Quantitative hydrocarbon potential mapping and organofacies study in the Greater Balder Area, Norwegian North Sea

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Abstract: Quantitative maps of the reconstructed oil and gas potential of the Draupne and Heather Formation in the South Viking Graben were produced in order to improve the understanding of lateral and vertical variations in the type of organic matter. For this purpose the Draupne Formation was subdivided into a lower synrift and an upper postrift part (Upper and Lower Draupne Formation, respectively). Both sections show large lateral variability in source rock quality and oil and gas potential. The total TOC distribution is strongly related to the depositional environment and also to the preservation of organic matter. The Upper Draupne Formation exhibits equally high amounts of oil- and gas-prone organic matter. The Lower Draupne Formation shows a considerably higher amount of land-derived Type III organic matter, which decreases upwards and towards the Utsira High. The marine Type II material in the synrift section is less abundant, because of dilution of the marine material by terrestrial material transported by mass flows from the surrounding highs. These findings are supported by environmental molecular data. The Heather Formation is a mixture of type-III and -II kerogen and shows moderate to good gas potential. The source rock sections were also correlated using the relative occurrence of bisnorhopane in the rock extracts.

Keywords: source rock, organofacies, mapping, oil potential, gas potential, North Sea, Norway, hydrocarbon system, bisnorhopane

The Norwegian Southern Viking Graben, from the Frigg to the Sleipner Fields, is a prolific hydrocarbon province with 255.2×10^6 Sm^3 oil and 429.7×10^9 Sm^3 gas recoverable in the Norwegian Sector. Although a mature exploration area, a number of undrilled leads and prospects remain with considerable reserve potential. An improved quantified understanding of this area will be an important tool in solving exploration and production problems, will uncover new plays and bring new life to exploration in the area.

This study is part of a 'Petroleum System Analysis' project in which the understanding of hydrocarbon generation, migration, filling- and loss-histories is emphasized. The aim is to improve the fundamental understanding of the processes controlling the accumulation of hydrocarbons and their quality in the South Viking Graben. Whilst the reservoirs on the eastern side of the basin (Norwegian Sector) are dominated by gas discoveries, oil is the dominant hydrocarbon phase on the western side (UK sector) (Eriksen *et al*. 2003). This distribution of petroleum in the asymmetric Southern Viking Graben seems primarily to be a function of the tectonostratigraphic distribution of source rocks, carrier beds and traps and, secondarily, the organic facies variations of the Upper Jurassic Draupne and Heather Formations.

This variation of organofacies and source rock potential in the Greater Balder Area was investigated by detailed source rock analysis and subsequent mapping and interpretation. The quantitative maps of oil and gas potential produced can be used for calculations of the hydrocarbon volumes produced and expelled, and hence charge-to-trap calculations.

Various kerogen facies maps have been published for the Upper Jurassic North Sea (Barnard & Cooper 1981; Baird 1986; Cooper *et al*. 1995; Cornford 1998; Isaksen & Ledje 2001; Kubala *et al*. 2003). However, apart from a study by Dahl & Yukler (1991), quantitative maps of the oil and gas potential of the Upper Jurassic have not to the authors' knowledge been previously published.

The Upper Jurassic shales are often regarded as homogeneous and as such not further differentiated in terms of organic matter type (Huc *et al*. 1985). However, large variations in organic matter type reportedly occur not only laterally, but also vertically in individual well bores (Huc *et al*. 1985). The understanding of the vertical and horizontal distribution of kerogen types, organofacies and molecular contents is also valuable in source rock–oil correlation. The C_{28} terpane biomarker bisnorhopane is a significant feature of Upper Jurassic sediment extracts and associated oils in the North Sea area (e.g. Grantham *et al*. 1980; Cornford *et al*. 1983; Dahl & Speers 1985; Huc *et al*. 1985; Dahl 1987; Isaksen *et al*. 1998). This common molecular component does not, however, occur throughout the entire Upper Jurassic stratigraphic column. As a result it has been thought to be a useful oil-to-source correlation and oil-to-oil correlation parameter (Huc *et al*. 1985). The rather 'enigmatic' occurrence of bisnorhopane (Hughes *et al*. 1985) has given rise to discussion about the origin of its precursor molecules. Various sources, among them direct production by anaerobic bacteria (Katz & Elrod 1983), have been proposed. The controls on the abundance of bisnorhopane have also been widely discussed (Grantham *et al*. 1980; Moldowan *et al*. 1984; Hughes *et al*. 1985; Moldowan *et al*. 1985; Noble *et al*. 1985; Isaksen *et al*. 1998; Bojesen-Koefoed *et al*. 2001). Association with high sulphur contents and anoxia (Grantham *et al*. 1980; Peters & Moldowan 1993; Bojesen-Koefoed *et al*. 2001) have been examined. Based on multi-well studies of the typical organic rich Upper Jurassic organofacies, the relative abundance of bisnorhopane has been shown to decrease with increasing maturity (Cornford *et al*. 1983), although Huc *et al*. (1985) observed the opposite trend. It has been shown by Dahl (1987) that the ratio of $17\alpha(H),21\beta(H)$-28,30-bisnorhopane to $17\alpha(H),21\beta(H)$-30-norhopane varies with stratigraphic position and can be used as a subregional stratigraphic marker in the Oseberg Area. In the present study it was attempted to test this in the Greater Balder Area.

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Geological setting

The study area is situated roughly 200 km west of Stavanger in the Southern Viking Graben in the Norwegian Sector of the North Sea and altogether comprises 16 Norwegian Blocks in Quadrants 15, 16, 24, 25 and 26. The area extends from 58°45′ to 59°45′ N and 1°35′ to 3°20′ E (Fig. 1).

