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Hydrocarbon generation and migration from Jurassic source rocks in the northern North Sea

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ABSTRACT

A combination of 3D basin and petroleum systems modeling and geological knowledge has led to increased understanding of petroleum generation and migration from the Jurassic source rocks in the northern North Sea. Based on subsidence history reconstruction, three distinct phases of basin formation, characteristic of a rift basin, are recognized: a pre-rift stage of slow subsidence, an active rifting stage of rapid subsidence, which was partly facilitated by pre-existing structural weaknesses created by the earlier Permo-Triassic rifting, and a post-rift stage of moderate subsidence.

The Draupne, Heather and Ness coal Fms were mature for oil generation in most locations by mid-Cretaceous. Oil generation from the Draupne Fm, the main source rock, began at 88 Ma in the Viking Graben. Peak oil generation began at 78 Ma and gas generation was initiated at 30 Ma. Primary migration is mainly hydrodynamically controlled and is directed vertically upwards and downwards. Expelled hydrocarbons migrate laterally through the Brent Group reservoirs and accumulate in traps and structural culminations in two main directions: northwest and southeast. The migration routes have not varied since the late Cretaceous but are terminated and somewhat redirected against sealing faults south of the study area.

The Draupne Fm generated most of the oil and gas but is poorly drained in comparison to the Heather and Ness Fms due to its direct contact with shales above and below. Most of the petroleum generated and expelled from the source rocks is lost through conversion and migration and did not reach the target Brent Group reservoirs. Much of the petroleum ultimately trapped is also lost through seal leakage and sideways outflow.

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CHAPTER 1

INTRODUCTION

1.1 Basin and Petroleum Systems Modeling

Basin modeling as defined by Hantschel and Kauerauf (2009) is "*the dynamic modeling of geological processes in a sedimentary basin over geological time spans*". Modeling a sedimentary basin basically involves reconstructing the whole history of the basin starting from the deposition of the oldest layer, moving through the sequential deposition of the entire sedimentary sequence until the present day is reached.

Reconstruction of the basin's history involves building a model, which is a digital representation of the geological processes that have acted in the basin and influenced its development. The model is developed based on input data which are simulated over several times steps. In each time step the geological processes are calculated and updated accordingly. The most important geological processes used in basin modeling include deposition, compaction, heat flow analysis, petroleum generation and expulsion etc.

A "Petroleum System" is a geologic system that encompasses the hydrocarbon source rocks and all the related oil and gas, and which includes all the geological elements and processes that are essential if a hydrocarbon accumulation is to exist (Magoon and Dow, 1994).

Petroleum systems modeling therefore involves building a digital data model of a petroleum system in which the interrelated processes and their results can be simulated in order to understand and predict them (Hantschel and Kauerauf, 2009).

Based on the above definitions, petroleum systems modeling is therefore a subset of basin modeling which focuses and specializes in capturing and producing a unique and complete record of the entire hydrocarbon cycle. Petroleum systems modeling is further able to identify and answer questions relating to hydrocarbon exploration risk factors such as trap adequacy, reservoir quality etc.

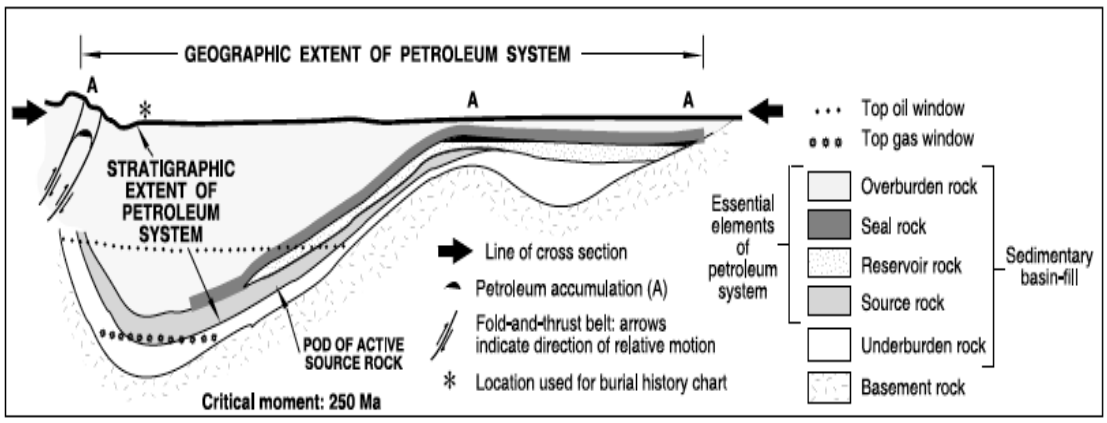


Fig.1.1.1 Concept of a petroleum system. From Magoon and Dow (1994).

1.2 Purpose of Study

The aims of the present study include:

i. Determining the burial and petroleum generation history of source rocks in the study area through subsidence history and thermal maturity modeling.

ii. Predicting potential migration mechanisms and pathways for source rock and reservoirs/carriers.

iii. Predicting potential hydrocarbon accumulations in the study area through 3D modeling and evaluating the volumes and distribution of the hydrocarbons in potential traps.

1.3 The Petromod Software

The Petromod Suite is a petroleum systems modeling software developed by Intergrated Exploration Systems (IES) a component of Schlumberger. The suite comprises Petromod 1D, 2D and 3D packages. The software integrates geological data and knowledge to model the generation, migration and entrapment of hydrocarbons in sedimentary basins. It is capable of predicting if, and how, a reservoir has been charged with hydrocarbons. These include the source/kitchen of the hydrocarbons, the timing of hydrocarbon generation, migration routes as well as the type(s) and quantities of the hydrocarbons at surface and subsurface conditions (Schlumberger, 2009). The package is used in both frontier exploration areas with limited data and well-explored areas where problems relating to source-reservoir correlations, seal efficiencies, and overpressure systems can be investigated.

Petromod 1D also enables 1D thermal, hydrocarbon maturation, and pressure history modeling. It includes special tools to model the effects of salt movements, igneous intrusions, etc. (Petromod 1D tutorial, 2009).

Petromod 2D combines seismic, stratigraphic and geological interpretations with multi-dimensional simulations of thermal, fluid-flow and petroleum migration histories in sedimentary basins. Its integrated 2D temperature-pressure simulator enables migration modeling with methods including Flowpath, Darcy, Invasion Percolation and Hybrid (Darcy+Flowpath) technology (Petromod 2D tutorial, 2009).

Petromod 3D comprises a set of packages including: PetroChargeExpress, PetroCharge, PetroGen 3D and PetroFlow 3D. The principal 3D packages are PetroCharge and PetroFlow 3D.

PetroFlow 3D has a full 3D temperature/pressure simulator and provides advanced 3D petroleum migration modeling technology as different migration modeling methods can be applied to the same 3D data model. PetroCharge is capable of Multi1D temperature/pressure simulation and Flowpath migration.

1.4 Previous Studies

Various studies in basin and petroleum systems modeling have been carried out in and around the study area. Earlier studies include that of Goff (1983), who investigated hydrocarbon generation from Jurassic source rocks in the East Shetland Basin and the northern North Sea. Iliffe et al. (1991), used 1D and 2D modeling techniques to predict known hydrocarbon occurrences in the North Sea Viking Graben. Burrus et al. (1991) and Moretti and Deacon (1995) also conducted studies on the hydrocarbon generation, expulsion and migration histories of the North Viking Graben and Tampen Spur area respectively using 2D TEMISPACK analysis.

Recent publications include the work of Kubala et al. (2003) in the *Millennium Atlas* in which a well was modeled to determine the subsidence and generation history of the study area, and a regional 2D model was used to predict potential hydrocarbon migration pathways. Childs et al. (2002) used a 3D model of the Cook Fm in the Gullfaks field to establish a methodology for incorporating fault capillary properties in migration studies.

Johanennesen et al. (2002), also conducted 3D modeling in the Statfjord area and much of the Viking Graben in their studies of source rock maturation and hydrocarbon migration.

CHAPTER 2

GEOLOGY OF THE NORTHERN NORTH SEA

2.1 Geological Setting

The northern North Sea (Fig. 2.1.1) is a rift basin, which stretches from the East Shetland Platform to the Øygarden Fault Zone, covering an area of nearly 40,000 km^2. It includes three main regions: the East Shetland Basin and Tampen Spur in the west, the North Viking Graben and the Horda Platform in the east.

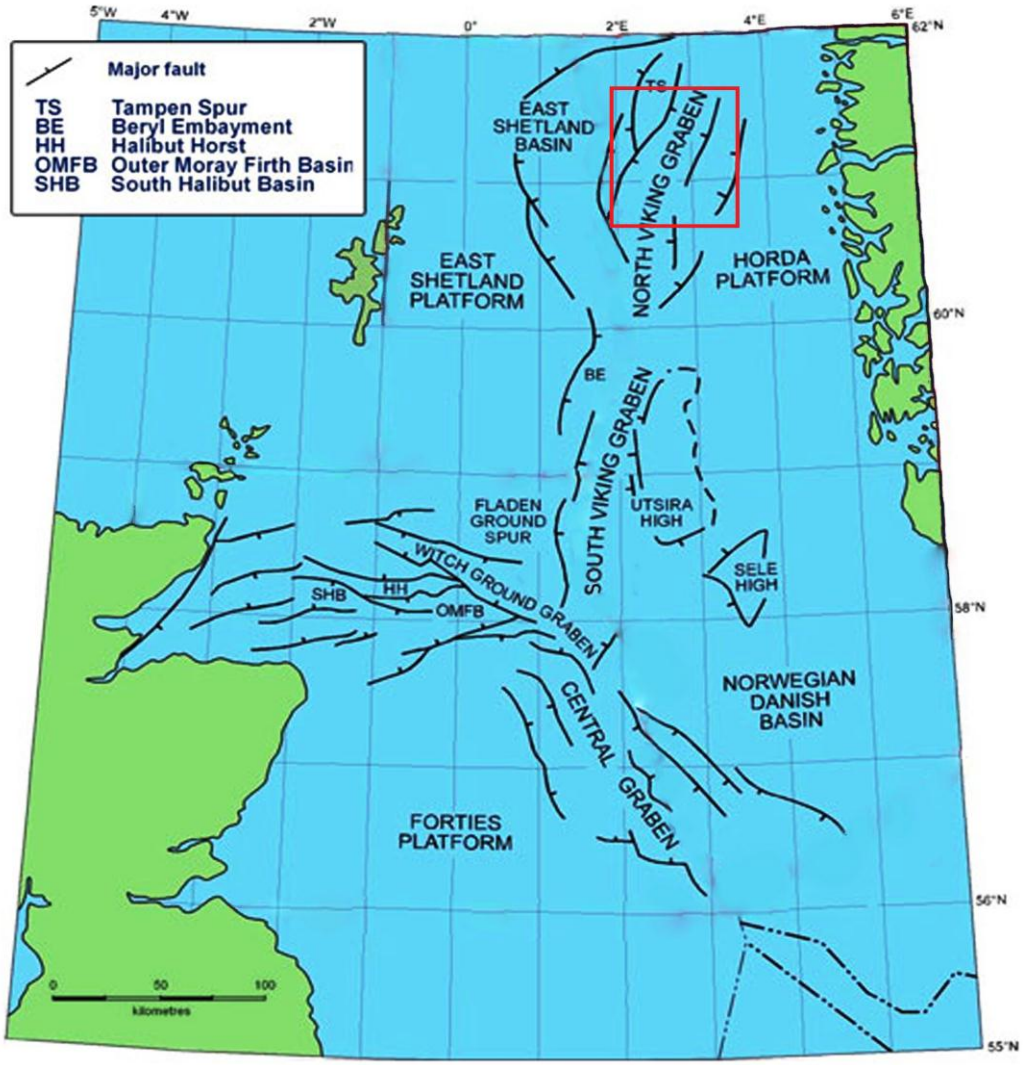


Fig.2.1.1 Map of the North Sea showing the study area (red rectangle). Modified after Ternan Ltd. (2012).

The North Sea rift basin is itself part of the north- west European continental shelf. It is characterized by a long and complex geological history (Glennie and Underhill, 1998) spanning from pre- Devonian times. The basin is characterized by a prolonged history of extension that began in the Devonian with the extension of the thickened crust formed during the Caledonian Orogeny (Zanella and Coward, 2003).

Subsequently, the basin was subjected to Permo-Triassic and mid-late Jurassic intracontinenetal lithospheric extensional phases, which were followed by thermal subsidence and cooling to produce the North Sea Sedimentary Basin (Fæseth et al. 1997). These two extensional events have mainly resulted in the present-day structural configuration of the North Sea (Zanella and Coward, 2003).

The Viking Graben is the main dominating structural feature in the northern North Sea. This rift structure largely formed during the main episode of crustal thinning in the late Jurassic followed by thermal subsidence and sediment loading in the Cretaceous.

The graben and its margins extend northwards into the Sogn Graben and are underlain by an older Permian-Triassic rift basin, the axis of which is believed to lie beneath the present day Horda Platform. Structures in this area are characterized by large tilted fault blocks with sedimentary basins in asymmetric half-grabens associated with lithospheric extension and crustal thinning (Faleide et al., 2010).

2.2 Structural Evolution

The main tectonic processes which controlled the structural development of the central and northern North Sea comprise those related to the original (pre-Mesozoic) tectonic reorganization (Glennie and Underhill, 1998) and those that reworked the

framework into the present day (Mesozoic-Cenozoic) configuration (Zanella and Coward, 2003).

The Mesozoic-Cenozoic deformational phases, which shaped the present day structural configuration, can been divided into six main phases namely:

- Permian to Triassic rifting
- Post rift subsidence in mid-late Triassic to early Jurassic
- Thermal uplift and volcanism during the mid-Jurassic
- Mid-late Jurassic to Early Cretaceous rifting
- Cretaceous to Cenozoic post rift thermal subsidence and,
- Cenozoic uplift of basin the margins

2.2.1 Pre-Mesozoic Tectonic Framework

The main events related to the original crustal framework of the North Sea include the Caledonian plate cycle and the Variscan plate cycle (Glennie and Underhill, 1998). Before these events, the North Sea was separated into continental fragments with and around the margins of the Early Paleozoic Iapetus Ocean and Tornquist Sea (Glennie and Underhill, 1998). During Devonian and Carboniferous times, strike–slip movements dominated (Ziegler, 1982). After this time, the North Sea has largely been in an intraplate setting (Glennie and Underhill, 1998).

2.2.2 Mesozoic-Cenozoic Tectonic Framework

These events modified the original structural framework formed in pre-Mesozoic times and are largely responsible for the present day configuration of the northern North Sea.

2.2.2.1 Permo-Triassic rifting phase

The Permo-Triassic rifting event in the northern North Sea is characterized N-S faults (Fig.2.2.2a), which have formed half graben structures, tilted to the east and west (Zanella and Coward, 2003). These structures are observed both on the east and west of the Viking Graben, but have been overprinted by the later Jurassic rifting event adjacent and beneath the graben (Ziegler, 1990). The present day Horda Platform represents the site of maximum Permo-Triassic stretching and fault activity (Fæseth, 1996). In this area, the event caused the formation of half grabens with shifting polarities across strike (Heeremans and Faleide, 2004). Modeling studies conducted by Roberts et. al (1993), suggest that the Permo-Triassic rifting event was centered beneath the present day Viking Graben.

Regional seismic of the Viking Graben shows Permo-Triassic sediments thickening to the east and into faults such as the Øygarden Fault Zone (Fig. 2.2.4). This was interpreted by Fæseth (1997) as indicating that a deep Triassic basin had formed in the centre or further to the east of the graben structure.

Most of the main Permo-Triassic faults in the North Sea trend north-south, suggesting the direction of extension during this period was east-west (Ziegler, 1990).

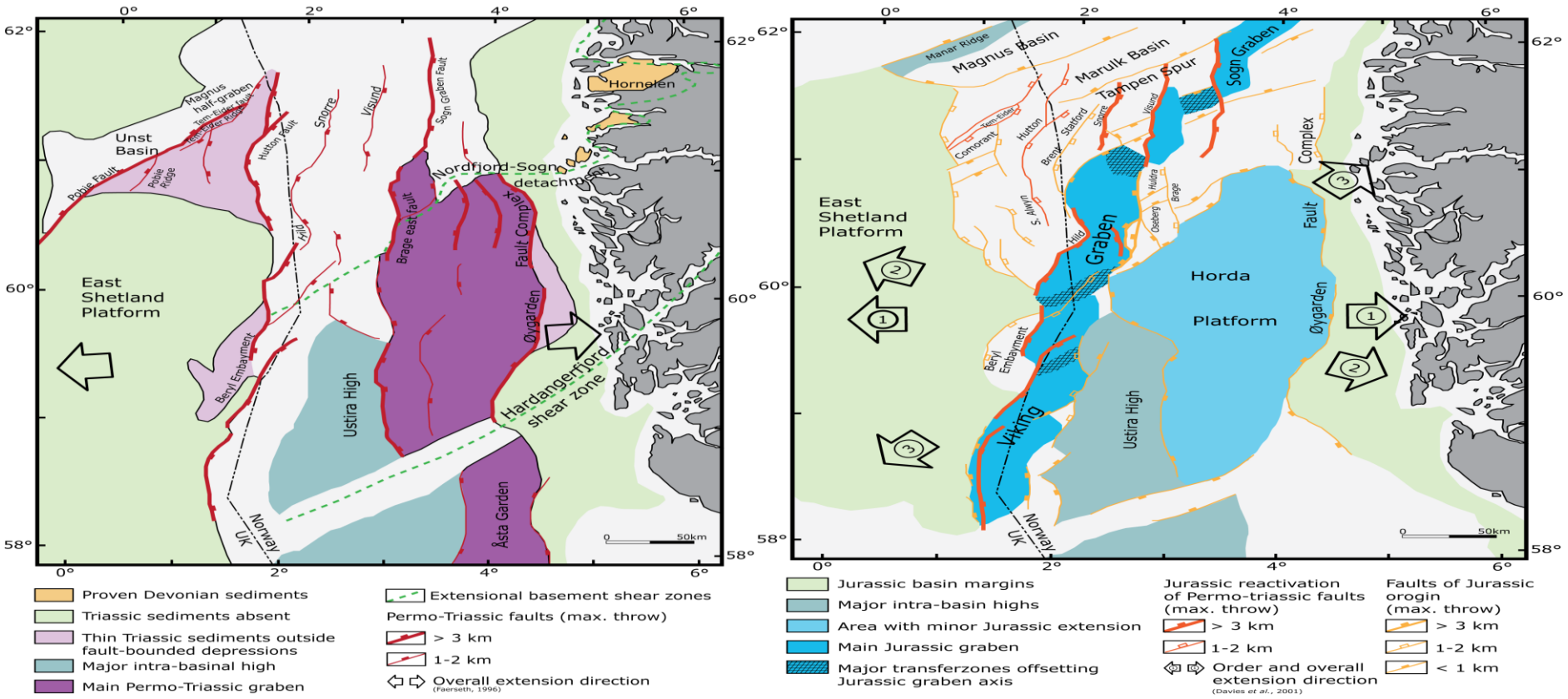
2.2.2.2 Early to Middle Jurassic pre-rift phase

The Triassic to Early Jurassic episode of thermal subsidence was abruptly ended by thermal doming in the Mid-Jurassic (Glennie and Underhill, 1998). Evidence suggests very little Early Jurassic rifting in the central and northern North Sea (Zanella and Coward, 2003). However, the occurrences of volcanic rocks in the central North Sea suggest the presence of a mantle hot spot that developed during the mid Jurassic (Underhill and Partington, 1993). This led to uplift and widespread erosion of the pre-existing Triassic and lower Jurassic sediments of central North Sea (Glennie and Underhill, 1998). Sediments derived from the uplifted and eroded area yielded Bajocian to Bathonian sands for the Brent Group reservoirs in the northern North Sea.

2.2.2.3 Late Jurassic to Early Cretaceous rifting phase

The single most significant deformational phase in the North Sea commenced in the mid Jurassic where crustal extension produced a triple junction of three distinct but joined rifts (Fig.2.2.3). The western arm of the triplet formed the Moray Firth basins, while the northern and southeastern arms formed the Viking and Central Grabens respectively (Zanella and Coward, 2003). This event formed the large, rotated fault blocks and major structural traps, which underlie and characterize the grabens (Glennie and Underhill, 1998).

There is evidence to suggest that rifting may have started during the later part of the mid Jurassic in the northern North Sea (Roberts et al., 1990). The main pulse of faulting however occurred in the mid-Oxfordian to early Kimmeridgian with rifting continuing into early Cretaceous times (Rattey and Hayward, 1993).



(a) (b)

Fig. 2.2.2: Map of the northern North Sea showing key structural elements in the (a) Permo-Triassic and (b) Jurassic rifting events (modified after Faerseth, 1996).

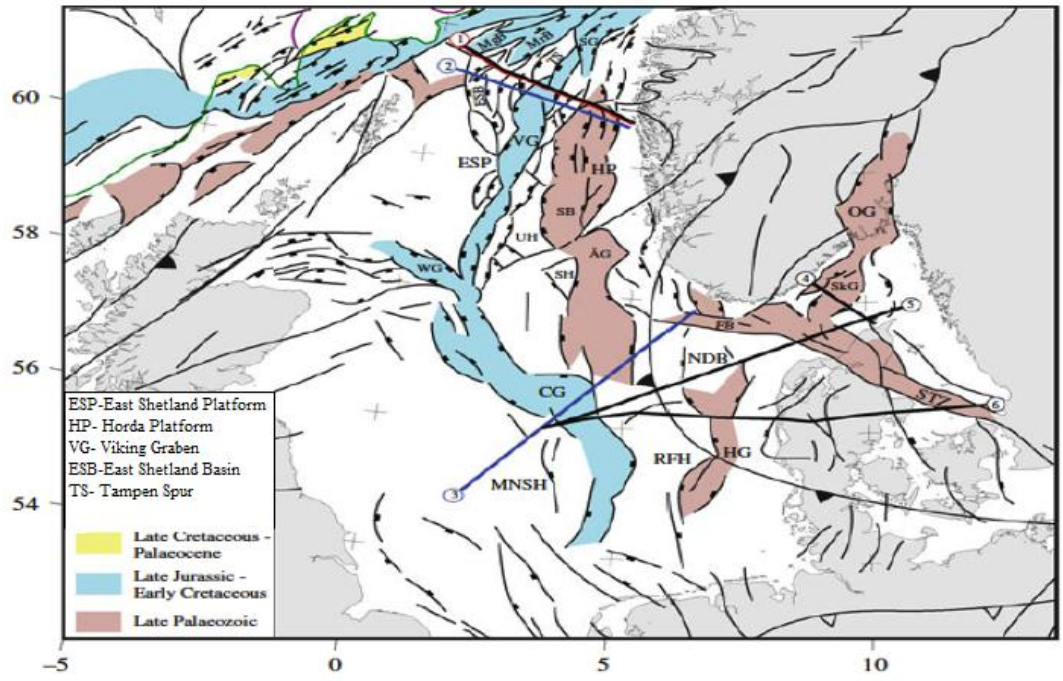


Fig. 2.2.3: Main structural elements of the North Sea and adjacent area resulting from Permo-Triassic and Jurassic rifting events (modified from Faleide et al., 2008).

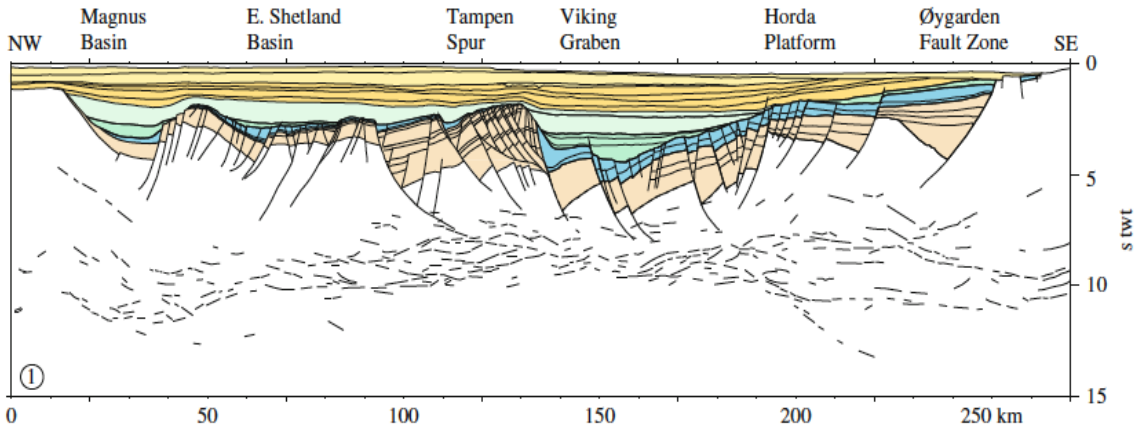


Fig. 2.2.4: Interpreted regional seismic line across the northern North Sea (modified from Christiansson et al., 2000). Position is seismic line is shown by the red line in Fig. 2.2.3.

