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Petroleum Migration, Filling and Biological Degradation in Mesozoic Reservoirs in the Northern North Sea

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Preface

This thesis is entitled **Petroleum Migration, Filling and Biological Degradation in Mesozoic reservoirs in the northern North Sea** and comprises a general introduction to the topic and five scientific papers. Three of the papers have been published, one is accepted for publication and is in press and the last paper has been submitted to the AAPG Bulletin.

The first paper discusses the distribution of petroleum within the Gullfaks Field, demonstrating how conventional geochemical techniques can be applied to characterise the petroleum distribution within a single field and how understanding geochemical heterogeneities in the petroleum fluids helped to build a better geological model of the development of the Gullfaks Field. Based on this work an improved filling model was proposed for the Gullfaks Field.

The second paper presents a discussion of the qualitative and quantitative aspects of the biological degradation of the hydrocarbons within the Gullfaks Field, and shows how several samples from neighbouring fields were analysed to confirm the filling model of the field. This paper also demonstrates how the quantification of biological degradation of hydrocarbons in the reservoir places constraints on acceptable models of the geological development of the Tampen Spur Area.

In the third paper, the source vs. sink problems of petroleum migration in the North Sea are discussed. It is demonstrated that, even though petroleum losses during secondary migration probably represent one of the most important factors in understanding the quantitative aspects of secondary migration, this parameter remains virtually unknown in most basins. Based on "back of an envelope" type of calculations it is shown that if the petroleum saturation in the carrier system is increased from 1 to 3 percent, the calculated losses of petroleum are so large that there would be insufficient petroleum ramaining in the system to explain the discoveries in the Tampen Spur area.

The fourth paper is a regional study of the petroleum migration within the Tampen Spur area, and based on a geochemical characterisation and mapping of petroleum populations, a regional migration model is proposed. It is also demonstrated how data from reservoir oils can be used to interpret the distribution of source rock facies within a basin and even to predict from which part of the source rock sequence the petroleum was generated and expelled.

The fifth paper is a detailed reservoir geochemical study of the giant Troll Field on the Horda Platform. A completely revised filling model has been proposed for the field, and this model has implications for the regional distribution of oil and gas in this part of the North Sea. It is

demonstrated how the petroleum distribution within the field can only be understood by reconstructing the paleoconfiguration of the field pre Neogene tilting. The geochemical mapping, combined with the geological model of the field, demonstrates how dynamic the petroleum systems in the North Sea are, and suggests that an understanding of paleostructure is an essential element in field-filling processes and active, as opposed to potential, migration pathways.

List of papers

Paper I:

Horstad, I., Larter, S.R. Dypvik, H., Aagaard, P., Bjørnvik, A.M., Johansen, P.E., and Eriksen, S.E. 1990: Degradation and maturity controls on oil field petroleum heterogeneity in the Gullfaks Field, Norwegian North Sea. *Org. Geochem.,* vol. **16,** p. 497-510.

Paper II:

Horstad, I., Larter, S. R. and Mills, N. 1992: A quantitative model of biological petroleum degradation within the Brent Group reservoir in the Gullfaks Field, Norwegian North Sea. *Org. Geochem.,* vol. **19,** p. 107-117.

Paper III:

Larter, S.R. and Horstad, I. 1992: Migration of Hydrocarbons into Brent Group. Reservoirs - some observations from the Gullfaks Field, Tampen Spur Area North Sea. In: *Geology of the Brent Group.* (edited by Morton, A. C., Haszeldine, R. S., Giles, M. R. and Brown, S.) Geological Society Special Publication No. **61**, p. 441-452.

Paper IV:

Horstad, I., Larter, S. R. and Mills, N. 1994: Migration of hydrocarbons in the Tampen Spur Area, Norwegian North Sea - a reservoir geochemical evaluation. In Press, Geological Society Special Publication.

Paper V:

Horstad, I. and Larter, S. R. 1995: Petroleum migration, alteration and re-migration within the Troll Field Norwegian North Sea. Submitted to the AAPG Bulletin.

Introduction and review of previous works

Petroleum Geochemistry is an applied, specialist section of organic geochemistry which seeks to determine where, why, when and how much petroleum has been generated and expelled from the source rocks and accumulated within reservoir rocks in a basin. A large number of different methods and approaches such as surface prospecting, source rock evaluation, maturation, generation, migration, alteration, correlation, biological markers, stable carbon isotopes and trace metals are integrated to understand the behaviour of petroleum in the subsurface. Many of the analytical procedures were adopted from coal chemistry and in the first decades (50's to mid 70's) the work was concentrated on the deposition and evolution of source rocks. It was important to understand the processes which controlled the generation of petroleum from rich source rocks within a basin. In the late 70's the focus of research was on understanding the primary migration of petroleum (expulsion) from shale sequences. In the 80's and 90's focus turned towards studying secondary migration and reservoir geochemistry which followed an evolution of computerised GC-MS and carbon isotope instruments allowing a much more detailed characterisation of the petroleum.

The importance of understanding the processes involved in secondary migration of petroleum has been realised for several decades (Tissot and Welte, 1984; Hunt, 1979; Berg, 1975; Schowalter, 1978; Gussow, 1954), but it was not until the late eighties that the petroleum geochemical aspects of secondary migration processes were studied in depth. It has been known for a long time that petroleum reservoirs often contain heterogeneous fluids (Sage and Lacey, 1939; Hirchberg, 1984), but the review paper by England *et al.* (1987) was the first paper that combined the physical, geological and the geochemical aspects of petroleum migration into a series of comprehensive geological models. The paper by England *et al,* (1987) is a good summary of our current understanding of the processes involved in secondary migration and accumulation of petroleum in reservoirs, and provides a good description of the physical framework in which secondary migration takes place. However, at that stage the number of detailed reservoir geochemical papers was limited and the need for new geochemical data to support the general conceptual models was addressed.

Traditionally an oil accumulation used to be characterised by a few production tests (DST, FIT, FMT, RFT or BHS) and the amount of geochemical information that could be generated from the cored section of an oil reservoir was to a large extent neglected. This was partly due to the relatively high cost of screening analyses and detailed geochemical characterisation of reservoir core extracts and partly due to a lack of focus on the potential and importance of the geochemical characterisation of the reservoir interval.

Since most exploration wells are drilled on the shallow flanks of basins, information on source rock and migration pathways in the kitchens is not usually available. The reservoir core extracts and the tested oil samples therefore represent the most valuable samples in a basin, since they can provide the only data giving direct information about conditions in the mature part of the basin from which they have migrated. Thus, if we can understand the processes involved in petroleum expulsion and secondary migration by analysing the accumulated fluids at shallow depth, this can be applied to provide information from the deep part of the basin. Potentially a detailed characterisation of the reservoir core extract could provide information on filling directions, estimated maturity of the source rock at the time of petroleum expulsion and mixing processes within the reservoir. Reservoir geochemical data therefore represents crucial information which is important when constructing geological models in an area.

Although studies in reservoir geochemistry typically apply conventional geochemical methods, the development of new instruments that have reduced the time and cost of geochemical analyses has been important to the development of reservoir geochemistry as a separate discipline. A procedure to apply the Iatroscan (TLC-FID) instrument as a rapid screening tool for reservoir core extracts was developed by Karlsen and Larter (1991). This technique provide an absolute and a relative distribution of bulk petroleum fractions in rock samples, and the speed of the technique allows a sub-metre scale screening of reservoir cores. This made it possible to quickly characterise the whole reservoir section and select samples for detailed GC-FID, GC-MS biological marker and stable carbon isotope analyses of the petroleum fractions.

The use of biological markers or geochemical fossils to give a detailed characterisation of the maturity and source rock facies of petroleum extracts from source rocks and reservoir rocks is now routinely applied in most oil-oil or oil-source rock studies (Seifert and Moldowan, 1978, 1979, 1981; Mackenzie, 1984; Moldowan *et al.* 1992; Mello *et al.*, 1988). The development of capillary columns, computerised bench top GC-MS instruments and automated on-column injection during the last five to ten years has improved the quality of data, and the amount of data that can be acquired in a single study has increased dramatically. Even though the steroids and hopanoids still represent the most common biological markers applied in reservoir studies (Mackencie 1984; Moldowan *et al.*, 1992), the application of new biological marker compounds in organic geochemistry and petroleum geochemistry is increasing rapidly. The stable carbon isotope signatures of petroleum fractions and gases have also been applied in oil-oil and oil-source rock correlations (Schoell, 1984; Stahl, 1977)

and the GC-IRMS and GHM-IRMS (Bjorøy *et al.*, 1990) allow a detailed correlation based on the carbon isotope signature of individual compounds in the petroleum.

The composition of petroleums accumulated in a reservoir is controlled by many processes and since several of these processes potentially act simultaneously on a volume of petroleum, it is often difficult to determine the petroleum accumulation history of an area. In addition to large variations in the amount and composition of petroleum extracted from a rich source rock on a millimetre scale (Tissot and Welte, 1984; Triboviallard *et al.*, 1994) and differences in the expulsion efficiency of individual compounds during primary migration from the source rock (Leythaeuser *et al.*, 1987; Leythaeuser and Poelchau, 1991), the pressure and temperature regime along the migration pathway might affect the composition of migrating petroleum (Thompson, 1987; 1988; Thompson *et al.*, 1990; Larter and Mills, 1991).

It has also been documented that the bulk composition of the petroleum might change during secondary migration due to chromatographic effects and fluid-rock inter-reactions (Silverman, 1965; Carlson and Chamberlain, 1986; Krooss *et al.*, 1991). Although described in qualitative terms, it has been difficult to document the significance of geochromatographic effects during secondary migration in a quantitative manner. However, the inter-reactions between the rock surfaces, migrating petroleum and water is a subject of continuos research.

The composition of the accumulated petroleum is also dependent on the maturity of the source rock at the time of expulsion, and in a continuously subsiding basin the expelled petroleum will have an increasing maturity as a function of time. If the general drainage configuration of the basin remains relatively stable, a single accumulation might receive a complete suite of early to late mature petroleum as described by Cornford *et al.* (1986). Thus, if an oil accumulation is filled in a systematic manner and in-reservoir mixing processes (diffusion and density driven overturning) failed to homogenise the petroleum within the field, it should be possible to detect gradients in the composition in the petroleum within a single reservoir (England *et al.*, 1987). The length squared to time relationship in the diffusion equation suggest that the petroleum accumulated in homogeneous sandstone reservoirs should be vertically homogenised within a few hundred thousand years while lateral heterogeneities could persist for several million years. Since the most mature petroleum will be located near the filling point of the field, mapping of gradients in the maturity of the petroleum might reveal field filling directions. However, decimetre scale heterogeneities have been discovered in clean, high quality, non-cemented reservoir sandstones within several fields, and it is difficult to

explain such differences if reservoir diffusion is as efficient as indicated by England *et al.* (1987). Such differences could be explained by local co-sourcing, a very recent filling, or by fluid-rock inter-reactions prohibiting free diffusion of individual compounds.

Potentially, as discussed by Wilhelms and Larter, (1994a, 1994b) filling points or key holes might be detected by mapping of single or stacked tar-mat zones within the reservoir. They suggested that the stacked tar-mats or polar enriched zones within the Ula Field (Karlsen and Larter, 1991) and the Oseberg Field (Dahl and Speers, 1985) might have been produced by precipitation of asphaltenes in the high permeability zones close to the filling points of the fields. However, tar-mats are not common in most North Sea oil and gas fields and their presence is probably controlled by the initial composition of the petroleum, filling processes and PVT properties of the migrating fluids.

In-reservoir alteration by water washing, biological degradation, gas deasphalting and in-reservoir cracking (Miller *et al.*, 1977; Connan, 1984) may change the composition of the accumulated petroleums within the reservoir. In-reservoir alteration of petroleum is a common phenomena even within the North Sea where several major accumulations have been biodegraded (e.g. Troll, Frigg, Gullfaks, Balder, Heidrun and many of the shallow Tertiary discoveries in the UK sector). These processes result in dramatic changes both in the chemical and physical properties of the petroleum, and it is important to differentiate between in-reservoir changes and changes that occur during secondary migration. Generally, water washing and biological degradation will take place in shallow reservoirs while gas deasphalting and in-reservoir cracking will take place in deep and hot reservoirs.

Thus, heterogeneous petroleum accumulations might be controlled by a number of processes and the variations in the fluid properties across an accumulation might be used to: 1) infer facies changes of source rocks, 2) evaluate differences in the maturity of the petroleum which might help locating filling points and filling directions, 3) identify potential reservoir barriers, 4) guide well perforation and test evaluation of production and exploration wells, 5) help locating production wells and 6) detect leaking production strings. In a recent North Sea appraisal well, reservoir geochemistry was applied to decide whether the well should be production tested or not.

As discussed above, core extracts and tested oil samples might represent a mixture of several different fluids that migrated into the reservoir at different stages. Recently, fluid inclusions have been used to predict the history of reservoir fluid content vs. time for several reservoirs. Potentially, fluid inclusions trapped at different stages of filling and at different pressures and temperatures,

might provide a detailed resolution of the reservoir fluids at any stage (Nedkvitne *et al.,* 1993; Karlsen *et al.,* 1993). Obviously fluid inclusions represent a powerful tool, however the quantitative importance of fluid inclusions remains to be understood. Often the fluid inclusions contain immature petroleums (less mature than encountered in any reservoirs in the North Sea) and have a very polar composition. It is crucial for the interpretation and application of this technique in petroleum exploration, that the fluid inclusion trapping mechanisms are understood and to determine to what extent the reservoir was filled (petroleum saturation and column height) at the time of fluid inclusion entrapment.

Recent work in reservoir geochemistry has focused on polar nitrogen and oxygen compounds, which interact more strongly with the water and mineral phases than the hydrocarbon fractions in the petroleum (Stoddart *et al.,* 1994). These compounds seems to have a major control on the PVT properties and fluid dynamic properties of the reservoir fluids and are important in understanding reservoir filling processes (migration) and in helping to tune reservoir production.

The source rock distribution and reservoir distribution within the northern North Sea has been discussed in several papers, and the petroleum systems in the area are well documented (Barnard and Cooper, 1981; Thomas *et al.*, 1985; Field, 1985; Dahl and Speers, 1985; Huc *et al.,* 1985; Karlsson, 1986; Chung, 1992) and several basin modelling studies have been performed (Moretti *et al.,* 1993; Duppenbecker and Dodd, 1993). The structural location of the Tampen Spur area suggests that several source rock kitchens are viable and that multiple migration pathways are likely into several structures in the area. Thus, even a good understanding of the structural configuration and sand distribution and detailed basin modelling studies can only provide a set of <u>possible</u> migration routes and cannot indicate the <u>most likely</u> and <u>active</u> migration routes. Thomas *et al.* (1985), proposed a fill-spill route through the Alwyn Field to North Alwyn, to the Brent Field and further into the Statfjord, Snorre and Gullfaks fields. This model was based on the principles of Gussow (1954), with an increasing GOR and a shallowing of the oil-water contact along the migration route, but was not founded on sufficient reservoir geochemical data.

Objectives

Studies on the generation, migration and accumulation of petroleum in a basin often lack a detailed study and characterisation of the oils and gases previously discovered in the area. Typically only a few source rock analyses are included in order to provide source rock richness, correlation and kinetics data (Schou *et al.*, 1985) and usually only a few oils are analysed. The major objective of this thesis is to demonstrate the importance and utility of a detailed characterisation and correlation of reservoired petroleums in the construction of geological models for petroleum exploration. The integration with other geological disciplines, i.e. seismic mapping, sedimentology, palaeontology and structural geology was considered essential in order to build a model founded on observed data that is consistent with geological and geochemical observations.

Is it possible to determine the petroleum filling history of an area based on the mapping of petroleum populations?

It was important to test this in an area where multiple source kitchens could have expelled petroleum and where the availability of geological samples and information was good. The northern North Sea was considered an ideal area, with several large oil fields and smaller sub-structures, in addition the presence of low GOR, undersaturated, oils in most of the structures eliminates the problems related to in-reservoir cracking of oil.

To test the fill-spill hypothesis proposed for the Tampen Spur Area by Thomas *et al.*, (1985) based on a detailed characterisation of the chemical composition of the petroleum in the area. The accumulated oils can be grouped into genetic oil populations and oil population maps will be used to understand the migration and fill-spill relationships between the different fields in the area.

Test the proposed filling history of the Troll Field and whether the current oil leg in the field was produced as a result of a retrograde condensation from a gas phase (Gray, 1987; Burrus *et al.*, 1991; Larter 1990).

The biological degradation of petroleum within the North Sea has not been discussed in detail in the literature and it is difficult to give a reasonable geological model which adequately explain the degradation of several North Sea oil fields. A second objective of this thesis has been to understand the quantitative aspects of biological degradation within the Gullfaks Field and Troll Field.

Results

The first paper is a detailed characterisation of the petroleum composition and distribution within the Brent Group, Cook Formation and Statfjord Formation within the Gullfaks Field. Based on the vertical screening and detailed biological marker analysis of selected samples it is concluded that the petroleum column within the field is vertically homogeneous but laterally heterogeneous, as would be expected if it has been filled in a sequential and systematic manner (England *et al.*, 1987), i.e. the most mature and latest petroleum being located at the fill point of the structure. The lateral heterogeneities are most pronounced in the extent of post emplacement biological degradation of the petroleum, increasing dramatically westward within the Brent Group.

Based on biological marker analyses, the oil within the Gullfaks Field was discriminated into two major oil populations, one within the Brent Group in the western part of the field and one within the Cook Formation and the Statfjord Formation in the eastern part of the field. Within each of these two major oil populations, small but statistically significant differences in petroleum maturity were observed in a systematic manner across the field. The trends of increasing maturity towards the west or north-west in the Brent Group and east or north-east in the Cook and Statfjord formations were interpreted to reflect the filling of the field from two different directions. This filling model was later supported by geochemical data from neighbouring fields.

It is also demonstrated that in-reservoir convection of petroleum fluids is less likely to occur in the North Sea, as has been demonstrated for North Sea water bearing systems (Bjørlykke *et al.*, 1988). The vertical homogeneity is most likely a result of effective vertical diffusion of petroleum components in this high quality sandstone reservoir, perhaps aided by density driven overturning due to gas production at the oil-water contact during biological degradation. The vertically homogeneous oil composition within the Brent Group in the Gullfaks Field suggests a relatively high vertical permeability within the reservoir. The Gullfaks Field is the only major field on the Tampen Spur that has suffered biological degradation, and even though the Gullfaks Field represents the shallowest structure on the Tampen Spur with a reservoir temperature within the range where bacteria are active, it is difficult to understand how this degradation could take place with our current understanding of the geological development of the Tampen Spur area.

The quantitative aspects of subsurface biological degradation of petroleum are discussed in the second paper. Calculations of the mass balance of petroleum degradation suggest that even the lowest estimate of nutrients and oxygen or sulphate necessary to degrade the petroleum requires an efficient

flux of water below the oil column in the reservoir. Sulphate reducing bacteria as degrading agent were excluded on the basis of available sulphate in the area (no evaporites) and lack of hydrogen sulfide or significant volumes of pyrite in the reservoir. Our most likely degradation model requires a significant charge of oxygen rich meteoric water into the reservoir after oil emplacement and this places restrictions on the geological models in the area. The Cretaceous and Tertiary evolution in the northern North Sea has recently received renewed interest and the new geological models should allow post oil emplacement circulation of meteoric water into the reservoirs containing biodegraded petroleum.

Recent publications on subsurface degradation of petroleum compounds have suggested that Fe^{3+} may represent an oxidising agent, and that this reaction might be thermodynamically favourable in the presence of organic oxygen ligands (e.g. phenols, carboxylate ions, NTA or EDTA) (Lovley *et al.*, 1994; Luther *et al.*, 1992). It is premature to conclude on the efficiency of these reactions and the quantitative aspects have to be further evaluated, however this might represent a crucial link to the understanding of subsurface degradation of petroleum.

The loss of petroleum during secondary migration from the source basin to the reservoir has been discussed by several authors, but the quantitative aspects of these losses have not been discussed in detail. In the third paper we have made rough calculations of the volumes available for migration and the proven volumes of petroleum within the Brent Group system in the northern North Sea. Such calculations will always be rough and prone to large uncertainties, however our estimates suggest that if the oil saturation within the carrier system is increased by a few percent, the total volume of generated petroleum would be lost in the carrier system before reaching the reservoirs.

It is therefore important to have a detailed knowledge of the petroleum migration pathways to estimate the proportion of the potential carrier system that has a high petroleum saturation and to determine the relative timing of oil and gas migration. A detailed characterisation of the geochemical composition of the accumulated oils within the Tampen Spur area has allowed a discrimination of the oils into several petroleum populations, genetically linked to the same migration carrier system.

In combination with information from structural configuration and sand distribution, petroleum population maps are used to assess the most likely migration routes in an area. The distribution of oil populations within the Tampen Spur area suggests that several basins have contributed to the

accumulations and it is crucial to the geological understanding of the area to have a detailed knowledge of these migration routes.

Petroleum charging from several source rock horizons from multiple basins could potentially result in mixing of several oil populations within a single structure. If the geochemical composition of the mixing fluids is similar it might be impossible to detect such mixed petroleum populations. Mixed oil populations have been discovered both within the Tampen Spur area and within the Troll Field where in-reservoir mixing of petroleums probably occurred within a reconstructed paleo-accumulation described in the fifth paper.

The dynamic nature of the petroleum accumulations in the North Sea is often neglected and the new filling model of the Troll Field illustrates how the petroleum column within the field has been re-mobilised due to the Neogene tilting, and describes the impact of the tilting on the current distribution of oil and gas in the field . Since the mobility of oil is much lower than that of gas, tilting of a reservoir with separate gas and oil columns results in a mainly lateral movement of gas and a mainly vertical movement of oil. The new gas-oil contact is established within a geologically short time period while it may take a geologically significant time to re-establish the oil-water contact over larger distances within the reservoir.

Our data from the gas cap within the Troll Field (paper V) suggest that the gas charging predates the oil charging, and that the gas within the field might have been biodegraded. A few thin zones within the gas cap in the Troll Field contain gas-fractionated petroleum which was preferentially re-mobilised as gas continued to migrate into the structure after oil emplacement.

General conclusions

Petroleum is a very heterogeneous fluid and its detailed composition is controlled by regional variations in source rocks, burial history and migration processes. Thus, a detailed analysis of the accumulated petroleum provides an important tool for reconstructing migration in space and time.

This thesis demonstrates how reservoir geochemical data provide crucial in-put to geological models in an area, and how a multi-disciplinary approach can constrain petroleum generation and migration. It provides information on the petroleum distribution within the northern North Sea but the methods and the approach to resolve petroleum migration are of a general nature and can be adopted in other areas.

It is stressed that a large, uniform and high quality data set is required to construct petroleum population maps and that over-interpretation of statistically insignificant differences must be avoided.

It is often impossible to predict which data will prove useful in a particular area, and it is therefore important to interpret all available data to find the most useful techniques to discriminate petroleums into genetic groups.

Grouping of petroleums into oil populations and families as described in the two last papers, is often based on regional experience from the area of interest, and it is therefore crucial to have a detailed knowledge of the geological framework (source rocks, carrier systems, reservoirs, pressure, temperature, burial history etc.).

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Degradation and maturity controls on oil field petroleum column heterogeneity in the Gullfaks field, Norwegian North Sea

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Abstract—A geochemical mapping of the Gullfaks reservoir petroleum column based on 226 reservoir core extracts, and 23 drill stem test (DST) and repeat formation test (RFT) oil samples indicates the presence of statistically testable lateral compositional heterogeneities in the petroleum column. These different petroleum populations can be related to lateral filling of the field from two source basins and a more pervasive, subsequent episode in-reservoir biodegradation. Petroleum maturity gradients within the field were detected using conventional biomarker GC–MS methods on saturated hydrocarbon fractions. The degree of biodegradation was monitored by quantitative GC of *n*-alkanes in whole oil samples, using a squalane internal standard. The observed compositional differences in the Gullfaks petroleum column are consistent with diffusion being the primary mixing process, thermal convection being eliminated on both compositional and modeling grounds. Compositional differences between core extracts and DST samples from the same intervals suggest that fractionation of petroleum might occur during testing, and that interpretation of reservoir petroleum columns from mixed sample sets should be treated cautiously.

Key words—reservoir geochemistry, biodegradation, petroleum mixing, maturity gradients, reservoir filling, Gullfaks, North Sea

NOMENCLATURE

K—permeability (m^2)
g—acceleration due to gravity (m/s^2)
β—coefficient of cubic expansion (1/K)
H—reservoir height (m)
ρ—density of the fluid (kg/m^3)
C—heat capacity of the fluid (J/kg K)
Γ—thermal conductivity of the medium (W/m K)
υ—kinematic viscosity of the fluid (m^2/s)
$\delta H/T$—geothermal gradient (K/m)
l—diffusion length scale (m)
θ—tortuosity (m/m)
D_i—diffusion coefficient (m^2/s)
f—denotes fluid

INTRODUCTION

Although large-scale compositional heterogeneities in petroleum accumulations have been known for some time (Sage and Lacey, 1938; Schulte, 1980; Hirschberg, 1984), it is only recently that petroleum column heterogeneities have started to be interpreted from the perspective of petroleum geochemistry (England *et al.*, 1987; England and Mackenzie, 1989; Karlsen and Larter, 1991; Larter *et al.*, 1989). Here, in addition to biodegradation and water washing effects, compositional variations in petroleum accumulations may be interpreted as being due to source facies and maturity variations in the petroleum charge feeding the accumulation. Over time, the variable composition of the charge to the field is integrated and preserved as compositional variations in the petroleum column due to incomplete mixing of the petroleum in the reservoir.

England and Mackenzie (1989) have suggested that in permeable reservoirs the diffusive or density-driven mixing may eliminate inherited compositional variations on a reservoir thickness scale (*c.* 100 m) in a short time (*c.* 1 m.a.), but that diffusion cannot equilibrate lateral compositional gradients on a kilometer scale in large petroleum reservoirs. These resulting compositional variations may then be interpreted to indicate field filling directions and place limits on the probable location and type of source rocks filling an accumulation. While generally confirmed by other workers (Leythaeuser and Rückheim, 1989; Karlsen and Larter, 1991) it is evident that other processes, including interaction of polar petroleum compounds with reservoir surfaces, do perturb this general rule and may prevent homogenization even on small scales (Larter *et al.*, 1990).

In this study we investigated in-reservoir heterogeneity in the Gullfaks giant oil field in the northern part of the Norwegian North Sea, which we conclude has suffered petroleum biodegradation in addition to retaining evidence of filling from two different source basins. In addition, to further evaluate the role of diffusion as a primary mixing process in oil reservoirs we also quantitatively evaluate the role of convection as a petroleum column homogenization agent.

This area of geochemical study may prove to be one of the most powerful applications of petroleum

geochemistry to basin evaluation problems. Even in well-drilled provinces such as the North Sea area the vast majority of well locations are aimed at evaluation of structural highs. Mature petroleum source rocks relevant to known petroleum accumulations are only rarely sampled. Thus, a systematic study of petroleum column heterogeneity is not only of academic interest but is also directly relevant to determining the location, type and maturity of the source rocks responsible for the accumulation. Further, by directly determining the location of field fill points it may prove possible to place more accurate estimates on the volumes of carrier beds, and thus estimate undiscovered reserves or define relevant petroleum carrier sytems and petroleum losses associated with the carrier system. Additionally, understanding mixing processes within fields may allow distributions of petroleum variations within fields to be used to tune production programs and detect flow barriers within reservoirs that are active on the time scale of production.

GEOLOGICAL SETTING

The Gullfaks field is located in Block 34/10, 175 km from the Norwegian coast (Fig. 1). A total of 500 million Sm^3 oil is present in the Middle Jurassic (Bajocian–Bathonian, 183–169 m.a.) Brent Group and the Triassic to Early Jurassic Statfjord formation (Rhaetian–Sinemurian, 218–196 m.a.) and the Jurassic Cook formation (Pliensbachian–Toarcian, 196–185 m.a.) (Erichsen *et al.*, 1987). In

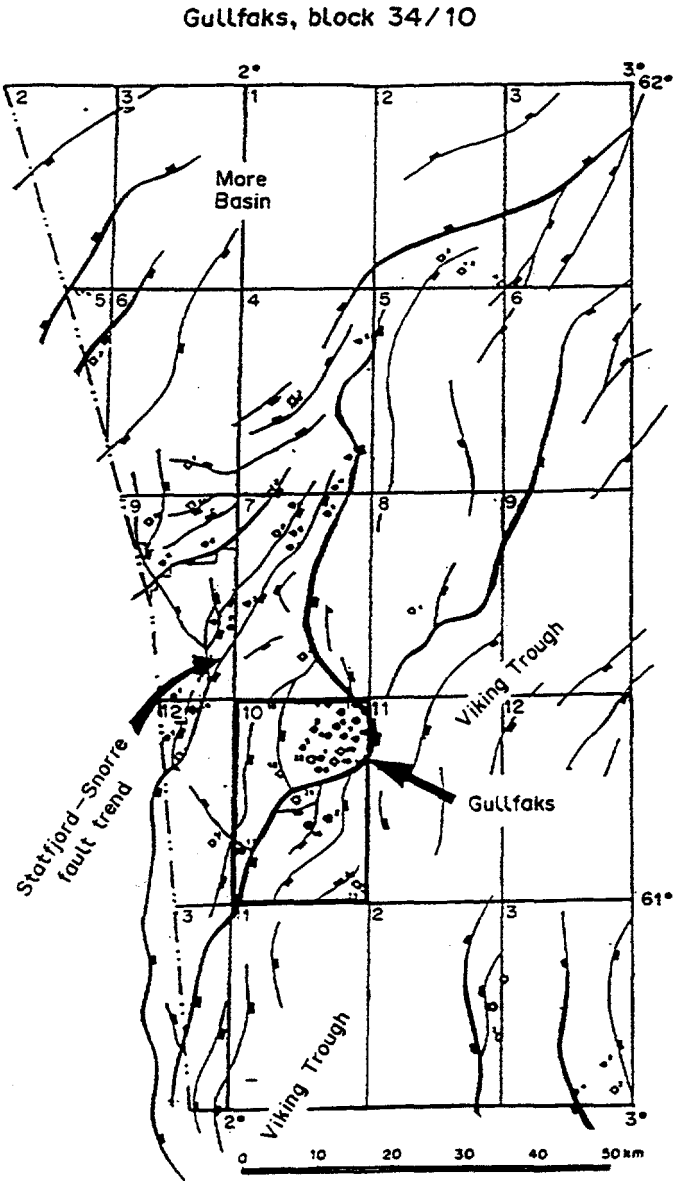

Fig. 1. Geographic location of the main Gullfaks field in Block 34/10, 175 km off the Norwegian coast. [Modified after Karlsson (1986).]

this study we concentrate on the Brent Group reservoir, but to complete the picture some analyses of oil samples from the Cook and Statfjord formations are included. The sediments of the Brent Group in the Gullfaks field area are at a depth of 1800–2000 m and are located in the structurally high Tampen Spur area, between the East Shetland Basin, East Shetland Platform and the Viking Graben (Karlsson, 1986).

The Brent Group sediments (Bajocian–Bathonian age) represent a regressive–transgressive megasequence showing a complete delta cycle (Eynon, 1981), and consist of five different formations with large variations in lithology and reservoir properties (Table 1). The variations in thickness within the different formations suggest that the major NE–SW fault system has some, but only limited influence on the distribution of the sediments (Eynon, 1981; Graue *et al.*, 1987). After deposition of the Brent Group, the Gullfaks field area was eroded and uplifted in the Late Jurassic, resulting in several westerly tilted fault blocks (Fig. 2). The erosion of the Brent Group sediments was most severe on the crests of the rotated fault blocks, and on the eastern most fault blocks the whole Brent Group sedimentary section has been eroded away (Karlsson, 1986). Thus, in this part of the field, reservoired petroleums are found only in the Triassic Lunde and Statfjord formations and the Lower Jurassic Cook formation. Most of the Upper Jurassic and Cretaceous sediments are missing on the main Gullfaks structure, only 1 m of the Draupne formation is present in the deepest and western most block (well 34/10-5) and the total thickness of Cretaceous sediment only ranges from 100 to 180 m, the greatest thicknesses being present in the northern part of the field (wells 34/10-3, -9 and -14). Since Upper Cretaceous time the whole area has been generally subsiding (Frost, 1988; Graue *et al.*, 1987).

The Jurassic and Triassic age petroleum reservoirs at Gullfaks are sealed by Upper Cretaceous fine-grained sediments, but gas leakage from the present undersaturated and overpressured reservoirs to the Paleocene sediments above has been reported (Irwin, 1989). This petroleum leakage for the Gullfaks reservoirs means that the system cannot be treated as a simple trap but may represent a partially open system in which more than one current reservoir petroleum volume has been emplaced. At present the structure is underfilled.

EXPERIMENTAL PROCEDURES

Sample set

Sample material analysed in this study included 226 core samples from more than 500 m of conventional core from 6 wells, in addition to 23 conventional drill stem test (DST) and repeat formation test (RFT) oil samples covering most of the field (Fig. 2).

Instrumental

TLC–FID (Iatroscan) analyses of rock samples and bulk oils were performed after the method described by Karlsen and Larter (1991). A Varian 3400 gas chromatograph (GC) equipped with a 50 m, i.d. 250 μm DB-1 column with a film thickness of 0.25 μm was used for the GC analysis of extracts and bulk oil. The GC was temperature programmed after 3 min delay at 40°C (oils) or 80°C (rock extracts) at a rate of 4°C/min up to 300°C with 12 min final hold time. Data were acquired and processed using VG Multichrom software. Quantitation of individual components in the petroleums was achieved using squalane as an internal standard. GC–MS analysis of separated aromatic hydrocarbon and saturated hydrocarbon fractions was performed using a Hewlett-Packard 5890 GC interfaced to a 25 m DB-1 column. Temperature programming was 80°C for 1 min, 4°C/min to 300°C with 10 min final hold time. MS detection was performed using an INCOS 50 quadrupole MS and software (Finnigan MAT). The MS electron energy was set to 70 eV and the ion source temperature was maintained at 200°C. The gas flow in both GC and GC–MS analyses was 1 ml/min and injector split ratios were set at 30 ml/min. Nitrogen and helium were used as carrier gases in the GC and GC–MS analyses, respectively. Simulated evaporation losses from oils were performed by adding dichloromethane:methanol (7:1, v/v) and subsequently removing the solvent by rotary evaporation (30°C, pressure >200 mbar).

Table 1. General petrophysical data on the five formations in the Brent Group in the Gullaks field: data from Bjørkum *et al.* (1987), Erichsen *et al.* (1987) and completion logs

Formation	Thickness	Lithology	Facies	ϕ (x)[1]	K (mdarcy)
Tarbert	0–74	Heterolithic	Tide/fluvial dominated delta, transgressive	30	50–800
Ness	0–122	Coal, clay-, silt- and channel sandstones	Delta plain	18–39	Up to 1000 but is much higher in channels 14,000–20,000 and reaches 25,000
Etive	0–35	Medium to very coarse sandstones	Upper delta front	31–35	1100–11,000 generally high
Rannoch	35–89	Very fine to fine good sorted sandstones	Prograding delta front, shoreface	20–36	1–1100, but generally 3–400. Increasing quality upwards
Broom	8–14	Clay-, silt- and sandstones	Prodeltaic	Low	Low

[1]He porosity.

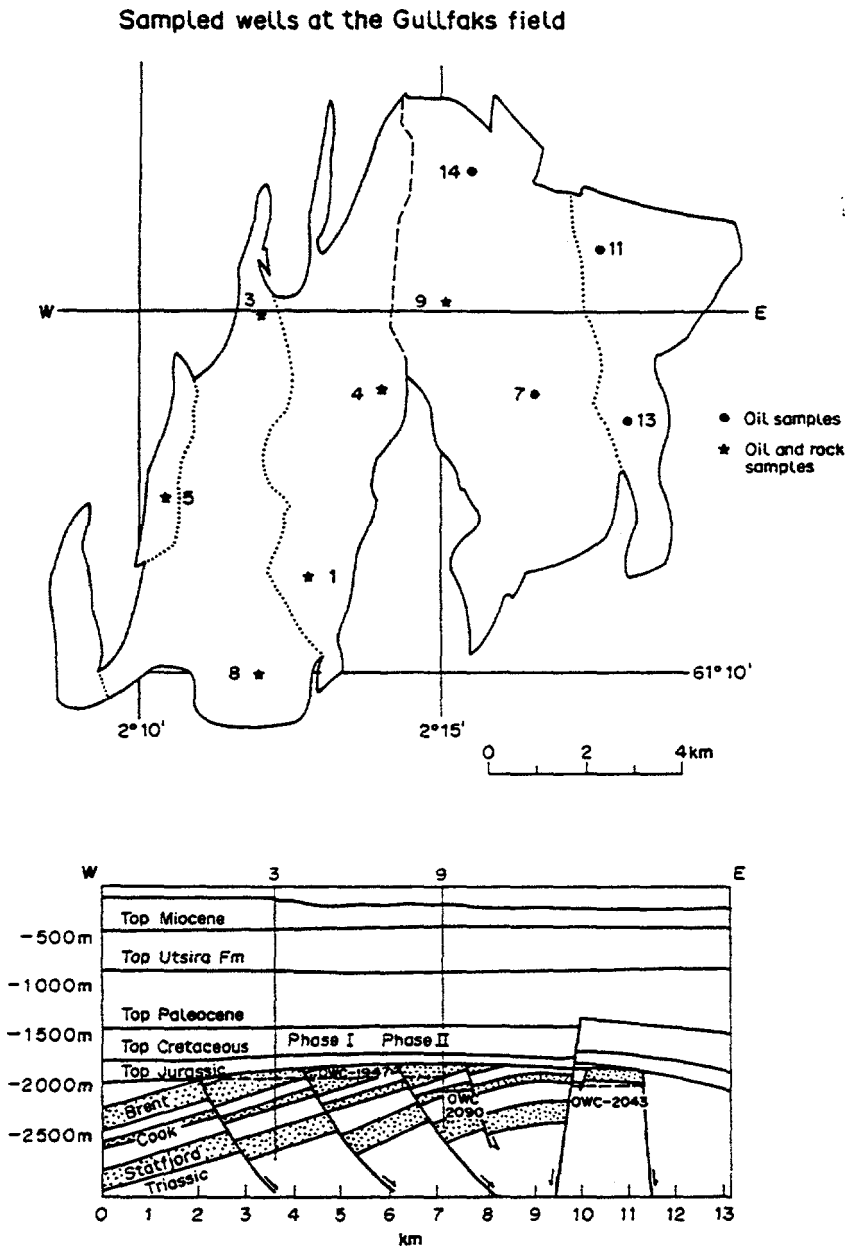

Fig. 2. Detailed map of the Gullfaks field showing the location of each well and the type of samples available in the different wells. An E–W geologic cross-section of the field shows the orientation of the rotated fault blocks in the area, and the erosion of the Brent Group sediments on the crest of the eastern fault blocks. [Modified after Erichsen *et al.* (1987).]

RESULTS AND DISCUSSION

Significant compositional differences in the C15+ fraction are observed when the compound class distribution (saturated hydrocarbons, aromatic hydrocarbons and polar compounds, i.e. resins + asphaltenes) in DST oils and rock extracts for the same reservoir zone are compared (Fig. 3). This might not seem too surprising, since the cores have been stored for several years and light hydrocarbons would be expected to be preferentially removed.

In an attempt to simulate the evaporation losses during storage, some oils were blown down by rotary evaporation. This resulted in a slight shift of the relative compound class distribution in the produced oils towards those of reservoir core extracts, however, a significant difference in composition still persisted (Fig. 3). This suggests that there are real differences in the compound class distributions between produced oils and core extracts from the same reservoir zone. These differences mainly affect the relative amounts of aromatic hydrocarbons and polar compounds in the sampled petroleum, while the relative

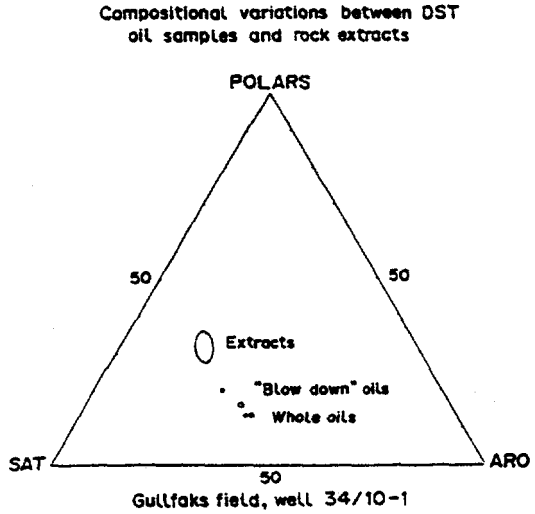

Fig. 3. A significant difference in the compound class composition of DST oil samples, "blow down" oil samples and rock extracts is observed from the same reservoir interval in well 34/10-1. These differences suggest that fractionation during oil sample production might occur. Based on Iatroscan (TLC–FID) data.

amount of saturated hydrocarbons remains virtually unchanged.

Thompson (1988) and Larter and Mills (1991) have shown that the vapor–liquid equilibrium properties of saturated and aromatic hydrocarbons favor selective retention of aromatic hydrocarbons and polar components by the liquid phase when a liquid and a gas phase are present. The production samples available to us were DST samples which represent only relatively small petroleum volumes. As the Gullfaks accumulation is near its bubble point it is possible that two petroleum phases were present in the well bore (would be at the bubble point at approx. 1400 m). This may have resulted in a fractionation of the small petroleum volume produced. While we are not certain of the origin of the compositional differences between DST and core samples (extracts), which may also be caused by adsorbed non-producible polar components (cf. Larter *et al.*, 1989), the differences do suggest that we should be cautious in interpreting small compositional differences in petroleum reservoirs interpreted from mixed DST/core extract data sets. Our experience has been that such differences are most confusing in the aromatic hydrocarbon fraction.

These compositional differences have, to our knowledge, not been reported previously, and might be significant in new prospect areas where sample sets are mixed (i.e. reservoir cores and DST oils) and limited. If such fractionation processes are not accounted for, they might result in misleading interpretation of the petroleum composition and heterogeneity in a petroleum reservoir. It is, therefore, important to further study these effects, in order to clarify what a DST oil sample and a petroleum core extract sample from a subsurface reservoir really represent in terms of reservoir composition.

INFLUENCE OF BIOLOGICAL DEGRADATION ON THE *n*-ALKANE DISTRIBUTION IN THE PETROLEUM COLUMNS IN THE GULLFAKS FIELD

The vertical composition of the petroleum column in the Brent Group reservoir at the Gullfaks field, as determined by Rock–Eval and Iatroscan analysis of core samples is generally very homogeneous at any location (Fig. 4). The only exceptions are samples selected from the Ness formation, where the bulk composition of core extracts varies due to contamination from *in situ* coals and the carbonate cemented zones which tend to be enriched in polar compounds (Horstad, 1989). Since the hydrocarbon column in the Brent Group reservoir at Gullfaks is vertically homogeneous, relatively few samples can characterize the petroleum column. In other fields where vertical heterogeneities are present, a much higher sampling density is required (Larter *et al.*, 1990). Vertical heterogeneities in the petroleum composition, are

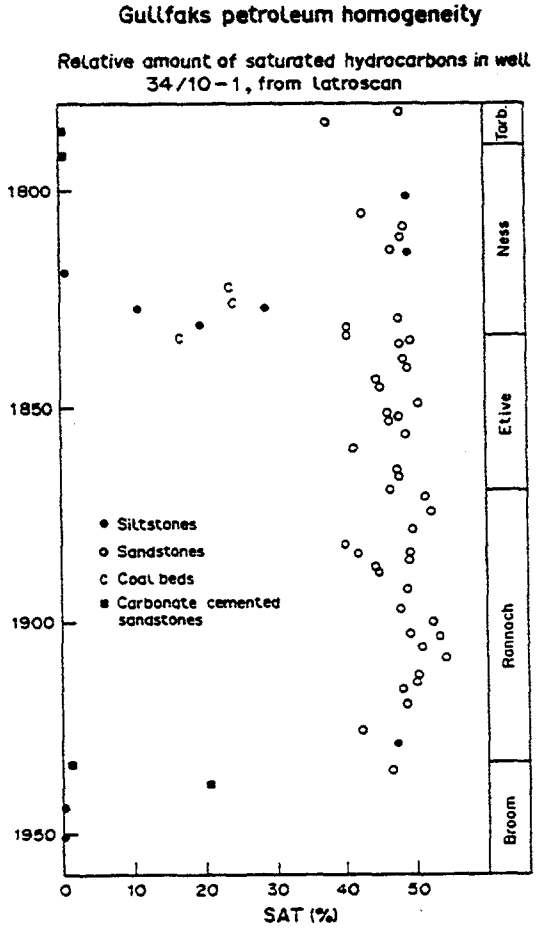

Fig. 4. The vertical composition of the petroleum column in the Brent Group reservoir is very homogeneous, shown here by the relative amount of saturated hydrocarbons as determined by Iatroscan TLC–FID.

most likely to be present in the lithological heterogeneous zones within the reservoir.

Systematic variations in the chemical composition of the petroleum within the Brent Group reservoir are recognized laterally across the field. Based on analysis of 12 different DST oil samples from the Brent Group reservoir in 7 wells, a systematic gradient in the absolute amount of C_9 to C_{34} *n*-alkanes is observed. The *n*-alkane concentration (Σn-C_9–*n*-C_{34}) varies systematically from 56.7 mg/g oil in the eastern part

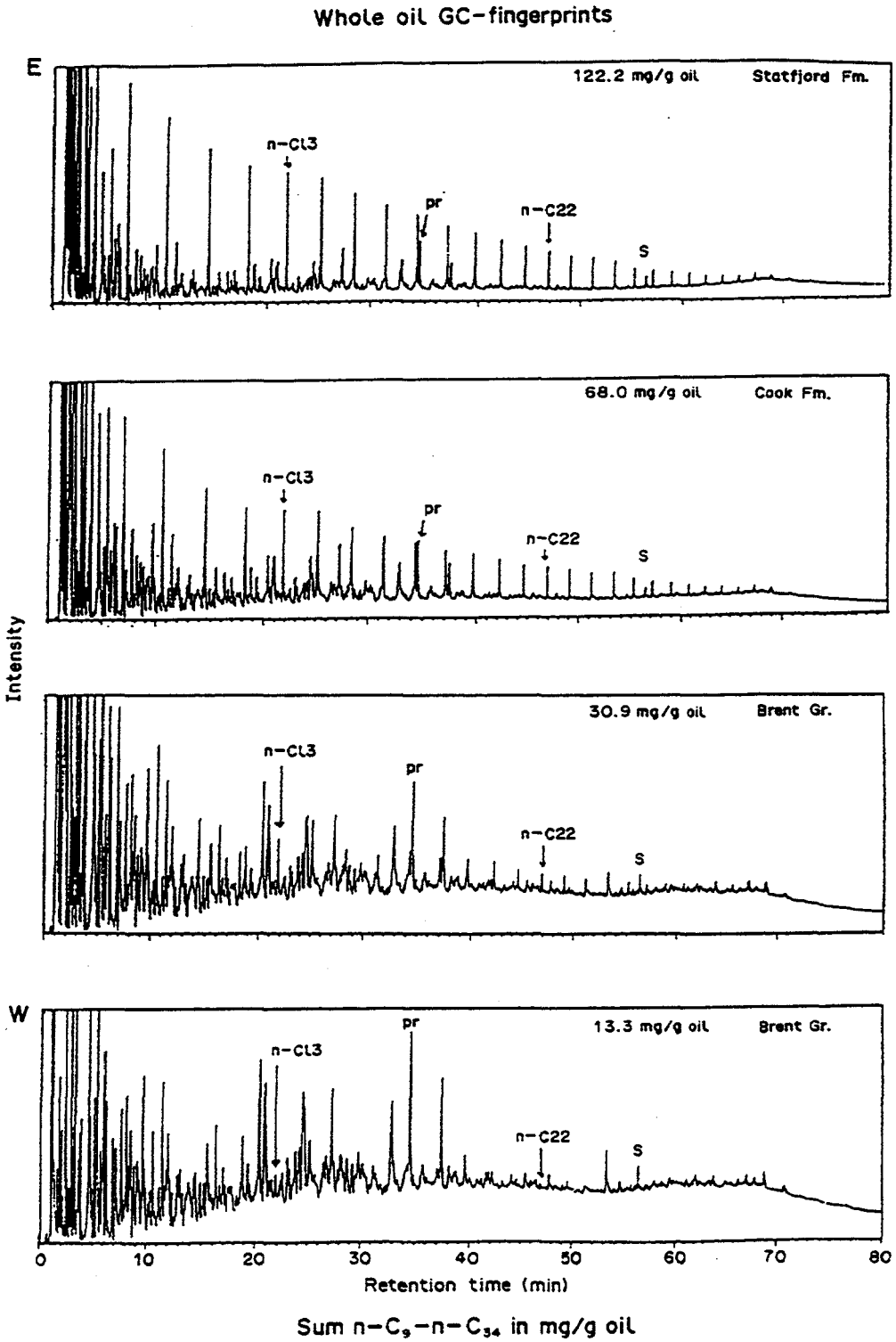

Fig. 5. Representative whole oil GC fingerprints from the different wells, showing the selective and systematic removal of *n*-alkanes by bacterial degradation of the petroleum.

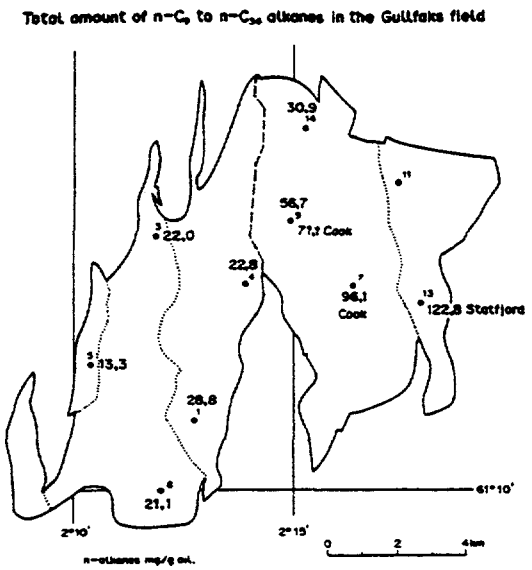

Fig. 6. Total yield of *n*-alkanes (C_9–C_{34}) in all the wells, average of all available DST samples in each well. Note the eastward increase in the absolute amount of *n*-alkanes due to a more severe degradation in the western part of the field. It is stressed that the samples within the Cook and Statfjord formations are not in communication with the Brent Group. Based on GC analysis of whole oil samples.

of the reservoir to 13.3 mg/g oil in the western part of the reservoir (Figs 5 and 6). The absolute amount of C_9 to C_{34} *n*-alkanes is even higher in petroleum reservoired within the Cook and Statfjord formations further east, but this petroleum belongs to another petroleum population, although of very similar composition. This systematic removal of *n*-alkanes might also be expressed by isoprenoid alkane/*n*-alkane ratios (i.e. pristane/*n*-C_{17}, phytane/*n*-C_{18}) or as an increase in the amount of long chain *n*-alkanes (Σn-C_{25}–*n*-C_{34}/Σn-C_9–*n*-C_{34}), all demonstrating the same systematic gradient across the field. A systematic removal of the pristane and phytane is also observed, although at a much slower rate than the removal of the *n*-alkanes (Horstad, 1989).

By comparison with several studies of biological degradation reported in the literature (Winters and Williams, 1969; Bailey *et al.*, 1973a, b; Connan, 1984; Jobson *et al.*, 1979; Milner *et al.*, 1977), it is concluded that the systematic decrease in the absolute amount of *n*-alkanes across the field is due to selective removal by biological degradation of the petroleum. A more complete discussion of the degradation of the field is found elsewhere (Horstad, 1989; Horstad and Larter, in preparation).

Simple mass balance calculations based on the stoichiometry for aerobic and anaerobic sulphate reducing bacterial oil degradation processes, suggest that anaerobic oil degradation, even if biologically viable, may only be important in reservoirs where very high concentrations of sulfate are present in the water associated with the petroleum, in the trap or during secondary migration (Horstad, 1989; Horstad and Larter, in preparation). Assuming that transport of molecular oxygen or sulphate to the oil degradation zone (close to oil–water contacts) is the rate-limiting process, our calculations suggest that anaerobic degradation is two orders of magnitude less effective than aerobic degradation, given typical oxidant concentrations in reservoir pore waters.

It is concluded therefore, that the biological degradation of the petroleum in the sulfate-deficient Brent Group reservoir at the Gullfaks field, was mediated by aerobic bacteria.

MIXING PROCESSES WITHIN THE BRENT GROUP RESERVOIR

In-reservoir mixing of petroleum is believed to occur by molecular diffusion or density-driven overturning or a combination of both processes (England *et al.*, 1987). Whether a fluid column is likely to thermally convect or not might be deduced by the Rayleigh number (Ra) defined by Bories and Combarnous (1973):

$$\mathrm{Ra} = \frac{Kg\beta H^2(\rho C)_t}{\Gamma v}\frac{\delta T}{H}. \qquad (1)$$

Ra is a measure of the magnitude of the thermal convection force vs viscous forces, which tend to resist convection. If $\mathrm{Ra} > 4\pi^2$ (approx. 39.5), convection might occur in the system. Based on reasonable values selected from the literature and measurement performed on DST oil samples from the Gullfaks field (see the Appendix), our calculations suggest that convection cannot proceed, since Ra is much less than the critical value. In order for thermal convection to occur, the reservoir thickness must exceed 300 m, even in a very high quality reservoir sandstone with 1 darcy permeability (Fig. 7). Convection is therefore unlikely to occur unless abnormal thermal regimes are present with very high geo-

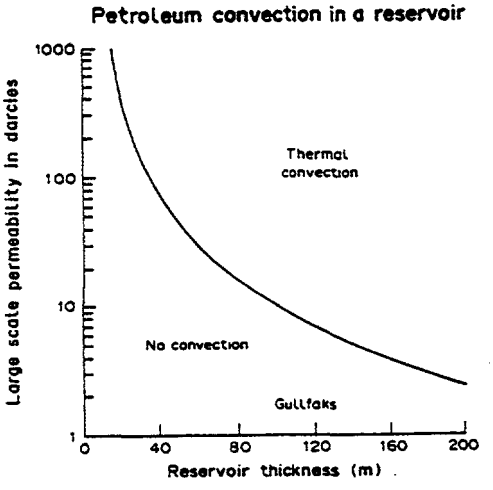

Fig. 7. Based on the present estimates of Ra, thermal convection of the petroleum in the Brent Group reservoir at the Gullfaks field seems unlikely.

thermal gradients. Further, any low permeability layers in the reservoir dramatically reduce effective Ra values in stratified media (Bjørlykke *et al.*, 1988). Even thin low permeability barriers, such as shales, siltstones and even tar mats, reduce the effective height of the convectible fluid column so as to effectively prevent convection in either water or petroleum columns in reservoirs (Bjørlykke *et al.*, 1988).

Molecular diffusion will occur within any system where compositional heterogeneities are present, and the time required to reduce the initial concentration gradient to 30% is given by (England *et al.*, 1987):

$$t_{eq} = \frac{l^2\theta^2}{10\,D_i}. \quad (2)$$

Equation (2) is plotted in Fig. 8 for estimated diffusion coefficients for C_1 and C_{12} molecular range compounds, demonstrating that it would take only a few hundred thousand years to equilibrate gasoline range compounds (C_5–C_{10}) on a 100 m scale (typical reservoir thickness), while it would require tens of millions of years to equilibrate the same compounds over a typical lateral reservoir scale (kilometers). It is therefore possible to explain both the vertical homogeneity and the lateral heterogeneity, or inability to homogenize the petroleum composition, by diffusion processes.

Further, large-scale convection in petroleum columns would result in a uniform petroleum composition both vertically and laterally across at least each block in the field. As lateral gradients are observed in, for example *n*-alkane concentration gradients, large scale pervasive convection over a long time can be eliminated as a mixing mechanism.

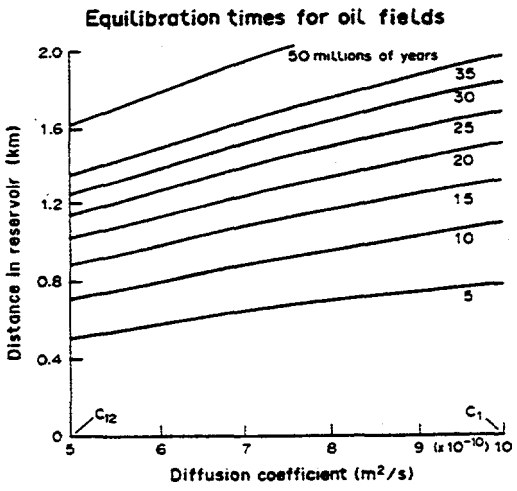

Fig. 8. The time required to homogenize a petroleum reservoir is largely a function of the diffusion coefficient of the involved species and the distance over which diffusion occurs. This explains why lateral heterogeneities might be preserved for tens of millions years, while vertical heterogeneities generally vanish in a few million years. [After Karlsen and Larter (1991) based on data from England *et al.* (1987).]

It is therefore concluded that diffusion is the main mixing process in the Brent Group reservoir in the Gullfaks field, which is consistent with the current view (England *et al.*, 1987; Larter *et al.*, 1990).

FACIES AND MATURITY DIFFERENCES AMONG THE TWO PETROLEUM POPULATIONS IN THE GULLFAKS FIELD

Karlsen and Larter (1990) defined a petroleum population as a contiguous charge of petroleum in a field, which is chemically definable in terms of a source facies or maturation level. Based on GC–MS analysis of the saturated hydrocarbon fractions, it is possible to distinguish two different petroleum populations within the sample set from the Gullfaks field: one early to mid-mature population present in the Brent Group in the western part of the field; and a slightly more mature population within the Cook, Statfjord and Lunde formations in the eastern part of the field. This is reflected in slight differences in the relative distribution of 5α(H),14β(H),17β(H) cholestanes in the petroleums. Although there is a considerable scatter in the data set, samples from the Brent Group reservoir generally contain relatively less 5α(H),14β(H),17β(H)-methyl-cholestane (C_{28} sterane) than samples from the Cook, Statfjord and Lunde formations (Fig. 9). The utility and significance of the "Huang–Meinschein diagram" (Huang and Meinschein, 1979) are debatable. However, even if we do not adequately understand the reason for a specific shift in the sterane carbon number distribution, such shifts can be used in correlation studies and sample set discrimination. The presence of two petroleum populations is also supported by the 17α(H),21β(H)-28,30-bisnorhopane/17α(H),21β(H)-30-norhopane ratio. Within the Brent Group this ratio varies from 0.52 to 0.64 (32 samples, mean = 0.58 and $\sigma = 0.02$), while within the Cook and Statfjord formations further east this ratio ranges from 0.44 to 0.49 (5 samples, mean = 0.47 and $\sigma = 0.02$).

The statistical significance of these conclusions was performed by applying a Student's *t*-test for two sample analyses (Davies, 1973), which confirmed discrimination of the two petroleum populations, at a significance level of 0.05 (5%), both for the distribution of 5α(H),14β(H),17β(H)-methyl-cholestane and the 17α(H),21β(H)-28-30-bisnorhopane/17α(H),21β(H)-30-norhopane ratio (Fig. 10). In general, in-field differences in the petroleum composition require the use of statistical testing of conclusions as compositional differences are often small.