Geological history

The Southern Viking Graben is part of the post-Caledonian North Sea rift system. The Viking Graben is located in the western half of the study area, while the eastern part is dominated by a large basement high, the Utsira High (Fig. 1). This basinal high is flanked by the Stord Basin in the east and shows a horst structure in the southernmost part of the study area. This structural setting is the result of two major phases of extension, the first during the Permo-Triassic and the second in the Late Jurassic (Ziegler 1992). The oldest recovered sediments in the study area are of Permian age (Isaksen & Ledje 2001) and consist of aeolian deposits and evaporites, deposited under an arid climate. Non-marine clastic sediments with red beds were deposited during the Triassic (Fisher & Mudge 1998). The Middle Jurassic was marked by transgression and the deposition of coals, shales and sandstones in coastal plain, delta and shoreface settings (Cockings *et al*. 1992). In the Late Jurassic to Early Cretaceous, the area experienced another episode of extension, resulting in the development of an asymmetric graben in the western half, the Viking Graben (Faerseth 1996). The eastern half of the area remained unaffected by the Late Jurassic to Early Cretaceous rifting episode (Faerseth 1996). Rifting was coupled with a general sea level rise and led to deep marine sedimentation and the deposition of the organic-rich Heather and Draupne Formations. During the Cretaceous, siliciclastics of the Cromer Knoll Group and the lime muds of the Chalk were deposited (Oakman & Partington 1998). The Late Paleocene was characterized by volcanic activity leading to the tuffaceous deposits in the Sele and Balder Formations, while falls in eustatic sea-level during the Paleocene caused an influx of clastics from the West (Ziegler 1992). The Paleocene and Eocene sands, deposited as submarine fan complexes, form important reservoir intervals, for example in the Balder Field (Hanslien 1987). In post-Eocene times, regional subsidence dominated the area and as a consequence the low-energy deposits of the Hordaland Group were deposited (Jordt *et al*. 1995). Further subsidence, uplift events, glacial and fluvial processes in the Neogene led to the deposition of the shallower Nordland Group (Jordt *et al*. 1995).

The Upper Jurassic source rocks in the South Viking Graben

The Kimmeridge Clay Formation Equivalent, termed Draupne Formation in the study area, is the major source rock in the North Sea (Barnard & Cooper 1981; Doré *et al*. 1985; Cooper *et al*. 1995; Cornford 1998). While the Draupne Formation is the dominant source for oil, the underlying Heather Formation shows fair to good gas potential with local oil potential (Cooper *et al*. 1995; Cornford 1998).

In the study area (Fig. 2), the grey, silty mudstones of the Heather Formation were deposited as synrift deposits during the most important stretching episode in the North Sea area in the Bathonian to Kimmeridgian interval (Vollset & Doré 1984). The base of the Heather Formation is diachronous due to its

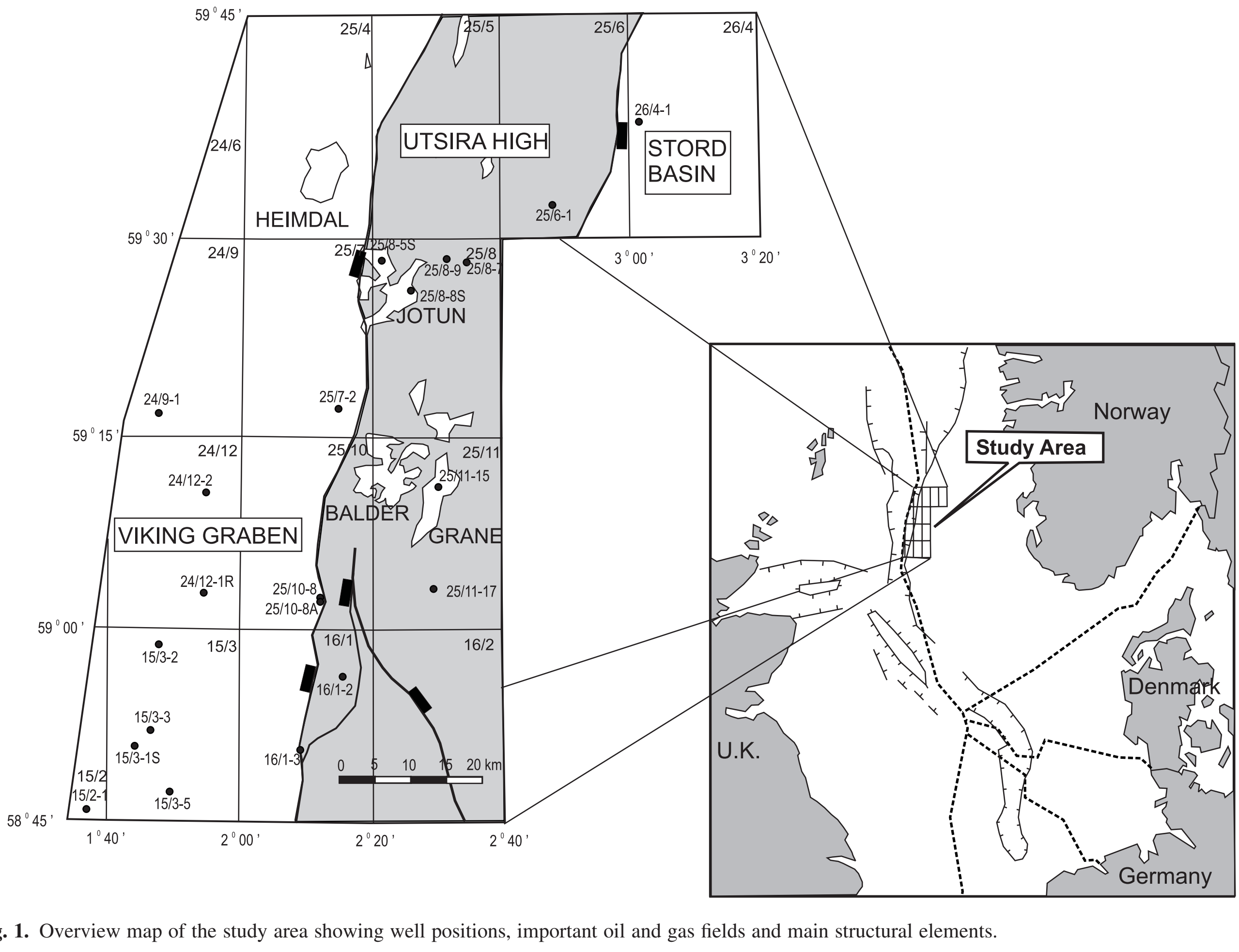

Fig. 1. Overview map of the study area showing well positions, important oil and gas fields and main structural elements.