Like most rift basins, extension in the North Sea occurred in multiple episodes, with a period of relative tectonic quiescence separating intervening episodes. This pattern

had a major influence on the nature and architecture of the sediments (Ravnas et al., 2000).

The rate of extension seems to have varied spatially across the graben system being extended by up to 30-40% in the axis of the Viking Graben (Zanella and Coward, 2003). Faulting created significant local topography with pronounced footwall highs, which were later, eroded to fill adjacent basins (Zanella and Coward, 2003).

In comparison to the Permo-Triassic event, rifting in the Jurassic was more localized, and faults formed in this period also display a larger degree of spread in orientation (Fæseth, 1996). As a result, there is considerable disparity among authors with regards to the direction of extension during the Jurassic, with at least three kinetic models proposed (Fig.2.2.2b). Some authors believe that there was a reorientation of extensional direction from E-W to NW-SE (Dore and Gage, 1987). Others believe that the direction of extension was consistent throughout the Jurassic rift phase and was either E-W (Roberts et al., 1990) or NW-SE (Ziegler, 1990, Erratt et al. 1999).

2.2.2.4 Late Cretaceous to Cenozoic post-rift phase

In the Late Cretaceous important inversion structures were created (Arthur, 1993). Effects of the inversion wane northwards and become very weak in the northern North Sea. The inversion structures were created due to intraplate compression resulting from the creation of the Atlantic Ocean (Glennie and Underhill, 1998).

The supply of siliciclastic sediments to the post-rift basin in Paleogene times was controlled largely by uplift and erosion of the western and eastern edges of the North Sea Basin and much of Inner Moray Firth Basin (Thomson and Underhill, 1993).

The North Atlantic Ocean developed between Greenland and Scotland in Eocene and Oligocene times. Subsequent compressional forces affected large transform faults and caused local inversion (Dore et al., 1999). Basins offshore Norway were affected with the northeast part of the North Sea affected only slightly (Zanella and Coward, 2003).

Riis (1996), suggested that a late Eocene to early Oligocene uplift of a deeply weathered erosional peneplain surface across Fennoscandia, leading to sediment outbuilding and an increase in the rate of sediment accumulation in the northern North Sea. According to Zanella and Coward (2003), the Pliocene sequence of the northern North Sea is characterized by outbuilding from Norway and the deposition of a major late Pliocene clastic wedge.

2.3 Stratigraphy

The stratigraphy of the North Sea spans from Devonian to the Cenozoic. A generalized stratigraphy of the North Sea is shown below:

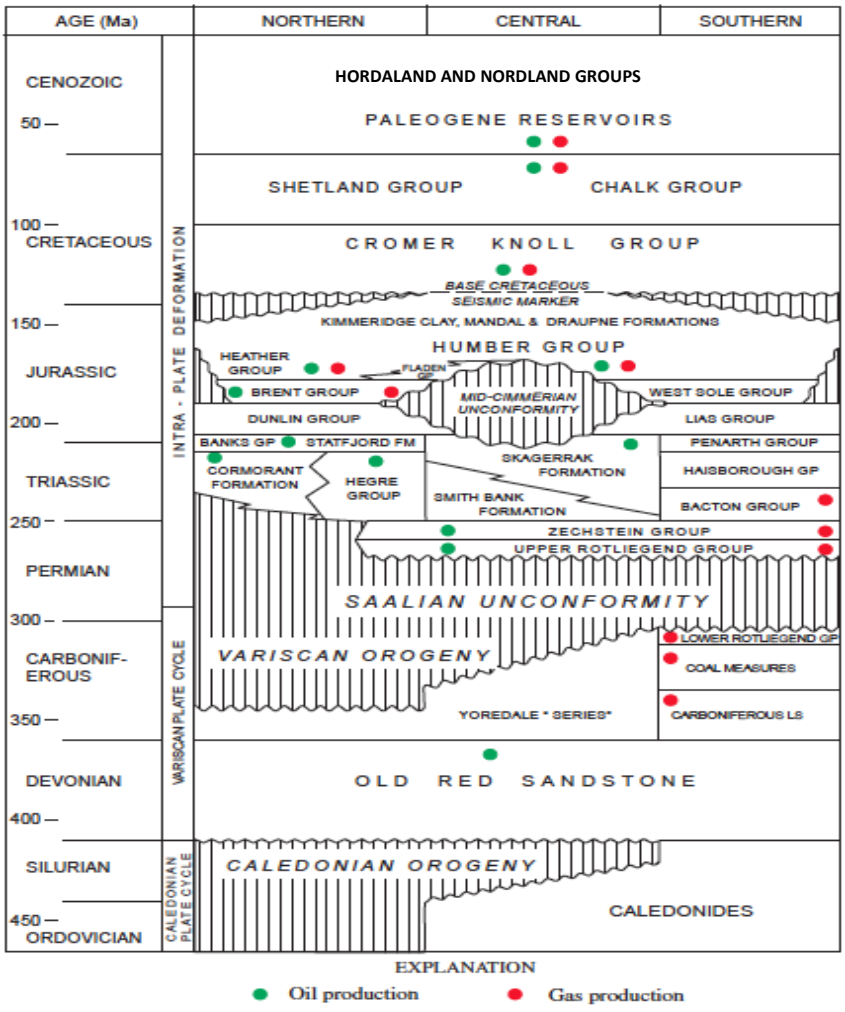


Fig. 2.3.1 Generalized stratigraphy of the North Sea (modified from Brennand et al., 1998).

2.3.1 Devonian

In the northern North Sea, Devonian sediments have been reached in only a few wells. However there are reasons to believe these sediments are present regionally in deeper parts of the pre-Triassic half grabens beneath the Horda Platform, Viking Graben and East Shetland Basin (Faleide et al., 2010).

2.3.2 Triassic

Triassic rocks are widely distributed in the central and northern North Sea and contain about 5% of the petroleum reserves (Goldsmith et al., 2003). The Triassic strata in the northern North Sea are largely monotonous and non- fossiliferous continental red beds. The group was assigned the informal name “Triassic Group”, which comprises the Cormorant Formation. The Cormorant Formation was later replaced with the Teist, Lomvi and Lunde Formations of the Hegre Group (Vollset and Dore, 1984).

Rifting in the early Triassic and later period s reflect a pattern of repeated outbuilding of clastic wedges from the Norwegian and East Shetland hinterland within a generally evolving post- rift basin (Steel and Ryseth, 1990). Differential subsidence across the basin resulted in the deposition of continental Triassic megasequences, sediments which were derived from the Variscan Mountains and the uplift of Scandinavia (Steel and Ryseth, 1990). The Øygarden fault zone, which forms the eastern margin of the Permo-Triassic basin, was active throughout most of this period.

In the northern North Sea, well penetrations to the base of the Triassic are rare making it difficult to establish the thickness. The depositional environments of the Triassic strata in the northern North Sea include alluvial fan, fluvial and lacustrine environments. Sediments deposited include arkosic sandstones and mudstones. (Goldsmith et al., 2003).

2.3.3 Jurassic

Towards the close of the Triassic, the climate became more humid and the depositional environment became fluvial and then changed to marine with a corresponding rise in sea level in the Early Jurassic (Faleide et al., 2010).

In the northern North Sea, fluvial–marine sandstones of the Lunde and Statfjord Formations were deposited in the Viking Graben. These form important reservoirs in some fields (e.g. Snorre field). The sandstones and lean marine shales of the Dunlin Group overlie the Statfjord Formation. The most important reservoir, the Brent Group then overlies the Dunlin Group (Faleide et al., 2010). The lower section of the Brent Group comprises upward coarsening, micaceous sandstones of the Etive and Rannoch Formations. The middle section, the Ness Formation, represents a fluvial-deltaic facies with channel, crevasse sand, lagoonal and coal deposits. The uppermost section, the Tarbert Formation, comprises well-sorted sandstones formed by reworked deltaic deposits (Faleide et al., 2010), representing a marine transgression.

The late Jurassic was characterized by subsidence, rotation and erosion of tilted fault blocks in the Viking Graben (Fraser et al., 2002). Transgression at the same time (Oxfordian) covered the graben with a thick drape of organic rich argillaceous sediments. These sediments became the Viking Group (Vollset and Dore, 1984). The lower and upper shale members are referred to as the Heather and Draupne (Kimmeridgian Clay) Formations respectively and they form the main source rocks in the northern North Sea.

2.3.4 Cretaceous

The latest phase of rifting and erosion of uplifted fault blocks in the late Jurassic-earliest Cretaceous was followed by a major rise in sea level across the North Sea. Subsequently, Cretaceous sediments were deposited unconformably on late Jurassic sediments of the North Sea. This major unconformity between the Jurassic and Cretaceous is called the Base Cretaceous Unconformity (BCU).

In the northern North Sea, the Lower Cretaceous deposits comprise shallow marine mudstones, calcareous shales and some sands. These belong to the Cromer Knoll Group (Vollset and Dore, 1984). The sea level attained its maximum in the Late Cretaceous and clastic sedimentation ceased. Planktonic carbonate algae then mainly dominated sedimentation. In the Viking Graben area, the carbonates are impure and have been replaced by marls. The Upper Cretaceous comprises mudstones and minor interbedded limestones of the Shetland Group (Surlyk et al., 2003).

2.3.5 Cenozoic

Tectonic activity related to the opening of the NE Atlantic Ocean resulted in vertical movements, which affected sediment architecture in the Cenozoic (Faleide et al., 2010).

In the Late Paleocene to Early Eocene, the uplifted Shetland Platform became a source of sediments for major depositional centres. Prograding wedges formed in the midst of a rapidly subsiding basin. Volcaniclastic sediments were also deposited regionally in the North Sea as a result of the volcanism related to the opening of the Atlantic Ocean. These volcaniclastics formed the smectite rich Eocene-Oligocene mudstones. Progradation from the Scotland/Shetland area was mainly from the

Shetland Platform in Eocene times with major depocentres developing in the Viking Graben (Faleide et al., 2010).

From Eocene-Miocene a combination of uplift and progradation cause swallowing of the North Sea. The Utsira Formation in the northern North Sea prograded towards the coast reflecting the Late Miocene-Early Pliocene uplift and erosion of mainland Norway (Faleide et al., 2010). The Pliocene-Pleistocene sediments are poorly sorted glacial and partly marine reworked sediments.

CHAPTER 3

PETROLEUM GEOLOGY OF THE NORTHERN NORTH SEA

3.1 Exploration History

Exploration in the northern North Sea started in the early 1970's following large discoveries such as the Ekofisk and Forties fields in the Central Graben area (Brzozowska et al., 2003). These major discoveries encouraged the acquisition of seismic data from the northern North Sea and led to the identification of buried tilted fault block structures on the flanks of the East Shetland Basin, Tampen Spur and Horda Platform areas (Gautier, 2005).

Shell/Esso drilled a large buried structure on the East Shetland Platform in 1971 and discovered the Brent Field. The Middle Jurassic pre-rift deltaic Brent sandstones in the field proved about two million barrels of recoverable oil. Ten major discoveries including the Statfjord Field were made in the following years based on the Brent exploration concept, which was based on exploration in shallow to marginal marine pre-rift sandstones in tilted fault blocks (Gautier, 2005). The Gullfaks Field was discovered in 1978 in the Tampen Spur area by a group of Norwegian companies. The accumulation occurs in Brent Group and Statfjord Formation sandstones.

By 1979, exploration efforts shifted to syn-rift Upper Jurassic sandstones in immediately adjacent tilted fault blocks. This effort led to the discovery of fields including the Troll, Oseberg and Snorre fields during the fourth licensing round. The Troll gas field accumulation was discovered in Upper Jurassic shallow marine sandstones in a series of tilted fault blocks in the northern part of the Horda Platform (Brennand et al., 1998).

The Oseberg field accumulation was also discovered in eastly dipping fault blocks on the eastern margin of the North Viking Graben to the west of the Horda Platform (Badley et al., 1984). The Snorre field was also another major discovery made during the fourth licensing round in 1979. The discovery in this field in the northern end of the Tampen Spur area proved the oil potential of the Triassic red beds (Brennand et al., 1998).

Although the northern North Sea is considered a mature province with regards to exploration, many new discoveries and large fields may yet be discovered.

3.2 Petroleum System

The only established petroleum system in the northern North Sea is the Upper Jurassic Petroleum System, which comprises Upper Jurassic marine shales as the major source rocks with Triassic and Lower to Middle Jurassic sandstone reservoirs.

Johnson and Fisher (1998) classified the northern North Sea plays as follows;

- Triassic-Lower and Middle Jurassic plays
- Upper Jurassic play
- Cretaceous play? and,
- Paleogene? play.

The existence of these plays is largely due to the combination of a regional Upper Jurassic source rock with a structural geometry created by a late Jurassic to early Cretaceous rift system and its subsequent subsidence (Spencer et al., 1996). The Lower and Middle Jurassic play is however the most explored and successful containing majority of the discovered resources in the northern North Sea (Eriksen et al., 2003).

3.2.1 Source Rocks

Two main source rocks occur in the study area. Both are members of the Viking Group and comprise the uppermost more oil prone Draupne Formation, also called Kimmeridge Clay, and the lower more gas prone Heather Formation.

Draupne Formation/Kimmeridge Clay

The Draupne Fm is the main hydrocarbon source in the source area. It is typically a brownish black, medium to dark olive grey, non-calcareous mudstones, which are locally silty and micaeous (Kubala et al., 2003). The thickness of the unit is mostly between 50-250 m but may locally exceed 1200 m.

Immature Kimmeridge Clay organic matter consists mostly of Type II kerogen (William and Douglas, 1980) and is rated as an excellent oil generating source rock generating gas at higher maturity levels (Goff, 1983). Type II kerogen is a mixture if bacterially degraded algal debris of marine planktonic origin and degraded humic matter of terrigenous origin (Cornford, 1998).

The source potential of the mudstones within this unit is directly related to the kerogen facies (Cornford, 1998), which varies laterally, and vertically within the unit (Goff, 1983). Total Organic Carbon (TOC) values average 6% but can locally be as low as 2% or in excess of 10 %. Hydrogen Indices (HI) are also variable and dependent of the kerogen composition but range between 200-400 mg/gTOC (Kubala et al., 2003).

The environment of deposition of the unit has been of much debate, however in the graben areas such as the northern North Sea, deposition occurred below wave base in

an anoxic environment with high biogeneic productivity and sedimentation rates (Cornford, 1998).

Heather Formation

The unit comprises dark grey silty mudstones with interbeded carbonate bands. The thickness of the formation is very variable but can be as much as 1000 m in the Viking Graben (Kubala et al., 2003). The Heather Formation is typically gas prone but studies by Gormly et al. (1994) indicate that it is locally oil prone in the eastern flanks of the Viking Graben. TOC values are typically between 2-2.5 % (Goff, 1983). Hydrogen indices are correspondingly low due to a greater proportion of terrestrial humic kerogen. Values typically range from 100-200mg/gTOC and rarely exceed 300mg/gTOC (Kubala et al., 2003).

The coal intervals within the Ness Fm. of the Middle Jurassic Brent Group are also considered as important source rocks for gas generation, especially in the North Viking Graben (Chung et al., 1995).

3.2.2 Reservoirs

Triassic and Lower Jurassic

The Triassic reservoirs commonly occur in tilted fault blocks with varying degrees of Jurassic-Cretaceous erosion and onlap. Fields in the northern North Sea with accumulations in Triassic reservoirs, with the exception of the Snorre field, have most of their accumulations in overlying Lower and Middle Jurassic reservoirs (Goldsmith et al., 2003). The main reservoir intervals comprise thick, fluvial channel and sheetflood deposits, which in the study area include the Statfjord and Lunde Formations. The characteristics of these reservoirs reflect deposition in terrestrial and

semi- arid conditions although the younger Statfjord Formation shows an increasing marginal marine influence. This is attributed to the combined effect of marine transgression and more humid conditions in the Early Jurassic (Johnson and Fisher, 1998).

Reservoir quality is both a function of the initial depositional facies with the more distal, matured and cleaner sands having higher initial and ultimate porosities (Goldsmith et al., 2003). The Statfjord Formation is the most important hydrocarbon-bearing reservoir in the category. In the Brent Field, for example, the formation has porosity and permeability ranging from 20-24% and 300-2000mD respectively (Johnson and Kroll, 1984).

Middle Jurassic

Most of the Middle Jurassic reservoirs in the northern North Sea are arkoses and subarkoses with quartz, clay minerals and feldspars constituting about 95% of the total mineralogy (Humso et al., 2002). These sandstones are both quartz and calcite cemented at depths exceeding 2500m (Walderhaug and Bjørkum, 1992).

The reservoirs form a thick clastic wedge comprising laterally extensive interconnected fluvial, deltaic and coastal depositional systems with porosities and permeabilities ranging from 20-30% and 50-500mD respectively at shallow depths (Giles et al., 1992). In the northern North Sea, the Middle Jurassic reservoirs are represented by the Brent Group, which comprises the Tarbert (youngest), Ness, Etive, Rannoch and Broom Formations (Vollset and Dore, 1984). The basal Brent is typically upper shoreface sandstones whiles the upper part of the group is represented by transgressive sandstones (Gautier, 2005).

Upper Jurassic

Upper Jurassic reservoirs are rare in the northern North Sea, except in the Emerald field in the East Shetland Basin (Stewart and Faulkner, 1991) and also in the Troll gas field where shallow marine sandstones occur in tilted fault blocks (Johnson and Fisher, 1998). Deep marine sandstones also occur in localized areas where their presence is attributed to major rift, fault footwall uplift and erosion (Johnson and Fisher, 1998).

3.2.3 Traps and Seals

There is great diversity in the traps and seals in the northern North Sea to equally match the variety in hydrocarbon accumulations. However most trapping mechanisms are provided by rotated faults blocks sealed by fine grained post rift sediments which drape onto the structures to form seals (Gautier, 2005). In the Viking Graben, for example, hydrocarbons trapped in the Middle Jurassic Brent Group are sealed vertically by unconformably overlying Jurassic Kimmeridge Clay and Heather Formation and Cretaceous shales of the Cromer Knoll Group (Johnson and Fisher, 1998). Lateral trapping and sealing is also formed where reservoir rocks are juxtaposed with non-reservoir rocks at fault contacts (Gautier, 2005). The sealing capacity of the cap rocks is limited by overpressures within the study area (Karlsson, 1986) and most seals are close to hydraulic fracture (Huem, 1996).

3.2.4 Migration

England et al. (1987) and Mackenzie et al. (1988) indicate that primary migration in the northern North Sea is through pressure driven flow of a discrete hydrocarbon phase through pores and micro fractures. Quantitative modeling results show that in

organic rich source intervals, such as can be found in the Kimmeridge Clay unit; high expulsion efficiencies may be expected (Cooles et al., 1986).

Secondary migration is mostly by buoyancy resulting from difference in density between the hydrocarbon and water. In the northern North Sea, vertical migration of hydrocarbons has occurred along the major half graben-bounding faults with possible leakage where sandstones within the Mesozoic section terminate against faults. Most of the hydrocarbons, however, follow structural contours along faults planes towards structural highs (Kubala et al., 2003). See Fig. 3. 1.1 below for details.

Sandstones of the Brent Group provide the main conduits of migration with the study area (Miles, 1990). Curtin and Ballestad (1986) identified three main mechanisms of primary migration as follows: (i) migration enhanced intercalation of source and reservoir (ii) migration due to juxtaposition of reservoir and source rocks across faults (iii) vertical migration across micro fracture systems. Cornford et al., (1986) and Cornford (1998) expanded on the earlier classification into five modes as follows:

- Short distance migration
- Migration in rotated fault blocks
- Migration through faults and micro fractures
- Up-flank migration from the graben and
- Unconformity and multiple conduit migration.

In the northern North Sea, short distance migration due to juxtaposition of reservoir and source rocks and migration in rotated fault blocks are the main mechanisms of migration.

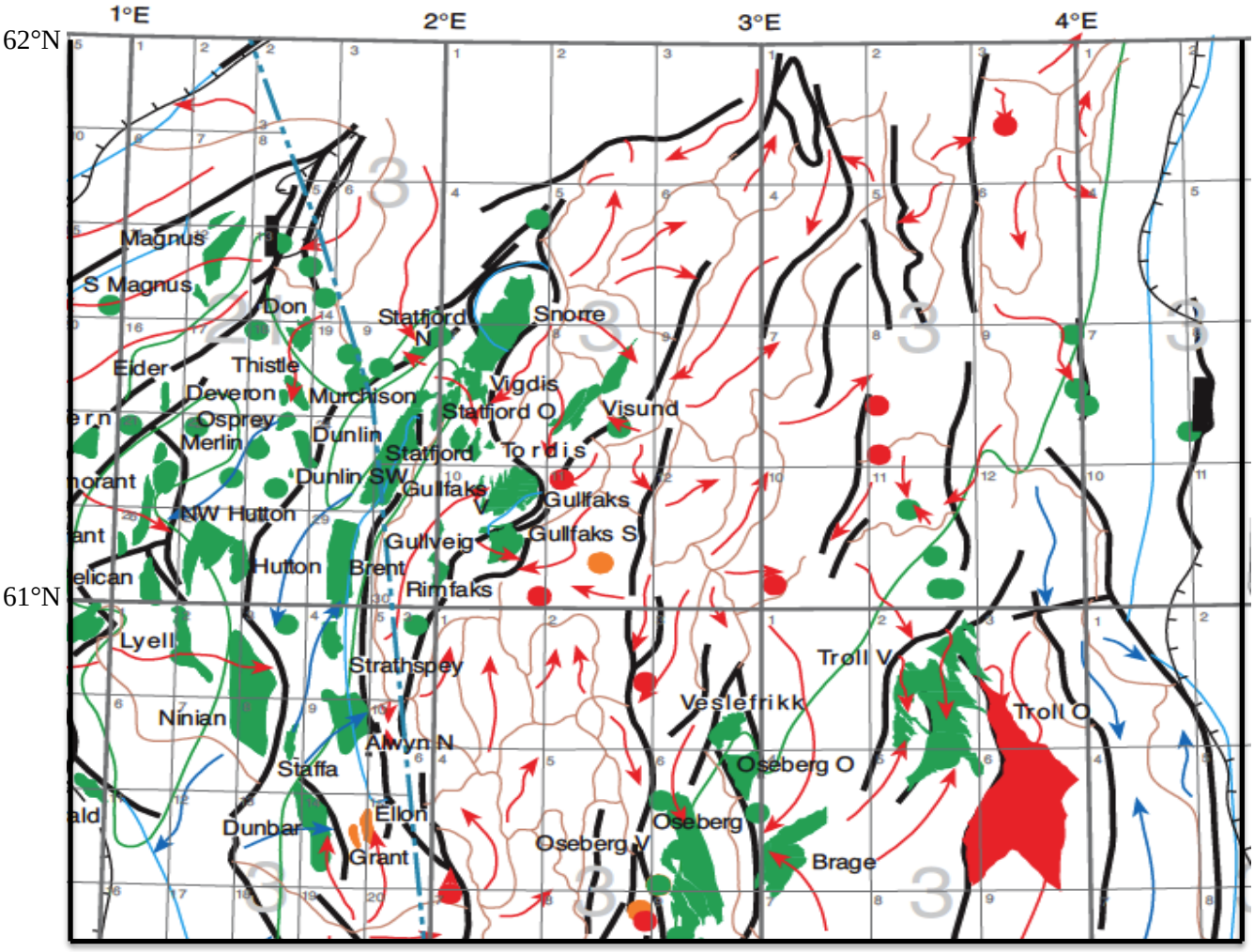


Fig 3.1.1: Regional drainage areas and interpreted migration pathways through Jurassic source rocks in the northern North Sea. Map is not to scale. Modified after Kubala et al. (2003). Blue arrows indicate drainage in immature areas, red and orange arrows are for drainage in the Draupne Fm. Green and red patches are hydrocarbon fields.

CHAPTER 4

METHODOLOGY

4.1 Background

The core aim of Basin and Petroleum Systems modeling is to access the dynamics of sedimentary basins and their associated fluids to determine if past conditions were favourable for hydrocarbons to fill potential reservoirs and be preserved there (Al-Hajeri et al., 2009). The kind of basin model to be used (1D, 2D or 3D) depends on the objective of the research and the data available. The objectives of this thesis require building a 3D model from which 1D and 2D extractions are also made for the purposes of well calibration and assessment of potential migration pathways in profile views respectively.

4.2 Workflow

The flow chart in Fig. 4.2.1 below summarizes the steps and briefly explains the input data required for modeling. As shown below, a series of interrelated steps are involved in modeling a sedimentary basin and its petroleum system(s). The two main steps are; (1) Model Building: which involves constructing a structural model and identifying the sequential occurrence of deposition and physical properties of each layer, and (2) Forward Modeling: which performs calculations on the model to simulate processes such as sediment burial, pressure and temperature changes, kerogen maturation and hydrocarbon expulsion, migration and accumulation.