PETROLEUM MATURITY GRADIENTS ACROSS THE FIELD

Since the generation and expulsion of liquid petroleum from a source rock occurs over a certain depth and temperature range (typically 50°C at any

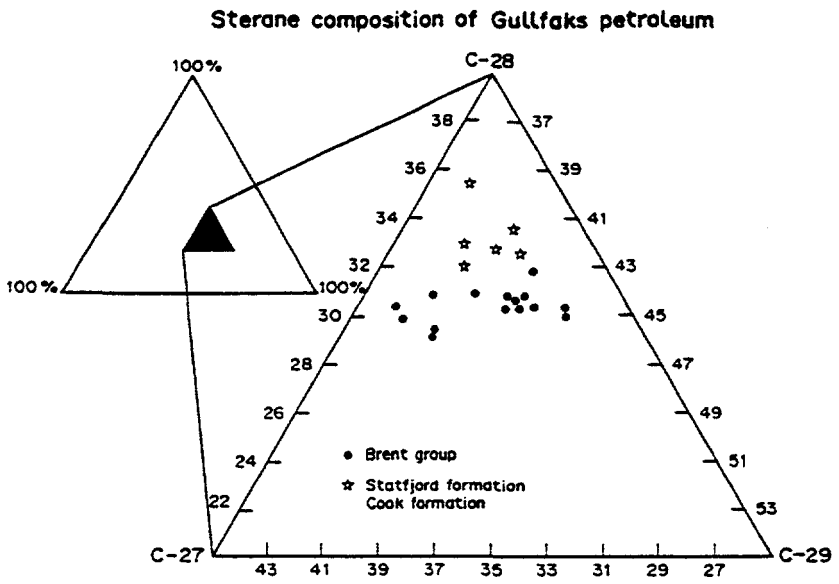

Fig. 9. Huang–Meinschein diagram showing the difference between the two petroleum populations present in the Gullfaks field. the oils from the Cook and Statfjord formations always have a larger amount of 5α(H),14β(H),17β(H)-methyl-cholestane (C_{28}) than the Brent Group oils.

location), a petroleum reservoir should receive more and more mature petroleum as it is filled from a continuously subsiding source rock basin, providing it remains in communication with the source rock. Thus, if a reservoir is filled from one end in a sequential manner, as proposed by England *et al.* (1987), the most mature petroleum in the reservoir should be located nearest the source rock basin or probable filling point (England *et al.*, 1987; England and Mackenzie, 1989; Larter *et al.*, 1990). However, a certain relationship between the reservoir length scale and elapsed time since filling is required, since diffusion tends to homogenize the petroleum composition and destroy compositional gradients in the field. This will occur in a time scale proportional to the square of the length scale of the petroleum column (Fig. 8).

Since the temperature range over which liquid petroleum is expelled from a high-quality source rock such as the Draupne formation/Kimmeridge clay is rather limited (Cooles *et al.*, 1986; Quigley *et al.*, 1987), the corresponding shift in the different maturity indicators will be small, typically in the range equivalent of 0.7–1.0% vitrinite reflectance (Cooles *et*

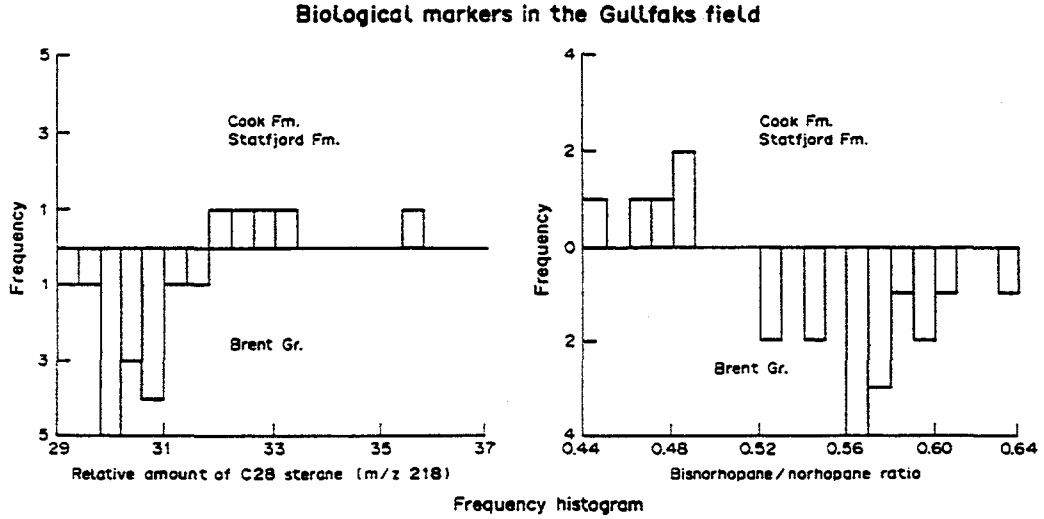

Fig. 10. Statistical testing of the relative amount of C_{28} 5α(H),14β(H),17β(H)-methyl-cholestane and the 17α(H),21β(H)-28-30-bisnorhopane:17α(H),21β(H)-30-norhopane ratio suggest that the Brent Group oils and the Cook/Statfjord formations oils belong to two statistically different petroleum populations, at a 5% level of significance (based on 21 analyses).

al., 1986). This requires a very precise determination of the source maturity indicators carried by the petroleum charge.

The relatively small maturity gradients across the field observed here may reflect the observation made earlier that the Gullfaks system may have been partially open during filling, the present gradients reflecting a relatively late stage maturity window (the quantitatively most significant part) in the evolution of the source rock basin. However, it is also possible that the Late Cretaceous–Early Tertiary age for filling of the reservoir will have allowed for a significant diffusion affected lateral mixing of the fields petroleum columns resulting in reduced gradients.

When the hopane X/[hopane X + 17α(H),21β(H) hopane] ratio (Cornford *et al.*, 1986) (Figs 11 and 12), the proposed isomerization at C-20 in 5α(H),14α(H),17α(H)-ethylcholestanes S/(S + R) (Fig. 12), the apparent isomerization from 14α(H),17α(H) to 14β(H),17β(H) in ethylcholestane ββ/(αα + ββ) and the 18α(H)-22,29,30-trisnorneohopane/17α(H)-22,29,30-trisnorhopane (Ts/Tm) are plotted on a map of the field, very tentative gradients in the petroleum maturities are observed (not shown for the two last maturity ratios). The most mature petroleum in the Brent Group reservoir appears to be present in the western part of the field, while the most mature petroleum in the Cook/Statfjord reservoir system is present in the eastern part of the field.

On the basis of statistically testable differences in source rock facies indicators and maturity differences between the two main petroleum populations, and the more tentative maturity gradients within each population shown in Fig. 12, it is very tentatively concluded that the Gullfaks structure probably was filled from two different source rock basins, one to the west and one slightly more mature to the east or north east of the Gullfaks structure. The conclusion based on maturity gradients is necessarily weaker but a typical gradient of several standard deviations is observed in the field for most of the maturity parameters. We feel that by using several facies and maturity parameters the problems associated with biodegradation itself are hopefully eliminated, thus the facies differences and maturity gradients are due to primary differences and not affected by biodegradation. Fortunately, biological markers such as hopanes and steranes are very resistant to the early stages of biological degradation (Connan, 1984; Williams *et al.*, 1986), although in severe cases of biodegradation, even these compounds are utilized by bacteria (Reed, 1977; Seifert and Moldowan, 1979). It is stressed that no evidence of biodegradation such as destruction of the steranes (Goodwin *et al.*, 1983), demethylation of the A/B ring in hopanes (Rullkötter and Wendisch, 1982), or C-ring opening in the hopanes (Schmitter *et al.*, 1982) are evident in the biomarker alkanes in any of the Brent Group oils from the Gullfaks field. This is, however, not surprising, since the oils are only slightly degraded, with *n*-alkanes still being present in all the samples. However, the effect of biodegradation of biomarkers and its effect on maturity and facies indicators clearly needs further study.

It is further noted that the standard deviations are calculated from analysis of several different petroleums (up to 12 in well 34/10-1) at each location, not re-analysis of the same sample.

TIMING OF FILLING AND BIOLOGICAL DEGRADATION OF THE PETROLEUM IN THE BRENT GROUP RESERVOIR IN THE GULLFAKS FIELD

To date, one of the major problems in this reservoir study, has been determination of the timing of the different events. To this point our observations of the Brent Group reservoir at the Gullfaks field might be summarized as:

—The most mature petroleum is located in the western part of the field, where the Brent Group sediments are not eroded and are buried at greatest depth.

—The most degraded petroleum is located in the west, and the *n*-alkane concentration gradient across the field suggests that the petroleum was degraded after entrapment in the reservoir.

Since the rotated fault blocks in the western part of the field are less eroded on the crests than the fault blocks to the east, it is likely that this part of the field has always been deeper, after the fault block rotation in Jurassic time. Thus, since the most severely degraded petroleum is located where the water first reached the reservoir, the input of oxygen-rich meteoric water to degrade the petroleum must have been derived from sources to the west. Initially we felt that this might be explained by a similar meteoric water flow pattern to that proposed for the Main Heather field, North Sea U.K. sector, by Glasmann *et al.* (1988). Meteoric water might have had access to the Gullfaks structure by down fault movements from elevated areas in the west, possibly along the Statfjord–Snorre fault trend (Fig. 1). Subsequent flow through a water-wet pathway in the Brent Group section might allow for a reasonably high flow, depending upon the magnitude of the hydraulic head.

Simple calculations, based on Darcy's law, suggested that with a 1 darcy permeability sandstone and a hydraulic head of 30 m, which is realistic even for loose sandstone sediments, the required amount of water, carrying oxygen at surface saturation, might be supplied in less than 5 m.a. It should be pointed out however, that there is no definite evidence available to us concerning the presence of palaeo-highs to the west of Gullfaks. Indeed the frequent occurrence of degraded oils in Tertiary reservoirs elsewhere in the North Sea may suggest that a later period of meteoric recharge occurred.

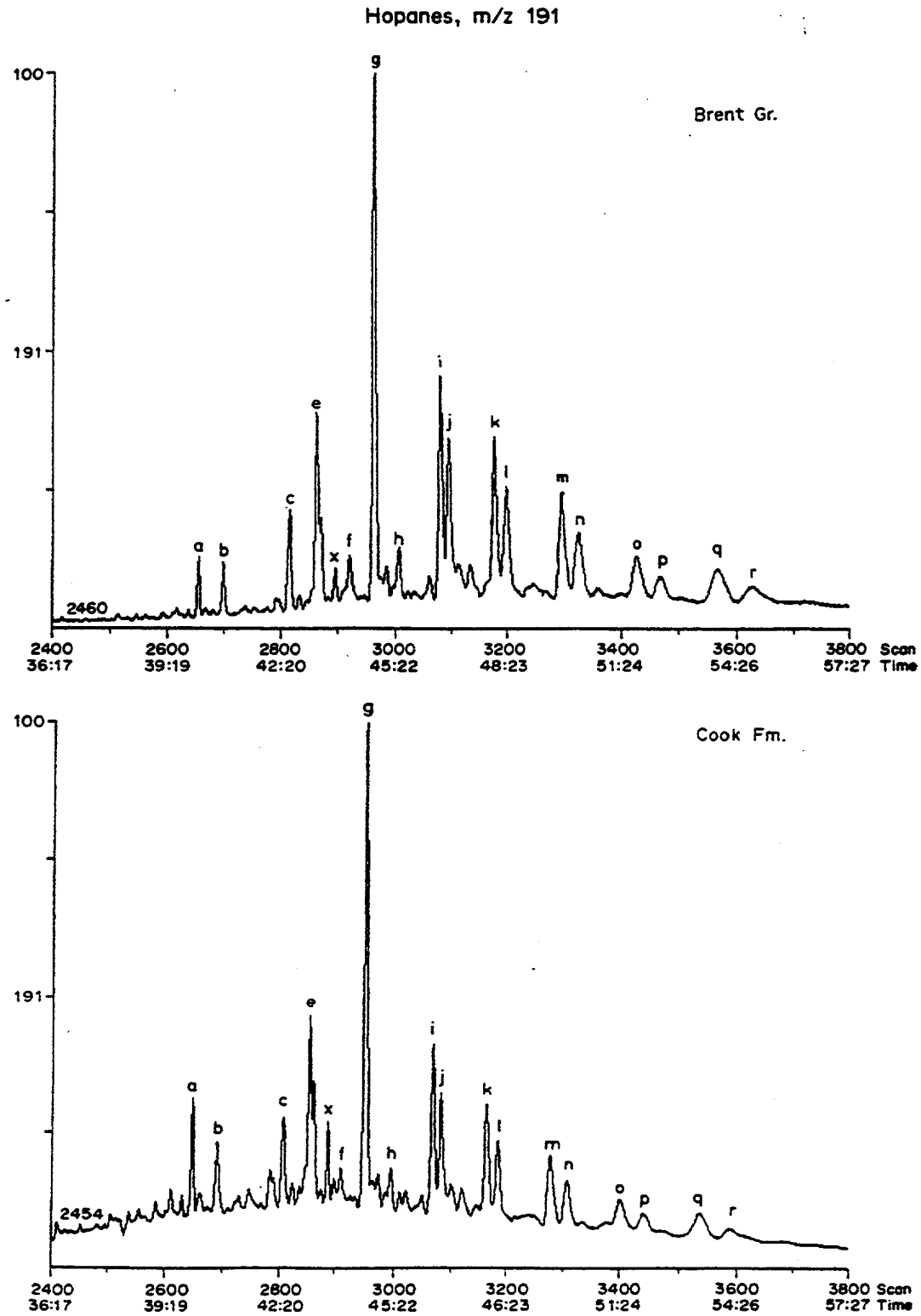

Fig. 11. Representative m/z 191 MC of 17α(H),21β(H) hopanes from the Brent Group oil (above, 34/10-1 DST 1) and the Cook/Statfjord formation oils (below, 34/10-7 DST 1). Note the differences between the two samples according to peaks a, b, x and f. Peak identification is given in Table 2.

Table 2. Assignment of identified peaks in the hopanoid *m/z* 191 MC in Fig. 11

a	18α(H)-22,29,30-trisnorneohopane	C_{27}
b	17α(H)-22,29,30-trisnorhopane	C_{27}
c	17α(H),21β(H)-28-30-bisnorhopane	C_{28}
d	17β(H),21α(H)-28-30-bisnormoretane	C_{28}
e	17α(H),21β(H)-30-norhopane	C_{29}
f	17β(H),21α(H)-30-normoretane	C_{29}
g	17α(H),21β(H)-hopane	C_{30}
h	17β(H),21α(H)-moretane	C_{30}
i	17α(H),21β(H)-homohopane (22*S*)	C_{31}
j	17α(H),21β(H)-homohopane (22*R*)	C_{31}
k	17α(H),21β(H)-bishomohopane (22*S*)	C_{32}
l	17α(H),21β(H)-bishomohopane (22*R*)	C_{32}
m	17α(H),21β(H)-trishomohopane (22*S*)	C_{33}
n	17α(H),21β(H)-trishomohopane (22*R*)	C_{33}
o	17α(H),21β(H)-tetrakishomohopane (22*S*)	C_{34}
p	17α(H),21β(H)-tetrakishomohopane (22*R*)	C_{34}
q	17α(H),21β(H)-pentakishomohopane (22*S*)	C_{35}
r	17α(H),21β(H)-pentakishomohopane (22*R*)	C_{35}
x	Hopane X (Cornford *et al.*, 1986)	C_{30}

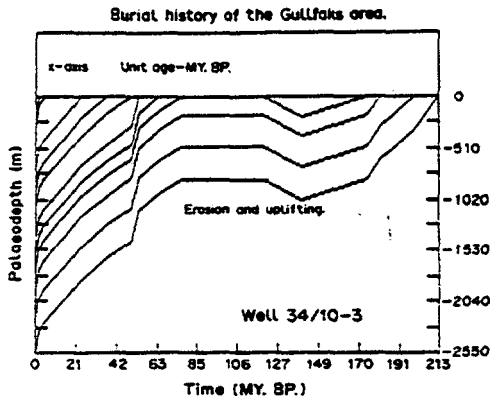

Fig. 13. Representative burial history of the Brent Group sediments in the Gullfaks area, based on information from the completion log from well 34/10-3. Very tentatively a 200 m uplift is assumed due to erosion of the Brent Group sediments. Based on completion logs made available by NPD, and constructed with a computer burial program.

This degradation model requires that the petroleum within the Brent Group reservoir was present in the trap before the whole northern North Sea was rapidly subsided during Upper Cretaceous–Early Tertiary time (Fig. 13). This would require that early-mature petroleum in the Brent Group reservoir, located in the western part of the Gullfaks structure, was generated from a source rock basin, probably to the west, which was mature in Late Cretaceous–Early Tertiary time (60–70 m.a.), when meteoric water had access to the Brent Group sediments in the Gullfaks field area. It is, however, stressed that eastern basins cannot be totally eliminated on the basis of our results only,

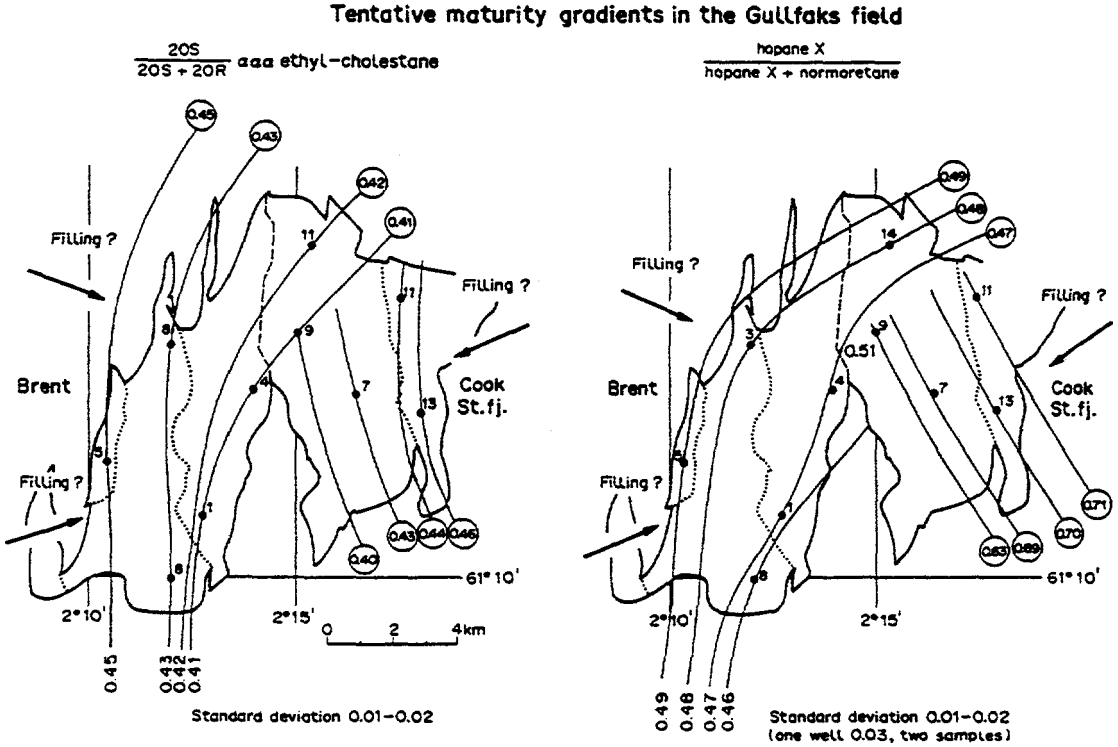

Fig. 12. Tentative interpretation of two different maturity gradients in the field according to the hopane*X*/(hopane*X* + hopane) ratio and isomerization of C-20 in 5α(H),14α(H),17α(H)-ethyl-cholestane, 20*S*/(20*S* + 20*R*), one within the Brent Group in the western part of the field and one within the Cook/Statfjord formations in the eastern part of the field. The contours are highly schematic and are for illustrative purpose only. These two maturity gradients might reflect the filling of the field from two continuously subsiding source rock basins. Based on up to 12 samples in each well.

and regional model studies are needed to test this hypothesis.

Unfortunately, we do not have access to a large data base which might help us to answer these questions, but this study will be continued as a part of a larger study of the petroleum accumulations in the whole Tampen Spur area. We feel that despite considerable uncertainty in our geological model, the study of the petroleum column at Gullfaks does provide a further geological constraint on the evolution of the Tampen Spur area.

The possibility of another in-reservoir petroleum degradation mechanism than anaerobic and aerobic degradation should also be further investigated. Although, reservoir fermentation has never been reported previously, it might be a possible explanation for the degradation of petroleum in apparently closed and overpressured reservoirs in the North Sea. The existence of some type of in-reservoir fermentation process is supported by the presence of carbonate cemented zones with high positive carbon isotope ratios (+5 to +20 per million) in the Brent Group reservoir at Gullfaks (Bjørnvik, in preparation; Saigal and Bjørlykke, 1987).

CONCLUSION

On the basis of geochemical analysis of the petroleum in the Brent Group reservoir at the Gullfaks field, the petroleum in the reservoir can be divided into two main petroleum populations on the basis of statistically tested biological marker analysis. Further, filling directions into the reservoir are possibly reflected in two more tentative gradients in the maturity of the petroleum.

After emplacement, the petroleum in the Brent Group, and to a lesser extent the petroleum in the Cook and Statfjord formations, were degraded by aerobic bacteria. The oxygen and nutrient supply was from the west, causing a gradient in the extent of biological degradation from west to east.

Compositional variations in the field and theoretical calculations suggest that diffusion is the main mixing process, and that diffusion is only able to homogenize the petroleum composition on a relatively small scale (reservoir thickness). Lateral heterogeneities may therefore persist for millions of years, however a relatively long time since filling (*c.* 60 m.a.) may have enabled diffusion to markedly attenuate compositional gradients across the field. A further complication may be that since the Gullfaks seal may not have been efficient throughout the fields history, the current reservoir charge may only represent a part of the petroleum that has flowed into the trap (Irwin, 1989), and that advective mixing may also have occurred.

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APPENDIX

Estimated Values

$K = 9.9 \times 10^{-13}$ m², i.e. 1 darcy.

$g = 9.8$ m/s².

$\beta = 1.6 \times 10^{-2}$ 1/K (Larter, personal communication).

$C = 2130$ J/kg K (Kreith, 1976).

$\rho = 880$ kg/m³ (Erichsen *et al.*, 1987).

$\delta T/H$—Norwegian Petroleum Directorate data.

$v = 1.36 \times 10^{-6}$ m²/s, calculated from $v = \mu/\rho$; $\mu = 1.2 \times 10^{-3}$ Pa s.

$r = r_{fluid}^{\phi} \times r_{rock}^{(1-\phi)}$, where r_{fluid} is 0.13 kg m/s³ K, i.e. W/m K (Kreith, 1976), and r_{rock} is 3.0 kg m/s 3³ K (Bjørlykke *et al.*, 1988); porosity, ϕ, is estimated to be 30% or 0.3.

H—kept as a variable.

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A quantitative model of biological petroleum degradation within the Brent Group reservoir in the Gullfaks Field, Norwegian North Sea

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Abstract—It has been documented that the degree of biological degradation of the petroleum in the Brent Group reservoir in the Gullfaks Field (quadrant 34/10, Norwegian North Sea) varies laterally. The most severe degradation has taken place in the western part of the field where the Brent Group sediments are not eroded. Lack of erosion in the West suggests that this part of the reservoir has always been buried at greater depths than the eastern part of the field. The geochemical description with the most severe biodegradation in the West, seems therefore to conflict with the most obvious geological model with easiest access for bacteria with meteoric water from the East. This suggests that we either do not understand the geology of the Gullfaks Field area or we do not understand the biological degradation process, or perhaps both. It is possible to give a reasonably good approximation of the amount of carbon that has been removed from the reservoired petroleum by bacterial degradation by comparing degraded and non-degraded petroleum with a fill–spill relationship in the area. By assuming that the supply of an oxygenating agent is the rate limiting factor in biological degradation of petroleum within a reservoir, it is possible to simplify the very complex processes and mechanisms involved in petroleum degradation, and to reduce the number of variables to three. These are: the thickness of the supply zone below the reservoir from which an oxygenating agent can be supplied, the flow of water within this supply zone below the oil water contact (o.w.c.) and the time available to degrade the petroleum in the reservoir. Geochemical and geological observations and modelling have demonstrated that it is unlikely that the degradation involves sulphate reducing bacteria but that degradation is probably aerobic bacterially mediated and a supply of oxygen "rich" water with nutrients or is related to a yet unidentified process. This mass balance based on the supply and demand of oxygen dissolved in meteoric water indicates that several thousand reservoir volumes are required to degrade the petroleum within the Brent Group to its present stage. This is difficult to explain with the current geological model of the field, however the biological degradation must be accounted for when establishing a realistic geological model in the Gullfaks area. The main advantage of our model is that it is quantitative and although some inaccuracies are inevitable it gives an order of magnitude estimate of the amount of water which must have been supplied into the reservoir.

Key words—Gullfaks, North Sea, Brent Group, Tampes Spur, biological degradation

INTRODUCTION

Several studies have been performed to get a better understanding of the processes and mechanisms involved in in-reservoir biological degradation of petroleum. It is today widely accepted that biological degradation is a combination of several processes which tend to remove different petroleum compounds in a very specific and systematic manner (Connan, 1984 and references therein). There is still some debate on the exact order in which different compounds are removed, but most studies seem to arrive at more or less the same degradation sequence. Short chain *n*-alkanes tend to be removed faster than longer chain *n*-alkanes which in turn are removed faster than branched and isoprenoid hydrocarbons. Biological markers are very resistant to biological degradation and will only be affected at severe stages of alteration. Steranes are removed faster than hopanes (Connan, 1984), and the degradation of steranes seems to be specific with respect to different isomers. Compounds with the biological 20R configuration are removed faster than compounds with 20S configuration, 5α(H), 14α(H),17α(H) faster than 5α(H),14β(H),17β(H) and C_{27} faster than C_{28} faster than C_{29} (Chosson *et al.*, 1991; Connan, 1984; Goodwin *et al.*, 1981). Several workers have simulated biological degradation under laboratory conditions (Jobson *et al.*, 1979; Goodwin *et al.*, 1981; Wehner *et al.*, 1985; Rowland *et al.*, 1986), and the systematic and selective removal of compounds has been successfully reproduced. It has also been proposed that biological degradation can produce new biomarker compounds, such as a series of demethylated hopanes created by removal of the methyl group at C-10 in regular hopanes (Seifert and Moldowan, 1979; Reed, 1977; Rullkötter and Wendisch, 1982). We think that the origin of des-methyl hopanes is less obvious, and we have observed these compounds within an Upper Jurassic source rock sequence and in apparently unaltered oils. This series of des-methyl hopanes can not be related only to in-reservoir biological degradation and can therefore not be applied as evidence of biological

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degradation. Although several workers have described the degradation processes as such, there has generally been little attempt to incorporate the biological degradation of petroleum into realistic geological models, and use the information to increase the geological understanding of an area. Thus, while general biochemical processes are reasonably well understood much work remains before reasonable geological models of degradation can be made. This paper is an attempt to describe, understand and model the biological degradation of petroleum in the Gullfaks Field offshore Norway (Block 34/10) on the basis of both petroleum geochemical and geological processes. Although this study concentrates on a specific North Sea reservoir, the ideas and outlines should be valid in other areas as well.

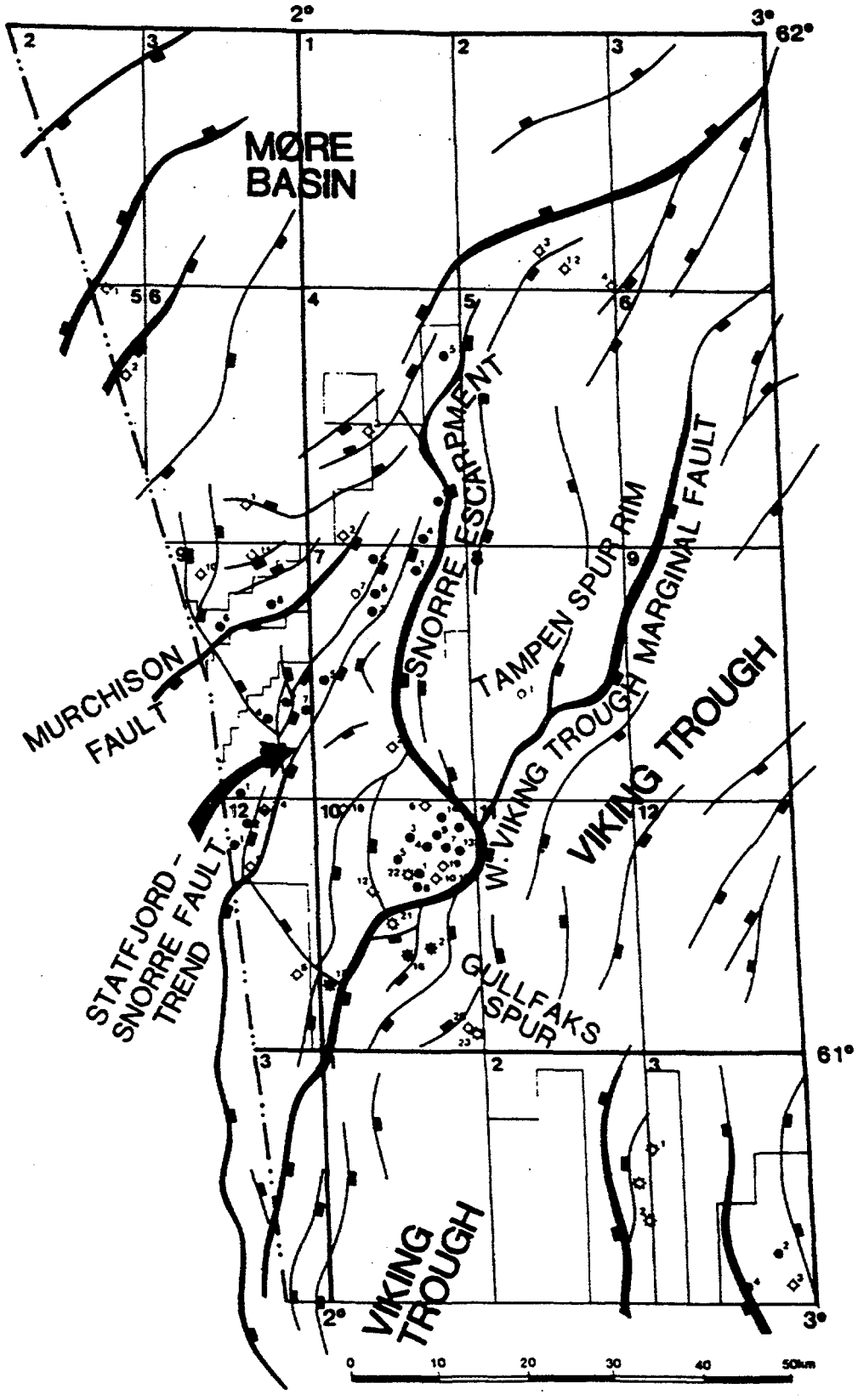

Fig. 1. Geographic location of the main Gullfaks Field in block 34/10. (Modified after Karlsson, 1986.)

GEOLOGICAL SETTING

The Gullfaks Field is located within block 34/10 in the northern North Sea about 175 km west of Norway (Fig. 1). Structurally it is located on the western shoulder of the NNE–SSW trending Viking Graben and with a depth to crest of 1740 m subsea (mSS) and an oil–water contact at 1947 mSS (Brent Group) the Gullfaks Field represents the shallowest structure in the Tampen Spur area. The whole area was uplifted in Upper Jurassic time and structural elements with rotated fault blocks were developed. The amount of uplift increases to the North and to the East within each major fault block. In the Gullfaks Field the whole Brent Group has been removed from the eastern part of the structure, and further North in the Snorre Field area (block 34/4) more than 1 km of sediments have been removed and the erosion cuts down into the Triassic section. The geology of the Gullfaks Field and the Tampen Spur area has been discussed in detail by Erichsen *et al.* (1987), Karlsson (1986), Graue *et al.* (1987) and Petterson *et al.* (1990). The Tampen Spur is a very prolific area of the North Sea and several giant fields are located in the vicinity of the Gullfaks Field adding up to a total of more than $2360*10^6$ Sm^3 oil in place (Norwegian sector only). Most of these reserves are accumulated in the Middle Jurassic Brent Group and Upper Triassic–Lower Jurassic Statfjord Formation. The petroleum within the Gullfaks Field is the only petroleum in the Tampen Spur area that has been significantly biodegraded.

PETROLEUM DISCRIMINATION AND MIGRATION

It has been documented that the petroleum accumulated within the Brent Group in the Gullfaks Field is different to the petroleum accumulated within the Cook and Statfjord formations in the eastern part of the field (Horstad *et al.*, 1990). The petroleum within the Brent Group has different source characteristics and is less mature than the petroleum in the Cook and Statfjord formations (Horstad, 1989; Horstad *et al.*, 1990; Larter and Horstad, 1992). Tentative gradients in the maturity within each population was also used to suggest filling directions into the field (Horstad *et al.*, 1990). The Brent Group was possibly filled from a westerly direction, the most mature petroleum being present in the western part of the field. The Tordis Field is located northwest to the Gullfaks Field and is located on the same migration route as the Gullfaks Field. The Tordis Field is filled to spill and a proposed spill point is located to the south. The similarity of the biological marker distribution in the Gullfaks and Tordis oils support the proposed filling direction into the Brent Group reservoir in the Gullfaks Field (Fig. 2).

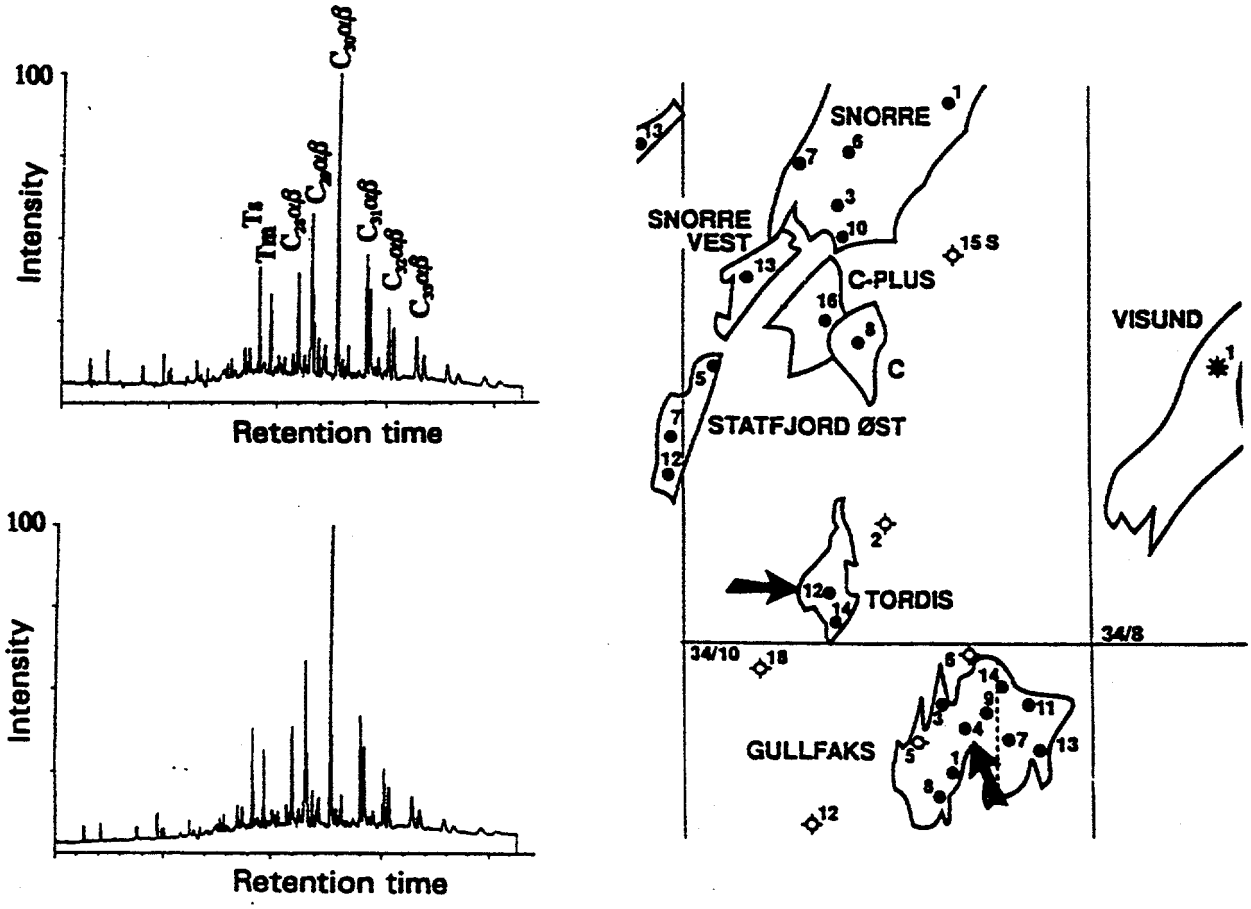

Fig. 2. Oil correlation (shown for hopanes, m/z 191) between the oils within the Brent Group in the Gullfaks Field and the Tordis Field (arrows), supporting the genetic relationship between the two oils. C_{28}–$C_{33}\alpha\beta$ represents regular 17α(H),21β(H) hopanes.

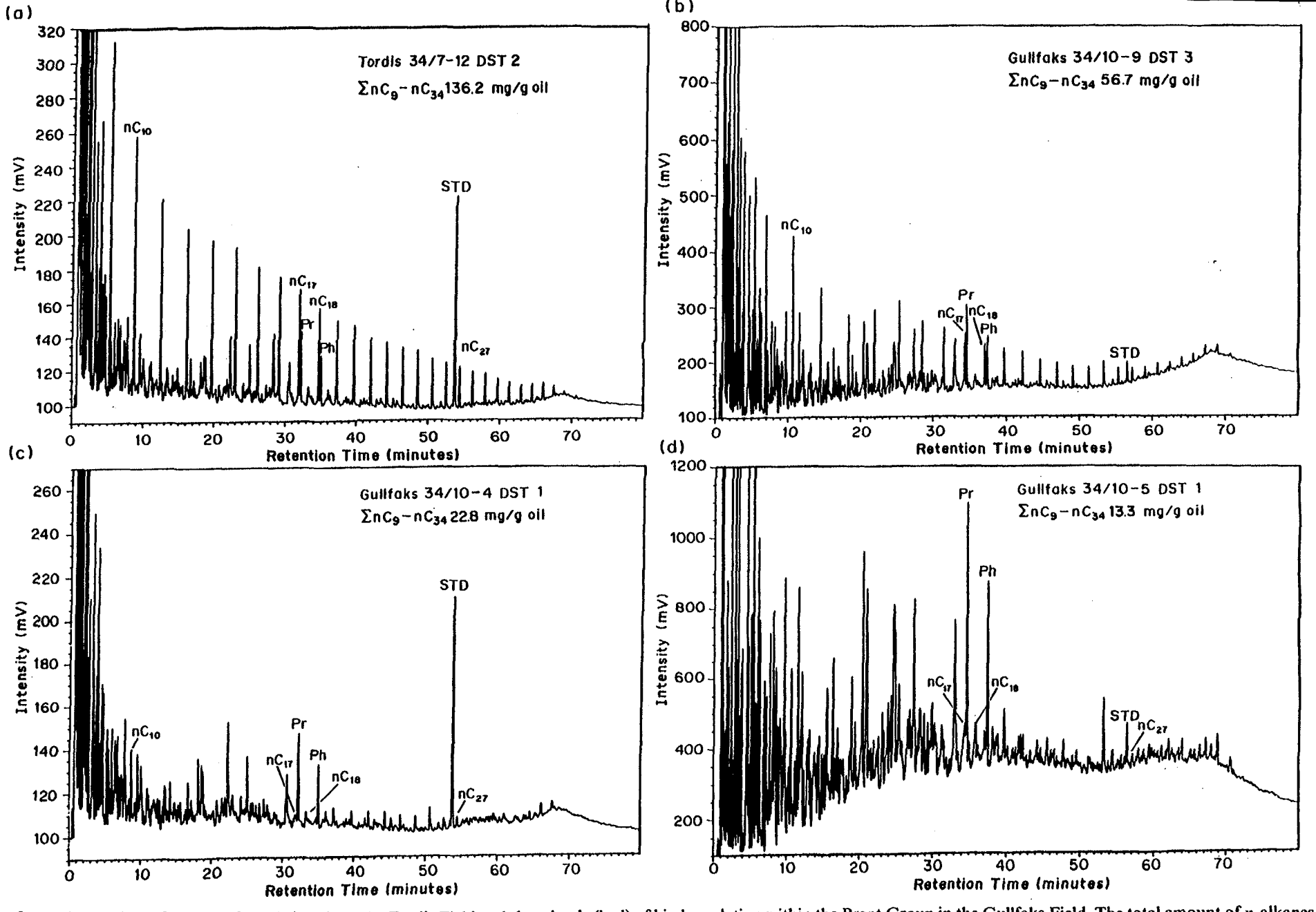

Fig. 3. GC-fingerprints of (a) an undegraded oil from the Tordis Field and three levels (b–d) of biodegradation within the Brent Group in the Gullfaks Field. The total amount of *n*-alkanes between C_8 and C_{34} has been reduced from 136.2 to 13.3 mg/g oil. STD is the internal squalane standard added to the samples prior to analyses.

The vertical composition of the petroleum within he Brent Group is very homogeneous both with respect to bulk composition, *n*-alkane distribution and biological markers. This suggests that there is a very good vertical communication within the Brent Group (at least on a geological time scale), and therefore that it was possible to supply fresh undegraded petroleum to the degradation zone as the degradation of the petroleum proceeded. Perhaps gas generation due to the bacterial degradation enhanced the perturbation and mixing of the petroleum column. The lateral heterogeneity of the petroleum within the Brent Group can be understood on the basis of the time to length squared relationship of diffusive equilibrium (England *et al.*, 1987) and/or lack of large scale horizontal communication due to the intense faulting of the structure.

BIOLOGICAL DEGRADATION OF THE PETROLEUM WITHIN THE BRENT GROUP

The petroleum in the Brent Group has been altered after emplacement and based on comparison with published GC-fingerprints of naturally and artificially degraded oils it is concluded that bacterial action is responsible for the systematic removal of *n*-alkanes observed (Connan, 1984; Goodwin *et al.*, 1981). There are still some *n*-alkanes left in the oils from the Brent Group (Fig. 3), and no signs of biodegradation are observed in the biological markers. Asphaltenes are believed to represent relatively large fragments of the kerogen in the source rock which generated the oil (Larter and Senftle, 1985; Horsfield, 1989) and since the asphaltenes in the Gullfaks oil are not affected by bacterial degradation, pyrolysis–GC of the asphaltene fraction (Bonnamy *et al.*, 1987) will give an indication of the original composition of the oil in the Brent Group. Pyrolysis–GC of the asphaltenes precipitated from the biodegraded oil yields abundant *n*-alkanes and *n*-alkenes (Fig. 4) and it is therefore likely that the source rock that generated the oil in the Brent Group generated an oil rich in *n*-alkanes which is typical for this area.

It has been documented that the degree of biological degradation of the petroleum in the Brent Group reservoir in the Gullfaks Field varies across the field (Horstad, 1989; Horstad *et al.*, 1990). The most severe degradation has taken place in the western part of the field (Fig. 5) where the Brent Group sediments are located at greater depths and therefore not eroded. Since no other structures in the area show signs of biological degradation to the same extent as the Gullfaks Field and the most mature petroleum within the Brent Group is the most severely degraded it is

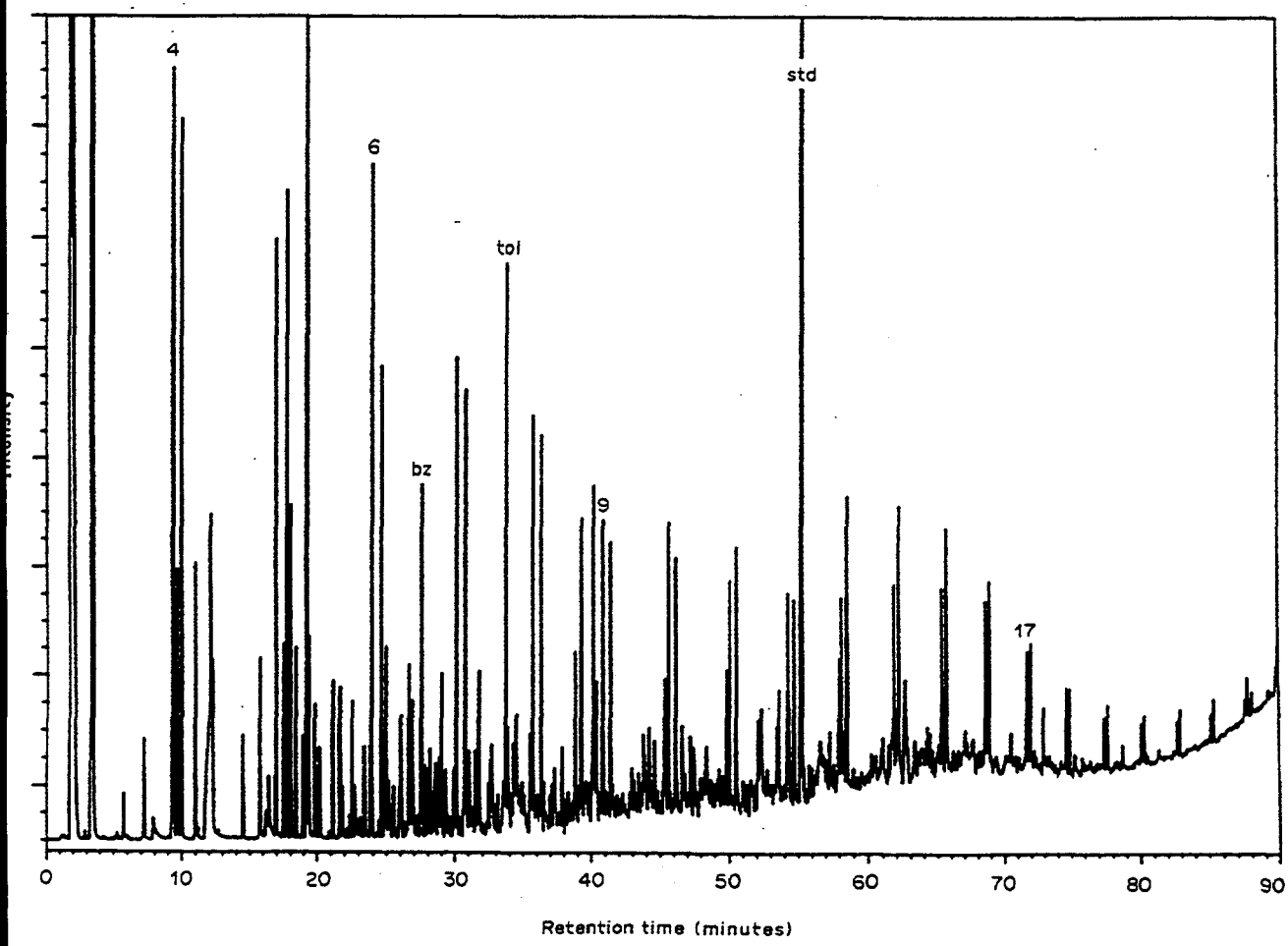

Fig. 4. Py–GC chromatogram of the asphaltene fraction from a biodegraded extract in the Gullfaks Field (34/10-8, 1935 mRKB; see Fig. 1 for location). Numbers refer to *n*-alkenes and *n*-alkanes; bz = benzene, tol = toluene, std = poly *t*-butyl-styrene internal standard added prior to pyrolysis.

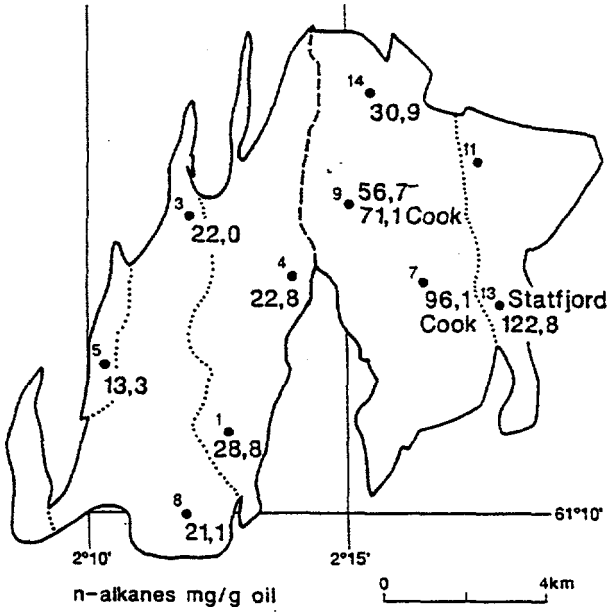

Fig. 5. Total amount of n-C_9 to n-C_{34} alkanes in the analyzed wells in the Gullfaks Field, demonstrating the more severe biodegradation (less n-alkanes) in the western part of the field. The unlabelled numbers refer to average values within the Brent Group in the reservoir. Numbers labelled with Cook and Statfjord represent samples analyzed from the Cook Formation and the Statfjord Formation in the Gullfaks Field. These samples belong to a different petroleum population (Horstad *et al.*, 1989), but the reduced amount of n-alkanes in the oil within the Cook Formation is probably related to the same phase of biological degradation as the oil in the Brent Group.

suggested that the process occurred in the reservoir and not during migration into the structure. It has been suggested that the petroleum within the Brent Group represents a mixture of a palaeoreservoir which was completely degraded during the uplift and exposure of the structure in Late Jurassic time and a fresh undegraded oil which subsequently migrated into the structure, i.e. the observed gradient in the degree of biological degradation is due to mixing. We feel that this is unlikely for two reasons: (i) if the Brent Group reservoir represented a totally biodegraded palaeooil accumulation we would expect to observe a zone in the reservoir which contains much more polar and asphaltic compounds or perhaps a palaeooil–water contact. It seems unlikely that a second oil population would be capable to redissolve the heavy tar created by the total destruction of the first oil. Based on our submetre scale screening of six wells covering the whole Brent Group we cannot see any evidence of a polar rich zone, a tar mat or a palaeooil–water contact which would be expected if a totally degraded petroleum had been present in the reservoir. (ii) Laboratory mixing experiments of the biodegraded oil with a non-degraded oil suggest that even small quantities of the non-degraded oil with abundant n-alkanes mixed with a degraded oil without n-alkanes gives a GC-fingerprint with distinct n-alkane distribution similar to that in the non-degraded oil. The only difference is a slight elevation of the baseline. Biological markers and the structural configuration of the field suggest a filling of the Brent Group from the West, if the current oil population had been mixed with a totally degraded oil we would expect to see n-alkanes in the westernmost (i.e. most mature) oil which is not observed.

BIOLOGICAL DEGRADATION MODEL

It is possible to estimate the absolute amount of n-alkanes that has been removed from the oil in the Brent Group reservoir (referred to as Gullfaks oil) by comparing it with the oil accumulated in the Tordis Field, which is believed to have sourced the Brent Group in the Gullfaks Field via a spill route to the south. The oil–water contact in the Tordis Field is 2224 mSS and no signs of biological degradation are observed in this structure. By assuming the following reaction:

$$\text{Reactant} + X \rightarrow \text{Product} + Y,$$

$$\text{Tordis oil} \rightarrow \text{Gullfaks oil}$$

where X is an oxidizing agent and nutrients and Y are degradation products other than n-alkanes. The absolute amount of C_8–C_{35} n-alkanes in the Gullfaks oil is 26.5 mg/g oil (representative weighted average of 11 oils) compared with 136.2 mg/g in the Tordis Field, thus 109.7 mg n-alkanes per gram oil or about 80% of the n-alkanes have been removed by biological degradation. The Tordis oil contains 13.6% n-alkanes (n-C_8 to n-C_{35}) and has a density of about 844 g/l thus 1 l contains:

$$844\ \text{g} * 0.136 = 114.8\ \text{g}\ n\text{-alkanes}.$$

Since about 80% of the n-alkanes have been removed from the Gullfaks oil, the amount of n-alkanes that have been removed from each litre becomes:

$$114.8 * 0.80 = 92.4\ \text{g}\ n\text{-alkanes}.$$

Assuming that the degradable hydrocarbons in the degraded oil contain an average 13 C-atoms, the average molecular weight would be 184 g/mol, with about 0.50 mol C_{13} or 6.5 mol carbon having been removed per litre oil. This must be regarded as a conservative estimate since only n-alkanes between n-C_8 to n-C_{35} are included in the model and the contribution from C_1 to C_7 and other compounds which are known to be partly degraded (e.g. pristane and phytane) are not considered.

The Stock Tank Oil Originally In Place (STOOIP) of the Brent Group at Gullfaks is about $420 * 10^6$ Sm^3 or $4.2 * 10^{11}$ l of degraded oil. Since 80% of the n-alkanes are removed and these initially made up 13.6% of the oil (as Tordis today), and since the Gullfaks Field is assumed not to be filled to its spill point, the original volume in the Brent Group in the Gullfaks Field was:

$$4.2 * 10^{11} + (4.2 * 10^{11} * 0.80 * 0.136) = 4.7 * 10^{11}\ \text{l}.$$

Thus, during the degradation of the Gullfaks oil the amount of carbon that was released becomes:

$$4.7*10^{11}\,l*6.5\,mol/l = 3.1*10^{12}\,mol.$$

These calculations suggest that in the order of $3.1*10^{12}$ mol carbon ($3.7*10^{10}$ kg) were released during the degradation of the petroleum in the Brent Group in the Gullfaks Field, and if it is assumed that this carbon was converted to CO_2 (or CH_4) it would have resulted in the formation of approximately $90*10^9\,Sm^3\,CO_2$ or $60*10^9\,Sm^3\,CH_4$ respectively.

Even if these calculations are only very approximate they give an order of magnitude estimate of the huge amounts of gas that could have been produced during the biological degradation of the petroleum, and even if the Gullfaks structure is leaking at present (Irwin, 1989) it is difficult to explain where these products are. The gas composition in the Gullfaks Field is at present not vastly different to the related gas in the Tordis Field. The GOR in the Brent Group in Gullfaks varies between 82 and 118 Sm^3/Sm^3 and in Tordis the GOR ranges from about 109 to 119 Sm^3/Sm^3 thus, there are no indications of large gas volumes produced within the Gullfaks Field due to biological degradation. The gas in Gullfaks is however affected by the biological degradation as shown by the relatively high i-C_4/*n*-C_4 and i-C_5/*n*-C_5 ratios (0.7–1.8 and 1.0–4.0, respectively) compared to Tordis (0.3 and 0.7, respectively). It is also worth mentioning that the gas dissolved in the Gullfaks oil seems to be much drier (45–50 mol% methane) and the oil contains a larger content of C_{7+} material (45–50 mol%) than the other oils in the area (the Tordis oil contains about 37 mol% methane and 39 mol% C_{7+} material). This could be related to the effects of the biological degradation, unfortunately there are no carbon isotope data available to the authors on the gas in the Brent Group at Gullfaks at present. The gas associated with the oil in Gullfaks only contains 0.5–1.2 mol% CO_2 and unless large amounts of carbon dioxide has escaped from the structure, removed in solution or been precipitated as carbonates during or after the degradation, it is difficult to believe that carbon dioxide is a major product from the degradation process. The carbon isotope ratio of most of the carbonates in Gullfaks is, however, much heavier (+5 to +13‰ PDB) than in the other structures and these values are abnormal in North Sea reservoirs (Saigal and Bjørlykke, 1987). Carbon isotope ratios in this range are normally associated with carbonates formed within the fermentation zone. If these isotopically heavy carbonates are associated with the degradation of the petroleum in the reservoir a major source of calcium (Ca^{2+}) must be identified. It is worth mentioning that extractable hydrocarbons are present within these carbonate cemented zones, and these extracts appear to be less degraded than the petroleum in the adjacent high quality reservoir zones. This could be explained by a less effective degradation of the petroleum entrapped in the carbonate cemented zones due to increased tortuosity or as a result of entrapment of petroleum in continuously growing carbonate benches as the degradation proceeded.

The next step in our model is an attempt to calculate the volume of water carrying oxidizing agents and nutrients that is required to degrade the petroleum. If the biological degradation occurred as an aerobic oxidation with supply of oxygen rich water the stoichiometric equations would be:

	O_2/C ratio
$C_2H_6 + 7/2\,O_2 \rightarrow 2\,CO_2 + 3\,H_2O$	1.75
$C_{13}H_{28} + 20\,O_2 \rightarrow 13\,CO_2 + 14\,H_2O$	1.54
$C_{20}H_{42} + 61/2\,O_2 \rightarrow 20\,CO_2 + 21\,H_2O$	1.53
$C_{35}H_{72} + 53\,O_2 \rightarrow 35\,CO_2 + 36\,H_2O$	1.51

This suggests that 1.50–1.75 mol O_2 are required per mol carbon, and 1.54 is used as a representative value. Thus, the required amount of oxygen becomes:

$$3.1*10^{12}\,mol\ C*1.54 = 4.8*10^{12}\,mol\ O_2.$$

The solubility of oxygen in water at room temperature is about 0.04 g/l or $2.5*10^{-3}$ mol/l and is even less at higher temperatures. The required volume of *oxygen-saturated* water becomes:

$$4.8*10^{12}\,mol\ O_2/2.5*10^{-3}\,mol/l = 1.9*10^{15}\,l \text{ or } 1.9*10^{12}\,Sm^3.$$

The lateral extension of the Brent Group in the Gullfaks Field is approximately 35 km^2 and assuming an average porosity of 25%, each vertical metre of the reservoir has a void volume of $8.8*10^6\,m^3$. Since it is difficult to determine the height of the water column from which oxygen can be supplied, this parameter is kept as a variable (h in Fig. 6). The number of times the water below the o.w.c. has to be exchanged then becomes:

$$1.9*10^{12}\,Sm^3/8.8*10^6\,m^3*h = 2.2*10^5/h \text{ times.}$$

The time required to supply this volume of water will be controlled by the water flux (f in Fig. 6) and assuming a reservoir length of 4700 m (Fig. 5) the required time becomes:

$$2.2*10^5*4700/h*f = 1.0*10^9/(h*f) \text{ years.}$$

This suggests that if all the oxygen from an oxygen saturated pore water zone of 50 m below the o.w.c. can be utilized by the bacteria and the water flux is 1 m/yr, enough oxygen could be supplied in 20 M.yr, which is a geologically reasonable time.