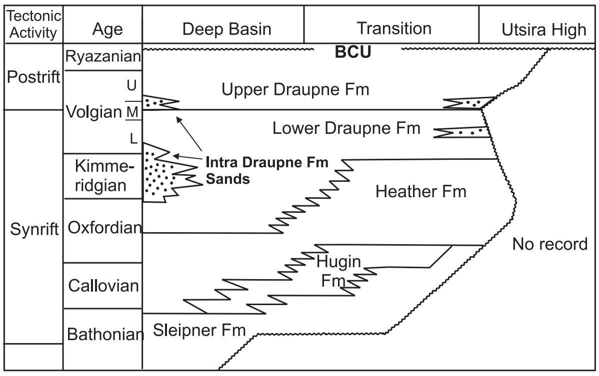

Fig. 2. Stratigraphic range and occurrence of the Draupne and Heather Formations in the study area altered from Cockings *et al.* (1992); Doré *et al.* (1985); Thomas *et al.* (1985). Both formations are of transgressive nature and have a diachronous base. The Draupne Formation can be subdivided into a lower part deposited during rifting and a younger postrift section. The Draupne Formation in the South Viking Graben contains a series of mass flow sands, here termed 'intra-Draupne' sands.

transgressive nature. The shales of the Heather Formation show average TOC values of 3 wt% and consist of kerogen Type III/IV with minor contributions of Type II (Cooper *et al.* 1995).

The Heather Formation is diachronously overlain by the Oxfordian to Ryazanian Kimmeridge Clay Equivalent/Draupne Formation (Vollset & Doré 1984). The Late Oxfordian was characterized by a transgressive phase, which marked the transition from the Heather to the Draupne Formation (Rawson & Riley 1982). The lower section of the Draupne Formation was deposited during rifting while the uppermost section represents postrift sediments (Fig. 2). The average thickness of the Kimmeridge Clay Equivalent in the study area is about 150 m, but it can exceed 1200 m in the graben centre. Average TOC values in the study area reach 4 wt%.

Various studies have been published, proposing depositional models for the Kimmeridge Clay Formation Equivalent (Hallam & Bradshaw 1979; Tyson *et al.* 1979; Demaison & Moore 1980; Parrish & Curtis 1982; Oschmann 1988; Miller 1990), including climatically and topographically controlled models. The overall impression of the Kimmeridge Clay depositional environment is that of a shallow sea with water depths up to 200 m, high bioproduction in the photic zone and anoxic bottom waters conditions (Cornford 1998). Oxygenation and mixing may have occurred occasionally (Wignall 1989), but the area was effectively cut off from the Tethys to the south and exchange of water with the Boreal Sea to the North was limited (Cornford 1998). In the South Viking Graben the Draupne Formation contains a series of basinward thinning and fining sandy wedges of Kimmeridgian to Volgian age (Partington *et al.* 1993; Sneider *et al.* 1995; Underhill 1998; Isaksen & Ledje 2001; Fraser *et al.* 2003). These 'intra-Draupne' sands are interpreted as proximal deep-water slope-apron complexes sourced from the Utsira High and the East Shetland Platform (Underhill 1998). These sands, which form important reservoirs in the South Viking Graben, interfinger with the shales of the Draupne Formation (Underhill 1998) and contain higher amounts of terrestrial reworked organic matter (Isaksen & Ledje 2001). According to Fraser *et al.* (2003) the deep water fan systems became more abundant as rifting intensified in the Kimmeridgian, were very abundant in Kimmeridgian to Mid-Volgian times, decreased in abundance in the Mid-Volgian together with calming rifting activity and were absent in the tectonically quiescent period from Mid-Volgian to Ryazanian. The mass flows in the study area are confined to the western half (Blocks 15/2, 15/3 and 24/12) and to Block 25/7 (Fraser *et al.* 2003).

The kerogen of the Kimmeridge Clay of the North Sea is typically a mixture of algal debris of marine planktonic origin and degraded humic matter of terrigeneous origin (Cornford 1998), but lateral and vertical variations are very common (Barnard & Cooper 1981; Huc *et al.* 1985; Cooper *et al.* 1995), especially in the narrow South Viking Graben with fringing land areas supplying terrestrial organic matter. The terrestrial contribution decreases from the lower to the upper part of the Draupne Formation (Huc *et al.* 1985) as a result of the transgressive trend in the Upper Jurassic and increasing marine influence. The land areas fringing the sea were probably rich in land plants, which contributed the land-derived organic matter (Cornford 1998). The richest source rocks probably accumulated in the deepest parts of the basin (Hallam & Bradshaw 1979; Wignall 1989; Miller 1990; Cornford 1998) where permanently restricted circulation dominated and processes leading to oxygenation and overturn had limited influence. Although sparsely drilled, basinal sections are generally considered to be richer in organic matter and to contain a higher amount of oil-prone material, while the marginal areas or intrabasinal highs are generally thought to show high terrestrial input with lower oil potential (Thomas *et al.* 1985; Kubala *et al.* 2003). This model is challenged based on the Balder area data discussed below.

In this study, the Draupne Formation was subdivided into syn- and post-rift sections. The identification of syn- and post-rift sections is not trivial (Gabrielsen *et al.* 2001) and has been discussed by several authors (Rawson & Riley 1982; Rattey & Hayward 1993; Gabrielsen *et al.* 2001; Fraser *et al.* 2003). Rattey & Hayward (1993) suggested cessation of rifting activity in the earliest Portlandian (Middle Volgian). Fraser *et al.* (2003) also suggest calming tectonic activity in the area from Mid-Volgian on. This interpretation was adapted for this study and the Ti4 maximum flooding surface after Jacquin *et al.* (1998) was chosen as the boundary between Upper and Lower Draupne Formation. This equals the base of the J70 sequence of Rattey & Hayward (1993) and the base of genetic sequence D of Fraser *et al.* (2003). The subdivision was based on sequence and biostratigraphic data for 17 wells provided by Esso Norway, while the remaining two wells, 15/3-2 and 24/9-1, lacked this information and were subdivided using well-log data. Very high gamma ray values were considered typical for the Upper Draupne Formation. Another indicator is the uniform pattern of high gamma ray values in contrast to the Lower Draupne Formation, which shows lower gamma ray values and more sandy intervals with a blocky pattern of gamma ray response. As mentioned above, the synrift section contains sandy mass flows, while the postrift section contains only a few such flows in the lowermost part.

Source rock mapping

Database

The source rock mapping is based upon Rock-Eval analysis of 774 samples from 21 wells in the Norwegian Quadrants 15, 16, 24, 25 and 26. In addition to this information, data from 139 GC-GCMS analyses and vitrinite reflectance depth plots of a total of nine wells were available. The samples from wells 15/3-3, 15/3-5 and 16/1-2 were analysed at the University of Bergen, while for other raw, analytical data were provided by Esso Norway and were mainly produced by Geolab Norway.