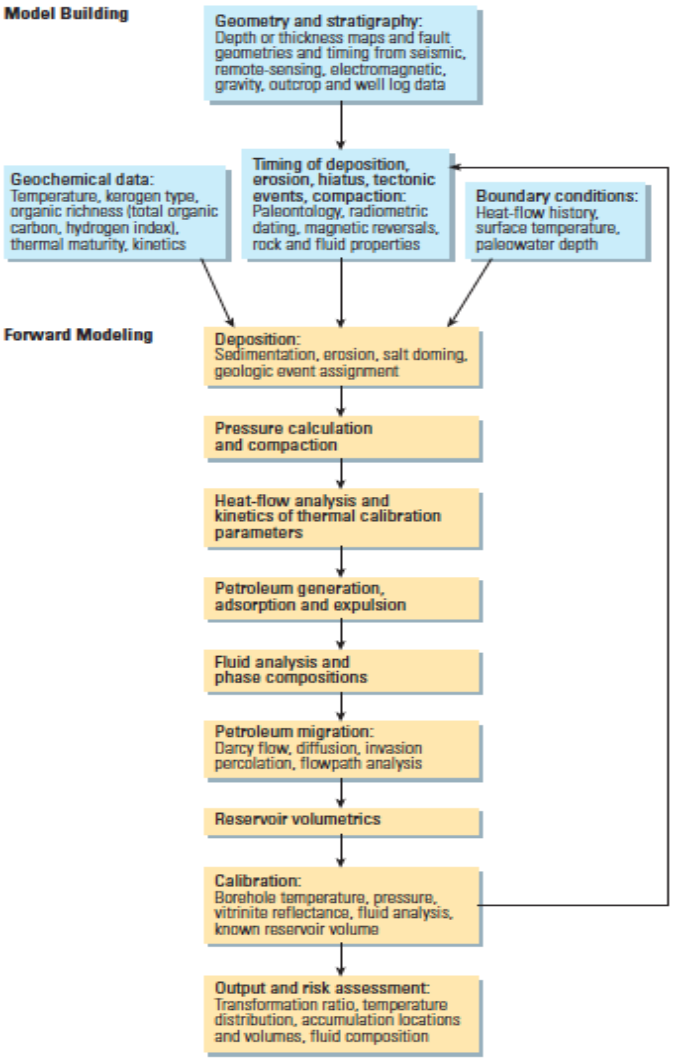


Fig.4.2.1 Flowchart showing interrelated steps and input data requirement for basin and petroleum systems modeling. Modified from Al- Hajeri et al. (2009).

4.3 Input Data

4.3.1 Surface maps

The main data required to build a 3D model are surface maps of the various layers, which comprise the stratigraphy of the study area. Gridded regional surface maps of the northern North Sea provided by Sintef Petroleum Research and Exploro A.S. have been used. Nine horizons were interpreted below the seabed (Table 4.3.1). These horizons were interpreted for major geological time periods. To obtain the complete present day stratigraphy and suit the purposes of the present study, the major

packages were split into layers based on lithostratigraphic data from well 34/8-7 which is located on the western flank of the Tampen Spur, approximately 7.4 km east of the Visund prospect. The well was chosen because; (i) it was drilled to penetrate the Triassic hence covering a significant portion of the geological section, (ii) the stratigraphy in the well is representative for the northern North Sea, and (iii) it encountered all the nine horizons as shown in Table 4.3.1. Also, vitrinite reflectance data and bottom hole temperatures were available to help in calibrating the model.

Table 4.3.1 Interpreted horizons and assigned ages.

Interpreted horizon (Irap format)	**Age (Ma)**
Top Seabed	0
Base Quaternary	2
Top Miocene	7
Top Oligocene	26
Top Paleocene	55
Base Tertiary	65
Intra - Cretaceous	110
Base Cretaceous	131
Top Middle Jurassic	158
Near Base Jurassic	194

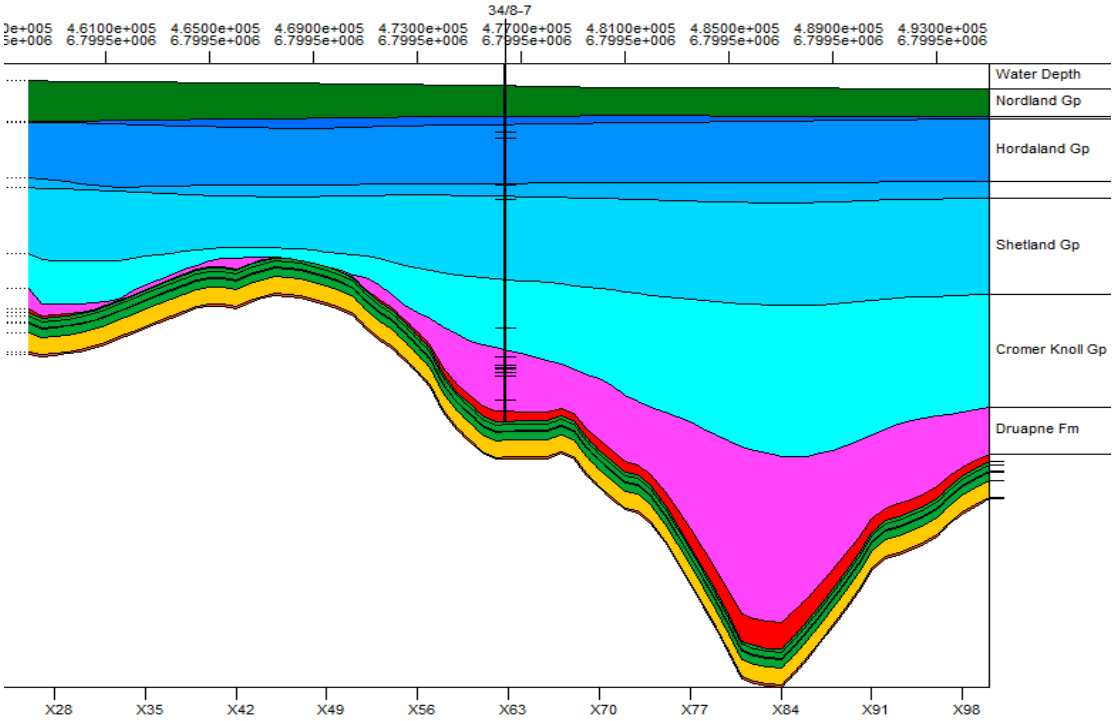


Fig.4.3.1: 2D cross-section across the control well showing the depth mismatch between interpreted horizons from the data and actual well picks.

One major constraint with the gridded data obtained from Exploro A.S. was with the depth mismatches. As shown in Fig. 4.3.1, the regional formation horizons interpreted clearly mismatch with well picks from the control well with the exception of Top Rogaland Gp and Top Shetland Gp. A consequence of this is that key petroleum systems elements, especially the source and reservoir rocks are buried deeper than they actually occur in the field.

4.3.2 Age Assignment

The ages of the various stratigraphic units/layers were estimated using lithostratigraphic sections of well 34/8-7 published in the Norwegian Petroleum Directorate's (NPD, 2012) well database/factpages. Some age boundaries were adjusted using the ages originally assigned, as shown in Table 4.3.1, and the Geological Time Scale published by the Geological Society of America (2009).

	Name	Color	Deposition Age from [Ma]	Deposition Age to [Ma]	Erosion Age from [Ma]	Erosion Age to [Ma]	Max. Time Step Duration [Ma]	Facies 1
15	Nordland Gp		5.00	0.00	0.00	0.00	10.00	Nordland Gp
14	Utsira		23.00	5.00	0.00	0.00	10.00	Utsira
13	Hordaland Gp		55.00	23.00	0.00	0.00	10.00	Hordaland Gp
12	Rogaland Gp		71.00	55.00	0.00	0.00	10.00	Rogaland Gp
11	Shetland Gp		99.00	71.00	0.00	0.00	10.00	Shetland Gp
10	Cromer Knoll Gp		135.00	99.00	0.00	0.00	10.00	Cromer Knoll Gp
9	Draupne Fm		155.00	150.00	150.00	135.00	10.00	Draupne Fm
8	Heather Fm		164.00	155.00	0.00	0.00	10.00	Heather Fm
7	Tarbert Formation		168.00	164.00	0.00	0.00	10.00	Tarbert Fm
6	Ness Formation		172.00	168.00	0.00	0.00	10.00	Ness Fm
5	Etive Fm		175.00	172.00	0.00	0.00	10.00	Etive Fm
4	Rannoch Fm		178.00	175.00	0.00	0.00	10.00	Rannoch Fm
3	Broom Fm		180.00	178.00	0.00	0.00	10.00	Broom Fm
2	Dunlin Group		190.00	180.00	0.00	0.00	10.00	Dunlin Gp
1	Top Statfjord Fm		203.00	190.00	0.00	0.00	10.00	Top Statfjord Fm

Fig.4.3.2: Age assignment table showing the various formations and groups and their ages.

4.3.3 Thickness and Lithology

The thicknesses of the stratigraphic units were estimated automatically in Petromod based the surface maps loaded into the software. This is calculated from the difference between the depth of the overlying surface map and the surface map just below that. Lithology type(s) of the various units was estimated from the lithostratigraphic section of the well obtained from the database of NPD (2012). The lithologies were generalized by selecting user-defined lithologies in Petromod. This was done to simplify the modeling. See Fig 4.3.5.

4.3.4 Erosion

The main erosional event, which occurred in the study area between 150-135 Ma mostly affected the Draupne Formation. The amount of erosion and present day thickness of the unit is variable across the basin. Petromod 3D offers the option of modeling erosion in units with variable amounts of erosion. The required input is the depositional thickness of the unit, from which the present day thickness is subtracted to give the amount of erosion. This is shown diagrammatically in Fig. 4.3.3.

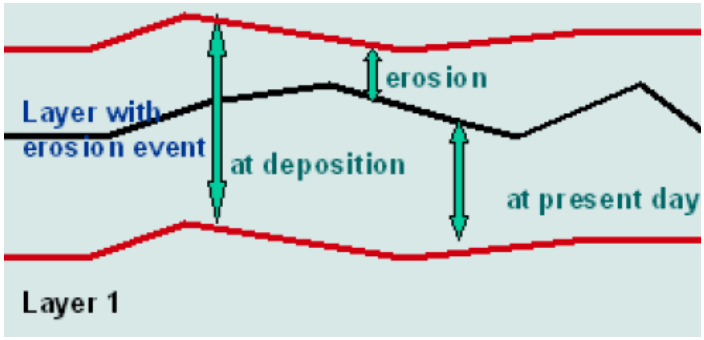


Fig. 4.3.3: Illustration showing estimation of erosion in Petromod. Modified from Schlumberger (2009).

The present day thickness of the Draupne Formation ranges from 250-1200 m, and the depositional thickness is difficult to constrain. An initial deposition thickness of 800 m has been selected for modeling purposes and based on this a present day erosional map of the Draupne Formation was developed (Fig. 4.3.4).

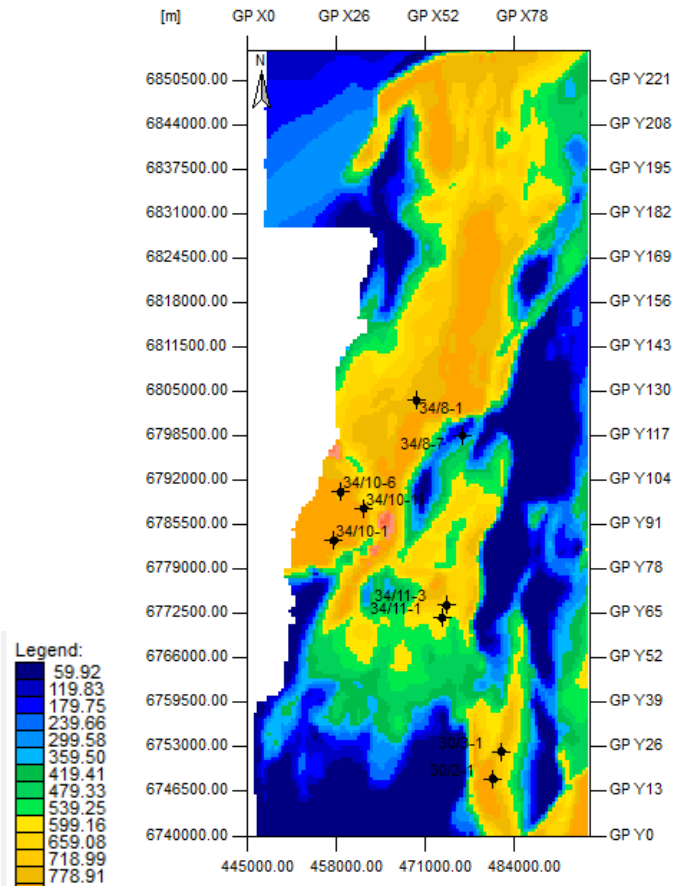


Fig. 4.3.4: Erosion map of the Draupne Fm. Legend shows amount eroded in metres.

4.3.5 Source rock properties

The kerogen in the Draupne and Heather Formations, which are the main source rocks for oil and gas, is Type II. The kinetics group of Burnham (1989)-TII and was used. Regional average TOC and HI values for the source rocks are from Kubala et al., (2003). The coal within the Ness Formation contains type III kerogen. The kinetics group of Burnham (1989)-TIII was used. Regional average TOC and HI values for the North Sea Ness Coal published by Andersen et al. (1994) were used. See Fig 4.3.5 for details.

	Name	Petroleum System Elements	Color	Lithology Value	TOC Model	TOC Value [%]	Kinetics	HI Value [mgHC/gTOC]
1	Nordland Gp	Overburden Rock		SHALE&SAND	Uniform	0.00	none	0.00
2	Utsira	Overburden Rock		SAND&SHALE	Uniform	0.00	none	0.00
3	Hordaland Gp	Overburden Rock		SHALE&SAND	Uniform	0.00	none	0.00
4	Rogaland Gp	Overburden Rock		SHALEsand	Uniform	0.00	none	0.00
5	Shetland Gp	Seal Rock		SHALEcalc	Uniform	0.00	none	0.00
6	Cromer Knoll Gp	Seal Rock		SHALEcalc	Uniform	0.00	none	0.00
7	Draupne Fm	Source Rock		Shale (organic rich, typical)	Uniform	6.00	Burnham(1989)_TII	400.00
8	Heather Fm	Source Rock		Shale (organic rich, typical)	Uniform	2.50	Burnham(1989)_TII	150.00
9	Tarbert Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00
10	Ness Fm	Source Rock		COALsandy	Uniform	61.00	Burnham(1989)_TIII	168.00
11	Etive Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00
12	Rannoch Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00
13	Broom Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00
14	Dunlin Gp	Underburden Rock		SHALE&SAND	Uniform	0.00	none	0.00
15	Top Statfjord Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00

Fig. 4.3.5: Facies assignment table showing lithologies, source rock properties and petroleum system elements assignments.

4.3.6 Boundary Conditions

Three boundary conditions, namely Basal Heat Flow (HF), Paleo Water Depth (PWD) and Sediment Water Interface Temperature (SWIT), are required in order to define the basic energetic conditions for the thermal development and maturation of organic matter through time (Schlumberger, 2009).

Paleo heat flow values have varied through time in the North Sea to reflect the varying tectonic regimes. The heat flow trend of Schroder and Sylta (1993) has been used for the modeling. This trend assigns the highest heat flow, 83 mW/m^2, to the late Jurassic rifting period and lower heat flows to the pre-late Jurassic and Cretaceous-present day periods (Fig.4.3.6a). The sediment water interface temperature was automatically assigned in Petromod by defining the hemisphere and latitude of the northern North Sea, which is at Latitude 62^oN (Fig.4.3.6b). The SWIT values are based on the global mean surface temperatures of Wygrala, (1989). The paleo water depth trend of Kjennerud et al. (2001) has been used (Fig.4.3.6c).

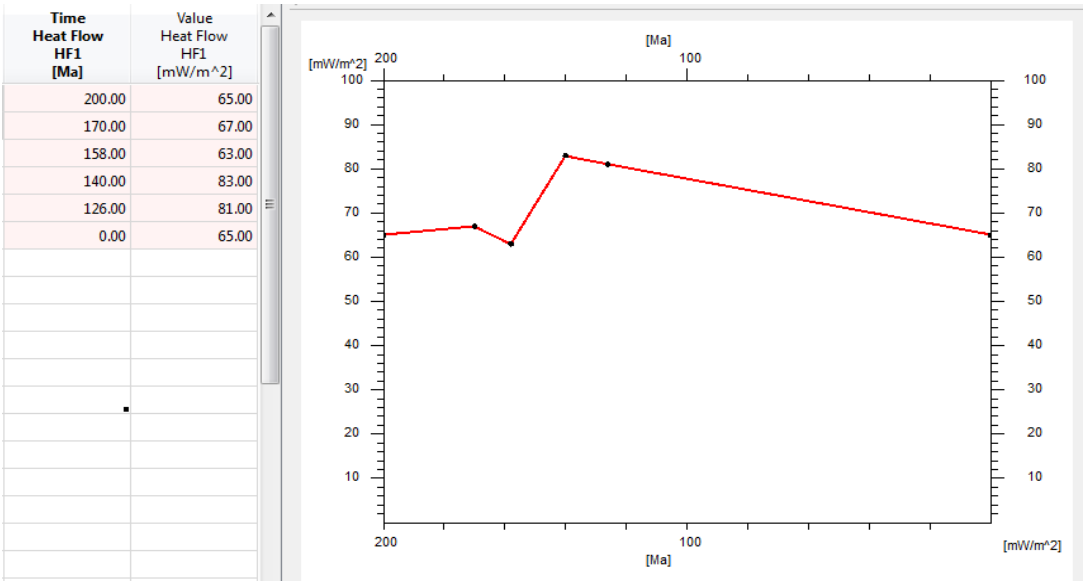


Fig. 4.3.6 (a): Heat flow values and trend based on Schroder and Sylta (1993).

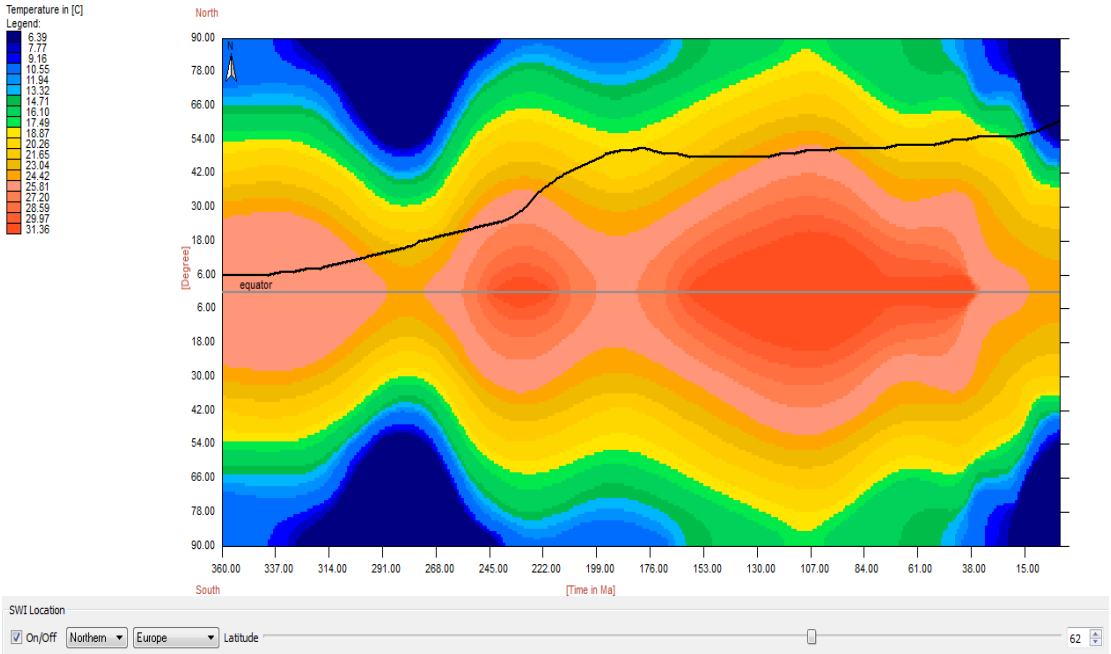


Fig. 4.3.6 (b): Sediment Water Interface Temperature after Wygrala (1989).

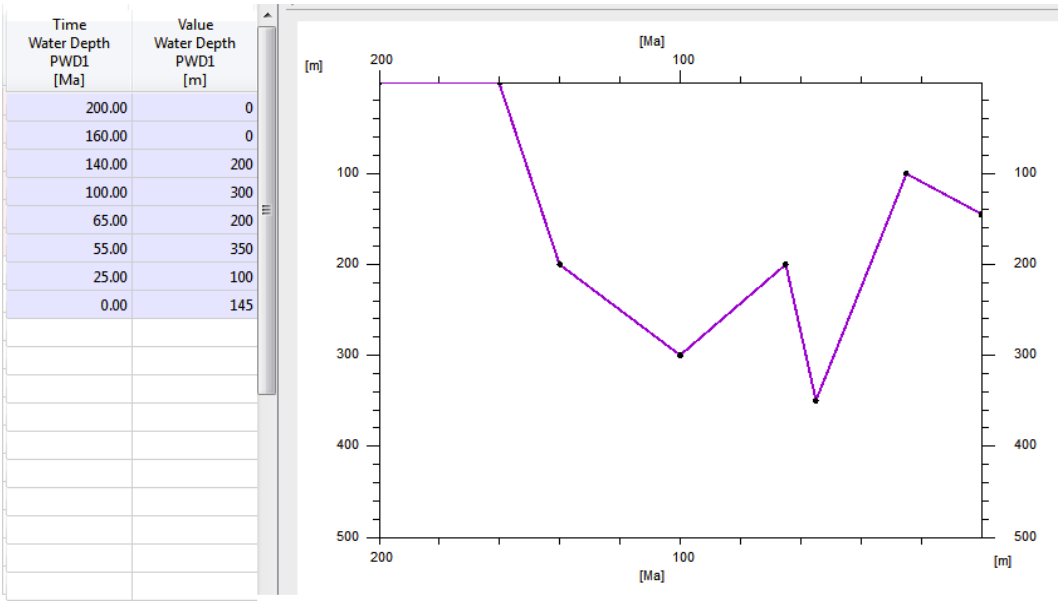


Fig. 4.3.6 (c): Paleo water depths and associated trend of the North Sea based on Kjennerud et al. (2001).

4.3.7 Faults

Fault plane traces and intersections for the Middle Jurassic Brent Group were also provided with the dataset. Out of a total of 523 fault intersections, only the main faults surrounding the major fields were selected (Fig. 4.3.8a). This was based on the assumption that the main faults may influence migration and accumulation of hydrocarbons in these fields. The fault intersections were merged in Input 3D and Seistrat modules of Petromod to form fault planes (Fig. 4.3.8b). The faults were assigned properties, which include an age and a property such as Shale Gouge Ratio (SGR) or Fault Capillary Pressure (FCP), which indicate the degree of sealing/openness of the fault. These properties determine the times(s) and degree to which the faults influence or influenced hydrocarbon migration and accumulation. Here, faults have assigned a given fault property (sealing, non-sealing or partly sealing) for a time period from 150-0 Ma as will be discussed below. The faults in the study area have been mapped and assigned transmissibilites based on overpressure

difference between adjacent pressure compartments by Borge and Sylta (2000). The transmissibilities of the faults (Fig.4.3.7) describe the ease with which fluids including hydrocarbons flow across the faults. Hence the sealing capacity of a fault can be inferred from its transmissibility. In this work, faults have been assigned properties based on their transmissibilities as follows:

Transmissibility	**Property**
Very high-high	Open
Intermediate	Partly Sealing, defined by SGR
Very low- low	Closed

Yielding (2002) suggests a SGR range of between 15-20% as the threshold value between sealing and non–sealing. Faults in the study area, which are partly sealing, have been assigned a SGR of 30%. See Fig. 4.3.9 for details.