If a sulphate reducing mechanism is assumed and the degradation of the petroleum obeys the following reaction:

$$2\,CH_2O + SO_4^{2-} \rightarrow H_2S + 2\,HCO_3^-.$$

This equation suggests that 1 mol sulphate is required for every second mol of carbon, however since the petroleum in the reservoir contains much less oxygen

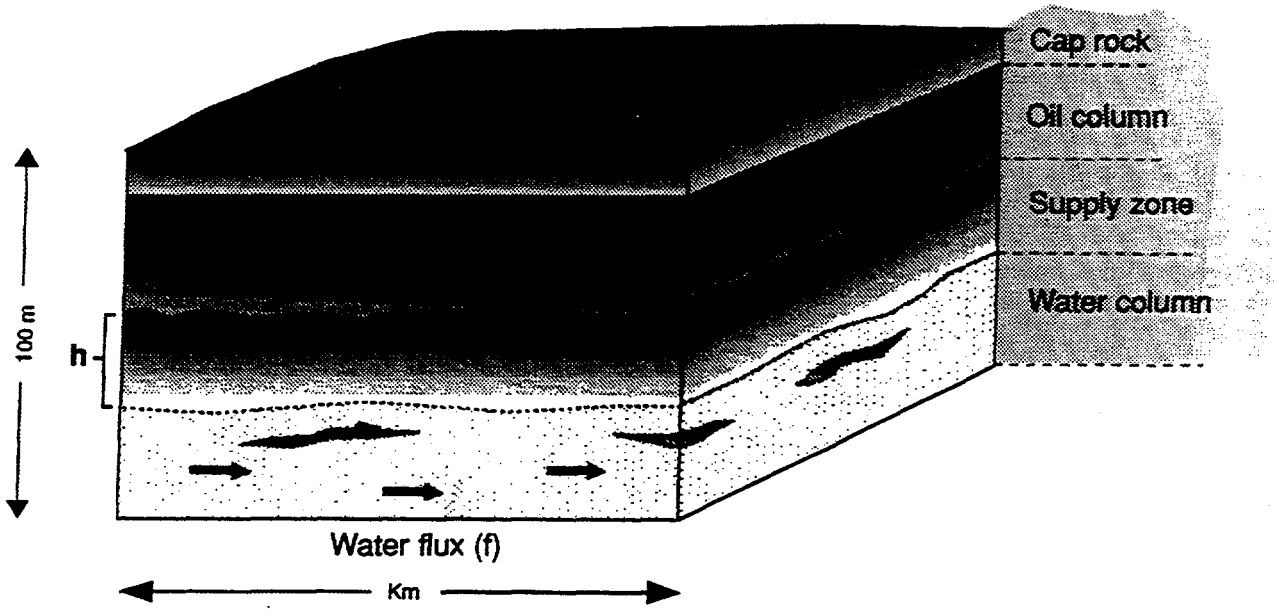

Fig. 6. Biological degradation model for the degradation of petroleum in the Brent Group. The layered model consist of an oil zone, a water zone and a supply zone in the upper part of the water column from which oxygen can be supplied to the bacteria. The height of the supply zone and flux of oxygen-containing water below will determine the volume of oxygen available to degrade the petroleum in the oil column.

Table 1. Time required (M.yr) to supply enough oxidizing agent to degrade the petroleum within the Brent Group at the Gullfaks Field with aerobic and sulphate reducing mechanisms for different values of h and f (cf. Fig. 6)

Flux (m/yr)	Height (m)	Oxygen	10 ppm	2100 ppm
1	10	100	800	0.4
1	50	20	160	0.8
0.5	10	200	1600	0.8
0.5	50	40	320	1.6

than CH_2O this equation underestimates the amount of sulphate required. The volume of water required to supply this amount is dependent on the concentration of sulphate and we have calculated this for pore water with a 10 ppm sulphate concentration which is the present sulphate concentration within the Brent Group and for a saturated solution with a concentration of 2100 ppm sulphate. By repeating the above calculations, the time required to supply enough sulphate with 10 and 2100 ppm concentrations becomes $8*10^9/(h*f)$ M.yr and $4*10^7/(h*f)$ M.yr respectively.

The time required for different values of h and f are listed in Table 1, and plotted as a function of h and f in Figs 7–9.

Obviously it is impossible to supply enough sulphate if the concentration is only 10 ppm, and even if enough can theoretically be supplied within a geologically short time with a sulphate saturated solution (2100 ppm) it is unlikely that such sulphate concentrations have been available in the area. Evaporites are not present in the northern North Sea and it is unlikely that it could have been supplied from sea water. In

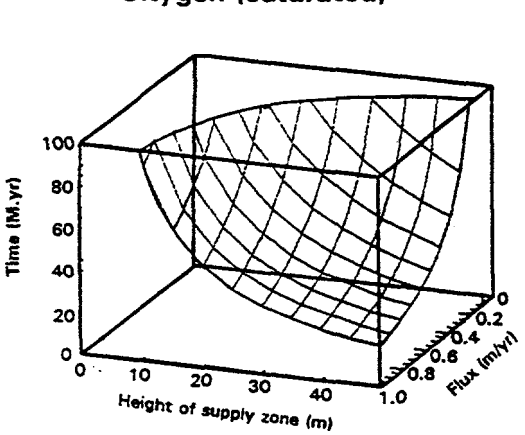

Fig. 7. 3-D surface of the time required to supply sufficient oxygen to degrade the petroleum in the Brent Group as a function of the thickness of the supply zone and the flux (m/year) of water below the o.w.c. in the Brent Group reservoir.

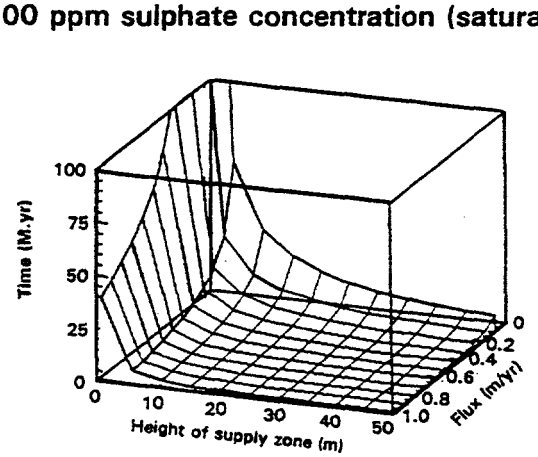

Fig. 8. 3-D surface of the time required to supply sufficient sulphate (2100 ppm) to degrade the petroleum in the Brent Group as a function of the thickness of the supply zone and the flux (m/year) of water below the o.w.c. in the Brent Group reservoir.

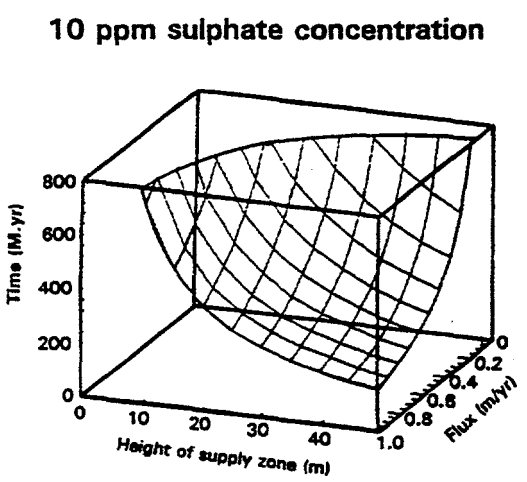

Fig. 9. 3-D surface of the time required to supply sufficient sulphate (10 ppm) to degrade the petroleum in the Brent Group as a function of the thickness of the supply zone and the flux (m/year) of water below the o.w.c. in the Brent Group reservoir.

addition sulphate reduction would have produced large amounts of H_2S, which are not observed in the area and pyrite is only observed in relation with coal beds. Thus, based on geological observations and modelling sulphate reduction seems unlikely.

DISCUSSION

Our calculation of the amount of carbon that has been removed from the Brent Group reservoir in the Gullfaks Field has highlighted several weaknesses in our understanding of biological degradation of petroleum and weaknesses in the Geological model of the area. Our "supply/demand" model demonstrates that if the biological degradation obeys simple stoichiometric equations, it most likely occurred as an aerobic process. This is the only possible way of supplying enough oxygen/water in a geologically reasonable time interval, unless major source of sulphate exists in the vicinity of the reservoir. In this case study sulphate reduction is unlikely since there is no source of sulphate, and no evidence of H_2S or pyrite—which would be the expected products from an anaerobic degradation process. If our model is correct, a major flux of meteoric water must have occurred below the oil/water contact. Dependent on the height of the supply zone, several thousand reservoir volumes are required to supply enough water. This is only possible by introducing a hydrodynamic flow model driven by a hydraulic head introduced by areas elevated above the Gullfaks Field at the time of the degradation. At present the Gullfaks Field is the shallowest structure in the whole Tampen Spur area, and it has been generally accepted by geologists that this has been true since Cretaceous times. We earlier attempted to explain the observed gradient in the extent of biological degradation by adopting Glasmann's flux model from the Heather Field (Glasmann *et al.*, 1988; Fig. 10) but this was generally not accepted as a likely model for this area (Horstad *et al.*, 1990). Careful evaluation of burial curves for several wells has demonstrated that the post Jurassic subsidence of this area is not straightforward. There is evidence of differential subsidence in the Tampen Spur Area during the Tertiary, but to evaluate the relative palaeoconfiguration of the whole area these data must be corrected for palaeowater depth and backstripped. However, even if other structures have been elevated above the Gullfaks Field during Tertiary it seems difficult to flow water through the Tertiary and Cretaceous sediments and into the Brent Group system to degrade the petroleum. One possibility is high pressure introduced by a major ice sheet discussed by Larter and Horstad (1992), though we find these arguments difficult. These observations do however suggest that the Tertiary development of this area may prove to be of vital importance to both oil and water movements, although it has been largely ignored until now, due to the low prospectivity of the Tertiary in this part of the North Sea. It is also worth mentioning that large possibly erosional or channel-like features can be observed in the Oligocene–Miocene section above the Gullfaks Field (Plate 1.1 in Ziegler

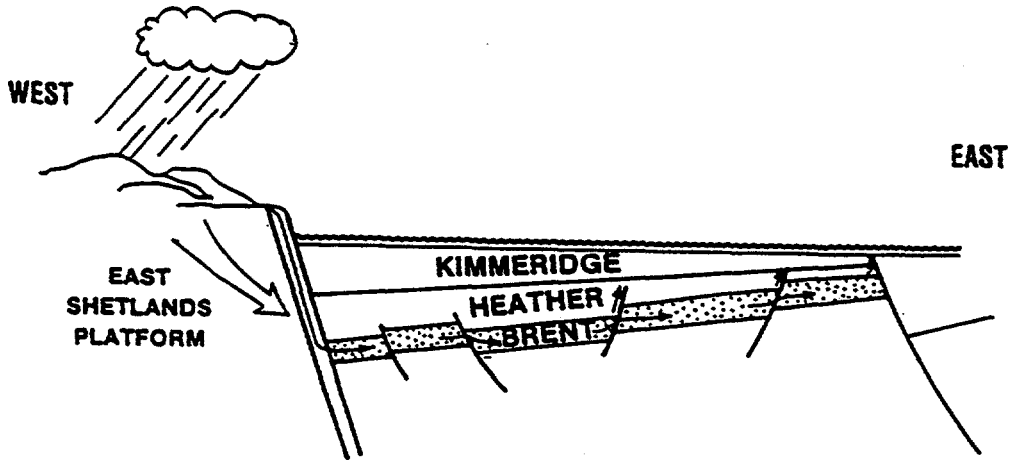

Fig. 10. Proposed meteoric circulation system within the Middle Jurassic reservoir during Lower Cretaceous time in the Heather Field (U.K.). (After Glasmann *et al.*, 1988.)

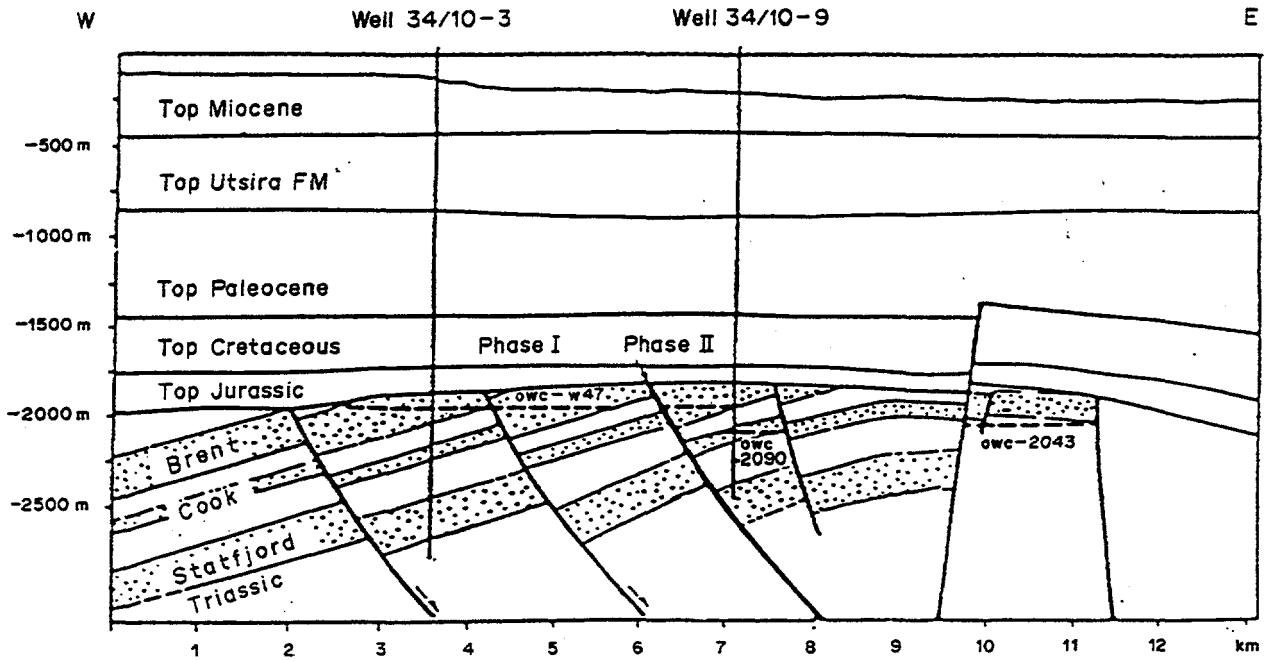

Fig. 11. E–W cross section through the Gullfaks Field showing the apparent relationship between the relative height of the water and oil columns and the extent of biological degradation within each well in the Brent Group in the Gullfaks Field. This suggest that the relative amount of oil and water within each section of the field might be a critical factor in the degradation of the petroleum in the reservoir. This ratio increases as the extent of biological degradation increases towards the West.

et al., 1986) and it can be speculated whether these could be related to the biological degradation of the Gullfaks Field. It is obvious that the quantitative field aspects of biological degradation are more or less unknown, and should be intensively studied in the future to get a better understanding of the geological significance of biological degradation. This is especially important as laboratory studies of petroleum degradation cannot reproduce the rate/time scales appropriate to geological degradation. The application of quantified data from different areas might give new insight into the process involved in biological degradation. We observed a relationship between the relative height of the water and oil columns in each well and the extent of biological degradation (Fig. 11), as the ratio of the water to oil columns increased, the degree of biological degradation increased towards the West in the Gullfaks Field. Possibly the observed gradient in the biological degradation can therefore be explained by the vertical section of the reservoir available to meteoric water flux and relative permeabilities in the reservoir, i.e. the meteoric water does not have to flow through the structures from West to East, as was suggested previously (Horstad, 1989; Horstad *et al.*, 1990). However, such a relationship must be better documented by using the relative pore volumes of oil and water within the whole field, which requires a detailed reservoir model. A second possibility is that the degradation occurred without a major water flux through the reservoir but by recycling the oxygen already present in the system (fermentation) but this seems unlikely on quantitative grounds. Other possibilities are mineral oxides or perhaps even by biochemical water decomposition, but these sources of oxidizing agents must be regarded as very speculative and little evidence exists to support them. The presence of isotopically-heavy carbon in carbonates (+5 to +13‰ PDB) in the Brent Group reservoir in the Gullfaks Field (Saigal and Bjørlykke, 1987) suggests that fermentation occurred in the reservoir at some time, but this might have occurred before the structure was filled with petroleum. This problem could be answered by examining the nature of the extractable hydrocarbons in these carbonate cemented zones.

CONCLUSIONS

After a detailed 3-D mapping of the entire Brent Group reservoir in the Gullfaks Field and by applying quantitative methods, we were able to give a reasonable estimate of the amount of carbon removed from the reservoir by biological degradation. We have also proposed a degradation model to evaluate different degradation mechanisms. We have pointed out several weaknesses in our understanding of biological degradation, and the necessity and power of combining geological and geochemical information. It has been demonstrated and modelled that with our current understanding of in-reservoir biological degradation, the petroleum within the Brent Group in the Gullfaks Field was degraded by aerobic mediated bacteria cultivated by a supply of oxygen and nutrient rich water through the reservoir. This is however difficult to explain with the current geological model for this part of the North Sea. The study of the biological degradation in the Gullfaks Field has demonstrated that several weaknesses exist in the geological model of the area, and perhaps the renewed interest in the

prospectivity of the Tertiary section in the area will bring new insight into the problems related to the biological degradation of the petroleum within the Gullfaks Field. It has also shown the necessity to incorporate geochemical information in the geological model of an area, and unless the geochemical observations are accounted for in the geological models, these must be regarded as incomplete.

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Paper III

Migration of petroleum into Brent Group reservoirs: some observations from the Gullfaks field, Tampen Spur area North Sea

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Abstract: Whereas the processes of petroleum generation and primary migration are beginning to be understood from a quantitative viewpoint, the process of secondary migration is still incompletely quantitatively understood. We estimate that typically the carrier systems feeding Brent Group reservoirs contain an average of around 3% residual oil saturation, the petroleum flowing in high saturation petroleum rivers through the most permeable carrier bed zones. Most of the carrier porosity contains no petroleum. The filling of the Brent Group reservoir in the Gullfaks field (Tampen Spur) is elucidated by petroleum geochemistry and this study indicates that the field has filled from more than one source basin and has been biodegraded post oil-emplacement. The complex filling and degradation history suggests that geochemical study of reservoir petroleum columns is a useful exercise providing information on the fillpoints of these complex reservoir systems and potentially information on the palaeohydrogeology of the area.

It is generally agreed that the major source rocks for the medium and high gravity black oil accumulations found in Brent Group sandstones in the rotated fault block structures of the Viking Graben and East Shetland basin are the organic rich marine shales of the U. Jurassic Draupne or Kimmeridge Clay Fms., (Goff 1983; Cornford *et al.* 1986; Thomas *et al.* 1985). While of variable organic facies (Huc *et al.* 1985; Larter 1985), at maturities of around 1% R_o vitrinite reflectance equivalent, the locally very rich (initial potential as high as 30 kg/tonne or more, Thompson *et al.* 1985) marine organic matter dominated clastic source rocks in the basinal areas may have expelled up to 80% of their generated oil (Cooles *et al.* 1986; Mackenzie *et al.* 1987) which may represent as much as 30%+ of the initial organic content of the sediment (Larter 1988). This efficient expulsion of oil occurs as a single phase (Mackenzie *et al.* 1987) from organic rich sediments such as the Draupne Fm (up to 10% TOC) driven by the compaction resulting from volumetrically significant conversion of solid phase kerogen to fluid petroleum and overburden driven expulsion. The volume lost from the sediment due to petroleum expulsion may be up to 7% in the oil window and may account for most of the volume loss during deep burial of source rocks (Larter 1988).

In addition to gross chemical changes and reduction of hydrogen index for the source rock kerogens with increased burial, maturation and petroleum generation, molecular indicators of source maturity also show systematic changes. For example Fig. 1 shows the evolution of the isomerisation at C_{20} of the C_{29} regular sterane (Mackenzie 1984) in extracts of Draupne Fm cuttings samples from the N. Viking Graben. This is one of a great many properties used by petroleum geochemists as indicators of source maturity (cf. Mackenzie 1984). While the mechanism of this reaction (20R $\rightarrow$ 20R + 20S) is unclear and simple isomerisation can be eliminated (Requejo 1989; Abbott *et al.* 1990), published 'kinetic' models (Mackenzie & McKenzie 1983) can be used in an empirical prediction engineering manner (Larter 1989) to provide viable predictions of the evolution of this parameter with maturation. Thus Fig. 1 shows data from analysis of the Draupne Fm. from several wells in the N. Viking Graben area and while the data shows much scatter (a result of caving problems primarily) a general agreement is seen between the source rock data and predicted profiles based on computer models using a variety of linear (constant heat flow with respect to time) and rift basin heat flow models (rifting event at 120 Ma, $\beta = 1.8$; after Mackenzie & McKenzie 1983).

The principal zone of hydrocarbon generation and expulsion covers the depth range 2.5–3.5 km in this area and in this range the sterane parameter 20S/20S + 20R) changes from about 30–55% 20S. The data on Fig. 1 from a cored petroleum reservoir shows values around 55% 20S and suggests this oil was sourced from source rocks around 3500 m. As

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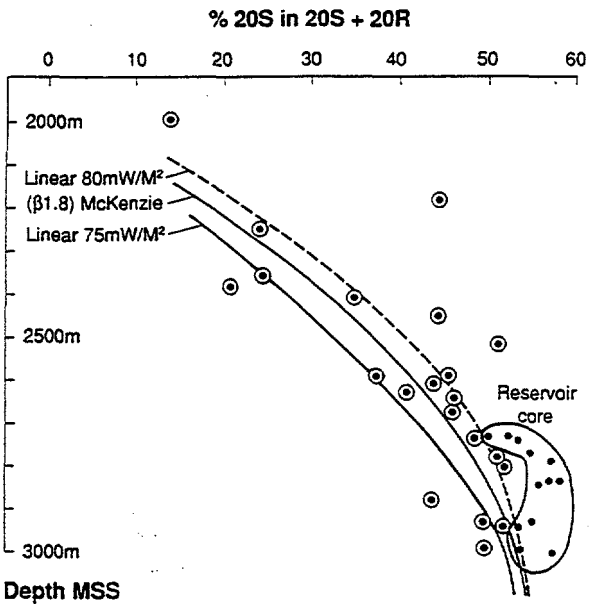

Fig. 1. Depth distribution of C_{29} sterane 20S/(20S + 20R) for Draupne Formation samples, N. Viking Graben. Computed profiles for this parameter are also shown based on generalised burial histories and the kinetics published by Mackenzie & McKenzie (1983). Data from analysis of reservoired petroleums are also shown.

secondary migration predominantly involves buoyant upward migration to cooler regions it is reasonable to assume that in many situations, temperature driven reactions involved in maturity parameters are effectively frozen once the petroleum has left the source rock. Thus the molecular markers carry information on the source rock temperature (maturity) and organic facies (cf. Mackenzie 1984 for a review). As we see later the use of such molecular markers as remote source rock probes may provide us with information on the actual processes involved in the filling of individual Brent Group reservoirs and we demonstrate their use in a study of the Gullfaks field from the Tampen Spur area.

Brent Reservoir geochemistry: examples from the Gullfaks field

Large-scale compositional heterogeneities in petroleum accumulations have been known for many years but it is only in the last few years that chemical heterogeneities in petroleum columns have been interpreted geochemically (England *et al.* 1987; England & Mackenzie 1989; Karlsen & Larter 1989; Leythaeuser & Ruckheim 1989; Larter *et al.* 1990; Horstad *et al.* 1990). It seems from these recent studies that, in addition to biodegradation and water washing effects, variations in petroleum column composition may additionally be interpretable as being due to source facies and/or maturity variations in the petroleum charges feeding the oil accumulation. The variable composition of the petroleum charges feeding oil fields is integrated and may be preserved as compositional variation in the petroleum column due to the slow rate of diffusive or density driven mixing processes in the reservoir (England & Mackenzie 1989; Larter *et al.* 1990) and the absence of thermal convection in most liquid petroleum columns.

In this paper we summarize a reservoir geochemical study of the Gullfaks field, paying attention to the clues provided on the filling of the Brent Group reservoir there. Petroleum reservoir geochemistry may prove to be one of the most powerful applications of petroleum geochemistry to geological basin evaluation problems. Even in well-drilled provinces such as the Brent Province, North Sea area, the vast majority of well locations are aimed at evaluation of structural highs. Mature petroleum source rocks relevant to known petroleum accumulations are therefore only rarely and often incompletely sampled. A systematic study of petroleum column heterogeneity in this province is therefore not only of academic interest but is also directly relevant to determining, using molecular marker approaches discussed briefly above, the location off-structure, type and maturity of the actual mature source rocks responsible for the accumulation. Further we have suggested before (Horstad *et al.* 1990) that by directly determining the location of field fill points for these fields it may prove possible to place more accurate estimates on the volumes of oil stained carrier beds involved in trap filling and thus better define relevant petroleum carrier systems and petroleum losses associated with the carrier system. We expand on this below.

Figure 2 shows a summary calculation of the volumetric aspects of petroleum entrapment assuming a perfect seal on the trap. The volume of petroleum trapped is equal to the volume expelled from the source bed minus the volume lost in the carrier as residual oil stain (oil shows). Corrections can be made for PVT effects on the migrating charge using empirical density, pressure, temperature relationships (cf. Glasø 1980; England *et al.* 1987). Mature source rock volumes (ST × SA) can be fairly accurately estimated using modelling and seismic definition and the mass of petroleum expelled (M_e) can usually be estimated to much better than an order of magnitude using mass balance ap-

Volume Petroleum in Trap (V_T)

= Volume Petroleum (trap P.T.) expelled from source V_S

minus

Volume Petroleum (trap P.T.) lost in carrier VL

$$V_T = V_S - V_L$$

$$V_S = Me \times ST \times SA / \rho_T \text{ (trap P.T.)}$$

$$V_L = CT \times CA \times \varnothing_{av} \times RS \times \rho_C \text{ (carrier P.T.)} / \rho_T \text{ (trap P.T.)}$$

Me	=	Mass Petroleum expelled / CuM Source Rock
ST	=	Mature Source Rock Thickness
SA	=	Mature Source Rock Area
ρ_T	=	Total Petroleum density at trap P.T.
ρ_C	=	Total Petroleum density at carrier P.T.
CT	=	Carrier Thickness
CA	=	Carrier Area
$\varnothing_{av}$	=	Average Carrier Porosity
RS	=	Average Carrier Residual Petroleum Saturation

Fig. 2. Petroleum migration volumetrics expressed in terms of the volume of petroleum in trap (V_T), the volume expelled from the source (V_S) and the volume lost in the carrier (V_L).

proaches (Goff 1983; Larter 1985; Cooles *et al.* 1986) calibrated where possible using geochemical data from wells (cf. Mackenzie & Quigley, 1988). In contrast the petroleum loss, V_L, is much less easily estimated.

The volume of total possible carrier bed connecting source rock basin to trap can usually easily be estimated from seismic studies and simplistic concepts of up-dip migration. Average carrier porosities can be estimated empirically or by calibration from well studies. However a major uncertainty exists on the magnitude of the effective residual petroleum saturation (RS) existing in most carrier systems (England *et al.* 1987; Macgregor & Mackenzie 1986). As petroleum will only flow as a discrete phase through a water bearing rock when the petroleum saturation reaches high values (greater than 50–80%; England *et al.* 1987) and as there is rarely enough petroleum to completely saturate an entire carrier system, petroleum will flow in a few zones of high saturation, most of the carrier being water saturated and not exposed to petroleum. As it is not practical to assess remotely where petroleum is flowing in the gross carrier volume, an accountancy parameter, the effective residual saturation, RS, is needed for the calculation. This parameter has no physical significance but merely represents an averaged petroleum saturation for the carrier as defined in terms of gross geometry.

England *et al.* (1987) estimate that the parameter RS varies from about 1–10% in most carrier systems and Macgregor & Mackenzie (1986) estimated using case histories and volume balances that for fluvial sand carriers in the Central Sumatra basin RS was about 2%. Such volume balances for Brent Group reservoirs, using estimates for petroleum expelled and subtracting in place petroleum, can be used to place broad estimates of RS for the East Shetland basin (using Goff 1983 data) and for other Brent Group reservoirs. While most Brent Group-reservoired fields are filled to trap spill-point by petroleum (in that regard Gullfaks is exceptional being underfilled) we can make crude maximum estimates that the average carrier residual petroleum saturations for Brent + Statfjord carriers are around 3% of the porous volume of the potential carrier volume for oil reservoirs in the N. Viking Graben and E. Shetland basin areas. What is concerning, is that doubling RS often results in a 'disappearance' of the accumulations i.e. V_L exceeds V_S. Clearly this empirically and crudely determined parameter is the critical parameter in a volumetric migration analysis yet is not accessible by any realistic deterministic approach that we know of. It is not yet clear to us whether the large uncertainties in V_S, but particularly in V_L (Fig. 2), render the estimation of V_T as anything more useful than a purely academic exercise.

While large uncertainties exist on our estimates of the fraction of a carrier system actively carrying petroleum we can be certain that only a small fraction of the carrier is active and that petroleum must flow into the traps through a few small 'keyhole' conduits. Analysis of published reservoir geochemical data from the Draugen field (Trøndelag Platform, Norway) certainly suggest that large oil fields do not fill on broad fronts (the classic text book drainage area) but fill through rather restricted zones (Karlsen & Larter 1989) from petroleum rivers, the location of which is perhaps not easily predictable from analysis of the carrier system alone. This strengthens our view that reservoir geochemical study may prove to have value in defining field fill points or keyholes.

We can now illustrate the field fill point concept with a geochemical study of Brent Fm. and Cook/Statfjord Fms. reservoirs in the Gullfaks field.

The Gullfaks field is located in Block 34/10, 175 km from the Norwegian coast (Fig. 3). A

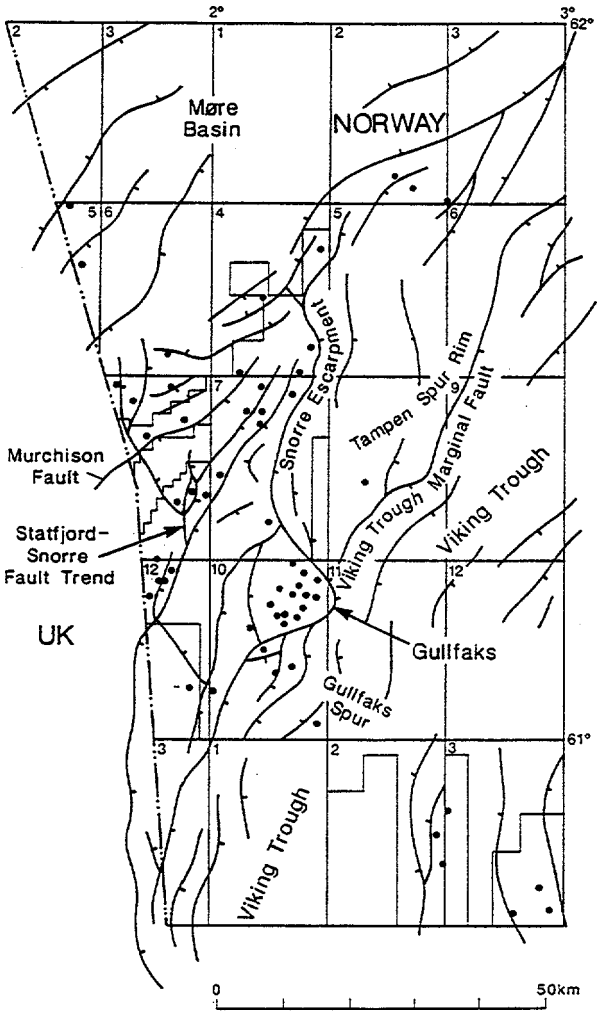

Fig. 3. Geographic location of the main Gullfaks field in block 34/10, 175 km off the Norwegian coast. (Modified after Karlsson 1986).

total of 500 million Sm^3 oil is present in the Middle Jurassic (Bajocian–Bathonian 183–169 Ma) Brent Group and the Triassic to Early Jurassic Statfjord formation (Rhaetian–Sinemurian 218–196 Ma) and the Jurassic Cook formation (Pliensbachian–Toarcian 196–198 Ma) sediments (Erichsen *et al.* 1987). In this study we concentrate on the Brent Group reservoir, but to complete the picture some analyses of oil samples from the Cook and Statfjord formations are included. The sediments of the Brent Group in the Gullfaks field area are buried at 1800–2000 meters, and are located on the structurally high Tampen Spur areas, between the East Shetland basin, East Shetland platform and the Viking Graben (Karlsson 1986). The Brent Group sediments (Bajocian–Bathonian age) represent a regressive–transgressive megasequence showing a complete delta cycle (Eynon 1981), and consist of five different formations with large variations in lithology and reservoir properties (papers in this volume). After deposition of the Brent Group the Gullfaks field area was eroded and uplifted in the Late Jurassic, resulting in several westerly tilted fault blocks (Fig. 4). The erosion of the Brent Group sediments was most severe on the crests of the rotated fault blocks, and on the eastern most fault blocks the whole Brent Group sedimentary section has been eroded away (Karlsson 1986). In this part of the field, reservoired petroleums are therefore found only in the Triassic Lunde and Statfjord formations and the Lower Jurassic Cook formation. Most of the Upper Jurassic and Lower Cretaceous sediments are missing on the main Gullfaks structure, only 1 m of the Draupne Formation is present in the deepest and most westerly well

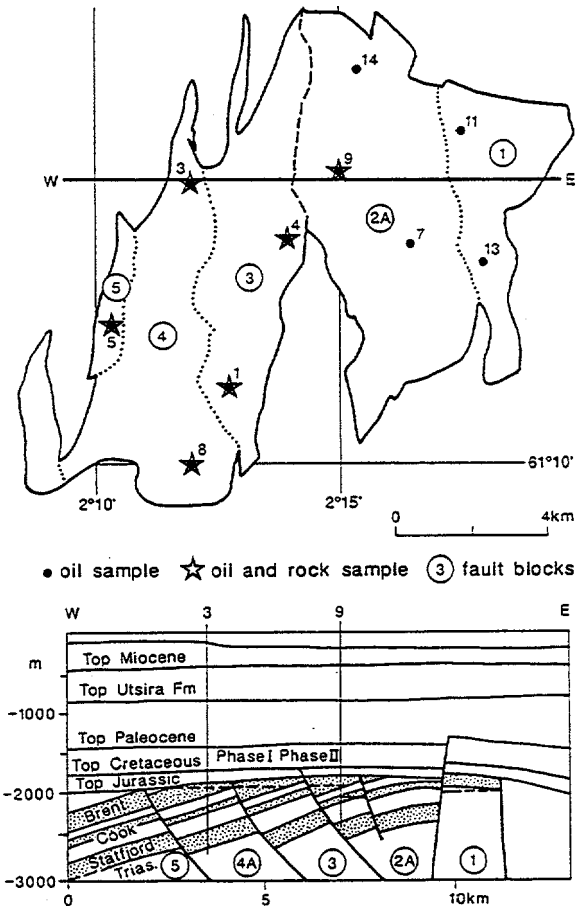

Fig. 4. Detailed map of the Gullfaks field showing the location of each well, and the type of samples available. An E–W geological cross section of the field shows the orientation of the rotated fault blocks in the area, and the erosion of the Brent Group sediments on the crest of the eastern fault blocks. (After Erichsen *et al.* 1987).

(34/10–5) and the total thicknesses of Cretaceous sediments is between 100–180 m, the greatest thicknesses being present in the northern part of the field (wells 34/10–3, 9 and 14). Since Upper Cretaceous time the whole area has been under general subsidence (Graue *et al.* 1987).

The Jurassic and Triassic Gullfaks petroleum reservoirs are sealed by Upper Cretaceous fine grained sediments, but leakage from the at present undersaturated and overpressured reservoirs to the Paleocene sediments above has been reported (Irwin 1989). This petroleum leakage from the Gullfaks reservoirs means that the system cannot be treated as a simple trap but may represent a system in which more than one current reservoir volume has been swept by petroleum during the trap's lifetime.

Figure 4 shows the locations of reservoir cores and reservoir fluid samples studied. For complete details of the study the reader is referred to Horstad (1989) and Horstad *et al.* (1990). The reservoir was studied using the general procedure outlined by Larter *et al.* (1990) the objective being to define a filling history for the Gullfaks field.

Petroleum geochemical approach

A model for petroleum accumulation development should among other features comprise the following information:

(1) definition of the organic facies, maturity level, expulsion efficiency, volume and location of source rocks charging petroleums to the reservoir;
(2) definition of the location, orientation, connectivity and residual petroleum saturation of the regional carrier system transporting petroleum from source basins to trap;
(3) determination of the times at which various portions of the field reached significant petroleum saturation levels and how this distribution of petroleum is related to the sedimentology and diagenesis of the reservoir;
(4) determination of the extent of post-filling mixing or transport of petroleum within the field by diffusive or advective processes such as mechanical stirring or reservoir tilting;
(5) evaluation of the mechanisms and extent of alteration of the petroleum column by biodegradation or other in-reservoir processes such as tar mat precipitation.

Our approach initially involves the 3-D compositional mapping of the petroleum accumulation (cf. Karlsen & Larter 1989) and the definition of the maturity structure of the field (the spatial relationships between petroleums of differing source maturities). The maturity structure of an oil accumulation is determined using one of the multitude of biomarker (Mackenzie 1984; Cornford *et al.* 1986) or alkylaromatic hydrocarbon based maturity parameters (Radke 1988) or in terms of gross maturity related parameters such as solution gas-oil ratio or saturation pressure/bubble point (England & Mackenzie 1989; Karlsen & Larter 1989). A filling direction for a single reservoir field may then potentially be ascertained in terms of a gradient of maturity within the field, the most mature petroleums being nearest the charging points of the reservoir (cf. Karlsen & Larter 1989; Leythaeuseur & Ruckheim 1989; England & Mackenzie 1989).

Mapping of the petroleum column must be based on a high resolution petroleum population distribution map of the reservoir (the term petroleum population refers to a petroleum zone of definable bulk composition with similar maturation and/or source characteristics). An approach to petroleum population mapping which permits rapid mapping of petroleum reservoirs on a metre scale for several wells within a field was described in Karlsen & Larter (1989) and Horstad (1989) using combinations of a thin layer chromatography-flame ionization detector system (TLC-FID) and Rock-Eval screening of reservoir cores to provide gross compositional information (i.e. concentrations of total petroleum, saturated hydrocarbons; saturated/aromatic hydrocarbon ratios etc.). This approach was applied to reservoir cores from the Gullfaks field and the screening formed the basis for selection of samples for further detailed molecular analysis.

The vertical composition of the petroleum column in the Brent Group reservoir at the Gullfaks field, as determined by the screening procedure is generally very homogeneous at any location (Fig. 5). The only exceptions are samples selected from the Ness Formation, where the bulk composition of core extracts varies due to local contamination from in situ coals (Horstad 1989). The screening procedure in which several hundred analyses were performed indicated that for this reservoir, DST samples provided an adequate description of the petroleum column. In other reservoirs this may not be so (Larter *et al.* 1990).

While at any location the vertical composition of the petroleum is quite constant, systematic variations in the chemical composition of the petroleum within the Brent Group reservoir are recognized laterally across the field. Based on

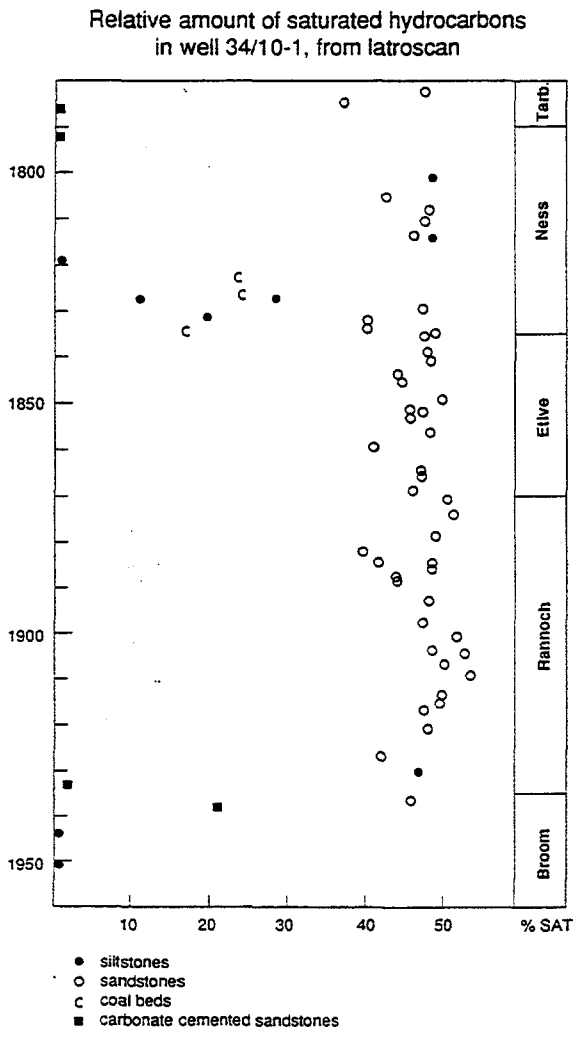

Fig. 5. The vertical composition of the petroleum column in the Brent Group reservoir is very homogeneous, shown here by the relative amount of saturated hydrocarbons as determined by Iatroscan TLC-FID.

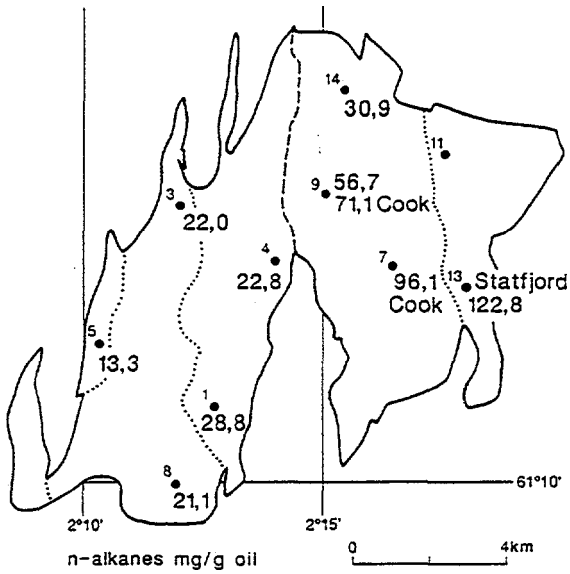

Fig. 6. Total yield of n-alkanes (C_9–C_{34}) in all the wells. The data is the average of all available Drill Stem Test samples in each well. Note the easterly increase in the absolute amount of n-alkanes due to more severe degradation in the western part of the field. It is stressed that the samples within the Cook and Statfjord formations are not in communication with the Brent Group. Based on G.C. analysis of whole oil samples with internal standard quantitation.

analysis of 12 different DST oil samples from the Brent Group reservoir in seven wells, a systematic gradient in the absolute amount of C_9 to C_{34} n-alkanes (determined by internal standard quantitation) is observed. The n-alkane concentration (ΣnC_9–nC_{34}) varies systematically from 56.7 mg/g oil in the eastern part of the reservoir to 13.3 mg/g oil in the western part of the reservoir (Fig. 6). The absolute amount of C_9 to C_{34} n-alkanes is even higher in petroleum reservoired within the Cook and Statfjord formations further east, but this petroleum belongs to another slightly more mature petroleum population, although of related source facies. This systematic removal of n-alkanes in the west of the Gullfaks structure can also be seen by isoprenoid alkane/n-alkane ratios (i.e. pristane/n-C_{17}, phytane/n-C_{18} ratios) demonstrating the same systematic gradient across the field. In the most degraded oils in the western Brent reservoir removal of pristane and phytane is also observed (Horstad 1989). By comparison with several studies of biological degradation reported in the literature (Winters & Williams 1969; Bailey *et al.* 1973; Connan 1984; Jobson *et al.* 1979; Milner *et al.* 1977) it is concluded that the decrease in the absolute amount of n-alkanes across the field is due to biological degradation of the petroleum. Large scale convection in petroleum columns would result in a uniform petroleum composition both vertically and laterally across at least each fault block in the field. This of course assumes that vertical and lateral reservoir barriers are essentially absent. While we cannot demonstrate this, a common oil–water contact in most wells does suggest that large scale communication on a geological time scale is good across the field. As lateral gradients are observed in the n-alkane concentration gradients (Fig. 6) large scale pervasive thermal convection over a long time can be eliminated as a mixing mechanism and this is confirmed by calculation of Rayleigh numbers for the petroleum accumulation (Horstad 1989) which indicate a stable thermally non-convective state for the reservoir.

It is concluded based on estimates of diffusive equilibration times that diffusion is the main mixing process eliminating chemical concentration gradients in the Brent Group reservoir in the Gullfaks field (Horstad *et al.* 1990).

Although anaerobic bacterial in-reservoir degradation of petroleum cannot be ruled out by laboratory study as slow laboratory degradation rates may be significant over geological time, it is generally agreed that aerobic bacterial activity is the principal initiator of biological degradation of crude oils in the geosphere (Connan 1984). Although fermentative processes have occurred in the Gullfaks reservoir at some time as indicated by the geochemistry of carbonate benches in the reservoir (Saigal & Bjorlykke 1987), fermentation is not linked to the petroleum degradation at this time. We therefore consider that the degradation of the Gullfaks petroleum was caused by bacterial degradation involving the interaction of molecular oxygen and petroleum mediated by bacteria.

An oxygen mass balance suggests that the observed petroleum degradation could be carried out in less than 10 Ma with a 1 m a^{-1} meteoric water flow through the Brent reservoir below the oil column (Horstad 1989). The gradient in partial degradation observable in Fig. 6 is interpreted to reflect an input of meteoric water, molecular oxygen and perhaps nutrients at least locally from the west of Gullfaks. Bacteria may have been supplied from the recharge area with the water flow, by particulate diffusion from the recharge area or may represent ancient dormant bacteria deposited with the Brent sediments and reactivated by oil and nutrient flow into the reservoir. While estimates of bacterial diffusion coefficients in water using Stokes-Einstein equations suggest that bacterial diffusion may be adequate to import bacteria into a reservoir from recharge areas this process most likely occurs by flow of bacteria with the oxygenated water from the recharge area which is relatively rapid (thousands of years). A gradient in n-alkane concentrations suggests that degradation post-dated reservoir filling. While we cannot conclusively eliminate a later phase of non-degraded oil mixing into the degraded reservoir the interpreted maturity gradients discussed below, are inconsistent with this hypothesis.

Facies and maturity differences among the two petroleum populations in the Gullfaks field

Karlsen & Larter (1989) defined a petroleum population as a contiguous charge of petroleum in a field, which is chemically definable in terms of a source facies or maturation level. Based on GC/MS analysis of the saturated hydrocarbon fractions of the Gullfaks oils, it is possible to distinguish two different petroleum populations within the sample set from the Gullfaks field: one early to mid-mature population present in the Brent Group in the western part of the field, and a slightly more mature population within the Cook, Statfjord and Lunde formations in the eastern part of the field. This is reflected in slight differences in the relative distribution of C_{27}, C_{28}, C_{29} 5α(H),14β(H),17β(H) cholestanes in the petroleums. Although there is a considerable scatter in the data set, samples from the Brent Group reservoir generally contain relatively less 5α(H),14β(H),17β(H)-methylcholestane (C_{28} sterane) compared to the C_{27}, C_{29} homologues than samples from the Cook, Statfjord and Lunde formations. The presence of two petroleum populations is also supported by the 17α(H),21β(H)-28,30-bisnorhopane/17α(H),21β(H)-30-norhopane ratio (Fig. 7).

The statistical significance of these conclusions was performed by applying Student's t-Test for two sample analysis (Davis 1973), which confirmed discrimination of the two petroleum populations, at a significance level of 0.05 (5%), both for the distribution of 5α(H),14β(H),17β(H)-methyl-cholestane (as a % of 27–29 homologues) and the 17α(H),21β(H)-28-30-bisnorhopane/17α(H),21β (H)-30-norhopane ratio (Horstad 1989). In-field differences in petroleum composition generally require the statistical testing of hypotheses as compositional differences are often small. We conclude that the Brent Group reservoir was filled from a related but slightly different source to those filling the Cook/Statfjord Fm reservoir. Though we have no direct basin oil-source rock correlations to fall back-on, regional considerations favour an Upper Jurassic source for both petroleum populations.

Petroleum maturity gradients across the field

Since the generation and expulsion of liquid petroleum from a source rock occurs over a certain depth and temperature range (typically 50°C at any location corresponding to times of 5–50 Ma with usual geological heating rates), a petroleum reservoir should receive more and more mature petroleum as it is filled from a continuously subsiding source rock basin, providing it remains in communication with the source rock. Thus, if a reservoir is filled from

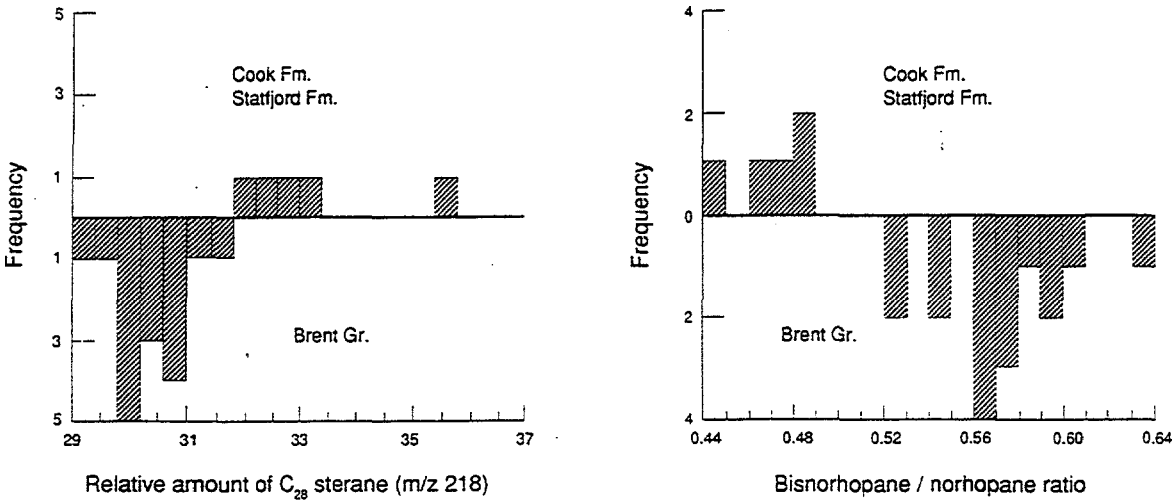

Fig. 7. Statistical testing of the relative amount of C_{28} 5α(H),14β(H),17β(H)-methyl-cholestane and the 17α(H),21β(H)-28-30-bisnorhopane/17α(H), 21β(H)-30-norhopane ratio, suggest that the Brent Group oils and the Cook/Statfjord formations oils belongs to two statistically different petroleum populations, at a 5% level of significance (based on a students-T test analysis of 21 samples).

one end in a sequential manner, the most mature petroleum in the reservoir should be located nearest the source rock basin or probable filling point (England *et al.* 1987; England & Mackenzie 1989; Karlsen & Larter 1989; Larter *et al.* 1990). We envisage the reservoir filling initially as suggested by England *et al.* (1987), by a progressive local petroleum saturation increase near the fill point. As filling continues we envisage that once extensive oil water contacts were locally established filling took place largely by density driven flow (England & Mackenzie 1989) driving petroleum in a rotational manner from fill point to reservoir extremity, thus maintaining a maturity gradient. Since the temperature range over which liquid petroleum is expelled from a high quality source rock such as the Draupne Formation/ Kimmeridge Clay is rather limited, the corresponding shift in the different maturity indicators will be small, typically in the range equivalent to 0.6–1.0% vitrinite reflectance. This approach therefore requires a very precise determination of the source maturity indicators carried by the petroleum charge.

When the hopane X/(hopane X + 17α(H),21 β(H) hopane) ratio (Cornford *et al.* 1986), the proposed isomerization at C-20 in 5α(H),14α (H),17α(H)-ethylcholestanes S/(S + R) (Fig. 8), the apparent isomerization from 14α(H), 17α(H) to 14β(H),21β(H) in ethylcholestane ($\beta\beta$/($\alpha\alpha$ + $\beta\beta$) ratio) and the 18α (H)-22,29,30-trisnorneohopane/17α(H)-22,29,30-trisnorhopane (Ts/Tm) ratio are plotted on a map of the field, related very tentative gradients in the interpreted petroleum maturities are observed (Horstad *et al.* 1990). The most mature petroleum in the Brent Group reservoir appears to be present in the western part of the field, while the most mature petroleum in the Cook/Statfjord reservoir system is present in the eastern part of the field. The relatively small maturity gradients across the field (3–4 standard deviations) observed here may reflect the observation made earlier that the Gullfaks system may have been partially open during filling, the present gradients reflecting a relatively late stage maturity window in the evolution of the source rock basins. However it is also possible that a Late Cretaceous/Early Tertiary age for filling of the reservoir will have allowed for a significant diffusion affected lateral mixing of the petroleum columns resulting in reduced gradients.

On the basis of statistically tested differences in source rock facies indicators and maturity differences between the two main petroleum populations and the more tentative maturity gradients within each population shown in Fig. 8, it is very tentatively concluded that the Gullfaks structure probably was filled from two different source rock basins, one to the west and one slightly more mature to the east or northeast of the Gullfaks structure. We are currently testing this hypothesis with maturation modelling methods. The conclusion based on maturity gradients is of necessity weaker based on few data points but a typical gradient of several standard deviations is observed across the field for most of the maturity parameters. It is further noted that the standard deviations are

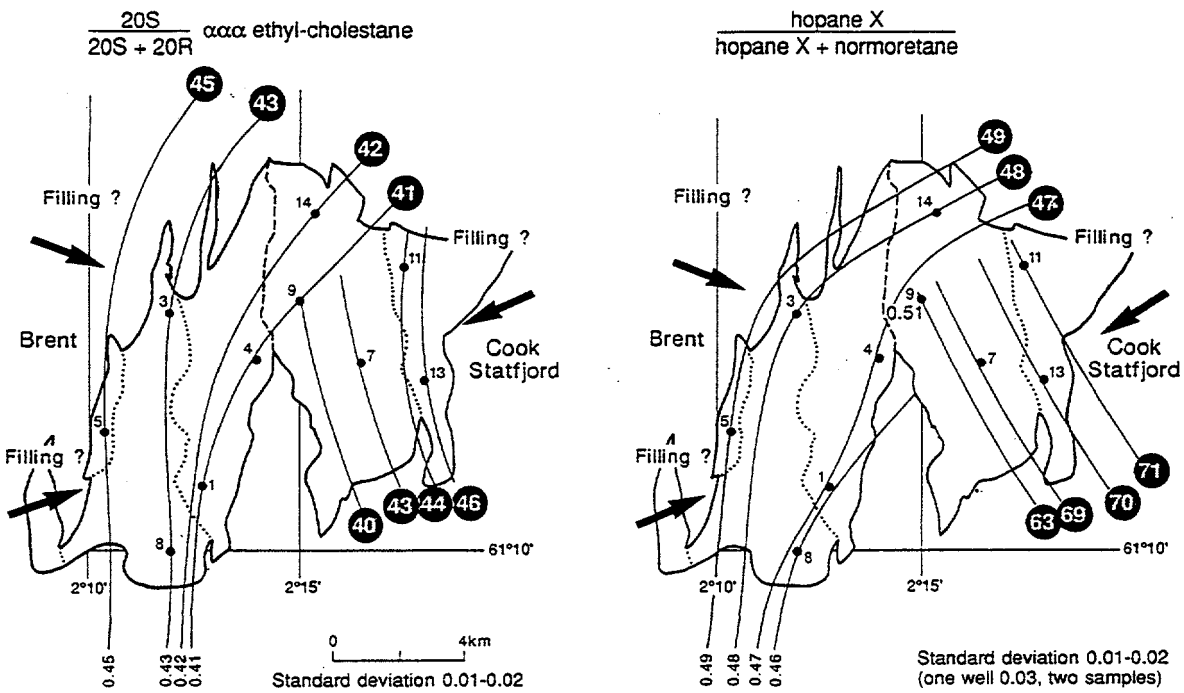

Fig. 8. A tentative interpretation of two different maturity gradients in the field based on the % hopane X/(hopane X + hopane) ratio and isomerization at C-20 in 5α(H),14α(H),17α(H)-ethyl-cholesterane, (%20S/(20S + 20R)), one within the Brent Group in the western part of the field and one within the Cook/Statfjord formations in the eastern part of the field. The contours are highly schematic and are for illustrative purposes only. These two maturity gradients might reflect the filling of the field from two continuously subsiding source rock basins. Based on up to 12 samples in each well.

calculated from analysis of several different petroleum samples (up to 12 in well 34/10−1) at each location, not reanalysis of the same sample. All the analyses were obtained in sequence by the same operator on the same mass spectrometer set up. While we cannot exclude biodegradation as a factor in influencing these maturity gradients we feel the bulk of the evidence supports the conclusion that these are maturity gradients. Recent oil correlation studies from oils in Tordis field (west of Gullfaks) and from block 34/8 are consistent with our conclusions.

To date, one of the major problems in this reservoir study, has been determination of the timing of the different events related to filling and degradation.

Since the rotated fault blocks in the western part in the field are less eroded on the crests than the fault blocks to the east, it is likely that this part of the field has always been deeper, after the fault block rotation in Jurassic time. Thus, since the most severely degraded petroleum is located where the water first reached the reservoir, the input of oxygen-rich meteoric water to degrade the petroleum must have been derived from water flow at least locally from the west.

To date we have not been able to reconcile all our observations of the Gullfaks field with the geology of the area. We can conclude with some certainty that the trap has been filled from at least two different basins and carrier systems but we cannot adequately define the fill time. The most probable time of degradation of the oils in the western part of the field is prior to the rapid subsidence of the whole area in early Tertiary time (Frost 1989) when, presumably, overpressuring of the reservoir and removal of recharge areas would have stopped meteoric water flow. While a Tertiary degradation event cannot be ruled out from our data, we have no geological information to support this concept and suggestions that oxygenated water could have been driven into the reservoirs by the up to 3 km ice sheets present in the North Sea area water columns during glacial times (Cornford, pers. comm.) are not physically convincing. It seems probable therefore that the oils were emplaced in late Cretaceous/early Tertiary time. This in itself is somewhat problematic in that preliminary maturation modelling suggests that only the Viking Graben source rocks would be mature at this time (Glasmann *et al.* 1989.) The major problem now concerns the explanation of the westerly degradation gradient

observed in the Brent reservoir. Our early attempts to explain the inflow of water from the west of the Brent Group reservoir by recharge from elevated areas along the Statfjord/Snorre fault trend (Horstad *et al.* 1990), in the manner described by Glasmann *et al.* (1988) for the Heather field, seem complicated by the absence, to our knowledge, of any indication of an exposed recharge area there in late Cretaceous/early Tertiary time. Simple calculations suggest that a hydraulic head of 30 m in a recharge area feeding a 1 Darcy permeability Brent sandstone could deliver enough water to degrade the Gullfaks reservoir in less than 4 Ma (Horstad, 1989), but we cannot define such an area at present. We cannot rule out much more complex filling/degradation scenarios that might explain the observed maturity/degradation gradients but these are not discussed here. We are continuing to study this problem by looking at the petroleum geology of the area and by continuing this study as part of a longer study of petroleum accumulations in the whole Tampen Spur area. Additionally we are reviewing the geochemistry of subsurface petroleum biodegradation which we feel is far from understood.

Conclusions

On the basis of a petroleum column geochemical study of the petroleum in the Brent Group and Cook/Statfjord Fm reservoirs at the Gullfaks field, the petroleum in the reservoir can be divided into two main petroleum populations on the basis of statistically testable biological marker analysis. Further, filling directions into the reservoir are possibly reflected in two more tentative gradients in the maturity of the petroleum suggesting the Brent Group reservoir filled from the west, the Cook and Statfjord Fms reservoirs filling from the north or north east.

After emplacement, the petroleum in the Brent Group, and to a lesser extent the petroleum in the Cook and Statfjord formations, were degraded by aerobic bacteria. The oxygen and nutrient supply was charged from unknown elevated areas driving water flow from the west causing a gradient in the extent of biological degradation of the Brent Group oil columns from west to east.