Source rock potential reconstruction

In order to perform source rock potential mapping, it is necessary to restore the original (prematuration) source rock properties. Several methods exist to reconstruct source rock potential (e.g. Cooles *et al.* 1986; Espitalié *et al.* 1987; Pepper 1991). In this study the method described by Espitalié *et al.* (1987) and the petroleum geochemistry interpretation software PEGIS were used. The first step is the determination of the transformation ratio, which indicates the degree to which the kerogen has converted to hydrocarbons at a particular depth. In addition to a depth plot of Hydrogen Index as used by Espitalié *et al.* (1987), plots of Production Index and S1/TOC*100 were used to determine onset of hydrocarbon generation, depth of peak oil generation and the Transformation Ratio (Fig. 3). S1/TOC*100 replaces the traditional EOM/TOC ratio and is here referred to as the Bitumen Index, BI. The Hydrogen Index in the immature section should be around a constant value for a given kerogen type and will start to decrease as a result of hydrocarbon generation at the entry of the oil window. The Production Index should be at very low levels (e.g. <0.05) in the immature section and will start to increase as the kerogen enters the oil window. The Bitumen Index should also increase from constant low levels, reach maximum values at peak oil generation and then decrease again.

To set up generation curves over the whole maturity range requires that the samples ideally have the same organic petrographic composition, as the generation depends strongly on the type of kerogen (Tissot & Welte 1984). The data set, however, exhibits a huge variation in organic matter. Therefore the data set was filtered and only the range from TOC 2% to 7% was used to set up the generation curves, as it was anticipated that narrowing the TOC range would narrow the type of organic matter. It was however not possible to test this assertion due to a lack of organic petrographic data. Trend lines for the Hydrogen, Bitumen and Production Indices were then subsequently set up (Fig. 3).

The Hydrogen Index depth plot was used to set up the Transformation Ratio for the area. Due to the large spread in values between 2000 and 2800 m, average values for 50 m increments were calculated and the original Hydrogen Index HI^0 was determined as the highest of the average values. Unfortunately the data set showed a large gap (absent values) in the range from 2800 to 3700 m. Between 3700 and 4900 m the trendline was best characterized by an envelope. The onset of generation was determined using the Bitumen Index depth plot. However due to the gap between 2800 and 3700 m, vitrinite reflectance (R_o) data were used as a secondary method to determine the entry into the oil window. It is important to note that vitrinite reflectance refers to thermal maturation, not hydrocarbon generation, and is here only used as an indirect indicator for the entry into the oil window. In addition, the onset of thermal maturity is also strongly dependent on the kerogen type. In this study, only one R_o value was used for the onset of bulk hydrocarbon generation.

The R_o value of 0.6% was chosen as the onset of generation (Isaksen & Ledje 2001) and an average depth of 3500 m was determined. This is close to the oil window at 3400 m proposed by Isaksen & Ledje (2001) and at 3340 m by Baird (1986) for the same area of the North Sea.

The initial Hydrogen Index, HI^0, and the individual Hydrogen Indices, HI^d, at depth were then measured and used to calculate the transformation ratio for different depths using Equation (1), modified from Espitalié *et al.* (1987). The decrease in TOC during maturation is quantified by introducing the factor α. The lost TOC can be derived from the lost S2 by multiplication with α. The α factor is the weight fraction of carbon atoms relative to carbon and hydrogen in the bulk generated hydrocarbons, multiplied by 0.1 as S2 is reported in ‰ and TOC in %. In this study an α value of 0.086 was chosen, based on the assumption that the typical hydrocarbon product has the gross composition $CH_{1.95}$. Although α will change during kerogen maturation, it was used as a constant in the present study for simplicity.

$$T_r = \frac{\frac{1}{\alpha}\times 100 \times (HI^0 - HI^d)}{HI^0 \times \left(\frac{1}{\alpha}\times 100 - HI^d\right)}. \tag{1}$$

The transformation ratio can then be used to recalculate the original $S2^0$ and TOC^0 values in Equation (2) and (3).

$$S2^0 = \frac{S2}{1 - T_r} \tag{2}$$

$$TOC^0 = TOC + \frac{S2 \times T_r}{1 - T_r} \times \alpha \tag{3}$$

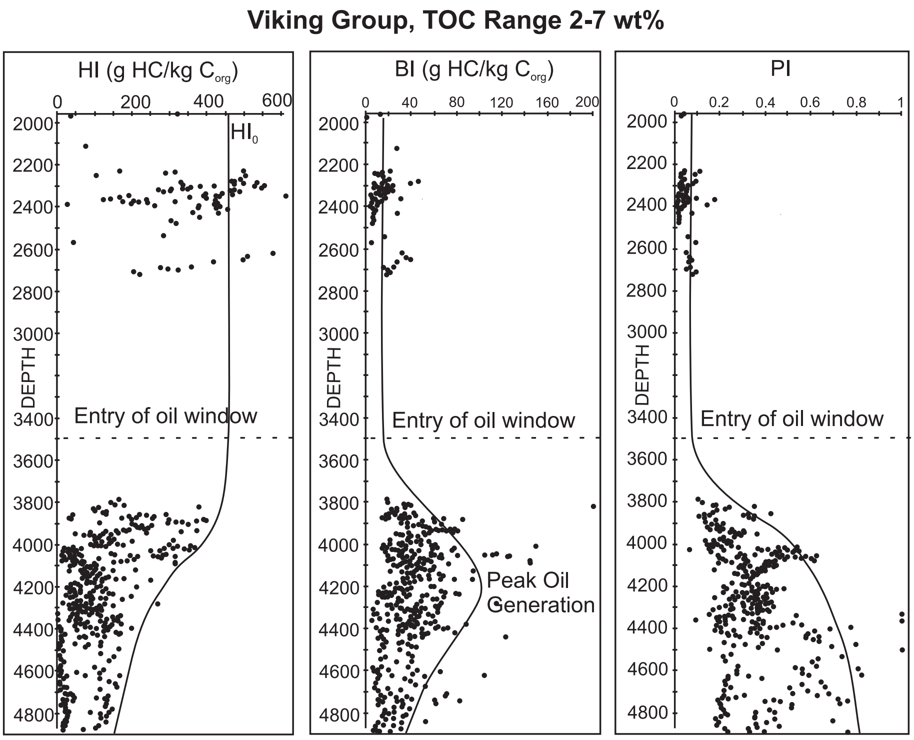

Fig. 3. Plots of Hydrogen Index (HI), Bitumen Index (BI) and Production Index (PI) used to determine the Transformation Ratio. A total of 499 samples were used. The entry into the oil window is situated at a depth of around 3500 m.

