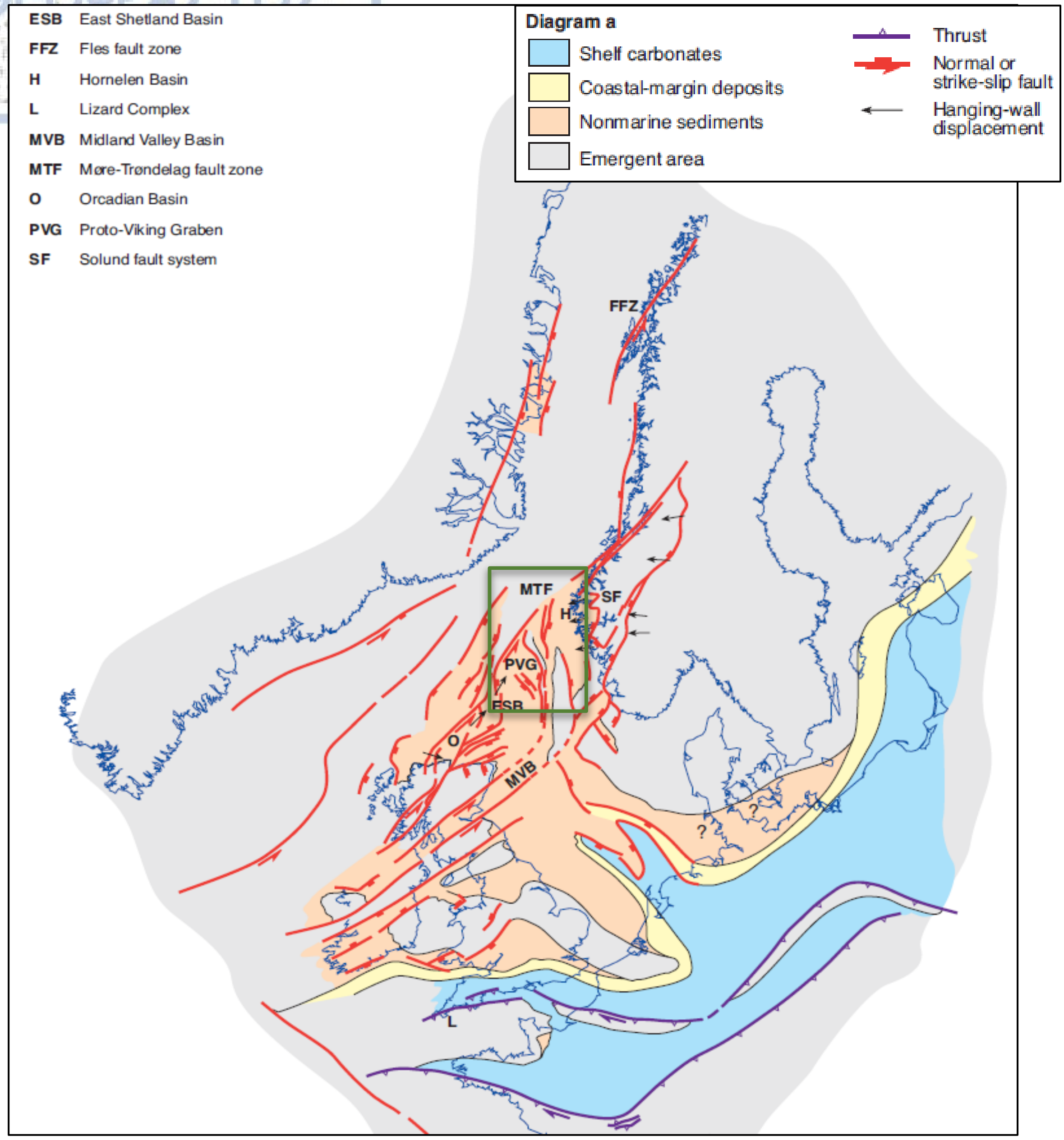


Figure 2.4: Palinspastic map of active structures and sediment facies during the Mid-Devonian.

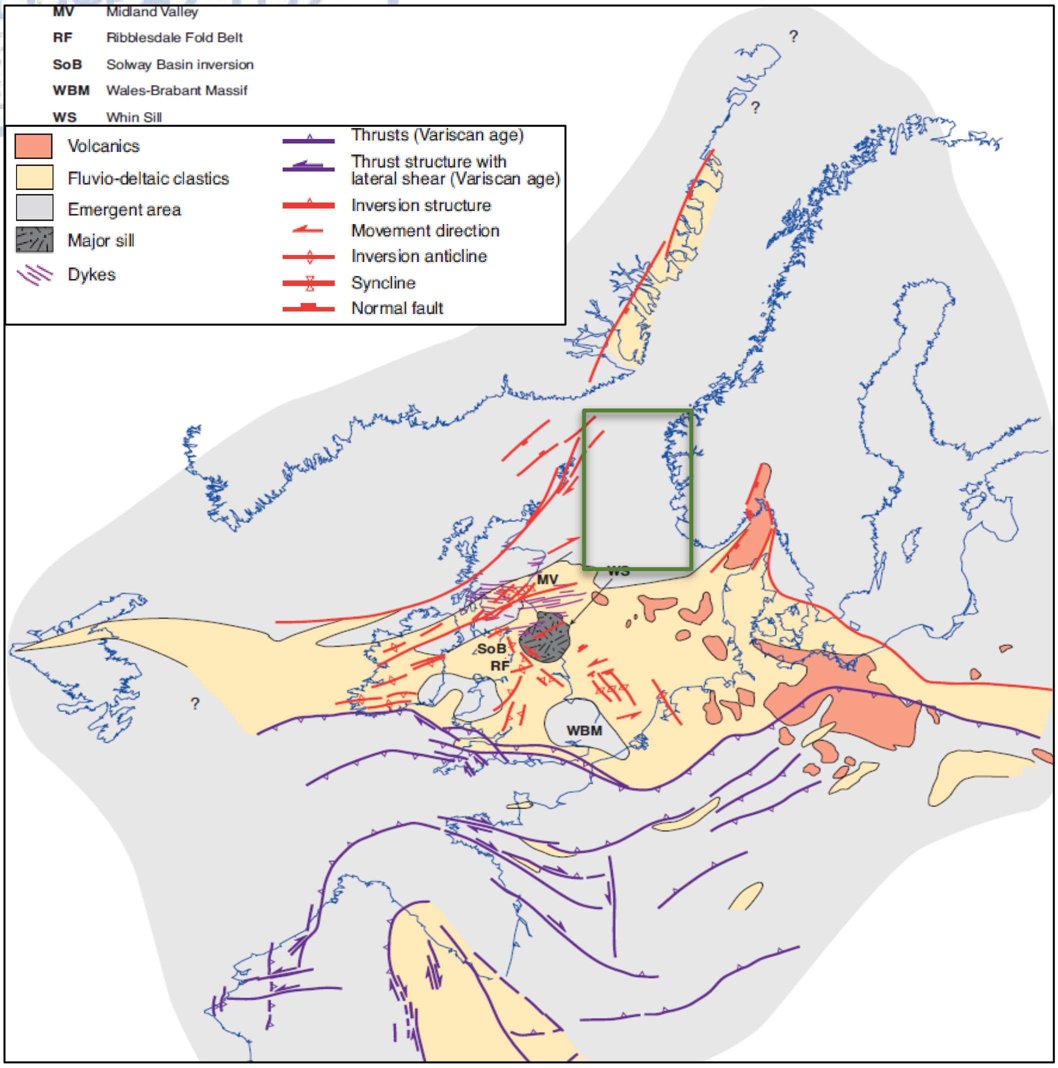


Figure 2.5: Palinspastic map for the Late Carboniferous showing the distribution of active structures and sediment facies.

Permian: East Greenland

On the Norwegian shelf, the Mesozoic shelf and section (Fig. 2.6), appears to be underlain by a thick package of Upper Paleozoic sediments, possibly deposited in a graben. A presumed intra-Permian reflector recognized on the Trøndelag Platform is possibly equivalent to the Permian carbonates exposed in East Greenland and similarly post-dates mid-Permian block faulting (Bukovics et al., 1984; Ziegler, 1985).

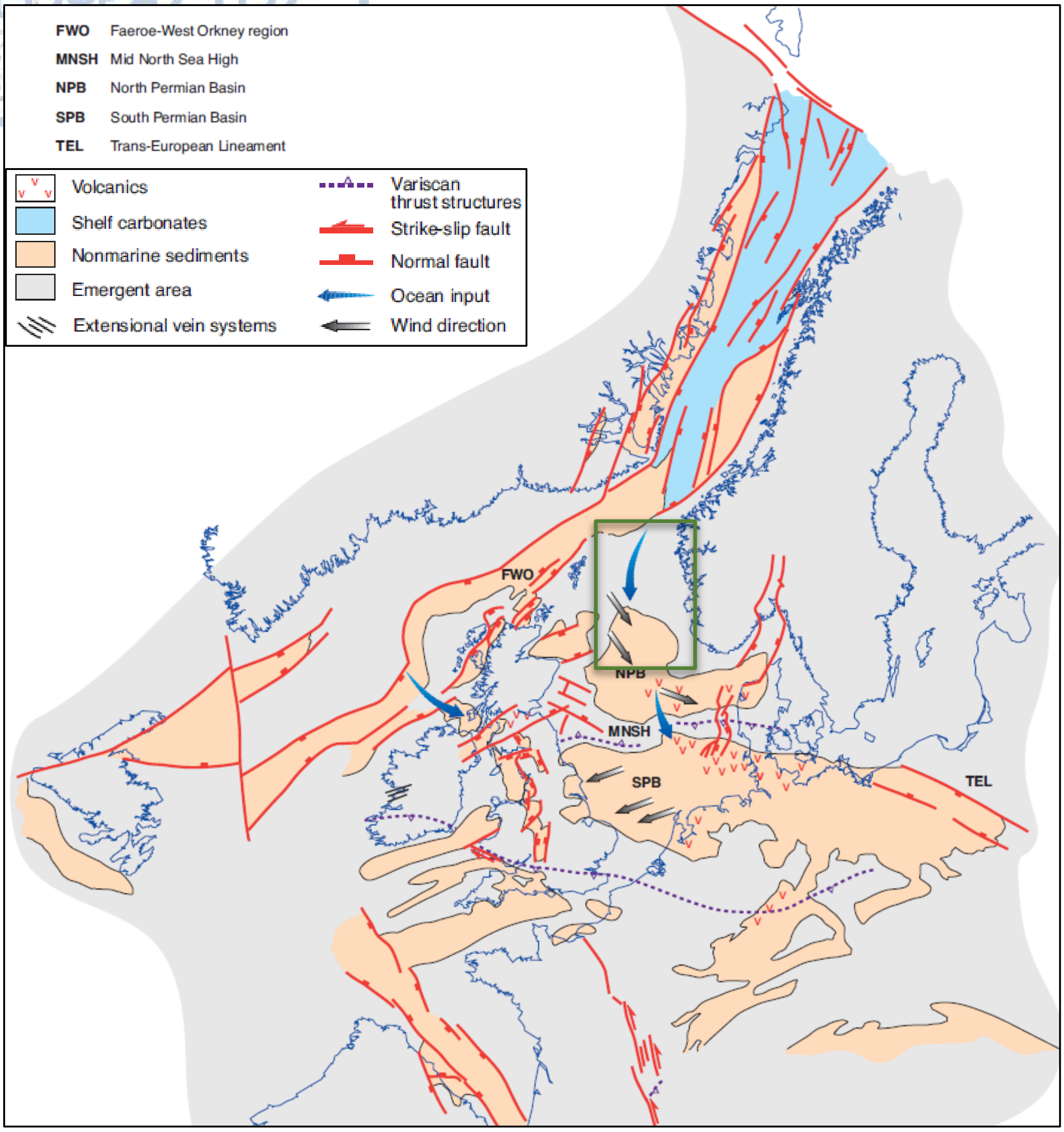


Figure 2.6: Palinspastic map for Early Permian and Rotliegend times showing the distribution of active structures and sediment facies.

2.3.2 Mesozoic continental rift tectonics

In the northern North Sea, a Devonian basin, the proto-Viking Graben, formed the locus of Jurassic-Cretaceous extension. During Cretaceous and Paleogene rifting, new basins developed to the west of the Paleozoic mountain belt of Scotland and to the west of Ireland where they cut across the Paleozoic structures

Triassic

The pattern of Triassic rifting in the study area can be differentiated from the influence of subsequent rifting during the Late Jurassic. Triassic faulting was particularly significant in the north-eastern North Sea in the region of the Øygarden Fault Zone close to the Norwegian mainland. In the central and northern North Sea, the Permian structural pattern was modified by the superimposition of a graben system that transected the Northern Permian Basin and breached the Mid North Sea-Ringkøbing-Fyn High. It has been suggested that the dominant extension direction in the northern North Sea was north-west to south-east and that the Central, Horn and Bamble grabens are pull-apart structures in a right-lateral system parallel to the Trans-European Lineament.

The presence of Zechstein salt that was deposited during Late Permian had a pronounced influence on the subsequent evolution of the North Sea Basin, beginning with its effects on Triassic sedimentation patterns. Salt tectonics were active in areas where faulting affected the Zechstein basin and mini-basins, associated with salt withdrawal, developed across much of the Central Graben. These basins are bounded by listric faults and their asymmetry demonstrates local tilting due to basement faulting and regional subsidence. Early to Mid-Triassic mini-basins subsided into the Zechstein salt over much of the central North Sea. Differential loading was important for mini-basin development near sediment entry points, and thin-skinned extension on the platforms was balanced by basement extension in the central axis of the basin. Along the edges of the Triassic fault basin, the faults are commonly soft-linked and offset through the Zechstein salt (Fig. 2.7).

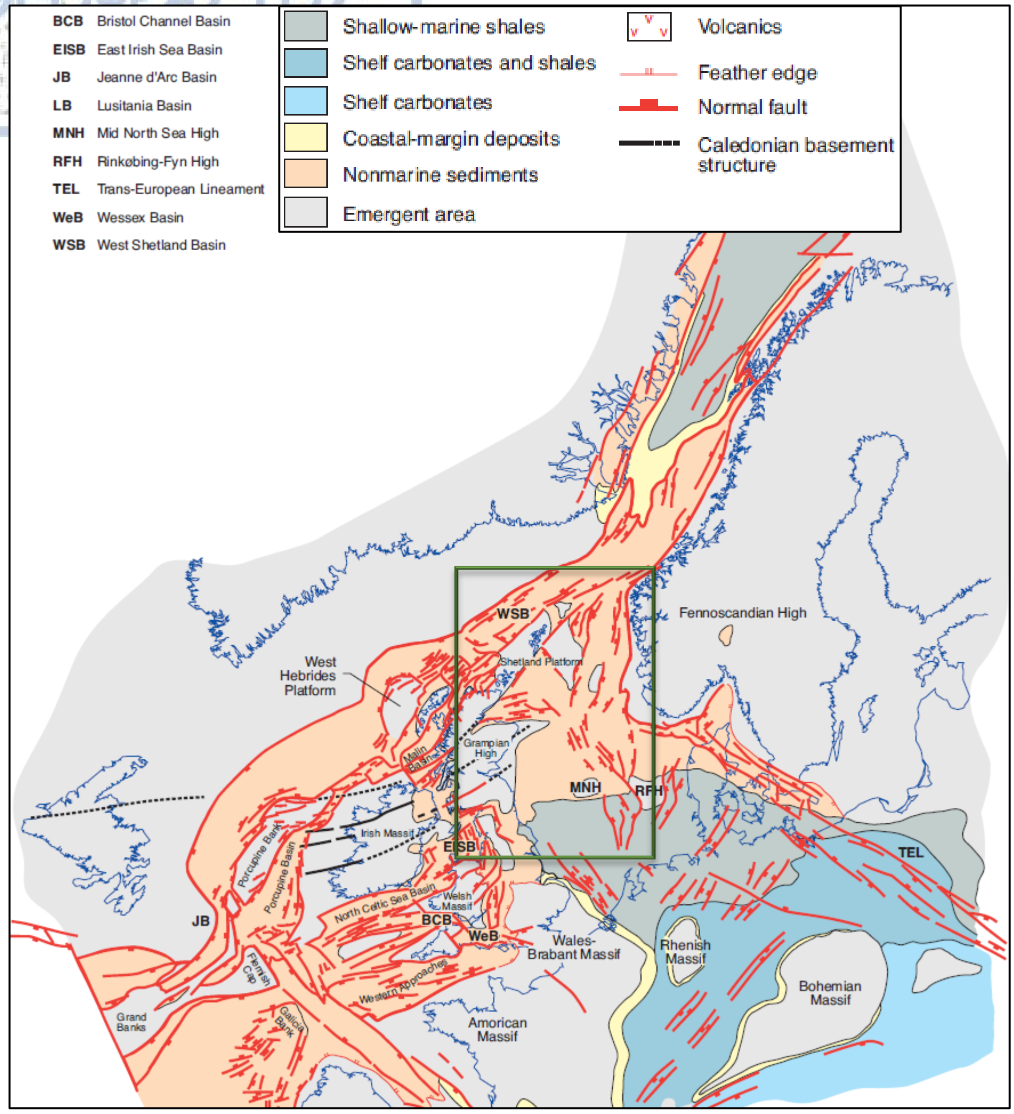


Figure 2.7: Palinspastic map for the Mid-Triassic showing the distribution of active structures and sediment facies.

Early to Mid-Jurassic

The continued northward drift of Europe in latest Triassic times, and the erosion and collapse of the Variscan mountain belt, led to an increasingly humid climate in north-west Europe, resulting in a rapid change from red to grey bends (Roberts et al., 1999). Ultimately this led to the deposition of paralic coal-bearing sediments in offshore Norway where there are up to 500 m of interbedded fluvial distributary channel sandstones, floodplain mudstones, and coals that may be local sources for gas.

There seems to have been very little Early Jurassic rifting in the northern North Sea (Fig. 2.8). The paleogeography indicates infilling of the passively subsiding Triassic-Lower Jurassic rift.

Callovian volcanics in the northern North Sea suggest the presence of a Mid-Jurassic mantle hot spot. According to Undelhill and Partington (1993), uplift associated with the hot spot allowed erosion down to Liassic or Triassic strata in the central North Sea. The shape of the Toarcian-early Aalenian regional well correlations showing the form of the Mid-Jurassic, Mid-Cimmerian Unconformity, identified as the Intra-Aalenian Unconformity by Underhill and Partington (1993). The uplift restricted, or completely closed, the seaway between the northern Boreal and southern Tethyan-Atlantic regions, causing faunal provinciality and unconformities as far west as the northern Porcupine and Slyne basins (Tate and Dobson, 1989).

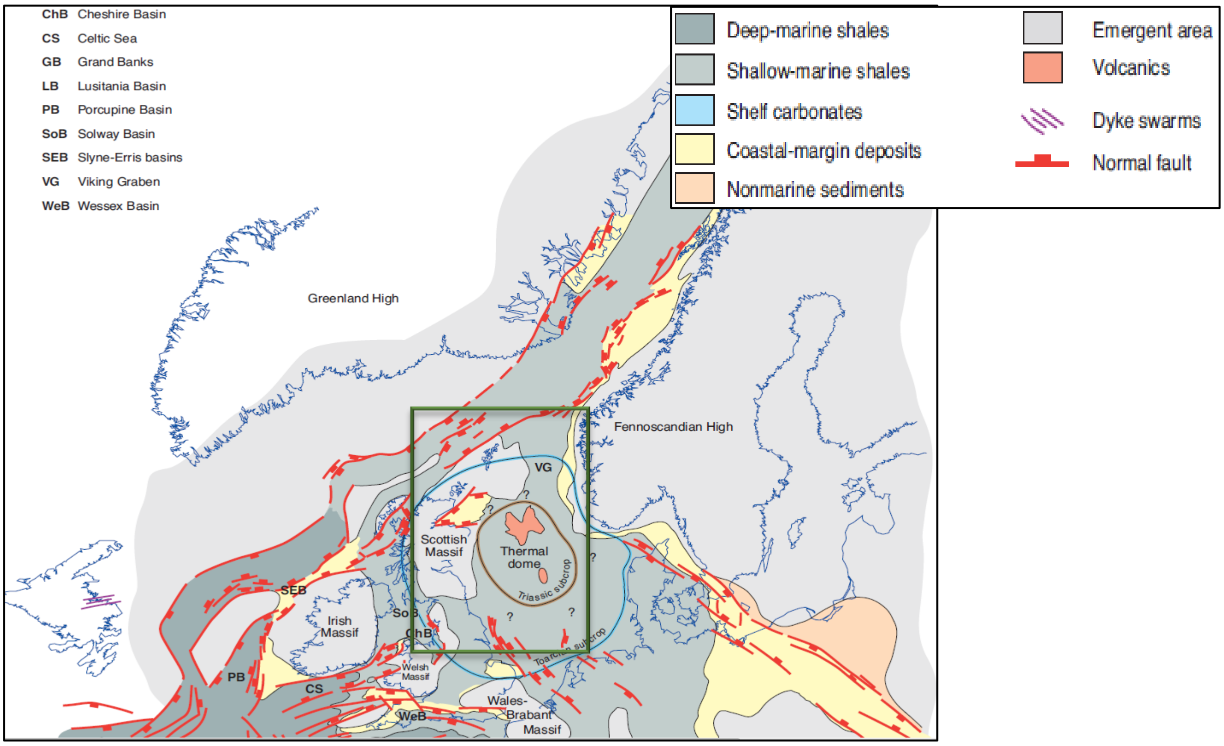


Figure 2.8: Palinspastic map for the Early Jurassic showing the distribution of active structures and sediment facies. The location of the Mid-Jurassic thermal dome in the central North Sea is also shown.

Middle to Late Jurassic

The most important rifting phase in the study area took place during the Late Jurassic, when the basic structural framework of the North Sea Basin was established. Relatively minor amounts of extension had probably begun in the Viking Graben during Bajocian to Bathonian times, but during the Callovian to early Kimmeridgian the rifting in the Arctic spread into the North Sea. There it formed north-easterly trending normal faults with north-westerly trending tear and transfer faults in the Viking Graben. In the northern North Sea and Viking Graben, there is evidence for continued extension during Oxfordian, and presumably the same occurred in parts of the mid-Norway shelf. This zone of extension can be traced into the Moray Firth. In the central North Sea much of the extension was oblique-slip, along earlier Triassic faults. However, some Late Jurassic grabens in southern Norwegian and Danish waters were nearly perpendicular to this extension, and in the eastern part of the Viking Graben the major Triassic faults were largely abandoned as basin development moved farther west.

There were multiple pulses of faulting separated by intervening stages of relative tectonic quiescence, this provided a fundamental control on sedimentation in the study area. For instance, the faulting created a considerable local topography, with pronounced footwall highs that became significant landmasses and provided a supply of sediment sufficient to fill adjacent basins, but elsewhere lesser footwall uplift led to relative sediment starvation (Fig. 2.9).

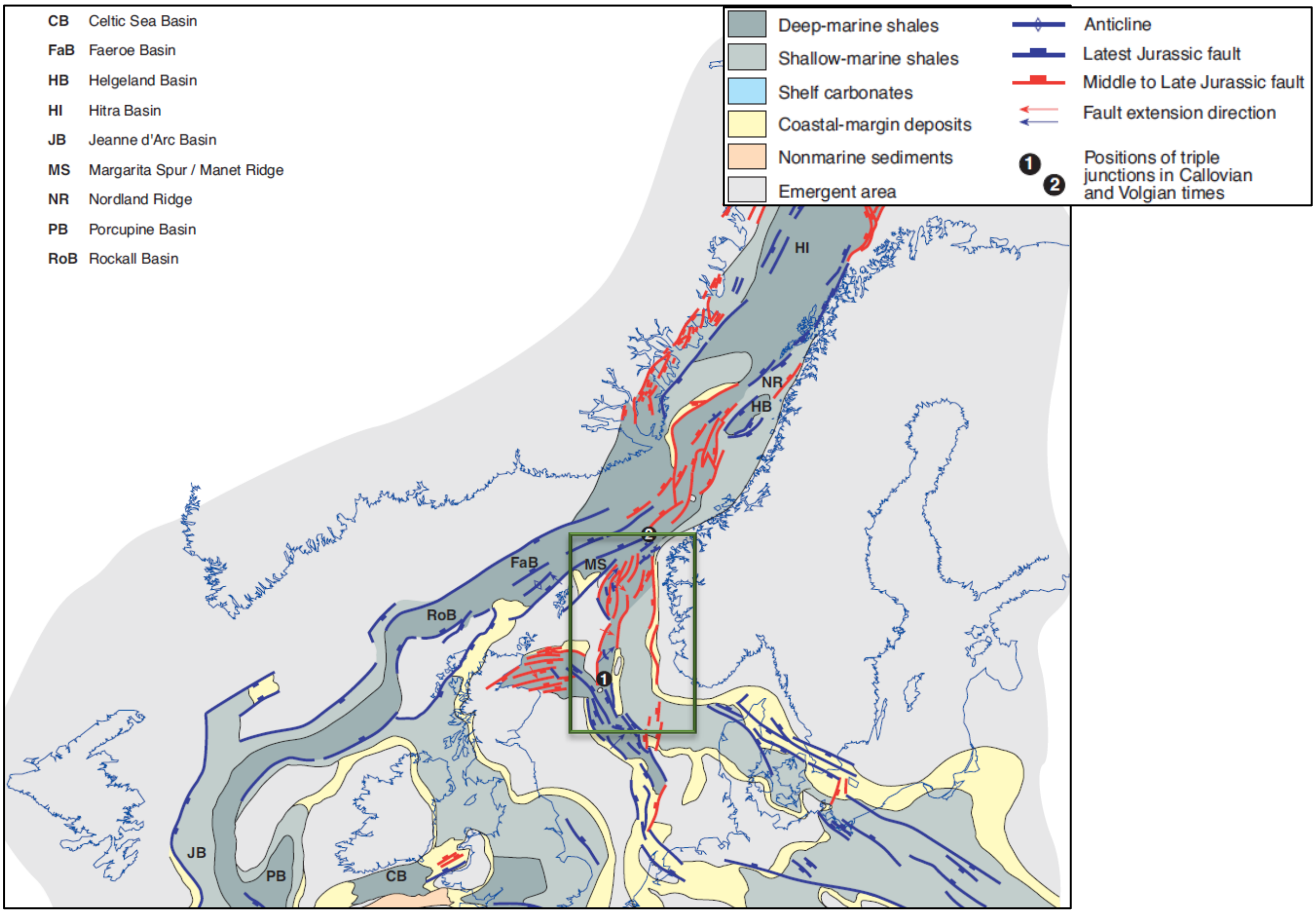


Figure 2.9: Palinspastic map for the Late Jurassic showing the distribution of active structures and sediment facies.

Early Cretaceous

In the central and northern North Sea, normal faults were still active during the earliest Cretaceous, with deposition of clastic wedges against the faults scarps. Extension ceased during the Early Cretaceous with the onset of passive thermal subsidence, the syn-rift topography was covered by transgressive sediments to form the so-called Base Cretaceous Unconformity. Marine shale deposition predominated (Fig. 2.10), the uplifted footwalls were gradually onlapped and covered, although there were several pulses of minor fault reactivation, possibly due to compaction of earlier sediments. The stratigraphy of the Lower Cretaceous records the competing effect on accommodation space of initial topographic relief inherited from Volgian rifting, of post-rift thermal collapse and of long-term changes in global sea level, all overprinted by local halokinetic and tectono-eustatic events.

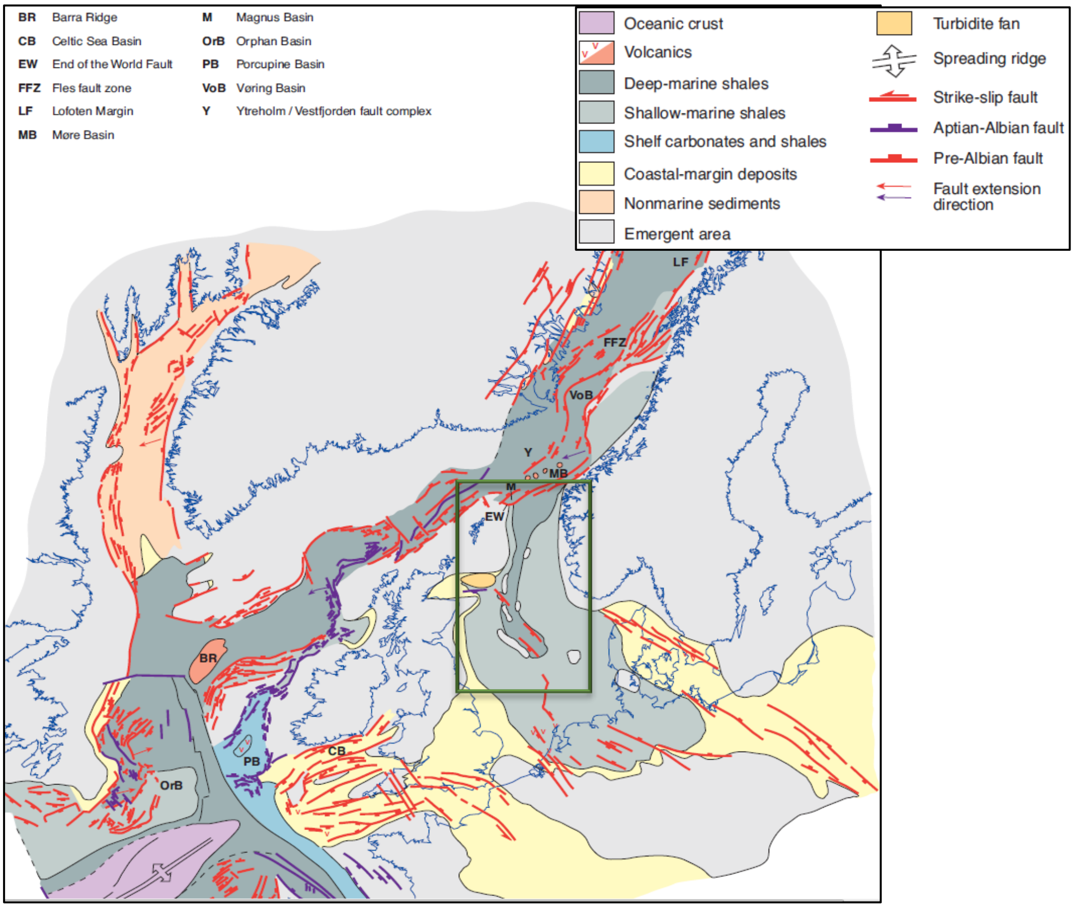


Figure 2.10: Palinspastic map for the Early Cretaceous showing the distribution of active structures and sediment facies.