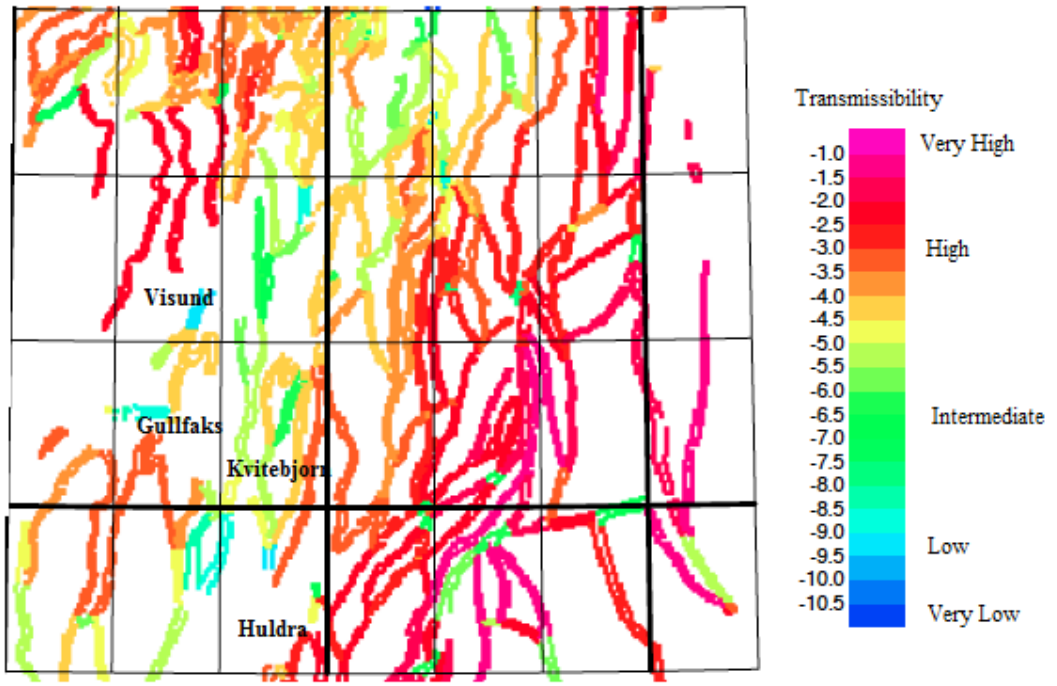
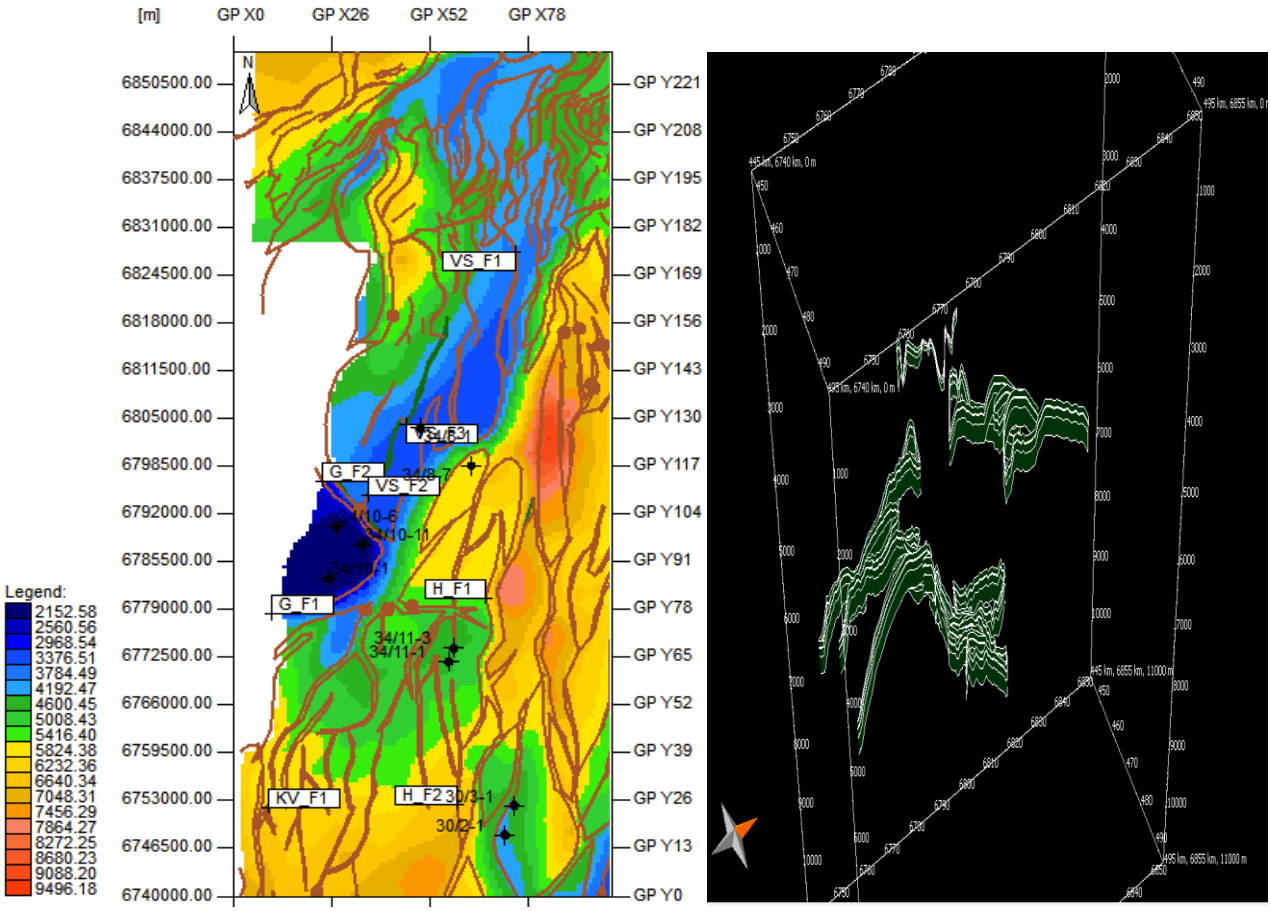


Fig. 4.3.7: Map of study area showing major fields and mapped faults with assigned average transmissibilities (m^3). Modified from Borge and Sylta (2000).



(a) (b)

Fig. 4.3.8: (a) Present day depth map of Tarbert Fm showing the seismically mapped Middle Jurassic faults in the study area and (b) 3D view of selected fault planes. Distances are in kilometres and depth in metres. Selected major faults bounding fields are labeled in white. Direction of view is towards the west.

Name	Color	Type	Period 1 SGR [%]	Period 1 FCP [MPa]	Period 1 Map	Period 1 Age from [Ma]	Period 1 Age to [Ma]	Type	Period 2 SGR [%]	Period 2 FCP [MPa]
G_F1		SGR	30.00	0.00	none	150.00	0.00	none	0.00	0.00
G_F2		SGR	30.00	0.00	none	150.00	0.00	none	0.00	0.00
G_F3		none	0.00	0.00	none	150.00	0.00	none	0.00	0.00
G_F4		none	0.00	0.00	none	150.00	0.00	none	0.00	0.00
V_F1		open	0.00	0.00	none	150.00	0.00	none	0.00	0.00
V_F2		open	0.00	0.00	none	150.00	0.00	none	0.00	0.00
H_F1		open	0.00	0.00	none	150.00	0.00	none	0.00	0.00
H_F2		closed	0.00	0.00	none	150.00	0.00	none	0.00	0.00
KV_F1		SGR	30.00	0.00	none	150.00	0.00	none	0.00	0.00
VS_F2		open	0.00	0.00	none	150.00	0.00	none	0.00	0.00
VS_F3		open	0.00	0.00	none	150.00	0.00	none	0.00	0.00
VS_F1		open	0.00	0.00	none	150.00	0.00	none	0.00	0.00

Fig. 4.3.9: Fault property assignment.

4.4 Simulation

Simulation defines the final stage of building a 3D model in Petromod. The most important steps to be defined include the Run Control, which determines the resolution of the output model and hence time used by the simulator, and the migration method, which depends on a lot of variables including the stratigraphic positions of the source and reservoir rocks, overpressure etc. In this modeling the Run Control sampling size has been set to 5*5, which allows it to make calculations for every 5^{th} cell. This has been done to achieve more realistic results since secondary migration of oil occurs in thin stringers and hence requires a fine grid. The Hybrid migration method, which combines both Darcy flow and Flowpath methods, has been used. This method has been used due to its superiority in situations with influence of overpressure and also where the source rocks are stratigraphically overlying the potential reservoir units.

4.5 Calibration

In order to check the accuracy of the model, it has been calibrated using measured vitrinite reflectance and the bottom hole temperatures from selected wells and pseudo wells in the study area. Vitrinite data for the pseudo-wells was obtained from nearby wells. As shown in Figs. 4.5.1a, there is a good correlation between the modeled and measured vitrinite reflectance values from the wells and pseudo-wells. Although the horizons in the model are somewhat deeper than what is observed in the actual wells due to data error as explained in section 4.3.1, there is an acceptable match between measured and modeled bottom hole and surface temperatures for the two wells (Fig.4.5.1b). The modeled bottom hole temperatures of wells 34/8-7 and 34/4-5 are 177^{o}C and 132^{o}C respectively. These are in good agreement with the measured values of 181^{o}C and 140^{o}C respectively. The modeled reservoir accumulations have also been compared with known field accumulations in the study area as discussed in Chapter 5.

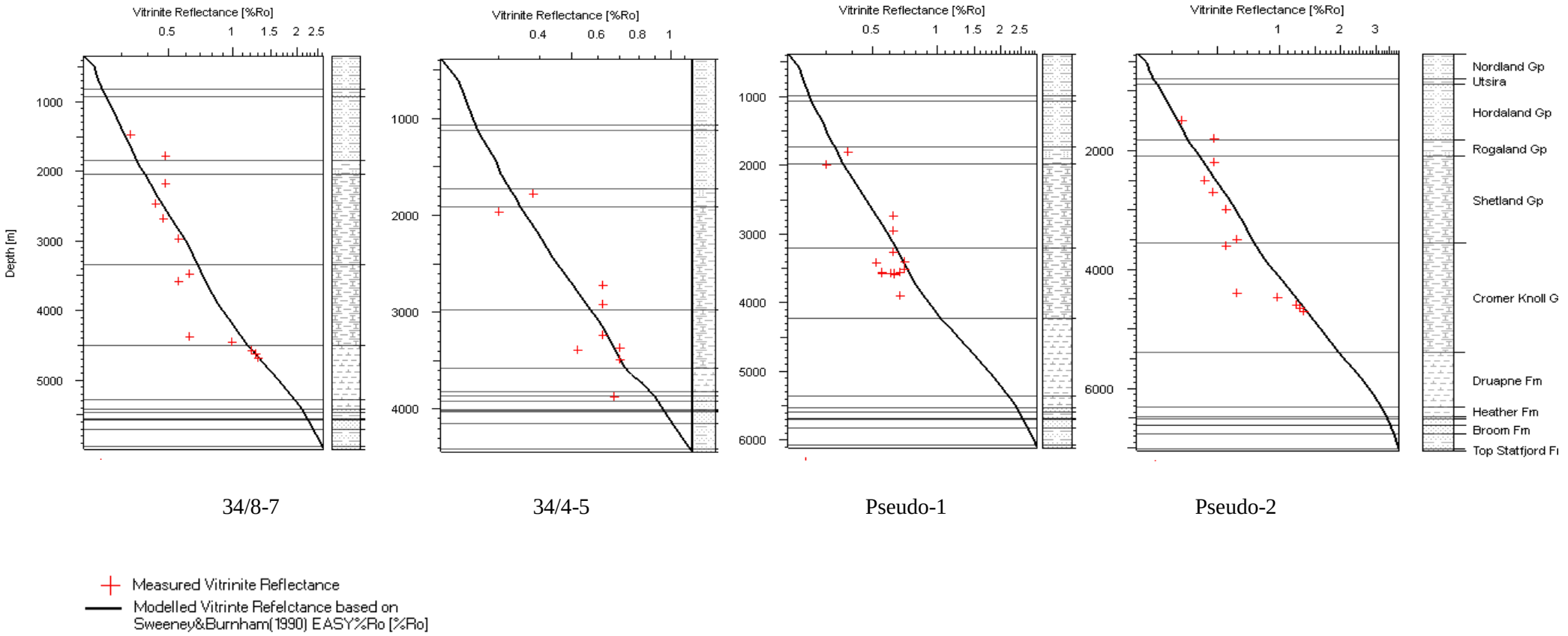


Fig.4.5.1a: Model calibration by comparison of measured and modeled vitrinite reflectance. Well 34/8-7 is from Visund field, 34/4-5 from NW of the study area, Pseudo-1 from the East Shetland Basin and Pseudo-2 from the Viking Graben. See location map of the wells in Fig. 5.4.4 (b).

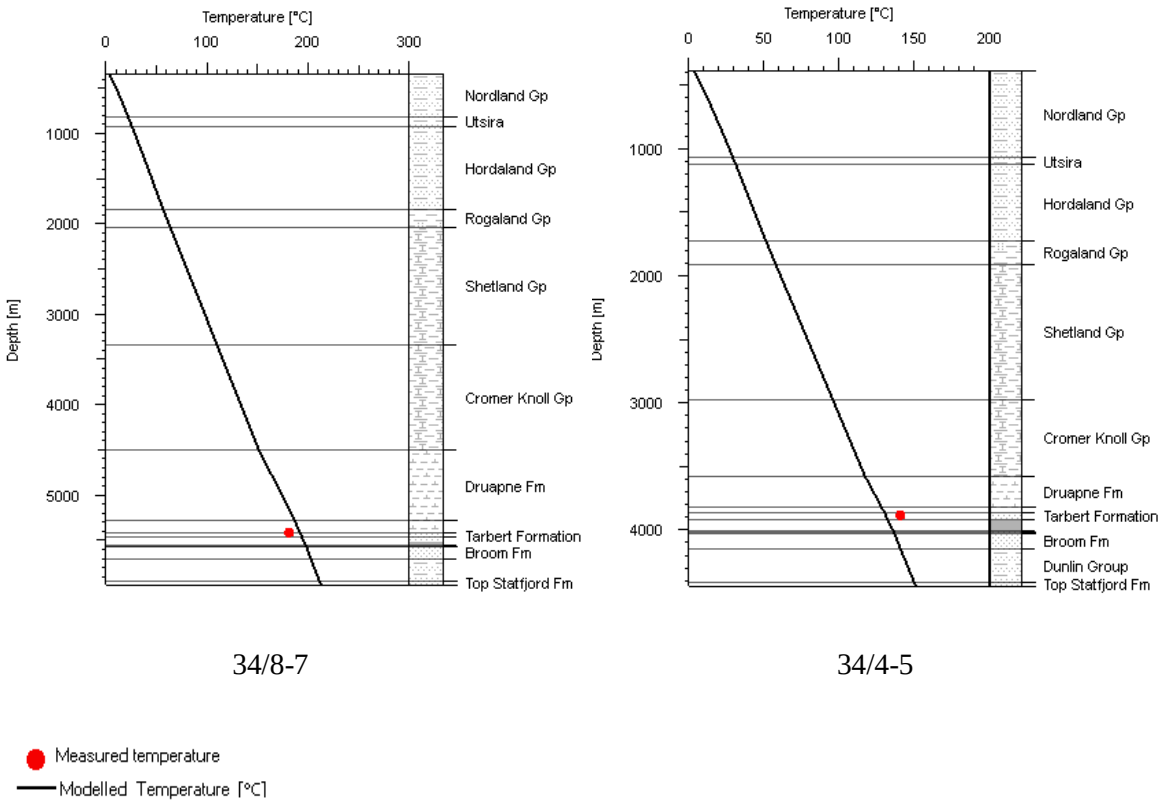


Fig.4.5.1b: Model calibration by comparison of measured and modeled temperatures for wells 34/8-7 and 34/4-5.

CHAPTER 5

RESULTS

5.1 Burial History

The burial history reconstruction of the northern North Sea based on the calibration wells is shown in Figs. 5.1.1 (a- d).

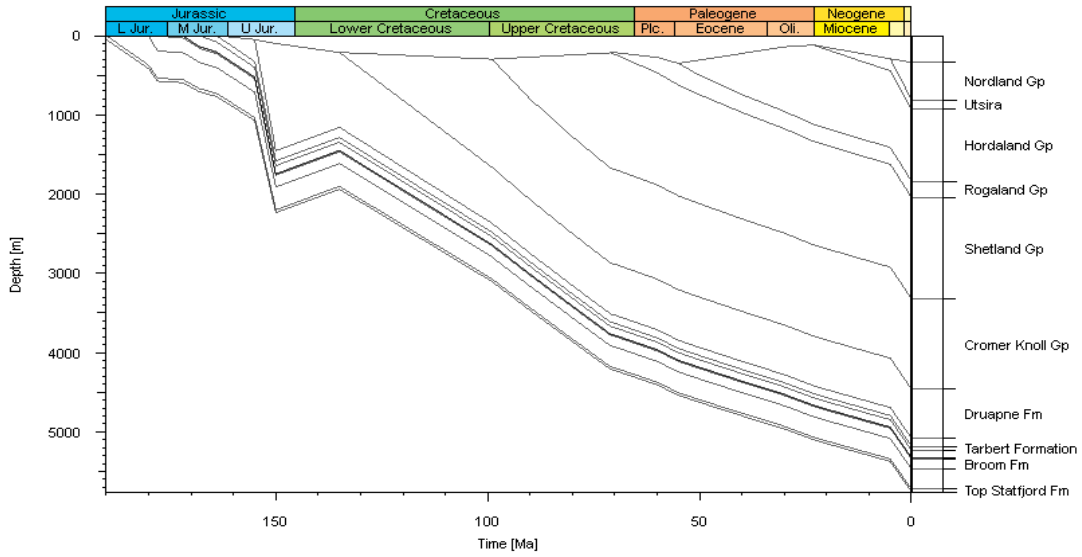


Fig. 5.1.1a: Subsidence curve for study area based on well 34/8-7.

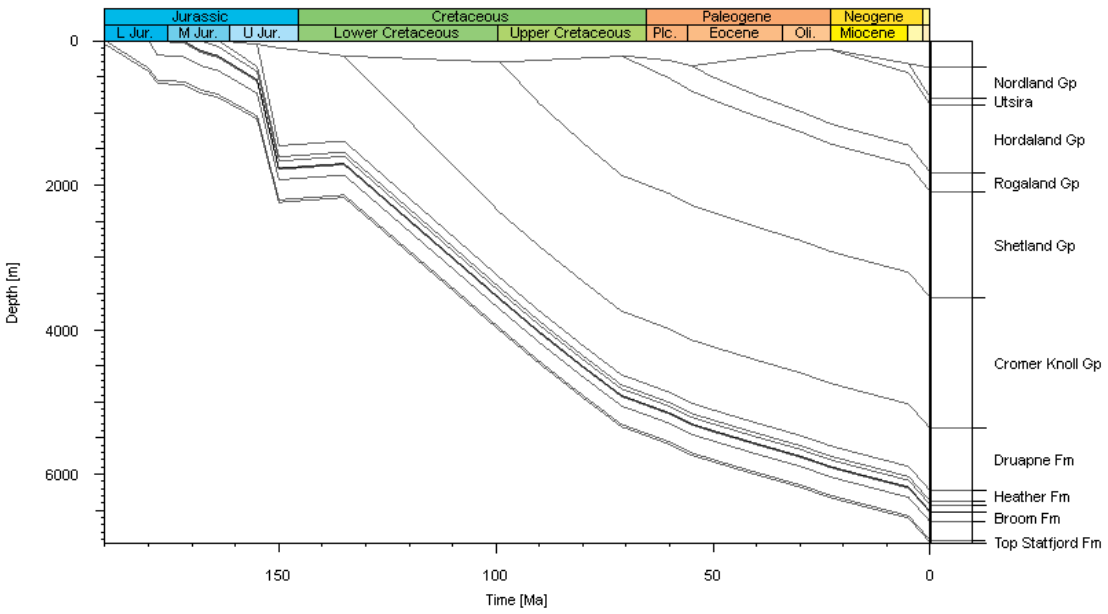


Fig. 5.1.1b: Subsidence curve for study area based on well Pseudo-2.

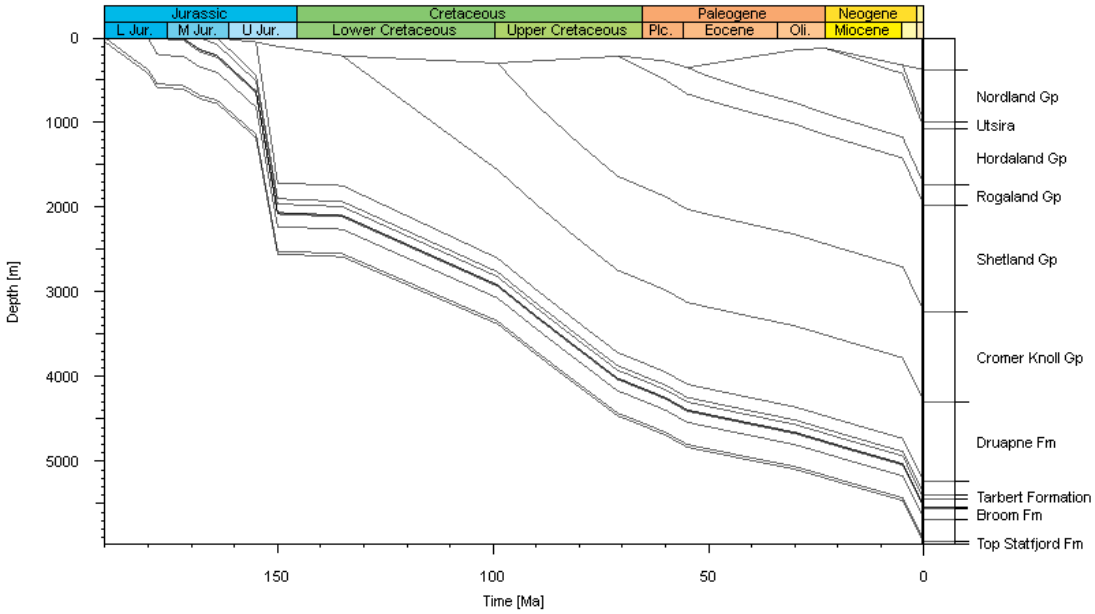


Fig. 5.1.1c: Subsidence curve for study area based on well Pseudo-1.

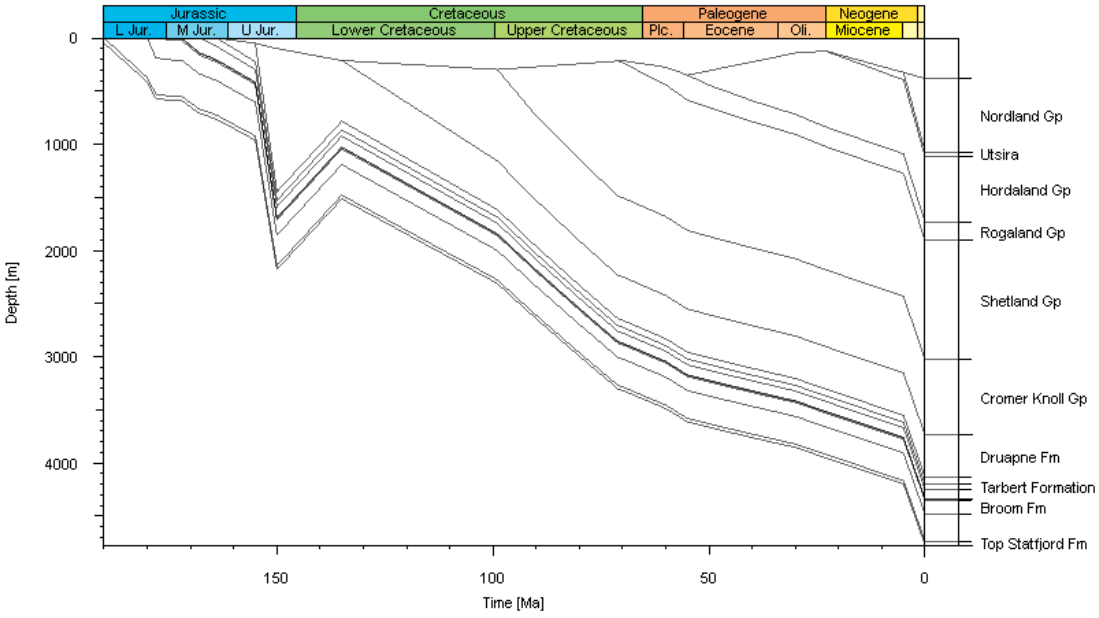


Fig. 5.1.1d: Subsidence curve for study area based on well 34/4-5.

From fig. 5.1.1a, the basin experienced about 1200 m of subsidence from early Jurassic to mid- late Jurassic times. Subsidence rates became high in the late Jurassic, and the basin was buried to a depth of about 2300 m. This period corresponds to the period of active rifting in the North Sea. There was a period of uplift and erosion

(Fig.5.1.1a) between 150-135 Ma where approximately 300 m of sediments were removed. From early Cretaceous times, the basin has experience average subsidence rates to its present day burial depth of about 5600 m.

The burial history of Pseudo-2, located in the Viking Graben (Fig.5.1.1b) is different from 34/8-7. The amount of uplift and erosion between 150-135 Ma was less than at the previous location. Subsidence rates were comparatively higher between late Jurassic and late Cretaceous. Sedimentation rates were higher between the late Jurassic and mid-Cretaceous. This is shown by the thicknesses of the Draupne Fm and Cromer Knoll Gp. Subsidence rates slowed from Paleogene time to a present day burial depth of about 6800 m.

The burial history of Pseudo-1 well (Fig.5.1.1c) is similar to well 34/8-7. Subsidence rates were high in the late Jurassic and became average from early Cretaceous time, to its present day burial depth of about 5800 m.