Determination of oil and gas potential

Various methods exist to assess the oil and gas potential of a source-rock horizon including pyrolysis–gas chromatography (Pepper & Corvi 1995) and visual kerogen description. In this study the oil and gas potential were determined using the method of Dahl *et al.* (2003), which is convenient as it is based on commonly available Rock-Eval screening results. The method is based on the assumption that the pyrolyzable fraction of the kerogen, the S2 peak from Rock-Eval, can be subdivided into two kerogen end members with fixed initial Hydrogen Indices, representing the oil and gas producing portion of the kerogen. The method does not determine the fractions for gas and oil potential of individual samples, but instead determines an average value for a suite of samples. This approach uses Rock-Eval and TOC data in a simple S2-TOC cross-plot to determine the oil and gas potential of a specific source rock section. The maturity-corrected Rock-Eval data are plotted in a S2-TOC plot and a linear regression line is established through the sample population. The regression line can be expressed as:

$$TOC = a \times S2 + b. \tag{4}$$

If the regression line intersects the origin, the value for b is zero and a can be expressed in Equation (5) as:

$$a = \frac{TOC}{S2} = \frac{100}{HI} \quad \text{with} \quad HI = \frac{100 \times S2}{TOC}. \tag{5}$$

The slope a of the regression line thus represents the average hydrogen index of the sample population. Often, the regression line does not intersect the origin and the intersection with the TOC-axis represents the 'dead' organic carbon (Cornford 1998). In cases where the regression line does not intersect the origin, the mean Hydrogen Index is different from the arithmetic mean of the Hydrogen Indices calculated from all the samples of the population. This 'dead' organic carbon (TOC IV) can be subtracted from the average restored TOC of the sample population to obtain the 'active' TOC. The 'active', restored Hydrogen Index can be calculated using Equation (6):

$$HI(live) = \frac{100 \times S2}{TOC(\text{average, restored}) - TOCIV}. \tag{6}$$

In a marine-dominated system the kerogen can be regarded as a mixture of the two end members, kerogen Type-II and kerogen Type-III. The active Hydrogen Index can therefore be expressed in Equation (7) as:

$$HI(live) = HI(II) \times m + HI(III) \times n. \tag{7}$$

Where *HI*(*II*) is the oil-prone end member Hydrogen Index value, *HI*(*III*) the gas-prone end member Hydrogen Index value and '*m*' and '*n*' are the fractions of oil-prone Type II and gas-prone Type III kerogen respectively.

This relationship can be used to deduce the kerogen composition and to determine the amount of oil and gas generating components (Dahl *et al.* 2003). HI values for both end members have to be determined. In this study the chosen values are 700 kg HC/t C_{org} for Type-II and 150 kg HC/t C_{org} for Type-III kerogen. These values truly represent end members in the study data set as almost all sample values lie within these boundaries. Using the end members mentioned above, an overlay transparency can be generated, as shown in Figure 4. The lines represent different kerogen 'mixtures' of the two end members. This overlay can be used together with the TOC-S2 plot and the regression line to estimate the gross kerogen composition. The regression line and the overlay lines are compared and the average composition of the kerogen in the analysed section

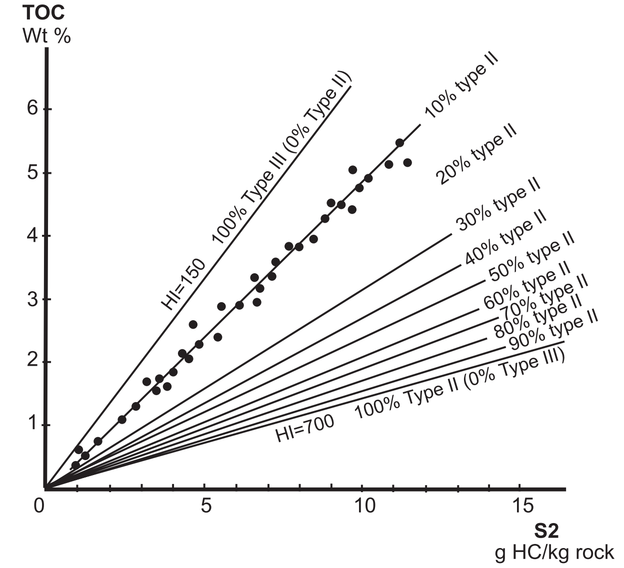

Fig. 4. Sketch of a TOC-S2 plot (containing constructed data) with overlay to determine the contribution of kerogen type II and III. The slope of the regression line through the sample population represents the average HI for immature kerogens. Based on the assumption that the kerogen is a mixture of two end member kerogens with fixed HI (150 kg HC/t C_{org} for Type III and 700 kg HC/t C_{org} for Type II), an overlay such as that displayed is used to determine the contribution of the end members. The example shown is a mixture of 10% Type II and 90% Type III.

can be read from the overlay. Figure 5 shows the TOC-S2 plot for the Lower Draupne Formation of Well 16/1-2 as an example. Based on the proportion of oil and gas generating constituents from the plot, the 'active' TOC can be split up in the same proportions into an oil-prone TOC (TOCII) and into gas-prone TOC (TOCIII). The direct hydrocarbon potential, S2, for the respective oil and gas fraction can be calculated using Equation (8) and (9).

$$S2(\text{oil}) = TOCII \times HI(II) \times \frac{1}{100} \tag{8}$$

$$S2(\text{gas}) = TOCIII \times HI(III) \times \frac{1}{100}. \tag{9}$$

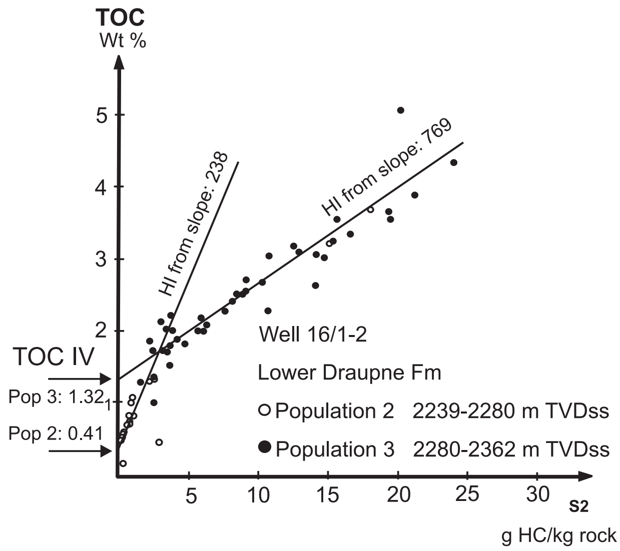

Fig. 5. TOC-S2 plot showing the data for the Lower Draupne Formation of Well 16/1-2. Two populations can be determined: Population '2' with an average Hydrogen Index of 238 kg HC/t C_{org} and population '3' with 769 kg HC/t C_{org}.