Late Cretaceous

The North Sea also underwent post-rift thermal subsidence, although inversion affected a broad swathe of the central North Sea, in particular the southern part of the Central Graben in the Danish sector (Cartwright, 1989). This inversion varied in intensity and timing along strike, and was probably associated with early Alpine collision in eastern Europe. These tectonic events exerted a profound influence on chalk deposition in the central North Sea because reversal of fault movement and uplift of local blocks triggered widespread mass movement of chalk that was redeposited in slope and basinal settings (Fig. 2.11).

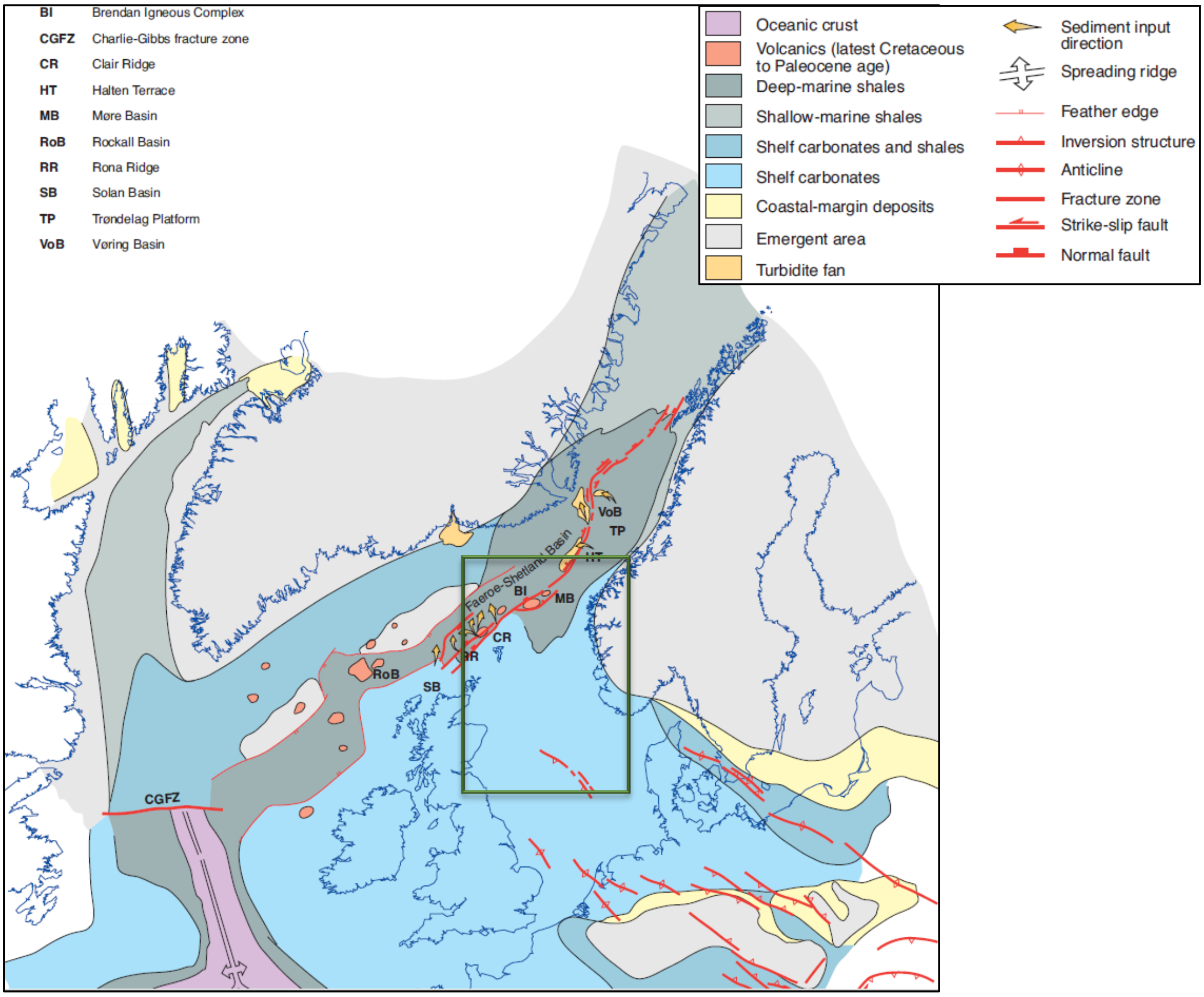


Figure 2.11: Palinspastic map for the Late Cretaceous showing the distribution of active structures and sediments facies. Coastlines are uncertain.

2.3.3 Late Mesozoic to Cenozoic continental separation and ocean spreading

Extension in the North Atlantic and the North Sea ceased around this time, and the basins underwent passive thermal subsidence, while locally there was basin inversion.

Paleocene to Eocene

Continental break-up and initiation of the Norwegian Sea began at about 57 Ma. During the early phase of continental separation, oceanic crust was formed by sea-floor spreading south of the Senja fracture zone when the north-north-westward motion of Greenland away from Svalbard took place along a regional transform fault without the formation of a deep basin (Fig. 2.12). Between 57 and 47 Ma, spreading occurred along a now-extinct spreading axis in the Norwegian Basin.

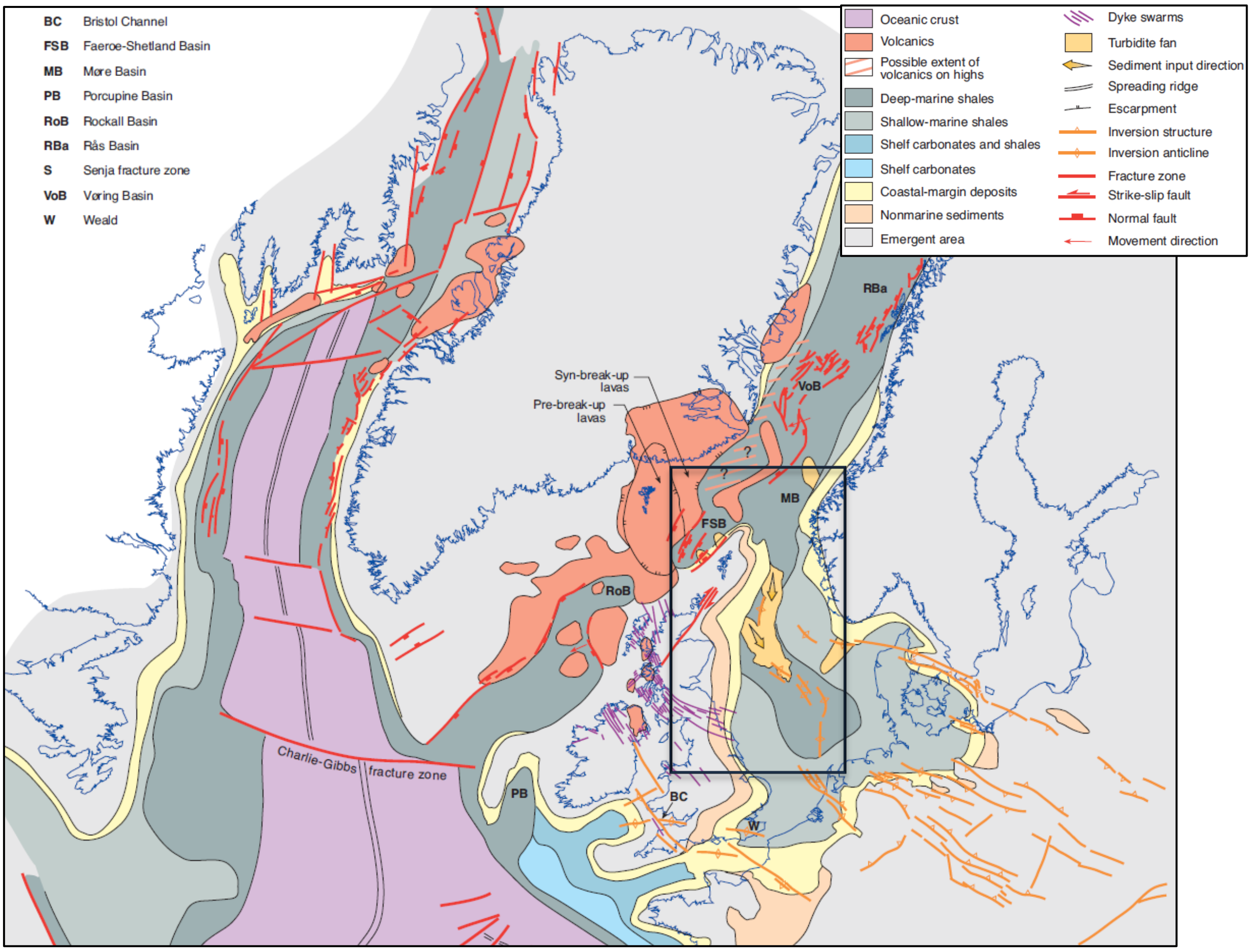


Figure 2.12: Palinspastic map for the Paleocene showing the distribution of active structures, sediment facies and volcanic rocks associated with the North Atlantic mantle plume.

Oligocene to early Miocene

The palinspastic map for the early Oligocene (36 Ma) illustrating the distribution of active structures and sediment facies is shown in Figure 2.13.

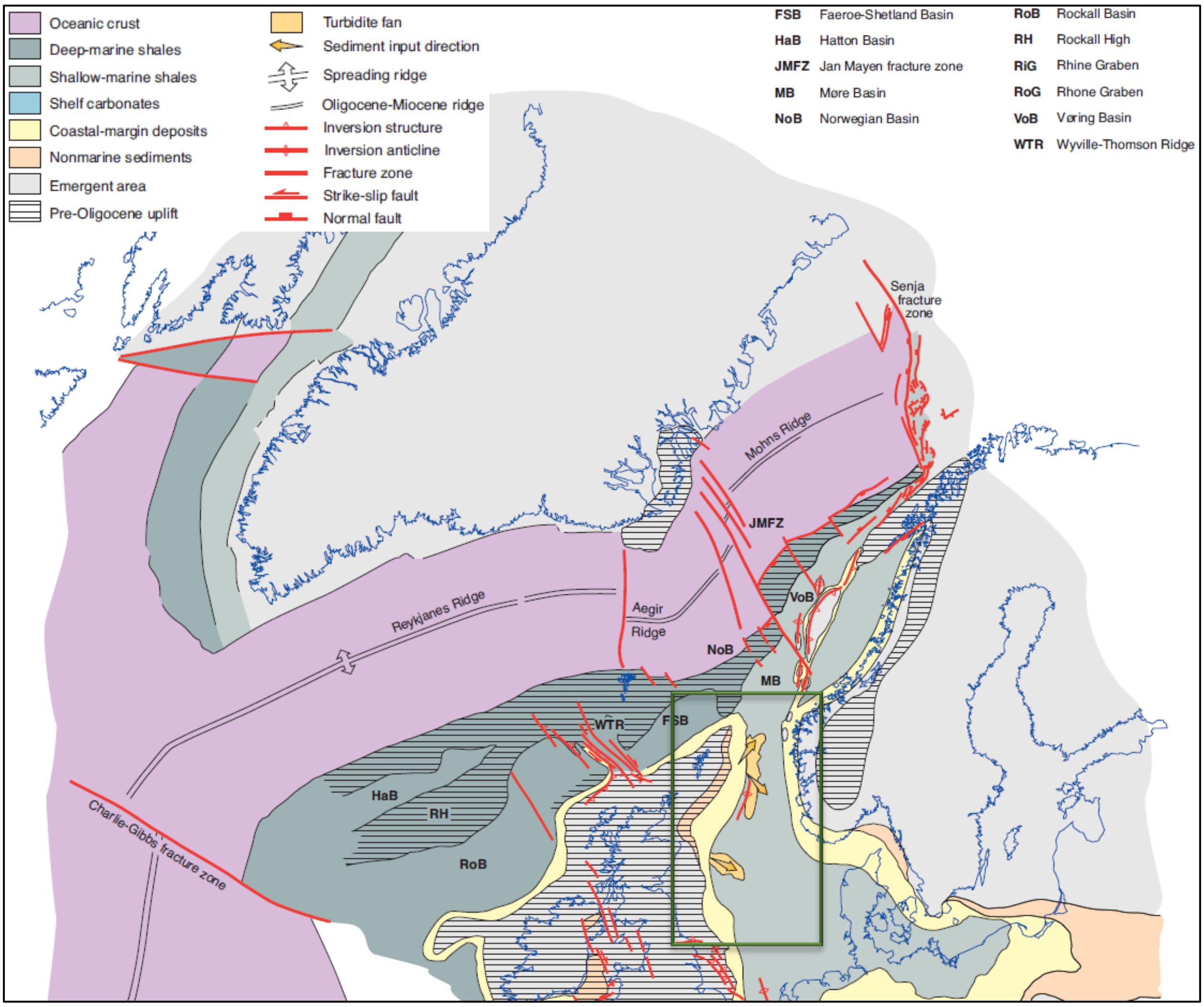


Figure 2.13: Palinspastic map for the early Oligocene (36 Ma) showing the distribution of active structures and sediment facies.

Miocene to Pleistocene

Uplift affected onshore and nearshore Norway (Japsen and Chalmers, 2000), and minor inversion affected parts of the north-eastern North Sea (Fig. 2.14). From fission-track data, an estimated 174000 km^3 of material has been eroded from Norway, and the volume of the thick Plio-Pleistocene sedimentary wedge produced offshore is 100000 km^3 (Riis and Fjeldskaar, 1992), most of which lies on the Atlantic margin (Evans et al., 2000, 2002). Much of this can be explained by rapid erosion onshore, and rapid deposition offshore during the Pleistocene glacial intervals.

However, if the calculated uplift is removed from the present topography and isostatically compensated, there must have been uplift across Norway during the Neogene. Seismic data nearshore suggest that some tilting and uplift of the Norwegian coast occurred during the Oligocene and certainly during the later Neogene. The uplift west of Norway may be related to renewed shear during the Oligocene to Miocene, with initial tectonic uplift magnified by subsequent glacial erosion and isostatic readjustments (Riis and Feldskaar, 1992).

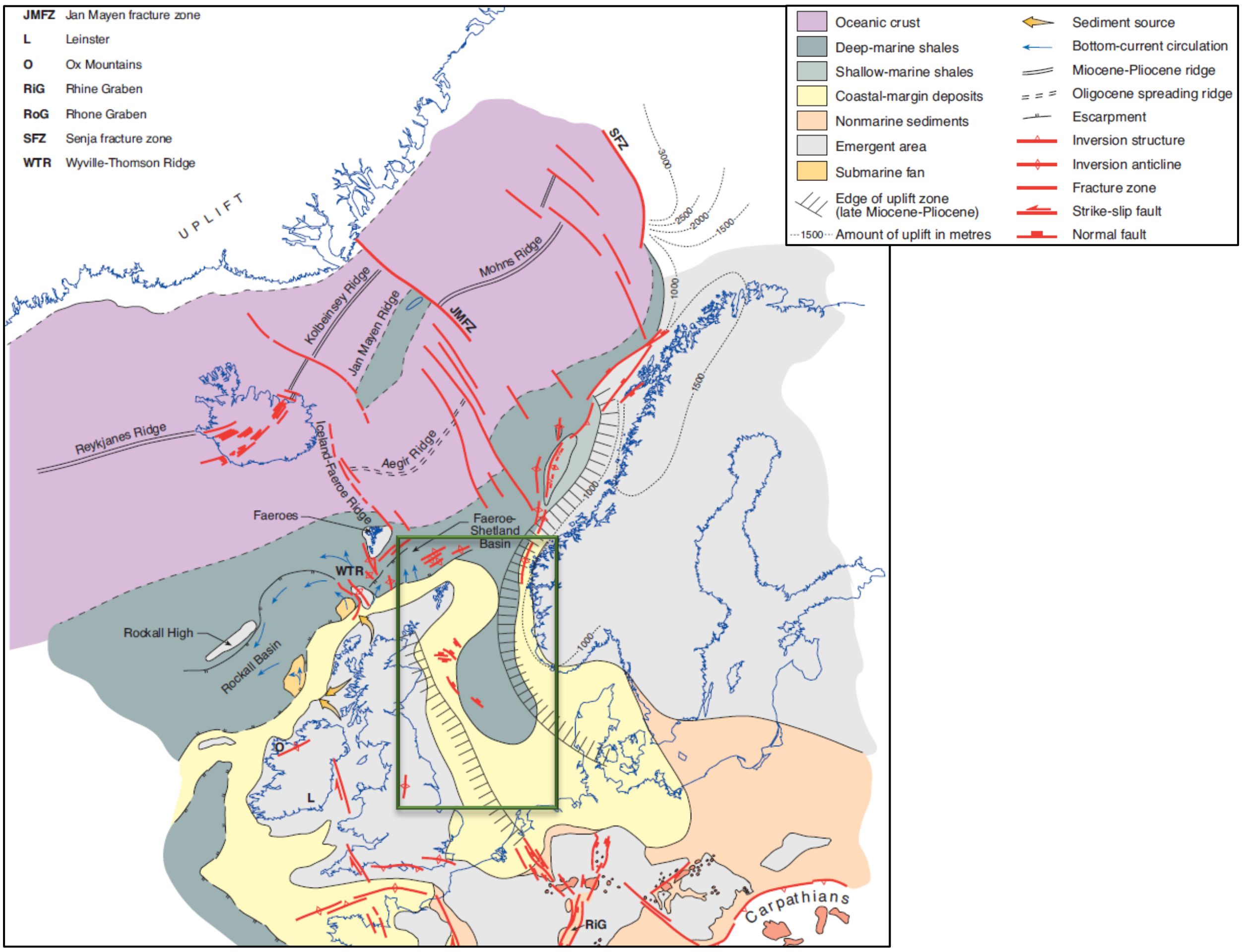


Figure 2.14: Palinspastic map for the early Miocene showing the distribution of active structures and sediment facies.

2.4 Stratigraphic framework

A number of Triassic-Jurassic formations with sandy intervals are found throughout the North Sea, as evident in the lithostratigraphic column shown in Figure 2.15. These units constitute important reservoirs and aquifers. Thick shale formations with good sealing capacity occur through both the Jurassic and Cretaceous sequences. Much later, Early Cenozoic rifting took place with the onset of break-up of NE Atlantic and sea-floor spreading. A number of sub-marine fans were built from the Shetland Platform (a local source also existed in western Norway) due to uplift of basin margins. These sands interfinger with marine shales (Rogaland and Hordaland Groups), which constitute good seal rocks (Fig. 2.15).

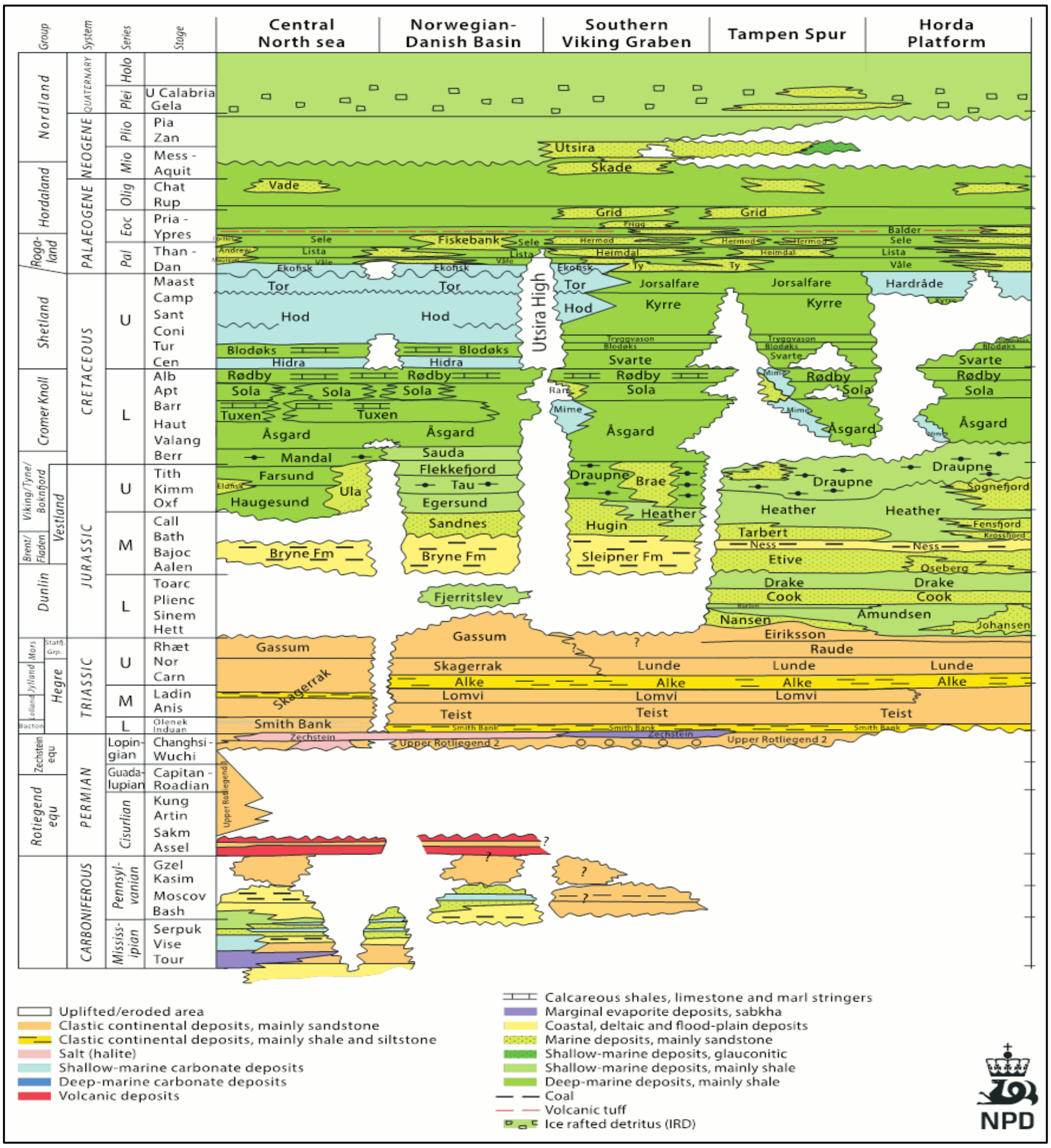


Figure 2.15: Lithostratigrapic summary for the North Sea (NPD, Halland et al., 2011).

Jurassic

The Upper Jurassic succession belongs to the Humber Group (Richards et al., 1993) and its lateral equivalents such as the Viking Group in the Norwegian sector (Vollset and Doré, 1984). It comprises several highly diachronous lithostratigraphic formations including the mudstones-dominated Heather, Kimmeridge Clay and Draupne formations (Fig. 2.16). It also contains a plethora of sandstone-dominated intervals, of which the most significant hydrocarbon-bearing intervals include the shallow-marine Fulmar and Piper formations, the deep-marine Magnus sandstone member and Brae Formation, and the coastal-deltaic Sognefjord and Fensfjord formations.

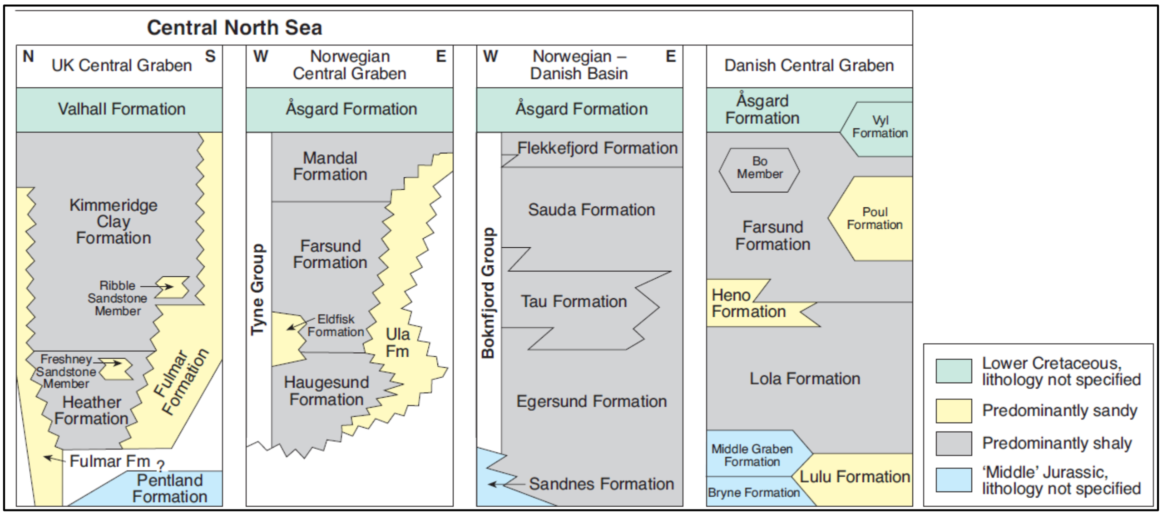


Figure 2.16: Table of the principal lithostratigraphic schemes used in the study area.

Kimmeridge Clay

The unit is typically made up of brownish black, medium to dark olive grey and grey-black, non calcareous mudstones. It is locally silty and micaceous, and may also include nodular carbonates. The type section for the Kimmeridge clay formation in the Wesssex Basin of southern England is up to 508 m thick (Ainsworth et al., 1998). Although the thickness may locally exceed 1200 m in the study area, a value of 50 to 250 m is a more typical thickness range. In the East Shetland Basin, the Kimmeridge Clay unit is up to 500 m thick (Goff, 1983). Organic acids generated in source rocks like the Kimmeridge Clay Formation in the North Sea are likely to be neutralised by reactions with calcite which is commonly present in these source rocks. The uppermost Jurassic Kimmeridge Clay Formation is transgressive and often forms a several hundred meters thick rich source rock which on the Norwegian side is called the Draupne Formation. The rift topography produced numerous, locally overdeepened, basins with poor bottom water circulation. The Kimmeridge Clay unit is absent on some structural highs, notably the Forties-Montrose High in the Central Graben, the Halibut Horst, and the Utsira High on the Norwegian flank of the South Viking Graben (Fig. 2.17c-d). The organic-rich shales of the Upper Jurassic are thus the prime source rock in the North Sea, and provided the main petroleum source in both the Statfjord and Ekofisk areas. The thickness of the Upper Jurassic sediments along the rift axis may reach 3,000 m. The source rock for the hydrocarbons at Ekofisk is the underlying Kimmeridge Clay which attains its optimal maturity at this depth. The source rock is the Kimmeridge Clay from the Upper Jurassic (Draupne Formation), and the oil has migrated up to the top of the fault blocks, but stratigraphically downwards from Upper to Middle or Lower Jurassic.

The Dunlin Shale succeeds the Statfjord Formation, and has enough organic material to be a source rock even if its contribution is very modest compared to the Kimmeridge Clay (Draupne Formation). TOC contents of mudstones within the Heather unit (Fig. 2.17a) are typically lower than in the Kimmeridge Clay unit, at around 2-2.5% (Goff 1983; Field, 1985; Brosse and Huc, 1986). Pyrolysis hydrogen indices are similarly lower, associated with a greater proportion of terrestrially derived, humic kerogen of vitrinitic and inertinitic composition. Organic carbon contents exceed 4% in a limited number of areas and exceed 7% only locally within the southern part of the South Viking Graben. These absences may be due to condensing over the paleohighs, or to subsequent erosion and the unit on these highs is likely to have been thin and also to have contained kerogens of marginal facies that have a high proportion of terrestrially derived organic material with rather poor source potential. The unit is fully preserved within the main depocentres where the best source rocks were likely to have been deposited, as well as in some restricted shelf areas such as north of the Witch Ground Graben.

The main source rock for the area is the Upper Jurassic Kimmeridge Clay. Where the Kimmeridge Clay is down-faulted deeply enough along the listric faults, oil has migrated up into the tectonically overlying but stratigraphically underlying Statfjord and Brent Groups. The oil began to migrate into the reservoir during early to mid-Tertiary times, when the source rock (Kimmeridge Clay) began to be mature. The oil/water contact in the Statfjord Formation and the Brent Group is at different levels which relate to two different pressure cells.