Well 34/4-5, located in the NW of the study area (Fig.5.1.1d), shows the most uplift as compared to the previous location. However, the burial history of this location agrees with that in well 34/8-7.

5.2 Maturity and Petroleum Generation History

Figure 5.2.1 shows the maturity and petroleum generation history of the study area based on the control well, 34/8-7.The maturity and petroleum generation history of the entire study area is shown as 3D surface maps of the source rocks in Figs. 5.2.2-5.2.7.

As shown in Fig.5.2.1, all three source rocks were generally immature until the mid Cretaceous from which time they have generated hydrocarbons. Onset of oil generation in the Draupne Fm occurred at about 88 Ma. Peak oil generation started 10 million years later at 78 Ma. The interval began to generate gas at 30 Ma and continues to generate gas to present day along with late oil. The deeper Heather Fm became mature for oil generation about 95 Ma with peak oil generation occurring at about 85 Ma. It became mature for gas generation approximately 46 Ma and generates gas to present day. The coal interval in the Ness Fm started generating oil approximately 105 Ma with peak generation at 90 Ma. It achieved maturity for gas generation from 57 Ma and continues to generate gas presently.

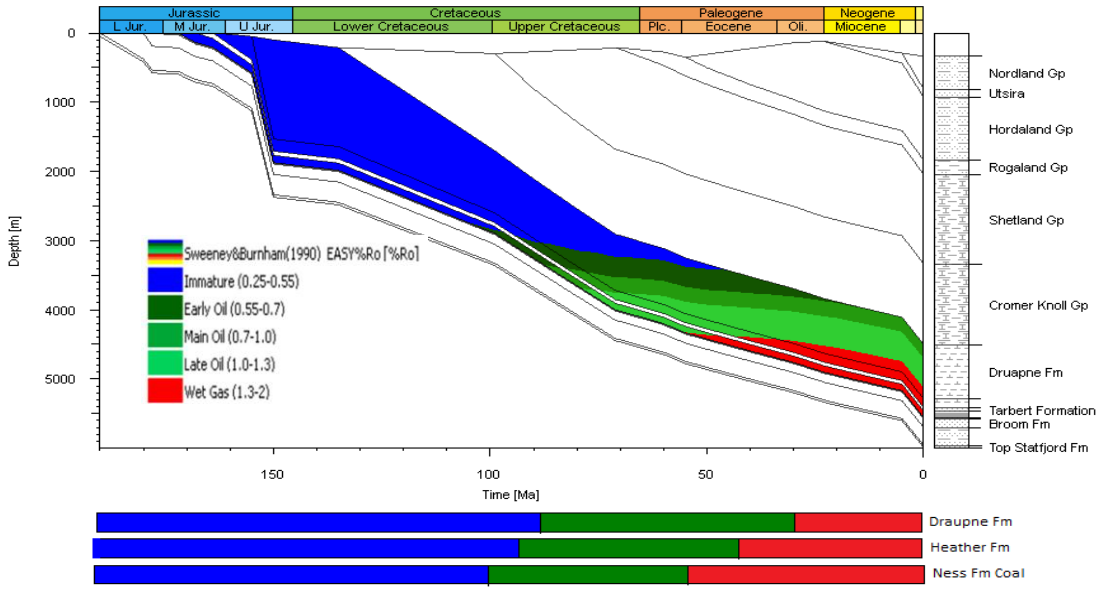


Fig. 5.2.1:Burial curve with maturity overlay for well 34/8-7.

Figures 5.2.2 and 5.2.3 (a-c) show the distribution of maturity over the Draupne Fm in the study area for four time steps. At 90 Ma, most areas were immature except for the northwestern most parts of the study area and the deepest parts of the Viking Graben. These areas had been buried to depths in excess of 2000 m and were in the early phase of oil generation. At 80 Ma, most parts of the formation had been buried sufficiently to reach maturity for oil generation. The top of the source rock in the deepest part of the graben was in the oil floor and gas generation had been initiated in locations, which had reached burial depths of about 3800 m. Most of the uplifted areas including the Tampen Spur and flanks of the East Shetland Basin were still immature for hydrocarbon generation. At 70 Ma, the deepest areas in the graben and parts of the northwest were mature for gas generation. Most areas were, however, in the peak- late oil generation phase except uplifted areas including the Tampen Spur. At present day, the Viking Graben and deep areas in the East Shetland Basin are generating gas. Most areas in the study area still generate oil except for the structural highs at the Tampen Spur, which are still at burial depth below 1600 m.

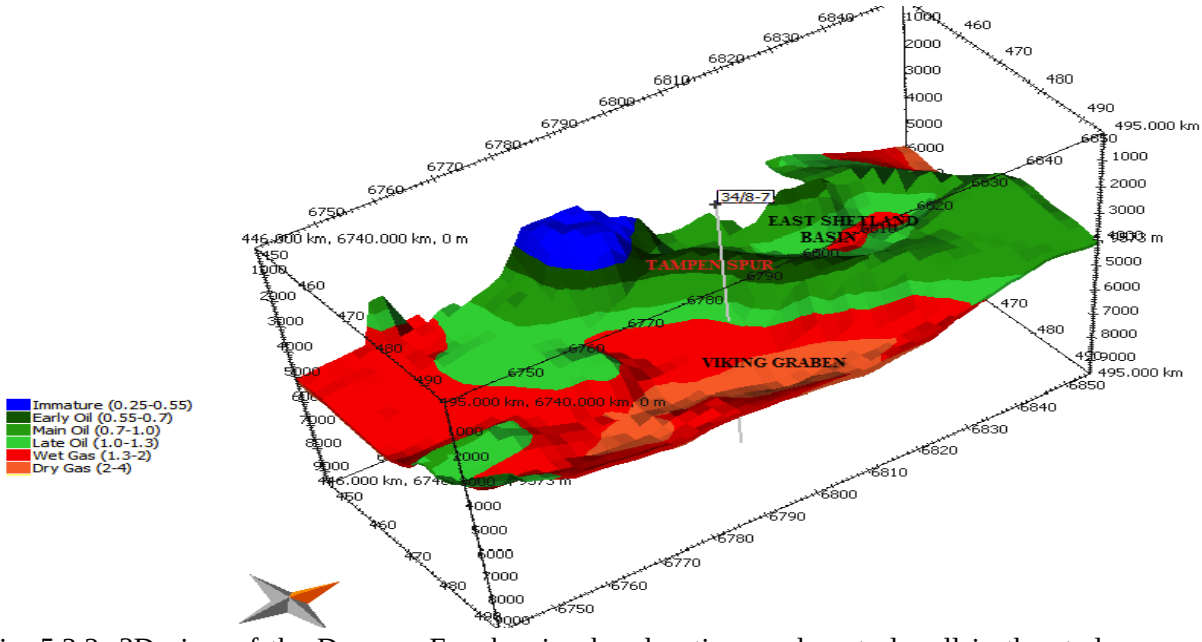
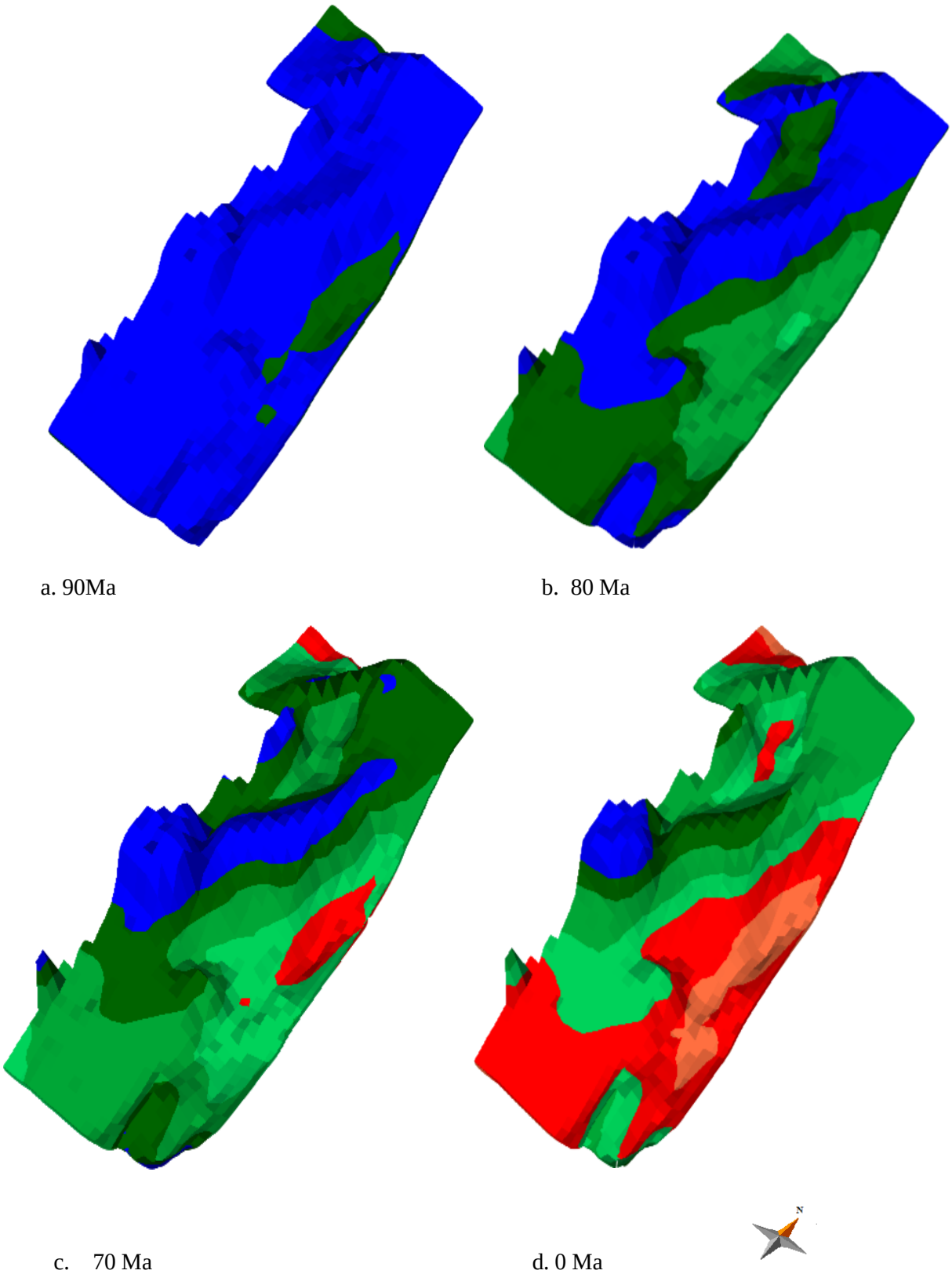


Fig. 5.2.2: 3D view of the Draupne Fm showing key locations and control well in the study area. Depths are in metres and distances in kilometres.



a. 90Ma

b. 80 Ma

c. 70 Ma

d. 0 Ma

Fig. 5.2.3: Surface maps showing maturity distribution of the Draupne Fm. See Legend in Fig. 5.2.2.

The Heather Fm, which is buried deeper than the Draupne Fm, reached maturity earlier and shows a greater distribution of maturity for the same time steps as in Fig.5.2.2. The distribution of maturity over the Heather Fm is shown in Fig 5.2.4 and 5.2.5 (a-c). At 90 Ma, 10 million years after onset of oil generation in the Heather Fm, areas in the northwest, southwest and the Viking Graben had been buried sufficiently and were in the early phase of oil generation. The deepest parts of the graben had started to enter the main phase of oil generation. Oil generation was also initiated in the central part of the East Shetland Basin. Uplifted areas such as the Tampen Spur and other shallow areas were immature. By 80 Ma, close to 50% of the source rock was matured for hydrocarbon generation. The deepest parts of the graben were in transition between late oil and gas generation. Most parts of the source rock were matured for hydrocarbon generation by 70 Ma, except the Tampen Spur area, which was still buried to depths below 1800 m. Presently, most parts of the graben and centre of the East Shetland Basin are generating gas. Uplifted areas in the Tampen Spur are mostly in the oil window except the structural highs.

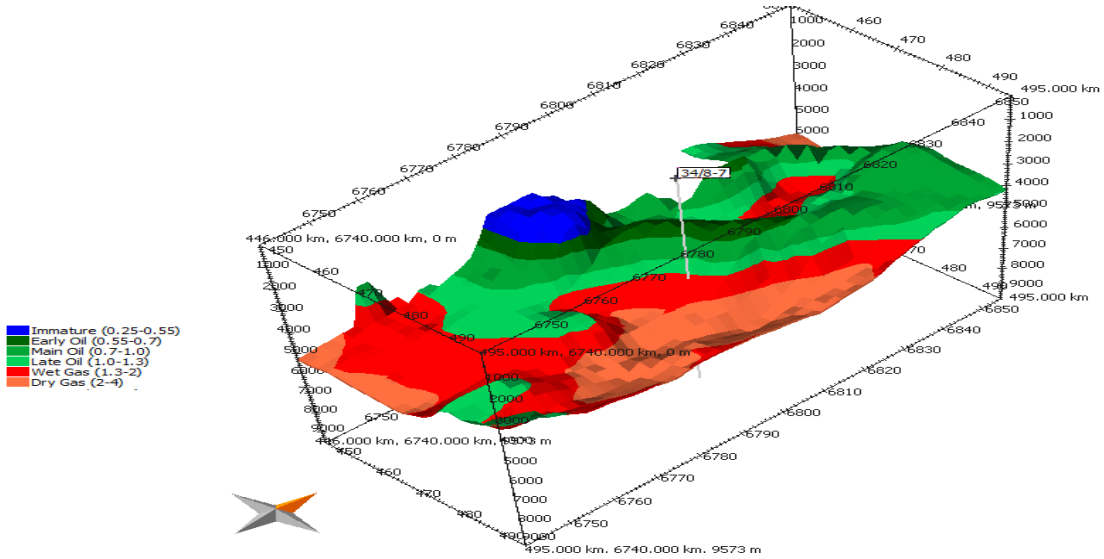
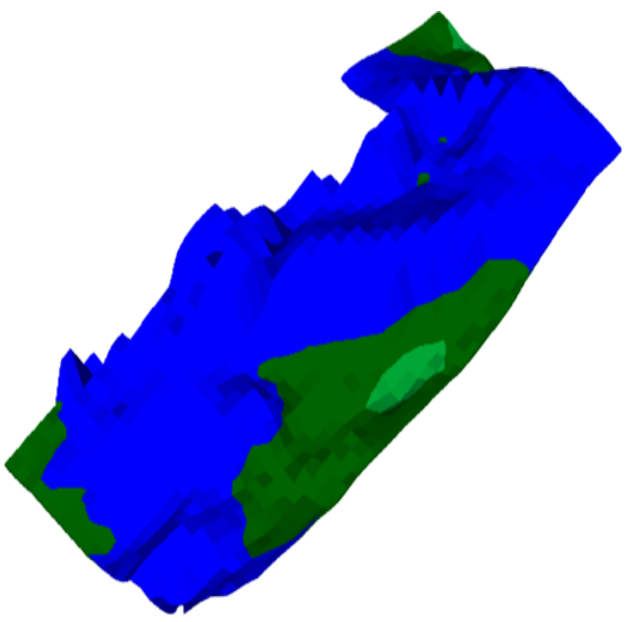
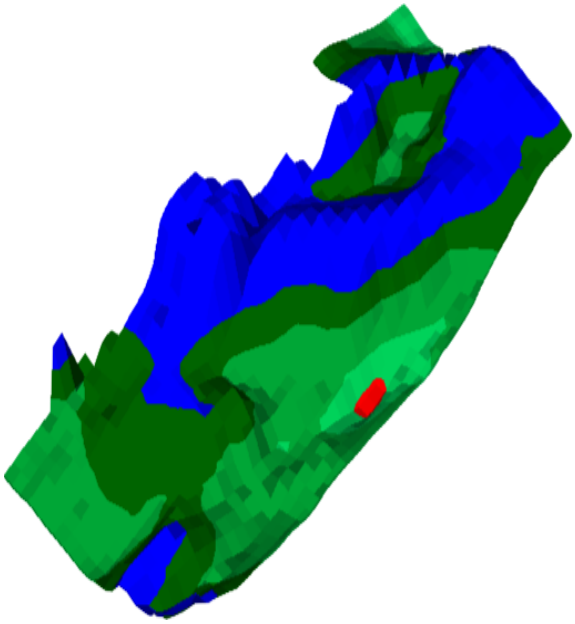


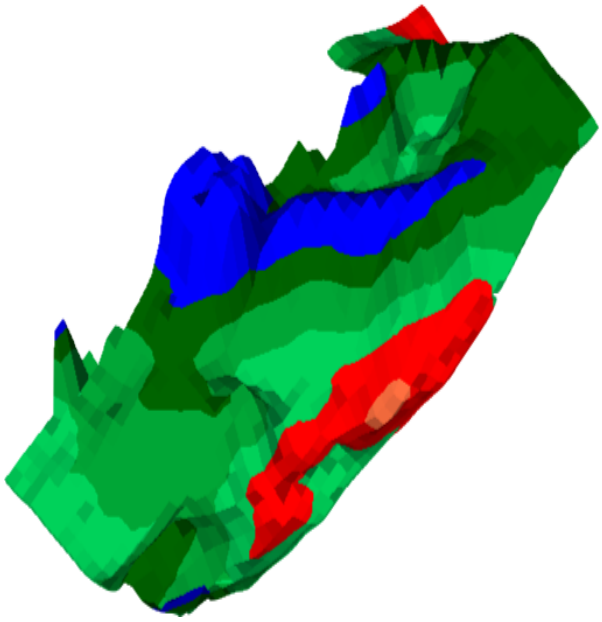
Fig. 5.2.4: 3D view of the Heather Fm and control well in the study area. Depths are in metres and distances in kilometres.



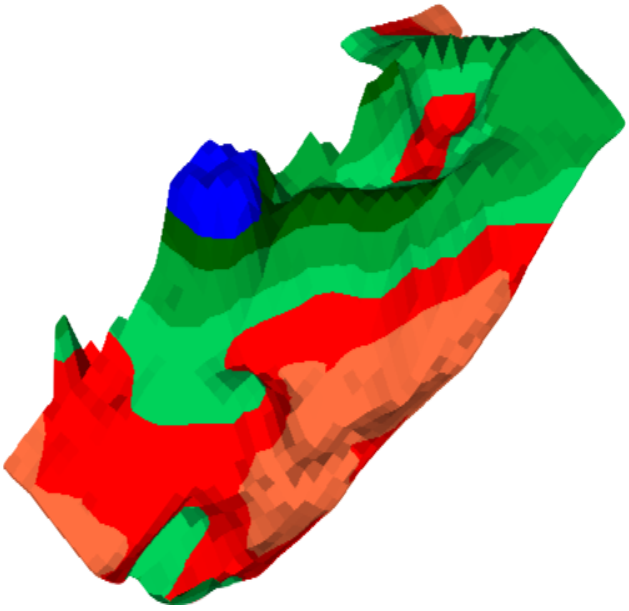
a. 90Ma



b. 80Ma



c. 70Ma



d. 0Ma

Fig. 5.2.5: Surface maps showing maturity distribution of the Heather Fm. See Legend in Fig. 5.2.4.

The coal intervals within the Ness Fm achieved earlier and greater distribution of maturity for the same time steps in comparison to the Draupne and Heather Formations (Figs. 5.2.6, 5.2.7 a-c). This is expected due to its deeper burial depth.

Areas to the southwest, centre of the East Shetland and Viking Graben were already generating oil at 90 Ma. By 80 Ma, close to 80% of the interval was mature for hydrocarbon generation and deep areas in the graben were in the oil floor and had started to generate gas. At 70 Ma, most parts of the graben were generating late oil and gas. Deeply buried areas in the southwest were also mature for gas generation. Presently, the interval is mature in all parts except for the structural high in the Tampen Spur.

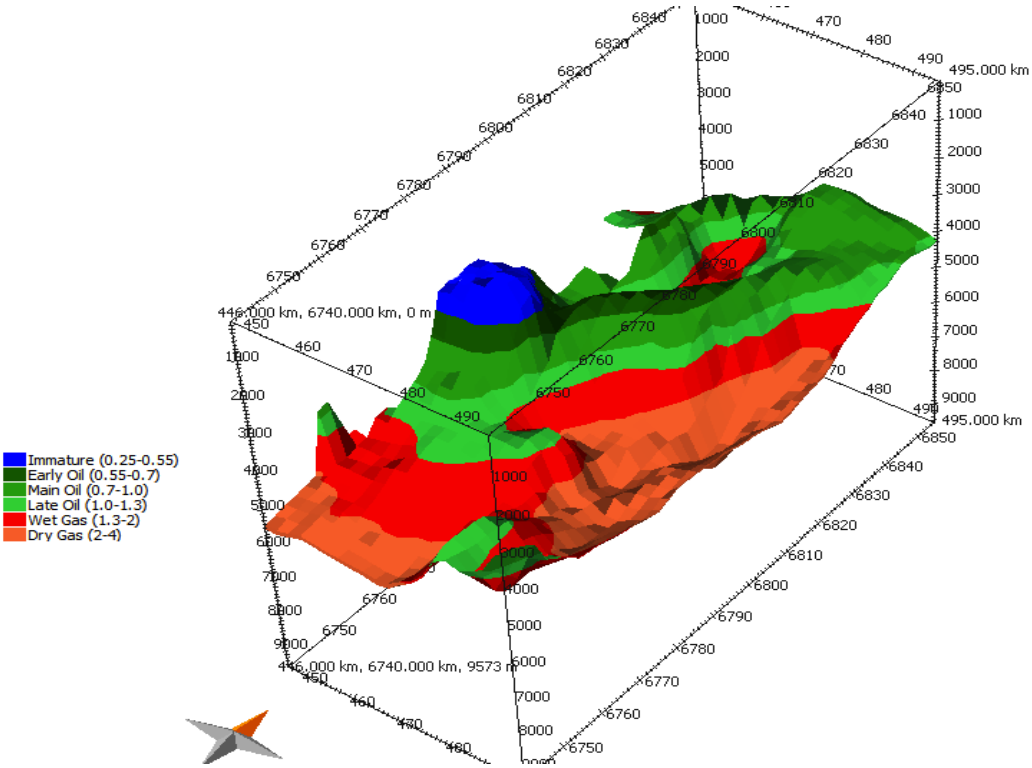
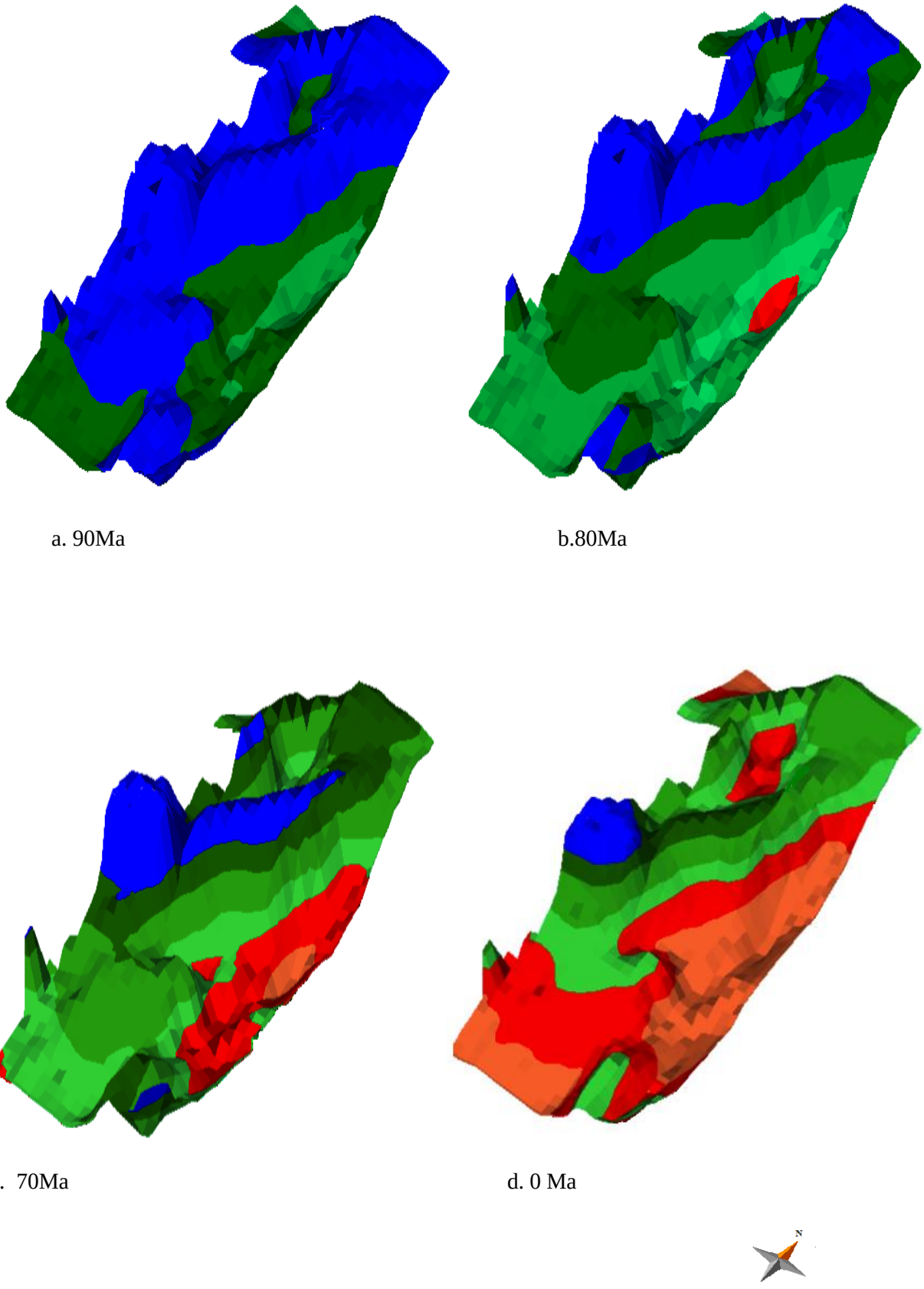


Fig. 5.2.6: 3D view of the coal interval within the Ness Fm.Depths are in metres and distances in kilometres.



a. 90Ma b.80Ma

c. 70Ma d. 0 Ma

Fig. 5.2.7: Surface maps showing maturity distribution of coal intervals within the Ness Fm. See Legend in Fig. 5.2.6.