The compositional variations in the field are not connected with convective mixing, and diffusion, the major mixing process, is only able to homogenize the petroleum composition on a relatively small scale. Lateral compositional heterogeneities may therefore persist for millions of years, but a relatively long time since filling (*c.* 60 Ma) may have enabled diffusion to markedly attenuate compositional gradients across the field. A further complication may be that since the Gullfaks seal may not have been efficient throughout the fields history, the current reservoir charge may therefore only represent a fraction of the petroleum that has migrated into the trap (Irwin 1989). This reservoir study confirms the view that petroleum traps fill in a complex manner, often from several source basins, reservoir geochemistry helping to better define the location of active fill points or 'keyholes' into the reservoirs.

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Paper IV

Migration of hydrocarbons in the Tampen Spur area, Norwegian North Sea: a reservoir geochemical evaluation

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Abstract: This paper describes the application of reservoir geochemical protocols to a study of oil-field and regional petroleum compositional variations in the major fields in the Tampen Spur area. The Tampen Spur high is located in the middle of several oil-mature to gas-mature source-rock kitchens and most of the structures might receive petroleum from several different directions. Based on the definition of several different petroleum populations within the Tampen Spur area, we define five major petroleum charging systems. Correlating the petroleum population variations with geological information allows us to derive likely migration/fill scenarios for many of the oil-fields and requires us to invoke a new Upper Jurassic carrier system in parts of the area connecting Brent Group reservoirs across major faults. Based on this hypothesis, two exploration wells were drilled on structures to test this carrier and petroleum was found in one of the structures. An understanding of the migration pathways and petroleum drainage efficiency of the basins is of great economic interest, because most of the smaller sub-structures are marginally economic. Thus, it is important to provide an effective risk analysis and ranking of the satellite prospects prior to drilling. This study has demonstrated that filling and migration in a geological province are controlled by a series of complex processes and that the filling history of the structures within the Tampen Spur is more complicated than suggested earlier.

Based on a detailed oil–oil correlation by conventional geochemical techniques (gas chromatography–flame ionization detection (GC–FID), gas chromatography–mass spectrometry (GC–MS) and stable carbon isotope analyses), we propose a detailed migration model for the northern part of the Tampen Spur area based on both geological and geochemical information. Thus, this paper represents a summary of a geochemical study of the Tampen Spur area and does not attempt to address all aspects of the geochemistry and geology of the East Shetland Basin and Tampen Spur in general.

Exploration history

It is far beyond the scope of this paper to give a detailed description of the geological history of the Tampen Spur area and the reader is referred to other papers that have discussed this subject in more detail. (Kirk 1980; Eynon 1981; Graue *et al.* 1987; Roberts *et al.* 1987; Karlsson 1986; Nystuen & Fält 1995; Erichsen *et al.* 1987; Olaussen *et al.* 1993).

The Tampen Spur area is located in the northern part of the Norwegian North Sea, between the north-south trending Viking Graben and the East Shetland Basin, and represents a continuation of the East Shetland Platform (Fig. 1). Several giant oilfields have been discovered in the area, of which the Statfjord Field (Fig. 2), discovered in 1974 on the border between the Norwegian and the UK sector, is the largest. The Statfjord Field is one of the largest oilfields in the North Sea, with a STOOIP of more than 1200×10^6 Sm^3. The main reservoirs in the Statfjord Field are the Middle Jurassic Brent Group, the Early Jurassic Cook Formation and the Late Triassic to Early Jurassic Statfjord Formation (Fig. 3) (Kirk 1980; Eynon 1981; Graue *et al.* 1987; Roberts *et al.* 1987).

The Gullfaks Field (Fig. 2) was discovered in 1978 and in addition to the Brent Group, the Cook Formation and the Statfjord Formation, the Triassic Lunde Formation was found to be oil-bearing in this structure, demonstrating that oil migration and accumulation have occurred locally via at least four different stratigraphic levels in this area (Erichsen *et al.* 1987; Olaussen *et al.* 1993; Horstad *et al.* 1990). The current estimates of the STOOIP in the Gullfaks Field are about 500×10^6 Sm^3 and, as for the Statfjord Field, about 80% of the reserves are present in the Brent Group. The Snorre Field (Fig. 2) is located on the northern rim of the Tampen Spur and was discovered in 1979. In this area of the Tampen Spur, the Late Jurassic to Early Cretaceous uplift resulted in removal of the Cook Formation and the Brent Group, and in the northern part of the field the erosion removed the Statfjord

From CUBITT, J. M. & ENGLAND, W. A. (eds), 1995, *The Geochemistry of Reservoirs*, Geological Society Special Publication No. 86, pp. 159–183.

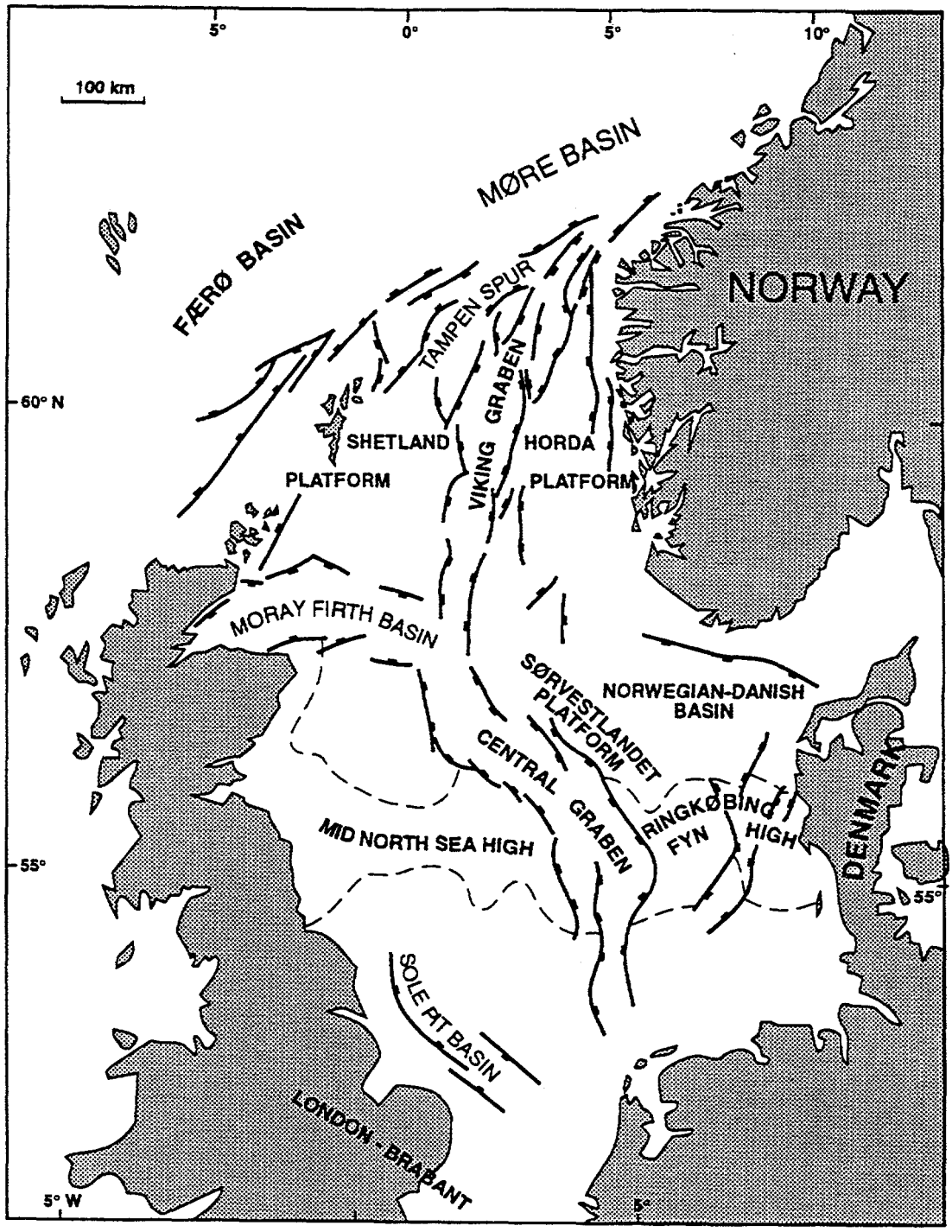

Fig. 1. Geographic location of the Tampen Spur in the North Sea.

Formation and cuts down into the Triassic Lunde Formation. The main reservoir unit in the Snorre Field is the Lunde Formation which contains about 75% of the total STOOIP of 490×10^6 Sm^3 (Hollander 1987), the rest being accumulated within the Statfjord Formation in the southern part of the field.

In addition to these three major accumulations upon the Tampen Spur high, several smaller structures have been discovered in between the larger fields. Statfjord Øst was discovered in 1976, Statfjord Nord in 1977, Tordis in 1987, Vigdis from 1986 to 1990 and Gullfaks Vest (34/10-34) in 1991 (Fig. 2). Along the border towards the Viking Graben, several oil and gas discoveries have been made in down-thrown terraces at several different structural levels. The Visund Field was discovered in 1986 and consists of several different segments with large differences in the petroleum composition and fluid contacts. Petroleum has been found in the Lunde Formation (condensate), the Statfjord Formation (oil) and the Brent Group (gas with oil

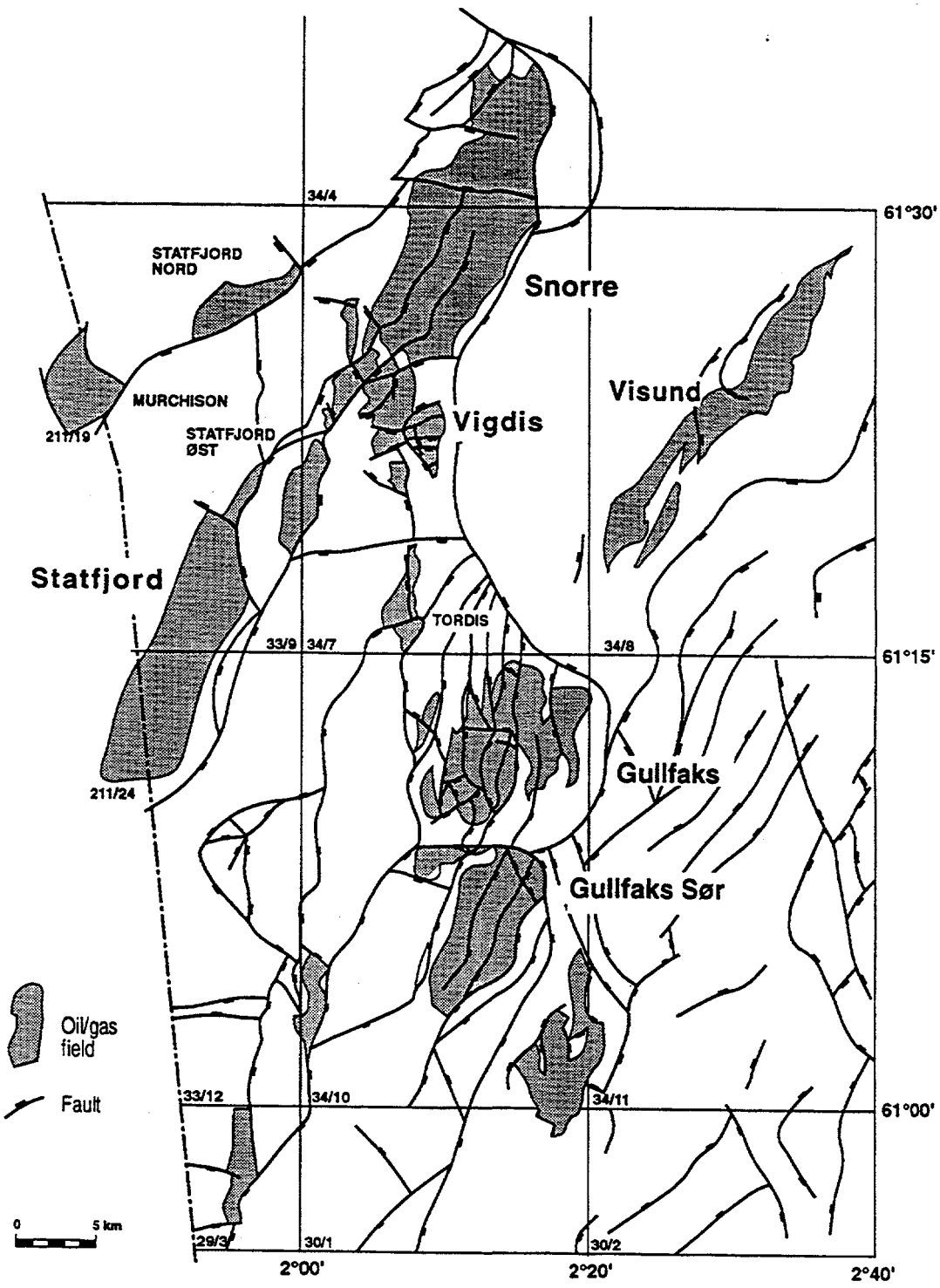

Fig. 2. Detailed map of the Tampen Spur area.

leg) and this is a good example of how complicated the migration is in the northern part of the North Sea. The Gullfaks Sør Field was discovered from 1978 to 1989 and is as complex as the Visund Field with respect to petroleum composition and fluid contacts. In this structure, petroleum has been found in the Lunde Formation, the Statfjord Formation, the Cook Formation and the Brent Group. The deepest producing discovery was made in 1985 on the 34/10 Gamma structure, where a relatively dry gas was produced from the Brent Group at 4090 m. Thus, the Tampen Spur contains a series of oil, condensate and gas discoveries with gas/oil ratios (GOR) ranging from 50 Sm^3/Sm^3 to 11 500 Sm^3/Sm^3, reservoir burial depths ranging from shallower than 2 km to deeper than 4 km, and variations in petroleum type from light, *n*-alkane-rich typical North Sea crude oil to biodegraded oils.

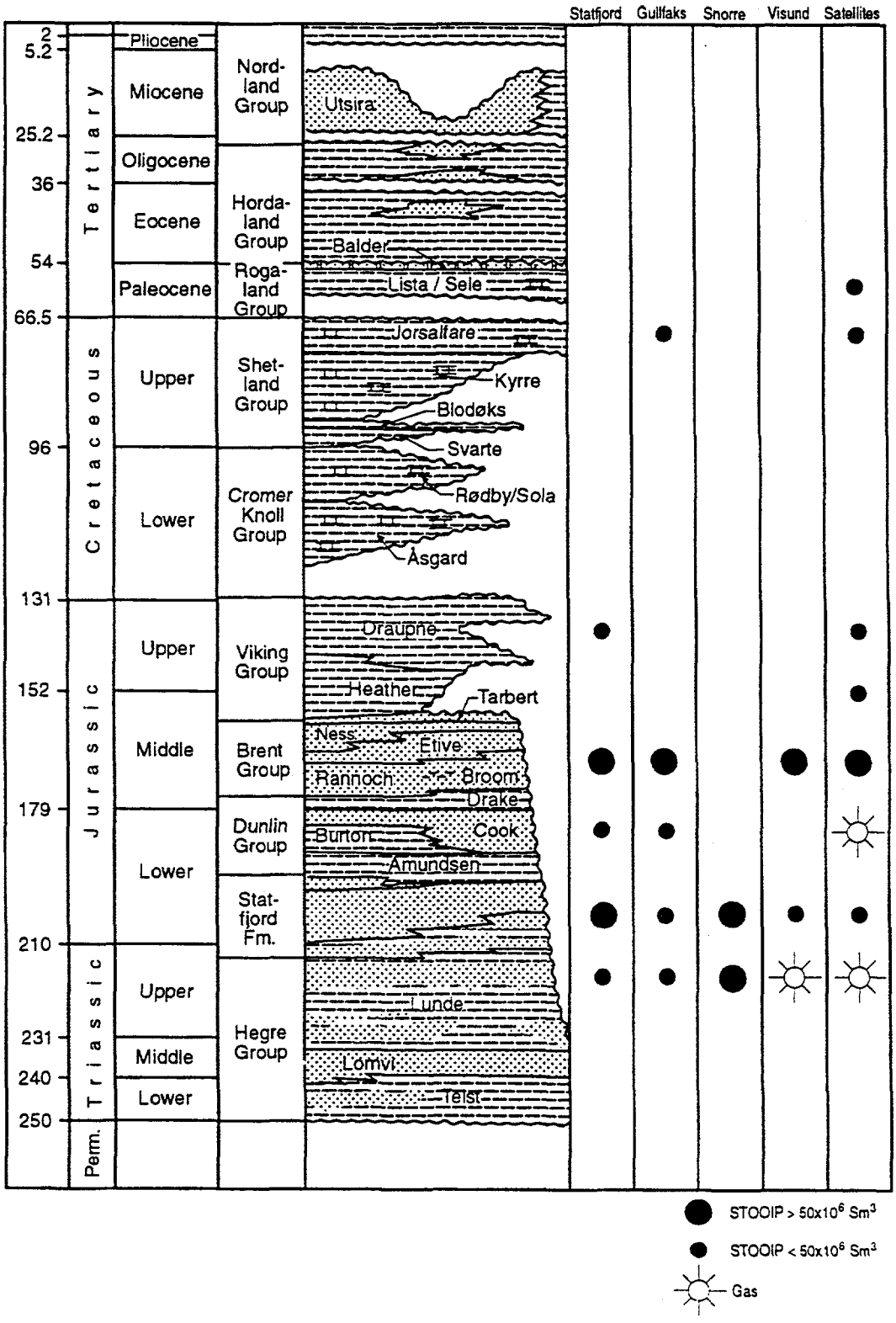

Fig. 3. General stratigraphy and reservoir levels in the Tampen Spur area.

Several of the oilfields on the Tampen Spur lie adjacent to multiple source kitchens and could have been filled from more than one direction.

The Tampen Spur represents a structural high which is surrounded by several source kitchens where the Upper Jurassic source rocks are oil-mature to gas-mature (Fig. 4) and capable of expelling petroleum at several different stages from the Late Cretaceous to present. Virtually all the structures in the area are located in such a position that they may have received petroleum from more than one direction and it is of vital importance to the further exploration of the area to understand the petroleum migration and emplacement systems in

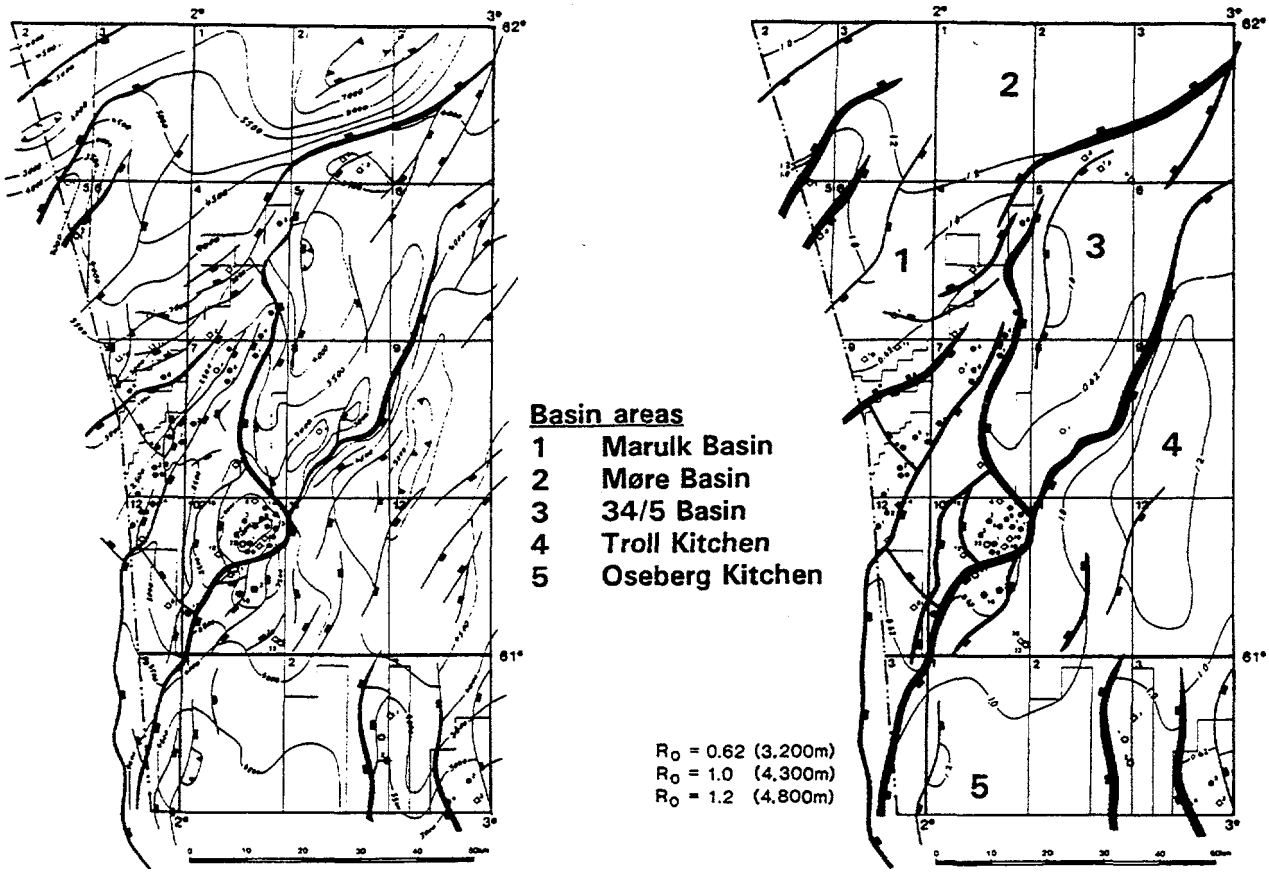

Fig. 4. Base Cretaceous depth map and major source-rock kitchens in the northern North Sea (modified from Karlsson 1986).

the area. The Marulk Basin is located to the northwest of the Snorre Field, the Møre Basin to the north, the 34/5 Basin to the northeast and the Viking Graben to the east (Fig. 4) and all have expelled petroleum towards the Tampen Spur high. In addition, a major spill route from the Oseberg Kitchens to the south, through the North Alwyn Field, Brent Field and Statfjord Field has been proposed (Thomas *et al.* 1985; Karlsson 1986).

Geological development of the Tampen Spur area

The Lunde Formation represents the upper part of the Hegre Group and has been divided into three units (Fig. 3). The main reservoir is present in the Upper Lunde Formation. The Upper Lunde Formation consists of alternating sandstones, oxidized claystones and palaeosols, deposited on an arid to semi-arid, wide alluvial floodplain. The net/gross sand ratio varies significantly through the formation and is controlled by climatic factors, sea-level changes, regional basin subsidence, rate of sediment influx, local faulting and local lake-level changes (Nystuen & Fält 1995). The lower part of the Lunde Formation represents a braided stream facies which gradually changes to a more meandering river system. The transition from the Lunde Formation to the Statfjord Formation represents a gradual change towards a more humid climate and a river system dominated by braided streams. Towards the upper part of the Statfjord Formation the marine influence decreases and the overlying Dunlin Group (Amundsen Formation, Burton Formation, Cook Formation and Drake Formation) represents fully marine conditions. The Dunlin Group is overlain by the Brent Group delta system, which built out in a northward direction in the Middle Jurassic. The Brent Group was transgressed by the Viking Group marine shales (Heather Formation and Draupne Formation). These were deposited in a tectonically active regime with major rifting in several pulses during the Upper Jurassic (Dahl & Solli 1993). Footwall uplift and exposure resulted in erosion of the Triassic to Middle Jurassic section and down-flank deposition of the Upper Jurassic sandstones interbedded with shales and claystones in structurally low positions (Solli in press). These sandstone intervals now represent prospective stratigraphic traps and also one of the keys to the understanding of the petroleum

migration in the area. The Cretaceous and Tertiary sections represent marine depositional conditions and is has earlier been suggested that this time period was dominated by passive subsidence. However, new data suggest that producible reservoirs are present at these levels and that the geological evolution of the Tampen Spur in the Tertiary might have been much more complex than previously realized. A good illustration of this complexity is the apparent Tertiary biological degradation of the oil within the Brent Group in the Gullfaks Field, which suggests that oxygen-rich meteoric water passed through the structure after oil emplacement (Horstad *et al.* 1990, 1992).

Most of the discovered fields in the Tampen Spur area represent rotated fault blocks which were cut by NNE–SSW and NE–SW faults during the two rift phases in the Upper Jurassic (Early Bathonian–Late Kimmeridgian and Late Kimmeridgian–Ryazanian) (Dahl & Solli 1993). During this time, the whole area was uplifted and the Triassic to Jurassic sedimentary section was eroded. Generally, the depth of erosion increases to the north and east and we consider that in the northern part of the Snorre Field more than 1000 m of sediments were eroded (Dahl & Solli 1993). Most of the sediments were transported and redeposited downslope on the footwall block and built Upper Jurassic to Cretaceous sedimentary wedges (Solli in press).

The petroleum-bearing structures in the area are sealed either by Lower Jurassic Dunlin Group shales deposited above the Statfjord Formation, or by Upper Jurassic and Cretaceous shales and marlstones which drape the whole area. The quality of the cap rocks varies considerably across the Tampen Spur and this has a major impact on the migration of petroleum. Cap-rock leakage is common in the area; for example, the seismic data quality on the eastern part of the Gullfaks Field is seriously affected by large amounts of gas escaping into the post-Jurassic section, which results in high seismic wave absorption and poor signal penetration (Saeland & Simpson 1981). The gas above the Gullfaks Field appears to be a mixture of thermogenic gas from the Jurassic and Triassic reservoirs and shallow biogenic gas produced within the post-Jurassic section (H. Irwin personal communication). Between the Snorre Field and the Gullfaks Field, gas and heavier petroleum have been encountered above a Jurassic structure which has only residual petroleum in the Statfjord Formation (well 34/7-2). Gas leakage has also been reported to occur above the Snorre Field (Leith *et al.* 1993) and the extent of the vertical leakage and dysmigration from the structures is controlled by the nature of the cap rock (entry capillary pressure), the intensity of faulting and the height of the petroleum column (Leith *et al.* 1993). Leak-off data in the area suggest that in structures such as Gullfaks, seal failure by fracturing has occurred. Thermogenic gaseous hydrocarbons are typically observed leaking 400 to 700 m into Cretaceous cap rock above the reservoirs in the Tampen Spur area. The low petroleum potential of the Cretaceous section in most instances clearly reveals the leakage of the hydrocarbons from the hydrocarbon column as the sole source of cuttings gas anomalies.

Recently, several discoveries have been made within the Upper Jurassic and Tertiary sections in the area and it is of great importance to understand the three-dimensional oil and gas migration network as exploration continues in the area. Previously, migration was thought to occur only within the major reservoir sections and it was difficult to explain how the petroleum could migrate from one structure to another. New wells in the area have demonstrated that the Upper Jurassic to Cretaceous sandstones play an important role in the understanding of the petroleum migration and fill–spill relationships in the area, with abundant oil staining commonly found in Upper Jurassic sands.

The main oil source rock in the Tampen Spur area is the Upper Jurassic Draupne Formation (Kimmeridge Clay equivalent) which demonstrates an excellent source rock–oil correlation with the reservoired oils in the area. The underlying Heather Formation locally represents a classical Type II kerogen-rich source rock with high oil potential, but usually possesses a much lower kerogen quality than the Draupne Formation. Head-space gas analysis of a deep well in the footwall (downthrown) block east of the Snorre Field shows that the shales in the Draupne Formation have total gas yields in excess of 25 000 µl gas/kg rock, while 8000 µl gas/kg rock are recorded in the Heather Formation (Fig. 5). Thus, even at the same location within the basin, the extent of petroleum generation from the Heather Formation (buried several hundred metres deeper) seems to be exceeded by that in the Draupne Formation. We conclude from the extensive oil–source rock correlation studies and from quantitative considerations that most of the oil accumulated in the Tampen Spur area has been generated from the Draupne Formation. Significant contributions from the Heather Formation or coal sequences remain to be documented in the area. Most of the oils in the Tampen Spur high are undersaturated with respect to gas, but in the structures located on the down-faulted terraces towards the Viking Graben, gases and condensates become more dominant (Visund, 34/10 Gamma). In the deepest structures (e.g. 34/10 Gamma), dry gas with only traces of heavier components is trapped and the Heather Formation

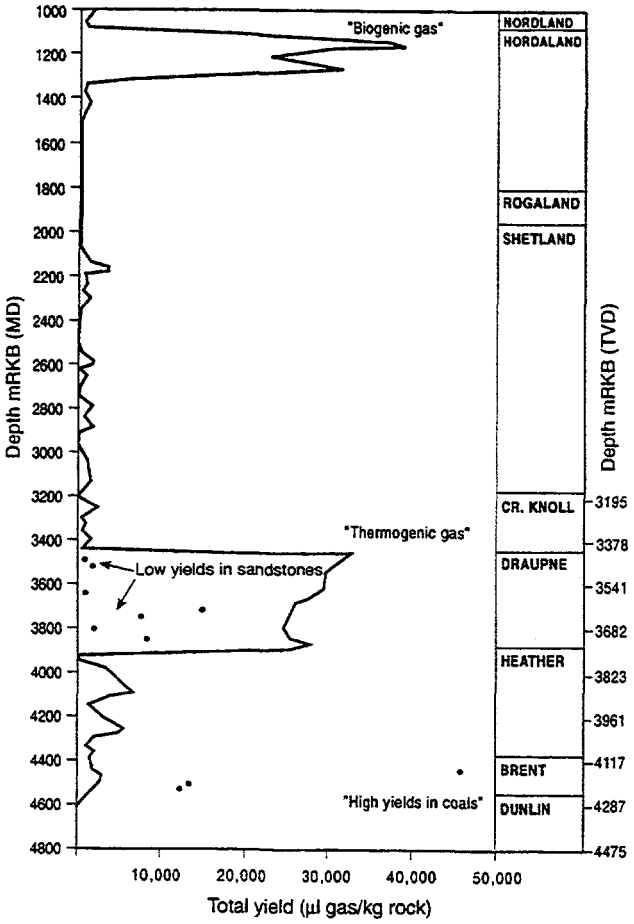

Fig. 5. Total gas as a function of depth from head-space analysis of cuttings from well 34/7-15S.

might represent an important source rock with respect to gas here. However, the generation and expulsion of gas from the Viking Group source rocks remains poorly understood and should be studied further.

The Tampen Spur high is located in the middle of several oil-mature source-rock kitchens (see numbered areas in Fig. 4) and might receive petroleum from several different directions. Although all oils appear to have been sourced from the same source-rock horizon, small differences in facies and maturity-dependent biological-marker parameters are to be expected among the different oils. It is not well understood whether biological marker maturity-related parameters of expelled oils are a function of the source-rock temperature at the time of oil expulsion or at the time of oil generation. However, it is clear that the potential petroleum expulsion mechanisms may become important in controlling minor differences in biological-marker signature in expelled oils. It has been demonstrated that the thickness and distribution of sand bodies within source-rock sequences have a large effect on the petroleum potential gradient and therefore the direction, efficiency and timing of petroleum migration (England *et al.* 1987; Mackenzie *et al.* 1987; Leythaeuser *et al.* 1988). Thus, the distribution of Upper Jurassic sands and siltstones within the source rocks in the area might well result in differences in drainage efficiency, drainage history, expulsion, timing and minor differences in the maturity of the expelled petroleum between different source-rock basins even at the same temperature. Despite concern over the detailed understanding of the mechanisms controlling the biological-marker signature in source rocks, empirical evidence gives us confidence in the use of this approach in oil-source rock correlation.

Several models have been proposed to describe the migration of petroleum into the giant oilfields within the East Shetland Basin in the northern North Sea. The most accepted models were published by Thomas *et al.* (1985) and Karlsson (1986), both suggesting a major spill along the North Alwyn–Brent–Statfjord–(Snorre)–Gullfaks trend. These models were based on Gussow's model (Gussow 1954), with a gradual change in the distribution of gas and oil along the migration route and a shallowing of the oil–water contacts along the same path. Along the fill–spill route from the North Alwyn Field to the Gullfaks Field, only the North Alwyn and the Brent Fields contain a separate gas cap and it is not obvious that Gussow's model can be applied directly to reservoirs with undersaturated oils with a separate gas cap, such as is the case in the Norwegian part of the North Sea. Clearly, the pressure–volume–temperature and phase relationships in this area are much more complex than the simple system described by the Gussow model, and this model should therefore be applied with great caution.

The combination of sample availability, reservoir interval distribution and the presence of multiple source-rock kitchens make the Tampen Spur area very suitable for a reservoir geochemical study. An understanding of the migration pathways and petroleum drainage efficiency of the basins is of great economic interest, because most of the smaller sub-structures are marginally economic. Thus, it is important to provide an effective risk analysis and ranking of the satellite prospects prior to drilling.

Methods

During the last five years, interest in reservoir geochemistry has shown a steady increase. At present, reservoir geochemical studies range from large-scale intra-reservoir petroleum compositional heterogeneities to sub-metre scale variations within a single reservoir zone or even down to the fluid

inclusion scale (Larter & Aplin 1995). Compositional variations examined vary from gross parameters such as GOR and petroleum asphaltene content (Wilhelms & Larter, 1995) to variations in individual compounds such as biological-marker hydrocarbons, sulphur, nitrogen and oxygen species (Larter *et al.* 1990; Horstad *et al.* 1990; Li *et al.* 1992).

Sampling

Both tested oil samples (DST, RFT and FIT) and solvent extracts from conventional reservoir cores have been used to construct the oil population maps of the area. This is necessary because the availability of produced oils is limited and because it is essential to include dry wells which only have oil shows and therefore have not been tested. Although significant differences in the relative distribution of petroleum compound classes (saturated hydrocarbons, aromatic hydrocarbons, NSO compounds and asphaltenes) (Horstad *et al.* 1990) and the distribution of nitrogen compounds such as arbazoles (Stoddart *et al.* 1995) have been reported to occur between core extracts and oils, our data from clastic reservoirs suggest that this does not have any influence on the distribution of aliphatic hydrocarbon biological markers and stable carbon isotopes in mixed core extract and tested oil sample sets (Fig. 6). However, the possibility of such effects should not be ignored, and duplicate sampling and analysis of both cores and tested oils is preferred whenever possible. Because the construction of a petroleum population map in a large area typically requires 50 to 200 GC–MS runs, it is difficult to avoid the use of data from different sources. The quality of the input data is important and because the geochemical differences that are detected between the different structures tend to be small in homogeneous source provinces, such as the Tampen Spur area, direct comparison of data from different consultants should be avoided. Our experience is that in some cases significant, small, but indeed real, compositional differences have been masked because the samples were analysed by different laboratories. In other studies, samples that belong to the same oil population may be grouped as two populations due to lack of reproducibility of geochemical data between different laboratories. Our oil population map of the Tampen Spur area is based on more than 300 GC–MS analyses from four different consultants. To allow synthesis of all these data, all sub-studies include several duplicate or reanalysed samples from previous studies, which allows a proper calibration of the different datasets. Thus, the construction of these maps is a continuous process and updating is required whenever new wells are drilled. When a new discovery is made in an area where an oil population map is available, we routinely reanalyse 5–15 relevant samples from the area as a single batch together with the oil from the new discovery. This allows a proper characterization and classification of the new oil and updates the oil population map of the area.

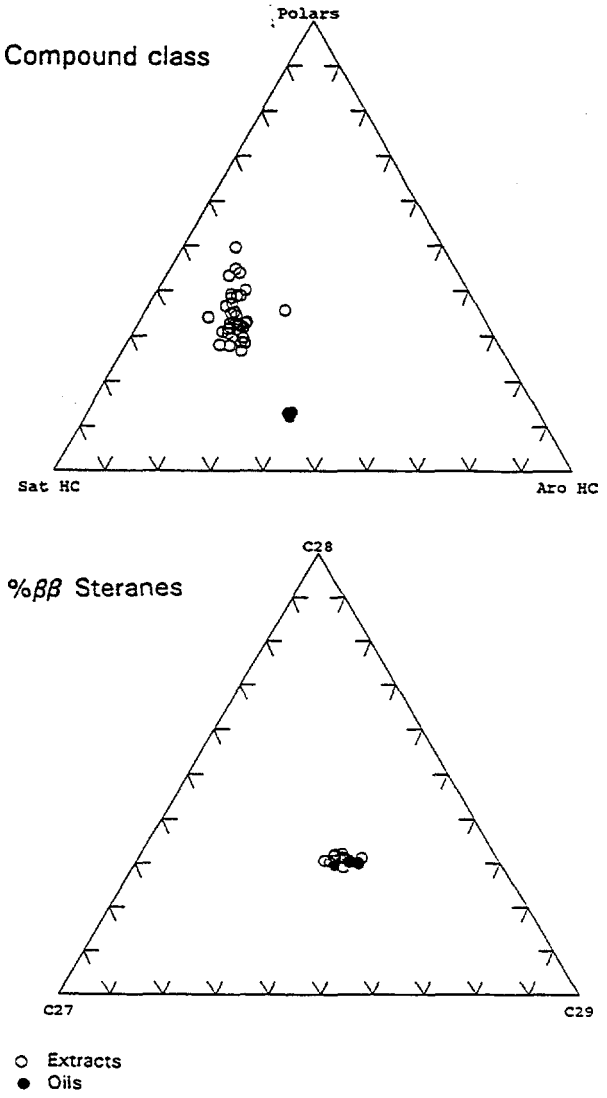

Fig. 6. Example of fractionation of compound classes between reservoir core extracts and tested oil samples from the Brent Group reservoir in the Gullfaks Field well 34/10-1. Note that biological markers (i.e. distribution of C_{27}–C_{29} ββ-steranes) do not show any signs of fractionation.

Analytical techniques

The general reservoir geochemical protocol followed is a modification of that developed by the Petroleum Geochemistry Group at the University of Oslo, Norway (Larter *et al.* 1990; Horstad *et al.* 1990; Karlsen & Larter 1991). All conventional cores have been screened by Iatroscan (thin layer

chromatography–flame ionization detection, TLC–FID) (Karlsen & Larter 1991) prior to selection of samples for detailed GC–FID, GC–MS and stable carbon isotope analyses of medium-pressure liquid chromatography (MPLC) separated fractions. Typically, screening includes five to ten samples from each reservoir interval in each well, and two to five of these are subsequently submitted for detailed analyses of the saturated hydrocarbon and aromatic hydrocarbon fractions. Some of the data have been acquired as part of full-field reservoir geochemical studies and such studies typically include 50 to 100 samples from each well. As mentioned previously, GC–MS analysis performed at different times or at different laboratories must be calibrated by reanalysing samples from each data subset. The temperature programmes applied for GC–MS analysis of the hydrocarbon fractions in the different laboratories have varied slightly and we have experienced that even with the same GC column and the same temperature programme, variable GC resolution of the biological markers can be documented, both between different laboratories and as a function of time in the same laboratory. This has a large impact on the quantification of individual compounds, especially for steranes (*m/z* 217 and 218) and monoaromatic steroids (*m/z* 253), where coelution is a serious problem for nominal mass GC–MS. The selected GC programme used here is a compromise between peak resolution and peak shape/definition, optimized for the compounds that are of interest. Currently, we use a DB-5 equivalent column for GC analysis of the aromatic hydrocarbons. The GC programme consists of four different gradients to allow maximum resolution of the naphthalenes and phenanthrenes: start temperature 80°C held for 1 min, 1°C min^{-1} to 103°C followed by 3°C min^{-1} to 140°C, then 1°C min^{-1} to 180°C and 10°C min^{-1} to 300°C. The GC programme for saturated hydrocarbons is 80°C for 3 min, then 4°C min^{-1} to 300°C with 12 min hold time at 300°C, on a non-polar column (DB-1 equivalent column). GC starting temperature for oil samples has been set at 40°C. The GC programme applied in the GC–MS analysis of biological-marker hydrocarbons allows maximum resolution of steranes and hopanes and has a single temperature gradient on a non-polar column (DB-1): starting at 180°C for 1 min, then 1.7°C min^{-1} to 310°C with 10 min hold time at 300°C.

In general, it is not possible to define a universal set of biological-marker ratios which can be used to differentiate all oils into various populations or to define how large differences among oils should be before they are classified into different populations. We have applied different statistical methods such as the Student *t*-test and principal component analysis (Davis 1986) to decide whether the differences perceived are statistically valid or not. Such analyses require a large and homogeneous dataset composed of a single subset of samples run by the same contractor in the same sample batch. If data from two different laboratories are analysed in the same principal components analysis, the main discrimination will usually be between the two (laboratory defined) data subsets and not between the multiple oil populations. The choice of biomarker hydrocarbons that should be used in any situation is based on experience within the area, and a large dataset should be applied in order to choose the most useful ratios. Within the Tampen Spur area, the 25-norhopanes are present only in trace amounts and cannot be applied to discriminate oils, while on the east flank of the Viking Graben (quadrants 30, 31 and 35) these compounds are extremely useful for discriminating between the different oil populations. The differences between the oil populations are typically expressed by variations in several biological-marker ratios, but are best illustrated by a few of the conventional ratios. Within the Tampen Spur area the 17α(H),21β(H)-28-30-bisnorhopane is one of the most useful compounds for discriminating between oils. The origin and occurrence of bisnorhopane has been debated since it was first reported in the late 1970s (Seifert & Moldowan 1978; Grantham *et al.* 1980; Moldowan *et al.* 1984), and while most of the other hopanes are ubiquitous in most source rocks and oils, the presence of bisnorhopane is variable. However, it is usually present in significant concentrations in the Upper Jurassic source rock in the North Sea, but seems to be more common in the Draupne Formation than in the Heather Formation. The relative amount of bisnorhopane in an oil seems to be more dependent upon the facies of the source rock from which the oil was expelled than its maturity at the time of expulsion. When the maturity range of the analysed oils is large, the relative concentration of 28,30-bisnorhopane might reflect a significant maturity component. The diahopanes, diasterenes and stable carbon isotope signatures have also proven to be useful correlation parameters in this area.

Field filling

Based on the theoretical considerations made by England *et al.* (1987), a reservoir will fill in a sequential manner. The petroleum will first enter the most permeable zones with the lowest pore-entry pressures and subsequently fill the reservoir in a set of advancing petroleum fronts (Fig. 7). Because the filling takes place over a certain period of time (e.g. 5 to 30 Ma in the North Sea), the source rock will continue to subside and an

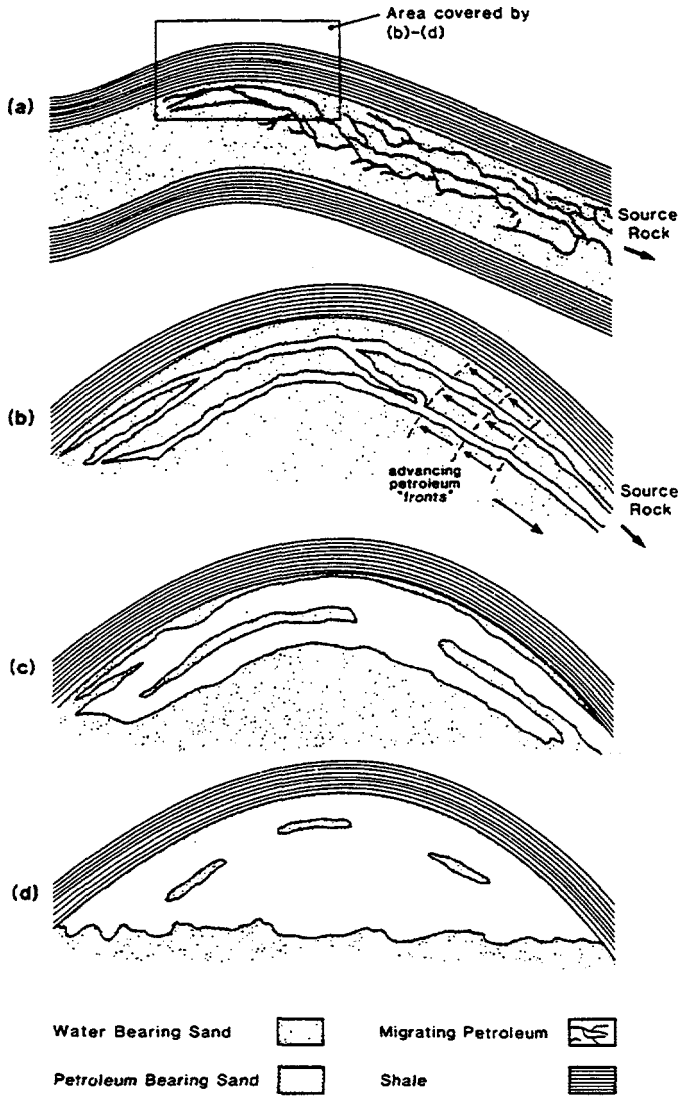

Fig. 7. Schematic filling sequence of a reservoir (from England *et al.* 1987).

increasingly mature petroleum will enter the trap. Thus. if a reservoir is filled from two different directions and the two oils do not subsequently mix within the reservoir, it should be possible to map the distribution of the two oils within the reservoir (Fig. 8). In addition, if the oil within the trap has been expelled over a significant range of maturities, it might be possible to detect gradients of maturity within each population which might give information on the filling directions into the field. Our data suggest that such differences exist in nature and that the geochemical analysis can be used to map heterogeneities in oil compositions in high quality well-connected clastic reservoirs (Horstad *et al.* 1990). This can be used to increase the understanding of field filling and regional migration routes in the area. Recent experience in more complex, less well-connected clastic reservoirs, both in this area and elsewhere in the North Sea, suggests that field-filling processes can be much more locally controlled and complex to unravel by reservoir geochemistry. Thus, fieldwide gradients in composition are sometimes not present for good geological reasons.

Several mechanisms will act to reduce the previous heterogeneities in the petroleum columns, but these processes (principally diffusion and density-driven overturning) are not efficient enough to homogenize the petroleum over the kilometre scale lateral distances of a large oil-field. There is no single technique that can be used to resolve the petroleum migration history in a province and a multidisciplinary approach is the only healthy approach to such a challenge. In order to attempt this, it is necessary to make a composite of structural maps, reservoir sand distribution maps, structurally possible migration paths and the distribution of oil populations in the area to evaluate possible migration and field-filling scenarios. Similarly, both inorganic and organic geochemical methods may be relevant, depending on the field (Larter & Aplin 1995). Based on combined evaluation and analysis of all the available information, the most likely migration pathways might then be proposed in the area. It is

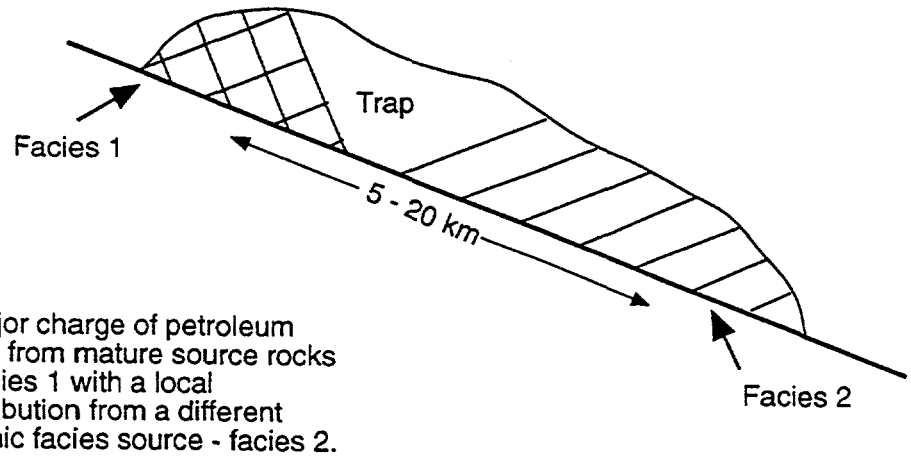

Fig. 8. Potential heterogeneties on a hypothetical reservoir caused by filling from two different sources.

important to test the evolving migration model continuously by analysis of new oil samples and incorporation of new geological information in the area.

Within the northern North Sea, most of the oil reservoirs are located at the crestal part of rotated fault blocks and therefore most of the wells are drilled in a structurally high position with only a few wells being aimed at down-flank prospects. Thus the available samples from the basins are heavily biased towards shallow areas and no conventional samples are available from higher pressure and temperature regimes within the deeper part of the basins. Although migration of oil and gas from the basin towards shallower structures at lower temperatures and pressures may result in phase changes (England *et al.* 1987; England & Mackenzie 1989; Larter & Mills 1991) the bulk of the samples studied here represent fluids accumulated as single-phase liquid petroleum, thus the geochemical data can be interpreted conventionally.

Table 1. *Number of tested oil samples analysed from each well*

Well	33/9	34/4	34/7	34/8	34/10
–1		1	3	1	3
–2					
–3			3	5 + 2	3
–4		3	1	4 + 2	2
–5		2	1		1
–6		1	3		
–7		2	2		3
–8			3		1
–9			1		4
–10			4		
–11					3
–12			2		
–13	2		1		2
–14	1		2		1
–15					
–16			2		
–17A			1		
–18			2		
–19			2		
–20					
–21/21A			2		

Oil populations

Based on detailed geochemical mapping of data from reservoir core extracts and tested oil samples from most of the exploration wells within the Tampen Spur area, it has been possible to differentiate the oils into several populations. Previously, it was suggested that the Gullfaks Field filled from two different source basins (Horstad *et al.* 1990). The Cook Formation and Statfjord Formation filled from the north and/or east while the Brent Group filled form the west. The proposed filling directions into the Gullfaks Field were based on tentative maturity gradients within each of the two major oil populations in the field. The oil within the Gullfaks Field was subsequently biodegraded and the extent of biodegradation varies across the field, from apparently undegraded oil within the Statfjord Formation in the eastern part to the most severely degraded oil within the Brent Group in the westernmost part of the field (Horstad *et al.* 1990). The extent of biological degradation was considered too mild to affect the large number of biological-marker parameters used. Later studies, which included more samples from neighbouring fields, have confirmed this model for the filling of the Gullfaks Field.

In this study, 86 different tested oil samples from 39 wells (Table 1) and *c.* 220 reservoir core extracts from 48 wells (Table 2) in the Tampen Spur area were analysed in four batches by GC–FID, GC–MS and stable carbon isotope analysis of saturated and aromatic hydrocarbon fractions. The selection of core samples for detailed geochemical characterization was based on Iatroscan (TLC–FID) screening of more than 1000 samples. The oils from the Tampen Spur that have been included in this study have been differentiated into five major oil populations (Table 3) which migrated into the area from

Table 2. *Number of reservoir core extracts analysed by GC–FID and GC–MS from each well*

Well	33/9	33/12	34/4	34/7	34/8	34/10
–1					7	11
–2		4	2	3		
–3		3	3	17	7	3
–4	2		10	3	10	2
–5			7	2	9	1
–6	2		9	4		
–7	2	3		10		1
–8	2			6		1
–9	3					1
–10	2			9		
–11						
–12	2			5		1
–13				6		
–14	4			1		
–15	1			4		
–16				3		
–17A				3		
–18				8		7
–19				3		
–20				1		
–21/21A				10		

Table 3. *Selected biological marker ratios and stable carbon isotope ratios from tested oil samples and reservoir core extracts from the different oil populations in the Tampen Spur area*

Group	Oil population	$\delta^{13}C$ Sat HC*	Bisnor/nor hopane* (*m/z* 191)	%ββ in C_{29} steranes† (*m/z* 217)	%20S in $C_{29}\alpha\alpha$ steranes† (*m/z* 217)	C_{30} dia hopane/ C_{30} dia hopane +$C_{29}\beta\alpha$† (*m/z* 191)	$C_{27}\beta\alpha$ dia 20S/($C_{27}\beta\alpha$dia 20S + $C_{27}\alpha\alpha\alpha$20T† (*m/z* 217)
I	Statfjord Nord	–28.8 to –29.3	0.44–0.50	0.54–0.57	0.47–0.53	0.64–0.75	0.63–0.71
II	Snorre Lunde Fm.	–30.3 to –31.1	0.67–0.70	0.55–0.57	0.54–0.59	0.61–0.64	0.63–0.66 Lunde Fm.
	Stfj. Fm.			0.54–0.55	0.55–0.56	0.52–0.56	0.55–0.60 Stfj. Fm.
III	Statfjord Øst	–28.4 to –29.8	0.54–0.61	0.52–0.57	0.46–0.56	0.47–0.60	0.55–0.60
IV	Statfjord (Statfjord Fm.)	–29.8 to –30.2	0.51–0.53	0.51–0.53	0.43–0.45	0.48–0.51	0.41–0.51
V	Visund	–29.2 to –29.7	0.26–0.37	0.56–0.67	0.56–0.64	0.73–0.86	0.73–0.79

* Mainly controlled by source rock facies within the study area
† Mainly controlled by maturity within the study area

different directions and at different stratigraphic intervals (Fig.9). The mapping of oil populations in the area has demonstrated that the Tampen Spur has a more complex filling history than proposed earlier (Thomas *et al.* 1985; Karlsson 1986) and that it is possible to evaluate the filling of such a complex area by a combined geological and reservoir geochemical approach. Previous methods suggest possible migration routes or pathways, but cannot be applied to decide from which direction the oil actually migrated into the structures (Nybakken 1991).

Based on the samples included in this study, five oil populations have been described in the Tampen Spur area, differentiated on the basis of stable carbon isotope analysis and molecular marker data (Table 3). With the exception of the Visund Field accumulation, which is more mature (based on

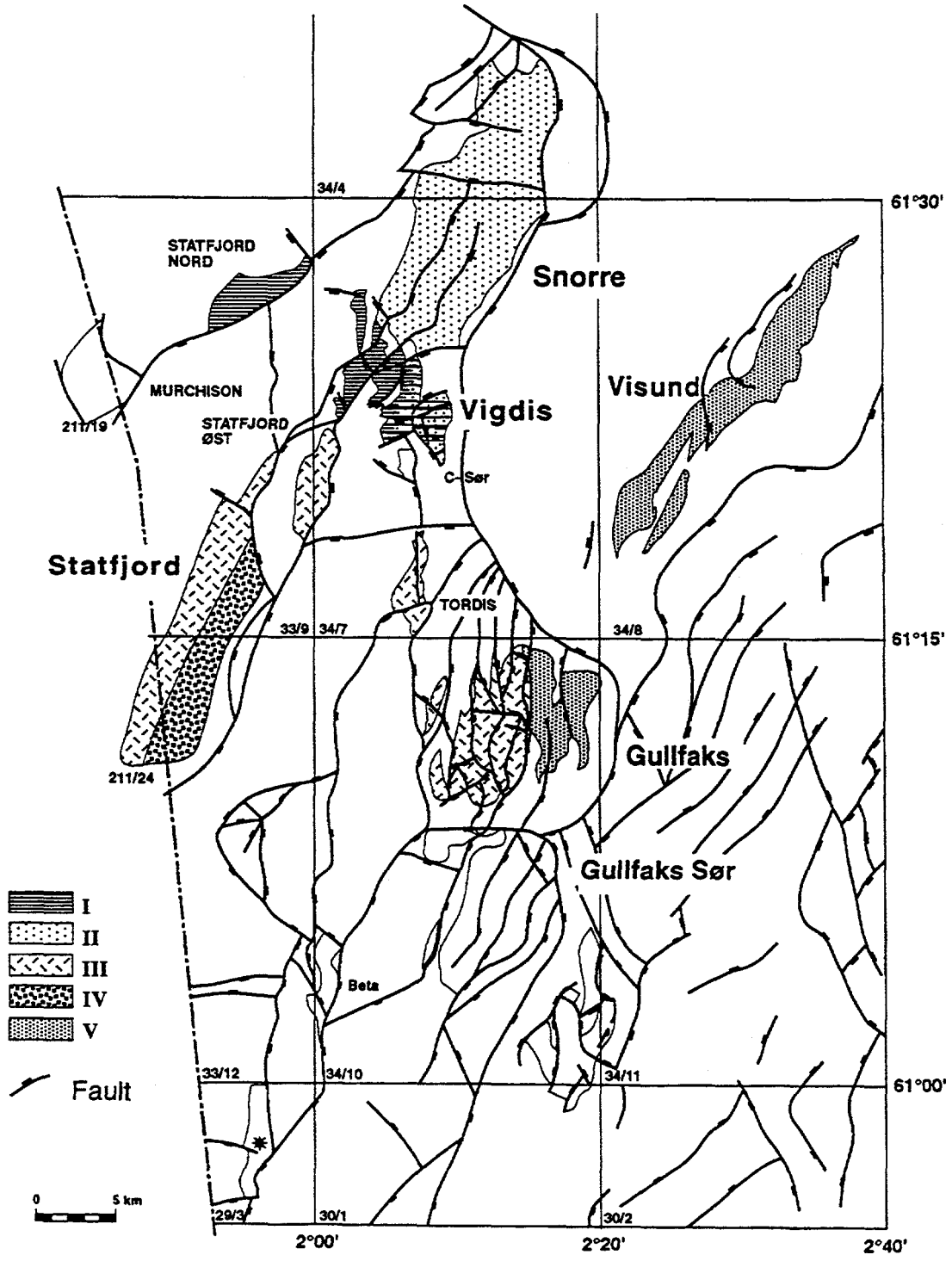

Fig. 9. Petroleum populations identified in the Tampen Spur area.

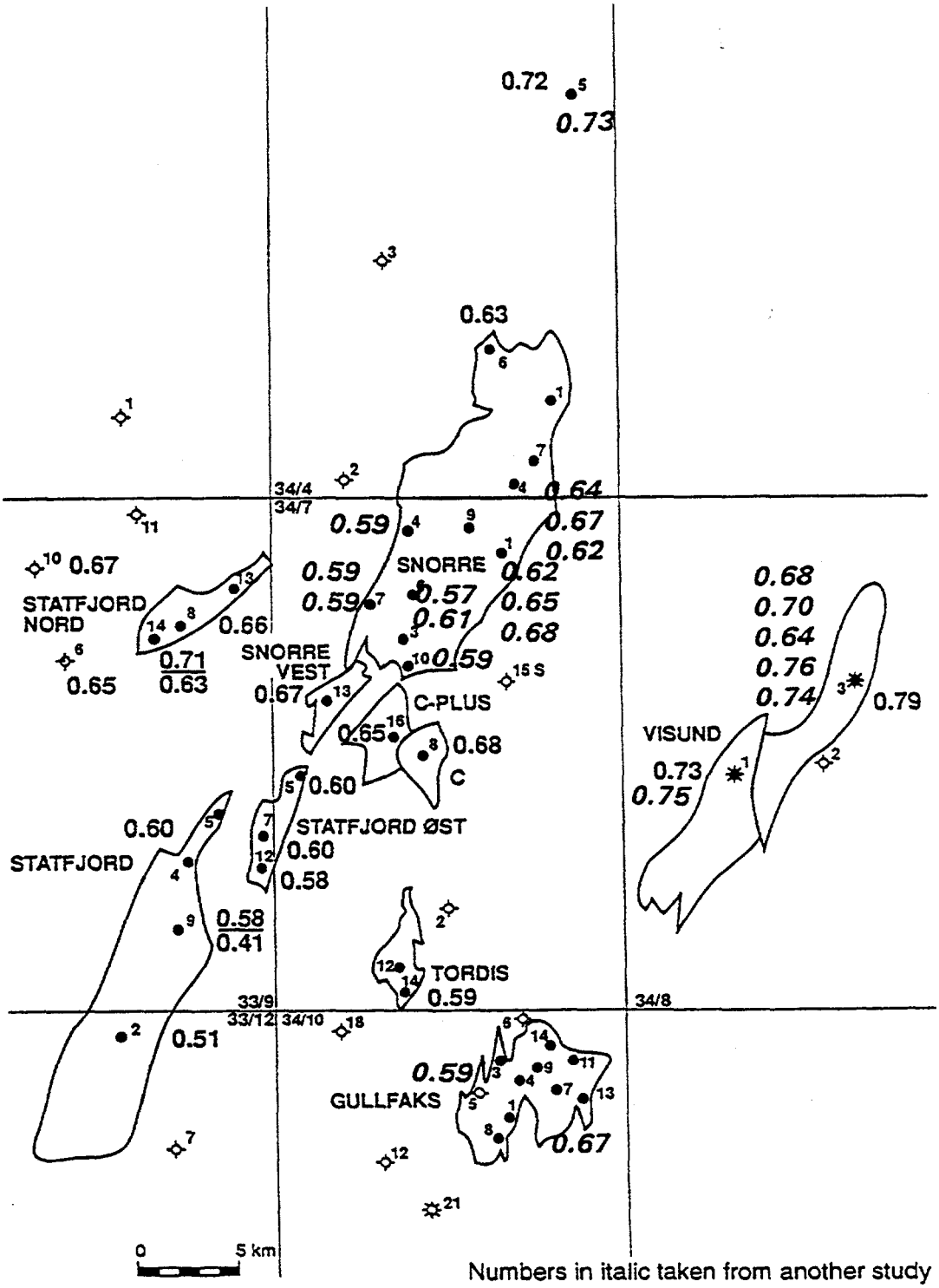

Fig. 10. Variations in the $C_{27}13\beta(H)$, 17α(H)-diasterane (20S)/[$C_{27}13\beta(H)$, 17α(H)-diasterane (20S) + $C_{27}14\alpha(H)$, 17α(H)-sterane (20R)] ratio in the study area. Note that data have been selected from two different studies.