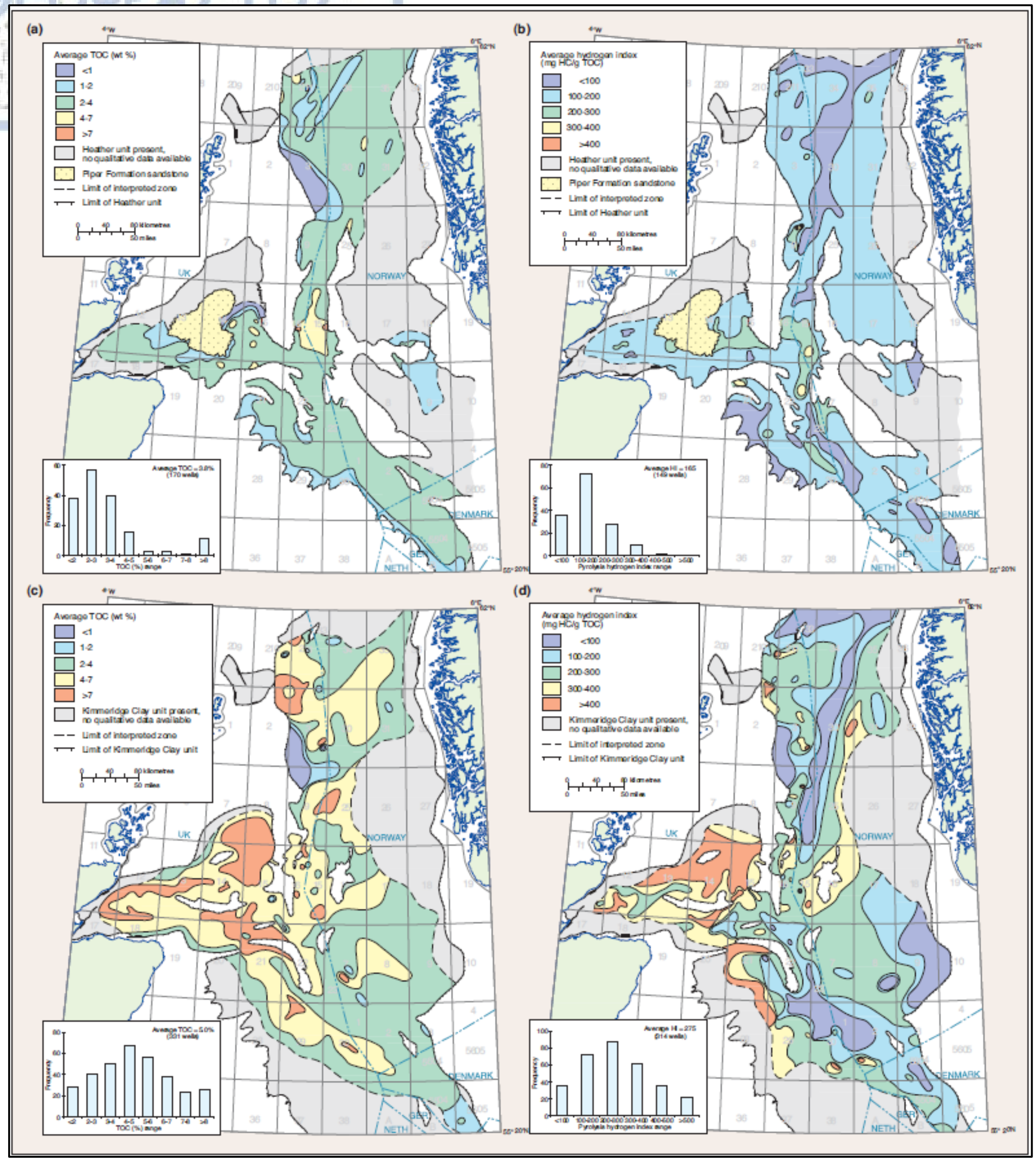


Figure 2.17: TOC and hydrogen index (HI) maps of the Kimmeridge Clay and Heather formations (Evans et al., 2003).

Draupne Formation

The Draupne Formation is a dark grey to black carbonaceous claystone that was deposited in a marine environment with restricted bottom circulation, often with anoxic conditions. It has very good seal properties and is the most important source rock in the North Sea, with a wide extent, found in East Shetland Basin, Viking Graben, and Horda Platform. It is generally quite thick, with 163 m in the type-well. It is of Oxfordian to Ryazanian age. The Draupne Formations (Viking Group) is also the primary seals for the Sognefjord Formation.

Sognefjord Formation (Upper Jurassic)

The Sognefjord Formation comprises a siliciclastic wedge covering the Horda Platform area in the northern North Sea. It was deposited in a shallow marine setting during the Jurassic rift phase (Oxfordian to Kimmeridgian) (Vollseth and Doré, 1984; Færseth, 1996) and is the latest of three westward-prograding deltaic formations within the Viking Group (i.e. Krossfjord, Fensfjord and Sognefjord formations).

Heather Formation

The Heather Formation is a grey silty claystone, in parts carbonaceous with limestone streaks. It is found over most of the northern North Sea, but has variable thickness. It is 30 m thick in the type-well, but has thickness variations from 14 to 232 m in reference wells, and may get more than 1000 m thick in graben areas. The sedimentation took place in an open marine environment during Bathonian to Kimmeridgian time.

Paleocene

Maureen Formation

The Maureen Formation (Fig. 2.18) is of mid-Danian to latest Selandian age and is laterally equivalent with the Ty and Vale formations. The formation is composed predominantly of amalgamated high- and low-density sediment gravity-flow deposits of sandstones interbedded with siltstones, and reworked slope and basinal carbonates. Liu (1995) indicated that the Maureen Formation has a 41% net sand-grain volume, making it the most sand-prone depositional system in the Paleocene. Lamp et al. (1992) provided a description of the Maureen Formation sandstones that from the main reservoir in the Maureen Field. The primary depocentre for the Maureen Formation extended from the Outer Moray Firth Basin to central North Sea, with an additional depocentre created in the hanging wall of the East Shetland Platform bounding fault in UK Quadrant 9. The sand-prone shelf and slope areas were restricted to the Moray Firth basins and the southern and southeastern margins of the East Shetland Platform; these areas were the primary sources for sand input into the deeper basin during mid-Danian to latest Selandian times. Additional minor sandstone fairways have been located on the northern Horda Platform and on the south-eastern margin of the Norwegian-Danish Basin.

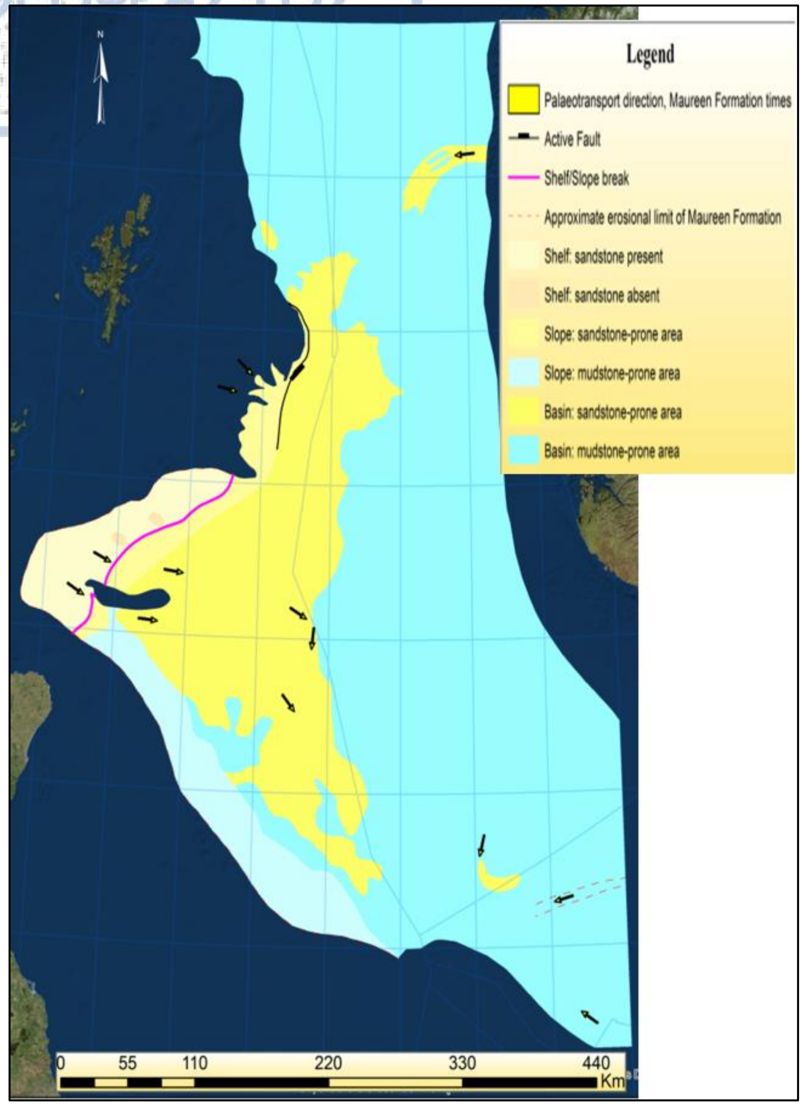


Figure 2.18: Paleogeographic map of the Paleocene for the Maureen Formation.

Lista Formation

The Lista Formation (Fig. 2.19) is of latest Selandian to Thanetian age and typically overlies the Maureen Formation, although on paleo-highs it may lie directly upon Cretaceous or pre-Createaceous strata. It is composed largely of non-calcareous, blocky, grey mudstones interbedded with sandy, high-density, gravity-flow or debris-flow deposits and minor volcano-clastic rocks. The Lista Formation, with thickness in excess of 600 m (Fig. 5.3), has an estimated net sand-grain volume of 35% (Liu, 1995), making it the second most sand-prone depositional system in the Paleocene after the Maureen Formation.

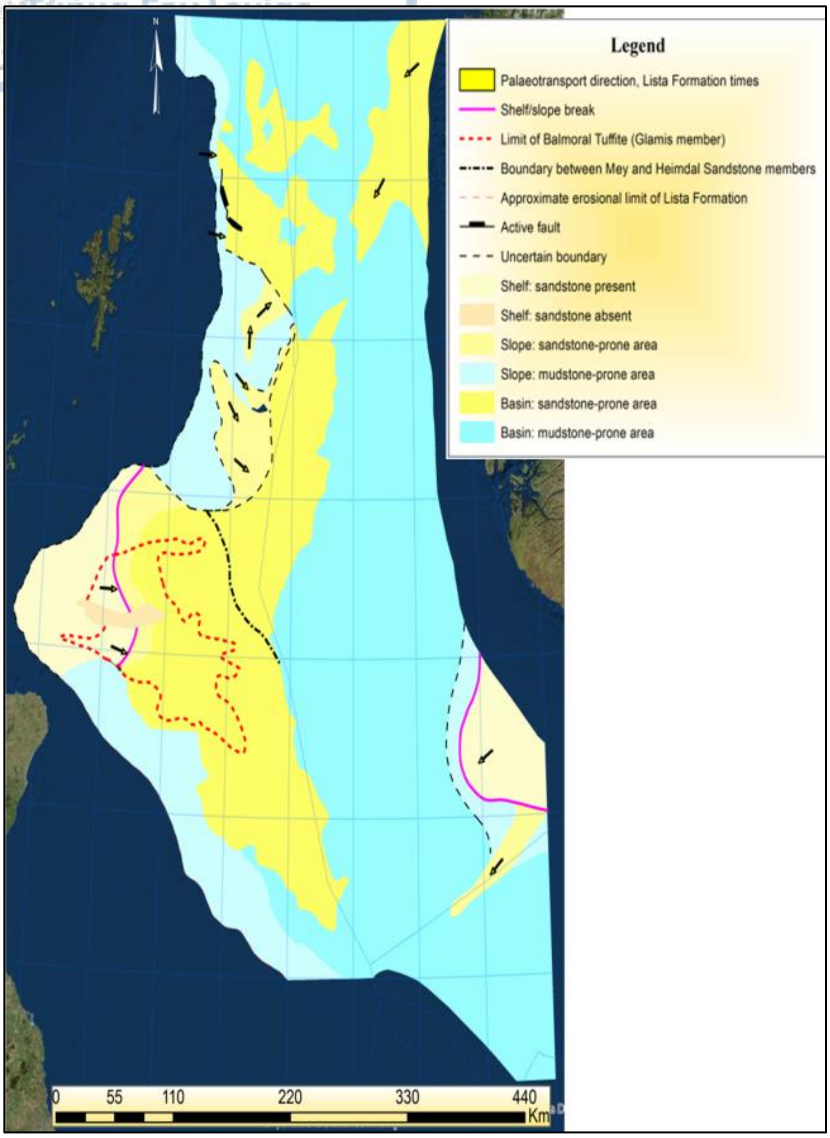


Figure 2.19: Paleogeographic map of the Paleocene for the Lista Formation.

Sele and Dornoch formations

The Sele and Dornoch formations (Fig. 2.20) are of late Thanetian to early Ypresian age. The Dornoch Formation is composed of shelf or deltaic sediments, whereas the Sele Formation contains time-equivalent sandstones and organic-rich hemipelagic sediments that were deposited in deeper-water and more-distal areas of the North Sea Basin. The Dornoch and Sele formations include the Forties, Cromarty, Flugga, Hermod¸ Skadan and Teal sandstone members as well as the Beauly Member.

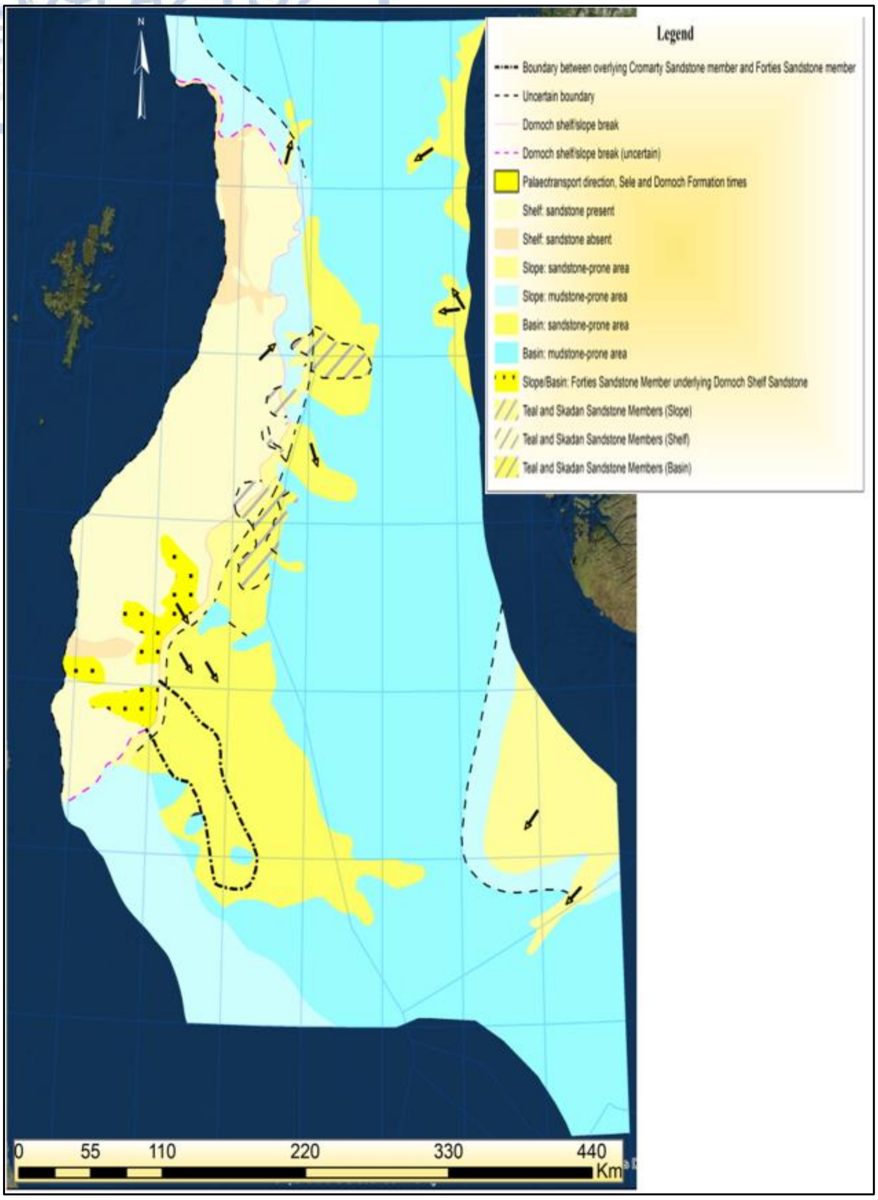


Figure 2.20: Paleogeographic map of the Paleocene for the Sele and Dornoch formations.

The recognition of at least four distinct sandstone members of the Sele Formation in restricted depocentres suggests that sand deposition became more localized at this time. Liu (1995) estimates 28% net sand-grain volume for Sele and Dornoch formations, which can reach respective thicknesses of 200 and 600 m. Sandstones from the Sele Formation form the reservoirs for 20 of the fields producing in the year 2000; the majority of these have the Forties Sandstone Member as their reservoir (Wills and Peattie, 1990; Whyatt and Rhodes, 1991; Wills, 1991).

Balder Formation

The Balder Formation (Fig. 2.21) is described here together with the Odin Member of Mudge and Copestake (1992b) and the self deposits of the Beauly Member. The transgressive Balder Formation largely comprises multi-coloured, laminated shales, with coals, tuffs, and occasional thin limestones interbedded with local sandstones that may be massive. The Balder Formation can be subdivided into two units. The lower unit, commonly called the Balder Tuff, is characterized by subaqueous airfall tuffs and provides a strong datum for correlation. The upper unit is characterized by poorly consolidated mudstone and contains the Odin Member sandstone. This upper unit marks a major transgression that resulted in widespread shale deposition. Liu (1995) indicated an estimated 10% net sand-grain volume for the Balder Formation, which generally has thicknesses of less than 100 m, but can reach 300 m where sandstones are common. Although the overall sand content is relatively low, the sandstones are usually very clean as they are derived directly from nearby mature shelf settings and make excellent reservoirs with average porosities of 33% and permeabilities of up to 10 Darcies (Newman et al., 1993; Timbrell, 1993).

Ty Formation

The Ty Formation (Lower Paleocene) was deposited from the Shetland Platform as a deep marine fan and has been identified in the southern Viking Graben in the north-western part of Quadrant 25, and northern part of Quadrant 15. The formation consists mainly of clean sandstones with a thickness in well 15/3-1 of 159 m. The lower boundary is calcareous rocks of the Shetland Group, and the upper boundary is transitional to the shales of the Lista Formation, but also against the sands of the Heimdal Formation. The formation may also interfinger with the Våle Formation to the east. The lithostratigraphy for the Paleogene and early Neogene reservoir units is illustrated in Figure 2.22.

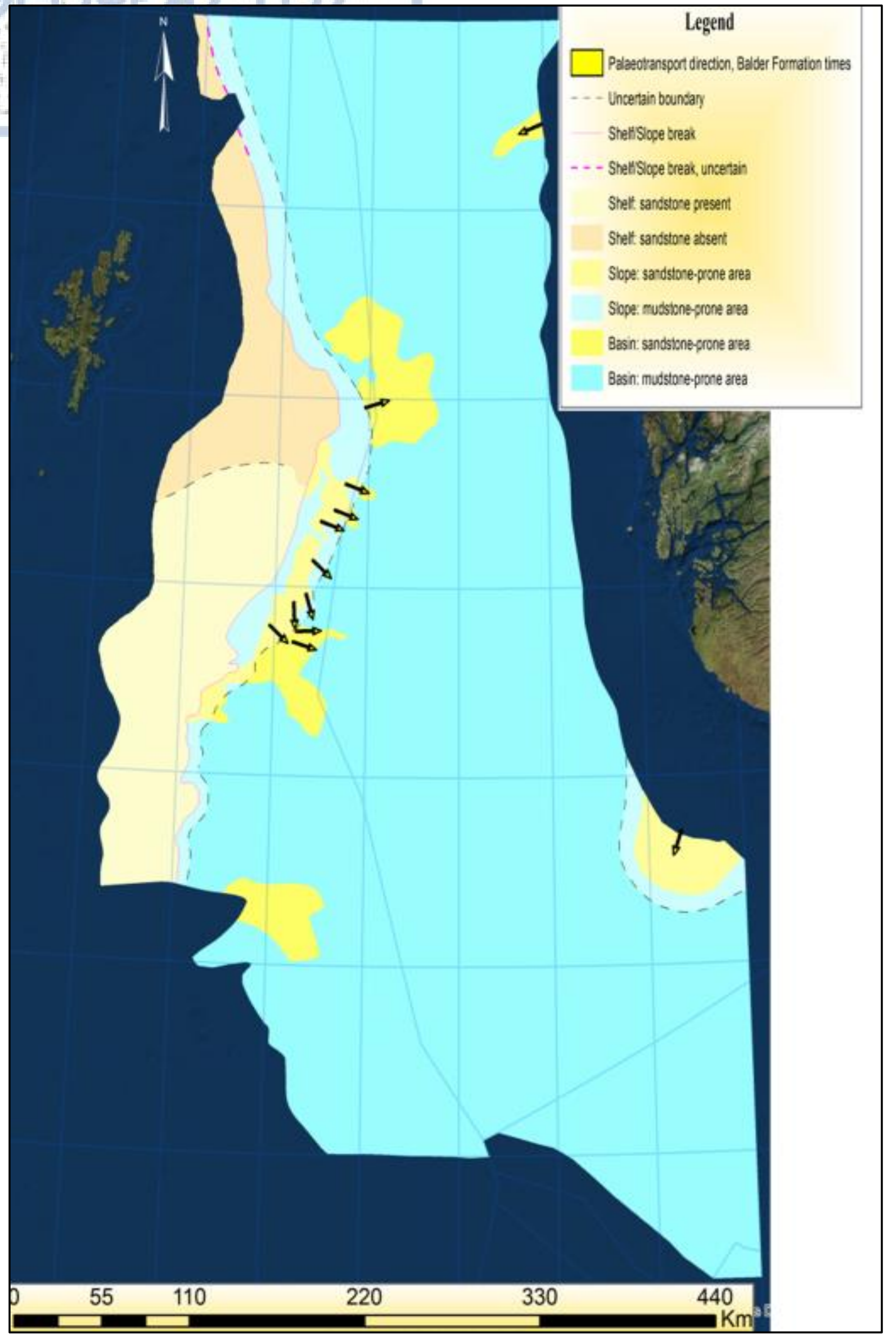


Figure 2.21: Paleogeographic map of the Paleocene for the Balder Formation.

Heimdal Formation

The Heimdal Formation was deposited as a submarine fan sourced by shallow marine sands on the East Shetland Platform. It is identified in the western parts of quadrant 30, most of quadrant 25 and 15 and as cleaner sand in the south-eastern part of Quadrant 15 into the north-western part of Quadrant 16 (Meile Member, informal). The thickness of the Heimdal Formation is 356 m in the type-well (25/4-1) and 236 m in well 15/9-5. It thins rapidly east of these wells and south of well 15/9-5. The base is usually the transition from the shales of the Lista Formation, but also sandstones of the Ty Formation. The upper boundary is usually a transition from the Heimdal sandstones into the shales of the Lista Formation. Locally it is overlain by the sands of the Hermod Formation.

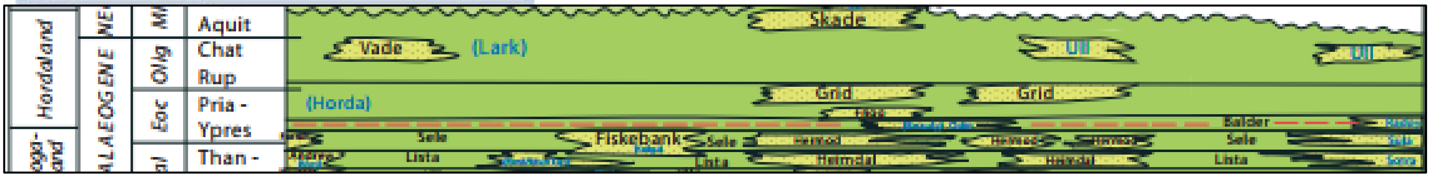


Figure 2.22: Lithostratigraphy for the Paleogene and early Neogene reservoirs.

Hermod Formation

The Hermod Formation consists of mainly fine-grained sandstones deposited in a submarine fan setting connected to the deltaic Moray Gp in the UK sector. The formation is located mainly in the South Viking Graben in the north-western part of Quadrant 25 and extends into the southern part of Quadrant 30. The thickness of the formation is 140 m in the type-well 25/2-6 and it thickens toward the central part of the distribution area. The lower boundary of Hermod Formation is usually a transition to silts and mudstones of the Lista Formation or the Sele Formation. It may also rest directly on the more varied sandstones of the Heimdal Formation. The upper boundary of the Hermod Formation is sharp against the dark silt and mudrocks of the time-equivalent Sele Formation.

Fiskebank Formation

The Fiskebank Formation has been identified from the Norwegian-Danish Basin and in the type-well, 9/11-1, with a thickness of 148 m. The lower boundary is silt and mudstones of the Lista Formation and the upper boundary is tuffaceous shales of the Balder Formation. The formation is developed mainly in the Åsta Graben in the Norwegian-Danish Graben. The thickness in wells varies between 26 to 148 m. The Fiskebank Formation probably represents basin margin deposit and appears to be mostly time equivalent with the Sele Formation.

<u>Lower Eocene</u>

Frigg Formation

The Frigg Formation is located offshore south-west Norway within the northern North Sea. The lower Eocene sediments have been deposited as submarine fans triggered by gravity flows coming from the East Shetland Platform. The formation has a thickness of 279 m in the type-well and 140 m in the reference well. The reservoir properties of the Frigg Formation are very good with porosities between 25 % and 32 % and high permeabilities varying between 900 mD and 3000 mD (NPD, www.npd.no). The Frigg Field, operated by Elf Norge, was discovered by well Nor 25/1-1 in 1971, which was used as a type-well for the Frigg Formation by Deegan and Skull (1977). The reservoir sandstones were deposited as part of a submarine-fan system in the South Viking Graben during early Eocene times (Fig. 2.23a-d). The Frigg Field comprises a number of hydrocarbon-charged closures formed by a combination of fault seal and differential compaction across the fan.

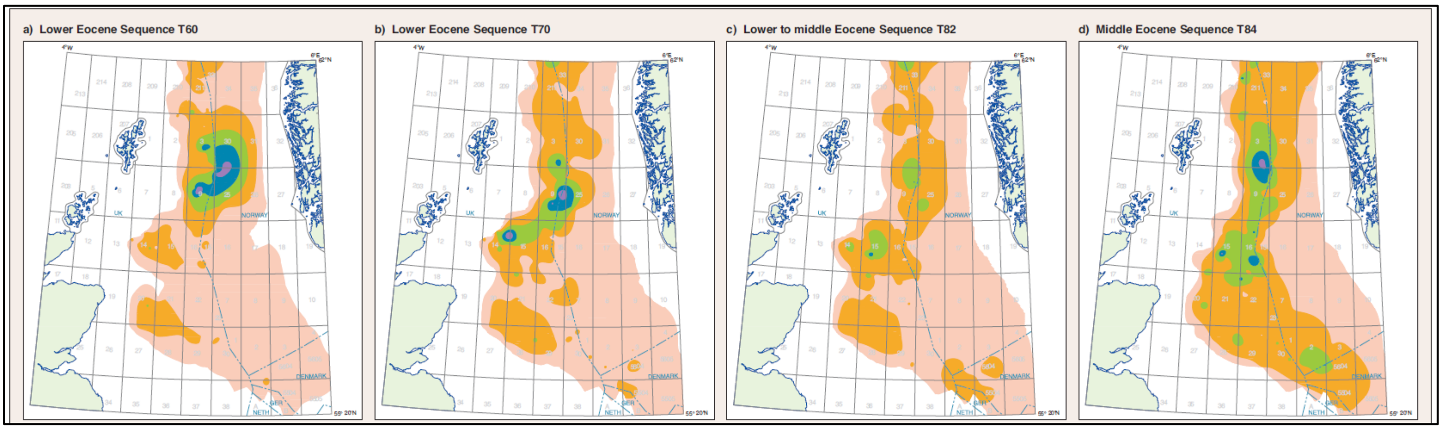


Figure 2.23: Thickness maps for the Eocene sequences.

<u>Lower Miocene</u>

Skade Formation

The Skade Formation, Lower Miocene, consists of marine sandstones (possibly turbidites) deposited over a large area of the Viking Graben (from 16/1-4 in the south to 30/5-2 in the north). The maximum thickness exceeds 300 m and decreases rapidly towards the east, where the sandstones terminate towards large shale diapirs.

3. Chapter 3

PLAY FAIRWAY MAPPING

3. Play fairway mapping

3.1 Play definition and concepts

It is an exploration "fact of life" that, while the Prospect is the economic unit of exploration, the Play is the operational unit. Due to the magnitude of expenditures (both money and manpower) and time framework involved, the most difficult and critical task in Exploration is selecting which plays to explore, not which prospects to drill. We present a simple but powerful method for evaluating the geologic (and economic) chance, volume and value of geologic plays. The methodology is applicable for a spectrum of opportunities, from a medium-sized concession to a full-geologic play. This monetization approach fills an 'analytical gap' between traditional methods for assessing volumes and geologic chance for plays (e.g. Baker et al., 1986) and assessing the value of individual prospects (e.g. Rose, 1992; White, 1993). Required inputs are tied to company strategy (e. g., activity level, risk tolerance), and to units of natural measure (forecast geologic discoveries, their size distribution, and historic success rates) that can be validated against historical (or analog) results. The small number of requisite input variables encourages making multiple sensitivity cases for an exploration program. Calculated outputs provide powerful information that can be used to prioritize a company's exposure to various trends, leading to a portfolio of Plays. Spreadsheets can be customized to model optimal activity levels and working interest, based upon a company's risk tolerance.

Play and acreage analysis form a key part of the exploration process (Fig. 3.1), but are generally the most poorly defined from a standardised process point of view. Decisions are often driven by subsets of the large volumes of data available to an exploration team, and by personal or historical bias, based on past experiences or exploration strategies. This can present a challenge to oil and gas exploration – as Peter Rose, the petroleum geologist, noted in 1996, “the most difficult and critical decision in petroleum exploration is not which prospect to drill, but instead, which new play to enter”. A play is defined here as a grouping of prospects with one or more common factors. Plays are groups of related hydrocarbon accumulations and prospects are characterized by combinations of similar geologic parameters such as charge type, reservoir-seal couplet and trap style. Plays should have a clear geographic distribution that can be defined on a map and be confined to limited stratigraphic intervals. Play is a geographically and stratigraphically delimited area where a specific set of geological factors is present so that hydrocarbons should be able to be proven in producible volumes. All fields, discoveries and prospects within the same play are characterized by the play’s specific set of geological factors and can, therefore, be distinguished from the fields, discoveries and prospects belonging to other plays. The play should consist of prospects with similar geologic character and history. To ‘value’ a play for a company (recommended), inputs should reflect company dry hole tolerance and success case activity levels.