5.3 Transformation Ratio

Figures 5.3.1-5.3.3 show plots of Transformation Ratios (TR) over time for the three source intervals based on the control well, 34/8-7.

Kerogen in the Draupne Fm began to transform to hydrocarbons in the mid-Late Cretaceous, about 4 million years before the onset on oil generation in this source interval (Fig. 5.3.1). Transformation rates increased steadily up to 62 Ma by which time close to 95% of the organic matter had been transformed. This is in good accordance with the main and late phases of oil generation. Transformation ratio reached close to 98% by Paleocene time and has since then increased slowly to 100%.

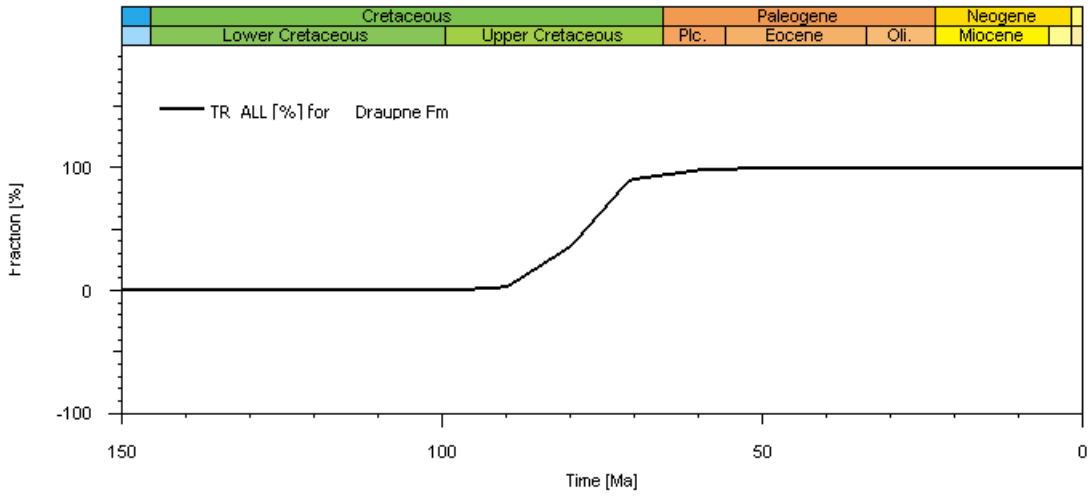


Fig.5.3.1: Plot of Transformation Ratio (TR) against time for Draupne Formation.

Transformation of organic matter in the Heather Fm began about 100 Ma (Fig.5.3.2). Over a period of 30 million years, conversion increased quickly converting about 80% of the organic matter by the end of the Cretaceous. Transformation rates increased slowly to about 98% by Paleocene time and have since Eocene time reached total conversion.

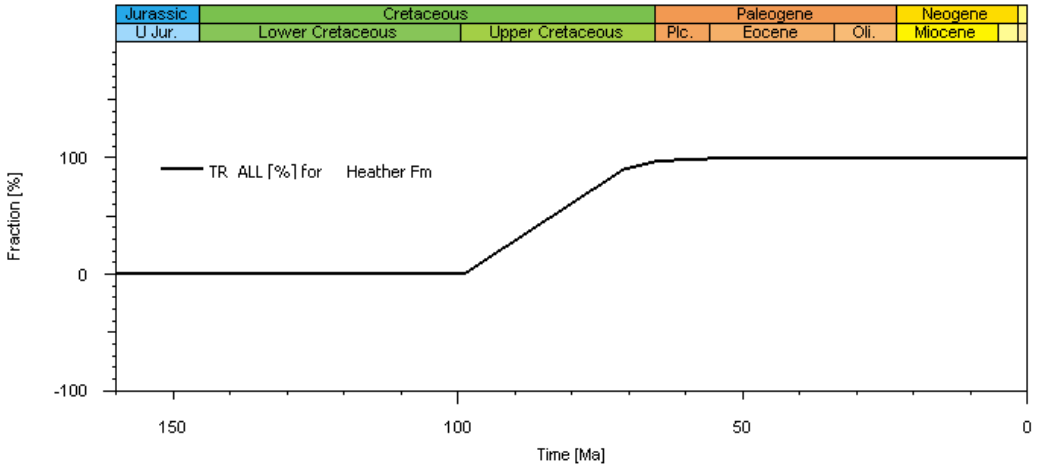


Fig.5.3.2 Plot of Transformation Ratio (TR) against time for Heather Formation.

Transformation of the coal intervals in the Ness Fm began about 115 Ma. The rate of kerogen conversion started to increase by Mid-Cretaceous time. By Eocene, close to 50% of the organic matter had been transformed and since then, transformation increased slowly to 60% by Miocene. Presently, only at 60% of the organic matter in the coals has been transformed to hydrocarbons.

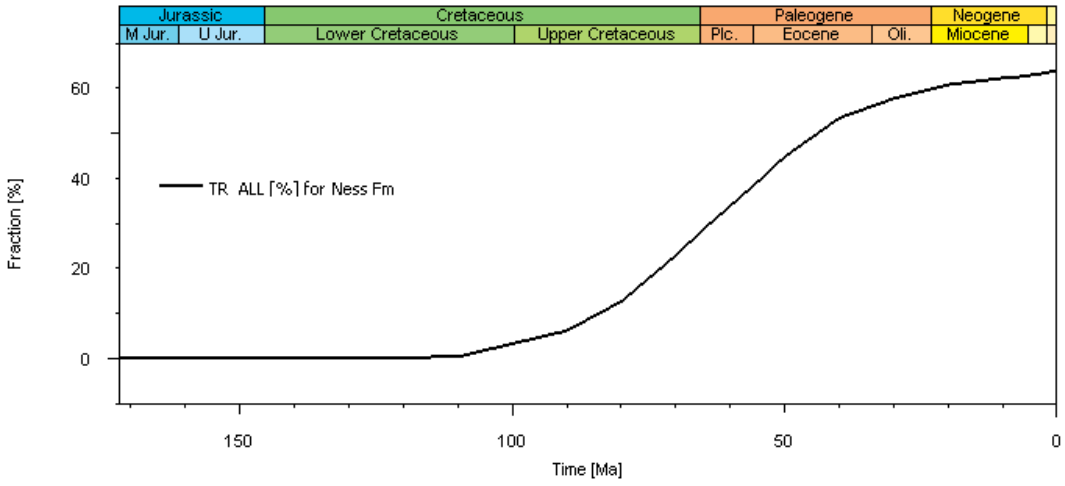


Fig.5.3.3: Plot of Transformation Ratio (TR) against time for Ness Formation coal intervals.

5.4 Migration

The results of the migration modeling, which are presented below, are based on Petromod's Hybrid migration method, which combines Flowpath and Darcy flow methods.

5.4.1 Primary migration

Figures 5.4.1- 5.4.4 show the present day distribution of migration vectors within and from the Upper Jurassic source rocks.

As shown in Fig. 5.4.1, migration of hydrocarbons in the Draupne Fm is both vertical (upwards and downwards) and lateral into the overlying Lower Cretaceous Cromer Knoll Group and underlying Heather Fm. Vertical migration however predominates. Both oil and gas are expelled from the top of the source rock and mainly gas from the base. In contrast to the Draupne, migration from the Heather Fm is almost exclusively vertically downwards into the Brent carriers (Fig.5.4.2). Both oil and gas are being expelled from the top and base of the source rock. The concentration of migration vectors in the Heather Fm in comparison with the Draupne Fm clearly shows that a greater volume of hydrocarbons is generated and expelled by the latter. Migration in the Ness Fm coals (Fig.5.4.3) is almost exclusively vertically upwards into the Brent carriers. The migration vectors indicate that the coals expel mostly gas with a little oil.

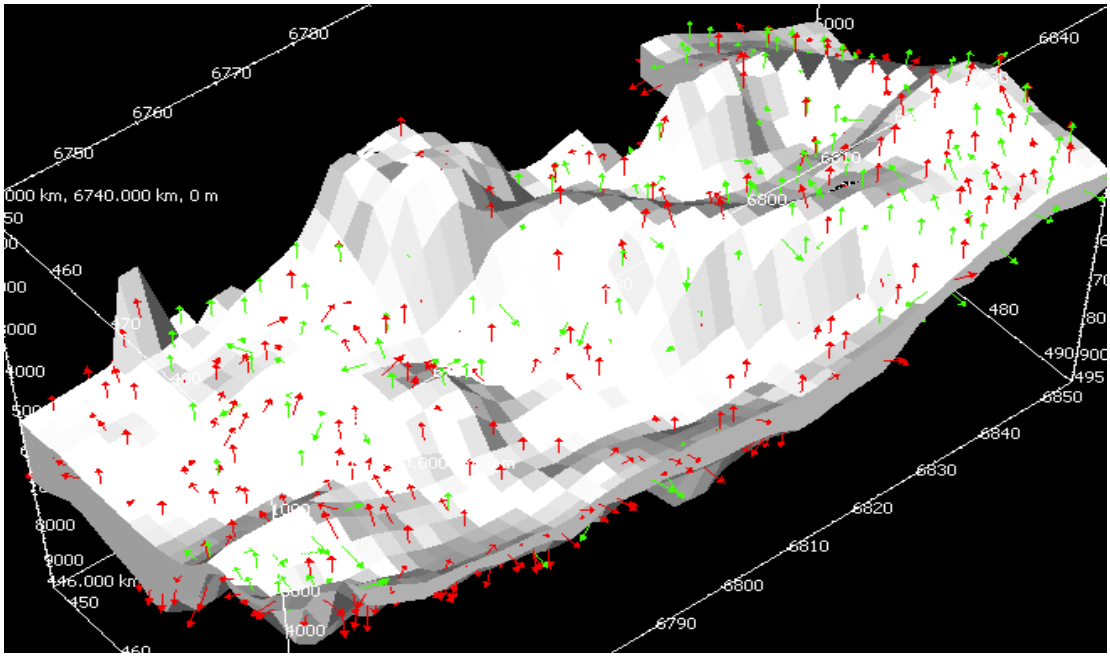


Fig. 5.4.1: Primary migration vectors in the Draupne Fm. Green and red arrows represent expelled oil and gas respectively.

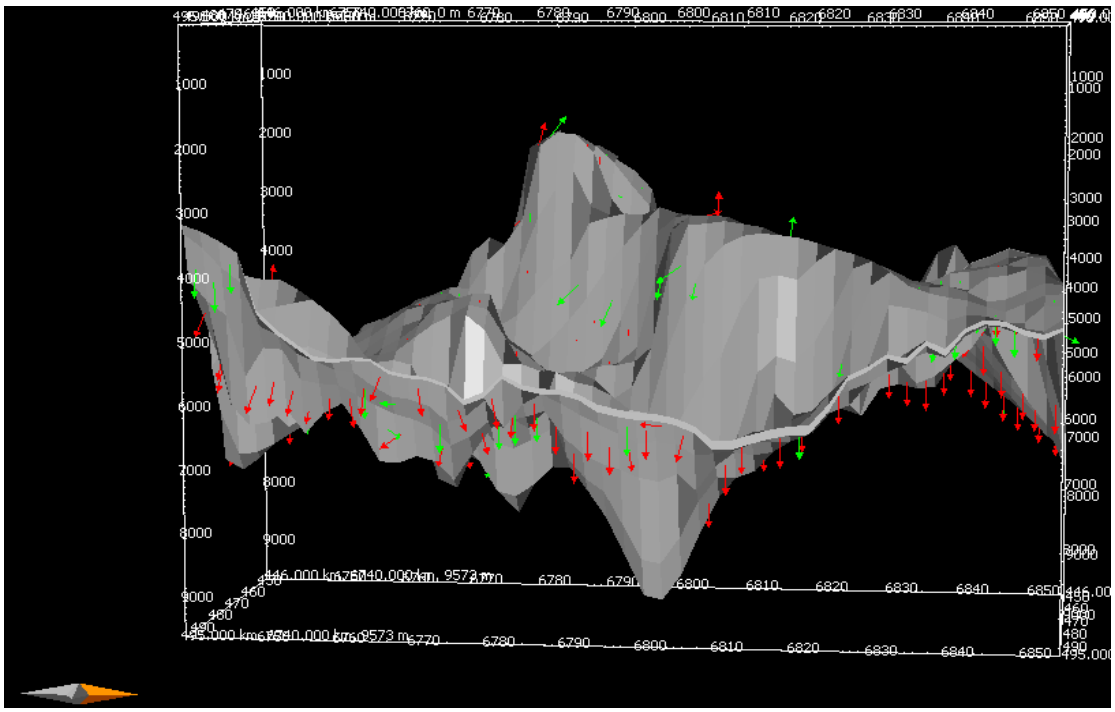


Fig. 5.4.2: Primary migration vectors in the Heather Fm. Note the dominant vertical downward migration of hydrocarbons.

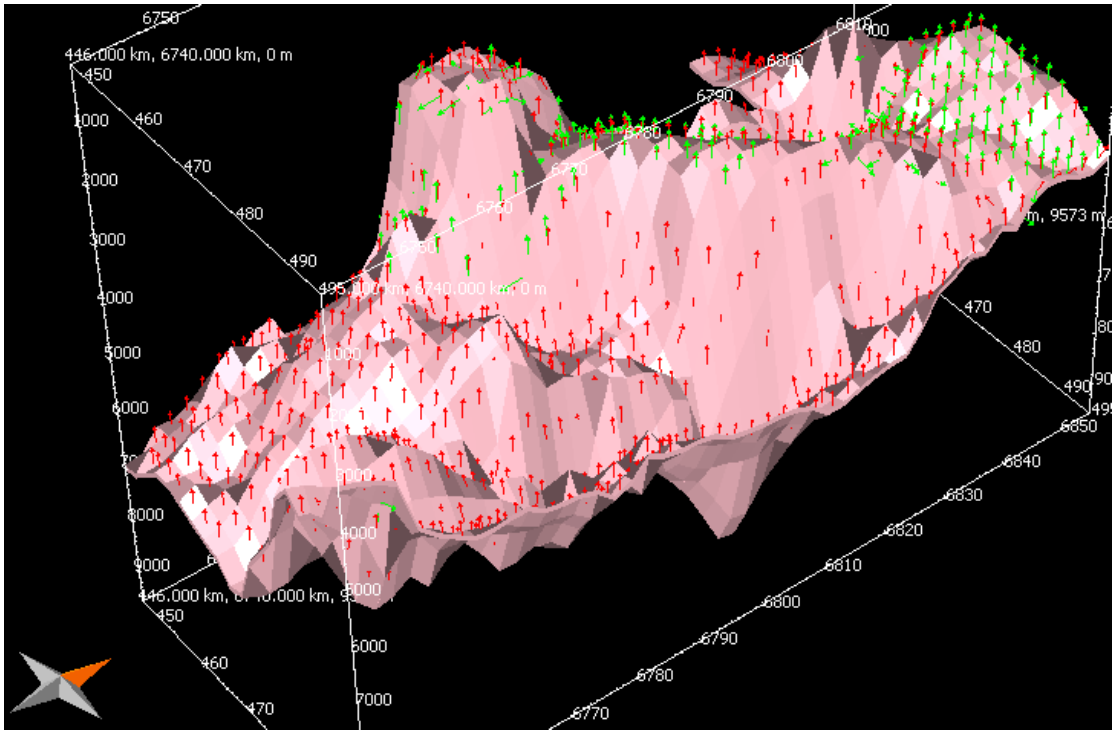
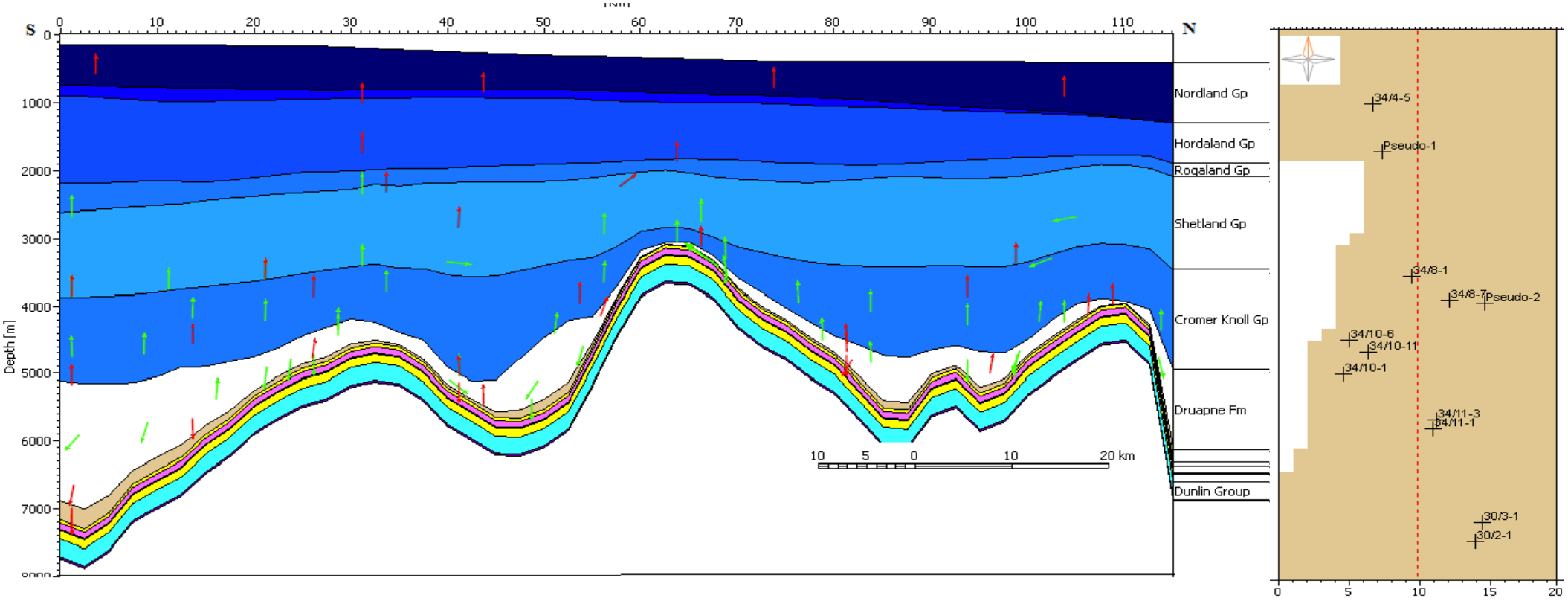


Fig. 5.4.3: Primary migration vectors in the Ness Fm coals.



(a) (b)

Fig. 5.4.4: (a) Regional 2D cross-section of the study area showing potential migration routes of hydrocarbons from the Upper Jurassic source rocks (b) Location map of the study area showing the cross-sectional line (red broken line). Distances are in kilometres and depth in metres.

5.4.1.1 Drainage Efficiency

The results of the modeling indicate that of the two Upper Jurassic source rocks, the Draupne Fm is not as well drained as the Heather. The Draupne Fm is located between the Lower Cretaceous Cromer Knoll Group and Heather Fm, which are both shales, while the Heather Fm is in direct contact with the Brent carriers. In order to reach the main carriers in the study area, which are the Brent Group sandstones, hydrocarbons expelled from the Draupne Fm have to migrate beneath the Lower Cretaceous or most likely through the Heather Fm. Figure 5.4.5 b shows hydrocarbon saturations in the Heather Fm. As shown, there is high hydrocarbon saturation in most parts of the source rocks. This is an indication that most of the hydrocarbons, which are expelled from the Draupne Fm, are unable to pass though the Heather Fm into the target Brent carriers; hence it is poorly drained in the study area. This result is in accordance with that of Moretti and Deacon (1995).

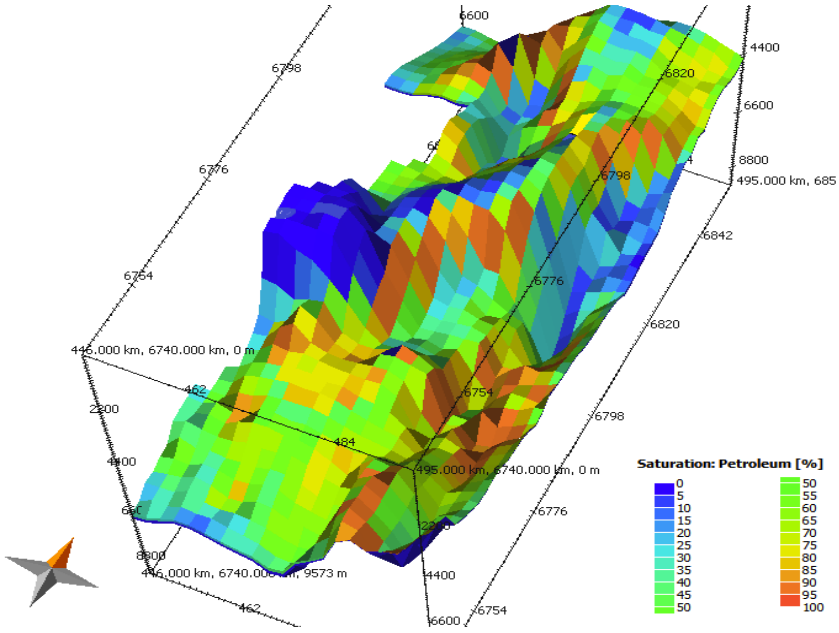


Fig.5.4.5: Top of Heather Fm showing hydrocarbon saturation distribution.

5.4.1.2 Possible Mechanisms of Migration

The results of the modeling within the study area suggest two possible mechanisms of migration of hydrocarbons from the source rocks into the carriers. These are:

- Migration directly from source rock into a permeable carrier unit and/or;
- Migration from source rock to carrier through a pressure gradient (hydrodynamics).

In most parts of the study area, the Heather and Ness Fms. are in direct contact with the Brent Group carriers. This association facilitates the movement of expelled hydrocarbons into the carriers. The Draupne Fm, in contrast, is located between two shales limiting the efficiency of primary migration. However, in some locations, such as the Visund area, the upper part of the Draupne Fm comprises a 135 m thick conglomeratic flow deposit termed the 'Intra Draupne Fm sandstone'. This direct contact is likely to enhance migration of hydrocarbons into the target Brent carriers.

Overpressures in the northern North Sea are well documented by some authors e.g. (Moretti and Deacon, 1995, Borge and Sylta, 2000). 1D extractions of 2 wells and 2 pseudo-wells clearly indicate overpressures in the Upper Jurassic source rocks and Brent carriers (Fig.5.4.6). Overpressure buildup in source rocks in believed to occur along with the transformation of solid kerogen into hydrocarbons (Sylta, 2000), while that carriers/reservoirs is largely due to sealing in faults (Borge and Sylta, 2000). Since the overpressure in the source rocks is greater than that in the carriers, due to their high permeability, a pressure gradient is established and the excess pressure pushes the expelled hydrocarbons out of the source rocks into the carriers (Sylta, 2004). Based on the results of the modeling, this mechanism possibly dominates in the study area.