This procedure was conducted using the petroleum geochemistry interpretation software PEGIS. Every sample population identified within one formation was treated separately, and average values were then calculated for each formation. Based on these values, quantitative maps of the oil and gas potential were hand contoured (Figs 6 and 7).

Summary and discussion of the mapping results

Total organic carbon. The highest TOC for Upper and Lower Draupne Formation is encountered in Block 25/7, the deep graben area, and on the Utsira High in Block 25/6 and its flank in Block 26/4. The TOC values decrease in the graben from West to East.

As discussed above, the overall TOC, as well as the oil and gas-prone TOC for Upper and Lower Draupne Formation, are strongly related to depositional environment, sea floor topography, preservation of organic matter in the sediment and the mode of deposition in the area.

Block 25/7 and the deep graben area are dominated by mass-flow sands (Fraser *et al.* 2003) which supplied high amounts of organic matter (Barnard & Cooper 1981; Cooper *et al.* 1995; Isaksen & Ledje 2001). The deepest graben also had the largest synsedimentary subsidence, and most probably the greatest water depth, at the time of deposition. In these topographic palaeo-lows, sediment and hence organic matter preservation was highest. The hydraulic energy level generally decreased towards lows, and low-density organic particles were winnowed and concentrated to these deep, more quiescent areas (Huc 1988). In addition to the concentration process, the preservation of organic matter in the deepest areas was also probably enhanced as anoxic water conditions are best developed in depressions with stagnant water (Cooper & Barnard 1984), where the processes leading to oxygenation and mixing are limited. Our corrected TOC data confirm the previous assertions, i.e. that the deeper areas show the highest overall TOC values (Hallam & Bradshaw 1979; Wignall 1989; Miller 1990; Cornford 1998). This trend is shown by Kubala *et al.* (2003) as being of regional extent once their TOC values have been corrected for maturity effects.

After Ibach (1982), TOC values increase with sedimentation rate due to faster movement through the zone of organic degradation. With an optimum sedimentation rate, dilution overrides the gain in organic matter preservation and reduction in organic matter concentration will occur. This basic principle applies to the sands, which were deposited very rapidly in mass flow events. In addition to dilution, the organic matter will have been strongly mechanically reworked and oxidized in the sand zones and therefore will have been of limited importance for oil generation. However, these rapid events cover the shale units deposited as the shale background sedimentation and remove them from the effects of oxygenation and bioturbation. The shale units are isolated by the sands and therefore the organic matter is better preserved.

The processes explained above cannot account for the unusually high values in the Upper Draupne Formation of Block 25/6 and 26/4. The high values could probably be explained by enhanced preservation in a local pool-like area with stagnant water, formed by flooding of an irregular topography of the Utsira High during transgression beginning in the Mid-Volgian.

Dead organic carbon. Mapping of dead organic carbon in Upper and Lower Draupne Formation (not shown) also reflects the influence of mass flows and the input of terrestrial reworked organic matter, as the highest values are encountered in the blocks 15/2, 15/3, 24/12, as well as in Well 25/7-2, which received mass flows from the East Shetland Platform and Utsira High to the West. These observations are supported by Barnard & Cooper (1981); Thomas *et al.* (1985); Cooper *et al.* (1995).

Oil- and gas-prone organic matter. The content of oil- and gas-prone organic matter of the Upper Draupne Formation differs significantly from the Lower Draupne Formation and varies a great deal laterally in the study area. The Upper Draupne Formation has equally high overall oil and gas potential. The oil-prone TOC in the Upper Draupne Formation increases from the graben areas towards the Utsira High in a northeasterly direction (Fig. 6a). High values are encountered in Well 25/7-2 which received deep marine sands from the Utsira High. Exceptionally high oil potential is encountered in blocks 25/6 and 26/4. This is in disagreement with the common assumption that the best source rock is located in the deep basin and oil potential decreases towards and on to the highs. The high oil potential in the Upper Draupne Formation on the Utsira High can be explained by enhanced preservation in local pools, which originated from the flooding of the Utsira High during the transgression beginning in the Mid-Volgian. The gas-prone TOC is highest in the western half of the study area and decreases towards the Utsira High (Fig. 7a) in the Upper Draupne Formation.

The Lower Draupne Formation consists of a mixture of Type-III land-derived material and Type-II marine organic matter with higher input from land by mass flow processes, compared to the Upper Draupne Formation. The oil-prone organic matter is less abundant, with values below 1 wt%, than the gas-prone material for the greater part of the study area in the Lower Draupne Formation (Fig. 6b). The western half of the study area shows values over 3 wt% gas-prone TOC which decrease towards the Utsira High (Fig. 7b).

The differences in oil and gas potential between the Upper and Lower Draupne Formations result from a significant change of environment. The distribution of oil and gas potential reflects of the varying degree of dilution of marine oil-prone material with terrestrial, gas-prone material. This is based on the assumption that the marine background sedimentation was constant and that mass flows were a major contributor of terrestrial organic matter. The Lower Draupne Formation was, as discussed earlier, deposited during active tectonism in a restricted marine environment with considerable terrestrial input by mass flows. After cessation of rifting, more open marine conditions were established, the area was drowned and covered with euxinic mud (Rattey & Hayward 1993) and terrestrial input by mass flows decreased (Fraser *et al.* 2003). The latter was probably a result of the cessation of rifting. The higher gas potential of the Lower Draupne Formation can be explained by the dilution of the marine material by terrestrial material transported by mass flows from the surrounding highs.

Alternatively the variations in organic matter quantity and quality could be explained using a depositional model with a uniformly high amount of land-derived organic matter and differential preservation. Favoured preservation of inertinite and vitrinite occurs in oxygenated environments of margins and highs (Cooper & Barnard 1984). This however does not fully explain the richness in gas-prone and dead organic matter in the deeper parts of the basin.

The database for the Heather Formation is quite limited, therefore only generalized trends are observed and no map is warranted here. The Heather Formation also shows considerable potential for oil and gas generation. However, the gas potential is much higher, with values of up to 5.57 wt% gas-prone TOC in Block 15/3 than the oil potential with values below 1 wt% in the graben area.