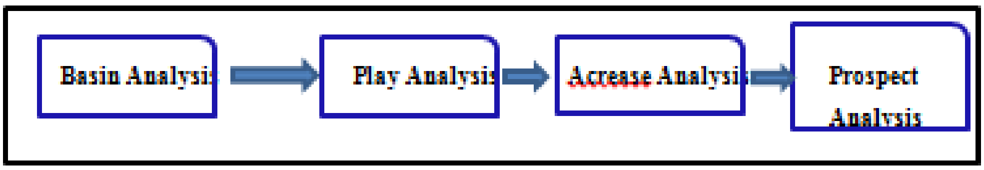


Figure 3.1: The exploration process.

In play assessment, we separate the probability factors into two groups; marginal play probability factors, and conditional prospect probability factors. The marginal play probability is common for all prospects in a given play and is hence similar to the product of the common probability factors. In practice, we face many challenges when attempting to define and delineate a play. These challenges are often due to lack of data control and/or inconclusive geological information. An assessment of whether we are dealing with mature, semi-mature or frontier areas also presents a challenge to play definition. A useful approach to play definition is to prepare play maps for all those factors that are anticipated to define the play. Such maps may illustrate reservoir facies, porosity and/or permeability changes, the presence and maturity of source rocks; areas of effective migration, effective traps and seals, together with areas favourable for effective retention of hydrocarbons. The main purpose of these maps is to illustrate where these factors are favourable or unfavourable to the success of the play.

Experience has shown that in some cases it is convenient to group together plays which exhibit large similarities, in particular in frontier areas where the plays are unconfirmed and the database is very limited. On the other hand, in mature and well-known areas with confirmed plays, it can be more useful to use the available data control and clearly defined criteria to distinguish between plays. In both cases, it is important to bear in mind that the purpose of defining distinct plays is to group mapped and unmapped prospects into manageable units which enable us to make as reliable an estimation of undiscovered resources as possible. A geographically and stratigraphically delimited area where a specific set of geological factors exists in order that petroleum may be provable in commercial quantities. Such geological factors are reservoir rock, trap, mature source rock and migration paths, and the trap must have been formed before termination of the migration of petroleum. All discoveries and prospects within the same play model are characterized by the specific set of geological factors of the play model.

It is also important to consider the possibility of interdependency between plays. In some geological basins, there may be geological factors that are common to two or more plays. A typical example would be a regionally extensive source rock. If the plays are unconfirmed, there will be interdependency between all plays which share the same source rock. When assessing the undiscovered resources in a basin, interdependent plays must be treated in similar way to interdependent prospects with respect to their conditional probabilities. Given that the play is properly defined (Fig. 3.2), the common or shared geological probability factors for all mapped and unmapped prospects in the play will form part of this definition. The product of these factors is the marginal play probability, which is equal to 1.0 if the play is confirmed.

Individual probability factors defining the marginal play probability may differ between various plays. This will be related to local geological conditions. However, “rule-of-thumb” guidelines are given in the table presented in Figure 3.3. The conditional prospect probability is an average probability factor for all mapped and unmapped prospects for a given play. Clearly, some prospects within the play will have a higher probability, and some will have a lower probability, than the average value. For confirmed plays, the historical success ratio is an important guideline in determining the average conditional prospect probability, although meaningful comparisons between plays must take the number of previously drilled prospects into account. A limited database may give misleading comparisons.

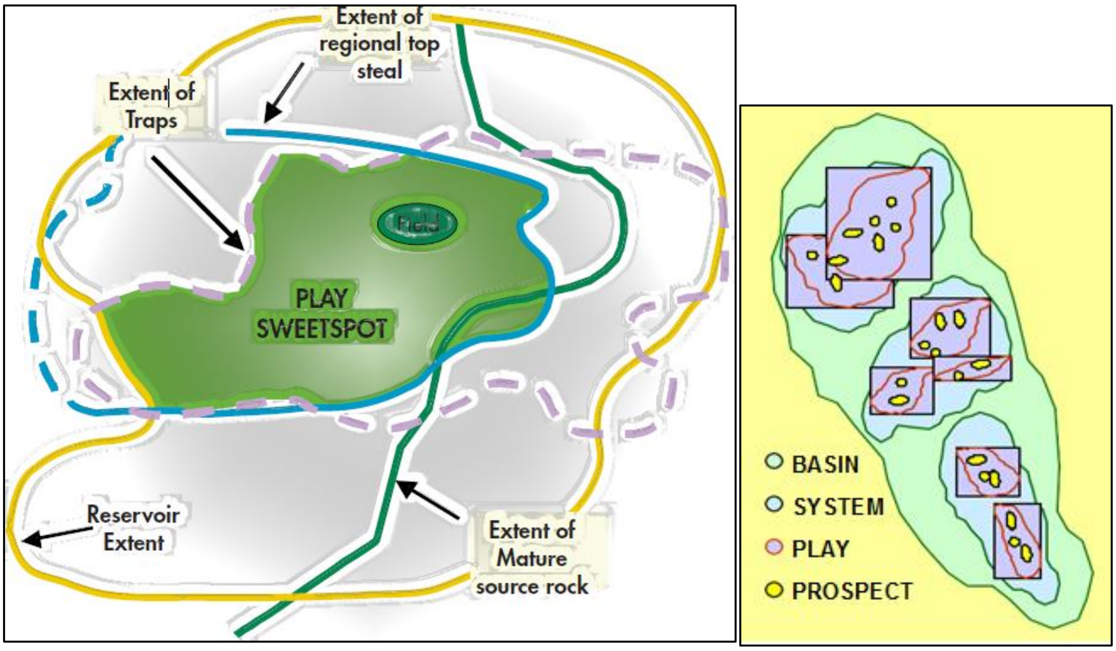


Figure 3.2: Schematic illustration of the relation between basin, petroleum system, play and prospect.

Probability factor	**Marginal play probabilities**	**Conditional prospect probabilities**	**Comments**
Reservoir	Reservoir facies	Effectiveness; porosity and permeability	Depends on continuity of reservoir facies
Trap	Sealing properties	Mapping quality and reliability	This subdivision may vary between different plays
Charge	Sufficient volume mature source rock	Migration	Be aware of possible long distance migration
Retention	**Retention**		**Unless local variations are identified**

Figure 3.3: Partial probabilities classified as marginal play probabilities and conditional prospect probabilities.

An independent petroleum system is defined as a continuous body of rocks separated from surrounding rocks by regional barriers to the lateral and vertical migration of liquids and gases (including hydrocarbons), and within which the processes of generation, accumulation, and preservation of oil and gas are essentially independent from those occurring in surrounding rocks (Ulmishek, 1986). According to this definition, a petroleum system may contain one or more plays, the success of which may depend on others. The common geological factor in a petroleum system is typically the source rock, but other common factors may also occur. It is therefore crucial to define the petroleum systems within a basin when we are assessing the basin's total petroleum potential. It is also important to take the interdependency of plays into consideration when performing an aggregation of their resources.

Play risk consists of regional risk elements, which can be determined by regional mapping, and are not just specific to a single prospect. Thus, the probability of discovering petroleum in a prospect often includes elements of play risk as well as those risks solely associated with the prospect. It is possible to draw a map for each of the regional risk elements showing areas of common relative risk for example, areas where there is a relatively high risk (low chance) of finding an effective reservoir due to depth of burial. These areas are termed risk segments, and the map of a regional relative risk element is termed a common risk segment (CRS) map. All of the regional risk elements for a specific play can be combined into one map which illustrates the overall variation in play risk across the fairway. Such maps are termed composite common risk segment (CCRS) maps or play fairway summary maps.

Risk comes in many forms and can be defined in various ways, as for example the effect of uncertainty on objectives. It is worth noting that this is a very broad definition that takes in both the positive and negative aspects of uncertainty. With regard to the oil and gas industry Risk is categorized in four major groups. First, there is geologic risk, which is basically or roughly the chance of making an oil and gas discovery. Second, there is economic risk. It's not enough to find and produce hydrocarbons. These ventures must be done is such a fashion, their profit can be realized. Third, we have political risk. These come in various forms varying from total political upheaval to legislation that impedes a development opportunity. There are many incidents around the world where major discoveries have been made but then suspended due to adverse political situations. Finally, we have environmental risk. When exploring and developing hydrocarbons, operations must be carried out in an environmentally friendly fashion. The risk of harming the environment must be considered in every project no matter its size, and every effort to eliminate a chance of an environmental error must be considered.

Geologic chance of success, or the inverse risk, is that element in the oil and gas industry, that defines the chance of making a discovery. As such, before discussing risks, and its association with the oil and gas exploration, we need to define what success, or the chance of making a discovery actually is. Significant quantity relates geology to economics, in the fact that the quantity discovered must be perceived as meeting an economic threshold. So, for a well to be geologically successful, it must meet criteria that are particular for its circumstance. A quick review of the geologic elements required for success is discussed below.

Generation of hydrocarbons imply that there must be a source rock where hydrocarbons have actually been generated. In brief, source rocks are formations that contain sufficient amount of TOC, or total organic carbon. It has matured to the point that hydrocarbons have both been generated and expelled. There must be a migration pathway through which hydrocarbons generated in the source rock interval can move, or migrate from that source rock interval into the sedimentary interval acting as the reservoir. There must be a reservoir section which is a sedimentary interval, where hydrocarbons generated in the source rock can be stored. A reservoir is a formation that has sufficient porosity and permeability, such that the hydrocarbons can first be stored in significant quantities, and then produced at a sufficient rates, that one or more wells can produce significant quantities of the hydrocarbons at a sufficient rate to constitute a discovery. Reservoir formations are geologic formations with significant permeability. In other words, they have properties that allow oil or gas to flow through that formation with relative ease. As this is the case, reservoir intervals must be in a subsurface configuration, such that hydrocarbons that have been generated from the source and then migrated into the reservoir are now trapped in that formation.

These traps take varying forms. From subsurface structures, such as anticlines, which tilt to fault blocks; to stratigraphic traps, formed by lateral variations in the types of sediments that were formed. All of these elements must take place in specific order. Hydrocarbons generated in the source rock must migrate into the reservoir rock at such a time as the trap has already been formed. Each of the five elements mentioned above must take place in order, to have geologic successful hydrocarbon discovery.

Prospect risk can be subdivided into play risk and prospect-specific risk. The play risk comprises the regional risk elements, i.e. those elements of risk which can be estimated and mapped regionally without detailed mapping of the prospect structure. Prospect specific risk reflects local risk elements within the fairway. In order to assess relative risk across the play fairway, each play can be subdivided into several risk elements or factors. These include:

- presence and effectiveness of a reservoir,
- presence of a source rock and the effectiveness of the carrier system,
- presence of an effective vertical seal

Each risk element is then subdivided into areas of common risk. This is done by subdividing each element into areas of low, moderate or high risk and assigning in a "traffic light" scheme a corresponding green, yellow or red colour to each to produce a common risk segment (CRS) map. In the case of reservoir, source or seal presence, the delineation of common risk areas is based on the regional understanding of the basin stratigraphy. Further data are then integrated to assess the risk that the predicted stratigraphy provides an effective reservoir, carrier system and/or seal. These data include core porosity and permeability, pressure and leak-off data, well test results, geochemical data, well log analysis and thermal/basin modelling work. Other regional risk elements (such as timing of trap formation and biodegradation) are often mapped but are not important regional risk elements for the play discussed here.

Individual common risk segment maps can be combined to provide play fairway summary maps and composite common risk segment (CCRS) maps for each play. These provide a powerful pictorial representation of relative risk within the play fairway. Uncertainty maps are also produced for each play. These illustrate our confidence in the geologic model. They are controlled by the density, quality and reliability of well and seismic data. They are used in conjunction with the risk maps, taking care not to confuse risk with uncertainty.

3.2 Play-based exploration and Common Risk Segment (CRS) mapping

The fundamental elements or building blocks of the play-based exploration (PBE) methodology are represented by the PBE pyramid. The pyramid is organised into Basin, Play and Prospect focus levels and appropriate key inputs and activities are identified in Figure 3.4. The essential ingredients for the petroleum system are verified by examining the basin as a whole. Elements such as the plate setting, tectonostratigraphic framework and basin history determine the fill, stratigraphic sequences and potential for generating and trapping hydrocarbons (Basin Focus). An understanding of the petroleum system in the basin leads to the identification, mapping and quantification of plays within the basin. Existing knowledge is summarised in play element, summary play maps, and common risk segment maps, leading to the identification of sweet spots (Play Focus). Most play execution activity is concerned with defining prospects through seismic interpretation/evaluation and other maturation activities, and eventually drilling selected prospects from a portfolio. A geological model is built and then volumetrics, technical risk and confidence are assessed for a range of models and prospects (Prospect Focus). New Venture opportunity evaluation usually occurs at the lower part of the pyramid (basin-to-play focus levels). Decisions are typically made about selecting the right basin, the right play and then the best acreage (sweet spots) for investment. Detailed prospect level evaluation activities occur in the upper part of the pyramid both for new and existing ventures, turning geological leads from the play inventory into firm, drillable prospects. In order to be done in the proper way, these prospect evaluations need to be carried out with a firm grounding in the play context (Fig. 3.4).

During the early stages of searching for new fields, explorers must build up a thorough understanding of the overall basin to evaluate and grade the potential of the petroleum systems. Across the globe, consistent and highly effective methods to analyze these systems are used. The process to develop this understanding is known as play-based exploration and it is a technique that has increased the ability to make timely and high-quality decisions. By the end of the studies in a certain area, geologists and geophysicists would have defined a certain number of prospects. For each prospect they would have calculated a range of probabilities for the accumulation of oil and gas. With the oil field engineers, they would have also calculated a range for the potential reserves. The reserves represent that part of the accumulation that can be extracted and brought to the surface for exploitation.

The pyramid (Fig. 3.4) shows the importance of the foundations that are the solid understanding of the basins and plays needed to build a good prospect inventory and select the best of these for drilling. An inventory built upon an incomplete understanding at the play or petroleum system will not be optimal. Play-based exploration can be seen as having quality assurance “toll-gates” at the conclusion of each of the basin and play focus levels that allow us to proceed with confidence to the next level of evaluation. Our understanding at each of the levels is not static and there is an iterative feedback loop that takes new information from conducted geological and geophysical (G&G) studies and drilling back to the appropriate level to update the totality of knowledge. For example it is very important to clarify the definitions below:

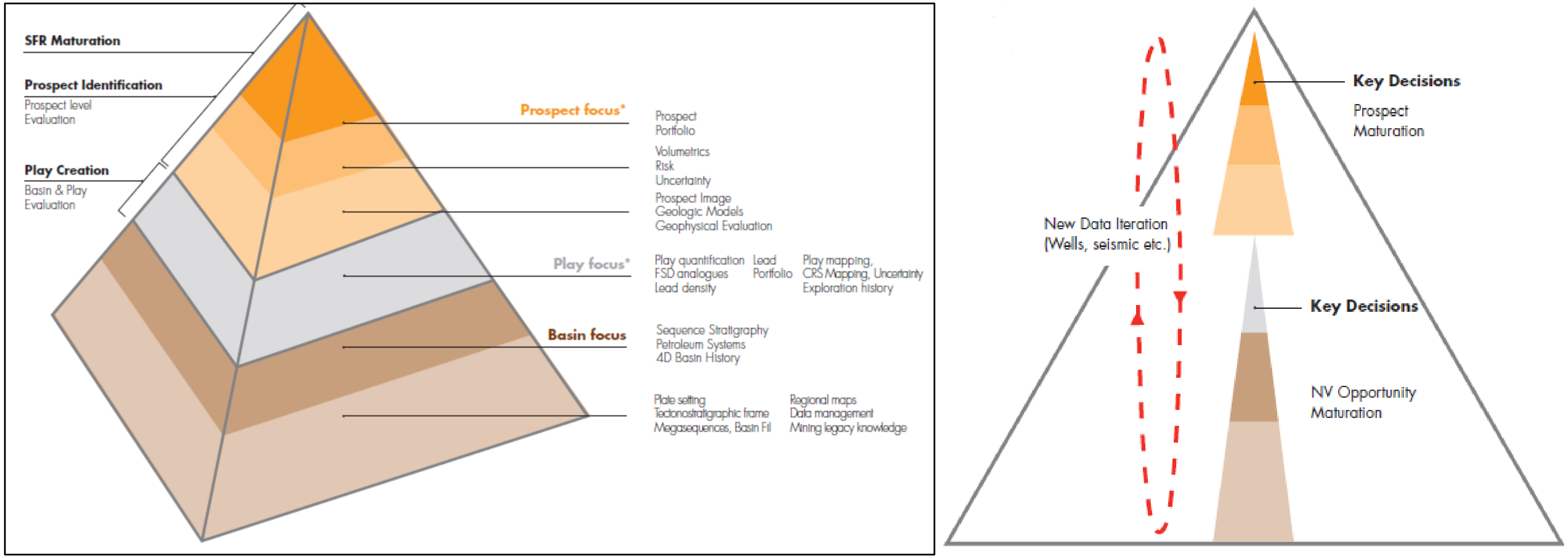


Figure 3.4: Play-based exploration (PBE) pyramid (from Royal Dutch Shell).

- Prospect: a potential trap, a successful prospect turns into an oil/gas field when drilled or disappears when it is unsuccessful. Many can exist in one play.
- Play: a group of hydrocarbon fields and prospects having a chance for charge, reservoir, and trap, and belonging to a geologically related stratigraphic unit (e.g. the Upper Jurassic play).
- Play Segment: subdivision of a geologic play. Fields and prospects that share common geological controls and thus a common probability of success (PoS) profile.
- Petroleum System: a natural system that links an active or once active source rock to all of the geologic elements and processes that are essential for a hydrocarbon accumulation to exist in time and space regardless of economics (Fig. 3.5).

Important geological factors include: reservoir rock, presence of a mature source rock and of migration routes, seal, trap and the requirement that the trap was formed before the migration of petroleum ceased. These factors are seldom all present simultaneously. If one or more are missing, no accumulations of oil and gas will be found in the area. Uncertainty always prevails about the presence of hydrocarbons, and wells must be drilled to establish it. A prospect is a potential trap and a successful prospect turns into an oil/gas field when drilled or disappears when it is unsuccessful. All discoveries and prospects in the same play are characterised by the play's specific set of geological factors. Mapped and unmapped prospects, discoveries and fields can be found within a single play.

A play fairway, in this case, is therefore the area defined by the maximum possible extent of reservoir rocks within the stratigraphic interval of the play. The extent of a play fairway is here defined as the maximum possible extent of reservoir rocks. This is based on sequence stratigraphic analysis of well and seismic data to predict the distribution of systems tracts. The maximum basinward extent of reservoir is based on the predicted distribution of the low-stand deposits.

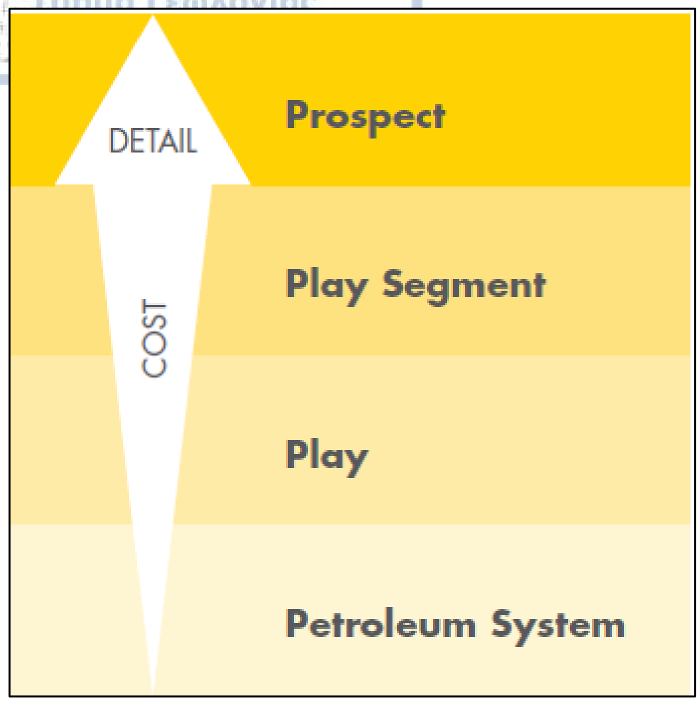


Figure 3.5: Petroleum system, plays and prospects (from Royal Dutch Shell).

A play fairway is the area where a particular play type is expected to occur and play fairway analysis is used to identify and rank areas within the fairway by examining the spatial distribution of the elements of the play. A minimum of three elements are typically used to define a play: a source rock, potential reservoir and seal or cap-rock. Additional elements may be added to the map set depending on the geologic circumstances in the basin or play. The goal of this approach is to provide an assessment of the elements of the play resulting in a more objective final product that can be easily understood. The method is usually referred to as Common Risk Segment (CRS) mapping. All the elements being considered are mapped at the same scale using a simple color code for the confidence level or the probability that the element has of being effective in that area. These maps are often called traffic light, or stop light, maps because they use green, yellow and red to depict high confidence, moderate confidence and low confidence, respectively. If probabilities are used, the green or yellow or red indicate high probability (low risk), moderate probability (moderate risk) and low probability (high risk), respectively. Actual probability ranges can also be assigned to these map colors.

When the individual element maps are completed, they are then overlain to produce a resultant map. The example shown in Figure 3.6 uses a common risk segment (CRS) approach for the source rock component of the petroleum system. Organic richness, kerogen type and maturity are the input elements. Map interpretation uses a Venn diagram approach to evaluate the area on a point by point basis. For any point in the map, if there is red on any of the input maps, the overall rating is red. If there is green on all the input maps, the overall rating is green. If there is yellow on all the input maps, the overall rating is yellow. For any combination of greens and yellows on the input maps, the overall rating is yellow. On the resultant map, the green regions represent the lowest risk exploration areas where efforts should be concentrated, while the red regions is the high risk areas and should be avoided. The yellow regions may or may not be prospective and will likely require additional study to make that determination. Although this is a very useful tool for visualizing exploration risk, it is not used extensively but should be considered as part of any petroleum systems analysis.

Figure 3.6: A simple example of common risk segment mapping for the source rock component

An area on a map that contains the same general chance for success or probability of success (PoS) and confidence for a given chance factor: reservoir, charge, seal or structure, define the Common Risk Segment (CRS) mapping and risking. CRS mapping and risking uses all available geological and exploration history data to create a view of the play-scale risks and dependencies. This work follows upon the play element mapping, and uses the boundaries (segments) created during that work. The play is divided into segments with similar probability characteristics, with the boundaries reflecting changes in either geology, or confidence (data quality and/or density). Probability values are assigned to each segment. The number of maps or chance factors that go into the CRS mapping exercise may vary, but experience has shown that play-level and prospect-level maps for Reservoir, Charge and Entrapment are usually sufficient to describe the risks.

The Common Risk Segment (CRS) analysis is a technique that enables geoscientists to summarise vast quantities of geological knowledge. This term is actually something of a misnomer as the accepted use of the analysis refers to probability or chance, rather than risk. The basic theory is that geological map data is converted into a numeric representation of chance for a particular petroleum play element. In play chance or common risk segment mapping, a geologist is able to assign a chance of success (COS) to each key petroleum play element, such as reservoir, seal, source, migration and structure. Once the data has been converted into a consistent numeric schema geoscientists can perform mathematical calculations on the play element data stack in order to summarize play adequacy or overall chance of success (Fig. 3.7). If a region has a high COS in all categories it is coloured green, if one or more categories are risky, it is coloured amber or yellow, and if a critical element is known to be absent the block is coloured red. The resultant layers or maps are referred to as play chance maps.

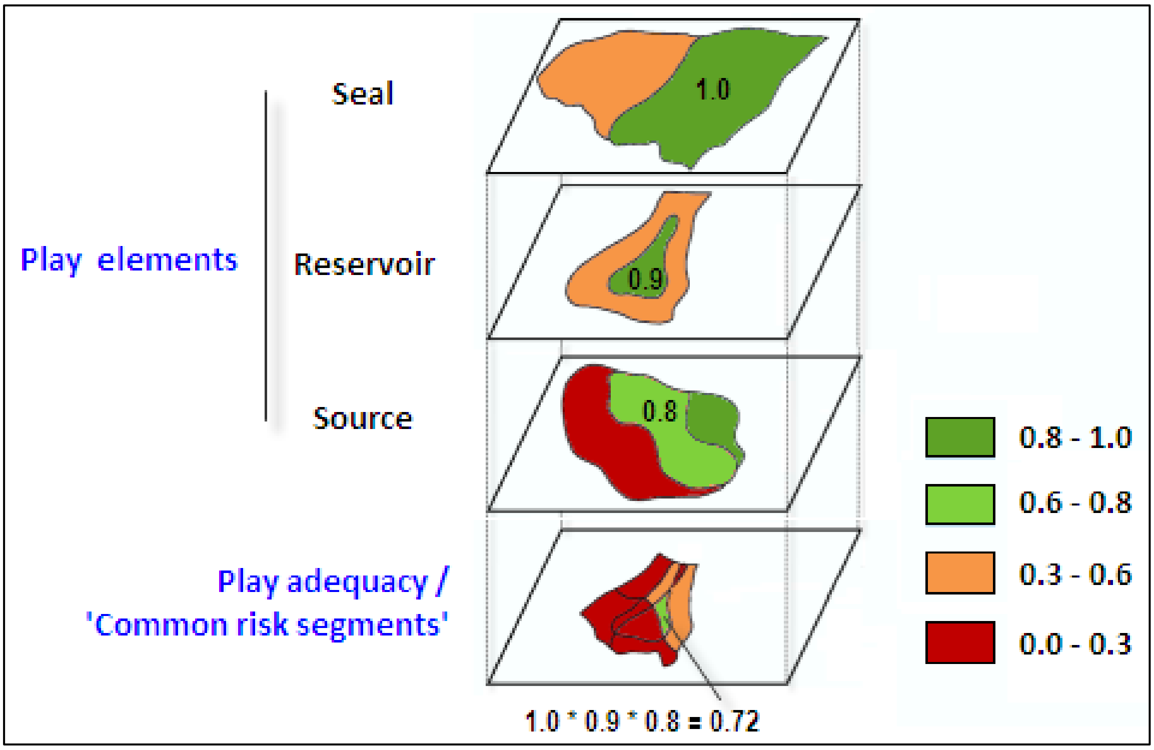


Figure 3.7: Common Risk Segment (CRS) analysis (after Hood, 2000).

Prior to the use of Geographic Information System (GIS) software and tools this could be a slow process, with each block having to be individually assessed against a series of regional maps. Any changes to the regional risk model would mean the whole process would need to be repeated. However, once the process is set up within GIS it can be carried out in minutes rather than days and iterated repeatedly which has the effect of dramatically improving decision quality. Exprodat's Exploration Analyst software contains easy-to-use tools for creating play chance or common risk segment maps using GIS. Ranking opportunities via quantitative analysis using all available information require data integration on a massive scale. It is usually seen as too time consuming to carry out on a regular basis, if it's ever carried out at all in a structured, repeatable way. GIS provides the perfect environment in which to rapidly evaluate and grade oil and gas acreage opportunities, such as license or lease blocks (Fig. 3.8). It provides a unique way of mining large quantities of different types of data in order to help make a decision. GIS allows the user to integrate multi-disciplinary asset data (e.g. geology, environment, economic, infrastructure) in order to define analysis criteria and weightings; rank acreage and company acreage positions; and ultimately identify and prioritise opportunities.

Using GIS technology, acreage and portfolio ranking workflows can be dramatically shortened, standardised and rapidly iterated in order to improve decision quality, reduce uncertainty and cut decision cycle-times. *Exprodat's Exploration Analyst* software contains tools for rapidly ranking petroleum leases, blocks and companies, using GIS data. GIS is occasionally used in prospect analysis, generally as a first-pass hydrocarbon reserve or volume estimation tool before more specialised software is deployed. In conventional hydrocarbon plays where petroleum reservoirs can be delineated and mapped it is possible to use GIS raster-based analysis to calculate the volume between two gridded surfaces, or between a single surface and a series of depth levels. The resulting volume can be multiplied by other volumetric factors such as recovery efficiency, net to gross, porosity and oil saturation to produce a first pass deterministic 'ball park' prospect volume. In unconventional hydrocarbon plays such as shale gas, shale oil or coal bed methane it is often useful to know the amount of area estimated to contain proven, possible and probable reserves, based on preliminary drilling results from exploration or development pilot wells using the common drill spacing unit (DSU) grid-based reserve classification technique.