C_{30}diahopane, $C_{27}\beta\alpha$dia20S sterane (Fig. 10) and $C_{29}\beta\beta$ steranes), the other four groups have similar ranges of maturities but significantly different bisnorhopane/norhopane ratios (Fig. 11) and stable carbon isotope signatures. Although we cannot disprove that the oils represent a maturity sequence from a single source rock, the relative amount of bisnorhopane and stable carbon isotope ratios suggest that the oils have migrated into the area from several different source-rock kitchens. This is consistent with the structural configuration in the area.

(1) *The Statfjord Nord oil population* is present within the Upper Jurassic sandstones and the Brent Group in the Statfjord Nord Field and in the Brent Group in Vigdis Vest (formerly Snorre Vest, well

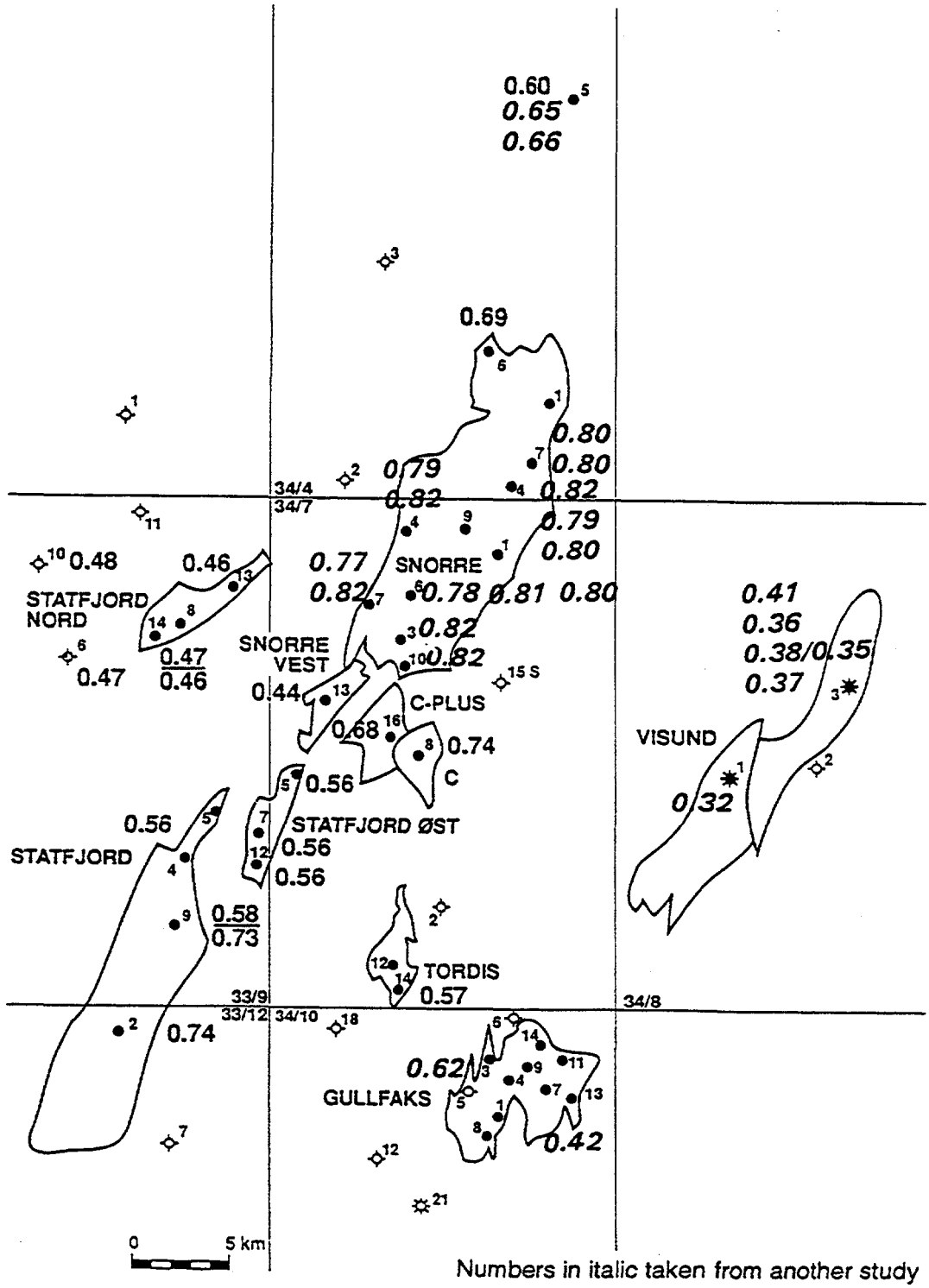

Fig. 11. Variations in the bisnor/norhopane ration in the study area. Note that the data have been selected from two different studies.

34/7-13) and part of Vigdis Middle (former C + II structure, well 34/7-19). This oil is characterized, and can be differentiated from other oils in the area, by a relatively low 28,30 bisnor/norhopane ratio and a heavy carbon isotope signature ($\delta^{13}C$ from –28.5 to –29.5 for the saturated hydrocarbon fraction) (Fig. 12).

(2) *The Snorre Field oil population* is present within the Statfjord Formation and Lunde Formation in the Snorre Field and possibly within the Zeta Structure to the north of the Snorre Field. This oil has a light carbon isotope signature ($\delta^{13}C$ from –30.3 to –31.0 for the saturated hydrocarbon fraction) and a high 28,30-bisnor/norhopane ratio

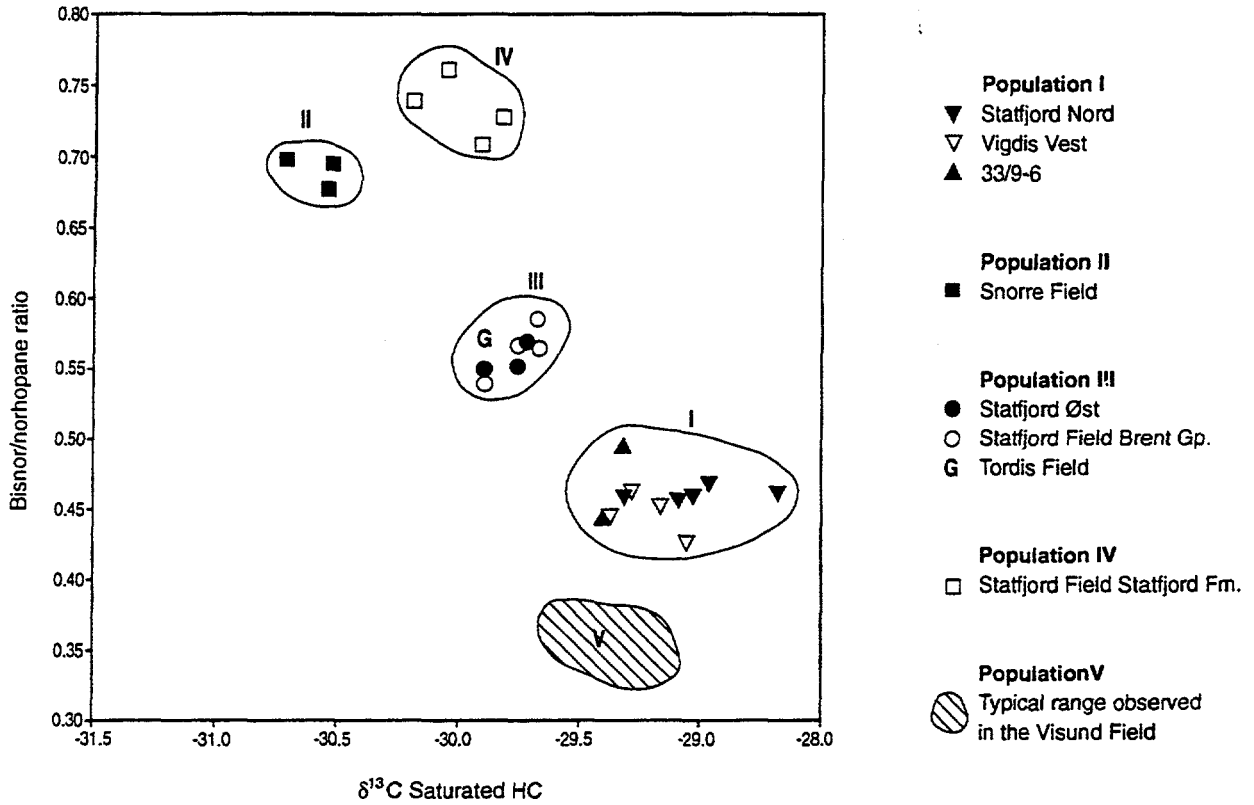

Fig. 12. Stable carbon isotope signature of the saturated hydrocarbon fraction and bisnor/norhopane ratio of selected samples from the Tampen Spur area.

(Fig. 12). The stable carbon isotope signature is usually a reproducible analysis even over a long data acquisition period, and our database consistently shows that the Snorre oils are relatively isotopically light while the Statfjord Nord oils are isotopically heavy (Fig. 13). It is interesting to note that these two oil populations, which are located geographically close to each other, are geochemically so different. The maturity of these two oil populations is the same (Table 3) and the compositional differences are possibly controlled by variations in source facies within the Draupne Formation source rock on the rim of the Møre Basin and the Marulk Basin. Alternatively, the oils within the Statfjord Nord accumulation might have migrated into the Tampen Spur area from the East Shetland Basin to the west, but we do not have any data to prove or disprove this hypothesis. The maturity within the Snorre family oils increases from south to north within the field (Fig. 10) and this suggests that the Lunde Formation reservoir in the northern part of the field drains a deeper and more mature part of the source-rock kitchen than the Statfjord Formation reservoir in the southern part of the field. The oil–water contact varies across the Snorre Field and is deepest in the southwest, suggesting a filling of the structure from the southwest. However, the oil in the Lunde Formation in the northern part is the most mature with a higher GOR, and most of the biological markers show a more mature distribution (Figs. 14 & 15; Table 3). It has been suggested that the increasing GOR in the northern part of the field is a result of a late gas migration into the field from the deep basins to the north. The Snorre Field is undersaturated with respect to gas (GOR varies from 63 to 215 Sm^3/Sm^3) and there is a good relationship between the maturity of the oil and the maturity/wetness of the associated gas, which suggests that the gas and oil have been generated at the same time (Fig. 16). It is therefore suggested that the Snorre Field has been filled through at least two fill points, one in the southwest charging the Statfjord Formation and one in the northwest charging the Lunde Formation. This model is able to explain the variations in the GOR, biological-marker parameters and the different oil–water contacts across the field. The similarity in the biological markers reflecting source facies and the stable carbon isotope signature of the oil in the Statfjord Formation and the Lunde Formation in the Snorre Field, suggests that there are minor variations in the source-rock facies in the drainage area of the Snorre Field.

The Snorre Field is located at the southern rim of the Møre Basin where the Draupne Formation is buried deeper than 5000 m (Fig. 4) and large gas volumes would be expected to drain southwards

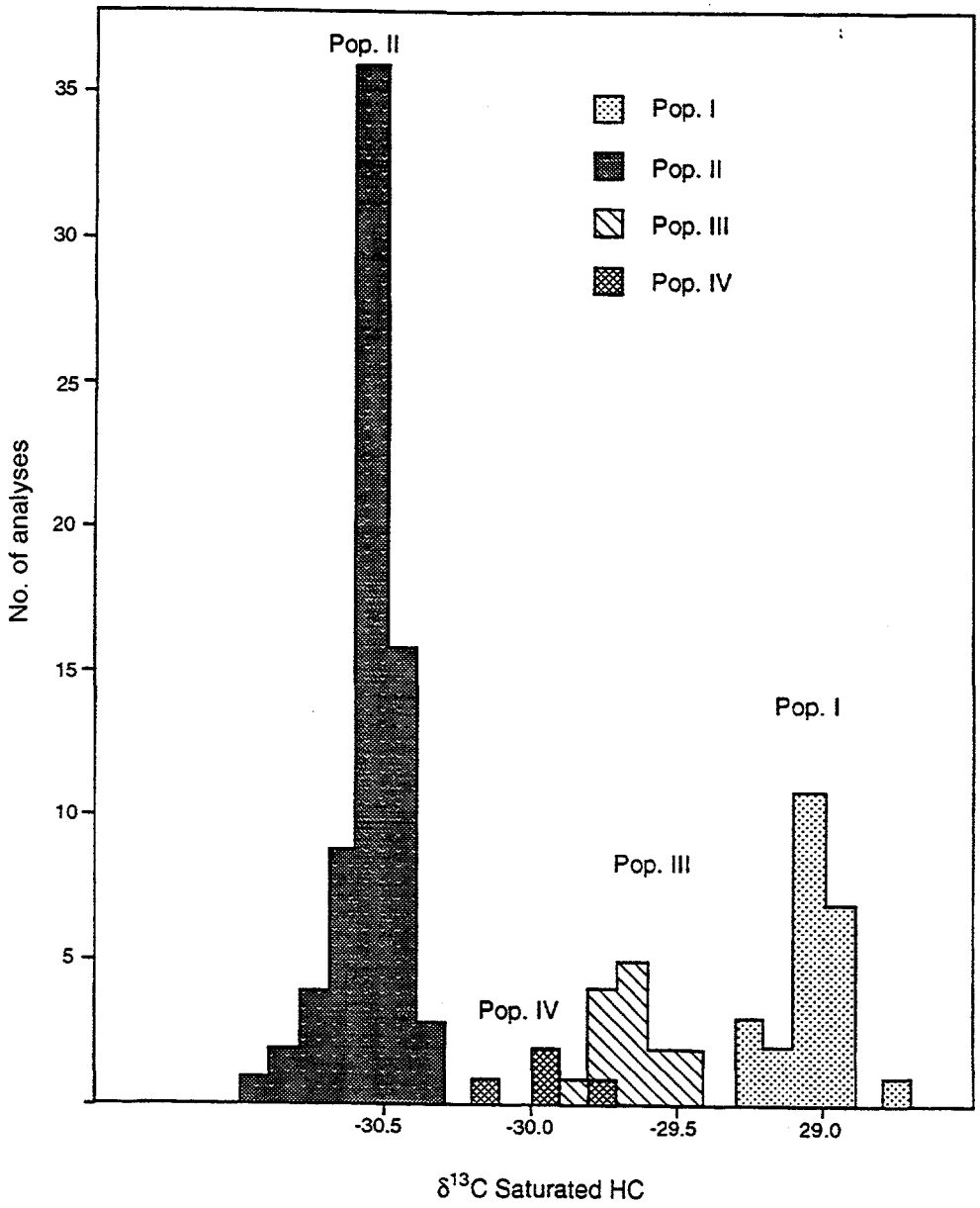

Fig. 13. Stable carbon isotope signature of the saturated hydrocarbon fraction of oils and extracts from four of the petroleum populations in the area.

into the northern part of the Snorre Field. The lack of gas in the Snorre Field might be explained by (i) non-deposition of oil and gas sources in the central part of the Møre Basin, (ii) erosion of the possible source rock, (iii) lack of migration pathways southwards from the Møre Basin into the Snorre Field, or (iv) a preferential drainage of gas in a different direction, controlled by the sand distribution and not by the structural configuration of the area. It is suggested that the absence of source rocks in the central part of the Møre Basin is the most probable cause of this lack of gas. The light carbon isotope signature of the oil within the Snorre Field might be due to the presence of only the upper part of the Draupne Formation in the source basin that is in communication with the major reservoirs in the Snorre Field. This section of the Upper Jurassic is isotopically significantly lighter than the lower part of the Draupne Formation and the Heather Formation in this area (Fig. 17). It would appear from the maturity levels in the Møre Basin and the GOR range in the Snorre Field that the bulk of the Møre Basin is not in communication with the Tampen Spur in the Snorre area. This demonstrates how the mapping of oil populations might be applied to evaluate the presence or absence of active, communicating source rocks in undrilled areas.

(3) *The Statfjord Øst oil population* is present in the Brent Group in the Statfjord Field, Statfjord Øst structure, Tordis Field and Gullfaks Field (Fig. 9). This is almost the same fill–spill route that was

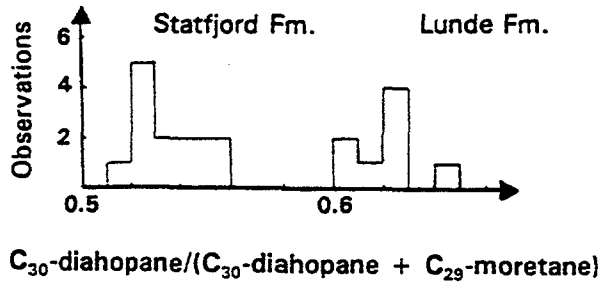

Fig. 14. Grouping of Snorre Field oils into two different subgroups based on maturity differences (i.e. C_{30}-diahopane/(C_{30}-diahopane + C_{29}-moretane).

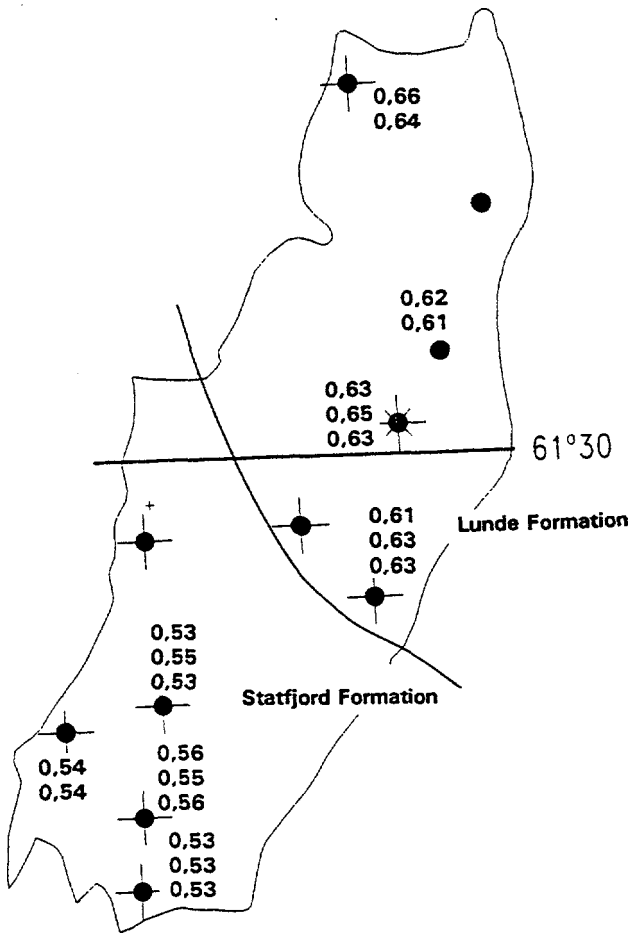

Fig. 15. Variations in the C_{30}-diahopane/C_{30}-diahopane + C_{29}-moretane) ratio across the Snorre Field, showing the higher maturity of the oil within the Lunde Formation in the northern part of the field as compared to the Statfjord Formation in the southern part.

proposed previously for the whole Tampen Spur (Thomas *et al.* 1985; Karlsson 1986), but this migration route was not confirmed by detailed reservoir geochemical information at that stage. This charging conduit is also in good agreement with the general migration model proposed for the Brent Group in the Gullfaks Field which was based solely on information from the Gullfaks Field (Horstad *et al.* 1990), demonstrating the ability to predict petroleum migration in remote areas. However, it is stressed that our experience elsewhere in the North Sea suggests that some fields have local near-field fill points which are not clearly related to regional drainage directions. The Statfjord Øst oil population has also been tested within a Paleocene sand in one of the sub-structures in the area. This oil population is characterized by an intermediate carbon isotope signature ($\delta^{13}C$ from –29.5 to –30.0 for the saturated hydrocarbon fraction) and an intermediate 28,30-bisnor/norhopane ratio (Fig. 12). Thus, a mixing of the Statfjord Nord oil population with the Snorre Field oil population results in a mixture similar to the Statfjord Øst oil population. Because these three oil populations migrate towards the same apex in the central part of block 34/7, it becomes difficult to elucidate the migration paths in this area. At this stage, it is believed that the three segments in the Vigdis Field have been filled from two different directions and that these two oil populations have mixed in the central part of the field. The Vigdis Vest and the western part of Vigdis Middle (34/7-19) have a Statfjord Nord type of oil, while Vigdis Øst (former C structure, well 34/7-8) has a geochemical signature similar to the Snorre Field. The transition zone has been filled from both directions. Such a migration and filling model of the Vigdis Field is supported by artificial oil mixing (equal volumes) studies performed with oils from the Snorre Field, Statfjord Øst and Vigdis Vest (Fig. 18).

(4) *The oil in the Statfjord Formation in the Statfjord Field* is different to any of the other major oil populations on the Tampen Spur, but has a similar maturity. This oil has a high 28,30-bisnor/norhopane ratio and an intermediate carbon isotope signature ($\delta^{13}C$ from –29.7 to –30.2 for the saturated hydrocarbon fraction). It is stressed that we have analysed only a few wells from the Statfjord Field and the filling and migration history of the Statfjord Field might be more complex than suggested by our data.

It is interesting to note that the oils within the Statfjord Formation and the Brent Group in the Statfjord Field are so different (groups III and IV in Table 3). This suggests that the Statfjord Field has been filled from two different sources, as was demonstrated earlier in the Gullfaks Field (Horstad *et all* 1990). Maturity differences between the oils in the Statfjord Formation and the Lunde Formation in the Snorre Field are also evident (Fig. 14). The different geochemical signatures of petroleum entrapped at different stratigraphic levels might suggest that migration and filling of the structures in the Tampen Spur area and the East Shetland

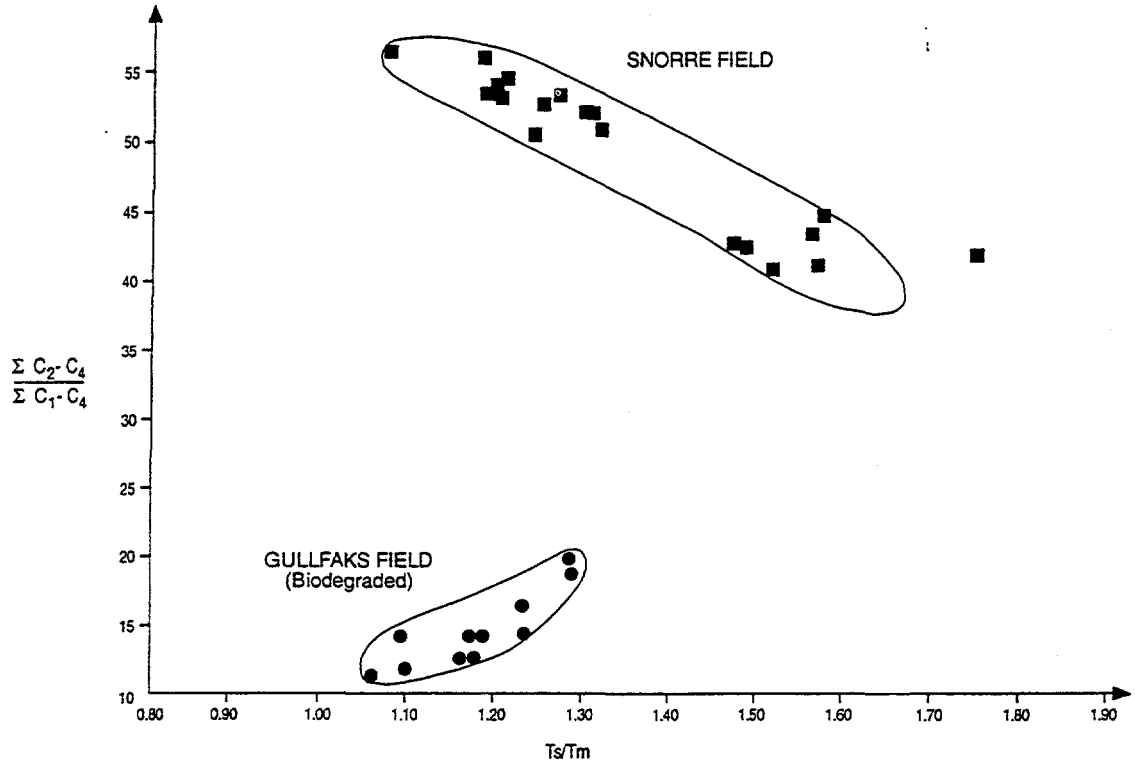

Fig. 16. Gas maturity (wetness) and oil maturity (T_s/T_m) correlation in the Snorre Field, suggesting that the gas is associated with oil.

Basin occur through several different stratigraphic levels. It is possible that the Brent Group, the Statfjord Formation and the Lunde Formation drain different geographical and/or vertical parts of the same source-rock kitchen, resulting in different petroleum charges within each stratigraphic level. This also implies that migration from one formation to another might be restricted even within areas where faulting occurs. Thus, in addition to geochemical mapping, detailed structural maps of

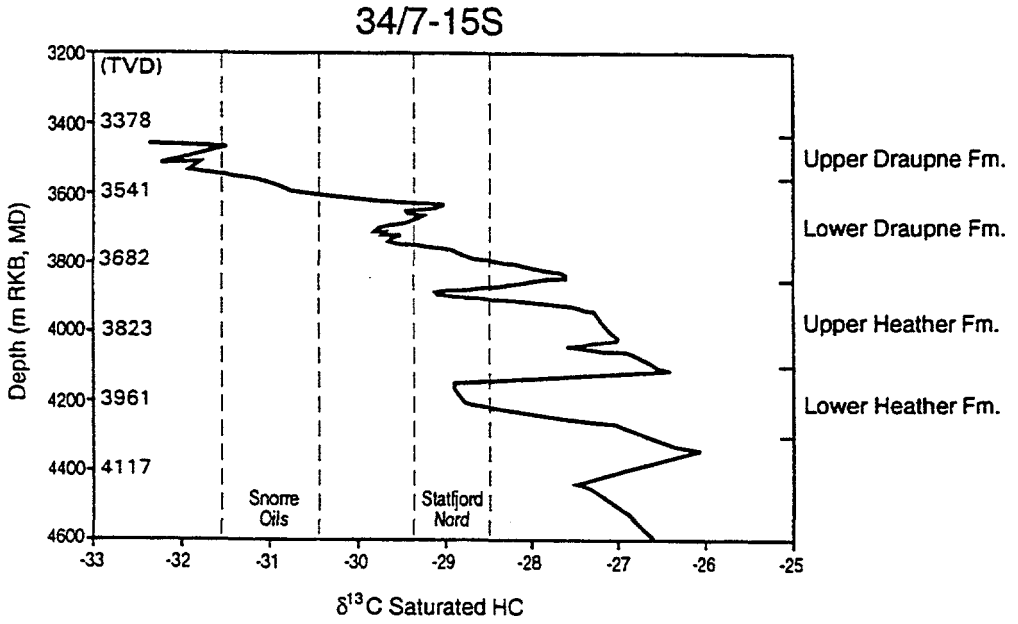

Fig. 17. Stable carbon isotope signature of the saturated hydrocarbon fraction as a function of depth in the Viking Group shales in well 34/7-15S, and the range observed in the Snorre and Statfjord Nord petroleum populations.

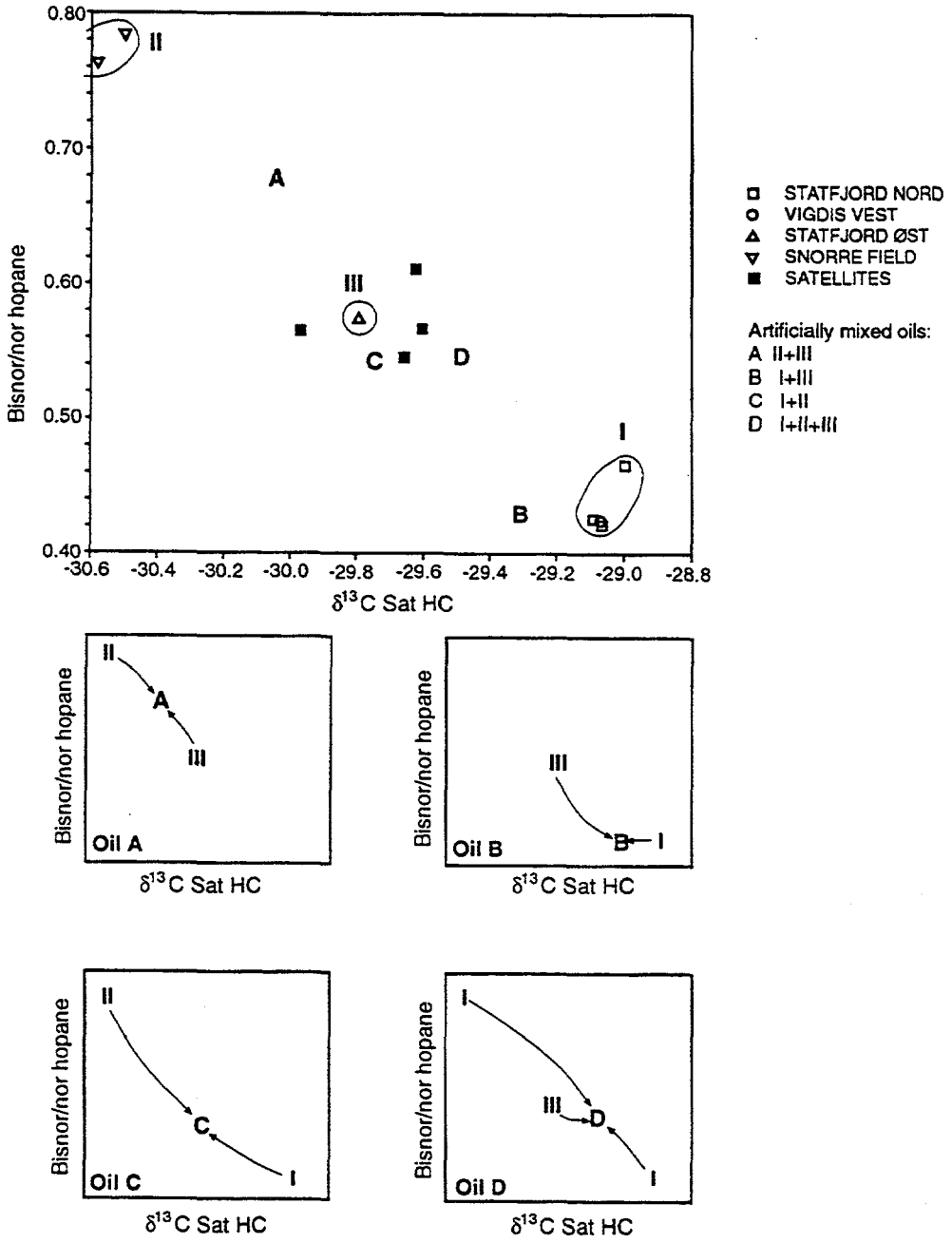

Fig. 18. *Stable carbon isotope signature of the saturated hydrocarbon fraction and bisnor/norhopane ratio of selected samples from the Tampen Spur area and artificially mixed oil samples from three major petroleum populations (mixed in equal volumes).*

possible migration routes should be constructed at several depths to elucidate migration routes in the area.

(5) *The Visund oil population* is located within the Brent Group in the Visund Field, which represents a down-thrown fault block or terrace towards the Viking Graben, and in the Cook Formation and the Statfjord Formation in the Gullfaks Field. This oil has a higher maturity than any of the other oils on the Tampen Spur (Table 3) and has been expelled from a high maturity source rock, probably near the Viking Graben axis. This is in accordance with the local presence of gas caps in the Visund Field and a relatively high GOR as compared to the structures on the Tampen Spur high, which host mainly highly undersaturated oils. The oil leg in the Visund Field probably spills to the southwest up the large fault towards the eastern part of the Gullfaks Field. Data from new wells suggest that the Visund Field might have been filled from several directions and that petroleum emplacement is complex. However, a spill route towards Gullfaks is in accordance with the proposed filling of the Cook Formation and the Statfjord Formation in the Gullfaks Field (Horstad *et al.* 1990), again demonstrating that oil population mapping can be used to

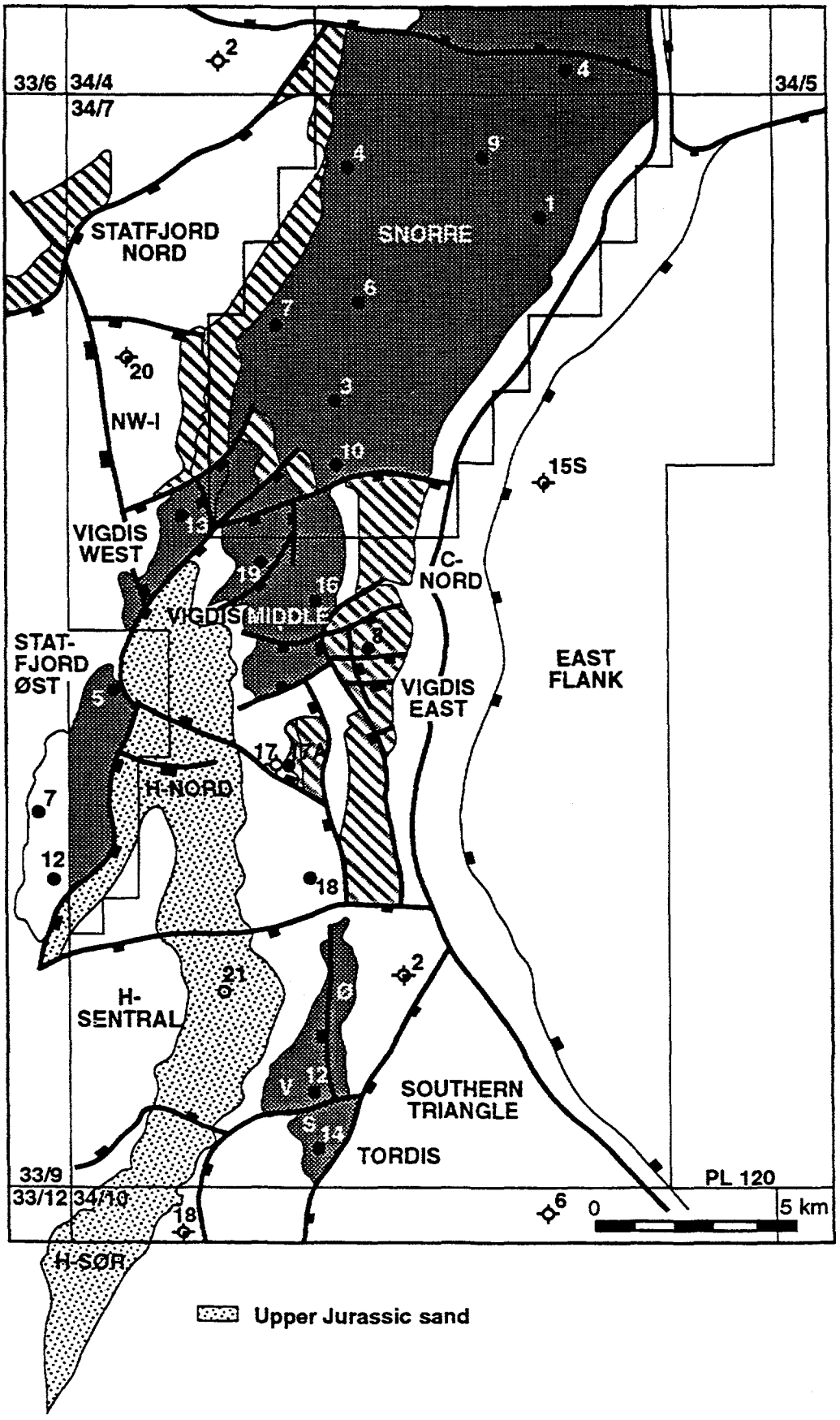

Fig. 19. Location of the two exploration wells (34/7-20 and 21) and the proposed extent of the Upper Jurassic discovery (after Solli in press).

predict oil migration and petroleum type in remote areas.

Ranking of undrilled prospects and model testing

Several prospects have been mapped between the large discoveries within the Tampen Spur, and the ranking sequence of drilling is dependent on a combination of several factors. Two wells were drilled within block 34/7 (licence 089) in 1992 and the petroleum population map that was constructed of the area was applied in the prospect ranking. Both wells were aimed at prospects that were considered to have a favourable position for migration in light of the model discussed previously.

The first well was spudded in July 1992 on an Upper Jurassic pinch-out trap in the northwestern corner of block 34/7 (well 34/7-20 in Fig 19). The petroleum population mapping suggested that the oil proven by three wells in the Upper Jurassic sandstone and the Brent Group in the Statfjord Nord structure and in the Brent Group in the Vigdis Vest segment were similar and could be grouped as a major oil population in the area. This suggested that there is, or has been, an active migration path between the two structures. based on seismic mapping, it was difficult to map and document a potential spill point from Statfjord Nord to Vigdis Vest at Brent Group level, and the Vigdis Vest accumulation was believed to have been sourced by spill from Statfjord Øst to the south rather than from Statfjord Nord to the north. The migration path required spill through a 15 m saddle point between the Statfjord Øst and Vigdis Vest and this was considered to be within the uncertainties of seismic mapping and depth conversion in the area. However, the conclusions from the geochemical mapping were convincing and a new oil-correlation study, including ten oils from the same area, was conducted by another laboratory. The results confirmed the similarities between the Statfjord Nord and Vigdis Vest oils and their dissimilarities with the other oil populations mapped in the area. This resulted in a seismic remapping of the northwestern area to see if it was possible to document a possible spill route between the two structures.

A combination of a sedimentological model and seismic mapping suggested that Upper Jurassic sands might possibly be present between the Statfjord Nord and Vigdis Vest structures and that these could have acted as active migration channels in the area. Because sandstones of Upper Jurassic age were missing on the structural highs, the possibilities of a stratigraphic trap seemed high. Unfortunately, only a few metres of Upper Jurassic sandstone were present at the well location. The Upper Jurassic sandstone was water-bearing , but had good oil shows in the upper part (EOM ranging from 5.4 to 16.4 mg/g rock) and the compositions of these shows were similar to the Statfjord Nord and Vigdis Vest oils. The most likely explanation for the lack of filling of this structure was a lack of proper seal to the stratigraphic trap. The penetrated sand most likely acted as an active petroleum carrier feeding the Vigdis Vest segment. The well was classified as dry with oil shows.

The second well was spudded in October 1992 on a stratigraphic play within the Upper Jurassic section in the western part of block 34/7 (well 34/7-21 in Fig. 19). A relatively thick Upper Jurassic wedge had been mapped in a down-flank position on the rotated footwall block and the sedimentological model suggested that it was likely that this wedge consisted of amalgamated sandstones, siltstones and shales (Solli in press). A horizontal seismic anomaly across the Upper Jurassic wedge represented a possible direct petroleum indicator. This seismic anomaly was later identified as an interference signal between effects due to structural dip and lithology changes. The structure was located between the Statfjord Øst structure and the Tordis field, and was considered to be located in a favourable position for petroleum migration. The petroleum mapping suggested that oil migrated through this area towards the Gullfaks Field in block 34/10 to the south of block 34/7. The well penetrated several sand intervals within the Upper Jurassic section and tested oil. The geochemical composition of the produced oil was similar to the geochemical signature of the oils from the Statfjord Øst structure and the Tordis Field. The prognosis of both sand distribution and petroleum population were in good agreement with the actual results from the well, which was classified as an oil discovery. This again demonstrated the ability to forecast petroleum migration and its utility as an exploration tool within mature petroleum provinces. In particular, confidence in the geochemical model tipped the balance in the assessment of risk with the prospect identifying a new target type in this area.

Conclusions

Based on a combination of conventional geological and geophysical data and a petroleum population map of the oils on the Tampen Spur, a refined migration model was constructed. The migration models proposed earlier were based largely on geological structure maps constructed from seismic and basin modelling. Neither of these methods can distinguish between a physically possible migration route and an active migration route through which the oil actually migrated. Because we have shown that in this area only minor portions of the potential

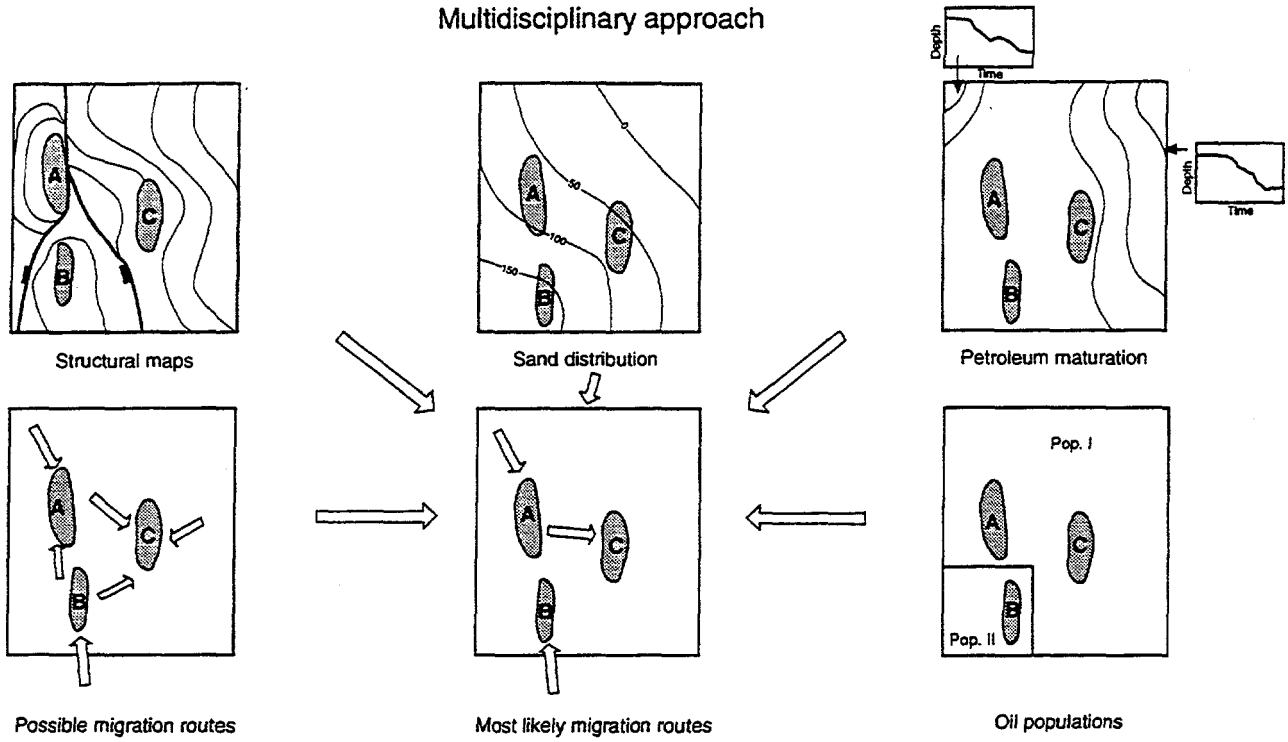

Fig. 20. Input parameters and maps used to evaluate a typical migration history.

carrier system typically carry petroleum (*c* <3% of the volume of the carrier, Larter & Horstad 1992), the distinction between possible and likely carrier routes becomes essential. Obviously, detailed reservoir geochemical information now represents an improvement and a necessary part of any future petroleum migration study.

The oils in the vicinity of block 34/7 have been differentiated into five major petroleum populations and it has been suggested that several of the structures have been filled from more than one direction. Usually, it is possible to distinguish between oils accumulated within different stratigraphic intervals in the same field. This study has demonstrated that filling and migration in a geological province are controlled by a series of complex processes and that the filling history of such structures within the Tampen Spur is more complicated than suggested earlier.

The migration model has been tested and verified by two exploration wells drilled in 1992. Some ability to forecast local-scale petroleum migration has been demonstrated. One of the wells was dry, but contained good oil shows from the same oil population as predicted. A lack of seal resulted in no accumulation and the well may have penetrated an active petroleum migration route. The second well was an oil discovery, again with the same oil type as predicted by the petroleum maps. It is stressed that both accumulations could potentially have received petroleum from several other directions, the oil populations mapping representing an important exploration tool when ranking the prospects in the area. We have also developed a series of procedures that should be followed when a migration model is constructed. It is vital to take all geological and geochemical data into account and apply fully integrated teamwork where both geologists and geochemists participate (Fig. 20). The geochemical dataset has to be of high and uniform quality and if different data subsets are used, several calibration samples should be rerun in every sample set. Likewise, if the model is updated by data from a new well, 5–15 relevant samples should be rerun in the same batch. The paper shows that early predictions of regional petroleum migration conduits can be obtained from analyses of lateral gradients in oilfields (Horstad *et al.* 1990), these models being updated and tested by new data. Reservoir geochemical gradients do appear to have predictive capabilities on a basinal scale. However, we emphasize that in other studies we have performed, complex sedimentology and tectonics may rupture simple interpretations and 'gradients' may not be at all obvious.

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Paper V

Petroleum migration, alteration and re-migration within the Troll Field, Norwegian North Sea.

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ABSTRACT

The Troll Field represents the largest petroleum discovery within the entire North Sea area in terms of oil equivalents, with 74% of the accumulated petroleum as dry gas and 26% as a heavy biodegraded oil leg with a thickness varying from 0 to 26 metres. The field is divided into several provinces based on the distribution of gas and oil, and it has been suggested that the gas and oil are co-genetic. Our migration and filling model suggests that the oil and gas represent two different migration phases and that the gas migration and filling predates the oil emplacement. Two different oil populations have been characterised and mapped in the Troll Field and it is suggested that the oil migrated into the structure from several directions and was subsequently biodegraded within the reservoir. These two oil populations have been found in neighbouring oil and gas discoveries and an oil-oil correlation with these discoveries has been used to suggest the location of field filling points and regional migration routes. When the oil biodegradation terminated, fresh oil continued to migrate into the reservoir and mixed with the residue of the biodegraded oil. The field was tilted downward to the west in Neogene time and the oil and gas re-migrated within the field with a possible spill of gas eastward. The tilting resulted in an upward movement of the oil phase while the gas migrated laterally. The residual oils within the water zone have been used to reconstruct the paleo configuration of the field, which controlled the current distribution of oil populations within the Troll Field.

Introduction

The giant Troll oil and gas field is located 60 km. offshore the west coast of Norway, in the Horda Platform Area (Fig. 1). The field covers four Norwegian North Sea blocks (31/2, 31/3, 31/5 and 31/6) and has a lateral extension of approximately 770 km^2. The water depth ranges from 298 metres in well 31/6-8 to 364 metres in well 31/2-18. A total of 34 wells have been drilled within the four blocks to delineate the enormous discovery (Fig. 2) which to date is the largest within the North Sea classified by oil-equivalents. It is beyond the scope of this paper to give a detailed description or a proper review of the geology of the Troll Field, which has been published in several other papers (Gray, 1987; Hellem *et al.*, 1986; Osborne and Evans, 1987), and we will only address the filling of the field.

The field has been divided into three main provinces based on the distribution of oil and gas, and the thickness of the oil column and the OWC's varies significantly across the field (Tab. 1). The Troll West Oil Province has a oil column of 22 to 26 metres, decreasing to between 12-14 metres in the Troll West Oil Province and into a very thin, currently non-commercial oil column of 0 to 4 metres, within Troll East. However the total STOOIP of $83*10^6$ Sm^3 ($522*10^6$ barrels) in Troll East is larger than many North Sea oil fields. The maximum thickness of the gas column reaches 230 metres and the total amount of petroleum accumulated in the Troll Field is $2,245*10^6$ tons oil equivalents of which 74% is gas. The total recoverable reserves have been estimated to $1,250*10^9$ Sm^3 gas, $44*10^6$ Sm^3 NGL and $55*10^6$ Sm^3 oil.

The Troll Field was awarded to two different licences, block 31/2 as Production Licence 054 in 1979 with Shell as operator and blocks 31/3, 31/5 and 31/6 were awarded in 1983 as Production Licence 085 which was jointly operated by Statoil, Norsk Hydro and Saga Petroleum a.s. The Troll Field has been unitised and the current licence consist of:

Statoil and Government direct financial involvement	74.576%
Norsk Shell a.s.	8.288%
Norsk Hydro Produksjon	7.688%
Saga Petroleum a.s.	4.080%
Elf Aquitaine Norge A/S	2.353%
Conoco Norway Inc.	2.015%
Total Norge A/S	1.000%

Geological setting

The Troll Field is located on the north-western edge of the Horda Platform close to the eastern border of the north-south trending Viking Graben. The hydrocarbons are accumulated in the Middle to Upper Jurassic shallow marine sandstones of the Sognefjord Formation and the Fensfjord Formation (Fig. 3). The fault blocks were rotated in the Late Jurassic to Early Cretaceous and have a gentle eastward dip (Fig. 2). The field is sealed by Upper Jurassic to Lower Tertiary mudstone and marls (Hellem *et al.*, 1986), and the burial history shows that the field lacked a proper seal until early Tertiary times which constrains the petroleum accumulation history of the field. The dominating fault trends in the area are N-S and NW-SE trending, and these fault trends partly controlled the migration of hydrocarbons into and the re-migration within this giant accumulation. The field has been interpreted to be filled to its current spill-point (Gray, 1987), although it is difficult to locate the exact location of the spill-point.

The Fensfjord Formation and Sognefjord Formation interfinger with and pinch out into siltstones and shales of the Heather Formation (Fig. 3). The shales have been given the subscriptions Heather A, B and C according to their location relative to the Fensfjord Formation and Sognefjord Formation. The Heather C (Upper Heather) is only present within the eastern part of the field. The sandstones were derived from the Norwegian mainland and transported into the continuously subsiding Horda Platform in Bathonian to Kimmeridgian times. The gentle eastward tilt of the Horda Platform prevented the sediments from being spilled into the Viking Graben (Pegrum and Spencer, 1990). Several different biostratigraphic events, reflecting periodic flooding and emergence of the system, can be correlated across the field. These events suggest that relative sea level changes through time controlled the distribution of sand and their reservoir quality. The Bajocian to Early Bathonian Brent Group is water bearing within the Troll Field, and only non-commercial oil discoveries have been made in the Bathonian Krossfjord Formation.

The deepest oil-water contact within the Troll Field is located at approximately 1570 mMSL and the reservoir temperature is only 68°C. This has prevented significant alteration of the primary porosity of the sandstones. The sandstones are virtually unconsolidated with porosities up to 34% and permeabilities from a few mD to above 10 D (Gray, 1987). The burial history of the Horda Platform area is very complex and several uplift episodes have occurred. The absolute amount of uplift and the detailed timing of the events is poorly documented, however, the extent of diagenesis of the sands,

vitrinite reflectance and apatite fission tracks data suggest that the Troll Field could have been buried in the order of 500-1000 metres deeper than at present (unpublished in house data).

Migration Model; previous work

The number of publications on the geochemistry and filling history of the Troll Field is relatively small. Cornford *et al.*, (1986) pointed out that the filling of the Troll Field with oil and gas had to invoke long distance secondary petroleum migration, since the distance from the mature source rock kitchen to the field is so large. Thomas *et al.* (1985) demonstrated that the Troll Field contained thermogenic gas based on its stable carbon isotope signature ($d^{13}C$ -44.5 for methane), and suggested that the source kitchen was located within the Viking Graben to the north-west of the Troll Field (Troll Kitchen). Further, Thomas *et al.* (1985) stated: *Although the Humber Group source rocks are currently gas-mature in the undrilled central kitchen area, a significant prior oil charge is indicated by a biodegraded heavy-oil rim in the Troll structure and evidence of oil-staining within the present Troll gas cap.* They suggested that petroleum entered the structure in Early Tertiary and that the current oil represents a mixture of the napthenic residue of an early biodegraded oil charge diluted by a later fresh paraffinic oil charge (Thomas *et al.*, 1985). The oil was partly considered to represent a spill from the Brage Field to the south-west.

Schou *et al.* (1985) analysed two oil samples from the Troll Field together with a suite of other oils and source rocks from the northern North Sea, and demonstrated that the oils from the Troll Field were different to the condensate in well 35/8-1 to the north and the oil in 30/4-2 to the east. The Troll Field oils have a similar composition to oils from the Oseberg Field, Brage Field and Veslefrikk Field (Schou *et al.*, 1985). They also noted the biological degradation of the Troll Field oils and an apparent loss of light end components from the oils (Schou *et al.*, 1985).

Field (1985) suggested that the Troll gas was sourced from the Sogn Graben (Fig. 1) and migrated southward up the Horda Slope and into the Troll structure. He also suggest that some of the oil migrated into Troll by a spill from the Brage Field to the south-west which in turn is filled by spill from the Oseberg Field to the west of the Brage Field. Based on numerical basin modelling in the Northern Viking Graben, Burrus *et al.* (1991) suggested that the Troll Field was sourced from the deep graben and that only gas could migrate across the Horda Slope due to its greater mobility than oil. They suggested that the primary generated oil was stopped by impervious faults and that the oil currently present in the oil leg was transported into the Troll Field in the gas phase and later

segregated to form the current oil leg (Burrus *et al.*, 1991). Larter (1990), briefly discussed the Troll Field as a possible candidate for a structure where the oil leg could have been formed by retrograde condensation of liquids from a gas phase as discussed by England *et al.* (1987).

To summarise, the general view among most geologists and geochemists is that the structure initially was filled by oil which migrated into the field from the Viking Graben to the west and/or the Sogn Graben to the north. As the Upper Jurassic source rock(s) in the Viking Graben and the Sogn Graben reached the gas generating stage the evolved gas migrated along the same migration route and displaced the oil downward in the reservoir (Gray, 1987) subsequently spilling out of the structure. This model suggest that the Troll Field previously contained enormous volumes of oil. With the exception of the paper by Schou *et al.* (1985), non of the papers provide detailed geochemical data on oil-oil correlation or oil-source rock correlation. Thus, while there are several suggestions and general models for the filling of the Troll Field, detailed information is somewhat lacking.

This study

Objectives

The main objectives of this study was to gain a better understanding of the reservoir filling processes in the Troll Field and to apply conventional reservoir geochemical methods to understand the extent of communication between the oil column in the different petroleum provinces within the Troll Field. It is of great importance to the further exploration of the east flank of the Viking Graben area to understand the relative timing of oil and gas migration and to provide a reasonable, data constrained, geological and geochemical explanation of how the Troll Field was filled. As discussed above previous models suggested a co-genetic (retrograde condensation) or a single source of the oil and gas in the Troll Field. It was also considered important to establish whether the whole structure previously had been filled with oil which spilled out of the structure as gas migrated into the field. Potentially this oil could be accumulated in shallower structures updip, unless it leaked to the surface. The east flank of the Viking Graben has recently gained new interest after two oil discoveries to the north of Troll in block 35/11 by Mobil in 1992, which demonstrated that not only gas and condensate potential remains in this area, but that normal gravity undegraded North Sea crude oil could be present if the timing of oil and gas migration and trapping has been favourable.

Sample set

A total of 796 reservoir core samples from 15 wells (31/2-4, 31/2-6, 31/2-7, 31/2-8, 31/2-9, 31/2-12, 31/2-14, 31/2-15, 31/3-1, 31/3-2, 31/5-2, 31/5-3, 31/6-2, 31/6-6 and 31/6-8,) were screened by Iatroscan (TLC-FID) to map the distribution of migrated hydrocarbons in the cored section of the reservoir (Fig. 4). This method allow a rapid screening and bulk characterisation of the core extracts by providing absolute concentration of saturated hydrocarbons, aromatic hydrocarbons and polar compounds in the samples (Karlsen and Larter, 1991), and the method gives a rough estimate of the degree of staining and on what scale vertical heterogeneieties occur within the reservoir (Horstad *et al.,* 1990).

Based on the Iatroscan (TLC-FID) screening 110 samples were selected for detailed characterisation of the petroleum by GC-FID and GC-MS of the saturated hydrocarbon fraction.

Analytical procedures

The Iatroscan (TLC-FID) analysis were performed as described by Karlsen and Larter (1991), on an Iatroscan MK-5 instrument equipped with Chromarod S-III. Elution times were 25 minutes in n-hexane, 9 minutes in toluene and 2 minutes in dichloromethane/methanol (93:7 vol/vol).

Deasphalting of reservoir core extracts were performed with n-hexane and compound class separation of the petroleum by conventional MPLC methods (Radke, 1980). GC-FID of saturated hydrocarbons was performed on a HP 5890 II gas-chromatograph with an autosampler equipped with a 25 metres CP-SIL 5CB column with a diameter of 0.25 mm and a film thickness of 0.25 mm. Helium was used as carrier gas. The temperature program was set at 80°C for 1 minute then 4°C/min to 300°C with a final hold time of 20 minutes. GC-MS analyses was performed on a HP 5890 II gas-chromatograph coupled with a HP 5971 A MSD. A 50 metres CP-SIL 8CB column with internal diameter of 0.25 mm and 0.25 mm film thickness was used. The temperature program was set at 180°C for 1 minute then 1.7°C/min to 300°C with a final hold time of 20 minutes, to allow a proper resolution of steranes and hopanes. The MSD monitored four different masses (m/z 177, 191, 217 and 218).

Data quality

The quality of the input data is very important in every reservoir geochemical study since, the geochemical differences that are to be expected between the different structures or regions of a single field, charged from a single source kerogen may be very small. Thus, direct comparison of data collected at different times from different consultants should be avoided (Horstad *et al.,* 1994). Our

experience is that in some cases significant small, but indeed real, compositional differences have been masked because the samples were analysed by different laboratories at different times. In other studies samples that belong to the same oil population may be wrongly grouped as two populations due to lack of reproducibility of geochemical data between different laboratories. All the data used in this study have been acquired in a single sequence at a single site and represent as uniform and as high a quality data set as was possible for such a large number of samples.

Petroleum Populations.