Vertical organofacies variations

In order to understand vertical changes in distribution of kerogen types and source rock quality, the variation of selected biomarker parameters was investigated. The Pr/Ph ratio and Homohopane Index as indicators for oxidizing and reducing conditions, and the C_{27}–C_{29} regular and diasteranes as indicators for marine vs terrestrial input (for all ratios see Appendix 1) were studied together with the Rock-Eval data and some organic petrographic data.

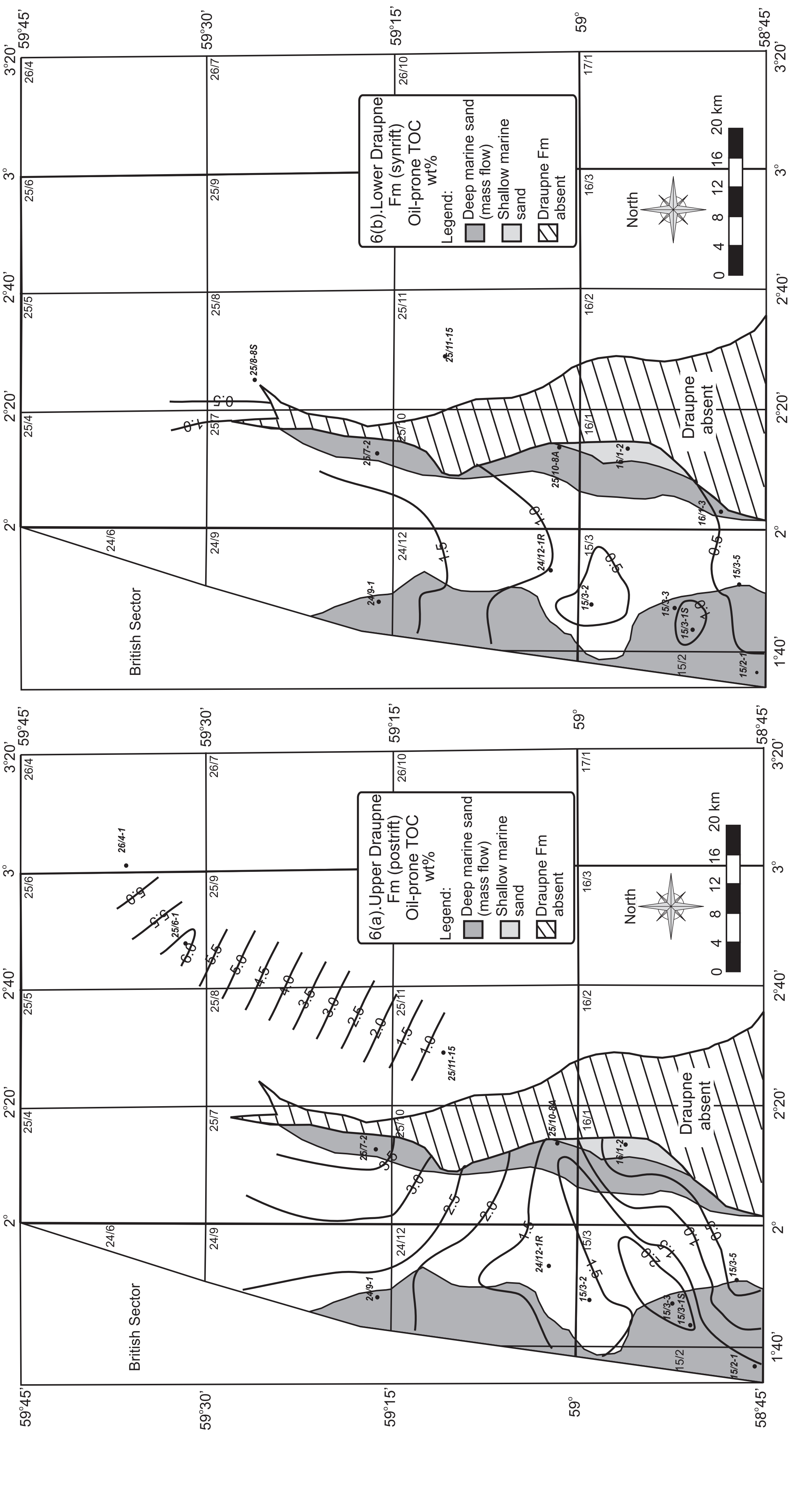

Fig. 6. **(a)** Upper Draupne Formation oil-prone TOC map. **(b)** Lower Draupne Formation oil-prone TOC map. The wells used for the mapping are marked. The extent of deep marine sands and the area where the Draupne Formation is not present (after Isaksen & Ledje 2001) is a generalization and applies to the Draupne Formation as a whole. No differentiation could be made between Upper and Lower Draupne Formations.