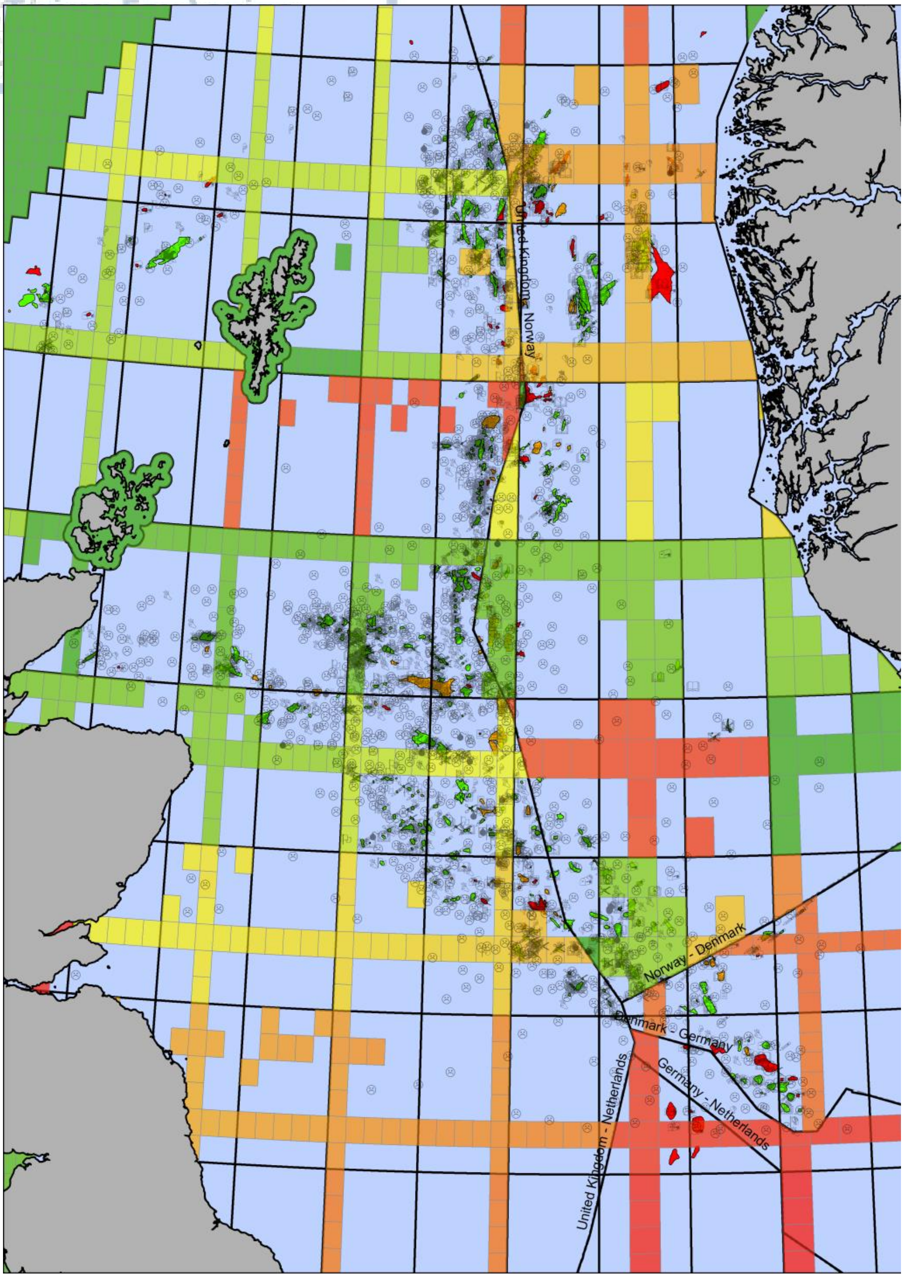


Figure 3.8: North Sea block outlines (modified from NPD database).

3.3 Utilised data

Many companies apply different processes to their analysis, varying between countries, assets or even individuals. This makes it very difficult to objectively review opportunities on a company-wide basis, and leads to greater uncertainty in opportunity ranking and portfolio management. It is also rarely seen as an iterative process; new data is rarely fed back on a regular basis to refine the model. Technology vendors have traditionally focused on the prospect analysis part of the exploration process, then down into the earth model and the

'Digital Oil Field'. There are also several innovative technologies associated with basin analysis, often driven by academic research. However, there is less technology support for the play and acreage analysis components. GIS technology has been used increasingly in this area in recent years, with much success. A challenge the oil-industry has is that 'out of the box' GIS, being a horizontal technology, is not 'tuned' to the needs of the sector. Many companies only use GIS as a data integration and visualisation tool, and don't exploit its full analytical capabilities.

GIS is beginning to be used more in basin analysis, generally as a first-pass screening tool before more specialised software is deployed. GIS can be used for petroleum systems analysis using data such as regional, structure, faults, gross depositional environment, hydrocarbon seeps, gravity and magnetics. Standard GIS functionality can be used to produce a number of exploration statistics, commonly employed by geoscientists such as creaming curves, field size distributions (Fig. 3.9) and yet-to-find analysis. *Exprodat's Exploration Analyst* software contains powerful tools for easily generating such basin (and play) statistics. More advanced GIS analytics we can be used to map likely sub-surface secondary fluid migration, using tools originally designed for hydrological mapping. GIS has been used for some time in exploration play fairway mapping and play assessment.

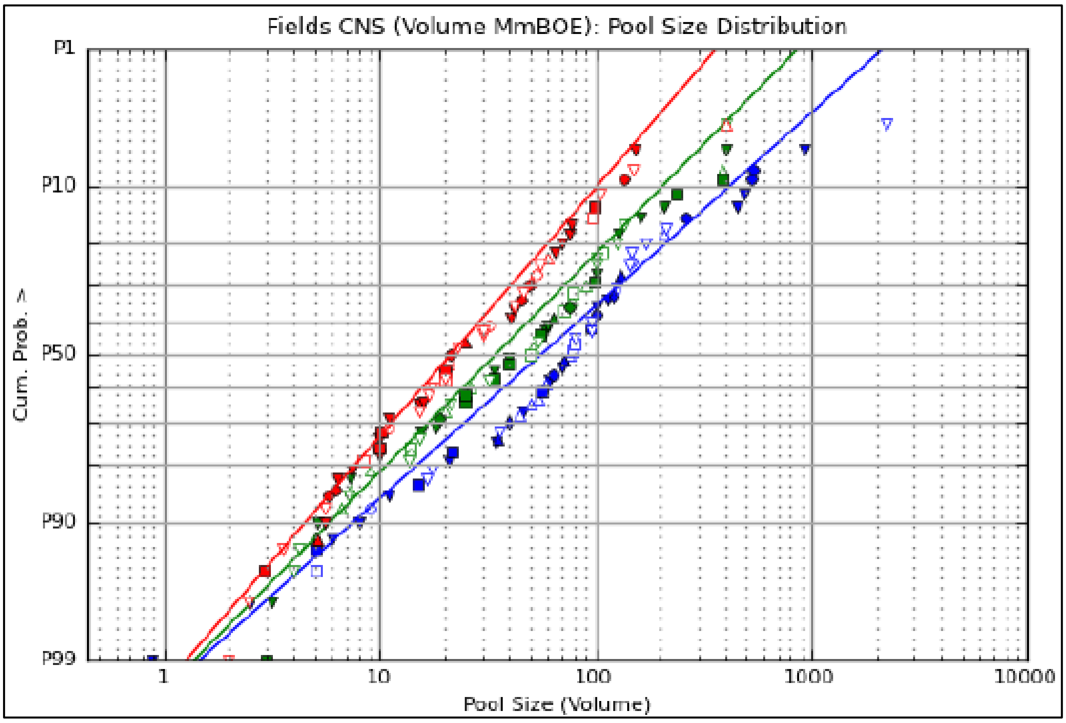


Figure 3.9: Pool size distributions produced using ArcGIS for desktop.

Maps of areas of interest can be produced showing well results, well penetrations, paleogeography, gross depositional environment, structure and other pertinent datasets. GIS allows the geologist to see all the data available in a single application for the first time. In addition, the ability of GIS to label and symbolise features using complex patterns and shapes allows multiple feature attributes to be displayed on the map, e.g. a well may show the well location, the depth of penetration, net to gross value, as well as indicators for whether the play source, reservoir and seal are present or not.

Exprodat's Exploration Analyst software was used as the interpretation tool in this study. The primary objective of the work is to perform a play-based exploration (PBE) and common risk segment (CRS) analysis of the main Cenozoic (Paleocene and Eocene) plays in the Norwegian North Sea. Furthermore, the basin maturity for these plays is analysed through the construction of basin and play statistics. The above analyses provide a simple and fast route to creating common risk segment maps to help identify play fairways and sweet spots; and powerful basin and play resources analysis, including the integration of Yet-To-Find (YTF) volume estimates.

Chronostratigraphic diagrams of the basin are used to identify the key petroleum system elements and for each play summary gross depositional environment (GDE) maps are constructed of each petroleum system element. Typically these maps would include reservoir, seal and source facies; these maps are then used to create component risk maps for reservoir, seal and source presence. Additional component risk maps are constructed for reservoir quality, seal effectiveness and source rock maturity. The maps are compiled in ArcGIS which facilitates the incorporation and synthesis of data from a disparate of data sources. Initially, areas of low play risk are identified by overlaying the component risk maps in ArcGIS. Subsequently, the layers are combined mathematically based on risk values and yield a composite map of play risk. This study is based on detailed work for the main Cenozoic (Paleocene and Eocene) plays utilizing all relevant geological information and hydrocarbon fields in the Norwegian part of the North Sea. The Norwegian Petroleum Directorate (NPD) has large amounts of public data about petroleum activities on the Norwegian Continental Shelf. The work is based on several studies as well as data from more than 40 years of petroleum activity in the North Sea area.

3.4 Workflow and approach

Initially, the key controls on a play first need to be summarised. Most commonly these will relate to specific stratigraphic levels and each play will have a well-defined set of likely reservoir, seal, source and trap lithologies and their ages. If the interpretation is to be tasked with investigating total basin prospectivity, then this needs to be repeated for each play in the basin. The utilized workflow with Explodat's Exploration Analyst software was to define input datasets for each of the petroleum system elements and use geologically meaningful proxies to convert the input maps into common risk segment layers. Such proxies are used as a way to represent the risk of having the play element present or of representing the quality risk associated with the play element. Common proxy layers used in such analysis are:

- Stratigraphic thickness
- Depth
- Paleogeography
- Gross depositional environment (GDE)
- Porosity
- Permeability
- Total organic carbon (TOC)

The use of proxies depends on the data available. Once the proxies have been identified, then numeric values of chance will be assigned. The probability scale ranges from 0.0 to 1.0; the end points of the scale are: P = 1.0 means 100% certainty and P = 0.0 means 0% certainty. The opposite of probability is risk, as shown on the left of Figure 3.10. Probability theory provides four fundamental rules, which must be considered when dealing with prospect or play risk assessments:

1. The probability of a given occurrence or event is equal to 1 minus the risk for this event not occurring:

   Pprob. = 1 – Prisk

2. The probability of the simultaneous occurrence of several independent events is equal to the product of their individual probabilities (the multiplication rule):

   P = Pa x Pb x Pc x Pd

The second rule is used when we estimate the probability of discovery for a mapped prospect. The prospect probability is the product of several independent factors. It employs four geological factors (reservoir, trap, petroleum charge and retention) all of which must be present concurrently to make a discovery.

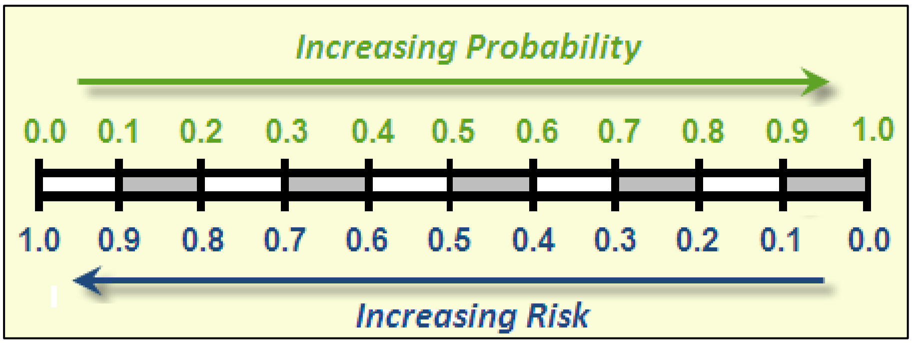


Figure 3.10: Probability and Risk (after Hood, 2000).

3. Given the occurrence of several mutually exclusive events, the probability of occurrence of at least one event is equal to the sum of the probabilities of each individual event (the addition rule):

   P = Pa + Pb

The third rule is used when dealing with several alternative outcomes such as the question of whether oil or gas will be the dominant phase in the prospect being evaluated. This rule is also frequently used when dealing with "decision trees" in which the sum of all possible outcomes is equal to 1.0.

4. The probability of either one or both of two independent events can be estimated by calculating the risk that neither of the events will occur (the combination rule):

   (1-P) = (1 - Pa) x (1 – Pb)

The fourth rule is used when risking outcomes that are dependent on one or more events occurring. For example, during the risking of an unknown area where two potential stratigraphic levels are predicted as possible hydrocarbon sources, but only one effective source rock is required to source the prospect being risked. This rule is also used when dealing with the interdependency between prospects.

The nature of the estimation of probability of occurrence of a given event will always depend on available information and knowledge. Depending on the quantity of relevant information, we may classify the probabilities according to how we arrived at them. For example, stochastic probability is represented by the ratio between how many times an event occurs and the total number of trials. An example is the success rate of drilling in a region. It is important to note that stochastic probability requires a statistical basis and cannot be applied directly when the database is limited. Objective probability is related to the extent to which available evidence/arguments support a given hypothesis. Empirical data, historical data and data from relevant analogues are used in this process. Subjective probability represents the sum of individual understanding of the probability of occurrence of a given event ("belief"). Such belief-based estimates should be avoided, or at least employed as little as possible. Our task as exploration geologists is to identify and evaluate evidence that contributes to the estimation of an objective probability.

The probability of discovery is a value that is based partly on objective knowledge and historical data, partly on extrapolations and partly on our subjective judgements of local geological parameters. It is also a value that cannot directly be measured after the fact, since the result of drilling will always be either a discovery or a dry prospect. Post-drill evaluation can be performed on a suite of exploration wells and the results analysed statistically for calibration purposes. Such studies can be very helpful in calibrating knowledge of the geological history and prospectivity in a given region. The calibration of risk parameters in an area should always be performed when new information is acquired. This will enable the consistent revision of petroleum geological models, which will in turn impact on the estimated probability of discovery of the remaining prospects.

The probability of discovery will vary from prospect to prospect, and is defined as the product of the component probabilities of well-defined geological factors, given that each of these factors is independent of the others. The four major factors are: reservoir (P1), trap (P2), petroleum charge system (P3), and retention after accumulation (P4). The probabilities of these factors are estimated with respect to the presence and effectiveness of the geological processes associated with them. The estimation of discovery probability is based on the principle of “geochronological risk assessment” (Fig. 3.11). This principle is applied in order to avoid “double risking” of the geological factors.

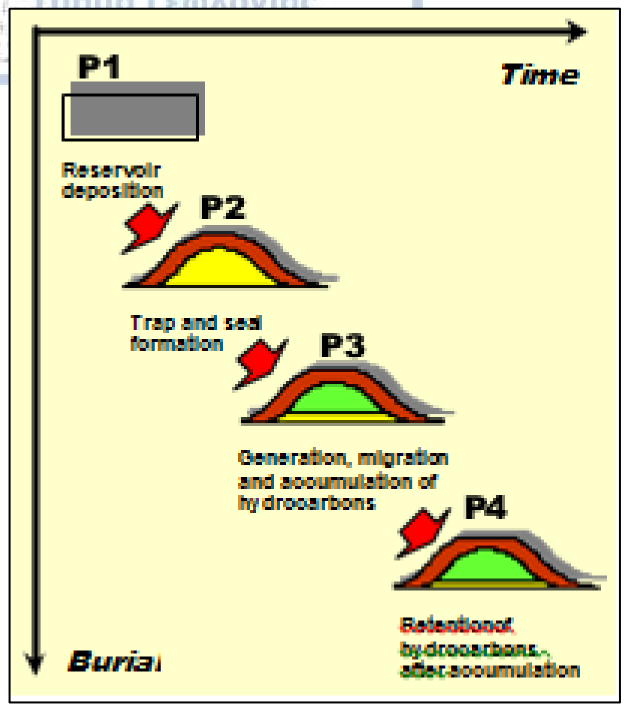


Figure 3.11: Geochronological risk assessment (after Hood, 2000).

Geochronological risk assessment is achieved by evaluating the relevant geological processes and events in a logical time sequence. The geological process starts with the deposition of the reservoir rock, and continues with the formation of a sealed trap. We must consider source rock maturation, the migration of hydrocarbons from the mature source rock into the trap, the accumulation of hydrocarbons in the trap, and finally the post-accumulation history of the trap and its hydrocarbons. If, for a given basin, we group together all prospects (mapped and unmapped) with common geological factors, we have defined a play. We may also define a petroleum system, which contains one or more plays, and we may also describe the interdependency between plays within the petroleum system. The most likely common geological factor within a given petroleum system is a source rock that may charge several plays.

4. Chapter 4

SUMMARY AND REVIEW OF THE MAIN PRE-CENOZOIC EXPLORATION PLAYS

4. Summary and Review of the main Pre-Cenozoic Exploration Plays

4.1 Sub-Trissic plays

The Triassic rocks of the study area are widely distributed but contain less than 5% of the study area's petroleum reserves (NPD, www.npd.no). The hydrocarbons are found in a few scattered fields where generally deep, Late Jurassic erosion has resulted in Triassic rocks forming the shallowest reservoirs (Fig. 4.1 and Table 4.1). The Triassic is notable for its lithologically monotonous red-bed intervals and for its common lack of fossiliferous sequences. Triassic and subsequent Upper Jurassic extension events were of the same order of magnitude, but Jurassic basin formation was focused to the west of the Triassic basins. During Permo-Triassic times, there was no significant continuation between the regions now forming the South Viking Graben and the Central Graben; the main, fault-bounded axis of Triassic sedimentation was located farther east (Erratt et al., 1999). This extended southwards from the Horda Platform into the Åsta Graben, and then south-eastwards into the Egersund and Norwegian-Danish basins. Other basin-controlling faults include the Ninian-Hutton fault and the western margin faults of the North and South Viking grabens. Triassic deposits are relatively thin in the South Viking Graben, where a minor phase of rifting is suggested by slight westward thickening and divergence of Triassic units (Thomas and Coward, 1996).

The Upper Jurassic Viking Group consists of the two subdivisions: Heather Formation and Draupne Formation (Figure 4.1). The group range from Bathonian to Ryazanian in age and mainly consists of dark, grey to black, marine mudstones, claystones and shales (Vollset and

Doré, 1984).

North Sea - Sub Triassic plays

	npl-2	npl-1 (unconfirmed)
Group/Formation	Rotligendes Group and unnamed groups of Devonian and Carbonaceous age	
Age	Devonian, Carboniferous, Permian and possible Triassic	
Area	Central Graben, southern Viking Graben, Sørvestlandet High and Jæren High	Danish-Norwegian Basin, Egersund Basin, Ling Graben and Sele High
Reservoir rock	Sandstone	
Depositional environment	Mainly continental	
Trap	Rotated fault blocks	
Source rock	Upper Jurassic shale (Haugesund, Farsund and Mandal Formations)	Unknown source of Pre Triassic age
Critical factors	Presence of mature source rock in the eastern part of the area is not confirmed, migration, timing, reservoir quality due to reservoir depth	

Table 4.1: Play summary of the North Sea pre/sub-Triassic plays (from NPD, www.npd.no).

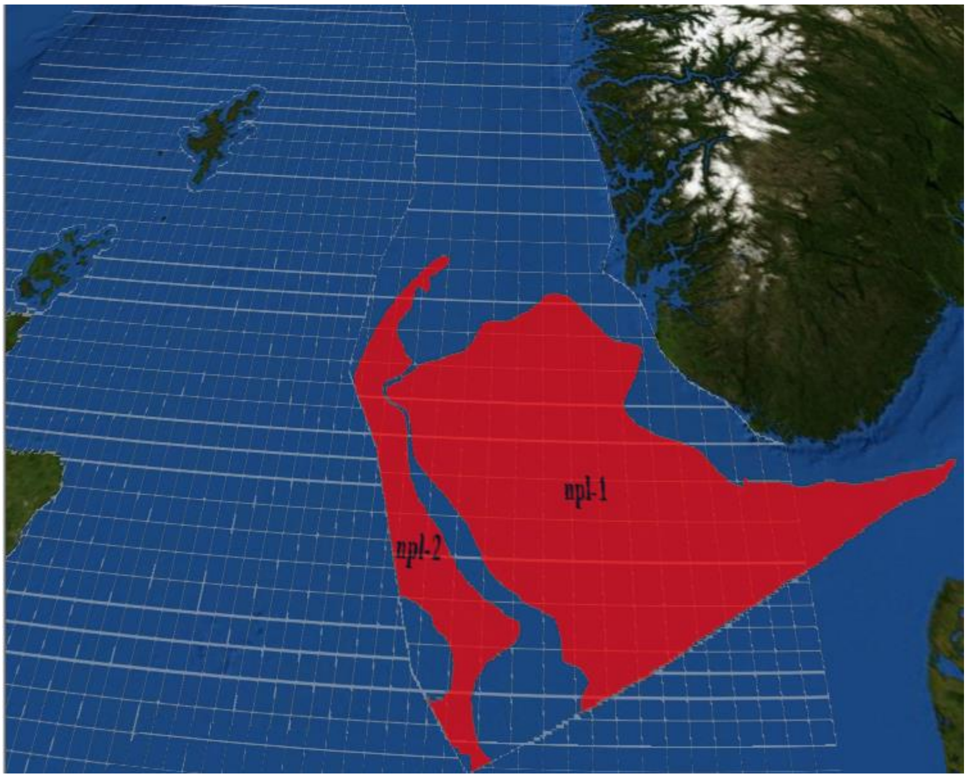


Figure 4.1: Location of the Norwegian North Sea pre/sub-Triassic plays (from NPD, www.npd.no).

4.2 Upper Triassic to Middle Jurassic plays

The pre-Jurassic play is of least importance and the most important field belonging to this play is the Snorre Field (Hollander, 1987). There, erosion has cut so deep that over large areas Cretaceous shales rest directly on the Triassic reservoir sequence and only in the west the important Statfjord Formation reservoir is still preserved. The pre-rift Upper Triassic to Middle Jurassic fluvial, deltaic and marginal marine sandstone play (Fig. 4.2 and Table 4.2) of the North Sea contains several major oil and gas fields (e.g. Gullfaks Field). This play alone contains 1/3 of the total Norwegian petroleum resources and more than half of the resources in the Norwegian North Sea. The Norwegian Petroleum Directorate (NPD) estimates that this play still has a significant undiscovered resource potential.

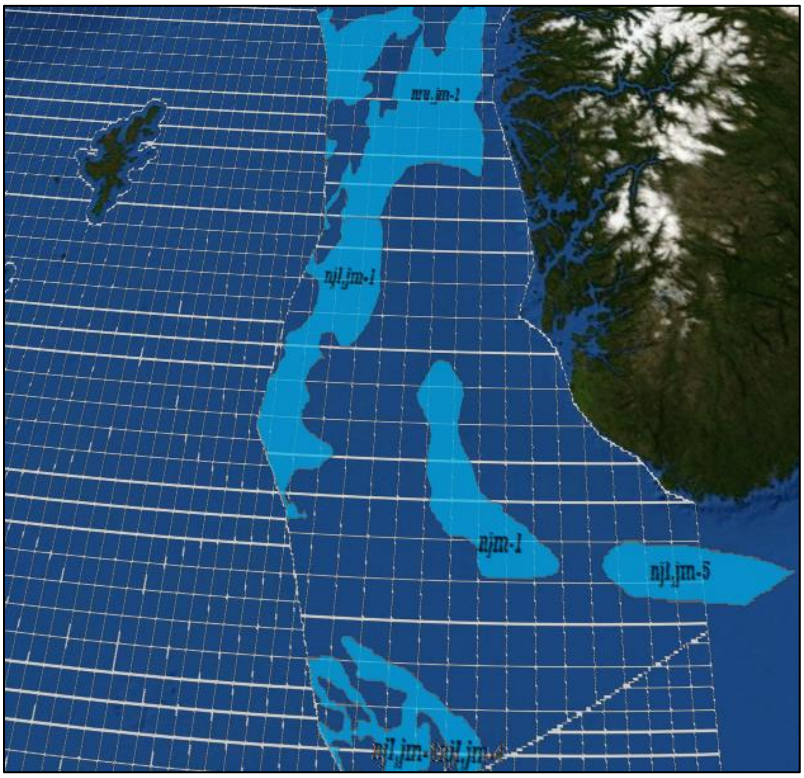


Figure 4.2: Norwegian North Sea Upper Triassic to Middle Jurassic plays (from NPD, www.npd.no).

In the northern part of the North Viking Graben, the Lower-Middle Jurassic sequence is of outstanding importance. These rocks contain many of the largest fields. During Middle Jurassic times, the Brent Group delta system dominated the North Viking Graben. All the subdivisions of the Brent Group are diachronous. The delta system prograded northwards during early Middle Jurassic times, reached its maximum extent in the late Bajocian times, and retreated southwards during Bathonian and Callovian times (Graue et al., 1987). The Brent Group play is the most successful to date with over 50% of the discovered hydrocarbon reserves. Although the basic source rocks throughout the northern North Sea are the Draupne and Heather formations, it seems that there are limited but further potential depocentres and kitchens such as at the Sleipner and Ness formations.

North Sea - Upper Triassic, Lower to Middle Jurassic plays

	nru,jm-1	njl,jm-1	njm-1	njl,jm-4
Group/ Formation	Hegre Group with Lunde Formation, Statfjord gp, Dunlin Group with Amundsen and Cook Formations, Brent Group with Broom, Etive,	Hegre Group with Skagerrak Formation, parts of Statfjord Group, Vestland Group with Sleipner and Hugin Formations	Vestland Group with Bryne and Sandnes Formations	Hegre Group with Skagerak Formations, Gassum Formation, Vestland Group with Bryne Formations
Age	Norian - Callovian		Bajocian - Callovian	Rhaetian - Bathonian
Area	Møre Basin, Tampen Spur, Lomre Terrace, Sogn Graben, Horda Platform, northern Viking Graben, Utsira High	Southern Viking Graben, Utsira High, Ling Depression, Jæren High	Egersund Basin	Central Graben
Reservoir rock	Sandstone			
Depositional environment	Fluvial, deltaic and shallow marine			
Trap	Structural, rotated fault blocks, occasionally with stratigraphic component, sealing faults			
Source rock	Upper Jurassic shale (Draupne, Heather, Tau, Farsund and Mandal Formations) and Middle Jurassic shale and coal (Gassum, Bryne, Ness and Sleipner Formations, possible Drake Formation			
Critical factors	Mature source rock in Farsund Basin			

Table 4.2: Play summary of the Upper Triassic to Middle Jurassic plays in the Norwegian North Sea (from NPD, www.npd.no).

4.3 Upper Jurassic plays

Upper Jurassic plays (Fig. 4.3 and Table 4.3) occur both in the southern and the northern parts of the Norwegian North Sea. Norway's largest field, the giant Troll Field ($47x10^{12}$ scf gas and $1.8x10^{9}$ bbl liquids) belongs to this play. The Upper Jurassic is the most variable and complex in the North Sea bot h for regional-fairway analysis and prospect evaluation. It is also one of the most important plays in terms of proven discoveries and remaining undiscovered hydrocarbon potential (David, 1996; Johnson and Fisher, 1998).

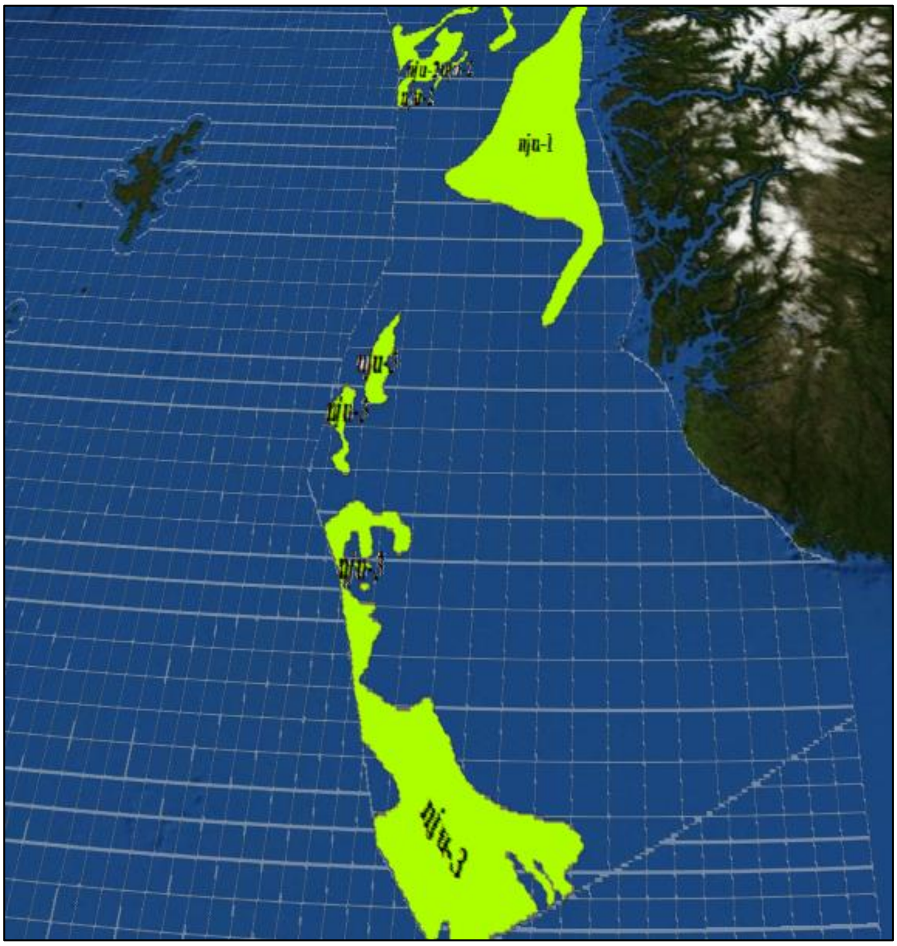


Figure 4.3: Norwegian North Sea Upper Jurassic plays. nju-1: Viking Group with Heather, Krossfjord, Fensfjord and Sognefjord formations; nju-2: Viking Group with intra Draupne and intra Heather formations (from NPD, www.npd.no).