During the last five years several vague classification systems have been used to discriminate oil and gases into different groups. Terms like oil populations and oil families have been used without clear definitions, and this lack of consistency is partly related to the confusion of old geochemical and reservoir engineering terms. We propose a hierarchical geochemical classification system which allows for the description of a grouping of oils based on their geological origin and their subsequent transformations in the subsurface. It is stressed that this classification system is constructed to help geologists and geochemists in petroleum exploration and is of limited use for engineers and technicians working with petroleum refining.

We define a petroleum population as a set of oils (or gases) with definable source characteristics which can be distinguished from other oils (or gases) within a geological province based on its geochemical properties i.e. biological markers, sulphur compounds, stable carbon isotope signature etc (Fig. 5). Thus, to been grouped into the same oil population the oils have to have been generated from the same source rock interval within the same source rock basin, but not necessarily at the same time or at the same maturity. Oil families represent sub-groups of an oil population, each family having different physical or chemical properties. Each petroleum population may potentially consist of several petroleum families due to differences in maturity or post generation processes which might change the composition of the petroleum (Fig. 5). Thus, we define a petroleum family as a set of oils (or gases) with similar bulk chemical and physical properties. The most likely geological processes causing changes in the bulk chemical and physical properties of an oil are a) delayed oil expulsion from the source rock resulting in a higher maturity, b) gas deasphalting, c) biological degradation, d) in-reservoir thermal cracking, e) water washing, f) phase fractionation during migration or within the reservoir due to uplift or seal leakage, g) geo-chromatographic effects during migration. While delayed expulsion could be classified as a primary effect, the other processes are classified as secondary processes. Thus, if two oil families have the same source origin but different maturities or

different physical and/or chemical properties due to secondary alteration processes, they should be classified into the same oil population (Fig. 5).

Two examples of oil populations which could be discriminated into different families was described from the Tampen Spur area by Horstad *et al.* (1994) and this case study illustrates the utility of this differentiation. The oil within the Brent Group reservoir in the Statfjord Field, Statfjord East Field, Tordis Field and Gullfaks Field has been classified as a major oil population on the Tampen Spur, accounting for more than 80% of the recoverable oil in the area. This oil population is usually present as a medium gravity undegraded oil with a gas-oil ratio between 100 to 200 Sm^3/Sm^3, however within the Gullfaks Field this oil population has been biodegraded (Horstad *et al.*, 1990,1992) and the Gullfaks oil therefore represents another oil family with different physical properties (bulk chemical composition, viscosity, density etc.). Another oil population was described within the Snorre Field on the northern part of the Tampen Spur and this oil population could be grouped into two families based on a generally higher maturity of the oils within the Triassic Lunde Formation than in the oils from the Triassic to Lower Jurassic Statfjord Formation (Horstad *et al.*, 1994).

It is often difficult to determine which processes that control the geochemical signature of an oil unless a detailed geological and geochemical understanding of the area is available. If the alteration of an oil has been very extensive, eg. severely degraded biological markers due to thermal cracking or biological degradation, it may be impossible to link this oil family to a specific oil population with any degree of confidence.

The differentiation between oil populations and oil families might at first sight seem unnecessary or academic, however it is important to remember that most petroleum geological and geochemical models of an area represent a status quo view at a certain time as they are often data limited. It is therefore necessary to continuously update the models as new information becomes available, and by differentiating between oil populations and oil families the updating and refining of the model becomes easier. It is stressed that this method is pragmatic but has utilities and experience is often a critical element in arranging the petroleums into oil populations and families.

Traditionally the understanding of migration pathways and history in an area is based on a combination of input from structural maps, sand distribution in carrier bed horizons and basin

modelling, and at best this provides a set of possible migration pathways and scenarios (Fig. 6). Based on the discrimination of oils into different oil populations and oil families it is possible to construct petroleum distribution maps, which if used in combination with other geological information (structural maps, sand distribution maps etc.). makes it possible to distinguish between a large number of possible migration routes and the most likely active migration routes within an area (Fig. 7) (Horstad *et al.*, 1990, 1994; Chung *et al.*, 1992; Piggot and Lines, 1991). This has a large impact on the exploration strategy in mature exploration provinces where well data and other geological and geochemical information is available.

Vertical characterisation of the petroleum column

Approximately 1920 metres of core from 15 wells (Fig. 8), were screened by Iatroscan (TLC-FID) giving an excellent picture of the distribution of the C_{15+} petroleum within the cored section of the Troll Field. However, the coring of the reservoir is biased towards the oil leg and this obviously affects the amount and coverage of data from the gas and water zones in the western part of the field. The gas zone has only been extensively cored and analysed in eight wells (31/2-4, 31/2-6, 31/2-12, 31/3-1, 31/5-3, 31/6-2, 31/6-6 and 31/6-8). Based on the screening analysis of the absolute amount of C_{15+} core extract petroleum (EOM mg/g rock) and the relative distribution of saturated hydrocarbons, aromatic hydrocarbons and polar compounds observed, the vertical section of the reservoir can be divided into five different geochemical zones (Fig. 9). The uppermost zone is the thick gas cap with a dry gas and a low concentration of C_{15+} extractable material, followed by a thin currently gas bearing zone with high concentrations of residual C_{15+} extractable material. Below this, the oil zone, a water bearing zone with high concentration of residual C_{15+} extractable material and a water zone without any extractable petroleum at the base. The thickness and depth interval of individual zones varies significantly across the field (Fig. 8). This zonation does not give any information about the origin of the petroleum in the different zones, but describes the distribution of C_{15+} petroleum in the Troll reservoir, and provides information on how the fluid contacts evolved through time.

Gas zone

The Troll Field gas is very dry (93% methane) and the iC_4/nC_4 and iC_5/nC_5 ratios of the gases are much higher than is usual in thermogenic gases. Figure 10 shows the iC_4/nC_4 ratio from PVT analyses of 98 tested gas samples (several duplicates) from the Troll Field, suggesting an average iC_4/nC_4 ratio above 6.0. This is much higher than typically observed in North Sea gases where the iC_4/nC_4 typically range from 0.3 to 0.5, suggesting some sort of alteration of the Troll Field gas. The

observed iC_4/nC_4 and iC_5/nC_5 ratios in the Troll Field could have been caused by biological degradation of the gas, gas fractionation as a result of changing PVT conditions during migration, uplift of the entire structure or a rapid pressure drop due to seal failure. During retrograde condensation or the formation of a separate gas phase, it is expected that the gas would be enriched in the iso components compared to normal butane and pentane.

Data by Larter and Mills (1991), who artificially brought an oil with a gas-oil ratio of 3707.1 Sm^3/Sm^3 from a pressure of 1000 bar and a temperature of 150°C to a pressure of 166 bar and a temperature of 70°C at various stages, suggest that the iC_4/nC_4 ratio in the gas dissolved in oil phase varies from 0.08 to 0.23, while the iC_4/nC_4 ratio in the resulting gas cap range from 0.72 to 0.96. This suggest a significant fractionation of gas components, not only by carbon number but also as a function of molecular structure. However, the fractionations observed by Larter and Mills (1991) are much smaller than the fractionation observed in the Troll Field with an average iC_4/nC_4 ratio above 6.0.

It is obvious that the oil within the Troll Field has been degraded by bacteria (see below), however it is not properly documented to what extent bacteria are able to degrade gas and residual C_{15+} hydrocarbon compounds within a gas column, and the literature on this topic is very limited. James and Burns (1984) suggested that microbial alteration of subsurface gas could result in a removal of the wet gas components and produces a dry gas that could be confused with an overmature dry gas whose wet components have undergone extensive thermal cracking. They suggest that microbial degradation of reservoir gas alters both the relative distribution of gas components and the stable carbon isotope signature of the gas in a predictable manner. The carbon isotope signature of propane is reported to be typically 4-7 per mill. heavier than what would be expected in an undegraded gas based on data by James (1983), but might be a as much as 24 per mill. heavier (James and Burns, 1984). In addition, data by James and Burns (1983) suggest an elevated iC_4/nC_4 of biologically degraded gases (three examples quoted with iC_4/nC_4 ratios 1.1, 2.0 and 9.0 respectively), as is observed in the Troll Field.

Figure 11 a and b show the carbon isotope signature of methane plotted vs. the carbon isotope signature of ethane and propane for gas samples from the Troll Field (filled circles) and other samples from the Northern North Sea (dots represent mainly tested gas reservoirs and a few solution gas data from the Oseberg Field, Gullfaks Field, Snorre Field and Visund Field). These data suggest

that the carbon isotope signature of the ethane and propane fraction of the Troll Field gas is enriched with respect to ^{13}C by 5-8 per mill., which is in the same range as was reported by James and Burns (1984). Thus, based on the dry nature of the gas, the observed fractionation of iso-butane vs. normal butane and the heavy carbon isotope signature of the ethane and propane in the Troll Field gas, it is suggested that the gas in the Troll Field could have been altered by bacterial action as has been observed in several other fields (James and Burns, 1984). The timing of this bacterial degradation remains uncertain, but since bacterial degradation of petroleum probably occur at the petroleum-water interface it may have occurred prior to the oil charging. We have no data to suggest an efficient degradation of the gas though an oil column with a thickness in the order of several tens of metres.

With the exception of the thin residual oil zone above the gas-oil contact discussed in the next section, no petroleum core extracts with a similar geochemical signature to the oil leg were observed within the current gas cap in any of the wells we analysed. Only a few extracts with high concentration of extractable organic matter were detected.

The generally low amounts of extractable C_{15+} petroleum (0.1 to 1.0 mg/g rock) within the upper part of the gas zones (Fig. 8) suggest that the upper part of the reservoir never contained significant concentrations of C_{15+} hydrocarbons and polar compounds, contradicting earlier views (Thomas *et al.*, 1985). If the upper part of the reservoir had been filled by an oil phase or an oil phase had passed through as a result of a downward moving oil leg resulting from continuous filling of gas or an expanding gas cap due to tectonic uplift and pressure drop in the reservoir, one would expect to see much more residual oil range hydrocarbons in the gas zone. In addition, if a relatively dry gas displaced an oil phase within the reservoir, a more polar rich composition would be expected for the residual oil left in the gas zone since the polar components are less soluble in the displacing gas phase and therefore less mobile than the saturated and aromatic hydrocarbons. The only reservoir core extracts that have a significantly higher proportion of polar compounds than the extracts from the current oil zone are samples with very low amounts of EOM. The high relative concentration of polar compounds in these samples is probably caused by contamination by polar compounds from immature *in situ* organic matter within the Heather Formation siltstones, and from small shale clasts within the sandstones. Commonly the biological marker signatures of gas zone extracts have an immature signature and some of the extracts contain oleananes, which are not present in the Troll oils which have been generated by Upper Jurassic source rocks.

If a migrating dry gas phase should be capable of removing all traces of a paleo oil accumulation, this would require a relatively high pressure (40-50 MPa) and a very efficient flushing of the entire reservoir. It seems unlikely that the entire gas cap within the Troll Field has been flushed with such volumes of gas at such high pressures, and that this gas would have been able to access all regions of the enormous field.

It has also been suggested that the oil leg in the Troll Field could be the result of a retrograde condensation of oil components from a gas phase due to a drop in pressure during migration (Burrus *et al.*, 1991; Larter, 1990), however this process would also be expected to result in a relatively high concentration of C_{15+} compounds in the entire gas zone.

Only five thin zones with a high concentration of extractable hydrocarbons (5-8 mg/g rock) have been discovered within the gas zone in wells 31/2-4 and 31/2-12 (Fig. 8). Detailed biological marker analyses of samples from the gas zone in wells 31/2-4 and 31/2-12 demonstrate that the composition of the core extracts from these zones are totally different to the composition of the EOM in the underlying oil zone. These core extracts are characterised by a higher Ts/Tm ratio, a higher relative concentration of diahopane (Moldowan *et al.*, 1991; Conford, 1986; Horstad *et al.*, 1990), more C_{27} diasteranes compared to C_{27} steranes and a higher S/(S+R) ratio in the $C_{29}\alpha\alpha\alpha$ steranes (Tab. 3), and they also have a higher concentration of C_{27} steranes and C_{27} hopanes relative to the higher homologues (Fig. 12). This biological marker signature could be interpreted to reflect cracking at a high temperature in an over mature oil source rock during gas expulsion and suggests that these extracts might have been generated at a much higher maturity than the petroleum within the oil leg underneath.

However, we interpret the biological marker signature of the core extracts from the EOM enriched zones in the gas zone in well 31/2-4 and 31/2-12 to be the result of gas stripping of the oil leg underneath. The GC-MS mass-chromatograms demonstrate a rapid decrease in the relative concentration of higher homologues in all biological marker series (Fig. 13), and we interpret this as an effect of selective remobilisation of the lower homologues from the oil leg into the gas cap during late stage gas charging.

Larter and Mills (1991), demonstrated that significant fractionation of biological markers might occur as a result of vapour/liquid partitioning between a petroleum liquid and petroleum gas phase in a North Sea crude oil. They demonstrated that the equilibrated gas phase is enriched in short chained homologues while the residual oil phase is enriched in heavier long chained homologues. Similar gas

fractionation effects have also been documented in several other papers (Thompson, 1987; 1988; Thompson *et al.*, 1990). The zones within the gas cap with a high amount of C_{15+} extractable material probably represent gas migration channels in which the heavier petroleum compounds reprecipitate from the migrating gas phase or are preferentially adsorbed to mineral surfaces. We have not been able to link these zones to petrophysical properties of the reservoir yet, but the location of these zones are probably controlled by the large scale permeability within the field and the location of focused gas supply into the reservoir.

An additional argument supporting a gas stripping event is that the core extracts from these zones seem to have been biodegraded based on the distribution and concentration of n-alkanes. The GC-FID traces of the extracts from the EOM enriched zones in the gas cap have a low concentration of n-alkanes compared to isoprenoids ($Pr/n\text{-}C_{17} >> 1$) and a high base line suggesting that biological degradation has occurred. This suggests that the petroleum in the EOM enriched zones was extracted from the oil leg after the biological degradation occurred (see below).
Thus, there are geochemical reasons to support a filling model with an early migration of gas into the Troll Field prior to the filling of the current oil leg and a subsequent charging of gas into the structure probably to the present. The free gas phase in the field, which probably was generated and expelled as a relatively dry gas, was later altered by bacterial action which resulted in an even drier composition by removing wet gas components, fractionation of iso-butane vs. normal butane and a fractionation of the carbon isotope signature of the ethane and propane in the gas phase in Troll Field. Thus, the geochemical composition of the gas within the Troll Field was probably controlled by a combination of sourcing from a very mature gas generating source rock and in-reservoir alteration by bacteria.

Residual hydrocarbons in the gas zone

As discussed above, there are only traces of C_{15+} components within most of the gas cap and significant concentration of residual oil is only observed to within a few metres above the current gas-oil contact in some of the wells (Fig. 14). The geochemical signature of the C_{15+} solvent extracts from these zones are very similar to the C_{15+} solvent extracts from the oil zone below, and this suggests that the gas-oil contact has been depressed in this part of the field. The thickness of the gas zone with residual oil varies from well to well, ranging from 0 to an absolute maximum of 11 metres, and this is a proxy indication of how many metres up-core the gas-oil contact has been. This zone might have been created by large scale tilting of the field resulting in re-mobilisation of oil and gas, gas expansion or a continuous migration of gas into the structure to the present. The relatively thick

residual oil zone in the gas cap in the north-western part of the field (wells 31/2-9, 15 and 31/3-1), suggest that this area might be located in the focus of recent gas migration, while the other wells may be more or less shielded from gas migration. This suggest a significant post oil emplacement gas migration into the north-western corner of the field and a south-eastward migration of gas through the area of well 31/3-1 and into the gas province where the gas either still accumulates or is spilled out of the structure. This is consistent with continuous burial to the present day of the source rock kitchen to the north-west of the field.

Oil zone

The thickness of the present oil column varies systematically across the field, from 0 in the eastern part to between 12 and 14 metres in the central part and between 22 and 26 metres in the western part of the field. The sandstones within the entire oil zone are well stained and the oil column seem to be vertically homogeneous within all the wells we analysed, based on Iatroscan (TLC-FID), GC-FID and GC-MS analysis. Details on the biological marker distribution and oil population characterisation will be discussed in the next section.

The origin of the thin oil leg in the Troll Field has been debated since the discovery of the field, and it has been suggested that the oil within the Troll Field represents a product of retrograde condensation of liquid hydrocarbons initially dissolved in a gas phase (Burrus *et al.*, 1991; Larter, 1990), which is not unreasonable based on the bulk gas-oil ratio (GOR) of the entire field. The bulk GOR of the field increases eastward from 174 Sm^3/Sm^3 in Troll West Oil Province, to 1,295 Sm^3/Sm^3 in the Troll West Gas Province and 12,916 Sm^3/Sm^3 in the gas province (see Fig. 2 for locations), giving a total GOR for the entire accumulation of 2462 Sm^3/Sm^3. This is within the same range as for other gas/condensate accumulations adjacent to the Viking Graben and Sogn Graben in the northern part of the North Sea, which at present are buried at much greater depths and therefore have only one rich condensate phase. However, it is important to take into account the differences in the composition of the oil and gas phases that are supposed to have been mixed at higher pressure and temperature. It is always difficult to predict the composition of the initial petroleum mixture that represents the source of the petroleum, but based on a regional perspective the most likely source from which the gas and oil in the Troll Field spilled, are by a) a spill of oil from the current oil leg in the Brage Field with gas exsolution due to a pressure drop (Fig. 21) or b) a spill from the condensate discoveries to the north of Troll, e.g. 35/8 and 35/11 discoveries, or another gas/condensate of a similar composition (Fig. 21).

If the composition of the oil in the Brage Field or the condensate from 35/8-2 discovery are assumed to be two possible sources of the gas and oil in the Troll accumulation, it is possible to compare the distribution of C_1 to C_{10+} components in the different petroleum systems, and calculate the range of components that have to be removed from or are missing when going from one petroleum system to another. Our calculations are based on matching the total volume of methane which is the most common compound in the Troll Field, or the total volume of iso-butane which is expected to be less affected by biological degradation. The oil and gas compositions used in these calculations are based on recombined fluid compositions from PVT analyses and therefore represent total reservoir fluid compositions. The details of these calculations are shown in Tab. A1 to A3 of the appendix.

Matching the total volume of either 1) methane or 2) iso-butane accumulated in the Troll Field at present by a spill from either the Brage Field oil or a spill from the gas/condensate in well 35/8-2, can only be achieved by assuming that large volumes of liquid petroleum have escaped from the field (Tab. 2). If the oil in the Brage Field oil is selected as a source for the oil and gas in the Troll Field, enormous volumes of C_2 to C_{10+} components must have been lost from the system to match the volume of methane in the Troll Field (Tab. 2). To match the volume of iC_4 in the Troll Field a loss of C_3 to C_{10+} and a lack of C_1 to C_2 components is required. Thus, it is considered very unrealistic that the Brage Field could be the source of the oil and gas within the Troll Field. However, the oil within the Troll West Oil Province was probably charged through the Brage Field (see below).

It might seem possible to produce the Troll accumulation from a fluid equivalent to the 35/8-2 discovery by losing $560*10^6$ Sm^3 of the C_2 to C_9 components and gaining $170*10^6$ Sm^3 C_{10+} components, however the condensate in well 35/8-2 has a very low concentration of asphaltenes (0.2%) which are present in larger quantities within the oil from the Troll Field (2-3%). To match the volume of iso-butane it the Troll Field the volume of methane is much too low and in addition a significant loss of oil range components is required. Based on the lack of oil range components in the gas cap, low concentration of asphaltenes in neighbouring condensate discoveries, and the rough mass balance of the petroleum compositions, support a model suggesting that most of the gas within the Troll Field represents a separate migration phase and therefore is not associated with the current oil leg.

Residual petroleum in the water zone

Several hundred samples from the current water zone were analysed by Iatroscan (TLC-FID) and Figure 8 shows that a fairly uniform staining of extractable C_{15+} petroleum is observed within the current water zone in most of the wells that we analysed. The presence of residual petroleum below the current oil-water contact can be explained by several different geological scenarios, and figure 15 shows an interpretation scheme for residual petroleum staining in reservoir cores. It is important to remember that an oil accumulation is a very dynamic system, and that a paleo oil-water contact can only be present if the spill point of the current structure is shallower than the spill point of the paleo structure, or if there has not been sufficient time or petroleum charge to refill the structure to a structurally deeper level than its paleo configuration allowed. If oil continues to migrate into the structure the residual oil will mix with the new oil charge and mask the evidence of field tilting or leakage. At present, there is no geochemical technique that can be applied to distinguish between all these alternative explanations, but a synthesis of geochemical and geological information from the whole field might give some indications of the controlling mechanism on residual oil zone occurrence.

The first and most important observation is to determine whether the residual staining is of a uniform or patcy nature in the core. If the residual oil staining is patcy and high quality reservoir sandstones intervals lack residual oil, they could be interpreted to represent migration routes feeding the structure or paleo migration routes for oil which have been cut off from the current migration routes. Alternatively patcy residual petroleum staining can represent relatively small petroleum slugs which have been cut off from the main petroleum charge by zones of higher water saturation (Fig. 15). If the residual oil represents a relatively small volume of oil that was cut off from the main oil charge, the reservoir extracts from the relatively small petroleum volume might be expected to have a different geochemical signature to the main oil charge in the reservoir. The main charge of petroleum may mix and partly homogenise within the reservoir and would represent an integration of the total petroleum charge into the structure. A small petroleum slug however, represents a snapshot of the oil generated and expelled from a specific part of the source rock at one time and it may have a different overall composition than the petroleum in the active carrier system. If the residual oil zone represents a paleo migration route, a less mature oil of a similar source facies would be expected (Fig. 15), unless source rocks within other drainage areas have contributed and modified the composition of the present day petroleum accumulation. If the "residual oil" zone represents an active migration channel which currently feeds the structure, the oil should be expected to have a slightly higher maturity than the accumulated oil.

If the residual oil staining is uniform and all reservoir quality sandstone intervals are stained, the zone might represent paleo oil columns which have been replaced by water due to reservoir seal failure, field leakage or tilting of the structure resulting in a shallower spill point and re-migration of petroleum into different segments of the field (Fig. 15). If the residual oil zone is recognised in several wells and is of a regional extent it most likely represents a paleo oil column, and if the base of the residual oil zone is horizontal seal failure is the most likely explanation for the residual oil zone. However, if the base of the paleo oil zone has a certain angle to the oil-water contact of the current accumulation it may have been caused by a regional tilting of the trap, or the whole area if the same tilted paleo oil-water contacts are present in neighbouring fields. This latter hypothesis might be further supported by seismic data on shallow horizons and well information which might provide information regarding the structural development of the area relative to the timing of petroleum migration and accumulation.

The relative distribution of the petroleum compound classes and biological markers are similar for most of the section within the oil and water zones, and the uniform residual oil staining below the current oil leg within the Troll Field suggests that it represents a "paleo oil leg" with a significant gas cap above and that the oil-water contact was significantly deeper at some stage in the fields history.

Water zone

Below the residual oil zone a clean water zone without any migrated petroleum is present, with very low concentrations of hydrocarbons (0-0.5 mg/g rock). The traces of extractable material in this part of the water zone are probably caused by organic material *in situ* in the core.

Biological marker analysis and petroleum populations

The current oil zone and the residual petroleum in the current gas and water zones have been extensively sampled in all wells and a total of 110 samples were analysed by GC-MS to provide a detailed characterisation of the saturated hydrocarbon fractions. Based on a careful analysis of all conventional biological marker ratios and a statistical testing (multivariate statistics/principal component analysis) of all the data, the oil leg in the Troll Field can be discriminated into at least two distinct oil populations. These two oil populations migrated into the reservoir from two different directions and were subsequently mixed in the central part of the reservoir. These two oil populations are both derived from the Upper Jurassic Heather Formation and Draupne Formation shales, but

geochemical heterogeneieties within these two source rock formations and perhaps different relative contribution from the two formations might result in a different geochemical signature of the generated and expelled oils.

It is always difficult to find biological markers which are solely influenced by and reflect only the geochemical facies within the parent source rock, and our experience from the North Sea suggest that most biological markers are influenced both by the maturity of the source rock at the time of expulsion and the source rock facies. However, it is usually much easier to find good maturity indicators than good source rock facies indicators. Traditionally the carbon number distribution of the C_{27} to C_{29} $\alpha\beta\beta$ steranes or $\alpha\alpha\alpha$ steranes in petroleum have been used as a good source rock facies indicator, however within the northern part of the North Sea where most of the oils have been expelled from organic rich marine source rocks with Type II kerogen, this parameter offers insufficient resolution to effectively discriminate the oils into different populations. Figure 16 shows the uniform carbon number distribution of C_{27} to C_{29} $\alpha\beta\beta$20S steranes in 85 reservoir core extracts from the Troll Field.

The distribution of 28,30-bisnorhopane and 25-norhopanes seem to be controlled mainly by source rock facies variations on the east flank of the Viking Graben. 25-30-bisnorhopane has previously been used as a source rock facies indicator for Upper Jurassic Draupne Formation derived oils in the Tampen Spur area on the opposite side of the Viking Graben (Fig. 1) (Horstad *et al.*, 1994), however 25-norhopanes are not present in significant concentrations in Tampen Spur oils and cannot be used for oil-oil correlation in this area. The presence of 25-norhopanes in oils and reservoir core extracts has previously been attributed to biological degradation (Reed, 1977; Seifert and Moldowan, 1979; Rullkötter and Wendisch, 1982; Volkman *et al.*, 1983). However, new data suggests that these compounds are common in non-degraded and are present in source rocks extracts as well (Blanc and Connan, 1992 and references therein). Their presence in an apparently non-degraded oil, based on a relatively low concentration of isoprenoids and low uniform base line in GC-FID, has been explained by mixing of an early severely biodegraded oil phase with fresh undegraded oil. However, our data suggest that a mixture of a severely degraded oil phase with an undegraded oil phase results in an oil with distinct n-alkane peaks superimposed on a large unresolved hump (Fig. 26). The presence of large concentrations of 25-norhopanes in source rocks have been explained by intense early biodegradation of organic matter at shallow depths. Although, the 25-norhopanes traditionally have been linked to biological degradation, more and more "ad hoc" explanations are needed to link the

25-norhopane compounds to biodegradation alone. We suggest that within the northern North Sea the relative concentration of 25-norhopanes may represent an indicator of the depositional environment of the source rock rather than extent of biological degradation of the oils. However, they may be relatively enriched in severely degraded oils (much more degraded than the Troll oils) due to selective removal of other hopanoids (Blanc and Connan, 1992).

The reservoir core extracts within the Troll West Oil Province (wells 31/5-3, 31/2-7 and 31/2-14) have significantly lower 25-norhopane/norhopane ratio (0.24, $\sigma = 0.03$, n = 26) than the reservoir core extracts from wells (31/2-4, 31/2-6, 31/2-9, 31/2-15, 31/3-1 and 31/3-2) in the northern part of the Troll Field (0.46, $\sigma = 0.06$, n =45) (Figs. 17, 18 and Tab. 2). The oil population in the northern part of the field is also characterised by a slightly lower 28, 30-bisnor/norhopane ratio (Fig. 17) and a higher ΣC_{29}steranes/ΣC_{30} hopanes ratio than the oil population in the Troll West Oil Province (Tab. 3). A summary of the statistics of mainly facies controlled biological marker ratios for the Troll oil populations and reservoir core extracts from neighbouring structures is presented in Table 3. The samples from the gas cap within the Troll Field which may have been gas fractionated have been grouped as a separate suite of extracts in the statistical calculations.

It is obvious that the reservoir core extracts from the Brage Field (Upper Jurassic reservoirs) and the Oseberg Area (Middle Jurassic reservoirs) are very similar to the oil population in the Troll West Oil Province and it is suggested that these samples represent an oil population of significant regional importance (Fig's. 17 to 20). This migration route has previously been proposed by Field (1985) and Thomas *et al.* (1985). The oil within the Statfjord Formation in the Brage Horst structure represents a different oil family which has been traced to the Oseberg Saddle and the Veslefrikk Field to the north of the Brage Field (Fig. 21). Structurally it is possible to migrate oil from the Oseberg Area through the Brage Field and into the Troll West Oil Province.

In addition to having a different source rock facies signature, the oil population in the northern part of the field is significantly more mature than the oil population present within the Troll West Oil Province, Brage Field and the Oseberg Area. The higher maturity of the oil within the wells in the northern part of the field is reflected in the higher relative concentration of diahopane, d30/(d30+C_{30}ba) ratio (Fig. 17 and Tab. 4) and more rearranged hopanes (27Ts and 29Ts) (Fig. 19). Many of the conventional maturity related biological marker ratios (%20S in aaa steranes, %22S in C_{32} hopanes, %ab in C_{30} hopanes), have reached their plateau values and can not be used for

correlation purposes. These parameters can therefore only be used to identify samples which have been "contaminated" by immature *in situ* organic material, and these samples were removed from the data set. Contamination from *in situ* organic matter is generally a minor problem in the oil zone where the hydrocarbon biomarker signatures are totally dominated by the hydrocarbon biomarkers in the migrated oil, however it is a major problem in samples from the gas zone where EOM's are very low. In figure 20, a composite maturity parameter composed of six conventional biological marker ratios ([(27Ts/27Tm) + (30d/(30d+30βα)) + (29Ts/(29Ts + 29αβ)) + (29ααS/(29ααS + 29ααR)) + ((29ββS + 29ββR)/(29ααS + 29ααR + 29ββS + 29ββR)) + (27dβS/(27dβS + 27ααR)]/6) is plotted vs. the 25-norhopane/norhopane ratio to illustrate the compositional difference among the different petroleum populations. The oil population within the Troll West Oil Province plot as a separate group with a lower maturity and 25-norhopane/norhopane ratio than the oil population in the northern part of the Troll Field. The large scatter in the data from the northern part of the field is partially due to core extracts from the upper part of the gas cap in which the biological marker signature is perhaps controlled by fractionation processes. The extracts from the Oseberg Area and Brage Field plot together with the samples from the Troll West Oil Province. The reservoir core extract from well 31/2-8 on a separate structure to the north-west of Troll with excellent residual oil staining, have a similar geochemical signature as the oil population in the northern part of the Troll Field, and is interpreted to be located on the migration route into the Troll Field. The oil in well 31/2-8 has not been biodegraded as the Troll oils have been.

Figure 21 shows a petroleum population map with the distribution of the identified oil populations in the Oseberg Field and Troll Field area. The most likely migration pathways into the structures based on the structural configuration and the petroleum population map has been indicated by arrows.

Based on the biological marker signatures, the oil within well 31/5-2 in the southern part of the Troll West Gas Province, was at first believed to represent a separate oil population with an intermediate maturity between the oil in the Troll West Oil Province and the oil in the northern part of the Troll Field (Fig. 20). However, the biological marker signature observed in core extracts from well 31/5-2 could be produced by mixing the oil population in the Troll West Oil Province with the oil in the northern part of the Troll Field. With the current structural configuration of the field, it is difficult to explain how the oil within the Troll West Oil Province and the northern part of the Troll Field could have migrated southward into the southern part of the Troll West Gas Province, and mix in only this part of the field, since the only communication between these two segments of the field at present is

through a relatively narrow zone in the northern part of the field (Fig. 2). However in the paleo Troll Field the reservoir configuration suggests that the filling route was less tortuous in the past (see below).

With the exception of one reservoir interval in a single well, the samples from Middle to Upper Jurassic reservoirs within block 35/11 to the north of Troll Field (Fig. 21) are characterised by a much lower relative concentration of 25-norhopanes and group as a fourth population with a significant variation in maturity (Fig. 20, Tab's. 3 and 4). It is stressed that the samples from block 35/11 might represent several petroleum populations, but it is beyond the scope of this paper to discuss the oils in block 35/11 in detail.

The presence of two different oil populations within the Troll Field has been confirmed by Principal Component Analysis of biological marker data from 94 reservoir core samples. All the samples from the gas cap, samples with an immature biological marker signature and samples with a low concentration of saturated hydrocarbons (< 2.0 mg/g rock) were removed from the data set to limit the variation in the data set to real variations in the composition of the migrated petroleums in the area. A total of 21 variables, peak heights from steranes and hopanes, were normalised and converted to $\log_{10}$ values. The data was analysed by a statistical program (RS/1 from BNN Software Products Corporation) to calculate the principal components scores and loadings. The two first principal components account for 47.0% and 13.7% of the total variance in the data set, and the principal component scores of the different samples are plotted in figure 22. The two petroleum population in the Troll Field described above are clearly revealed and only minor overlap of the populations is evident.

Two samples from well 31/2-7 in the northern part of the Troll West Oil Province appear to have a certain affinity to the northern oil population, and this might suggest some inter-fingering of the two oil populations in this part of the field. However, this is not reflected in the conventional biological marker data discussed above. The samples from the Brage Field and the Oseberg Area plots among the samples from the Troll West Oil Province and the extracts from well 31/5-2 which is interpreted as a mixture of the two Troll Field oils, plot between the two major petroleum populations. As suggested by the biological marker ratios above, the sample from the 31/2-8 structure to the north-east of the Troll Field, groups with the northern oil population. The samples from the block 35/11 overlap with the northern Troll population but the lack of 25-norhopanes in these samples suggest

that they do indeed represent a separate oil population. The large spread among these samples suggest that they might represent several oil populations, however it is beyond the scope of this paper to discuss this in detail.

The identification of the two oil populations mapped within the Troll Field, within the Oseberg/Brage area to the south-west and in the paleo oil accumulation in well 31/2-8 to the north-west support the discrimination of the oils and suggest that at least two different oil migration routes have been active feeding the giant Troll Field.

Only minor heterogeneieties in the biological marker composition are observed vertically within the Troll Field, suggesting a vertically homogenous oil column throughout the field (Figs. 23 and 24). With the exception of well 31/2-9 in the north-western part of the field (Fig. 2), the biological marker signatures of reservoir core extracts from the current oil zone and the residual petroleum in the current water zone also seems to be very similar (Figs. 23 and 24), although some parameters show more scatter than others. In well 31/2-9 a significant decrease in the relative concentration of saturated hydrocarbons is observed in extractable residual petroleum within the current water leg, from between 62-68% above 1597 mRKB to between 32-51% below 1600 mRKB (Fig. 25). This change in the composition is also reflected in the relative concentrations of 28,30-bisnorhopane and 25-norhopanes which increases significantly across the same interval and the extent of biological degradation as measured by the phytane/nC_{18} ratio decreases (Fig. 25). However, maturity controlled biological marker ratios do not show any significant variations across this boundary (Fig. 24), suggesting that contamination by immature *in situ* organic matter is less likely. These changes in the composition of the extractable petroleum occur at a lithological boundary in the reservoir with a significant reduction in the reservoir quality below 1600 mRKB (Fig. 25). At this stage we have no reasonable explanation for this phenomena.

Biological degradation

All the reservoir core extracts from the Troll Field that have been analysed in this study have a relatively high concentration of isoprenoid alkanes and an elevated base line in the GC-fingerprints, suggesting variable extents of biological degradation (Fig. 26). A few samples have a uniform n-alkane distribution and appear to be less degraded than the current oil leg, however these samples are located within the gas cap and have an immature biological marker signature and are interpreted to represent extractable *in situ* organic matter. Other samples have a uniform n-alkane distribution but a

higher relative concentration of isoprenoids and higher base lines than normally observed for non-degraded North Sea crude oils (Fig. 26b). These samples are interpreted to represent a mixture of a degraded oil phase and a non-degraded oil phase. There is no relationship between the extent of biological degradation of the oil and the relative distribution of steranes and hopanes, and the most degraded oil has a relatively low concentration of 25-norhopanes which have been suggested to represent a product of extensive biological degradation. It is therefore concluded that most of the variations in the biological marker parameters are controlled by source rock facies, maturity or phase changes in the migrating petroleum in the carrier bed or in the reservoir, and are not related to the extent of biological degradation.

Biological degradation processes in crude oils have been described in a number of papers, and there is a general agreement on how it affects the individual components in an oil. Based on the isoprenoid alkane/n-alkane ratio (eg. phytane/nC_{18}), the degree of biodegradation of the petroleums apparently increases along the sequence from Troll East to Troll West Gas Province, to the northern part of Troll West Oil Province, to the southern part of Troll West Oil Province (Fig. 27). It is difficult to explain why the western part of the field has been most severely degraded, since the Norwegian mainland would be the most obvious place to create a hydraulic head to drive meteoric water into the field (i.e. from the east). This might suggest that the low phytane/n-C_{18} ratios in the eastern part of the field are related to a combination of mixing degraded oil with a fresh undegraded oil phase, as discussed below, and that the geological configuration of the field resulted in focused local water flux through the southern part of the oil province at the main time of degradation.

The quantitative aspects of biological degradation are much less documented, and recent observations from the Gullfaks Field (block 34/10) suggest that biological degradation requires large volumes of meteoric water if oxygen is the oxidant (Horstad *et al.* 1990, 1992). They also suggested that the extent of degradation might be related to the volume of meteoric water to which the oil was exposed to within the reservoir. Since the biological degradation of the oil occurred in the reservoir, the extent of degradation may provide information on how effective the meteoric water circulation was in each segment of the reservoir, and possibly some indications on the vertical and lateral connectivity of the reservoir. The relatively large lateral variations in the extent of biological degradation in the Troll Field might suggest that the current oil composition is the result of a locally restricted water circulation in the reservoir at the time of degradation, a highly localised water input, a lack of time to degrade the whole reservoir, or possibly an over-printing by a later charge of a undegraded oil. Since

there is evidence of mixing of a degraded oil phase with a fresh oil phase in the northern part of the field, based on a high relative concentration of isoprenoid alkanes and the presence of an apparently undegraded suite of n-alkanes superimposed on a significant unresolved hump in the gas chromatogram, a mixing of two oil families is preferred to explain the observed variations in the extent of biological degradation within the Troll Field.

The fresh oil charge that has migrated into the structure seems to have been localised and mixed with the degraded oil within the reservoir, and this complicates interpreting the filling history of the field. If a non-degraded oil phase with abundant n-alkanes and a typical pristane/nC_{17} ratio between 0.5 and 0.8 (Fig. 26a) is mixed with a heavily degraded oil with abundant isoprenoids, almost no n-alkanes and a large unresolved hump (Fig. 26d), the net result is an apparently non-degraded oil with abundant n-alkanes superimposed on a large unresolved hump with a higher pristane/n-C_{17} ratio than in the fresh oil phase (Fig's 26b and c). The geochemical composition of the mixed oil phase is controlled by the relative proportion of the degraded and non-degraded oil phases within the reservoir, and without knowing the geochemical composition of the end members that mixed, it is impossible to determine the relative contributions to the oil mixture.

Figure 28b shows the excellent match between a mathematically recombined mixture of a degraded oil without n-alkanes (Fig. 26a) and an undegraded North Sea oil (Fig. 26d) compared with an oil from the northern part of the Troll Field (Fig. 28a) mixed assuming equal concentration of pristane in the samples. This supports a mixed origin for the Troll oils. In addition, observations from the Gullfaks Field on the other side of the Viking Graben, suggests that the development of an elevated base line in a gas chromatogram due to an unresolved hump does not occur before most of the n-alkanes have been removed from the oil. Thus, a continuous series of n-alkanes superimposed on an unresolved hump in the gas chromatograms of the Troll Field oils, might be taken as an indication of mixed biodegraded and non-degraded oil phases. Apparently mixed oil phases are present within wells 31/3-2, 31/2-6 and 31/2-15 in the northern part of the field, but the zone of mixed oil phases might extend southward in the field, as indicated by the phytane/nC_{18} ratio (Fig. 27). The reservoir core extracts from well 31/5-3 in the southern part of the Troll West Oil Province (Fig's. 2 and 27) are the only reservoir core extracts without a significant concentration of n-alkanes. Thus, the lateral extent of this apparently non-degraded oil remains unclear and it may extend into the thin oil leg in the Troll East gas province.

The degree of biodegradation of the present oil column and core extracts from the residual oil in the current water leg is generally very uniform within each well and suggests that there is good vertical communication within the reservoir. The only well with relatively large vertical variations in the extent of biodegradation is well 31/2-9 where most of the residual oil in the water leg appears to be less degraded than the oil above (Fig. 25).

Evidence of a post-filling tilting of the Troll structure and an explanation of the paleo fluid contacts observed in the field

The thickness of the paleo oil zone varies significantly across the field, however within most of the wells we analysed from the western part of the Troll Field, the residual oil staining in the current water zone occurs throughout the whole cored interval. This makes it impossible to locate the exact position of the paleo oil-water contact and only a paleo oil down to (ODT) level can be determined. The deepest positive identification of a paleo OWC is observed within well 31/2-4 where significant oil staining (13.5 mg/g rock) occurs down to 1618 mMSL or 63 metres below the current oil-water contact located at 1555 mMSL (Fig. 29).

Based on the observed paleo oil-water contact in several wells (Fig. 29), it is possible to construct a plane which represent an approximation to the tilted paleo oil-water contact of the field (Fig. 30). Obviously, this map is constructed on the basis of only a few data points in a restricted part of the field and the exact angle and direction of the tilting and the extrapolation of this tilting away from the observed data points are prone to large errors. However, after the completion of this study two new wells were drilled within the Troll Field, and both wells confirmed our estimated surface through the paleo oil-water contact. One of these wells were drilled in the southern part of the Troll West Gas Province and this well suggests that the plane constructed on the basis of wells in the northern part of the field could be extrapolated at least 15 km to the south and therefore confirmed our model over a much larger area of the Troll Field. It is interesting to note that the map of the observed paleo oil-water contact seems to represent a plane which suggests that the field was tilted 2.7° in a dip direction of WSW, which is in good agreement with the proposed geological models based on seismic interpretation of the shallow horizons.

If the constructed map of the tilted paleo oil-water contact surface is subtracted from the top reservoir structural map of the present Troll Field reservoir, and the resultant structure is cut at the level of the paleo oil-water contact, it gives a picture of the structural configuration of the "Paleo Troll Field"

before the Late Neogene tilting (Fig. 31). The main differences between the paleo accumulation and the present accumulation have been high lighted in figure 32. Based on this paleo configuration of the field there seems to have been a direct communication between the Troll West Oil Province and Troll West Gas Province within the southern part of the field before the Neogene tilting. Thus, by applying the current configuration of the field during the filling of the structure, the migration paths become very tortuous and seems to be unrealistic (Fig. 33a). However, if the paleo configuration of the Troll Field is examined it is evident that there was good communication between the Troll West Oil Province and the southern part of the Troll West Gas Province and the paleo configuration of the field can explain the filling and mixing of the two oil populations in the southern part of the Troll West Gas Province (Fig. 33b).

It is therefore concluded that a westward tilting of the entire structure with a resulting change in the position of the spill point and an eastward re-migration of gas and oil is the main controlling factor on the residual oil staining in the current water zone. Possibly the variations in the thickness of the current oil column (0-26 metres) and the variations in the level of the oil-water contacts across the field might be explained by this relatively recent tilting of the structure and the lack of time to re-equilibrate the oil column across the entire field. Since the Troll Field represents a relatively flat structure with a width of approximately 35 km and a petroleum column of 250 metre, even a small tilting of the field might result in large changes in the location of the field spill point and consequent adjustment of the fluid contacts.

It is not possible to decide whether the current Troll East Gas Province (Fig. 2) was filled with gas prior to the tilting, although the configuration of the paleo Troll Field suggests that a significant structure was present in the Troll East area (Fig. 31). Rough volume calculations of the wedge of residual petroleum below the current Troll Field, suggest that the western part of the paleo Troll Field outlined in figure 31 could have contained in the order of 800-1,000 $*10^9$ Sm^3 more gas than present in the current Troll West Oil Province and Troll West Gas Province. Compared to the current GOIP of $1,072*10^9$ Sm^3 in Troll East (Tab. 1), it could be speculated that Troll East was water bearing before the Neogene tilting, even though the back tilting suggests that a structure was present prior to the Neogene. Thus, with the exception of the recent petroleum charge, most the petroleum in the entire Troll accumulation could have been present within the western part of the paleo Troll Field a few million years ago.

Density driven redistribution of petroleum in the Troll Field

If a tilting of a petroleum filled structure results in a physically unstable distribution of fluids in the reservoir, the fluids would tend to move in order to physically re-stabilise the petroleum column. If the spill point of a gas accumulation with an oil leg underneat is changed the structural position of the new spill point and the total volume of the new structure will determine whether only oil or whether oil and gas are spilled out of the structure. The change in the spill point of the paleo Troll Field probably resulted in a significant spill of gas since the volume of the paleo structure was significantly reduced and the thickness of the oil column was relatively small. To understand the development of the structure and the re-mobilisation of the petroleum, it is important to understand the physical processes controlling the movements of oil and gas in the reservoir. The Troll Field has a hydrostatic fluid pressure gradient and it is reasonable to assume that buoyancy was the principal force acting to redistribute oil and gas in the field. Gas has a much higher mobility than the oil within the good quality sandstones with high petroleum saturation and moves approximately 300 times faster than the oil, both due to its large density contrast to water and its lower viscosity.

Below we calculate the time restabilise the gas-oil contact by Darcy's law and the time to restabilise the oil-water contact by the equation for density driven overturning (England and Mackenzie, 1989). The pressure gradient acting on the gas column within the reservoir at the initial stage of tilting is controlled by the amount of tilting and the subsurface density of the gas. The time required to move the fluid within the reservoir can be estimated assuming Darcy flow:

$$v = \frac{k \Delta P}{\mu L}$$

v	velocity of fluid (m/s)
k	permeability of the reservoir
ΔP	pressure gradient in gas phase
μ	fluid viscosity (Pa s) (gas: 2×10^{-5} Pa s)
L	distance (m)

Assuming an instantaneous tilting of the field, the GOC would be on the order of 100 metres deeper in the western part of the field (Fig. 30), giving an instantaneous pressure difference on the order of $8.82*10^5$ Pa for gas laterally across the gas column ($\Delta P = rgh$). With a migration distance of 30 to 40

km to spill gas into Troll East and a large scale permeability of the reservoir of 100-1000 mD, the gas column would equilibrate within a time scale of the order of 500-5000 years. This suggests that gas would migrate rapidly and spill eastward out of the structure until the level of the spill point of the new structure is reached.

The pressure gradient across the oil column would be on the order of $1.96*10^5$ Pa, but the lower mobility of the oil results in a mainly vertical movement to fill the reservoir space left by the gas. With a vertical migration distance for oil on the order of a few tens of metres locally in a high quality reservoir sandstone, this would require no more than a few years. Thus, shortly after the tilting of the structure, the GOC will re-equilibrate and become semi-horizontal while the OWC will be physically unstable and oil will spill relatively slowly out of the eastern part of the paleo accumulation and into Troll East. Assuming that the capillary effects are relatively small in a high quality reservoir sandstone, the time scale required to equilibrate the oil column is given by (England and Mackenzie, 1989):

$$\text{time} = \frac{f L^2 m}{S k g Dr H}$$

f	porosity (0.3)
L	distance (m)
m	fluid viscosity (Pa s) (oil: 1.5×10^{-3})
S	petroleum saturation (0.8)
k	permeability of the reservoir (m^2)
g	acceleration of gravity (9.8 m/s^2)
Dr	density difference (oil vs. water 250 kg/m^3)
H	height (m)

Substituting typical values for the different parameters the time to stabilise the oil column becomes:

time (yr) = 7.3×10^{-3} L^2/k H where k is in Darcy

Table 5 shows the time required to migrate oil over a 15 and 30 km distance driven by a horizontal pressure gradient across the oil column due to a 20 m oil column height difference for large scale reservoir permeabilities varying from 100 mD to 1 D. It is important to remember that the

permeability refers to the large scale permeability of the reservoir and not core permeabilities, thus 1D must be regarded as very unrealistic over larger distances within a reservoir. Since the communication between Troll West and Troll East is probably restricted to a narrow channel in the north, even the 100 mD estimates above might be an optimistic estimate of the large scale permeability of the field. In addition, if the geology of the Troll Field is more complex than the current model indicates, the time to equilibrate the structure might be even larger due to in reservoir tortuosity.

Thus, since the mobility of the gas is much higher than the mobility of oil, an instability in the fluid column in the Troll Field would result in a rapid movement of gas potentially over large distances, while oil would tend to move slowly and over shorter distances than the gas (Fig. 34). If a gas cap is present above the oil column and the spill point of the new structure is located at a shallower level than the paleo gas-oil contact, gas will tend to move laterally while the oil will tend to move upward into the structure to replace the, however a smaller proportion of the oil will migrate slowly out of the structure and eastward into the gas province.

If the tilting of the Troll structure occurred as late as Neogene, the differences in the fluid contacts might partly be explained by lack of time to physically stabilise the fluid column by oil migration.

Filling history

Based on the detailed characterisation of the hydrocarbon composition and distribution within the Troll Field a new filling model is proposed for the Troll Field. This model must be consistent with all the observations described above:

1. very dry gas (93% methane) in the gas cap
2. lack of significant residual oil staining within most of the gas cap throughout the whole field
3. high concentrations of apparently gas fractionated oil components in a few thin zones within the gas cap
4. significant residual oil staining in the lower section of the gas cap (<11 metres) in the northern part of the field
5. vertical homogeneous oil column
6. significant variations in the thickness of the oil column across the field (0-26 metres)

7. two different oil populations in the field, based on detailed biological marker analyses, located within the Troll West Oil Province and in the northern part of the field
8. mixing of the two oil populations in the southern part of the Troll West Gas Province
9. variable extent of biological degradation of the oil column
10. mixing of biodegraded and non-degraded oil in the northern part of the field
11. significant residual oil staining below the current oil-water contact
12. presence of a tilted paleo oil-water contact.

The filling history of the Troll Field is summarised at four stages in figure 35. It is difficult to give an exact timing of the four stages described in figure 35, however the Troll Field lacked a proper top seal until early Tertiary times and stage I therefore represents Early Tertiary. The second stage is difficult to place in time, but the migration and biological degradation of gas and oil in the Troll structure was probably a contineous process from Early Tertiary to Neogene times. Stage III represents the Neogene tilting of the Paleo Troll Field and rapid remobilisation of gas in an eastward direction. Stage IV represents the time span from Neogene to present with continuous gas and oil charging, rapid eastward movement of gas and a slow re-migration of the oil in an eastward direction to re-equilibrate a horizontal oil-water contact.

The lack of residual oil staining in the gas cap suggests that most of the gas migrated into the Troll Field before any oil reached the structure. We have not been able reconstruct the details of the configuration of this structure since this would require a detailed back stripping of the field and a basin modelling of the gas generation from the Troll Kitchen. However, based on rough volume calculations of the paleo Troll Field, it might seem reasonable to suggest that Troll East was water bearing before the large scale Neogene tilting. It is not possible to determine which source rocks that generated the dry gas within the Troll Field but compositionally similar gases have been discovered in the Gullfaks Gamma structure and in the Hild Field, suggesting a possible long distance migration route from the deeper parts of the Viking Graben, with a possible modification of the composition by bacterial degradation. The shales of the Draupne Formation are not likely to be the source of the gas since oil generation and expulsion is likely to commence first for this prolific rich oil generating source rock. Simple 1D basin modelling of the Upper Jurassic source rocks in the central part of the Viking Graben to the north-west of the Troll Field, suggests that the lower part of the Heather Formation might generate and expel dry gas before the Draupne Formation starts to expel oil at the

same location. Thus, the leaner Heather Formation shales or gas prone coals within the Statfjord Formation and the Brent Group could act a sources of the Troll gas.

An alternative explanation for the presence of the very dry gas in the Troll Field is gas exsolution from water in the drainage area of the Troll Field due to pressure drop which might have occurred during the recent uplift of the Horda Platform area. This model was proposed to explain the dry nature of the gas in the Frigg Field in the southern Viking Graben (Goff, 1983) it being suggested that gas was exsolved as water migrated vertically out of the subsiding graben. According to the new basin scale fluid flow models, the vertical flow of compaction water is negligible and large scale movement of water as proposed by Goff (1983) seems unlikely (Bjørlykke, 1994). However, an aquifer pressure drop would be initiated by recent uplift in the area. The regional aquifer map of the Troll Field suggests communication with an aquifer volume in the order of 40-100 times the hydrocarbon pore volume (HCPV) in the Troll Field, depending on the relative contribution from the Sognefjord Formation, Fensfjord Formation, Krossfjord Formation, Brent Group, Statfjord Formation and the Triassic section in the vicinity of the Field (Osborne and Evens, 1987). The HCPV of the Troll Field is $12.5*10^9$ m^3 (Gray, 1987) suggesting a total water volume of 0.5 to $1.25*10^{12}$ m^3. The solubility of methane is not a linear function of depth, but published data suggest that the solubility at a depth of 3 km increases at about 1 Sm^3/m^3/km (Goff, 1983; McAuliffe, 1978). Thus, assuming 1 km uplift in the entire area (which probably represents a maximum) the volume of the exsolved gas is between 480-$1{,}200*10^9$ Sm^3, which is 1.4 to 3.5 times to small to explain the gas charge within the Troll Field. These calculations suggest that gas exsolution from a water phase cannot be the only source of the gas in the Troll Field and it is suggested that bulk phase gas migration from active source rocks has occurred in the area.

Since the Upper Jurassic sandstones present in the Troll Field pinch out towards the graben, the most likely regional carrier bed for this gas is the Brent Group sandstones which probably are present in the central part of the Viking Graben. This requires that the Brent Group is juxtaposed with the Upper Jurassic sandstones somewhere between the Troll Field and the Viking Graben.

After gas emplacement and gas biodegradation, oil migrated into the structure from two different directions, one in the southern part of Troll West Oil Province and the other in the northern part of the field (Fig. 21) Both oil populations were probably generated and expelled from the Upper Jurassic Draupne Formation with a possible contribution from organic rich intervals of the Heather

Formation. The source rock quality of the Heather Formation is usually low in this area, however a ca. 50 metres thick interval of Lower Callovian age has a similar source rock quality as the Draupne Formation shales above. The oil migrated into the field from the south-west via a spill from the Brage Field and into the north-western part of the field via a spill from a paleo accumulation to the north-west of the Troll Field. The two oils subsequently mixed within the central part of the paleo Troll Field. After and possibly during oil emplacement, the oil and possibly some of the gas continued to be degraded by bacterial action. The degradation was probably caused by aerobic bacteria and was maintained by a flux of meteoric water through the field, supplying oxygen and nutrients. No evidence of anaerobic degradation has been found, however recent studies suggest that anaerobic petroleum degradation of crude oil hydrocarbons under subsurface conditions may potentially occur by using Fe^{3+} and organic ligants (Lovley *et al.*, 1994; Luther *et al.*, 1992).

When the biological degradation stopped oil continued to migrate into the northern part of the field. This fresh oil phase mixed with the severely biodegraded oil resulted in a mixed oil phase which might give an impression of a quite variably extent of biodegradation of the oil across the field. The southern part of the Troll West Oil Province has probably been shielded from this late oil migration and it is not known whether oil still migrates into this part of the field. The regional uplift of the entire Horda Platform area a few million years ago, tilted the Troll Field down to the west and change the spill-point of the field. The high mobility of the gas phase resulted in a rapid eastward migration of gas into Troll East and gas probably spilled out of the structure. The lower mobility of the oil resulted in a predominantly vertical movement of the oil to replace the gas in Troll West, while the eastward migration of the oil is relatively slow and the oil column has not been physically stabilised yet. The lower mobility of the oil and the reduced large scale permeability due to faults and tortuous migration channels within the field controls the variations in the thickness of the oil column. Gas continues to migrate into the structure and the new gas charge migrated through the oil column and preferentially extract shorter chained hydrocarbon homologues from the oil column and re-precipitate these compounds in gas migration channels within the gas cap.

This new migration and filling model of the Troll Field is broadly consistent with all the observed phenomena and represents, we hope, an improvement over previous models. This model suggests that most of oil that migrated into the structure still is accumulated within the Troll Field and that only gas has spilled eastward from the Troll reservoir. This clearly has large implications for oil prospectivity to the east of the Troll structure.

Conclusions

Based on a large geochemical data set a new filling model is proposed for the Troll Field which represents the largest petroleum discovery within the North Sea. It is suggested that gas migration and filling predates oil charging and that most of the gas was generated from a different source rock interval. The source rock of the gas cannot be positively identified but the most likely candidates are coal beds within the Statfjord Formation and Brent Group or gas prone shales of the Upper Jurassic Heather Formation. The Draupne Formation with a possible contribution from the Heather Formation sourced the oil within the field. The differences in the relative timing of oil and gas migration and the potential differences in their drainage patterns will be crucial to the further exploration of this part of the North Sea. After oil emplacement and biological degradation the field was tilted down to the west and oil and gas re-migrated within the field in a dominantly vertical (oil) and lateral (gas) direction respectively. A potential eastward spill of gas from the current structure cannot be documented but might have occurred. This study has demonstrated the dynamics nature of oil and gas accumulations in the North Sea and has illustrated the importance of a coupling geological and geochemical models in assessments of field charging models.

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Fig. 31 Possible paleo configuration of the Troll Field, constructed by subtracting the plane0 through the paleo oil-water contact in figure 30 from the current top reservoir structural map and cutting at the level of the paleo oil-water contact. Note the change in the communication between Troll West Oil Province and Troll West Gas Province.

Fig. 32 As figure 31, but areas where major changes in the structural configuration have occur compared with the present configuration has been highlighted.

.Fig. 33 Migration and mixing of oil population within the present field configuration (a) and the paleo configuration of the Troll Field. If the Troll Field had been filled with its current structural configuration the filling patterns become very tortuous, however the paleo configuration of the field (b) helps to explain the current distribution of oil populations in the field with much less tortuous migration routes.

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Fig. 35 Cartoon illustrating the new migration and filling model for the Troll Field at four stages (see text for details).