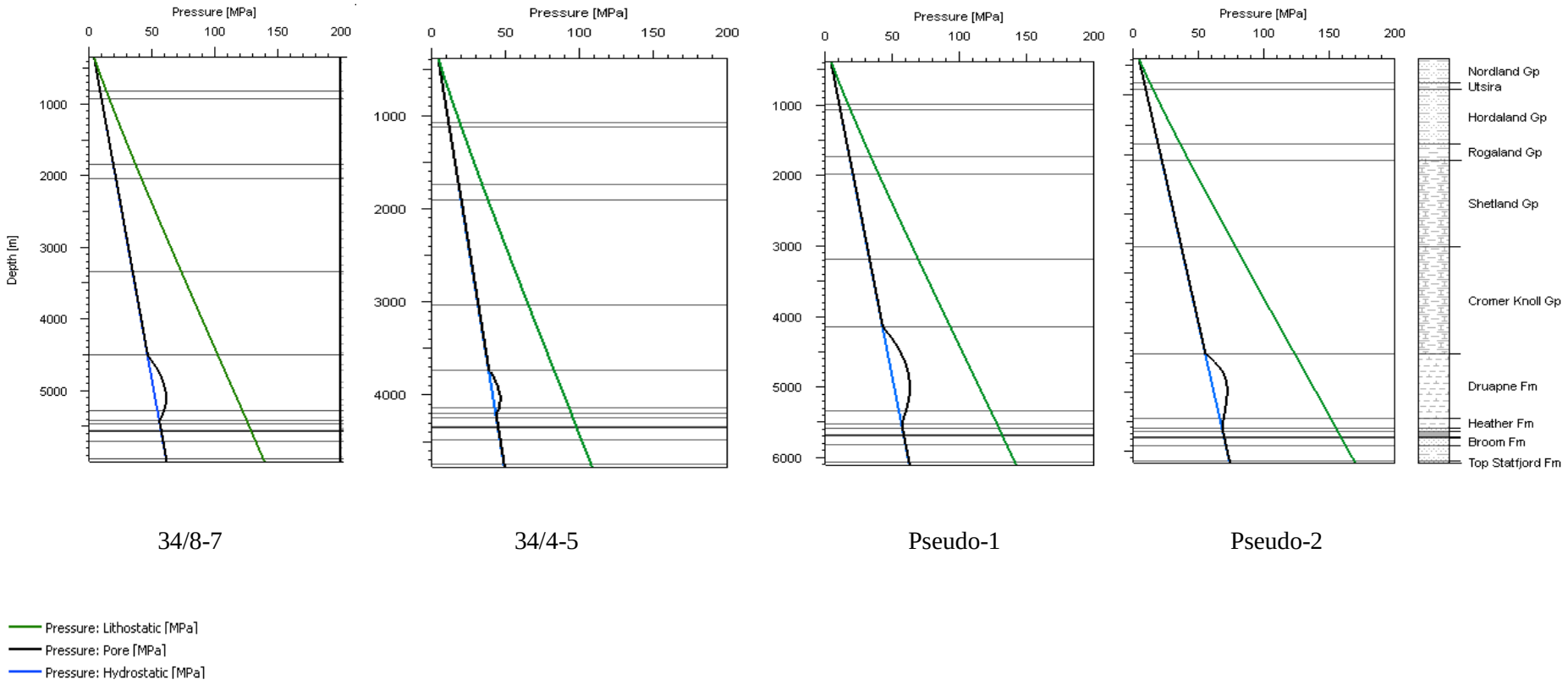


Fig.5.4.6: Depth profiles showing overpressures in Upper Jurassic source rocks and the Brent Group. Well 34/8-7 is from Visund field, 34/4-5 is from NW of the study area, Pseudo-1 from the East Shetland Basin and Pseudo-2 from the Viking Graben. See location map of the wells in Fig. 5.4.4 (b).

5.4.2 Secondary migration

Figures 5.4.7-5.6 show maps of the Top Brent carriers with modeled hydrocarbon migration pathways and accumulation for six geological time periods starting from the Late Cretaceous. Fig. 5.4.7 shows that, in most parts of the study area, hydrocarbons expelled from the source rocks migrated laterally through the carriers from the northwest and southeast into traps. Exceptions occur in areas close to the Horda Platform, such as the Huldra field, where hydrocarbons migrate from both the east and west. Both oil and gas migration and accumulation had started by 99Ma. The density of the flow paths/migration pathways indicates that more oil migrated relative to gas. Most of the hydrocarbons in this period migrated from the Viking Graben and deep parts of the East Shetland Basin.

The Ness Fm coals were mature for oil generation by 105 Ma and were likely sourcing the Brent carriers. Based on the results of the burial history curve in Fig 5.2.1 gas generation and possibly migration began in the coals from 57 Ma. This contradicts with the early migration and accumulation at 99 Ma. However, the source rock is gas prone and is naturally expected to produce mainly gas and a little oil.

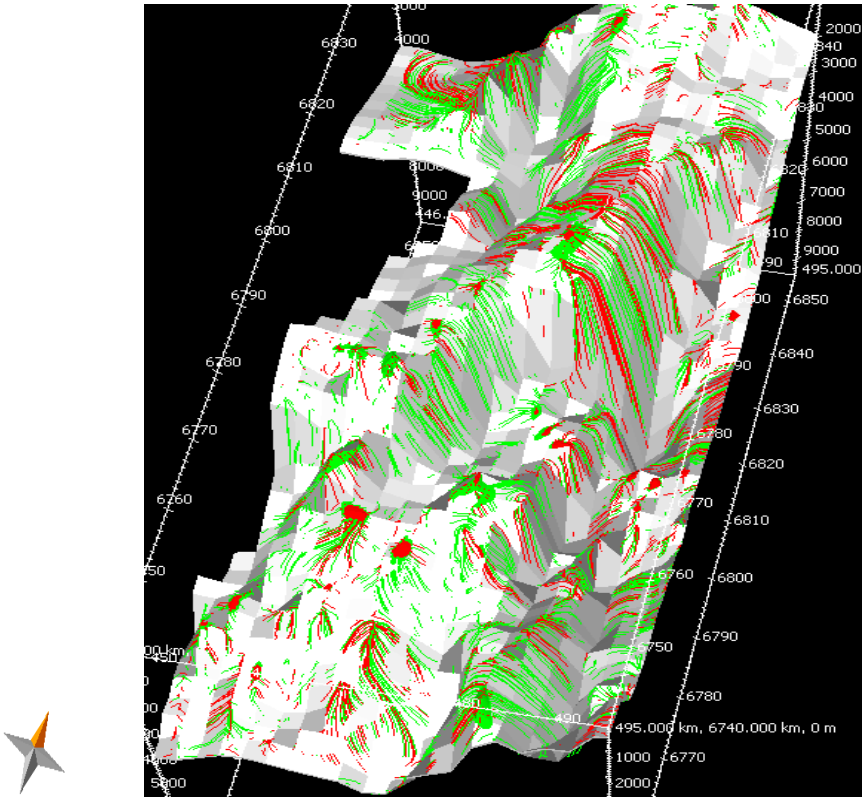


Fig 5.4.7: 3D view of Top Brent carrier at 99 Ma showing hydrocarbon migration pathways. Oil and gas migration pathways are colour coded green and red respectively. Direction of view is to the north.

Between 90 and 60 Ma, there is an increase in the density of the migration pathways and oil was accumulating in the Gullfaks, Visund, Kvitebjørn and Huldra fields. Gas caps started to form in the Huldra and Kvitebjørn fields (Fig.5.4.8 a, b). This increase in density of migration pathways of especially gas is most likely due to combined expulsions from the Brent coals as well as the oil and gas prone Draupne and Heather Fms, which had started to expel oil by 88 and 97 Ma respectively.

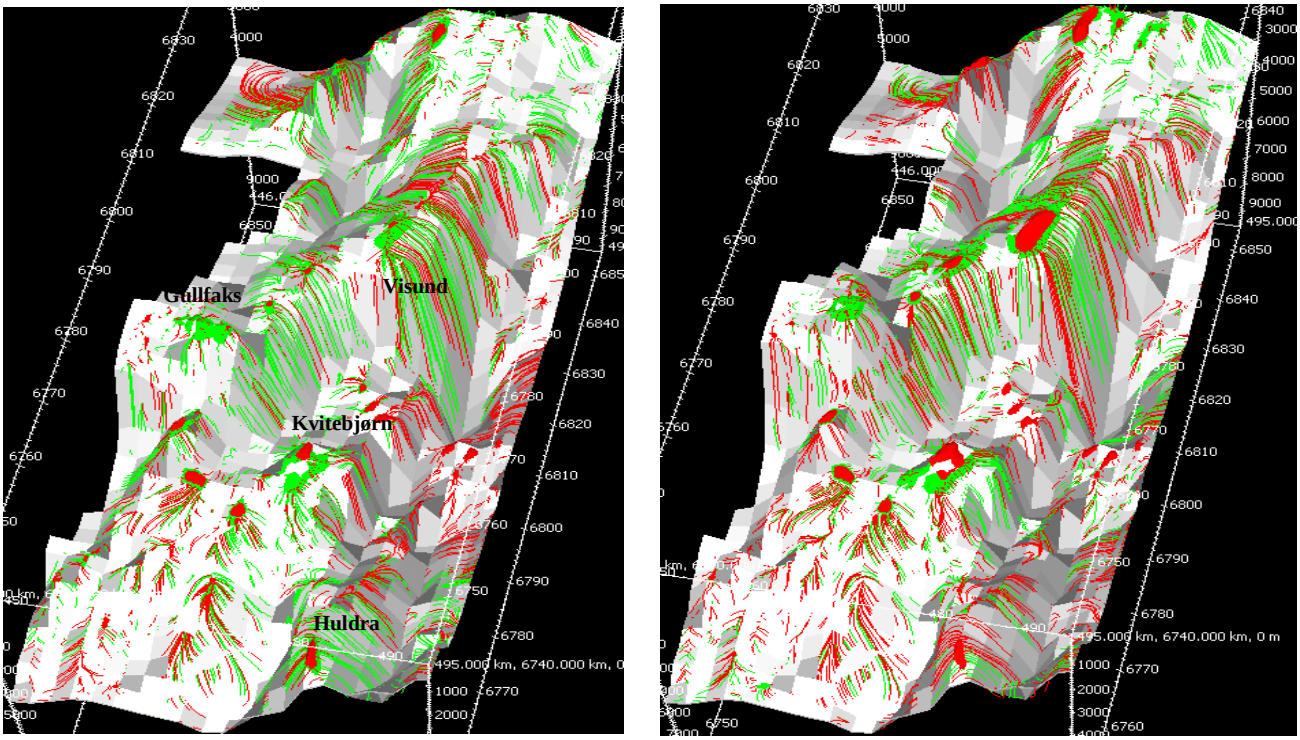
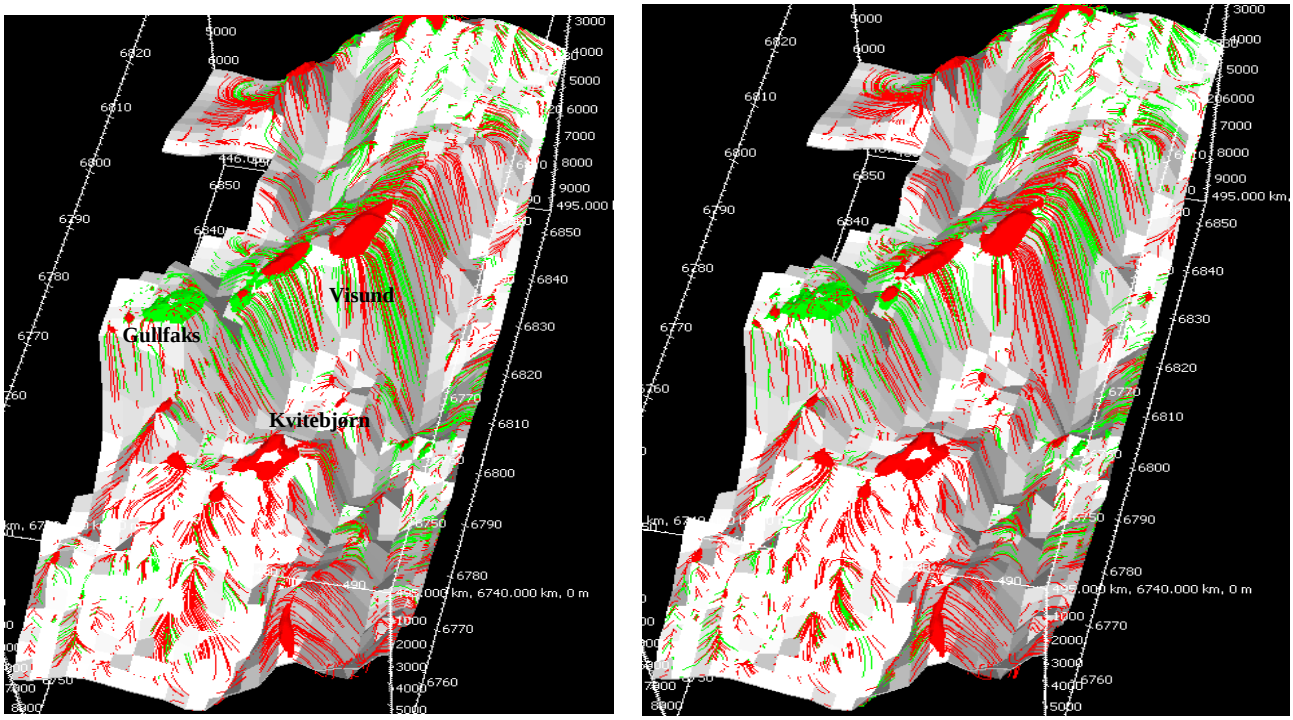


Fig 5.4.8: 3D view of Top Brent carrier showing hydrocarbon migration pathways at (a) 90 Ma and (b) 60 Ma. Note the clear gas caps in Visund, Kvitebjørn and Huldra fields at 60 Ma.

By 20 Ma, more gas was being expelled from the Ness Fm coals, Heather Fm and base of the Draupne Fm. As a consequence, there is a marked increase in the concentration of flow paths of gas as shown in Fig.5.4.9a. Only the Gullfaks field to the west of the study area still had only oil migrating into the traps. At 5 Ma, however, more gas had been expelled from the source rocks or spilled from other traps and hence gas started to migrate into the Gullfaks field (5.4.9b).



(a) (b)

Fig 5.4.9: 3D view of Top Brent carrier showing hydrocarbon migration pathways at (a) 20 Ma and (b) 5 Ma.

The migration pathways at the present day (0 Ma) are still in the same direction as when migration started in the study area, except in the Huldra field where the sealing fault, where the migration routes terminate against the fault, and seem to have been redirected to the south (Fig. 5.4.10). More gas is however migrating into traps and structural highs or culminations relative to oil due to the level of maturity of the source rocks (Fig.5.4.11a). These results are in agreement with those of Kubala et al. (2003) and Childs et al. (2002).

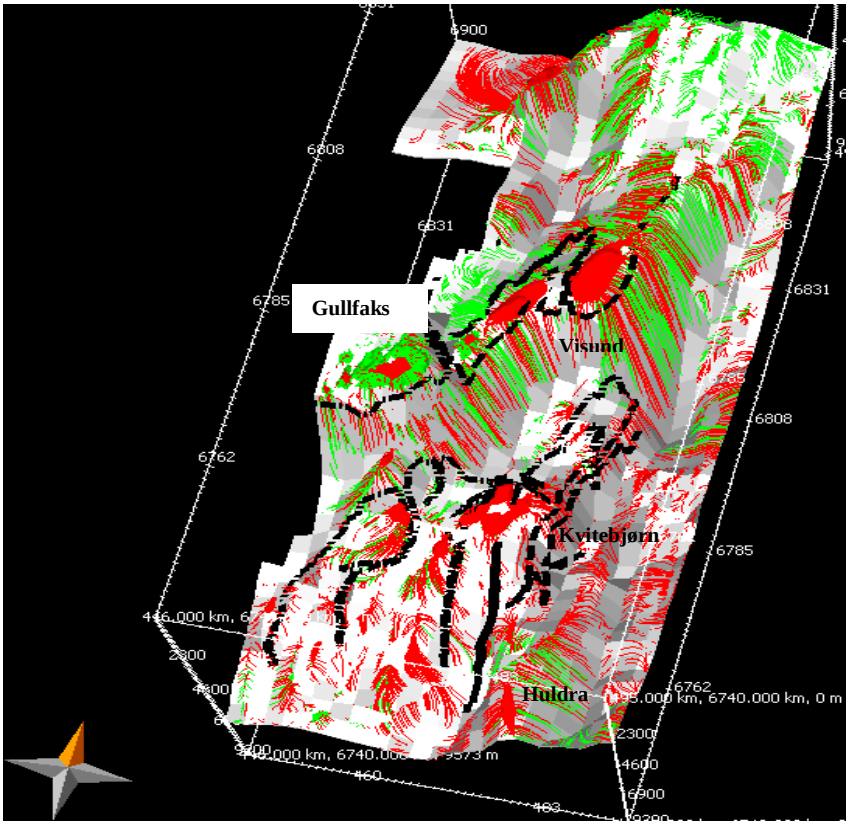
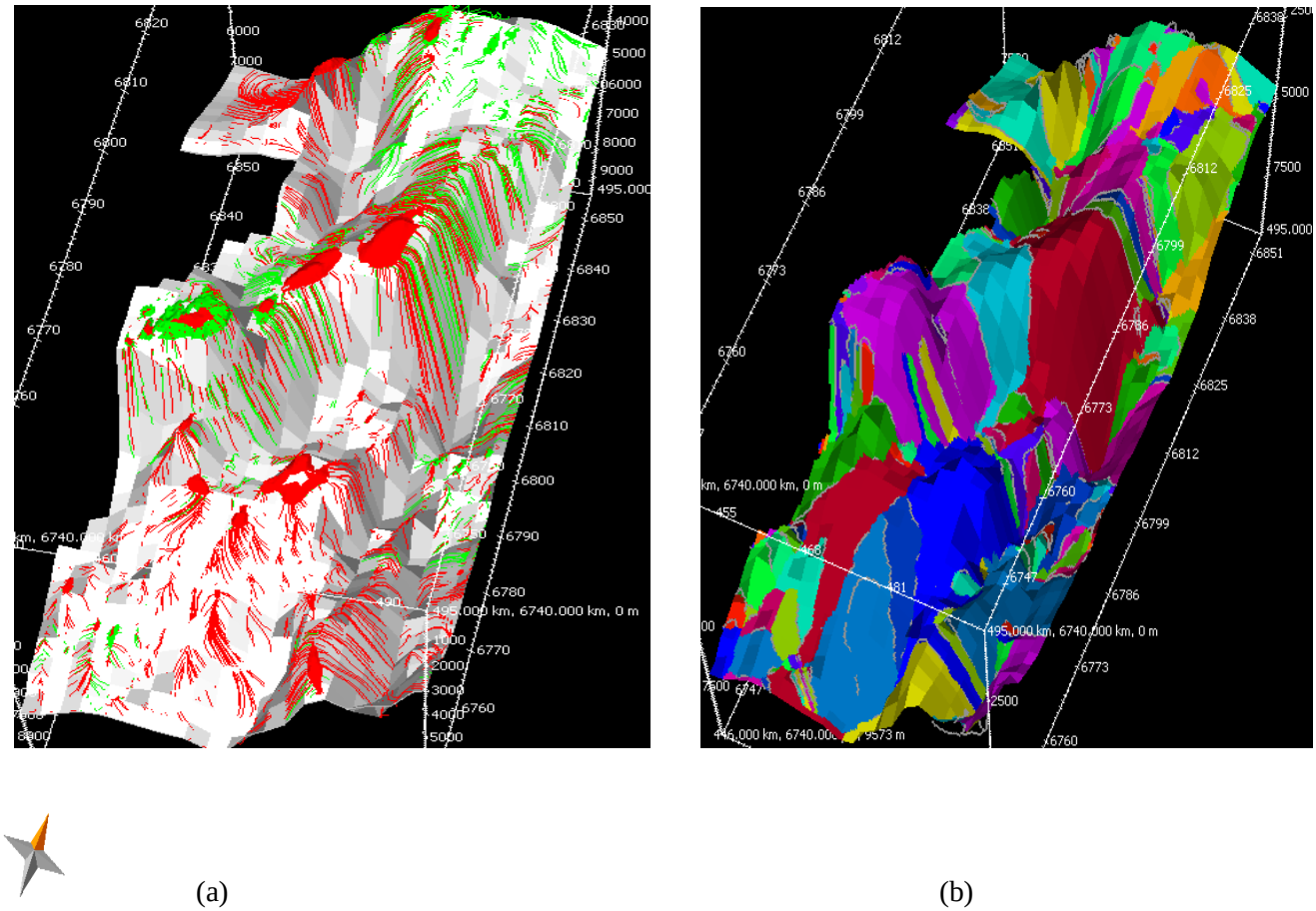


Fig. 5.4.10: Top Brent Gp showing major faults and migration routes. Solid line represents closed fault, broken lines represent partly sealing and open faults. Note abrupt termination of migration routes against closed faults near the Huldra field.

Based on the results of the modeling, four distinct accumulations have formed in the study area corresponding to the Gullfaks, Visund, and Kvitebjørn and Huldra fields. The accumulations in these fields are sourced from 165 drainage (catchment) areas (Fig.5.4.11b).



(a) (b)

Fig.5.4.11: Map of Top Brent carrier at 0 Ma showing (a) modeled migration pathways and accumulations and (b) Colour coded drainage areas. Note that colours of drainage are not associated with scale.

5.5 Accumulations

The resulting model has predicted four major accumulations two of which contain mainly gas and two contain both oil and gas. These accumulations in comparison with the accumulations map of NPD (2012) correspond to the Gullfaks, Visund, Kvitebjørn and Huldra fields. See Fig.5.5.1 for details.

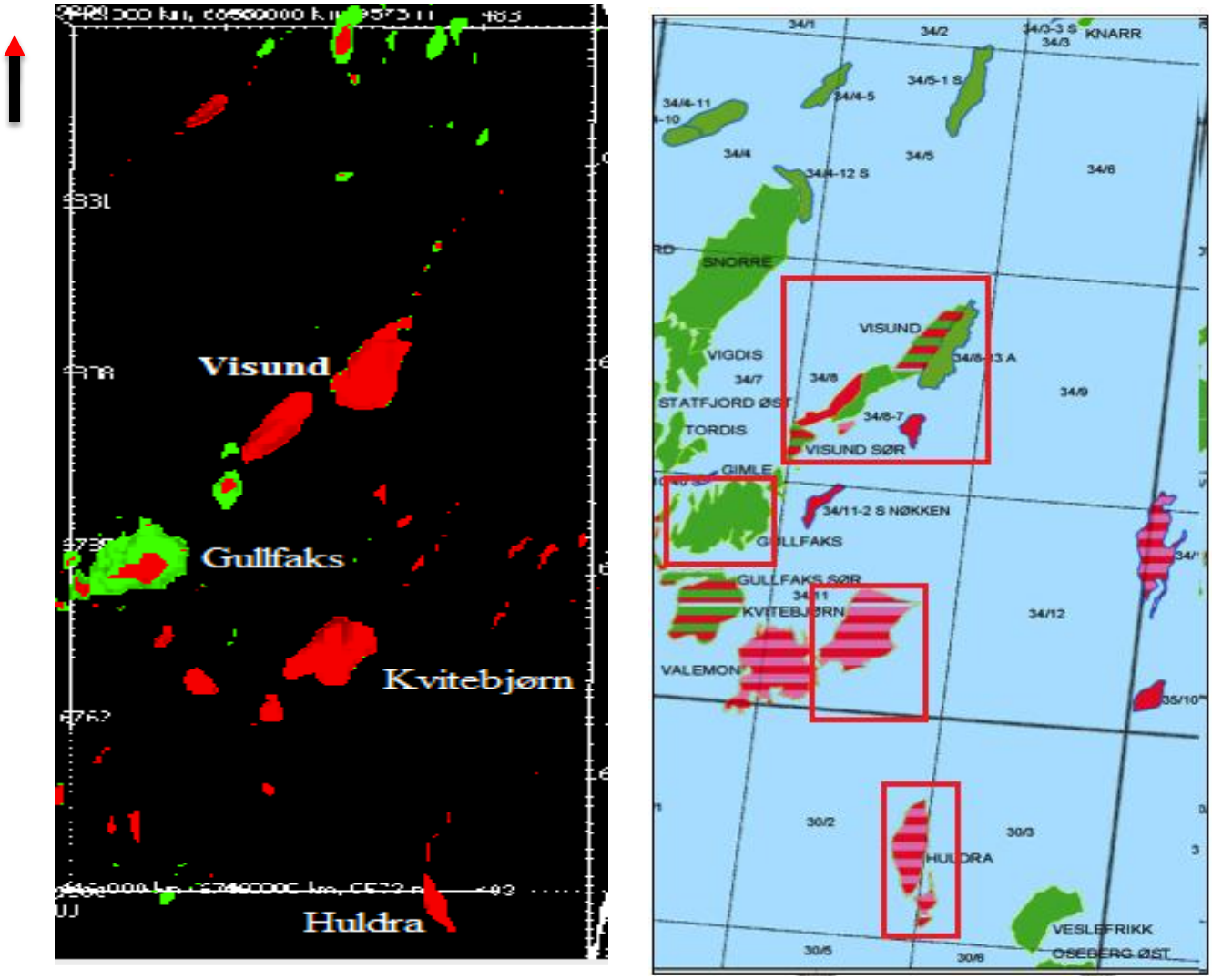


Fig. 5.5.1 (a) Map of the study area showing the major predicted accumulations (b) Map of the study area with the main fields in the northern North Sea based on NPD (2012). Oil and gas accumulations are colour coded green and red respectively.