Within the Upper Jurassic play fairway, the key controlling parameters of both the shallow-marine and deep-water sandstone plays are reservoir, top seal, and hydrocarbon charge (Johnson and Fisher, 1998). The key success factors of this play comprise: (1) widespread, high-quality sandstone reservoirs, although these have a complex distribution; (2) the overlying and/or interfingering Kimmeridge Clay Formation, which provides both the top seal and, in graben areas, a mature source rock; (3) short-distance migration routes, generally not more than 10-15 km up-dip of the mature oil kitchens (Cayley, 1987), and (4) significant overpressures in the grabens, which have enhanced the preservation of porosity at depths of over 3900 m (Gaarenstrom et al., 1993).

North Sea - Upper Jurassic plays			
	nju-1	**nju-2**	**nju-3**
Group/ Formation	Viking Group with Heather, Krossfjord, Fensfjord and Sognefjord Formations	Viking Group with intra Draupne and intra Heather Formations	Vestland Group with Ula Formation, Tyne Group with Eldfisk and Farsund Formations, Viking Group with intra Draupne, intra Heather and Brae Formations
Age	Bajocian - Barriasian?	Oxfordian - Barriasian	
Area	Sogn Graben, Horda Platform, Stord Basin, northern part of Viking Graben and Øygarden Fault Complex	Tampen Spur, Sogn Graben and northern part of Viking Graben	Central Graben and southern part of Viking Graben
Reservoir rock	Sandstone		
Depositional environment	Marginal to shallow marine and deep water		
Trap	Stratigraphic and structural, rotated fault blocks		
Source rock	The main source rock is Upper Jurassic shale (Draupne and Mandal Formations). The oil discovery 2/2-5 (NJU-3) is sourced from an unknown, possible Pre Triassic source rock		
Critical factors	Migration to the eastern part of the play	Presence of reservoir and seal	Presence of reservoir

Table 4.3: Play summary of the Upper Jurassic plays in the Norwegian North Sea (from NPD, www.npd.no).

4.4 Cretaceous plays

In recent years, the hydrocarbon potential of Lower Cretaceous sediments has increasingly been the focus of exploration effort in the mature areas of the North Sea area. Hydrocarbon reserves in Lower Cretaceous mass-flow plays in the UK suggests a substantial remaining potential (Garrett et al., 2000), and this potential may be extended into the untested graben settings of the North Viking Graben (Fig. 4.4) and the East Shetland Basin (Crittenden et al., 1988). Drilling in these areas will be costly due to the depth of burial of the Lower Cretaceous sediments, consequently predictive models need to be as robust as possible, and the depositional-sequence framework outlined above provides a basis for such models.

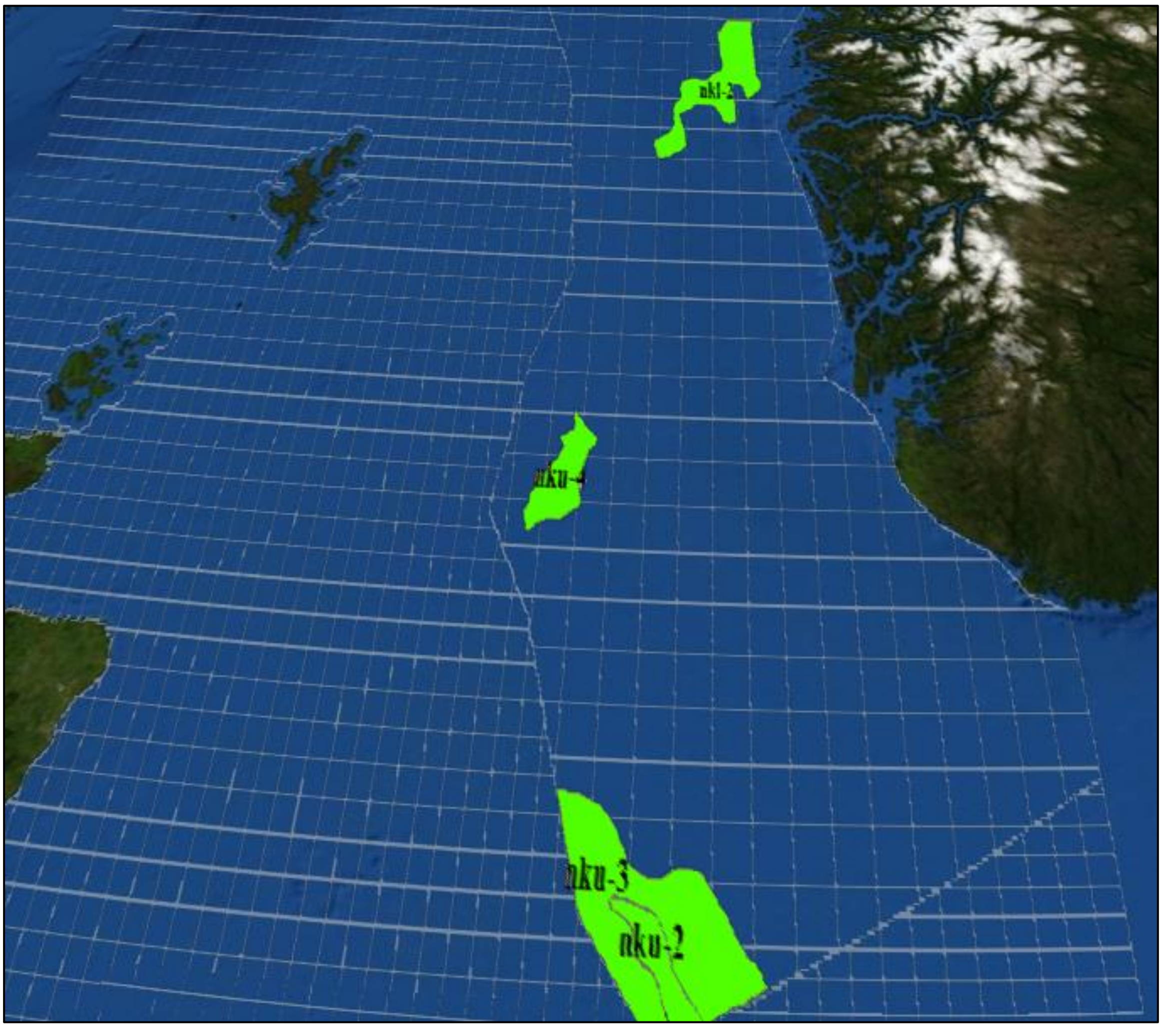


Figure 4.4: Norwegian North Sea Cretaceous plays (from NPD, www.npd.no).

A marine environment prevailed during the entire Cretaceous period with deposition of hemipelagic clay, interrupted by sand deposition in certain periods. The sand was deposited in a slope-to-basin-floor setting by gravity mass flows, primarily debris flows and turbidity currents, and was probably sourced from shallow marine sands in the east. The sand transport was concentrated in certain fairways and followed topographic lows. Some of the Albian sands in the Agat area seem to be deposited in local slide scars, thus explaining why there is no pressure communication between large sandstone bodies. Upper Turonian-Coniacian sandstones were deposited after the topography was filled and have a slope-fan geometry. Structural closures of Cretaceous strata are few and limited in extent in the northeastern North Sea, and any hydrocarbon prospectivity will depend purely or partly on stratigraphic closure (Table 4.4).

North Sea - cretaceous plays					
	nkl-2	**nku-2**	**nku-3**	**nku-4**	**nku-5**
Group/ Formation:	Cromer Knoll Group with Agat Formation	Shetland Group with Hod, Tor and Ekofisk Formations, Rogaland Group with Vidar Formation.			Shetland Group with Kyrre Formation, Tryggvason Formation is possible
Age	Berriasian? Cenomanian?	Santonian(?) – Early Paleocene			Cenomanian - Maastrichtian
Area	Sogn Graben	Central part of Central Graben from Albuskjell to Hod	Surrounding parts in Central Graben outside the large chalk fields	Utsira High	Sogn Graben
Reservoir rock	Sandstone	Chalk			Sandstone
Depositional environment	Deep marine	Open marine, redeposited			Deep Marine
Trap	Stratigraphic	Halokinetic and stratigraphic			Mainly statigraphic, structural is a possibility
Source rock	Upper Jurassic shale (Draupne and Heather Formations), Lower to Middle Jurassic shale and coal (Ness Formation?)	Upper Jurassic (Mandal and Draupne Formations)			Upper Jurassic shale (Draupne- and Heather Formation), Lower to Middel Jurassic shale and coal
Critical factors	Distribution of reservoir	Reservoir quality			Distribution of reservoir and seal

Table 4.4: Play summary of the Cretaceous plays in the Norwegian North Sea (from NPD, www.npd.no).

5. Chapter 5

EXPLORATION SUCCESS RATES

5. Exploration success rates

5.1 Basic considerations

The oil-industry is, by definition, interested in lower exploration acreage costs, higher success rates, and larger average sizes of new discoveries. In this aspect, the strategy of individual oil companies in order to explore or not a particular area takes into consideration the following parameters: discovery probability, actual success rate, predicted target volumes, actual size of new discoveries, discovery efficiency (barrels found per meter drilled), working interest, prospect origin, geologic reasons for dry holes, and finding cost. For example, one might compare working interest to discovery probability in order to see if the oil-company really is spreading risk on rank wildcat ventures. This contributes to determine whether the oil-company can successfully distinguish high-risk from low-risk prospects, establish classes of low, intermediate, and high discovery probability and compare them with the actual discovery rate of the three classes.

To check whether created prospects are truly paying their direction, one may think about prospect beginning (by classes) with real size of found gatherings, revelation proficiency, achievement rates, or discovering costs. One of the main elements in the subject company's strategy was to maintain a substantial exposure to high-potential exploration prospects, which naturally tended to have lower chances of success. Figure 5.1 is a cross-plot comparing discovery probability of successful wildcats with the estimated ultimate recovery of the new fields these wildcats found. Despite some scatter, the data show a generalized trend: if we want to find larger oil and gas fields, we should drill higher risk prospects. In the example, fields larger than 1 million bbl of oil tended to be found only by prospects having a discovery probability of about 20% or less.

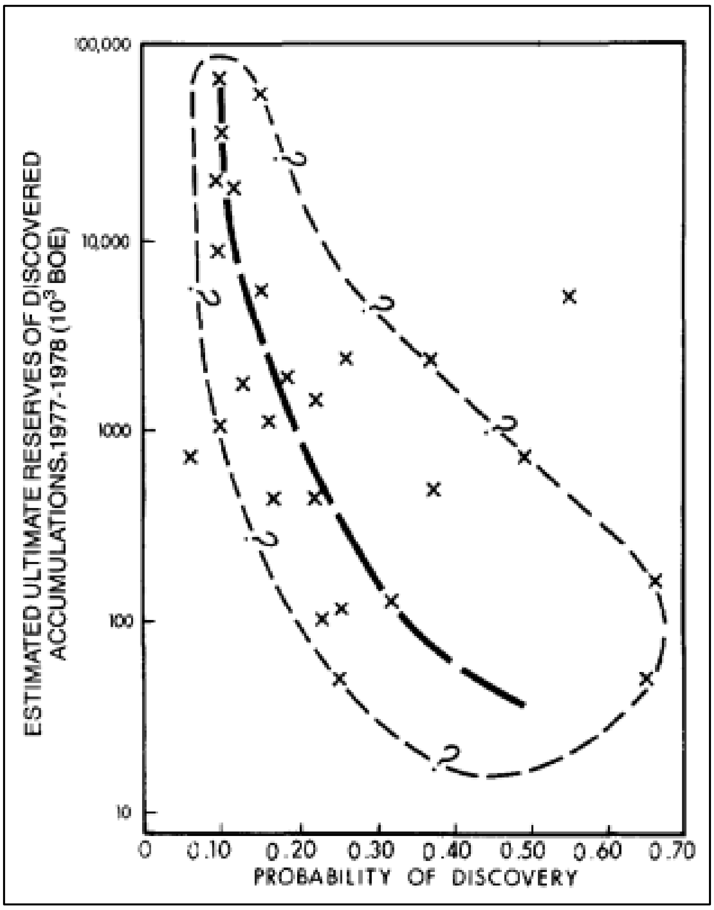


Figure 5.1: Crossplot showing relationship between discovery probability and size of company's 1977 and 1978 discoveries. Figure indicates that "high risk" new-field wildcat wells found larger fields than "low-risk" new-field wildcat wells.

In a discussion of these data, similar experience with another independent company, has shown that when the company avoided all low-risk (i.e. high discovery probability) prospects, its exploration program has been vastly improved. The basic reason, of course, is that low-risk prospects tend to be located in areas of high drilling density, in which the larger fields have already been found. As a result, low-risk discoveries tend to be mostly small, often non-commercial fields. This trend relates to the well-known principle of log-normal field-size distribution (Kaufman, 1963): most of the total volume of producible oil and gas in any trend, basin, or province is contained in a relatively few large fields. Conversely, considering all fields in a basin, most are small and together contain only a fractional proportion of the total recoverable oil and gas in the area. In addition, in the exploration history of any region or basin, the larger fields tend to be discovered early in the exploration cycle, whereas the smaller fields tend to be found during the later stages of exploration.

5.2 Paleocene/Eocene fields

The table below (Table 5.1) shows recoverable reserves originally present in descending order of some selected Paleocene fields in the northern North Sea.

NORWAY					
FIELD NAME	**STATUS**	**DISCOVERY YEAR**	**ORIGINAL RESERVES (Sm^3 o.e.)**	**REMAINING RESERVES (Sm^3 o.e.)**	**PRODUCTION START**
GRANE	Producing	1991	144,2	37,5	2003
FRIGG	Shut down	1971	116,7	0	1977
BALDER	Producing	1967	77	9,9	1999
ALVHEIM	Producing	1997	56,7	20,3	2008
HEIMDAL	Producing	1972	52,7	0,7	1985
ODIN	Shut down	1974	27,5	0	1984
JOTUN	Shut down	1994	24	0	1999
VOLUND	Producing	1994	14,1	4,6	2009
NORDØST FRIGG	Shut down	1974	11,7	0	1983
MARTIN LINGE	Approved for production	1975	10,9	10,9	Planned for 2019
ØST FRIGG	Shut down	1973	9,3	0	1988
BØYLA	Producing	2009	3,6	2,1	2015
JETTE	Shut down	2009	0,4	0	2013

Table 5.1: Original and remaining reserves measured in million standard cubic meters oil equivalents (Sm^3 o.e.) of the main Paleocene/Eocene fields in the northern North Sea (last updated in 2016) (from Norwegian Petroleum website www.norskpetroleum.no).

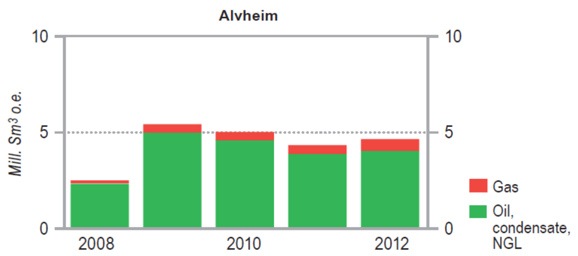
Figures 5.2 and 5.3 show an overall production history of some of the most important Paleocene/Eocene fields of the northern North Sea in the Norwegian sector.

Alvheim

Blocks and production licences	Block 24/6 - production licence 088 BS, awarded 2003 Block 24/6 - production licence 203, awarded 1996. Block 25/4 - production licence 036 C, awarded 2003 Block 25/4 - production licence 203, awarded 1996.	
Development approval	06.10.2004 by the King in Council	**Discovered** 1998
On stream	08.06.2008	
Operator	Marathon Oil Norge AS	
Licensees	ConocoPhillips Skandinavia AS	20.00 %
	Lundin Norway AS	15.00 %
	Marathon Oil Norge AS	65.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	37.2 million Sm^3 oil	17.5 million Sm^3 oil
	6.8 billion Sm^3 gas	4.7 billion Sm^3 gas
Estimated production in 2013	Oil: 59 000 barrels/day, Gas: 0.58 billion Sm^3	
Expected investment from 2012	1.8 billion 2012 values	
Total investment as of 31.12.2011	17.7 billion nominal values	

Balder

Blocks and production licences	Block 25/10 - production licence 028, awarded 1969. Block 25/11 - production licence 001, awarded 1965. Block 25/8 - production licence 027, awarded 1969 Block 25/8 - production licence 027 C, awarded 2000 Block 25/8 - production licence 169, awarded 1991.	
Development approval	02.02.1996 by the King in Council	**Discovered** 1967
On stream	02.10.1999	
Operator	ExxonMobil Exploration & Production Norway AS	
Licensees	ExxonMobil Exploration & Production Norway AS	100.00 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	72.1 million Sm^3 oil	16.2 million Sm^3 oil
	2.0 billion Sm^3 gas	0.6 billion Sm^3 gas
Estimated production in 2013	Oil: 32 000 barrels/day, Gas: 0.04 billion Sm^3	
Expected investment from 2012	9.6 billion 2012 values	
Total investment as of 31.12.2011	23.2 billion nominal values	
Main supply base	Dusavik	



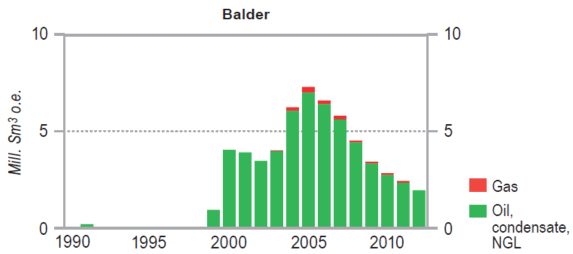


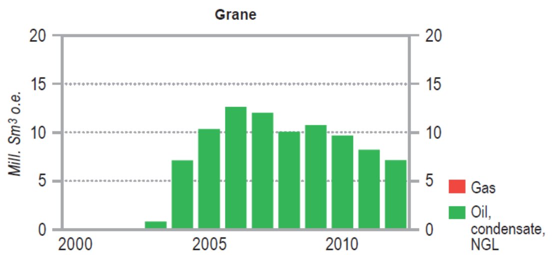
Figure 5.2: Production history and status of the Alvheim and Balder fields (NPD, Facts 2013).

Grane

Blocks and production licences	Block 25/11 - production licence 001, awarded 1965 Block 25/11 - production licence 169 B1, awarded 2000.	
Development approval	14.06.2000 by the Storting	**Discovered** 1991
On stream	23.09.2003	
Operator	Statoil Petroleum AS	
Licensees	ConocoPhillips Skandinavia AS	6.17 %
	ExxonMobil Exploration & Production Norway AS	28.22 %
	Petoro AS	28.94 %
	Statoil Petroleum AS	36.66 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	124.6 million Sm^3 oil	36.1 million Sm^3 oil
Estimated production in 2013	Oil: 98 000 barrels/day	
Expected investment from 2012	10.0 billion 2012 values	
Total investment as of 31.12.2011	19.7 billion nominal values	
Main supply base	Mongstad	

Heimdal

Blocks and production licences	Block 25/4 - production licence 036 BS, awarded 2003.	
Development approval	10.06.1981 by the Storting	**Discovered** 1972
On stream	13.12.1985	
Operator	Statoil Petroleum AS	
Licensees	Centrica Resources (Norge) AS	33.80 %
	Petoro AS	20.00 %
	Statoil Petroleum AS	29.44 %
	Total E&P Norge AS	16.76 %
Recoverable reserves	**Original**	**Remaining as of 31.12.2012**
	8.2 million Sm^3 oil	1.6 million Sm^3 oil
	46.9 billion Sm^3 gas	1.7 billion Sm^3 gas
Estimated production in 2013	Oil: 330 barrels/day, Gas: 0.11 billion Sm^3	
Expected investment from 2012	0.2 billion 2012 values	
Total investment as of 31.12.2011	10.0 billion nominal values	
Main supply base	Mongstad	



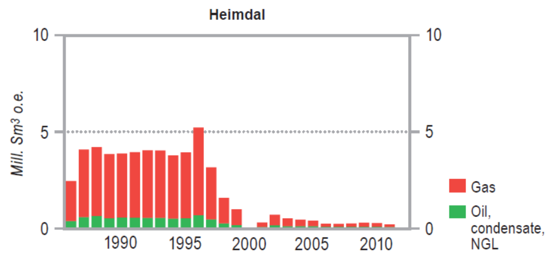


Figure 5.3: Production history and status of the Grane and Heimdal fields (NPD, Facts 2013).

5.3 Licensing rounds and exploration success rates

Exploration activity is essential if undiscovered resources are to contribute to production and create value both for the industry and for society. The oil-companies are given access to exploration acreage in both mature and frontier areas. Concerning Norway, a high level of exploration activity on the Norwegian Continental Shelf (NCS) since 2005 has resulted in a number of profitable discoveries. The production license gives a company or a group of companies a monopoly to perform investigations, exploration drilling and recovery of petroleum deposits within geographical area stated in the license. The licensees become owners of the petroleum that is produced. A production license may cover one or more blocks or parts of blocks and regulates the rights and obligations of the participant companies with respect to the Authorities. Production licenses are awarded by the Norwegian Ministry of Petroleum and Energy in numbered licensing rounds, or by yearly awards in predefined areas (APA) (Fig. 5.4). APA awards cover mature areas, while numbered rounds concentrate on frontier areas. Mature areas are characterised by known geology and well-developed or planned infrastructure. They usually offer a greater probability of making discoveries than frontier areas, where geological knowledge is more limited and infrastructure lacking. Frontier areas are likelier to yield large discoveries than mature ones.

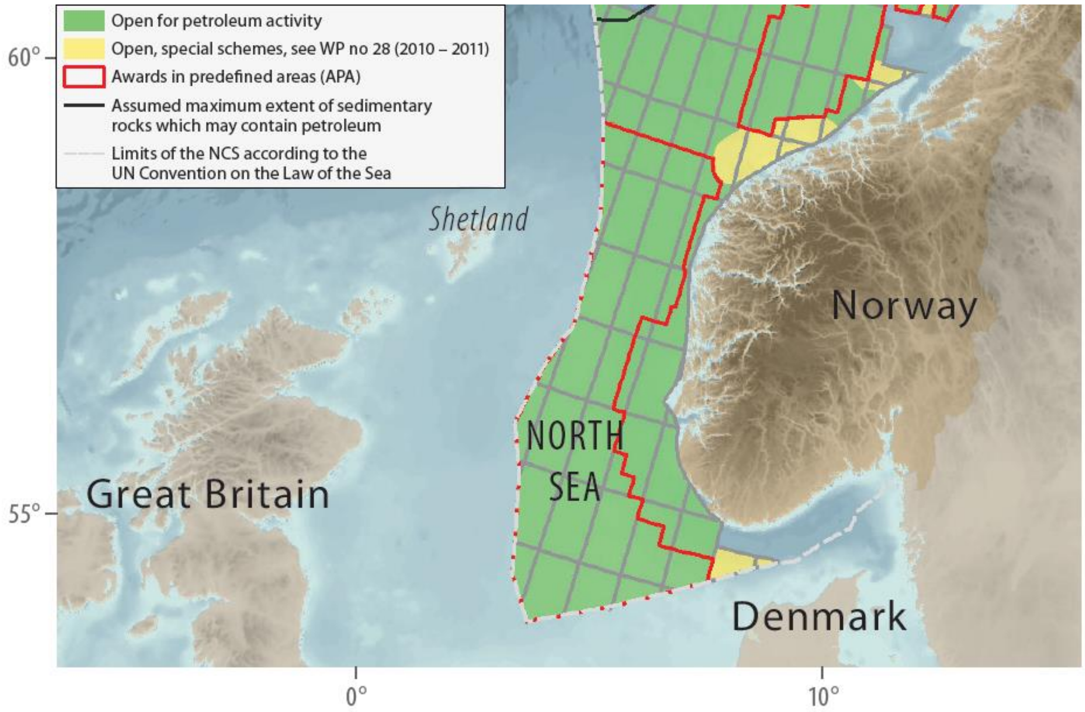


Figure 5.4: Exploration status of the northern North Sea in the Norwegian Continental Shelf (from NPD website www.npd.no).

New (medium to small size) exploration companies have been especially prominent in APA rounds, where blocks in mature areas are announced. Exploration in frontier areas, on the other hand, is mainly carried out by the larger companies. The little known geology increases the potential for discoveries, but greater challenges may be met during exploration, development and production. Exploration costs include costs related to seismic data acquisition to map potential petroleum deposits under the seabed and to drilling exploration wells. In 2016, preliminary estimates of exploration costs on the Norwegian shelf totaled about NOK 22 billion (~2.5 billion Euros). Figure 6.5 shows a comparison between oil price, number of companies on the shelf and spudded exploration wells at year-end, 2000-2016.

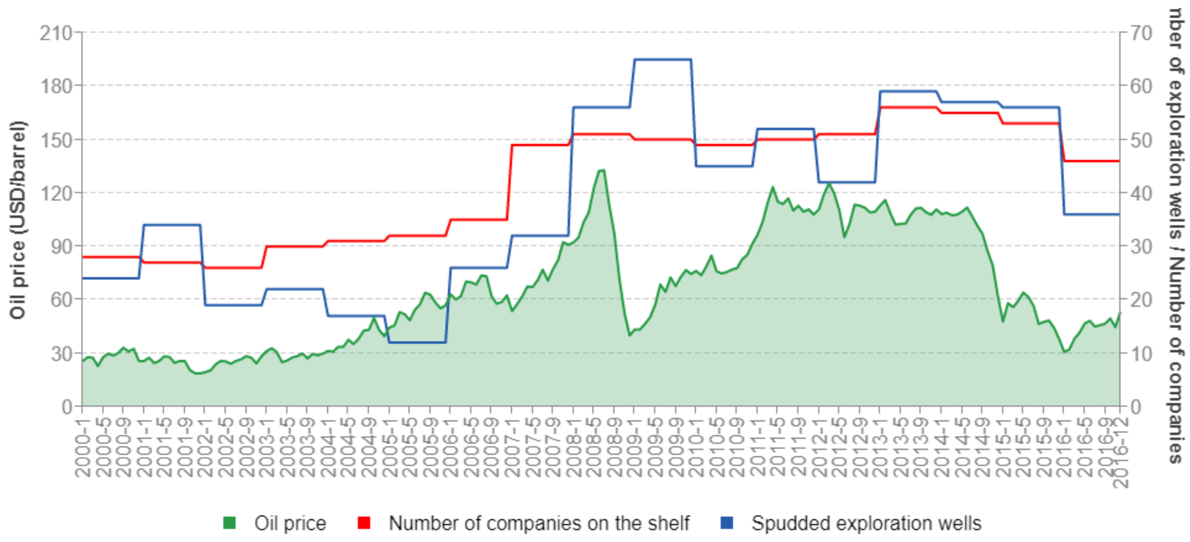


Figure 5.5: Oil price, number of companies on the shelf and spudded exploration wells at year end, 2000-2016 (from Norwegian Petroleum website www.norskpetroleum.no).

6. Chapter 6

CREAMING CURVES

6.1 Hydrocarbon Plays

6. Creaming curves

6.1 Hydrocarbon Plays

The creaming curve method of analysis focuses upon a petroleum province in a given geographic area with known commercial accumulations. The petroleum province being analyzed need not have distinct geologic, tectonic, or oil-accumulation properties or boundaries (Meisner and Demirmen, 1981). Creaming curves is a smart way of forecasting future oil discoveries from the evolution of the exploration effort. The development of new finds can be used to predict the expected findings. For this purpose, the cumulative finds are set in relation to the test wells that were necessary for the finds, or alternatively to the number of oil fields. The creaming curve is extrapolated to create a forecast of the possible finds. In practice, the creaming method is typically applied to exploration plays, following the definition of an exploration play as provided by Magoon and Sanchez (1995): a play emphasizes traps but also includes hydrocarbon charge and timing. The decision to enter into an exploration of a play /basin is one of the most important tasks of a geoscientist. The timing of entry and timing of exit on exploration failures/maturity is also very important. These judgments are as important as the decision to drill an individual prospect in a play or basin (Brown and Rose, 2002). Creaming curve is one of the methods to evaluate a hydrocarbon play.

A creaming curve is a diagram used to present the relationship between aggregated or cumulative resource growth from discoveries and wildcats drilled. Its name probably derives from the fact that the biggest discoveries in an area or a play (the cream of the crop) are normally made early in the exploration history of the area or play. As time passes, remaining prospects will be smaller and have a lower discovery probability. Such a curve presents the exploration history of an area or play. The x-axis is linear, with the number of wildcats in the order of their completion. When a well proves resources in a new discovery, the volume found is plotted as a cumulative value on the y-axis. The result is a rising curve which shows how the area or play has been explored. If the curve is steep, a lot of resources have been found or possibly large discoveries made. A gradual curve indicates that proven discoveries have been small or that many dry wells have been drilled.

Two brief examples might clarify this concept for example a very specific example of how creaming curves form in different areas of the North Sea in the UK. This expanded definition for an exploration play aligns the concept with that of a petroleum system, an assemblage of elements such as reservoir, source, trap, seal, migration pathway, etc. that allow accumulation of oil and gas (Magoon and Dow, 1994). To put it in another way a creaming curve is a plot showing discovered resources against either the number of wells (well count) or time since start of exploration in years. Only exploration wells may be plotted and all volumes within a field must be back-dated to the original discovery well. It is an essential tool in understanding the history of a basin and provides context in order to look to the future. Figure 6.1 shows a generic creaming curve showing the four phases of a typical basins life:

a. Frontier – this is the initial phase of exploration up to the first discovery well, at this stage the basin is unknown and views amongst geologists vary from optimistic to very pessimistic or dismissive.

b. Emerging – this is the early part of the basin's life when most of the large discoveries are made (in the majority of cases). The basin becomes the place to be and there may well be a scramble by international oil companies to get a position. Success rates vary as the explorers try new plays, some of which succeed and others don't. Some companies can achieve a great deal of success and discover resources that can transform their fortunes.

c. Maturing – this is the middle part of a basin's life with steady additions in resource, but with fields of a diminishing size. The established companies now understand the basin with high success rates as they have worked out what works and what does not. These companies also make a lot of profit during this phase as they own the infrastructure and can tie-back any smaller discoveries. There may also be some new entrants that focus on a new play, this may work well, for example Encana with Buzzard in the UK continental shelf, but may also not be so successful. Larger companies or exploration companies may sell their assets and leave the basin.

d. Mature – this is the later part of a basins life. Discovery sizes are small and success rates high in established plays, with exploration led by infrastructure availability.