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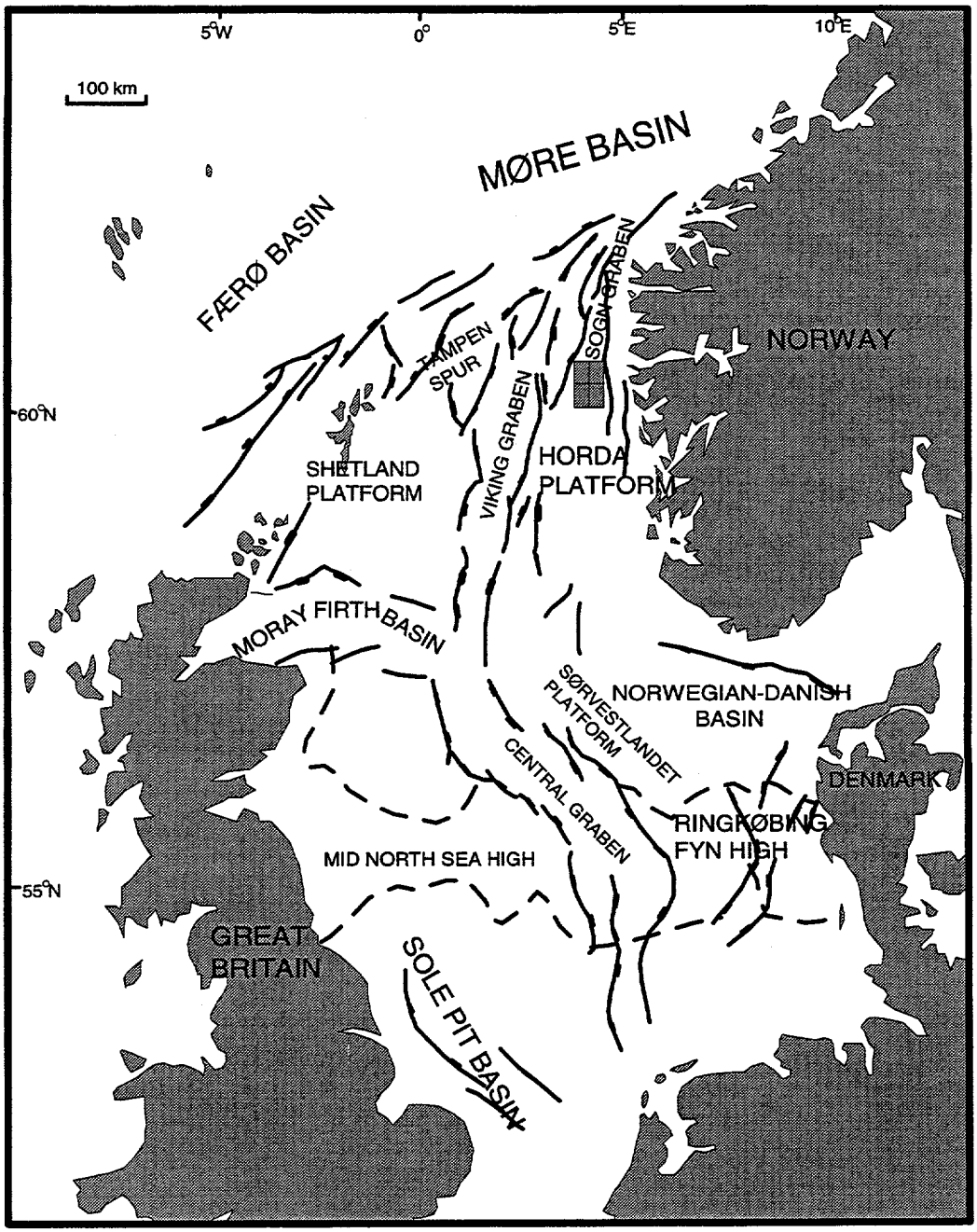

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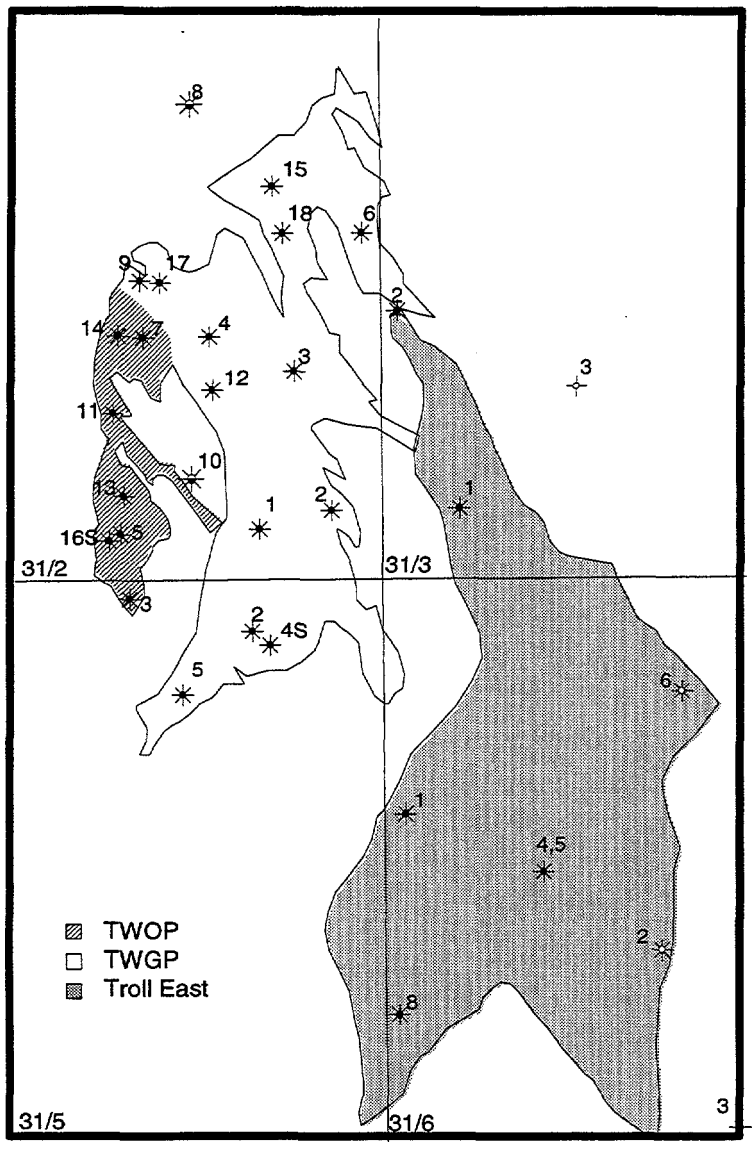
Fig. 1



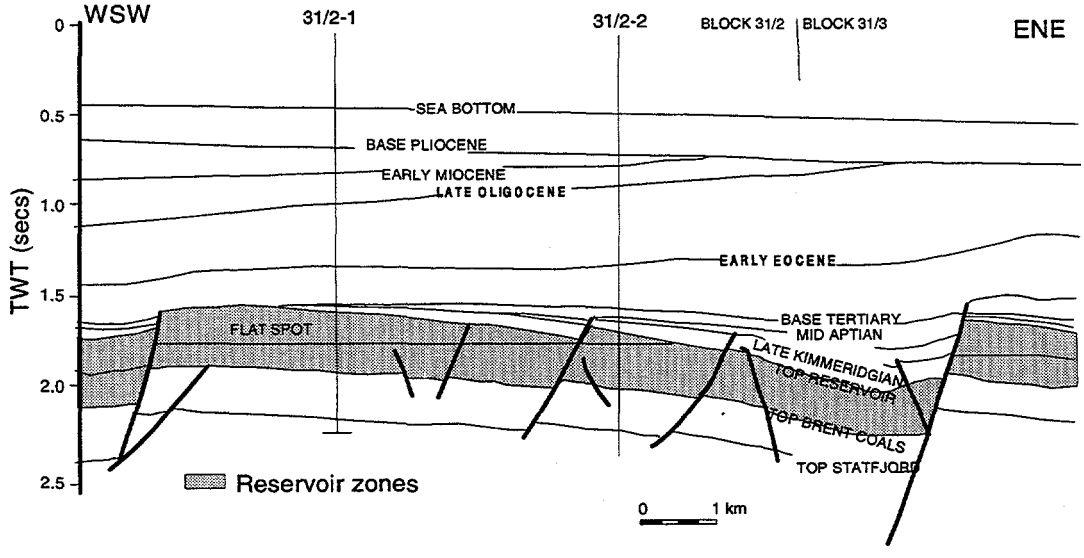


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Fig. 2

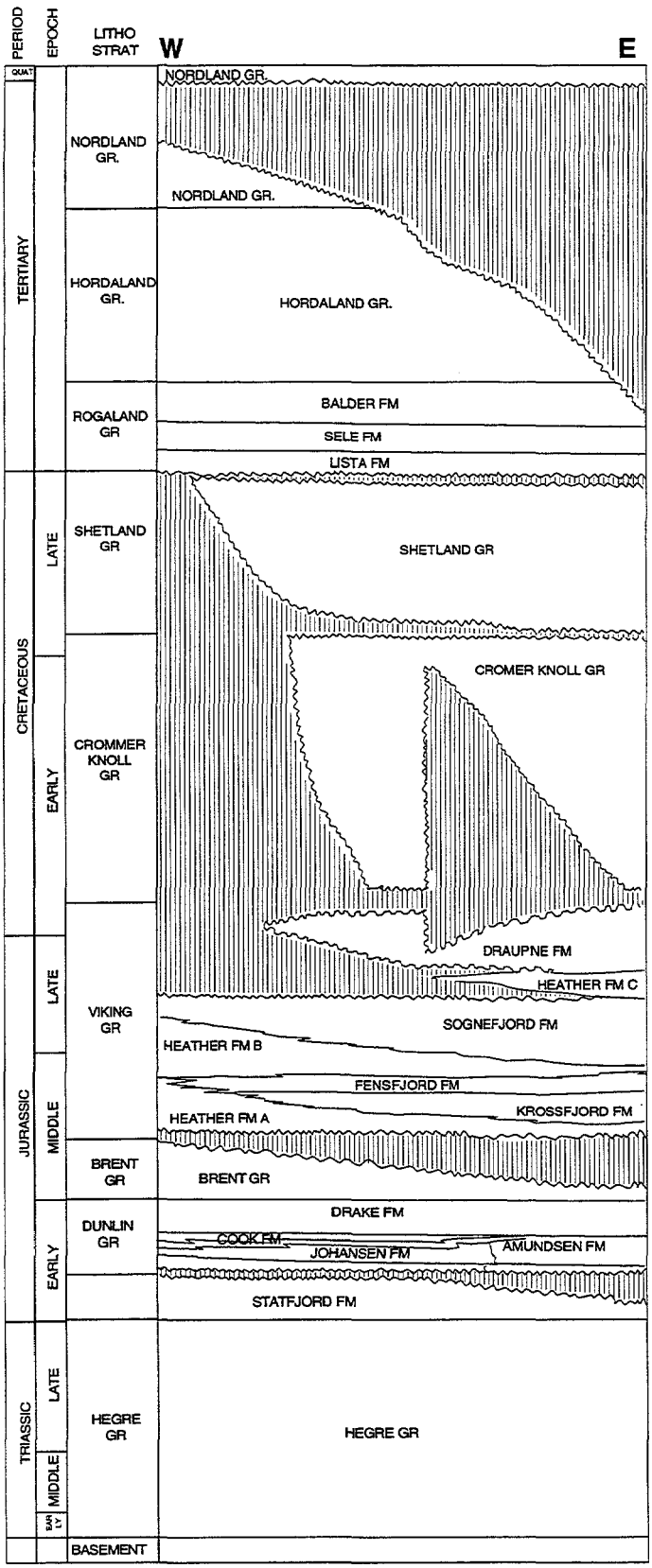

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Fig. 3

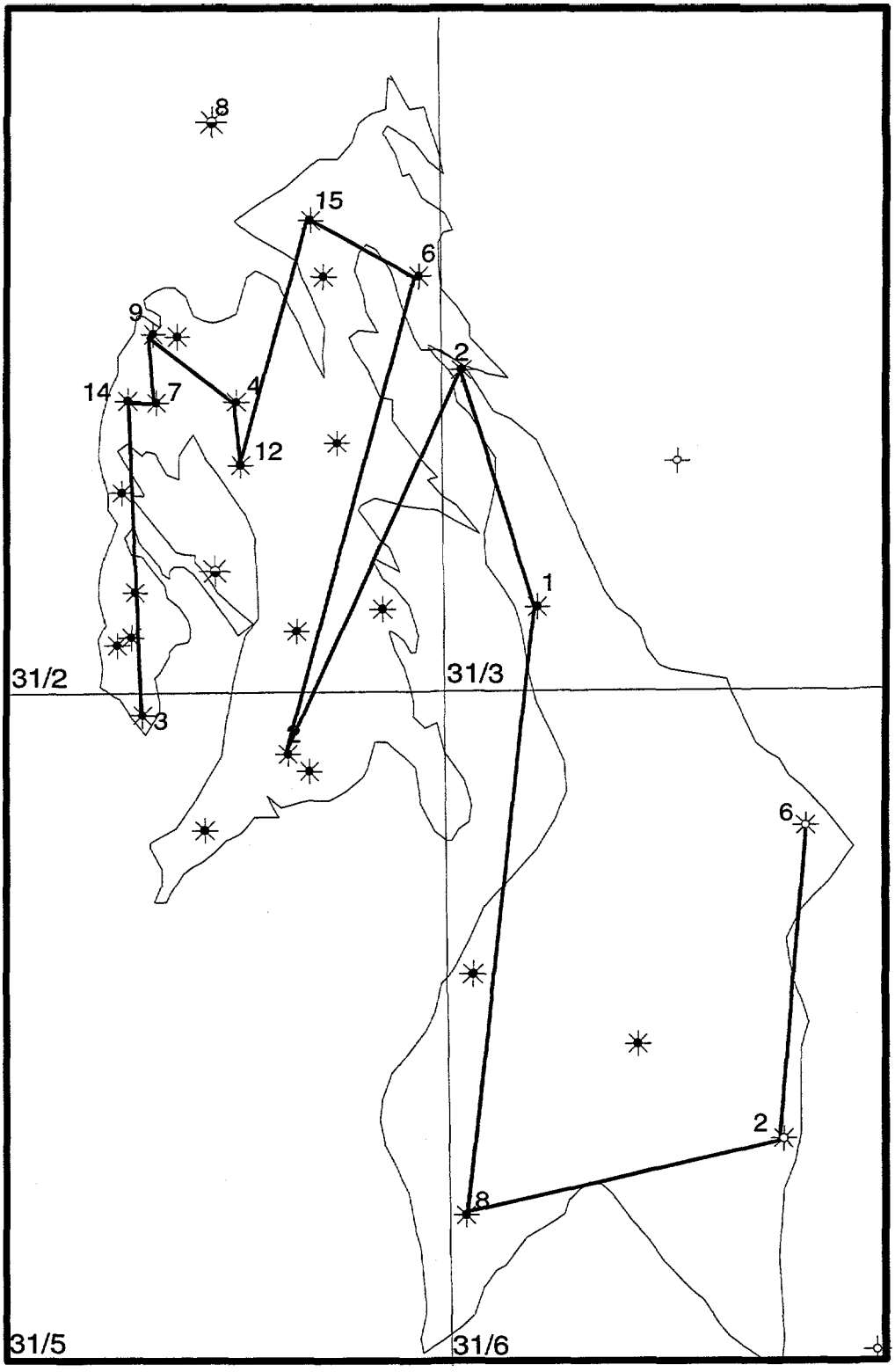

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Fig. 4

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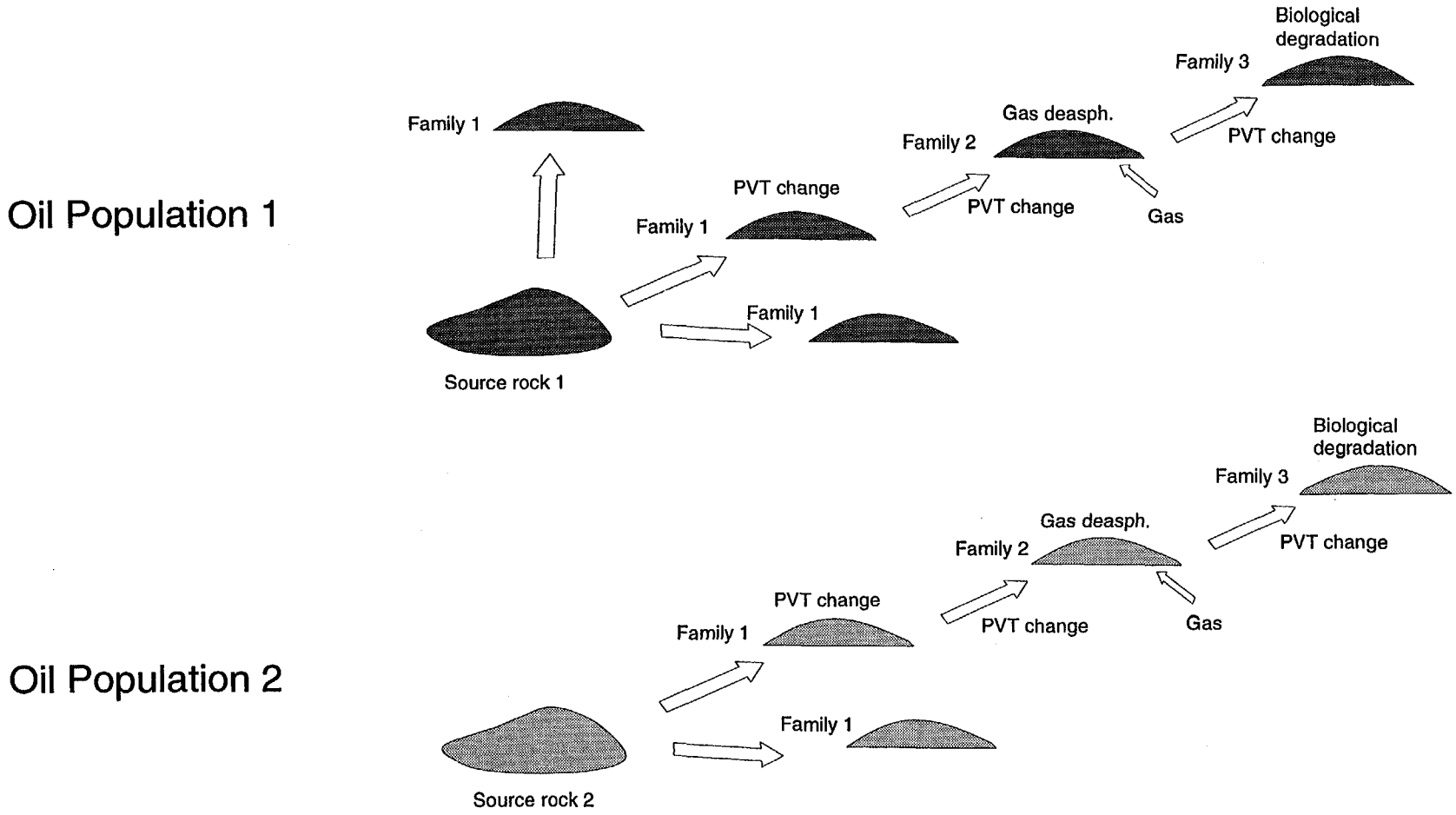

Fig. 5

migmod.drw

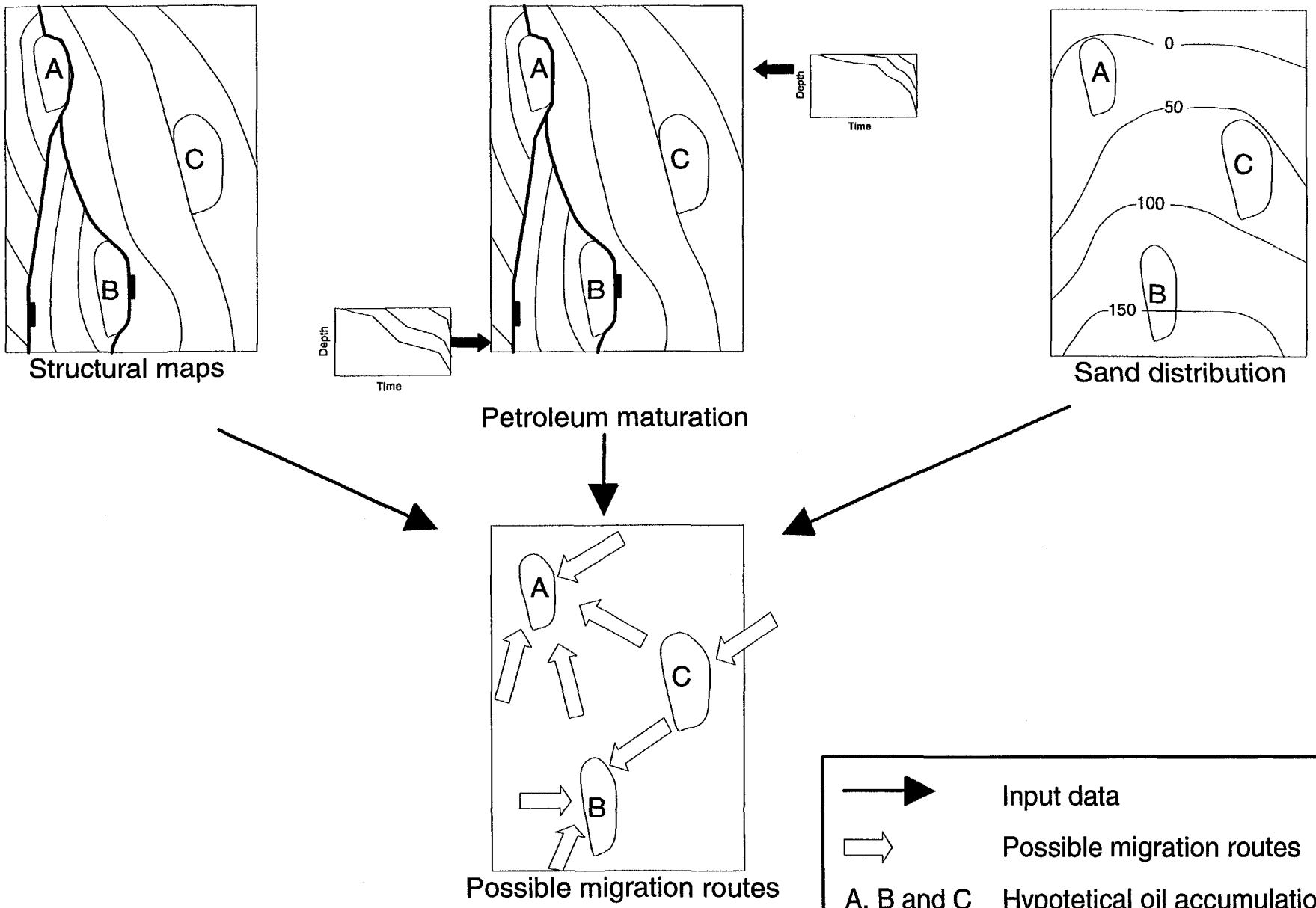

Fig. 6

migmod.drw

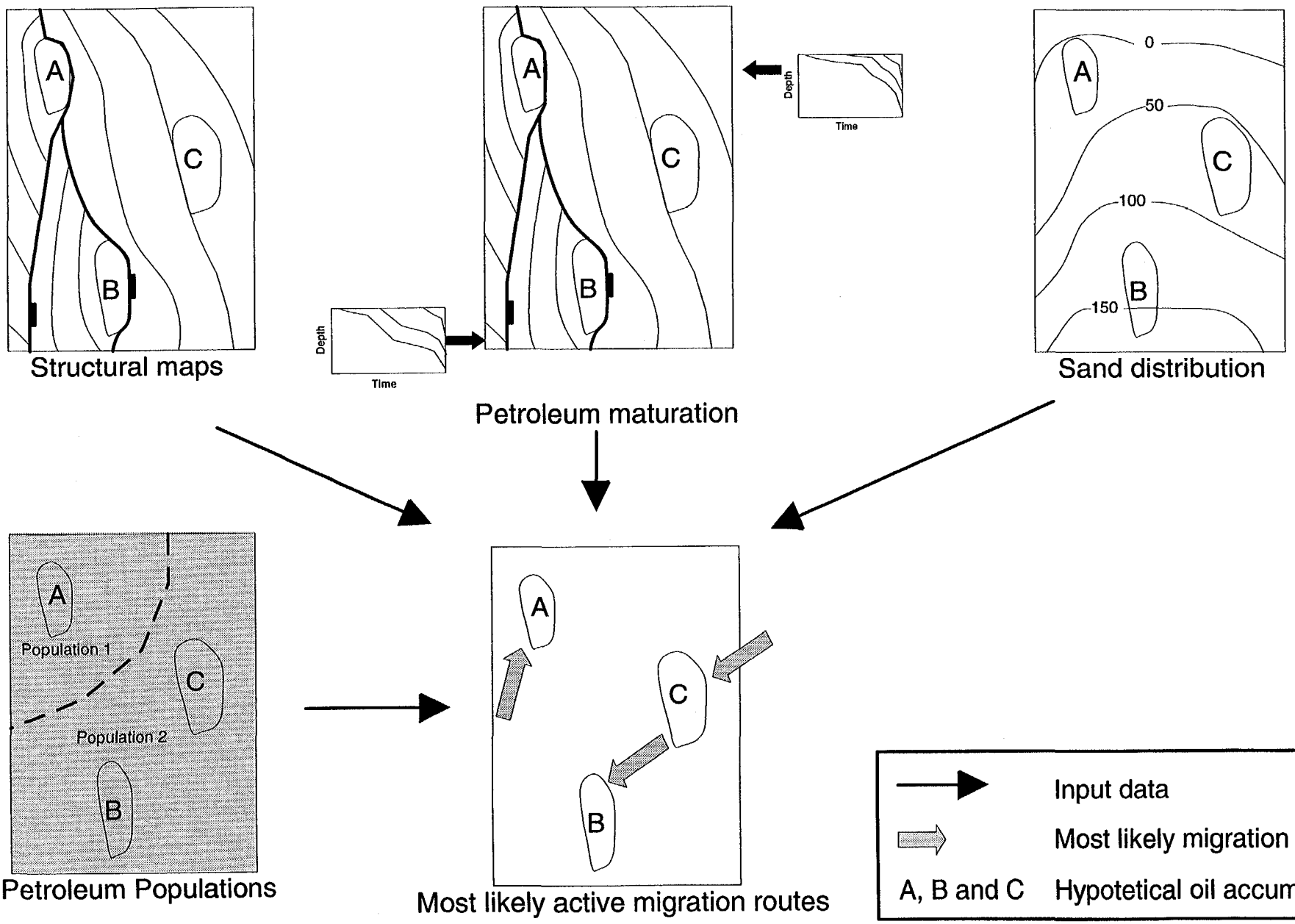

Fig. 7

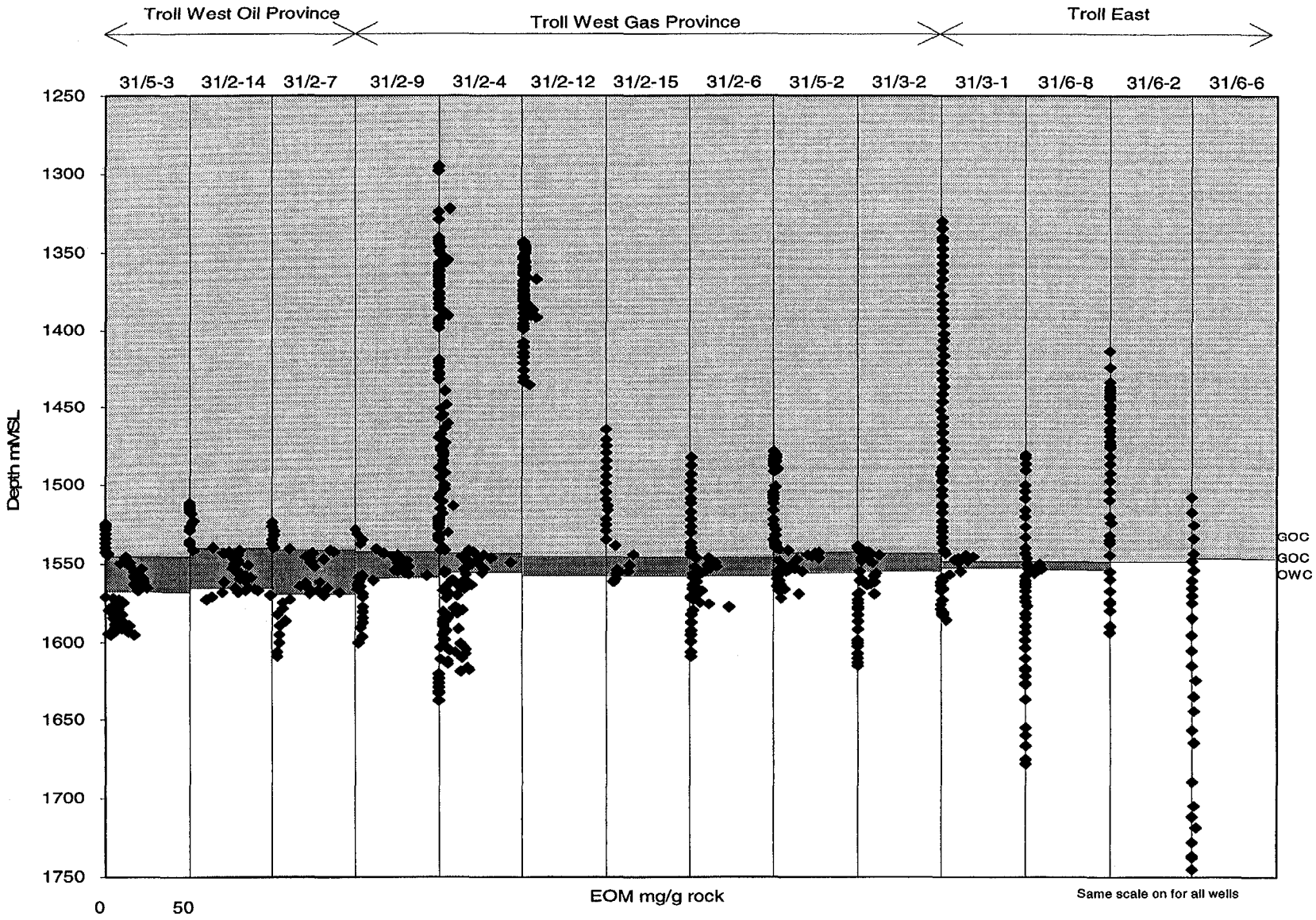

Fig. 8

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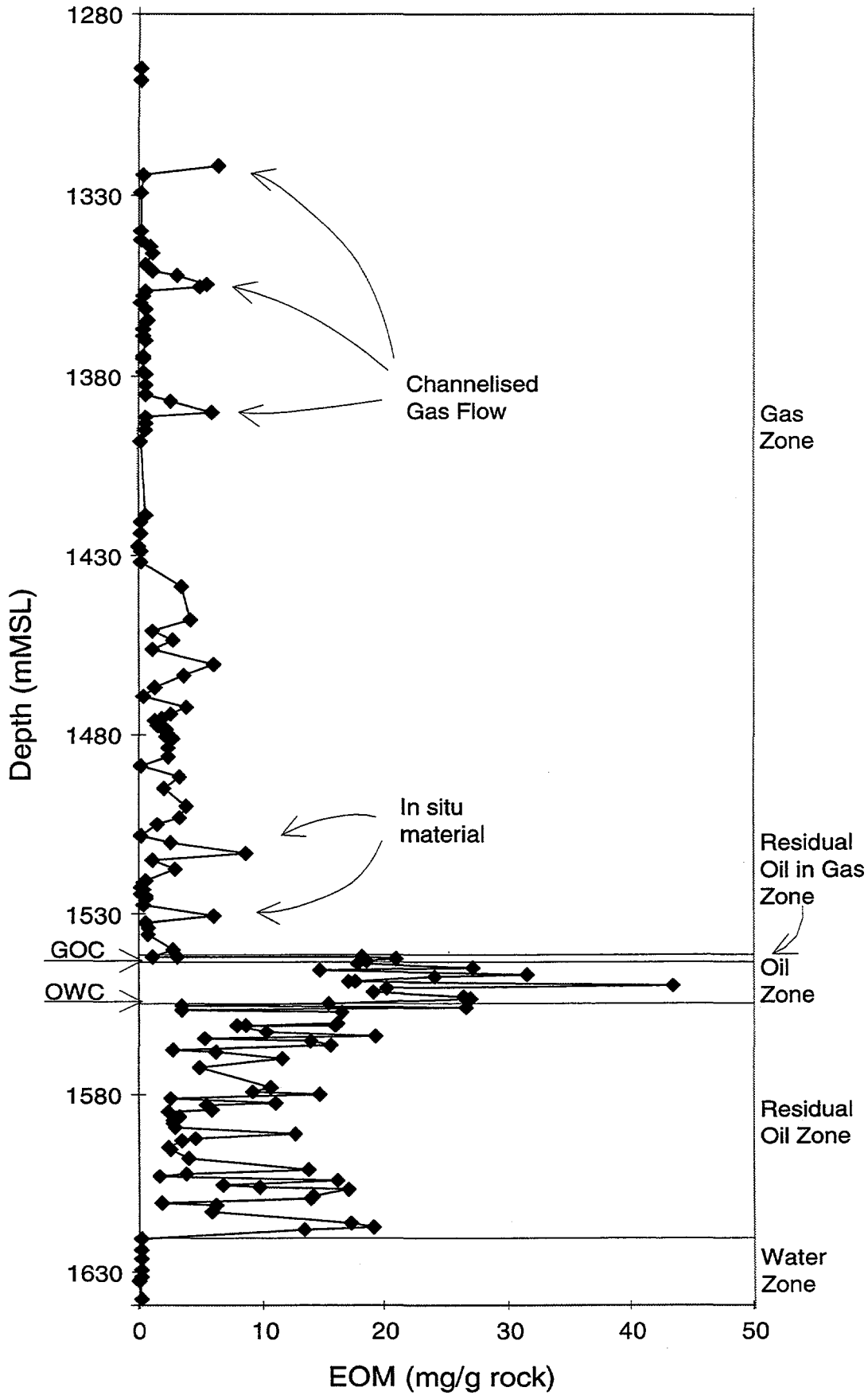

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Fig. 9

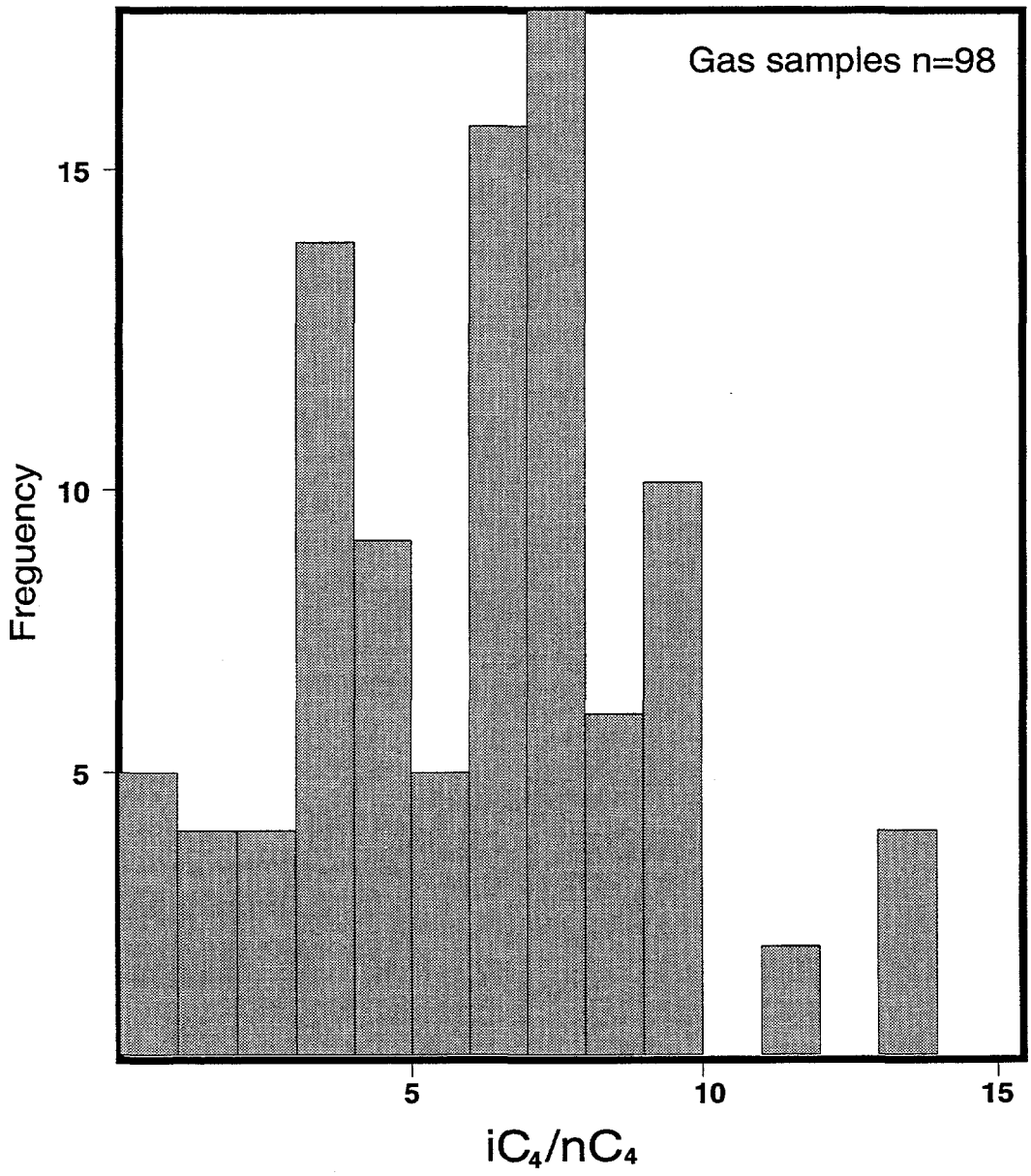

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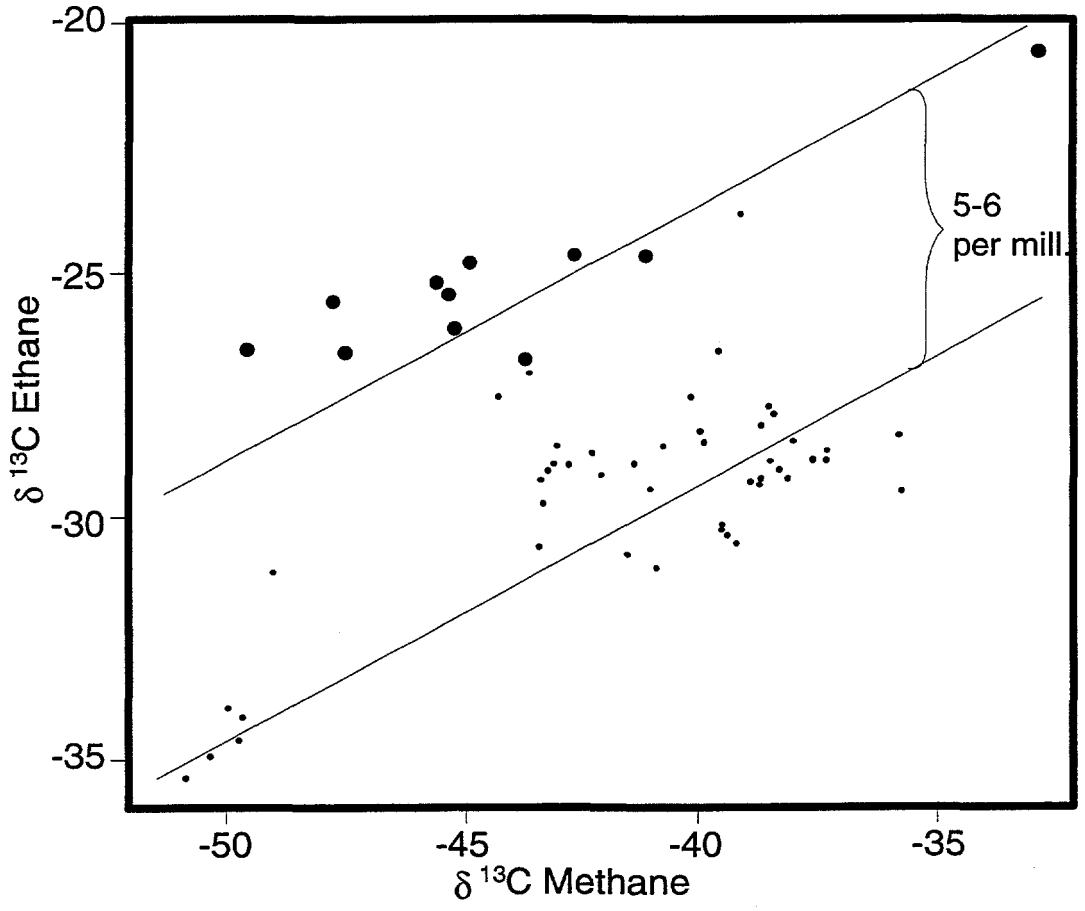
Fig. 10



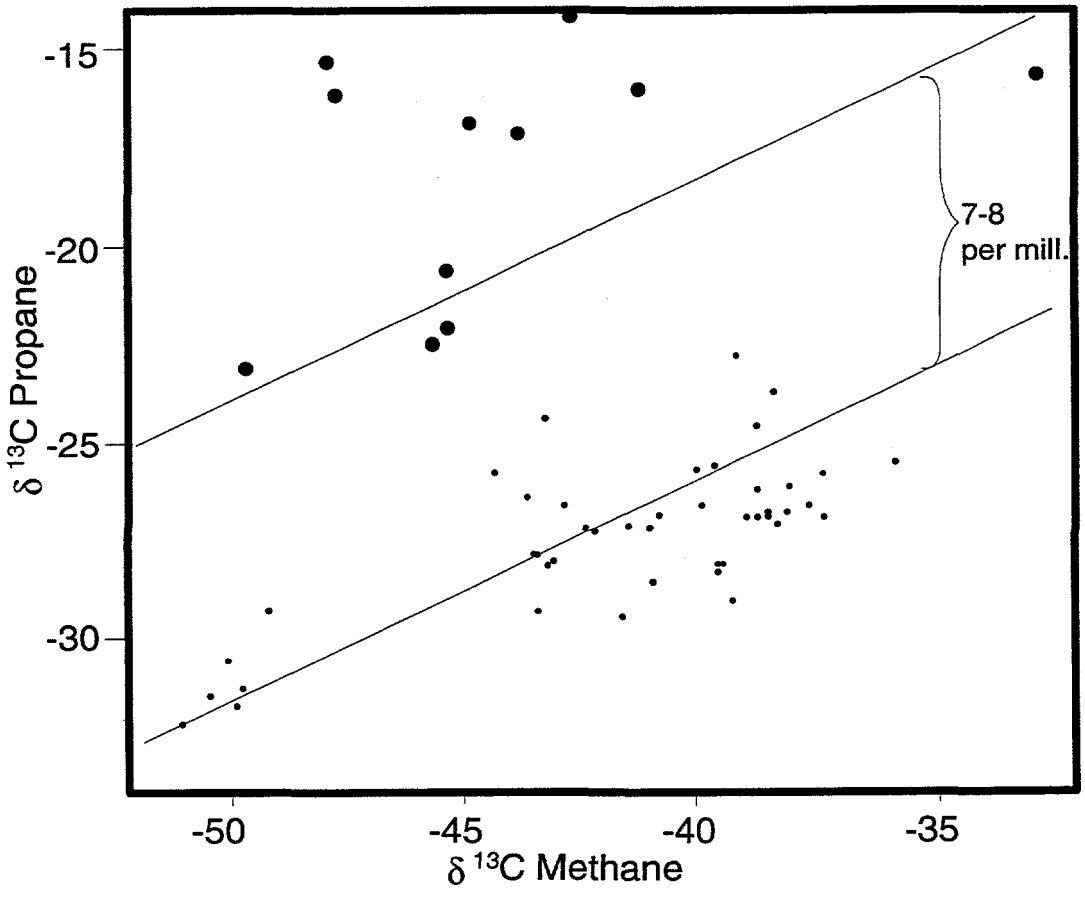


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Fig. 11

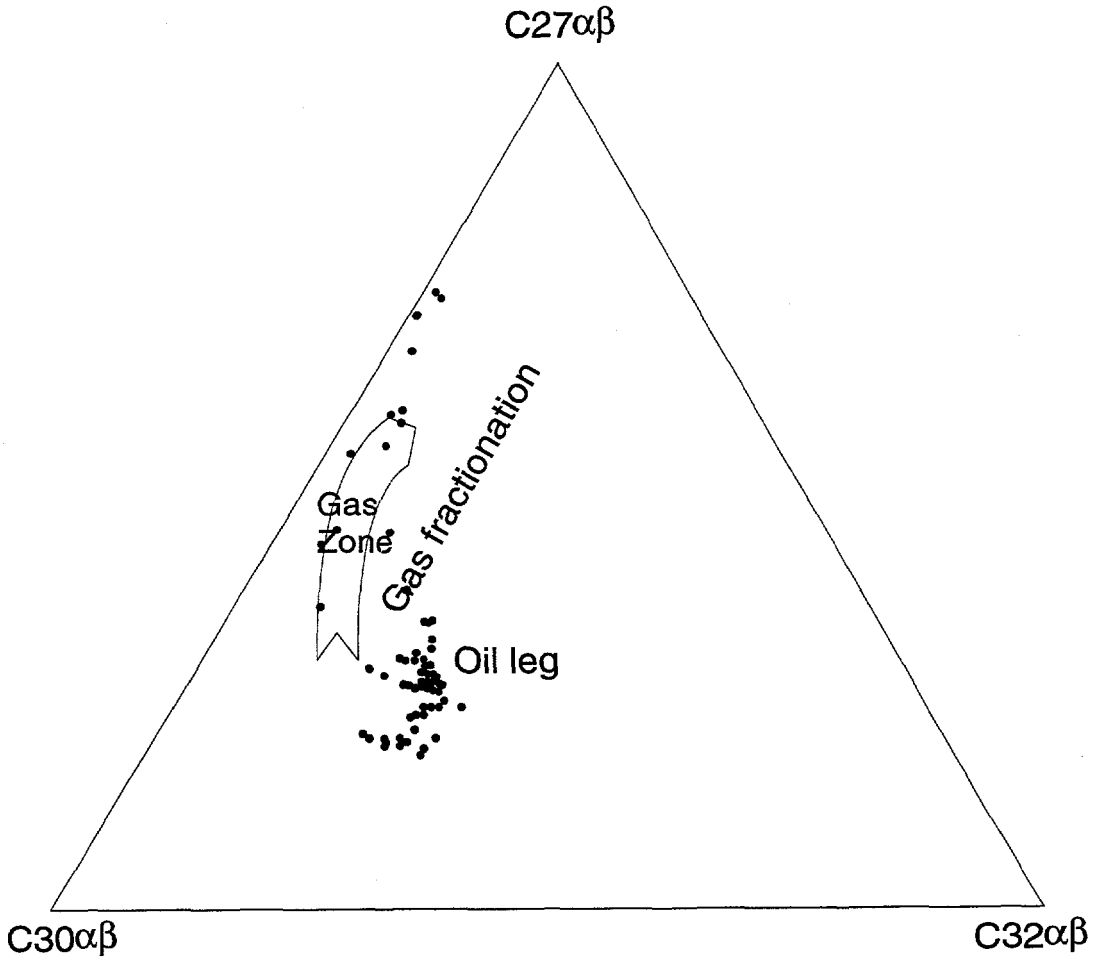

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Fig. 12

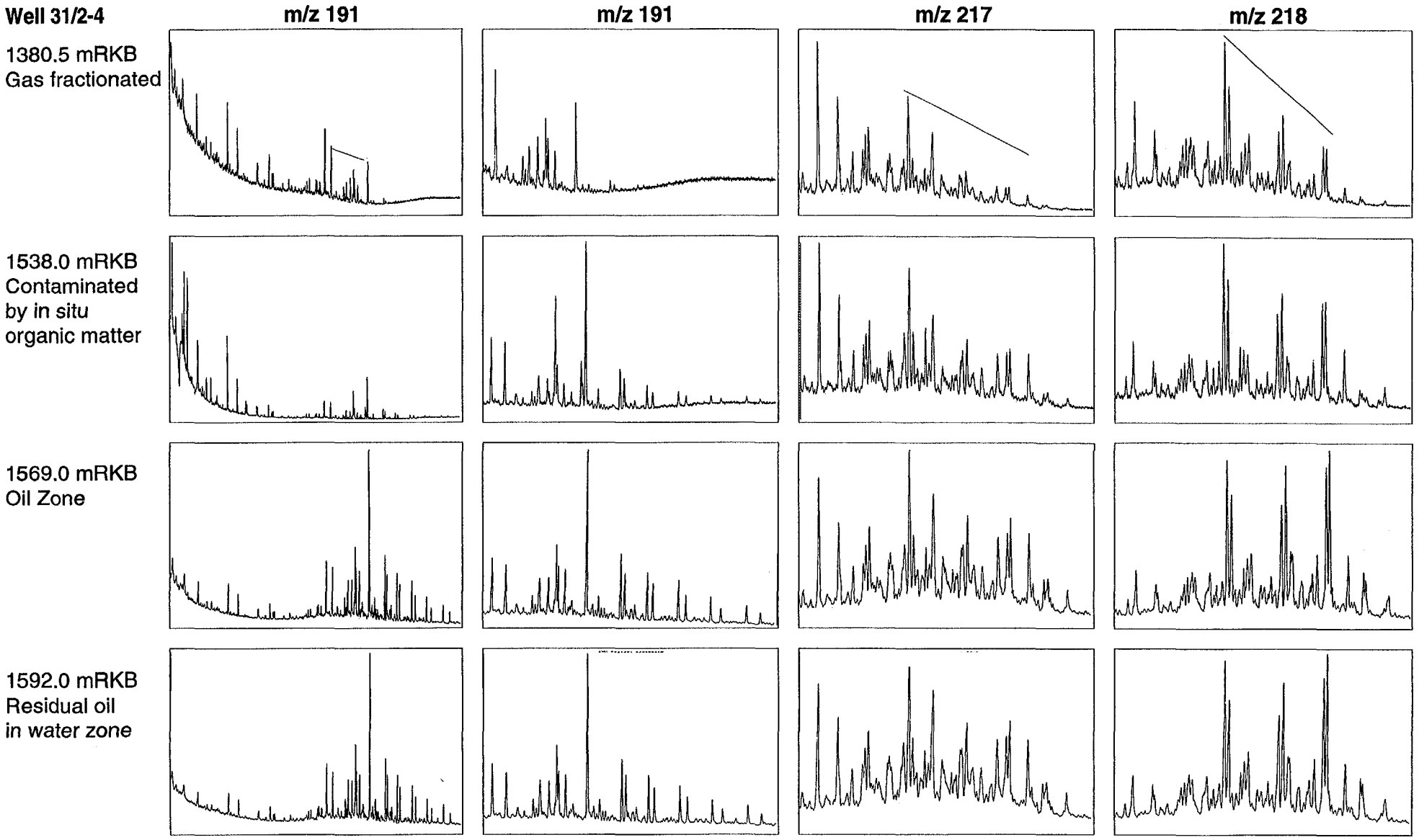
Well 31/2-4
m/z 191
m/z 191
m/z 217
m/z 218
1380.5 mRKB
Gas fractionated
1538.0 mRKB
Contaminated
by in situ
organic matter
1569.0 mRKB
Oil Zone
1592.0 mRKB
Residual oil
in water zone

Fig. 13

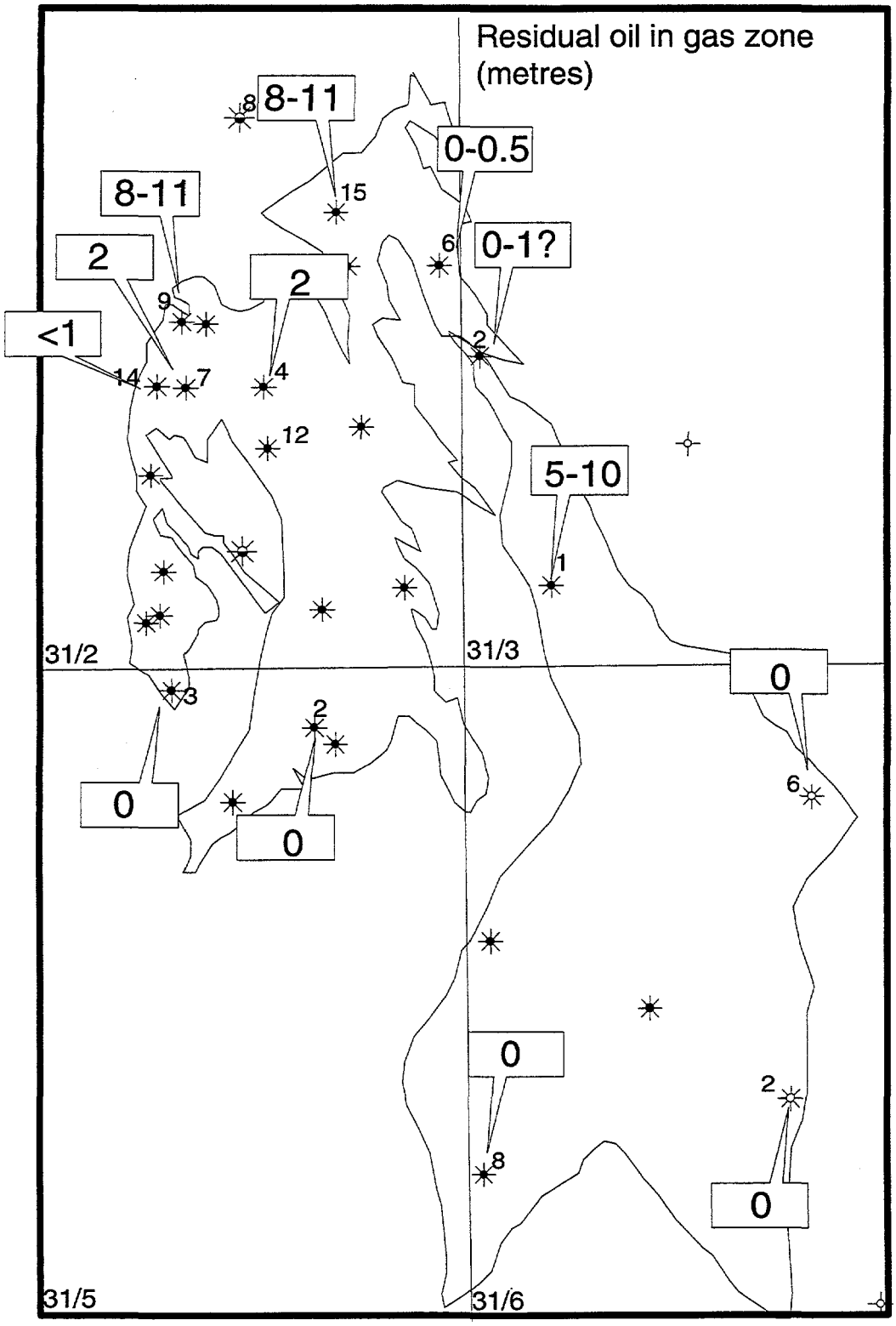

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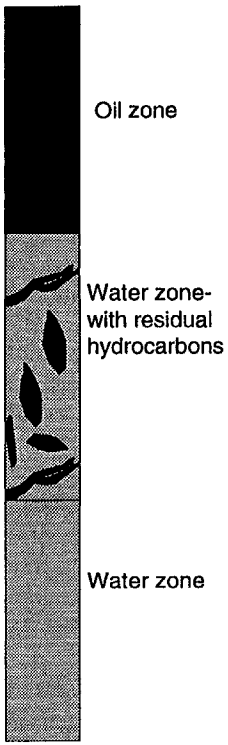
Fig. 14

Troll.drw



Observation		*Possible interpretation*
Patchy residual oil staining	Same oil family as in oil zone	→ Migration route
	Less mature oil than in oil zone	→ Paleo migration route
	Different bulk composition source facies or maturity than current oil zone	→ Small oil slug detached from main charge

Observation	*Possible interpretation*	*Observation*	*Possible interpretation*	*Mechanism*
Uniform residual oil staining	→ Paleo oil column	Similar composition to current oil zone	→ Inclined paleo OWC	→ Tilting
			→ Horizontal paleo OWC	→ Seal failure
		Residual oil has a dfferent composition to current oil zone	→ Possible paleo oil accumulation	→ Inclined paleo OWC → Reservoir destruction due to tilting
				→ Horizontal paleo OWC → Reservoir destruction due to seal failure

Fig. 15

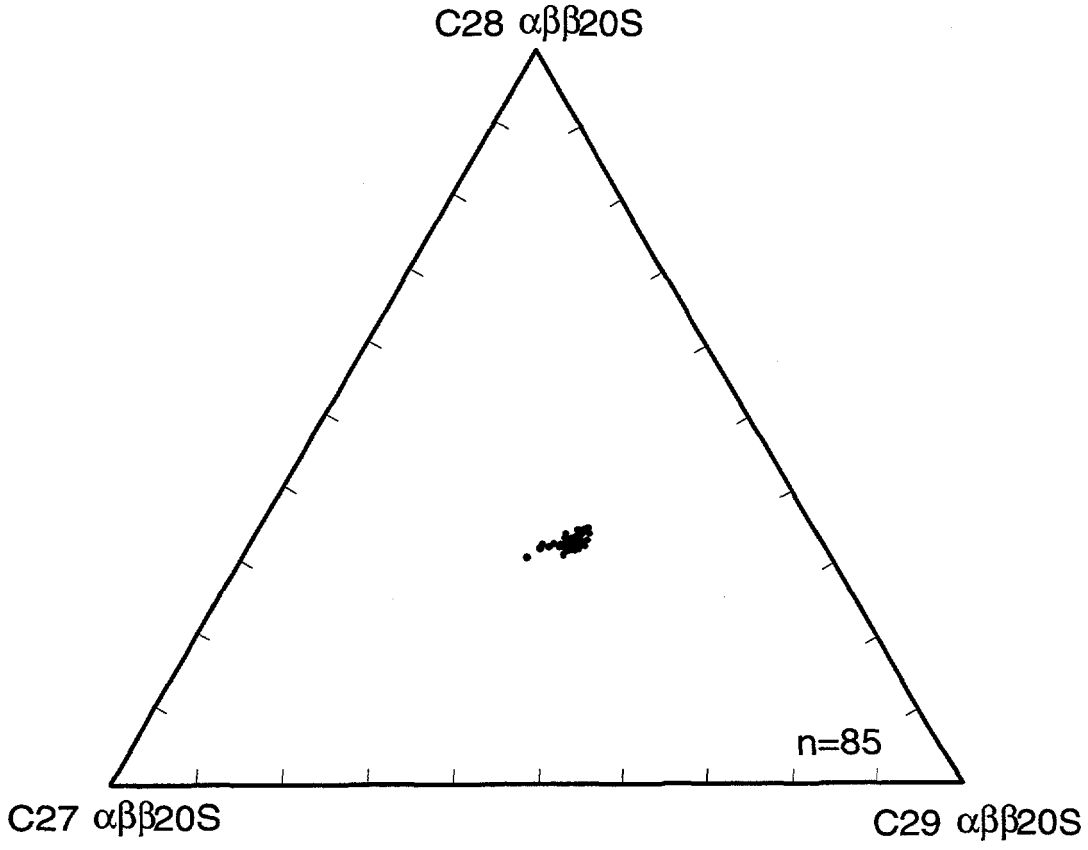


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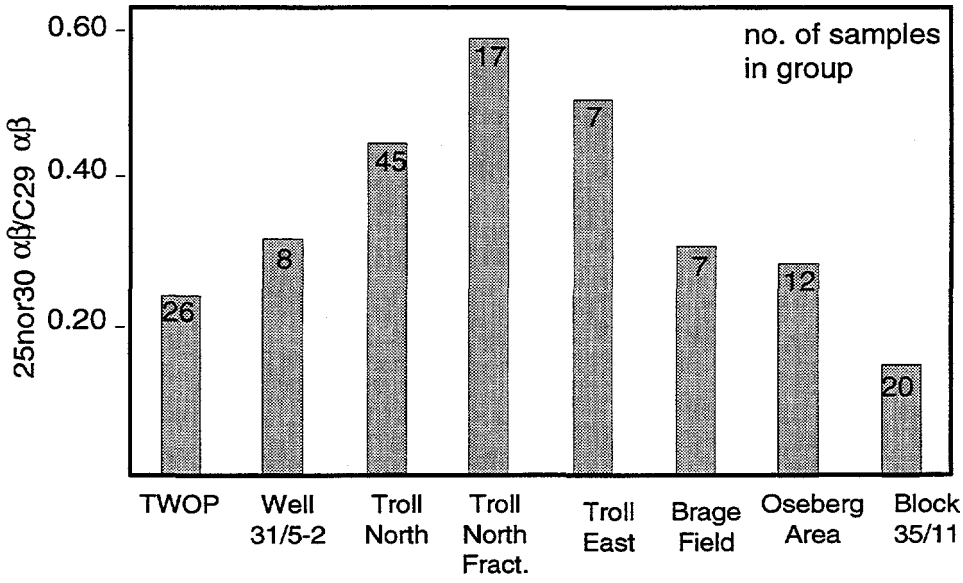
Fig. 16