Most of the predicted accumulations in the model are trapped mainly in the Tarbert Fm. This is likely due to three reasons:

- It is the shallowest Brent Group reservoir and is comparatively less compacted making it more likely to have better reservoir properties.
- It is in direct contact with the Heather Fm and also in better proximity to the Draupne Fm than the other reservoirs and,
- It is sealed by the Heather Fm, which lies directly above.

Figure 5.5.2 and Table 5.5.1 show the Tarbert Fm with the distribution of accumulations in the study area.

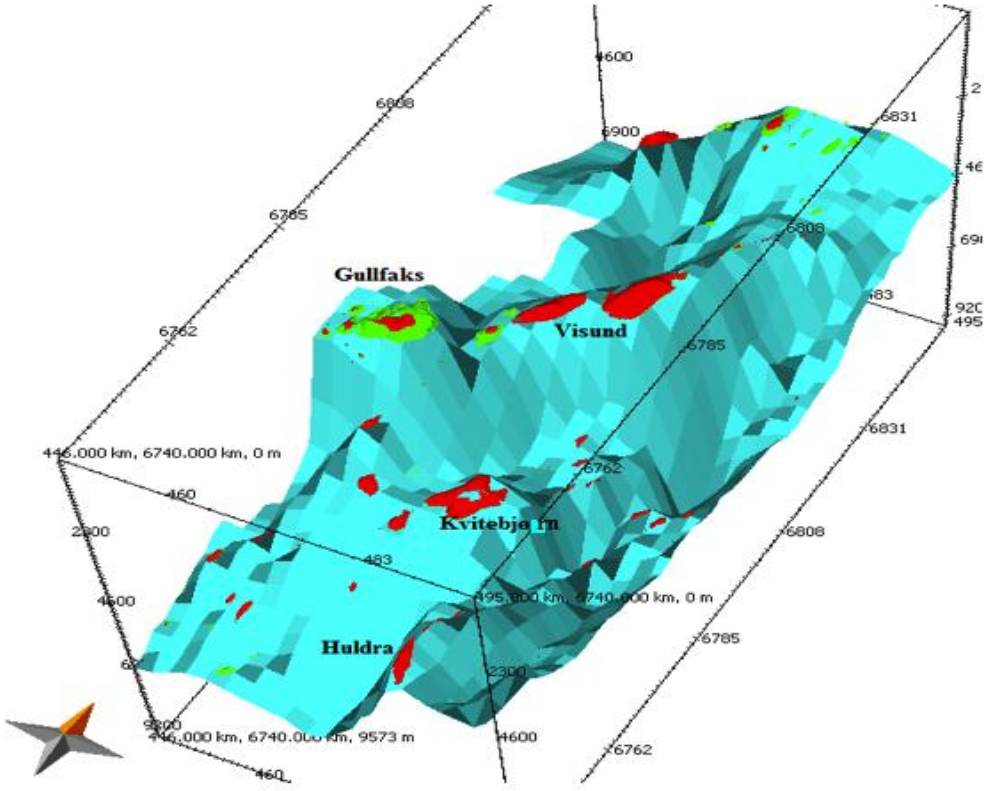


Fig. 5.5.2: 3D view of top Tarbert Fm showing the modeled accumulations and major fields.

Table 5.5.1 Comparison modeled and reference hydrocarbon volumes originally in place.

	Modeled hydrocarbon volumes		*Reference hydrocarbon volumes	
Field	Oil (MMm^3 o.e)	Gas (billion sm^3)	Oil (MMm^3 o.e)	Gas (billion sm^3)
Gullfaks	309.94	33.01	575	25
Visund	32.33	374.1	90	70
Kvitebjøn	-------	143.88	-------	90
Huldra	--------	20.96	-------	30

* Reference hydrocarbon volumes are estimates by Humso et al. (2002) in *Millennium Atlas: petroleum geology of the central and northern North Sea.* pp. 10-44

From the table, the volumes of oil in the Gullfaks and Visund fields are less than the reference values, but the volumes gas especially for the Kvitebjørn and Visund fields are significantly higher than the reference values. These differences may be due to a number of reasons:

1. The model was developed and generalized based on the stratigraphy and lithostratigraphy of well 34/8-7 in the Visund field. Variations in stratigraphy, lithotype and stratigraphic position of petroleum systems elements occur from one field to another and this to some degree affects reservoir quality and hence volumes accumulated.

2. The grids used for the model were made from regional seismic data, which is only sufficient to identify regional large-scale structures and traps. Hence smaller sub-seismic traps were not identified and mapped.
3. Due to data limitations, only the Middle Jurassic reservoirs were mapped and used in the model. However, in the Gullfaks and Visund fields, the Upper Triassic Statfjord and Lunde Fm sandstones are also reservoirs. Also the western part of the Gullfaks field is not part of the study area.
4. The source rocks kinetics and heat flow trend used are regional and average values. These may have significant local variations and could have resulted in over or underestimations or even generation of one hydrocarbon phase over another.
5. The most significant traps in the study area are dependent on rock juxtaposition in tilted fault blocks. However, one limitation of Petromod, like most other basin simulators, is its inability to treat fault juxtapositions. Hence accumulations in such traps were not modeled.

5.6 Hydrocarbon loses

Table 5.5.2 shows a summary of petroleum generation, migration and accumulation losses in the model. The results were generated in *Petroreport*, one of the modules of the Petromod software. Values assumed for liquid and vapor densities are 635.6 kg/m^3 and 1.0381 kg/m^3 respectively.

Out of 2545840 MMbbls of petroleum generated from the three source rocks, about 2009230 MMbbls representing 79% were expelled. The Draupne Fm generated 69% of the total petroleum while the Ness and Heather Fms. generated 29% and 2 % respectively.

About 5925.41 MMbbls, representing less than 1% of the expelled petroleum accumulated in reservoir while 29% was lost during migration and approximately 30% and 38% were lost through leakage and sideways outflow respectively.

Table 5.5.2 Summary of hydrocarbon losses

	Gas (MMbbls)	Oil (MMbbls)	Sum (MMbbls)
Draupne Fm	681150	1.08E+06	1.76E+06
Heather Fm	21071.3	10600.8	31672.1
Ness Formation	563065	187288	750353
Sum Generated	**1.27E+06**	**1.28E+06**	**2.55E+06**
Draupne Fm	401204	834199	1.24E+06
Heather Fm	17274.3	8382.37	25656.7
Ness Formation	562497	185669	748164
Sum Expelled	**980976**	**1.03E+06**	**2.01E+06**
Tarbert Formation	2254.8	3004.8	5259.6
Etive Fm	40.4763	155.91	196.386
Rannoch Fm	285.019	184.398	469.418
Sum Accumulated in Reservoir	**2580.3**	**3345.11**	**5925.41**
Migration Losses	302982	272077	575059
Leakage	531305	412808	944116
Sum Outflow Side	421359	338122	759480
Sum HC Losses	**978397**	**1.02E+06**	**2.00E+06**

CHAPTER 6

DISCUSSION

Based on the results of the burial and thermal history reconstruction, in combination with the structural history of the study area, three distinct phases of basin formation are recognized; the pre-rift, rift and post rift stages. The pre-rift stage corresponds to the period from early–mid Jurassic during which the basin was tectonically stable with slow subsidence and sedimentation rates. This phase is a part of the post-rift stage to the earlier Permo-Triassic rifting event. The main rifting phase based on the modeling spanned from mid-late Jurassic to early Cretaceous. Subsidence rates were higher than previously due to the widespread active faulting across the basin, which might have been enhanced by the pre-existing structural weakness caused by the Permo-Triassic event. The burial curves show that subsidence rates were here higher in the Viking Graben as compared to other areas. The thickest deposit of the Draupne Fm (about 1000 m) was also observed in the graben. This could have been due to an increase in sediment supply, accommodation space created by the numerous tilted fault blocks or a combination of both. Sediments in the basin subsided to a depth of approximately 2200 m by the end of the rifting phase. A period of uplift and erosion on structural highs closely followed the active rifting phase. This resulted in erosion of variable thicknesses of the Draupne Fm across the basin. The post- rift phase of the basin spans from the end of rifting in the early Cretaceous to the present day. This phase from the burial curve clearly indicates the average subsidence and sedimentation rates characteristic of the thermal subsidence phase. Close to 1400 m of sediments have been deposited over the past 70 million years to a present day maximum burial depth of approximately 5500 m in the graben centre.

The three source rocks defined in the study area generated hydrocarbons from the mid-Cretaceous. By this time, the threshold burial depth for kerogen maturity had been achieved in most locations. Heat flow in this period was on average 78 mW/m^2, which was high enough to further facilitate maturity and hydrocarbon generation. The depths to the oil and gas windows of the source rocks are deeper than obtained in previous works done on the study area. This is the result of the depth mismatch between formation tops in the control well, which are much shallower than the formation tops in the grids provided for the work. Since this is an error associated with the data provided and could not be corrected, it becomes unreliable to talk about the depths to the oil and gas windows.

Primary migration from the source rocks is dominantly vertical upwards and downwards. The concentration of migration vectors indicates the Draupne Fm is the main source rock for oil and gas, the Ness Fm also contributes limited oil and significant gas and the Heather Fm produces the least amount of hydrocarbons. Although the Draupne Fm generates most of the oil and gas in the study area, hydrocarbon saturations on the top of the Heather Fm are high. This indicates that hydrocarbons expelled vertically downwards from the Draupne Fm are not able to pass through the Heather Fm to the target Brent Gp reservoirs. Hence within the study area, the Draupne Fm is poorly drained as compared to the other two source rocks. This is expected since it is sealed above and below by shales.

The main possible mechanism of primary migration based on the modeling is through hydrodynamics. Well extractions show overpressures within the source and reservoir rocks. The pressure gradient established is believed to push and expel the generated petroleum out of the source rock. In locations where the source rocks are in contact

with the reservoir units, migration is likely direct from the source into the reservoir rocks.

Hydrocarbons migrate laterally through the carriers into traps from two main directions; northwest and southeast. An exception is the Huldra field, which has migration from both the east and west, possibly because it is sourced from a different kitchen further south in the Oseberg area. The direction of migration has not varied since the late Cretaceous, because the basin has not experienced any major form of tectonism since the Jurassic rifting.

The main faults surrounding the fields have a significant control on migration routes/ pathways. As expected, hydrocarbons migrate across the open and partly sealing faults surrounding the Gullfaks, Visund and Kvitebjørn fields and maintain the northwest and southwest direction of flow. In contrast, hydrocarbon migration routes terminate abruptly against the closed fault to the west of the Huldra field.

The model has predicted four major accumulations. These correspond to four of the known fields (Gullfaks, Visund, Kvitebjørn and Huldra) in the study area. Although, the locations and types of hydrocarbon phases of the fields have been reasonably correctly estimated, the volumes show only an acceptable match the known in-place reserves. The volumes of oil in Gullfaks and Visund fields have been underestimated, while the volumes of gas have been overestimated for Kvitebjørn and Visund fields. Apart from the absence of the Lower Jurassic and Triassic reservoirs in the model due to data limitation, the regional TOC and HI values used may be lower or higher locally and could have affected the type and quantity of petroleum generated.

The heat flow trend used for the modeling is considered high in comparison with other published trends for the study area. The effects of this high trend on the

modeling include an earlier maturation of organic matter and onset of petroleum generation as compared to other previous studies conducted in the study area. The high heat flows also resulted in the generation of higher volumes of gas relative to oil. These notwithstanding, this trend gave a good fit with the measured vitrinite reflectance data in most of the well locations.

A comparison of the volumes of hydrocarbons generated to the amounts expelled and ultimately trapped shows that most of the hydrocarbons expelled from the three source rocks did not reach the target Brent Gp reservoirs. This is mostly due to losses during migration and conversion, leakage from traps and sideways outflow.

CHAPTER 7

CONCLUSION

A 3D approach to basin and petroleum systems modeling in combination with geological knowledge has allowed the hydrocarbon generation and migration history of the Jurassic source rocks in the northern North Sea to be studied in space and time.

The study indicates that the Upper Jurassic Draupne and Heather Fms. and the coal intervals in the Middle Jurassic Ness Fm are mature in most locations in the study area, except the structural high in the Tampen Spur area. Hydrocarbon generation started in the mid Cretaceous and continues to present day. In the Viking Graben and deepest part of the East Shetland basin, all the three source rocks are overmature for oil generation and expel gas in the present day. In areas intermediate between the Tampen Spur high, Viking Graben and deepest part of the East Shetland Basin, the coals in the Ness Fm generate gas. The Draupne and Heather Fms. generate both oil and gas presently.

The Draupne Fm has generated most of the hydrocarbons in the study area, but is poorly drained due to its immediate contact with shales above and below.

Primary migration is mainly controlled by hydrodynamics (pressure), with expelled hydrocarbons migrating both vertically upwards and downwards into the Brent Gp reservoirs. Expelled hydrocarbons migrate laterally in the Brent reservoirs and accumulate in traps and structural culminations. Migration directions are mainly from the northwest and southeast and have not varied through geological time.

Most of the hydrocarbons generated and expelled by the source rocks do not reach the target Brent Gp reservoirs, as a result migration loses and leakage from traps.

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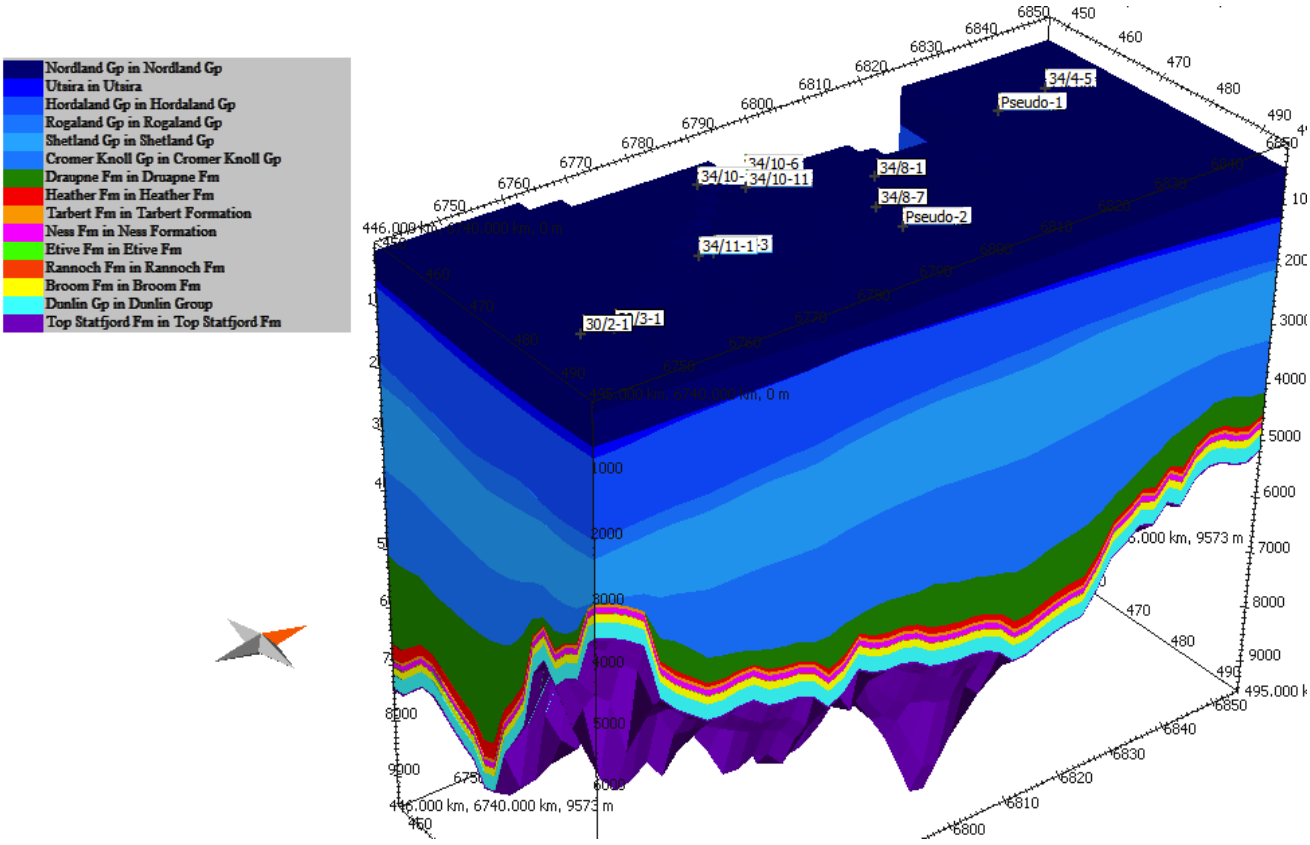
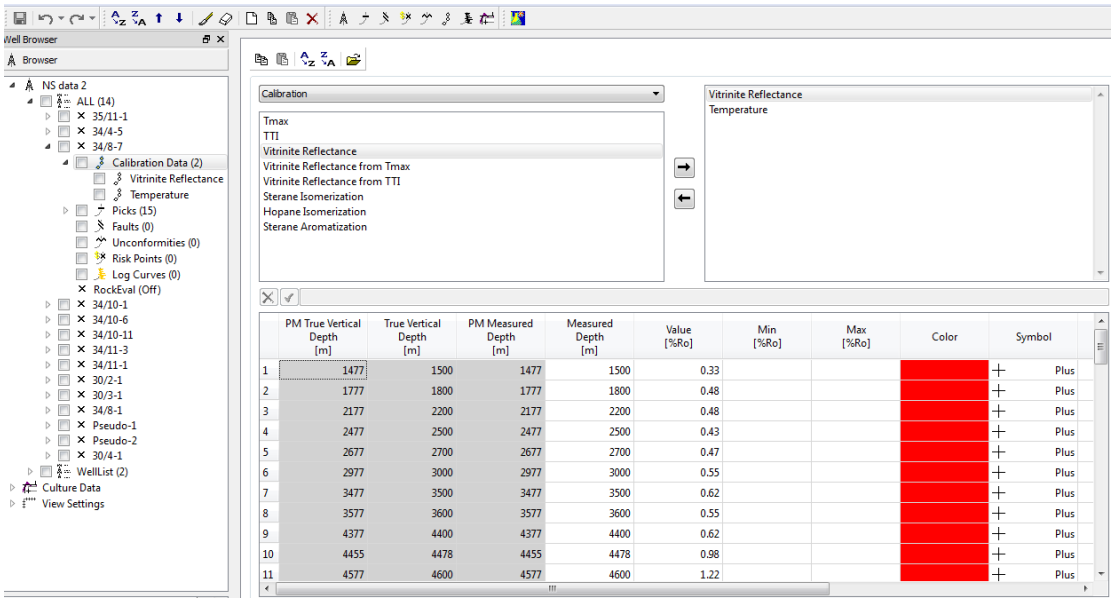
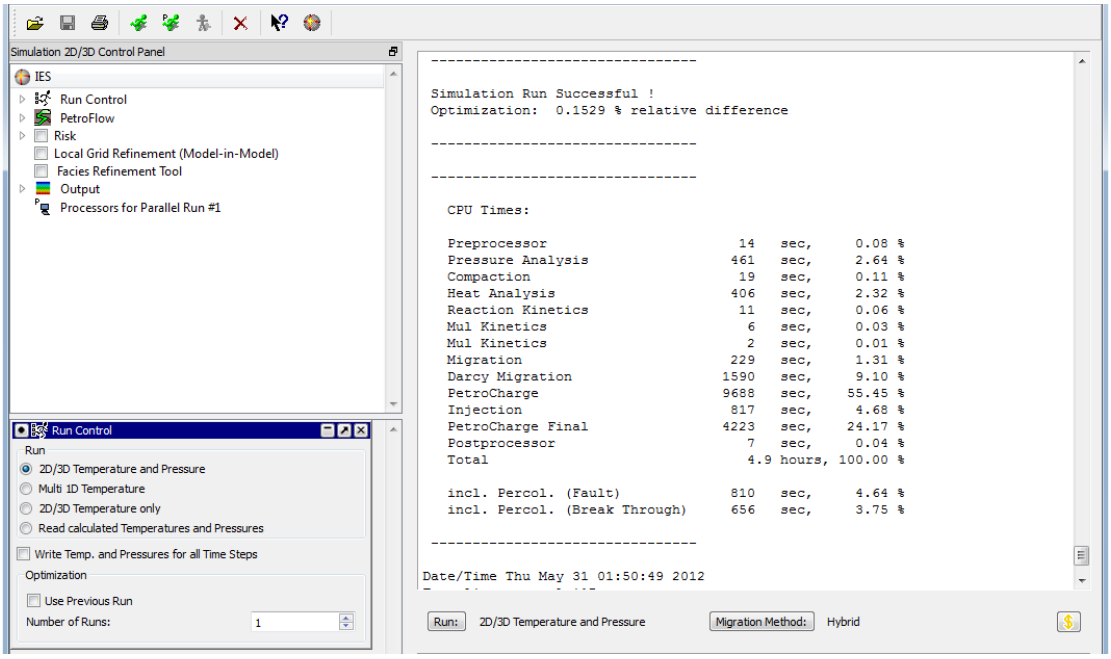
APPENDIX



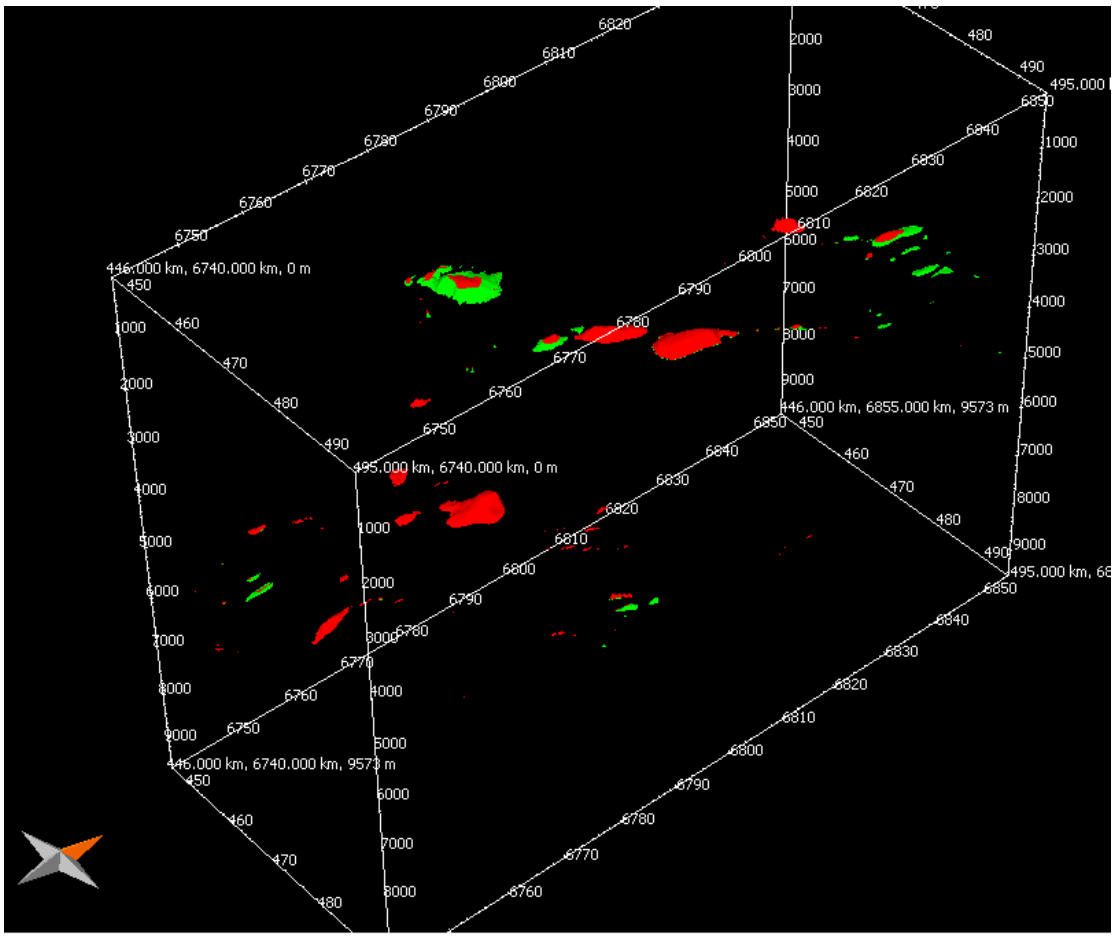
A1: Present day input model of the study area.



A2: Model calibration with measured vitrinite reflectance data.



A3: Simulation run for the model.



A4: 3D view of petroleum accumulations.