Some companies leave the basin to focus exploration efforts elsewhere, and others spend efforts in testing new plays.

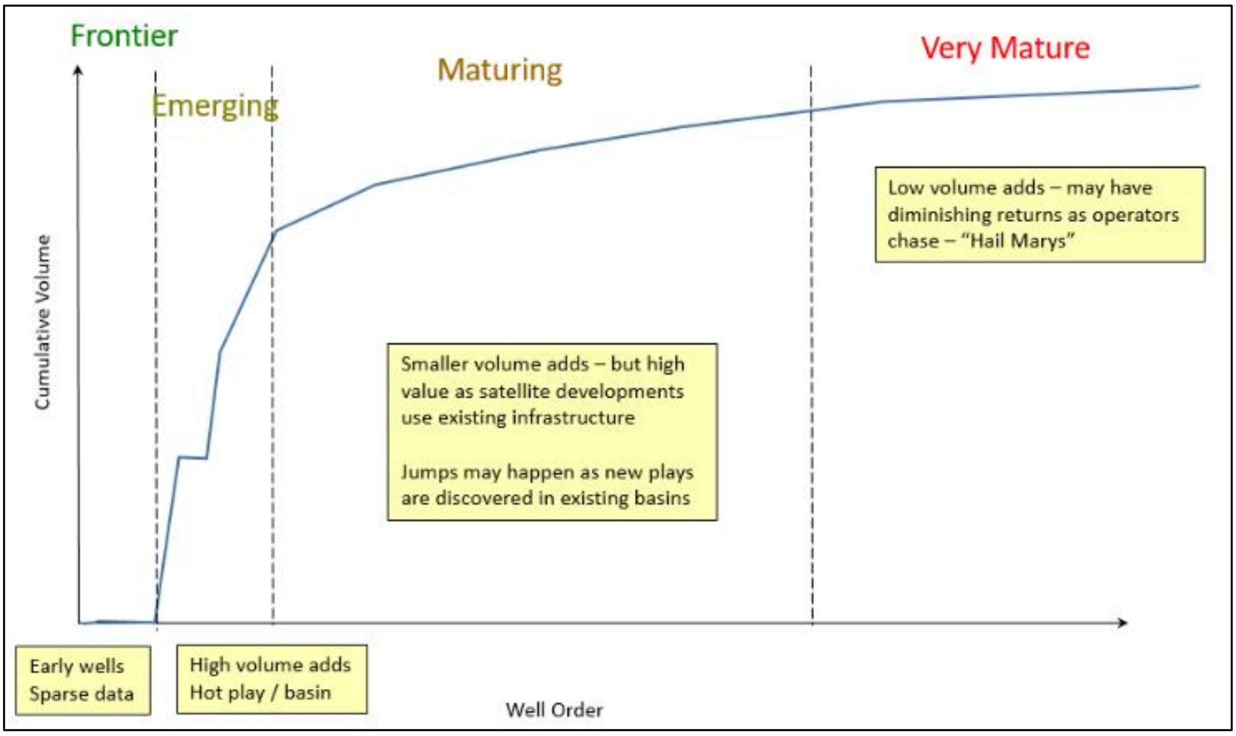


Figure 6.1: Generic creaming curve.

The normalised creaming curve technique consists of plotting the percentage of resources discovered (y-axis) against the percentage of exploration wells drilled (x-axis). This plot can be used to easily distinguish basins with apparent potential, where the line slopes at a 45-degree-angle, against basins where most of the discoveries were made early, where the line zooms up and then flattens out. Figure 6.2 shows normalised creaming curves for two basins. Both have had over 300 exploration wells and have discovered over 10 billion barrels equivalent of hydrocarbon resources. One has a growing curve where the other is flat.

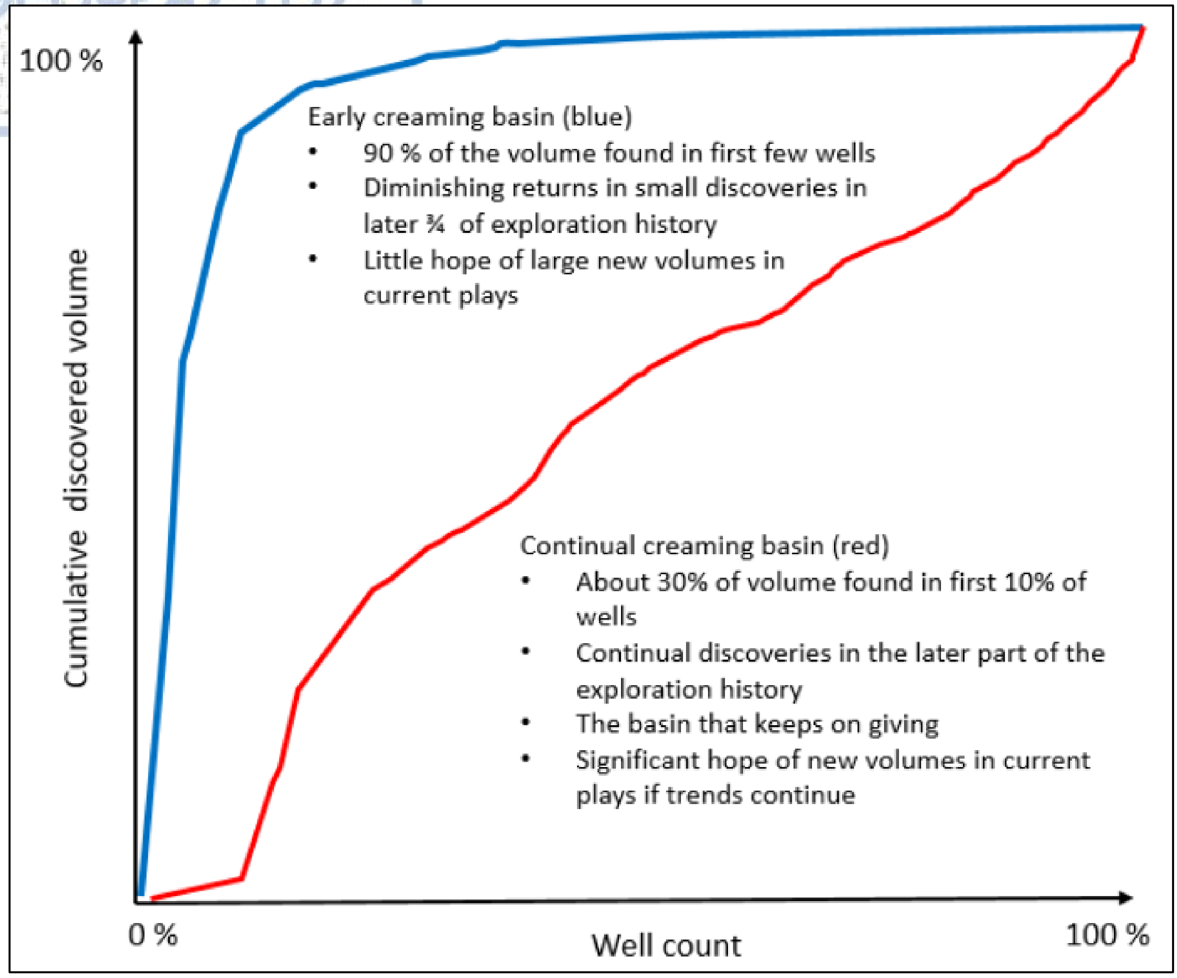


Figure 6.2: Normalised creaming curve (Gordon Knox, AAPG, 2003).

Creaming curves have also been used to estimate Yet-to-Find remaining hydrocarbon resources. This is done by fitting a hyperbolic curve and deriving an equation. The likely number of wells can be inserted into the formula and a corresponding resource number can be the outcome. However, this is very dangerous and should not be used because:

1. Any new plays cannot be accounted for using this method. Any new plays will significantly add to the reserve base leading to an underestimate.
2. The curve fit may not be very accurate and adjustments such as vertical shifts can distort the curve.
3. The minimum field size, chance of success or any other geological factors are not taken into account.
4. Any lateral play extensions are not taken into account. This is where new field sizes may be larger than those expected in a mature area where the larger fields in the play would have already been discovered.
5. Information about field sizes particularly scouting data may not be accurate.

A creaming curve is a tool for the explorationist to determine what the maturity of the basin is. The curve in the middle shows how the cumulative resource discovered in the basin has grown over time as extra wells have been drilled in the basin (Fig. 6.3). This is a very typical curve for a basin where we start in the early days with significant discoveries to be made early on in the basin life and as the basin becomes more mature and more wells get drilled typically that curve tends to fatten off. One can try to make a prediction of how the curve will look in the future. The curve either is going to continue as a flat line in other words only small discoveries as additional wells are drilled or if something new is going to happen in the basin and the chased play utilising perhaps new technology or better seismic data will allow this curve to tick off again and give yet more resources.

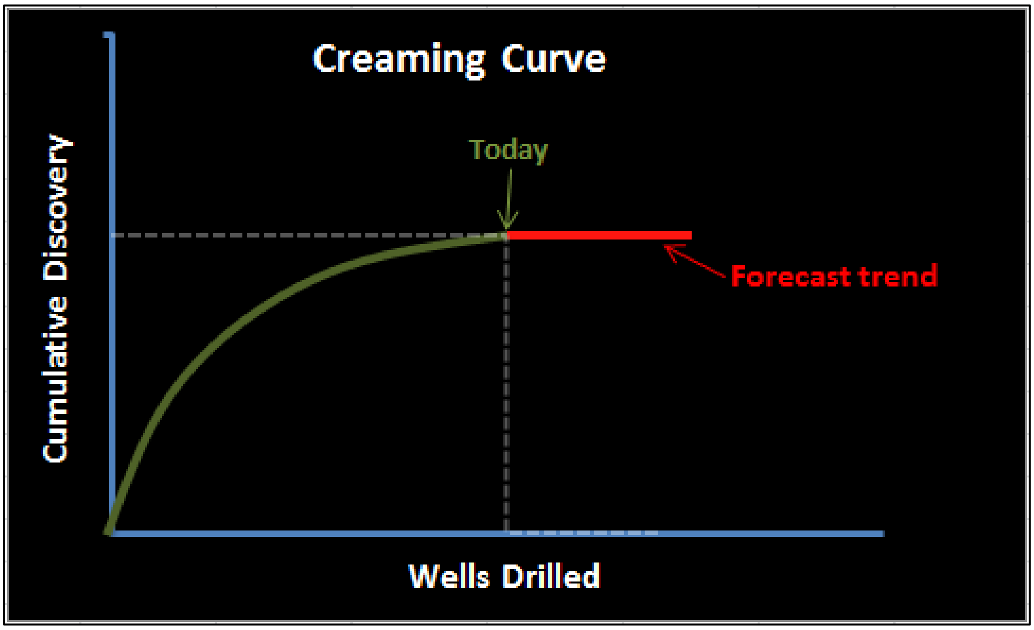


Figure 6.3: Creaming curve (Gordon Knox, AAPG, 2003)

Figure 6.4 illustrates the creaming curves for four different basins in the UK North Sea: west of Shetland (WS), where approximately two hundred exploration wells have been drilled (red line); southern North Sea (SNS), where approximately 800 wells have been drilled (pink line); central North Sea (CBS), with over a thousand wells drilled (blue line); and northern North Sea (NNS), with some 500 wells drilled (orange line). The creaming curves are telling different stories about these basins. If we go for example to the northern North Sea (NNS) here (orange peak, Alwyn N. Murchison), we can see that after the initial exploration phase, very quickly (~4000-12000 MMBOE) all the large fields were discovered very early on in the basin. So it's a very steep rise to a point after about 70 wells when the incremental resources being added were relatively modest compared to the early years (Alwyn N. Murchison).

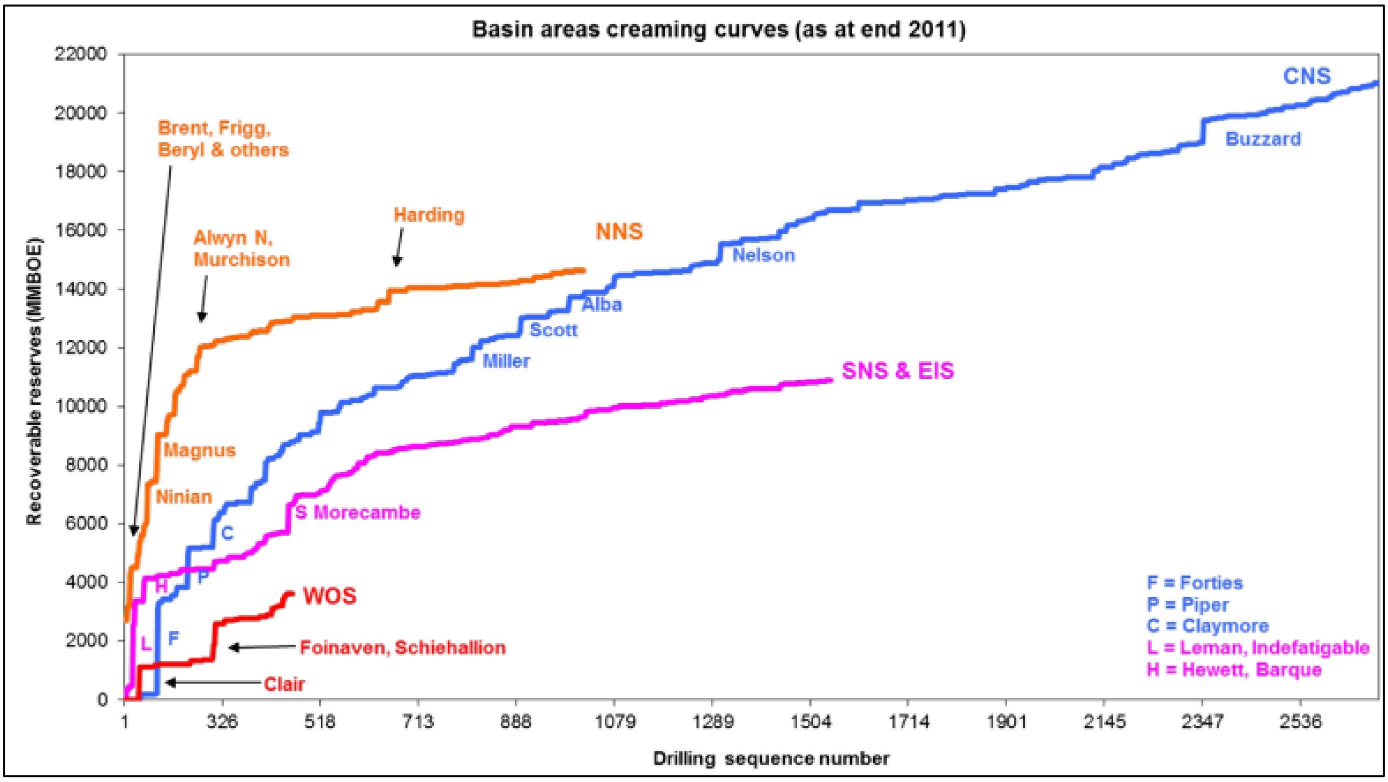


Figure 6.4: Creaming curves for areas of UKCS (source: DECC).

In contrast, in the west of Shetland where only 150 wells have been drilled there was an early step (red line, WOS), then a period of not much activity (first red peak) - drilling activity but not too big of a discovery - after over 30 years of West of Shetland exploration, it is a fact that only three oil-fields are in production; then a big step up with (Foinaven, Schiehallion, Clair) and then not too much resource growth and then as towards the end of this period a little step up again (WOS). We can see on one hand a very mature basin where lots of drilling is going on and very incremental resource has been added (NNS), and a basin where one would feel the story hasn't been fully told yet (WOS). There's been a series of steps up responding to new discoveries, but relatively few wells have been drilled (WOS).

The Central North Sea (CNS) creaming curve is very similar to the classic creaming curve. We can see early on big discoveries being made in a very rapid rise with some of the main fields there and after 500 wells things are beginning to level off (blue peaks line, Miller, Scott, Alba), but after a thousand wells another step up. This was a new play concept, the Buzzard field, and new oil was found in a relatively mature exploration area, and the North

Sea then was stimulated into a fallow period of exploration. So, it can be seen how the creaming curve tells a little bit about the story of a basin and tells how much resource has been added for the number of drilled exploration wells.

The question one asks when looking at a creaming curve is always the same: are we at a stage perhaps like the northern North Sea in a state of maturity and therefore further exploration isn't paid off, or are we in an area like the Central North Sea, where actually there has been discoveries even fairly recently, new play concepts being developed and discoveries continue to be made. This is the choice that faces explorations in any basin in the world, deciding whether the basin has reached its full potential or whether the creaming curve is going to take another step up and enter a new phase of its history of development.

It is a well-known fact that commercially significant reservoir rocks, mostly sandstones but including limestones, are present in every system from Devonian to Oligocene, and six groups of hydrocarbon plays have been described for the study area by Pegrum and Spencer (1990) and Spencer et al. (1996): Palaeozoic to Triassic, Lower and Middle Jurassic, Upper Jurassic, Lower Cretaceous (Chalk) and Paleogene. Mudstones of Cretaceous and Cenozoic age seal the main reservoirs. The existence of the plays is very largely due to the widespread presence of mature Upper Jurassic source rocks combined with the structural geometry created by the Late Jurassic to Early Cretaceous rift system and its subsidence (Knag et al., 1995; Spencer et al., 1996). The rifting provided structural traps for the Jurassic and older reservoirs, and the subsidence allowed hydrocarbon generation from the source rock. The post-rift Upper Cretaceous and Paleocene plays contain traps defined by stratigraphic pinch-outs and drapes over highs.

Charting the total hydrocarbons discovered as wildcat wells are drilled is a method of identifying the most successful play types. Based on the above play classification, creaming curves, or S-curves, show the resource growth for each play. The curves are plotted per reservoir target of each well, be it primary, secondary, tertiary or, in the event, serendipitous. Each well may have penetrated several reservoir targets. Each successful penetration or targeting of a play will show the reserve/resource growth as an upward step on the curve. The degree of upward movement is equivalent to the increase of the reserves/resources found in that play; consequently, there is only a horizontal movement of the curve if there was no discovery in a well. In many cases there is an impact of licensing policy on the shape of the creaming curve. The creaming curves presented in Figure 6.5 show the total number of targets in the study area. The curves include all targets in a well, so that the total number of targets shown is larger than the total number of wells drilled. The Norwegian curves include data up to 1999, whereas the UK data cut-off is 1993. The figure shows the total hydrocarbon reserves/resources in oil equivalents, which includes both oil and gas. The most successful plays in the study area, both in the UK and Norwegian sectors, are the Jurassic plays. In addition, the Cretaceous in the Norwegian sector and the Paleocene in the UK sector are major plays.

Several fields and discoveries have reservoirs in more than one play. The resource growth has therefore been allocated to the most important reservoir or play in a field or discovery. This means that the total reserve/resource growth due to a discovery, for instance, the Snorre Field, will be listed in the Triassic creaming curve even though Snorre also has reservoirs in the Lower and Middle Jurassic. The vertical scales are identical. The Lower and Middle Jurassic play is by far the most explored and most successful both in the UK and Norway. The Cretaceous plays are considerably more successful in Norway than in the UK, but the Paleocene play has almost three times the volume of reserves and resources in the UK compared to Norway. The Norwegian curves generally display steeper growth resulting from larger petroleum accumulations, whereas the UK curves show smoother build-up as a result of smaller discoveries and the greater number of wells drilled.

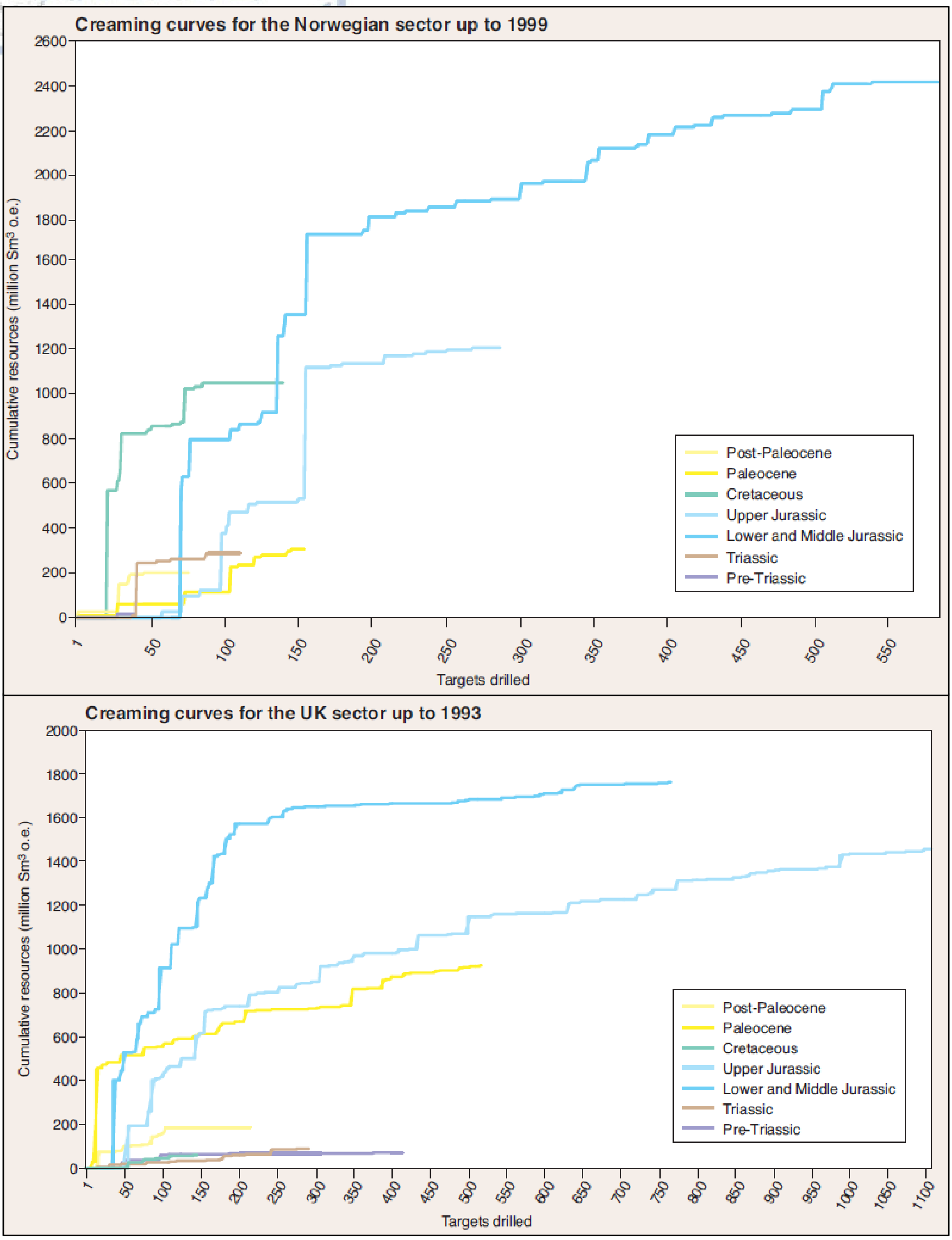


Figure 6.5: Norwegian and UK creaming curves (Evans et al., 2003).

In more details, the most important Paleocene/Eocene discoveries played an important role on the cumulative resources of the northern North Sea, as shown in Figure 6.6.

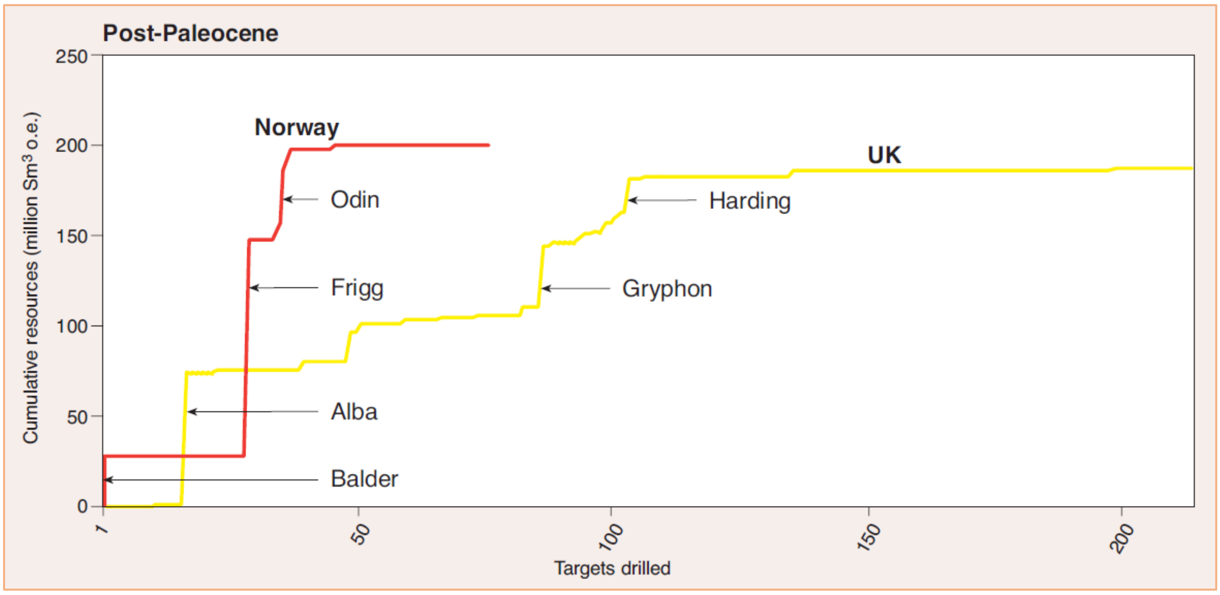


Figure 6.6: Creaming curve for the Paleocene/Eocene play of the North Sea (Evans et al., 2003).

7. Chapter 7

YET-TO-FIND RESOURCES

7. YET-TO-FIND RESOURCES

7.1 North Sea: all main plays

Yet-to-Find (YTF) resources are an estimate of the remaining hydrocarbon potential of a petroleum basin, territory or country. It is a risked estimate of the as yet undiscovered recoverable hydrocarbon resources which are expected to be found in the target area. It is an estimate of both volumes (resources) and risks and therefore highly uncertain. There are several methods described below and each of these methods has advantages and drawbacks. Estimating yet to find potential is important in focussing exploration effort in areas that are more likely to yield hydrocarbon discoveries. However, it is a bit like driving using the rear view mirror and all methods extrapolate from previous results. None of these methods can effectively look at new and untested plays. It is also important to look at how any YTF estimates are made, all of them have drawbacks as well as advantages. It is also important to look at who is making the estimate and what their motivations are. For instance it a government body trying to encourage investment?

Nevertheless, a range of YTF estimates done using different methods can give a context within which to place the exploration efforts. One needs to remember that this is an estimate and not reality. Since production started in 1971, oil and gas have been produced from a total of 102 fields on the Norwegian Continental Shelf (NCS). At the end of 2016, 62 fields were in production in the North Sea. The first well on the NCS, well 8/3-1 in the south-eastern part of Norway's North Sea sector, was spudded in 1966. Since then, some 615 wildcats have been drilled in the Norwegian-sector of the North Sea and provide the data set for the creaming curve. The creaming curve in Figure 8.1 shows that discoveries were made after a few wells in the North Sea. In addition, Figure 8.1 presents the uncertainty range of ~3000 to 8000 Mboe for the undiscovered resources. The latter are estimated on the basis of current knowledge about the areas, and the figure will probably change with new information.

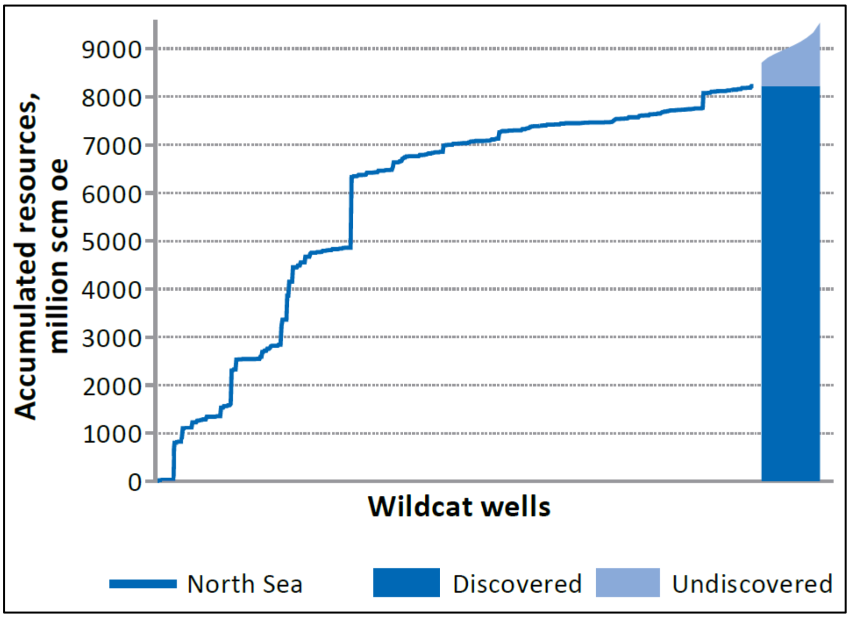


Figure 7.1: Proven and undiscovered resources (light blue) in the North Sea (from NPD site www.npd.no).