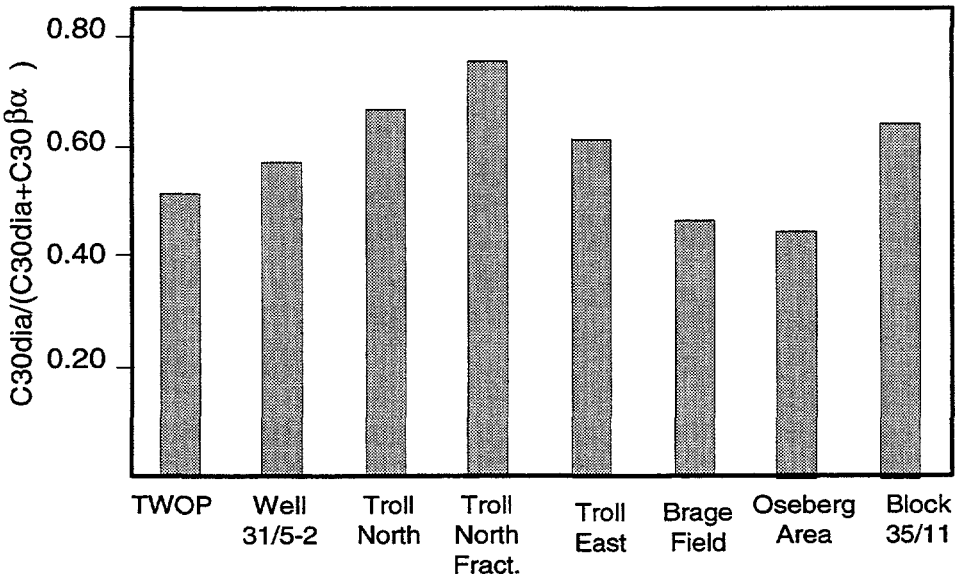


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Fig. 17

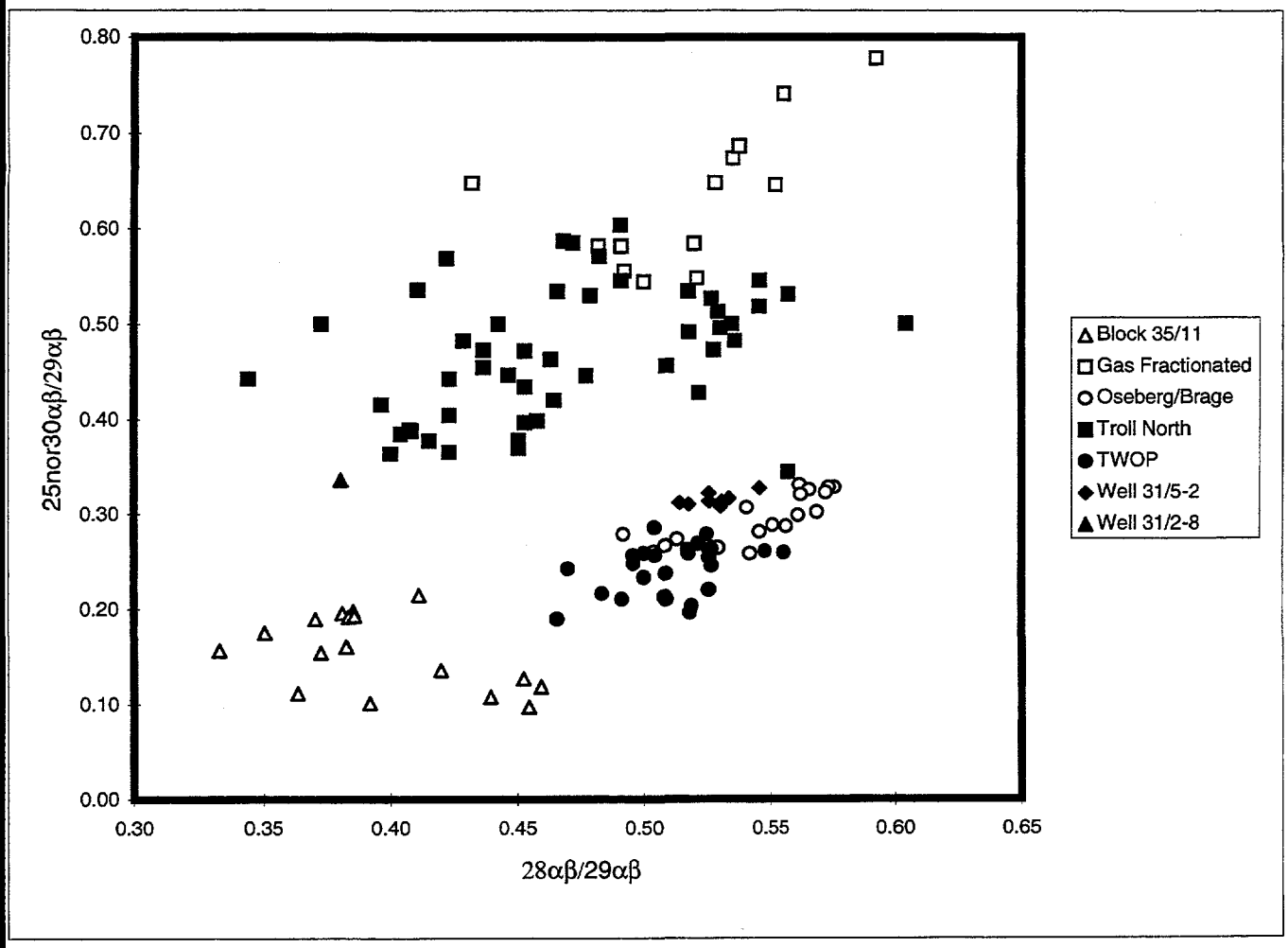

0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
25nor30αβ/29αβ
0.30
0.35
0.40
0.45
0.50
0.55
0.60
0.65
28αβ/29αβ
Block 35/11
Gas Fractionated
Oseberg/Brage
Troll North
TWOP
Well 31/5-2
Well 31/2-8

Fig. 18

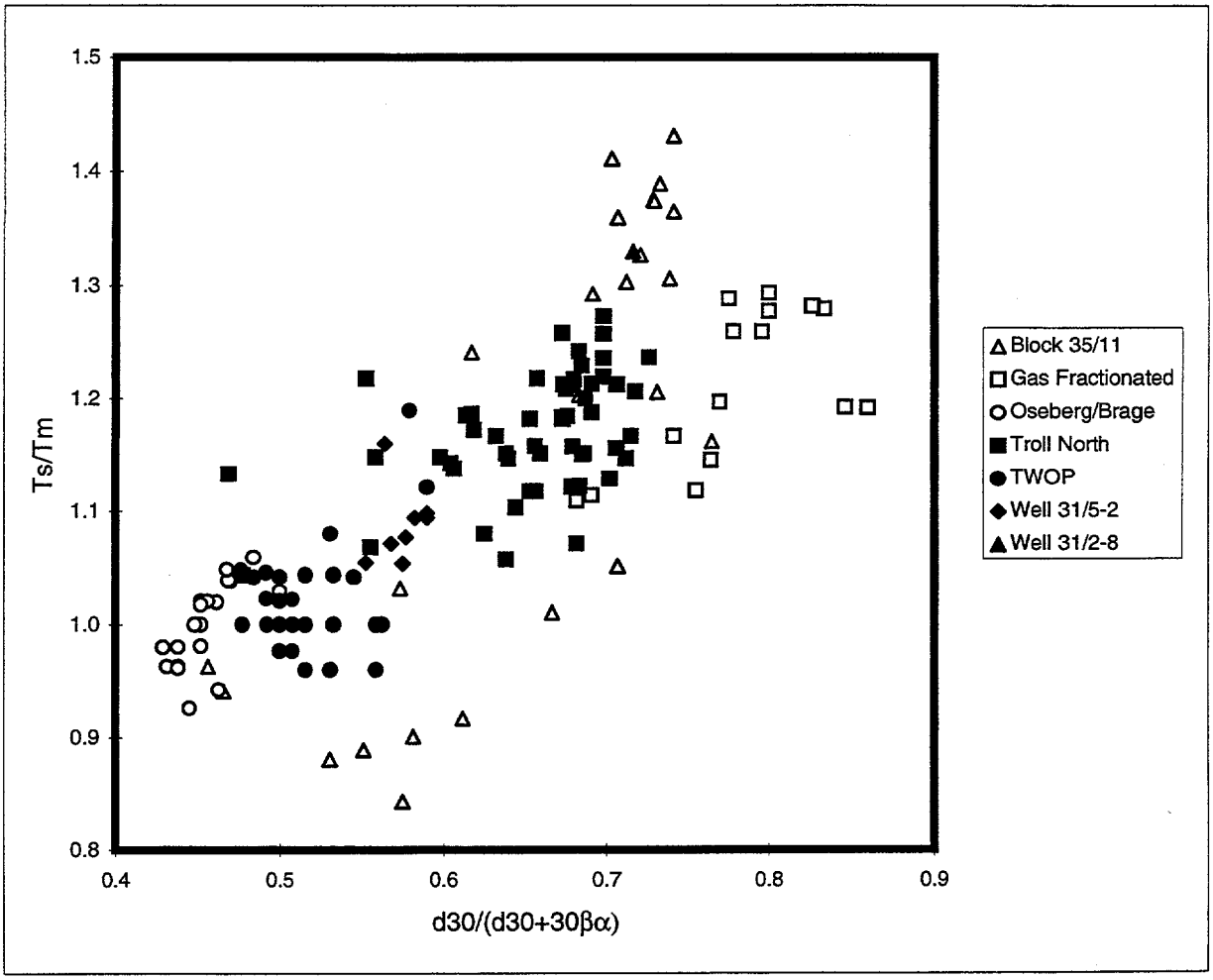

1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
Ts/Tm
0.4
0.5
0.6
0.7
0.8
0.9
d30/(d30+30βα)
Block 35/11
Gas Fractionated
Oseberg/Brage
Troll North
TWOP
Well 31/5-2
Well 31/2-8

Fig. 19

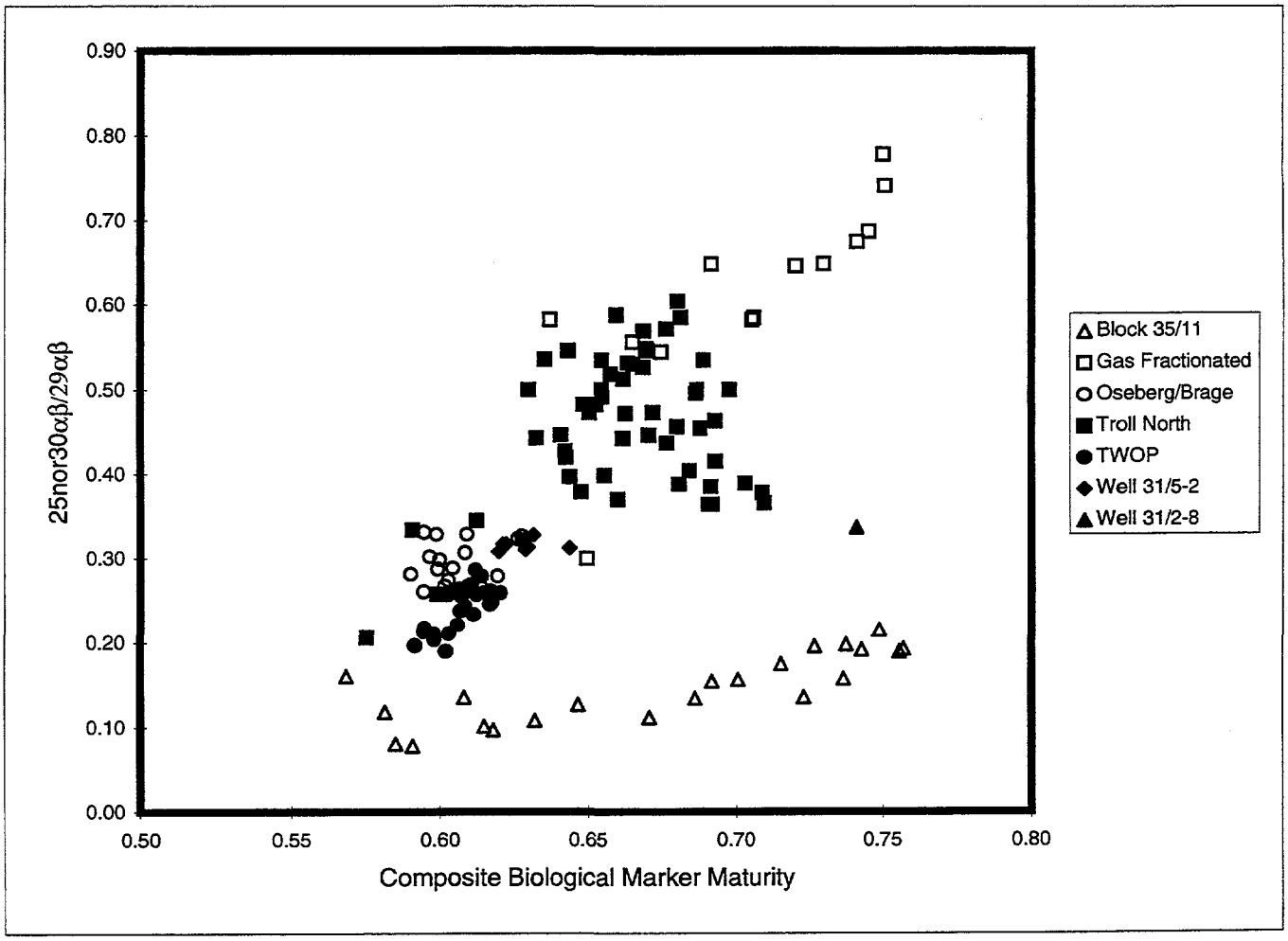
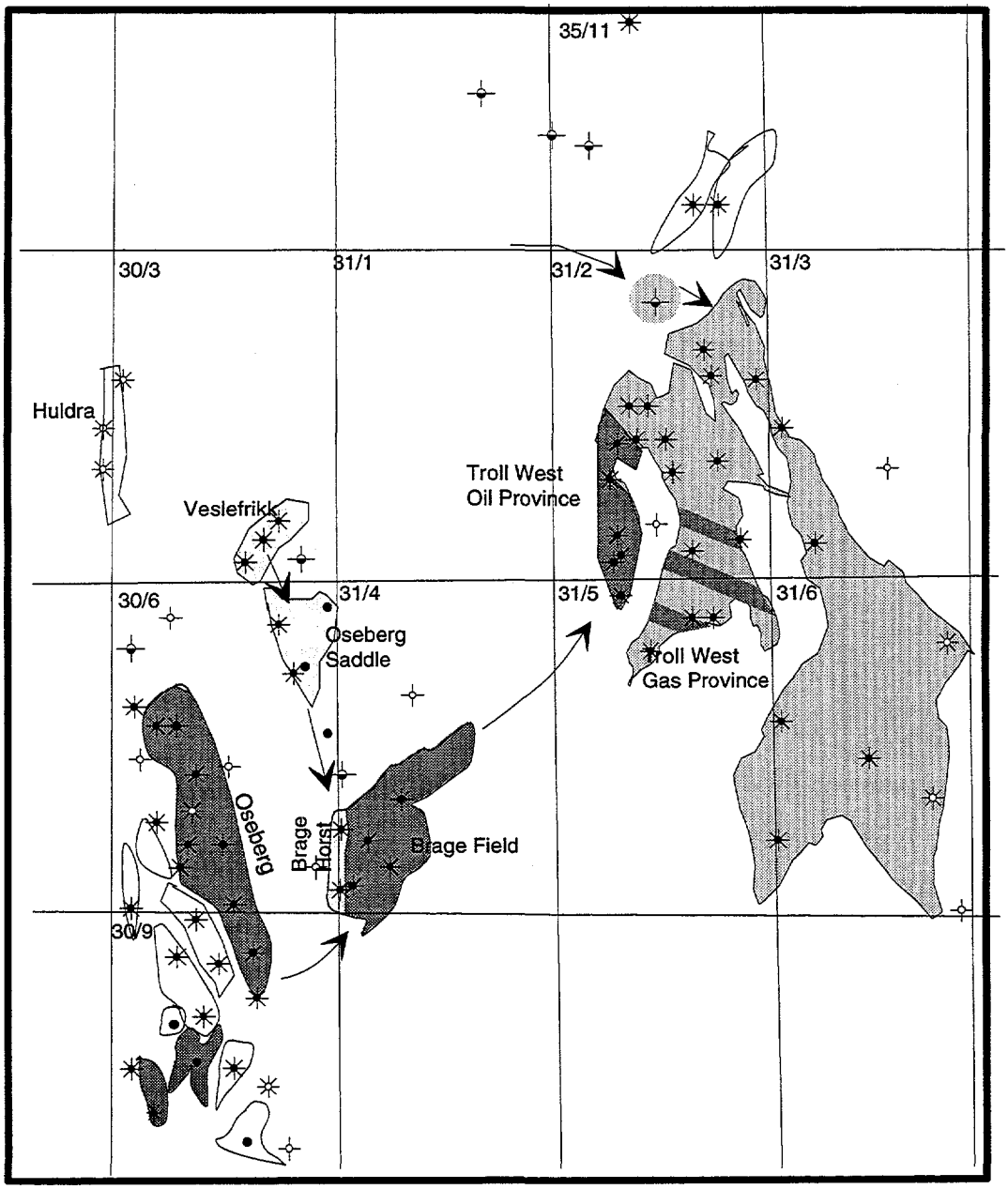

0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
25nor30αβ/29αβ
0.50
0.55
0.60
0.65
0.70
0.75
0.80
Composite Biological Marker Maturity
Block 35/11
Gas Fractionated
Oseberg/Brage
Troll North
TWOP
Well 31/5-2
Well 31/2-8

Fig. 20



Oil Populations

- Oseberg, Brage TWOP oil population
- Northern Troll oil population
- Veslefrikk, Oseberg Saddle, Brage Horst oil population

→ Most likely migration routes

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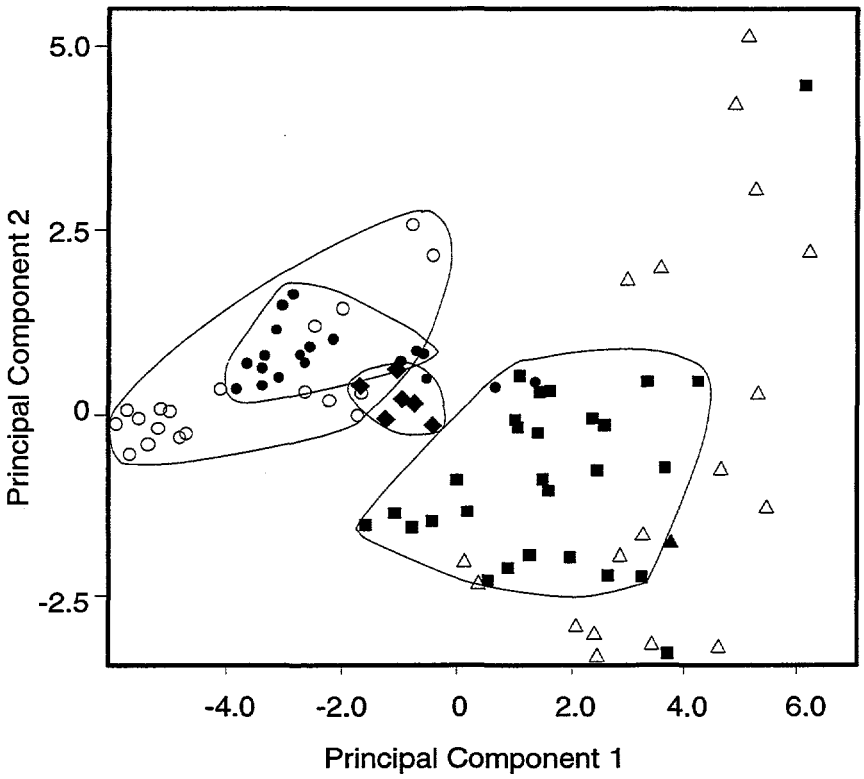
Fig. 21



■ Troll North (oil and water zone)
◆ Well 31/5-2
● TWOP
▲ Well 31/2-8
○ Oseberg/Brage

△ Block 35/11

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Fig. 22

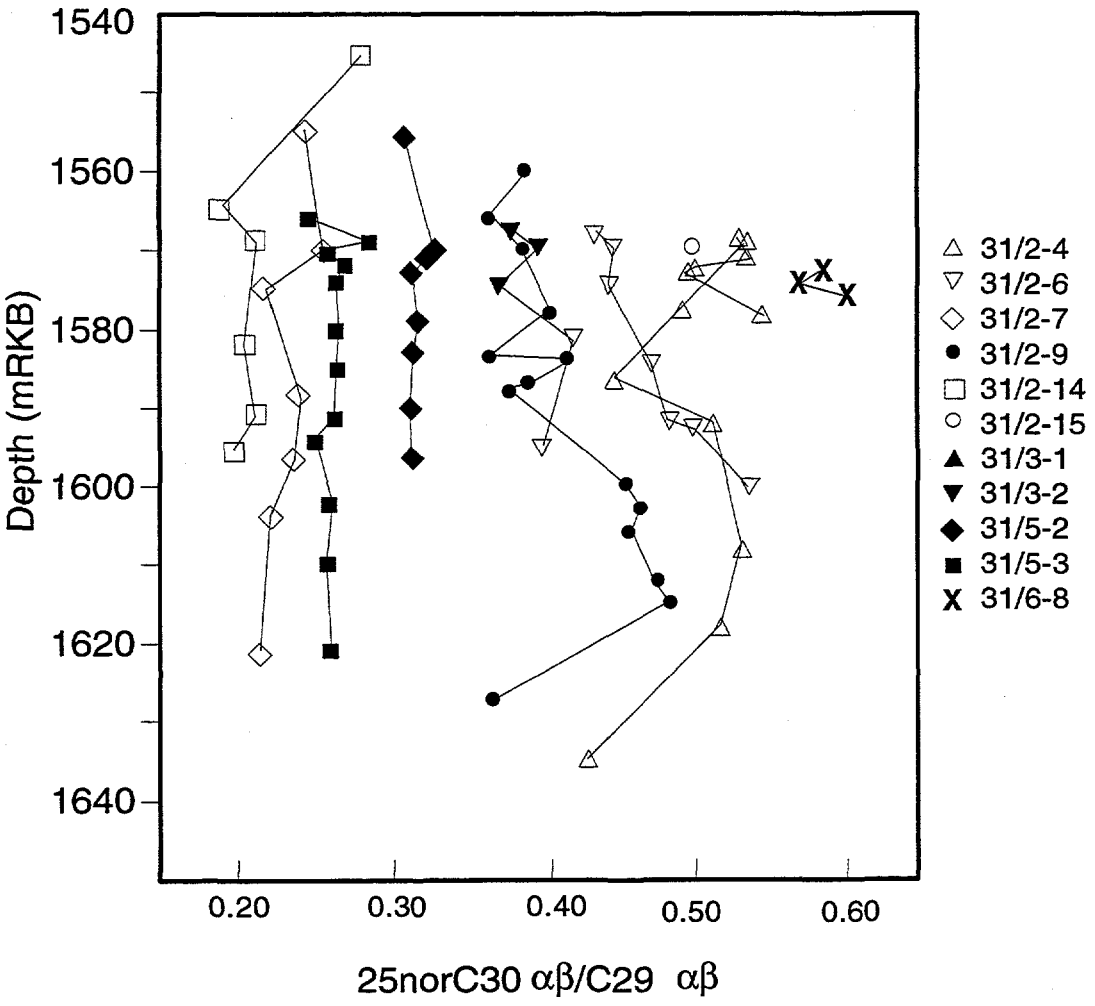

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Fig. 23

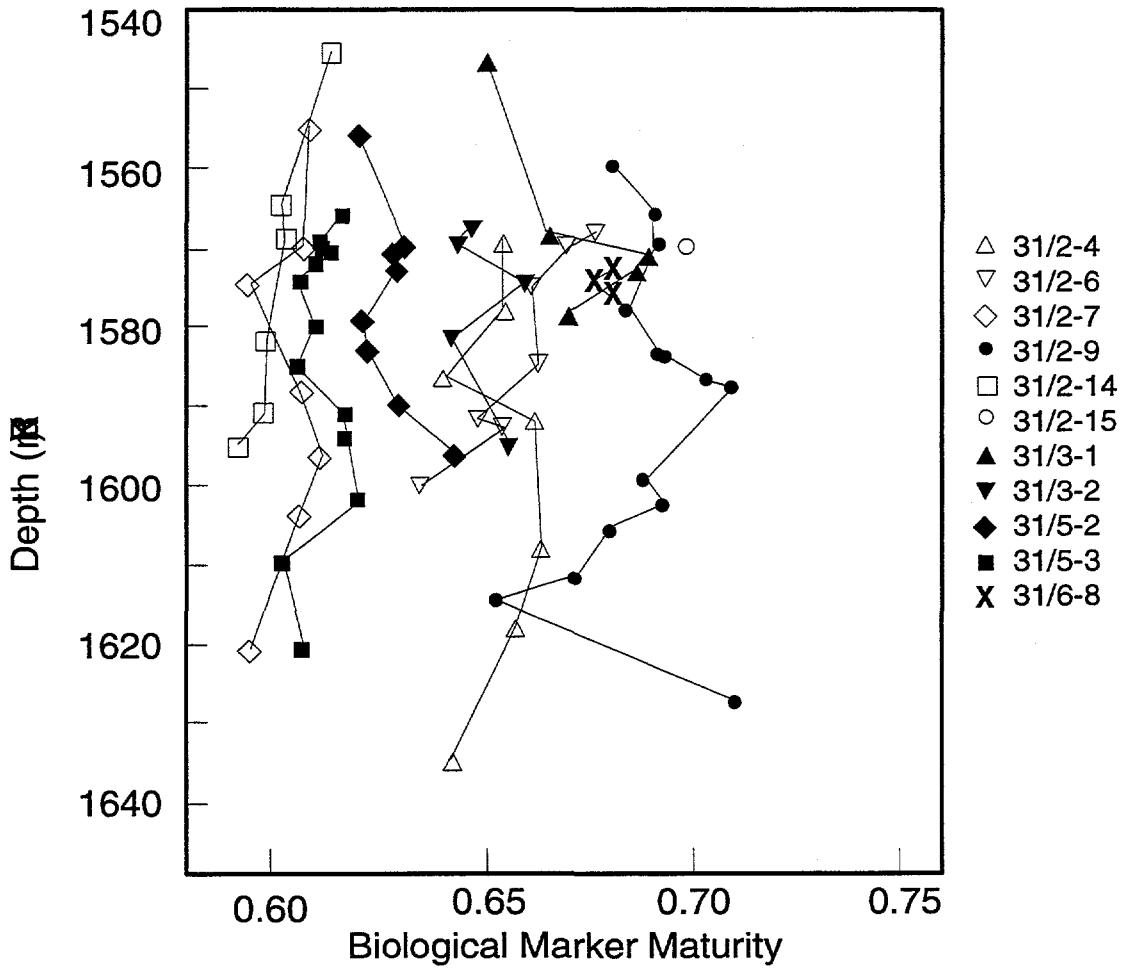

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Fig. 24

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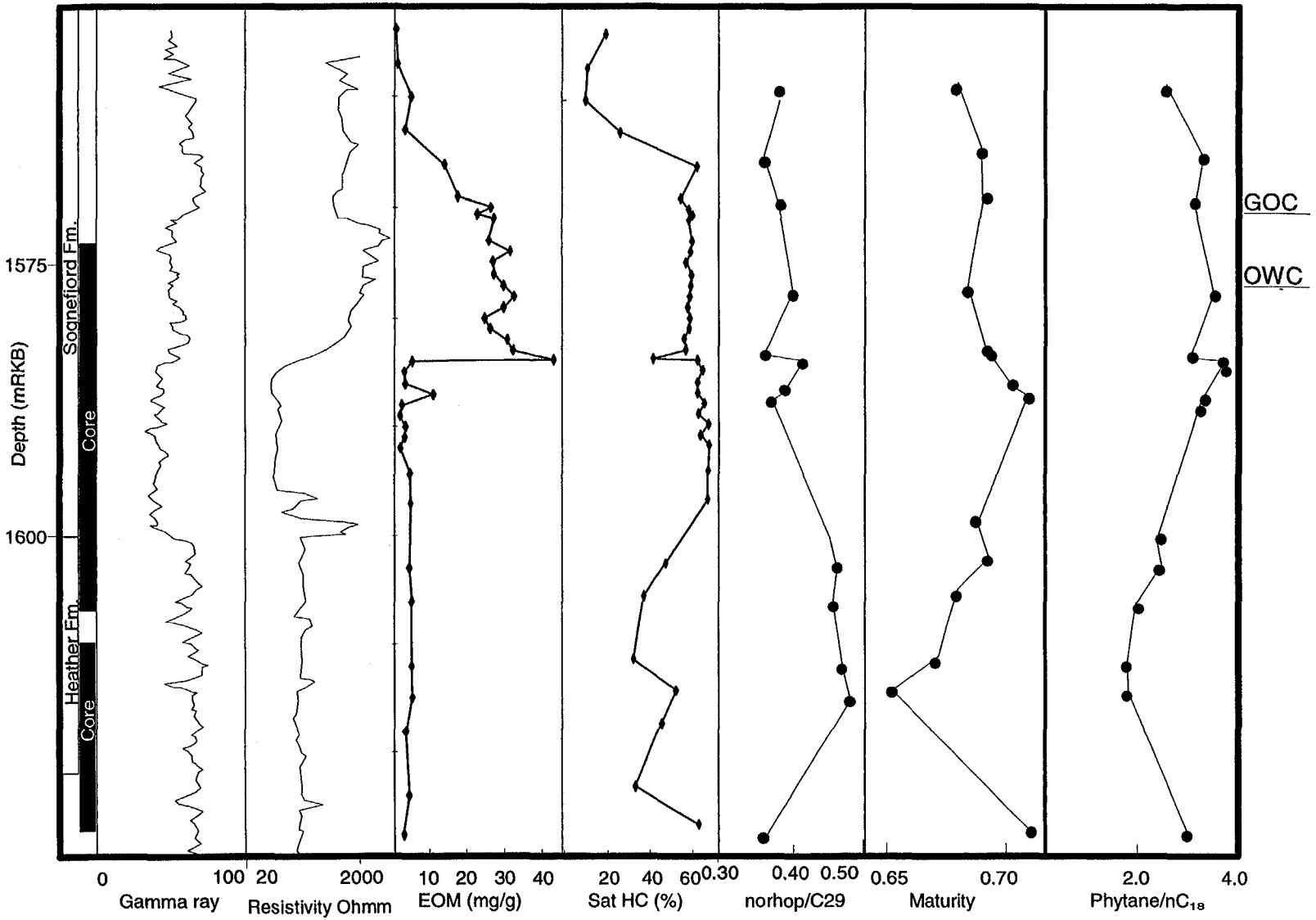
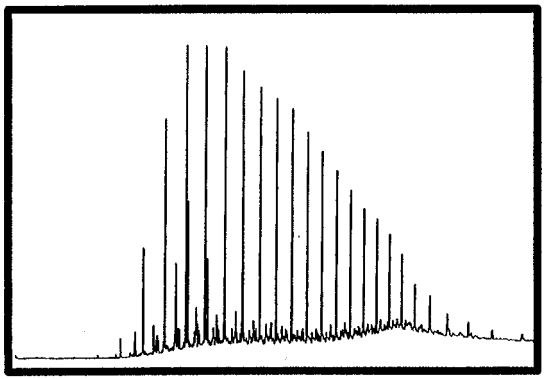


Fig. 25

a



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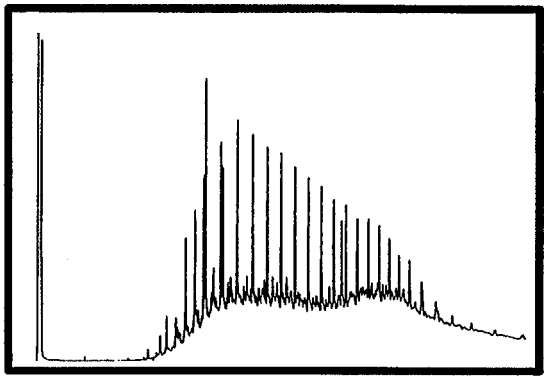
b



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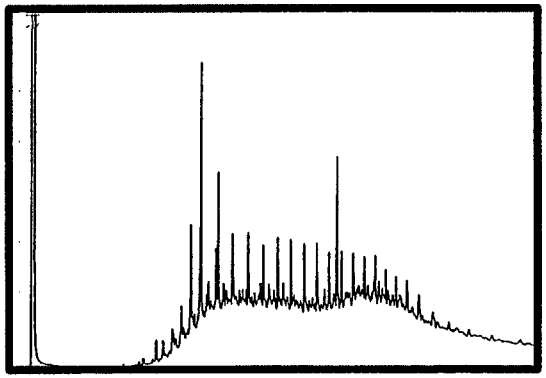
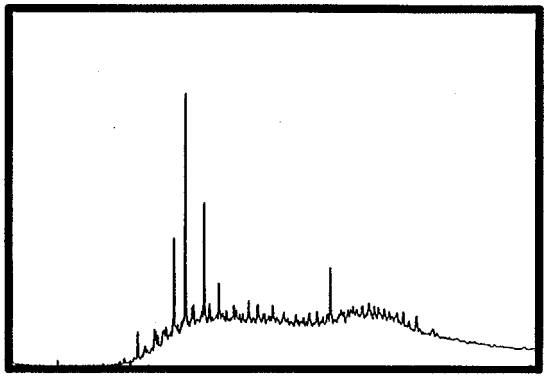
c



31/2-14 1564.5 mRKB

d



31/5-3 1574.0 mRKB

Fig. 26

Gcdrw.drw

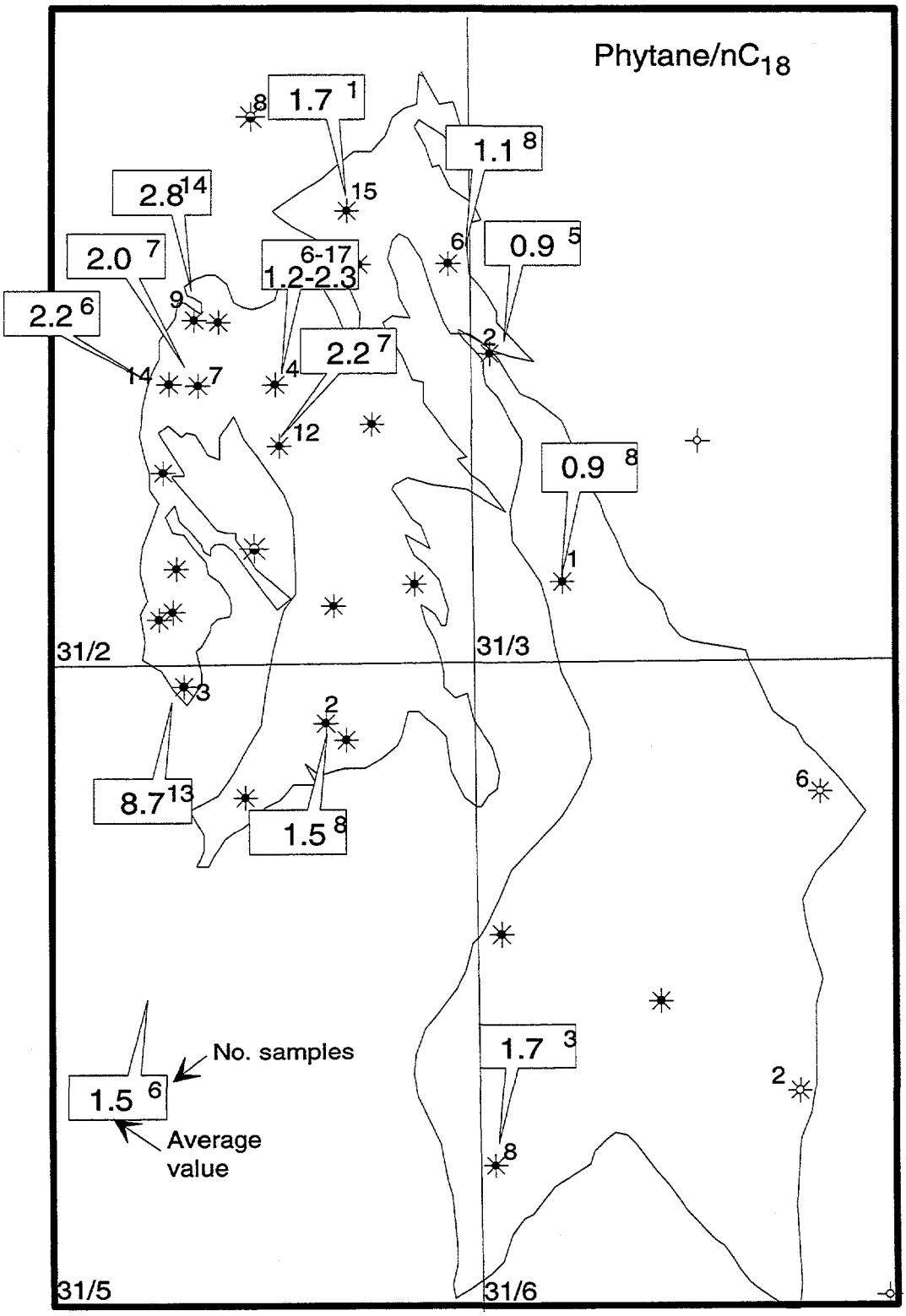


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Fig. 27

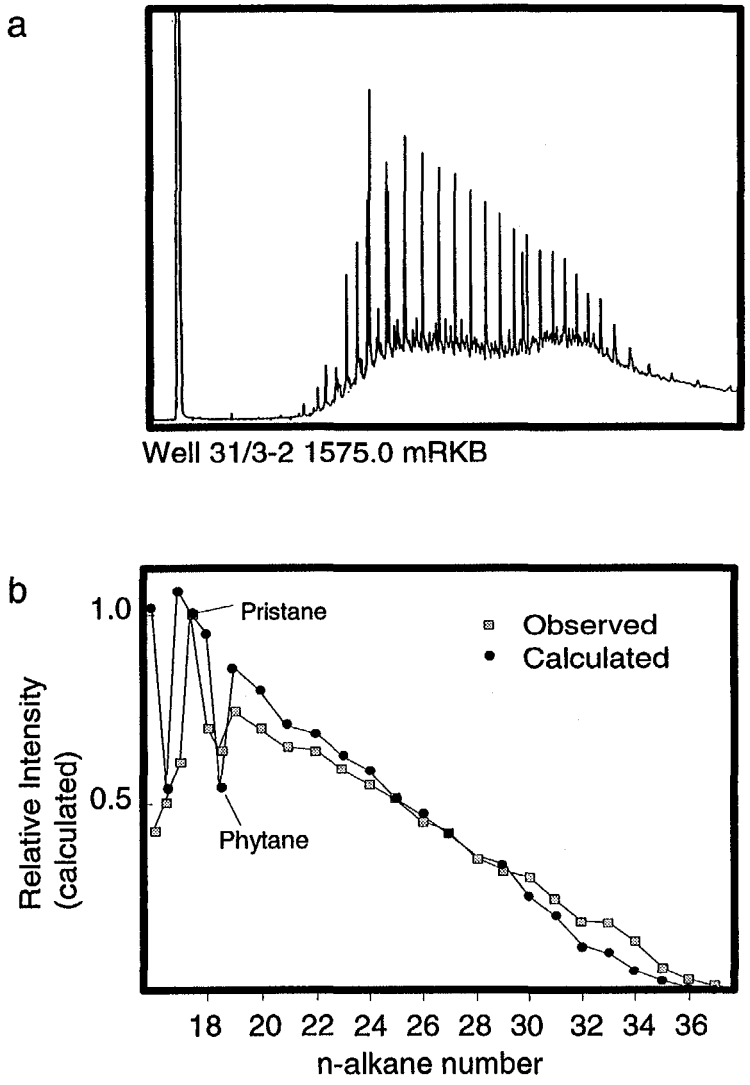

Fig. 28

Gcdrw.drw

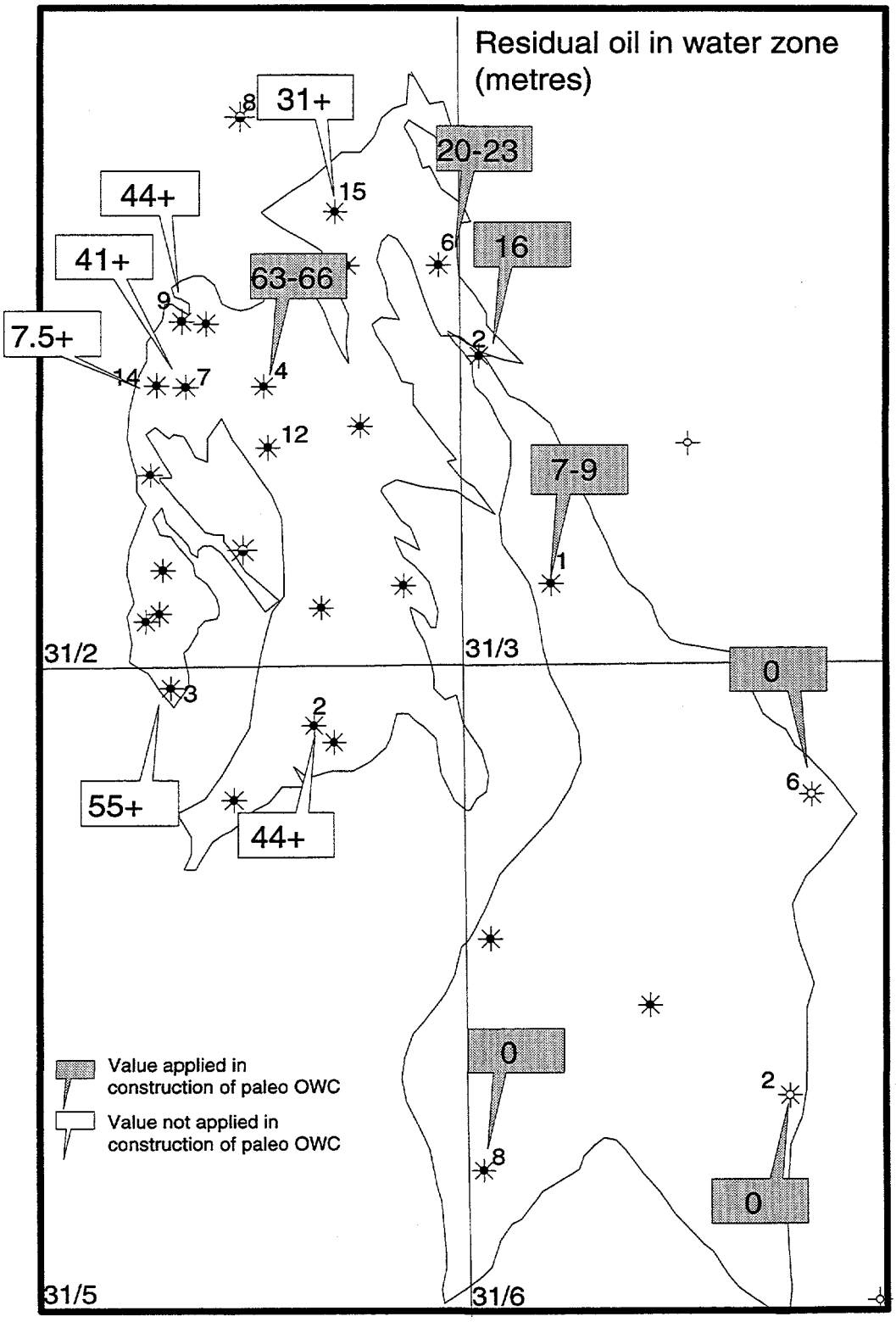

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Fig. 29

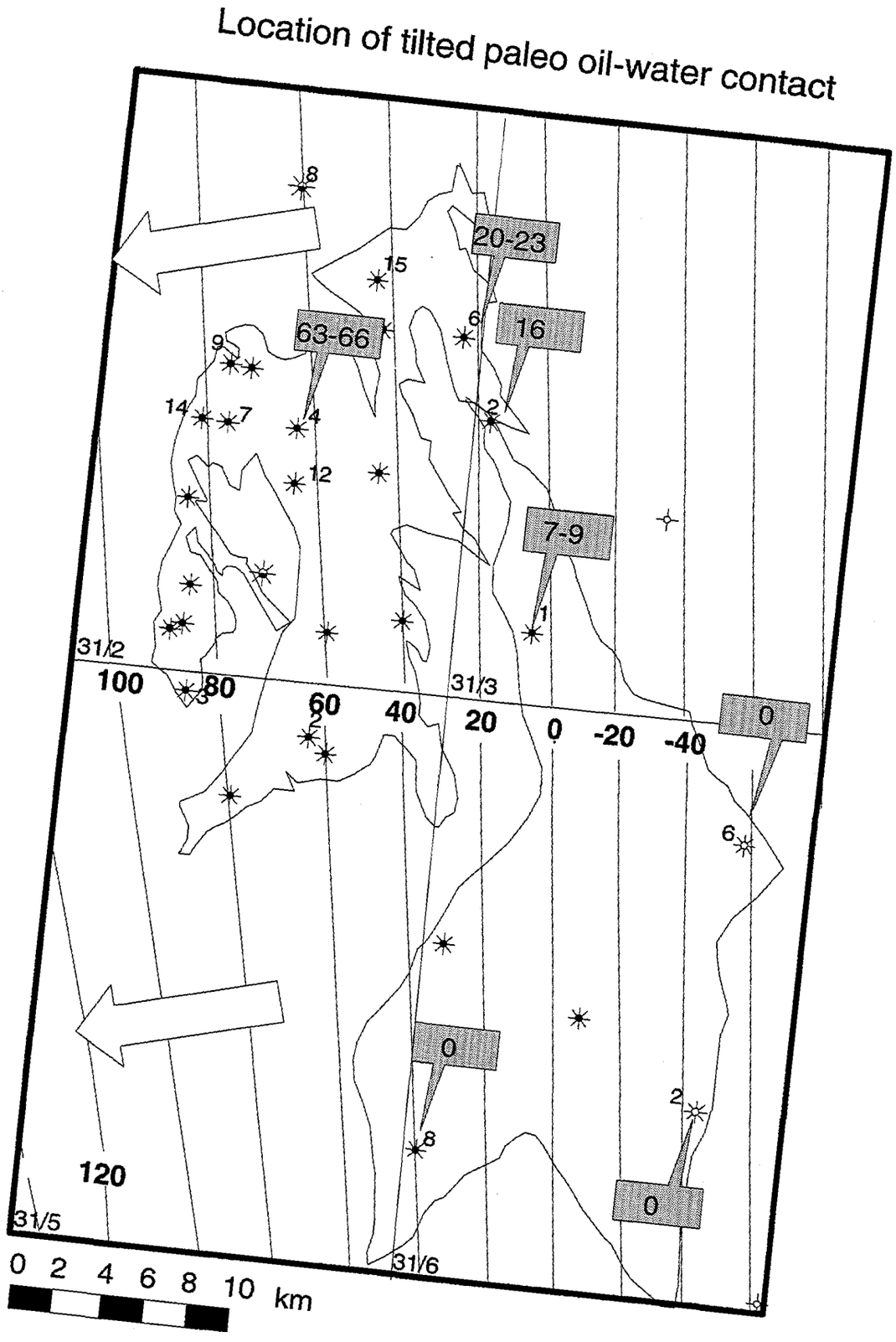

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Fig. 30

Trollres.drw

Fig 31

Trollres.drw

Fig. 32

h:\trollw9.drw

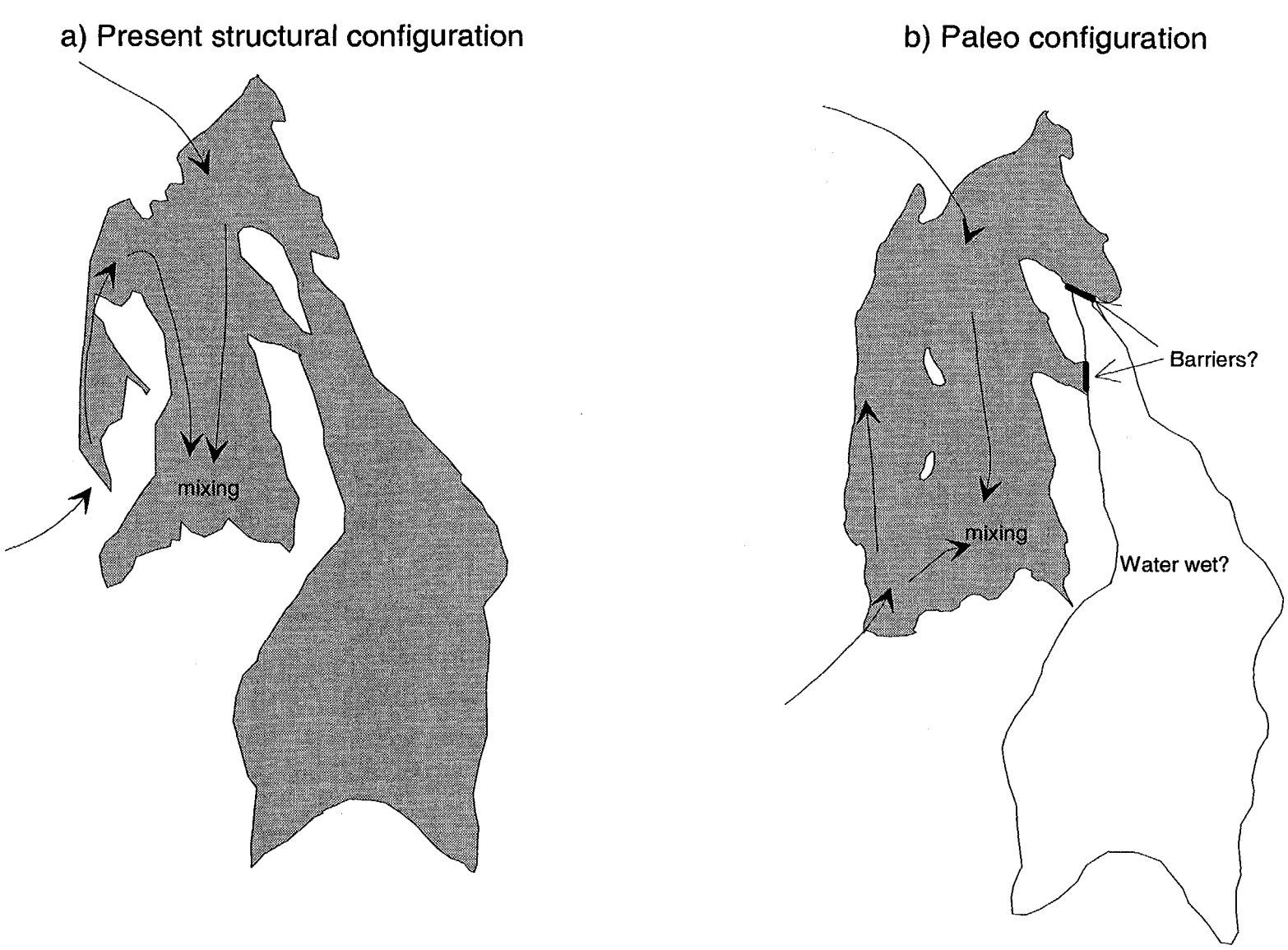

Fig. 33

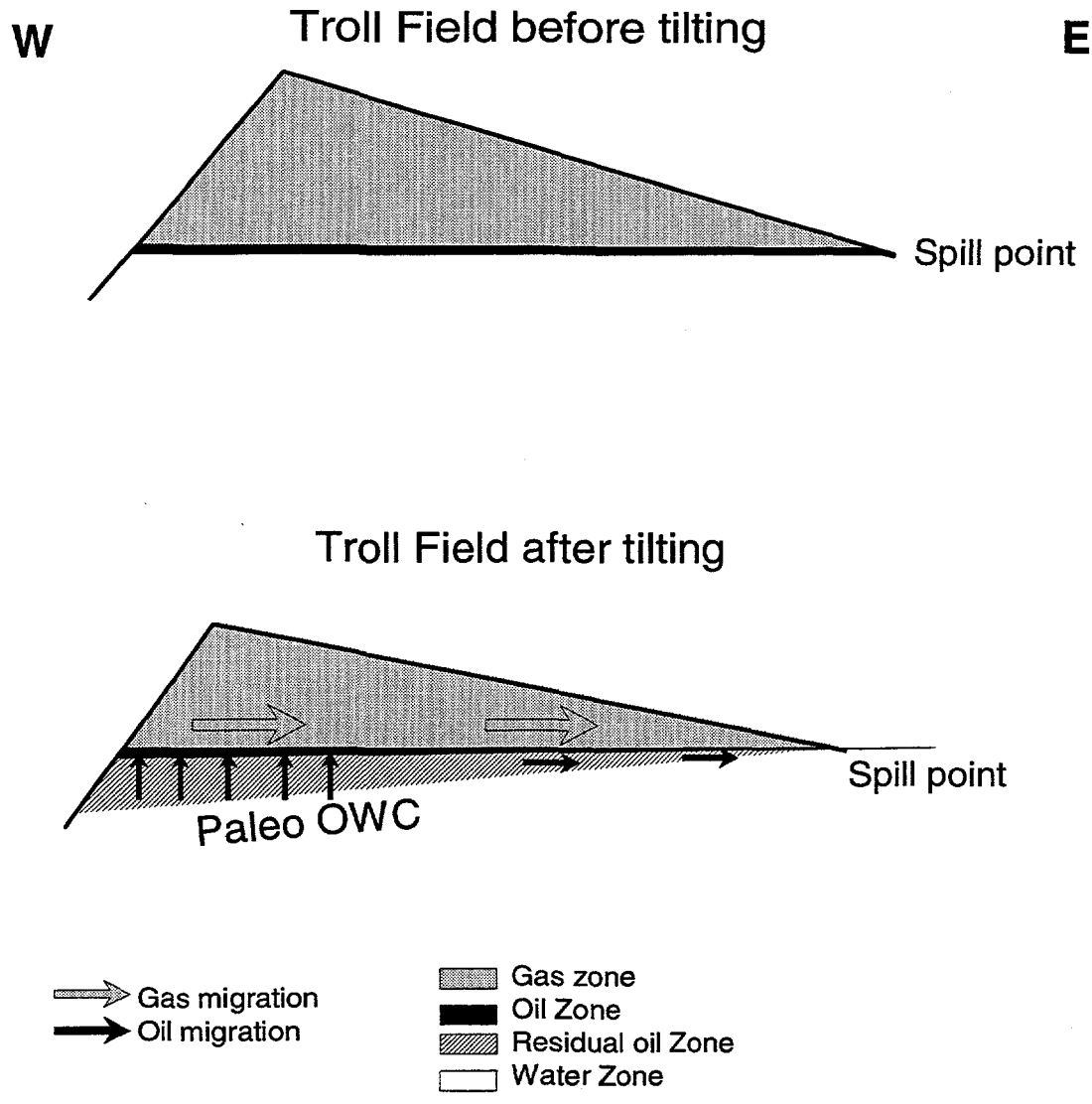

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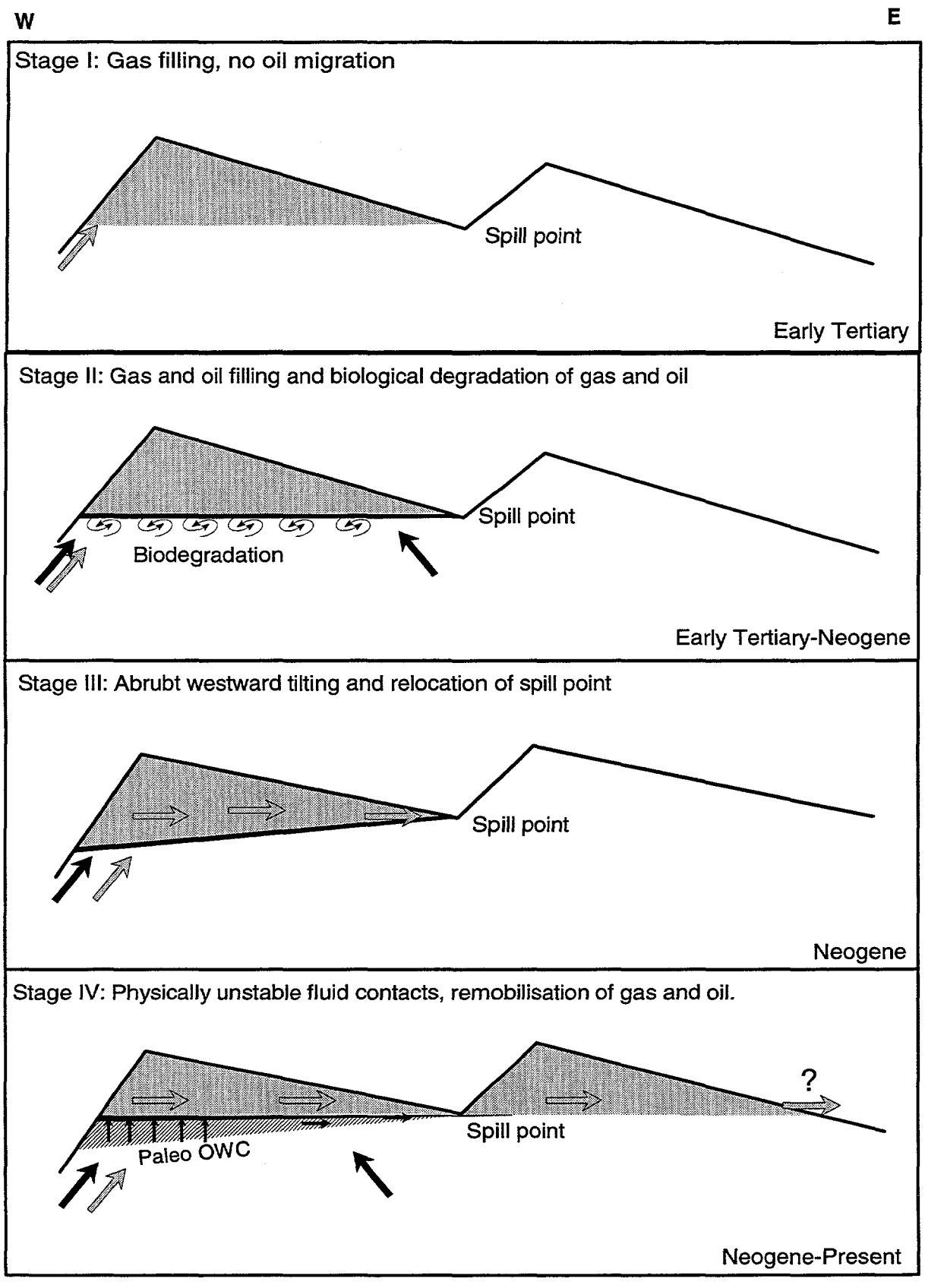
Fig. 34



H:\trolltil.drw

Fig. 35