The resource accounts for the North Sea show that 160 million Sm^3 o.e. were sold and delivered from this part of the Norwegian shelf over the year 2015. At the same time, the growth in gross reserves, or the licensees' estimates before production is deducted, amounted to 59 million Sm^3 o.e. This means that the reserves that remain in the North Sea were reduced by 101 million Sm^3 o.e. in 2016 (Table 7.1).

ORIGINAL RECOVERABLE RESOURCES						
RESOURCE CLASS	**OIL (mill Sm^3)**	**GAS (bn Sm^3)**	**NGL (mill tonnes)**	**CONDENSATE (mill Sm^3)**	**SUM (o.e.)**	**CHANGE SUM (o.e. y-o-y)**
Produced	3581	1722	136	75	5635	160
Reserves	842	1220	72	-4	2194	-101
Contingent resources in fields	312	130	12	0	464	42
Contingent resources in discoveries	139	121	9	1	277	-30
Undiscovered resources	430	230	0	40	700	-45
Total	5303	3422	228	111	9270	26

Table 7.1: Original recoverable petroleum resources in the North Sea as of 31.12.2016 (from Norwegian Petroleum website www.norskpetroleum.no).

The resource estimate for the unproven resources was not updated in 2016. The expected value is estimated at 700 million Sm^3 o.e. This is a reduction of 45 million Sm^3 o.e. in relation to last year's accounts, and approximately corresponds to the volume proven in new discoveries in 2016. The Upper Triassic is included in Lower to Middle Jurassic plays in the North Sea, but contributes a smaller share of their resources (Fig. 7.2). Plays older than the Late Triassic account for less than two-three per cent of total expected resources in the North Sea.

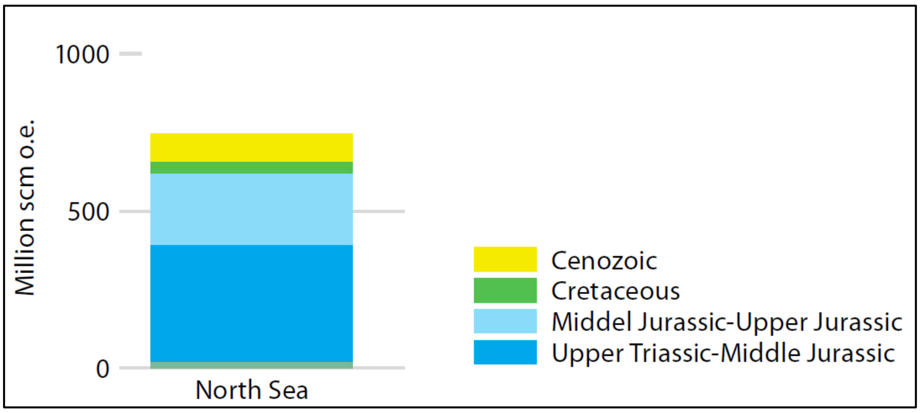


Figure 7.2: Recoverable undiscovered resources for the North Sea by geological stratigraphic level (from NPD resource report, 2016).

Figure 7.3 shows annual production from fields in the North Sea. Oil production rose in 2016 for the third year running, after a continual decline from 2001 to 2013. Important reasons for this are higher production regularity of Norway's oil fields and new fields coming on stream. Gas production remained high in 2016, at about the same level as in 2015. Gas sales totaled 115 billion Sm^3 in 2016. The growing demand for natural gas in other parts of Europe is an important explanation for this rise. In 2016, natural gas accounted for just under 50% of total production by oil equivalents. In the 50 years since Norwegian petroleum activities began, about 48% of the estimated total recoverable resources on the continental shelf have been produced and sold. Thus, there are large remaining resources, and it is expected that the level of the activity on the Norwegian shelf will continue to be high for the next 50 years as well.

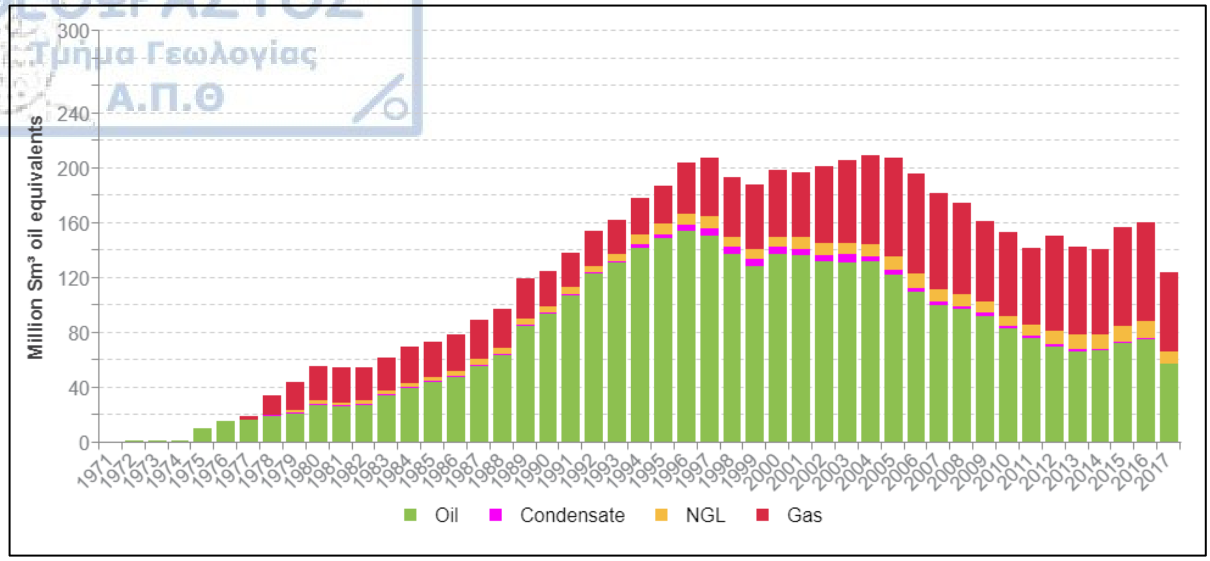


Figure 7.3: Annual production from fields in the North Sea (from Norwegian Petroleum website www.norskpetroleum.no).

The production profile of a typical oil field shows a rapid increase to a maximum production rate, then a stable period of high production (the plateau phase), followed by a gradual decline in production. Without further investments, oil production will decline rapidly, and even with considerable investment to improve recovery, it can be difficult to maintain production from a field. Without new fields or large-scale intervention to maintain production from existing fields, oil production from the Norwegian shelf would, therefore, continue to decline as it did from 2001 to 2013. Given the high-level of development activity in recent years, production is expected to remain relatively stable for the next few years. The level of production will depend on new discoveries being made, the development of discoveries and the implementation of improved recovery projects on existing fields (Fig. 7.4).

Proving resources close to existing and planned infrastructure represents one of the main challenges in the North Sea. Finding additional resources while the big facilities are still on stream is important. Even very small discoveries can be profitable if existing infrastructure can be utilised effectively. Phasing discoveries into fields on stream also helps to extend the producing life of the latter, and thereby maintains their profitable production and improves recovery from them. Relatively few wells were drilled in the North Sea from 2000 to 2005 (Fig. 7.4)

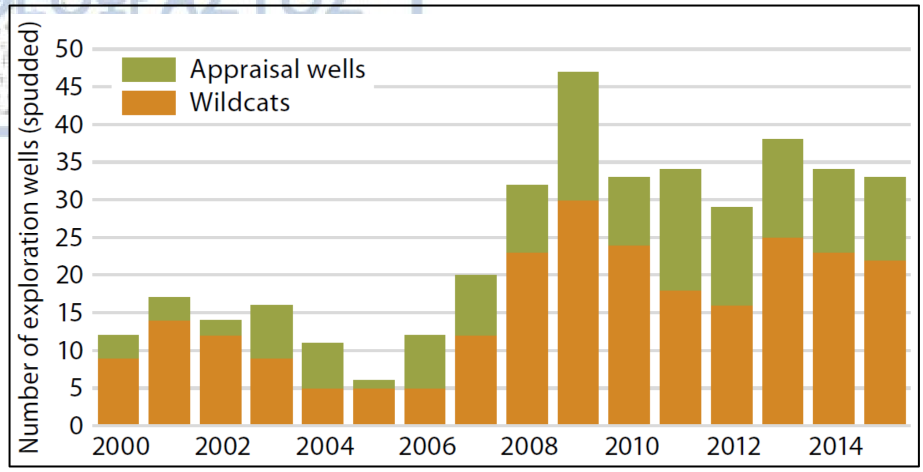


Figure 7.4: Exploration wells spudded per year in the North Sea (2000-2015) (from NPD resource report, 2016).

However, their number rose substantially from 2005 and peaked in 2009 at 47. Exploration activity has remained high since 2010, with an annual average of 34 wells. A total of 127 discoveries have been made since 2000 (Fig. 7.5).

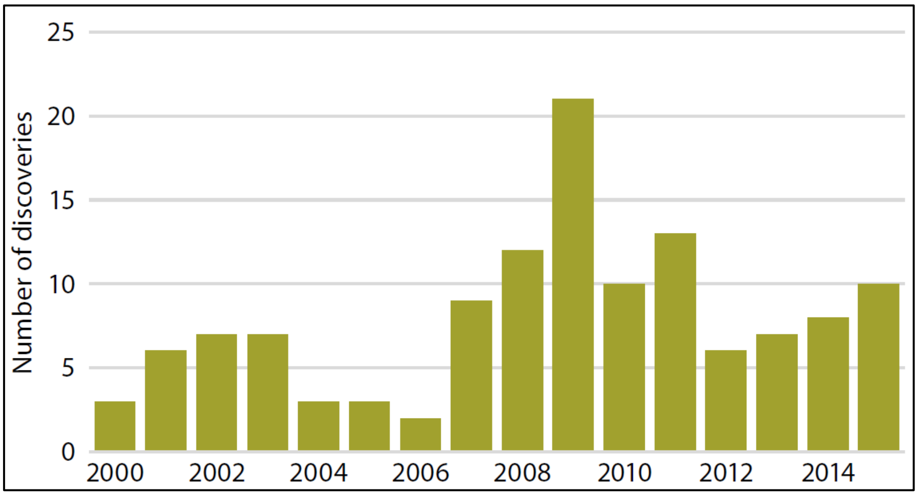


Figure 7.5: Discoveries per year in the North Sea (from NPD resource report, 2016).

The discovery rate in the North Sea has been relatively high over the same period, averaging 0.2-0.7 per annum (Fig. 7.6). Resource growth since 2000 has been highest in the North Sea, but most of the discoveries are small (Fig. 7.7). It peaked in 2008-2011 at about 600 million Sm^3 o.e., largely thanks to the discovery of Johan Sverdrup. Nearly 3000 billion Sm^3 of gas and 5100 million Sm^3 of liquids had been proven in the North Sea at 31 December 2012 (Fig. 7.8). Statfjord and Ekofisk are the biggest oil fields, and by far the largest gas field is Troll East.

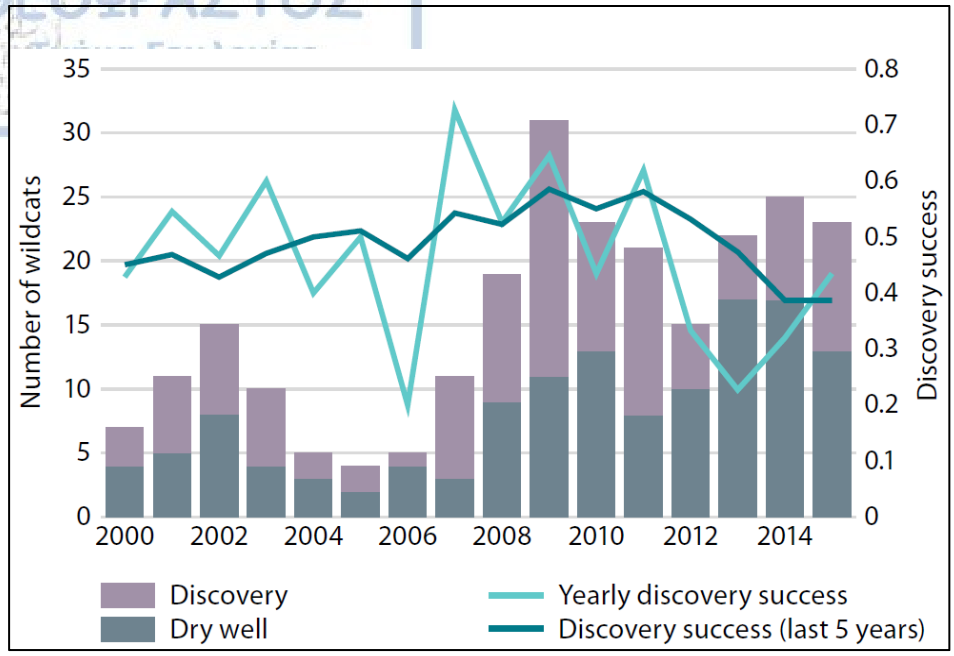


Figure 7.6: Completed wildcats and finding rate in the North Sea (2000-20015) (from NPD resource report, 2016).

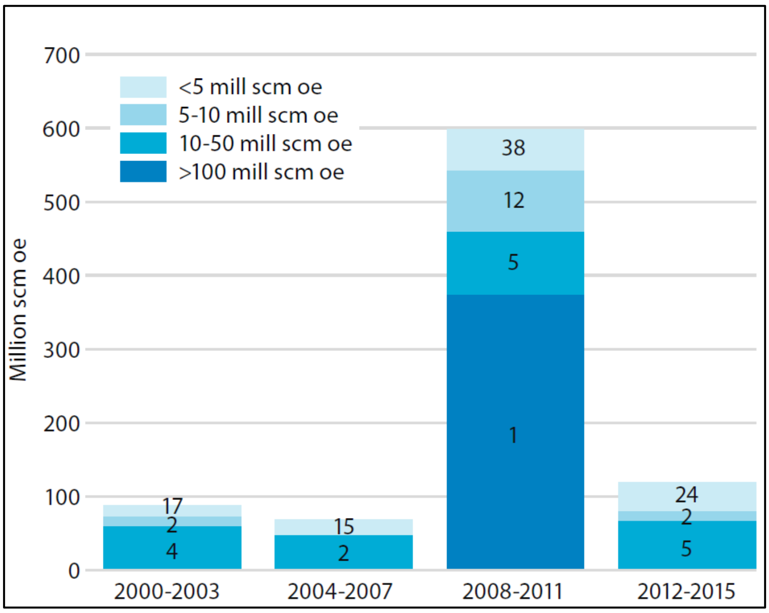


Figure 7.7: Resources in discoveries by discovery size in four-year periods, North Sea (2000-2015). Number of finds specified in the columns (from NPD resource report, 2016).

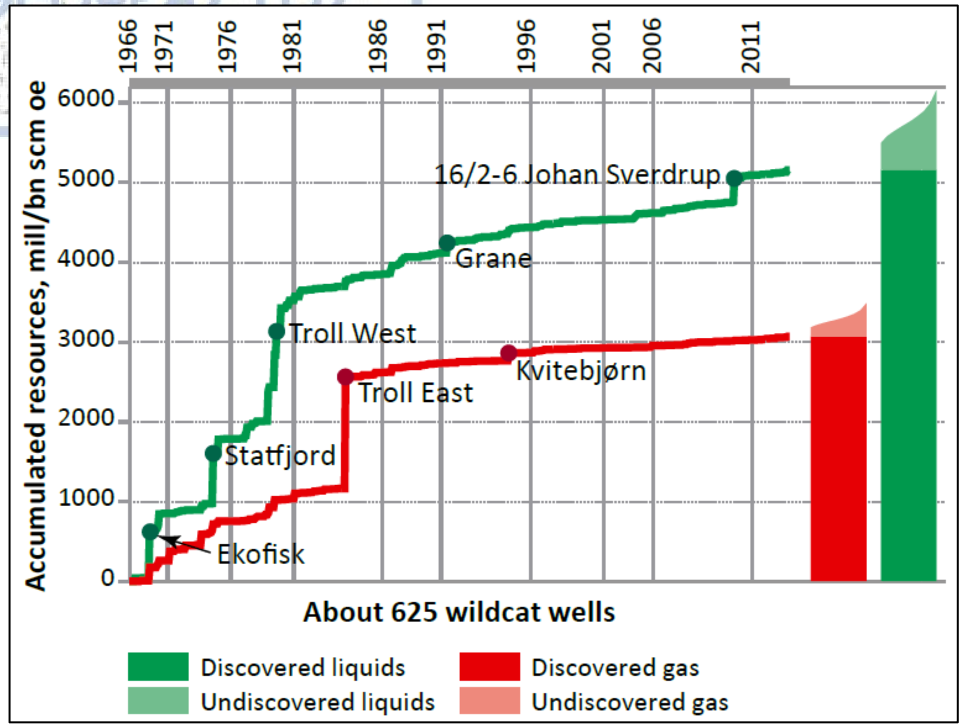


Figure 7.8: Proven and undiscovered (light colours) liquid and gas resources in the North Sea (from NPD resource report, 2016).

After Grane was discovered in 1991, the curve for liquids rose weakly until 16/2-6 Johan Sverdrup was found in 2010. The curve for gas shows a weak rise after the discovery of Kvitebjørn in 1994. The estimate for undiscovered resources in the North Sea is less uncertain than for the Norwegian and Barents Seas because this area has been more thoroughly explored. Over three times as many wildcats have been drilled there than in the Norwegian Sea, and about eight times more than in the Barents Sea. Opportunities for making interesting discoveries in the North Sea are still present.

For the most part, oil production has historically been larger than gas output. This position has been reversed over the past five years. Gas revenues outstripped income from oil for the first time in 2015. Figure 8.9 in each column shows expected recoverable volumes not yet discovered at year 2015 end. The plays discussed are Upper Triassic-Middle Jurassic, Upper Jurassic and Paleocene.

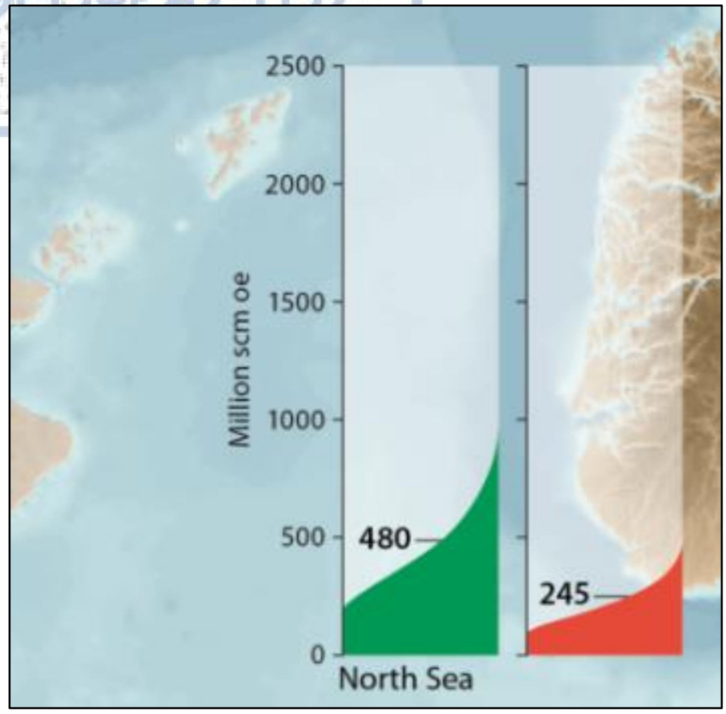


Figure 7.9: Recoverable undiscovered resources for the North Sea, broken down by liquid and gas. The expected value is specified in the columns. The uncertainty in the estimates is shown in the slanted line; low estimates on the left. High estimates on the right (from NPD resource report, 2016).

7.2 North Sea: Paleocene play

The Paleocene play in the central part of Norway's North Sea sector has a long exploration history (Fig. 8.10). Since the Balder oil-field was proven in 1967, about 100 wildcats have been drilled in the play. Relatively few resources were found between the discovery of Jotun in 1994 and the Alvheim find in 1998. Four discoveries were made in 2003, of which 25/4-7 (Kneler) and 24/6-4 (Boa) are part of the Alvheim field. The other two are 16/6-1 (Verdandi) and the 25/4-9 S Vilje oil-field. A discovery was also made in production well 25/8-C-20 on Balder. Proven in 2008, 25/11-25 Svalin is now under development. Some 10 wildcats have been drilled since 2008, but with few resources proven. The potential for finding more is present.

Figure 7.10 illustrates the total resources, proven and undiscovered YTF (light blue), in the Paleocene play in the central North Sea sector Sea. According to NPD, the remaining undiscovered YTF resources for the Paleocene play is in the range of 50-150 million Sm^3 o.e.

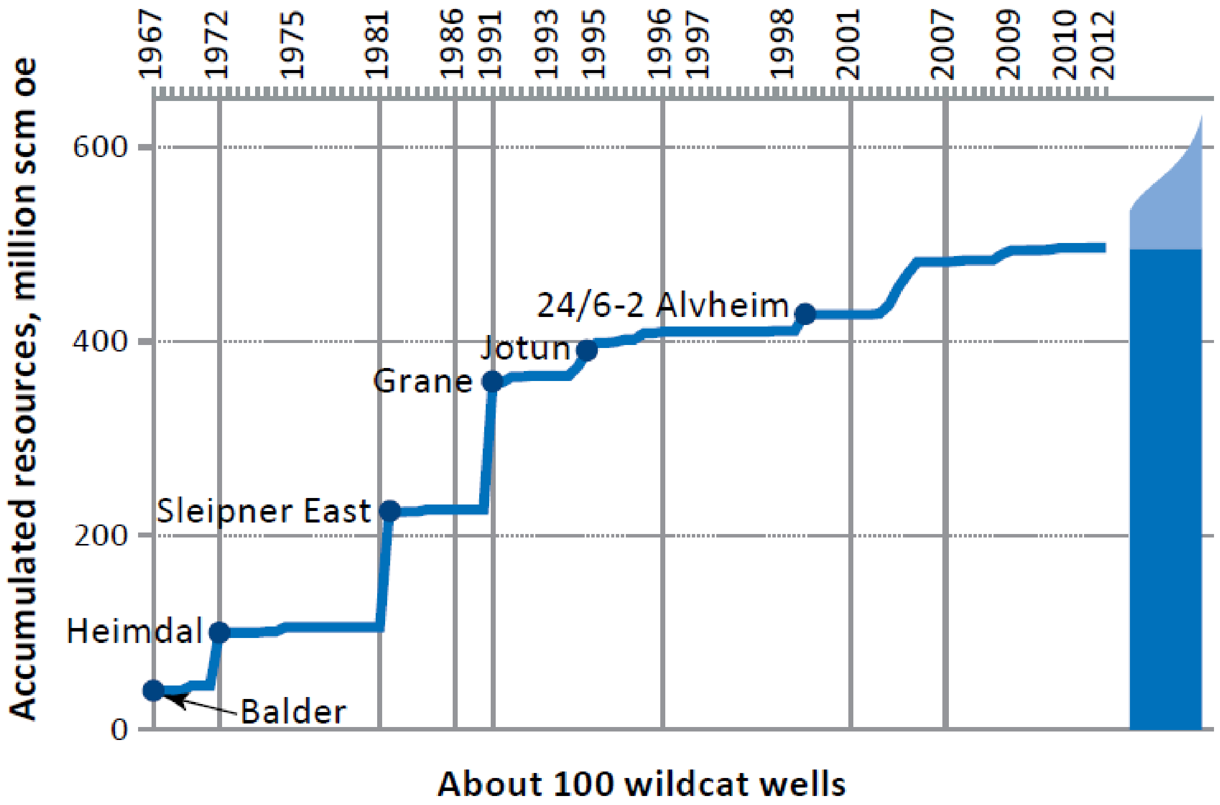


Figure 7.10: Total resources, proven and undiscovered (light blue), in the Paleocene play in the central North Sea sector Sea (from NPD resource report, 2013).

8. CONCLUSION

8. CONCLUSION

Chapter 8
CONCLUSIONS

Following a review of the various exploration plays, the main Cenozoic, i.e. Paleocene and Eocene, plays in the Norwegian and UK parts of the North Sea have been mapped and studied in detail utilizing publicly available data. Play fairway mapping techniques have been initially reviewed and then utilized to construct play chance and common risk segment (CRS) maps for the Paleocene and Eocene plays and their associated play elements. Furthermore, the exploration maturity of the North Sea has been reviewed through published basin and play statistics, including exploration success rates and creaming curves focussing specifically on the Cenozoic plays. Finally, yet-to-find (YTF) resources with focus on the Paleocene/Eocene plays have been reviewed.

Although North Sea is a mature hydrocarbon province with more than 50 years of exploration, there are still discoveries that are being made. There is no doubt that the most important discoveries in the area comprise the Lower-Middle Jurassic play with structural (rotated fault-block) traps. Nevertheless, Paleocene and Eocene fields comprise an important part of the discovered oil and gas fields in the North Sea, and thus assessing these plays in a systematic way is a key priority that could potentially lead to maximizing discoveries. In this context, play-based exploration (including play fairway mapping and common risk segment analysis) provides the most effective way of building and leveraging on understanding of the existing basins, petroleum systems and geological plays contained in the North Sea region. The creation of a petroleum play utilises its essential elements, namely the source rock, reservoir and seal.

During the Paleocene and Eocene periods, uplift of basin margins due to inversion in the North Sea region resulted in a series of submarine fans transported from the Shetland Platform towards the east. These sands interfinger with marine shales that provide the lateral and top seals for stratigraphic and combined traps. In this context, such traps are related to the depositional geometry of the preserved sandstone, enhanced by differential compaction of the surrounding shale envelope. Stratigraphic traps associated with lateral reservoir pinch-out have been also proven to be successful in the area. Concerning, the active petroleum system this is related to the Upper Jurassic Kimmeridge Clay/Draupne Formation that was buried to adequate depths within the deep Viking and Central grabens for hydrocarbons to be generated and expelled, and to reach the Paleocene and Eocene reservoirs through faults or percolation in a short- to long-distance hydrocarbon migration framework.

The main part of the study included the construction of all associated play elements both for the Paleocene and Eocene plays. The play elements included: (1) reservoir presence and effectiveness; the latter was split into reservoir thickness and burial depth; (2) source rock presence and effectiveness; the latter was split into vertical effectiveness representing maturity and thus generation and expulsion of hydrocarbons, and horizontal effectiveness representing the effectiveness of the carrier system with hydrocarbon migration and charging; and (3) seal presence and effectiveness. In particular, based on published paleogeography and gross depositional environment (GDE) maps for the various Paleocene and Eocene formations associated probabilities for reservoir presence (low, medium and high probability) can be assigned. The main objective was to define the probability for reservoir sandstone presence in the various depositional environments based on the expected sedimentological facies. Similarly, reservoir effectiveness is mainly controlled by the reservoir petrophysical properties (net-to-gross, porosity, permeability). The main two components that impact reservoir effectiveness are reservoir thickness and burial depth; these were set to >250 m Paleocene/Eocene sequence thickness and <2500 m burial depth for highest probability of reservoir effectiveness, respectively. A high probability for Upper Jurassic source rock presence (with high TOC and HI values) was set for Upper Jurassic sequence thickness of >50 m, while a high probability for the source rock vertical effectiveness (source rock maturity) was set for burial depths >3000 m and for horizontal effectiveness (migration halo, i.e. charging) the high probability was approximated with a polygon that encompassed the discovered (Paleocene/Eocene) fields. Finally, as the post-Paleocene and post-Eocene successions represent the seal for the Paleocene and Eocene plays, respectively, the isochore thicknesses of these successions were constructed and the highest probability for seal presence and effectiveness was set for seal thickness >250 m.

A series of maps have been subsequently constructed for Paleocene and Eocene in order to portray the above play risk elements. *Exprodat's Exploration Analyst* software (a plug-in to ESRI's ArcGIS) was used in this study in order to construct the various play risk elements. In particular, for each play element a proxy conversion table was constructed based on publicly available data and detailed geological reasoning, and the software was utilized as a conversion tool. A "traffic-light" colour scheme was provided to represent the numerical conversion. The intermediate outcomes of this analysis are the combined common risk segment (CRS) maps for reservoir, source rock and seal for each of the Paleocene and Eocene plays. The final outcome for each play is a single CRS map that derives from the combination (multiplication) of the intermediate combined outcomes. The final CRS maps for both the Paleocene and Eocene plays encompass the relevant fields and discoveries and can be used in combination with the available wells to chase further the two plays in a local-scale on available 2D, and mainly 3D seismic reflection data.

Creaming curves have been presented and reviewed for the Paleocene and Eocene plays in the North Sea. A creaming curve is a diagram used to present the relationship between aggregated or cumulative resource growth from discoveries and wildcats drilled. The largest discoveries in an area or a play (the cream of the crop) are normally made early in the exploration history of the area or play. As time passes, remaining prospects will be smaller and have a lower discovery probability. Such a curve presents the exploration history of an area or play. Furthermore, yet-to-find (YTF) resources are, among other, an estimate of the remaining hydrocarbon potential of a play. It is a risked estimate of the as yet undiscovered recoverable hydrocarbon resources which are expected to be found in the target area. In this context, the Paleocene play in the central part of Norway's North Sea sector has a long exploration history. Since the Balder oil-field was proven in 1967, about 100 wildcats have been drilled in the play. According to NPD, the remaining undiscovered YTF resources for the Paleocene play are in the range of 50-150 million Sm^3 o.e.

In combination with the final CRS maps for the Paleocene and Eocene plays, the YTF resource range demonstrate the level of potentially additional discoveries that could be made in these plays. Play-based exploration can play a significant role in this aspect by addressing the key risk play elements to be considered in the exploration effort.

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