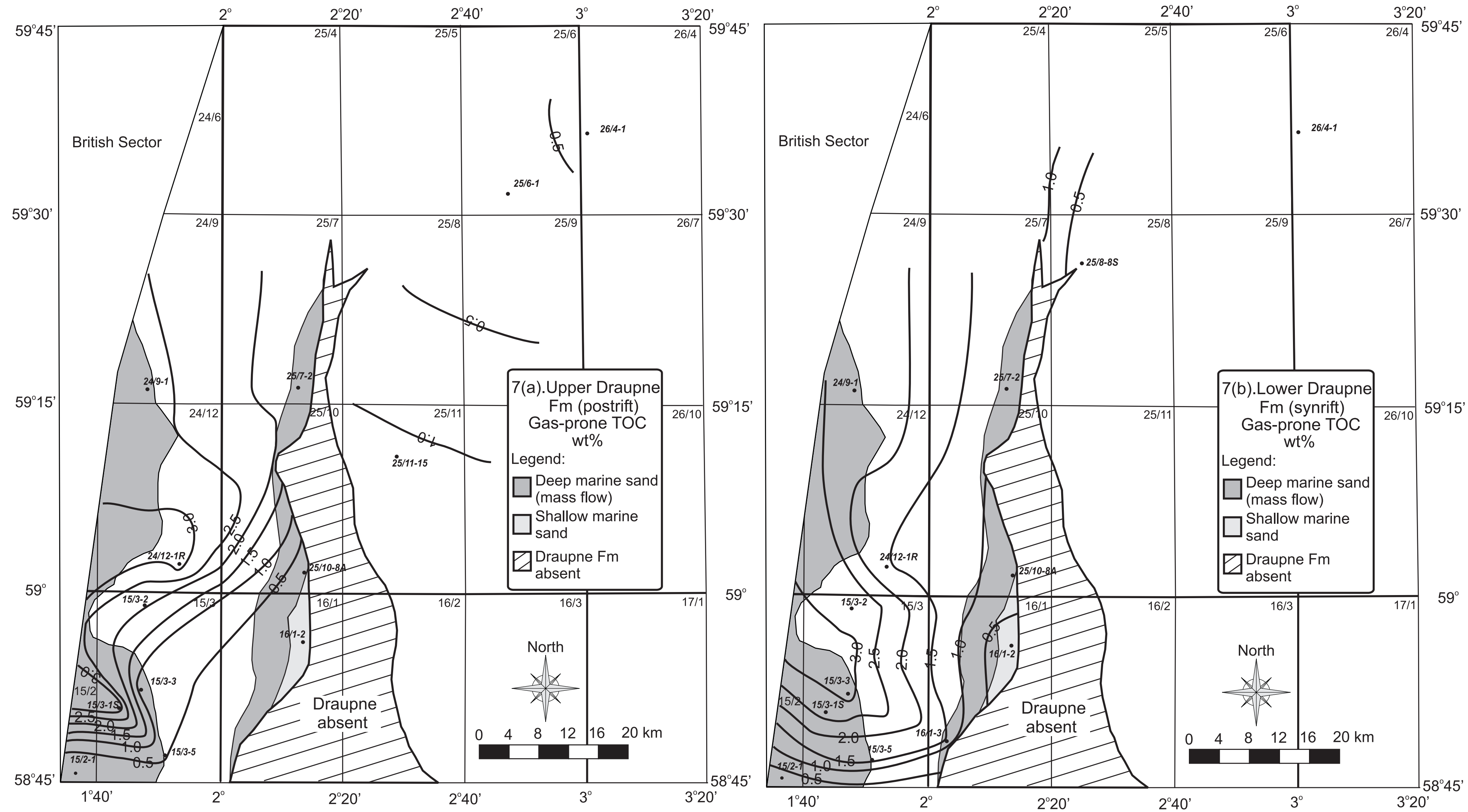

Fig. 7. (**a**) Upper Draupne Formation gas-prone TOC map. (**b**) Lower Draupne Formation gas-prone TOC map. The wells used for the mapping are marked. The extent of deep marine sands and the area where the Draupne Formation is not present (after Isaksen & Ledje 2001) is a generalization and applies to the Draupne Formation as a whole. No differentiation could be made between Upper and Lower Draupne Formations.

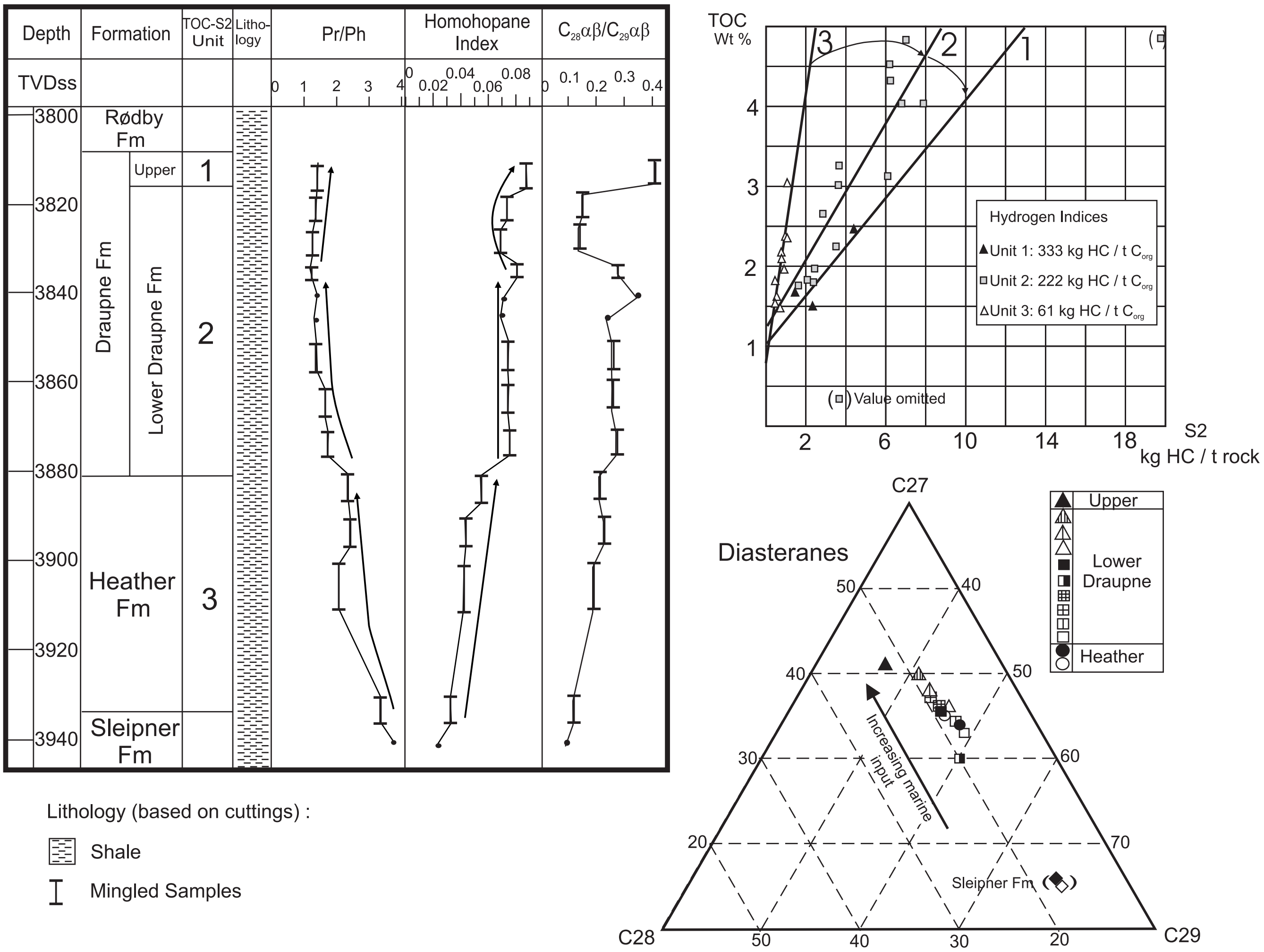

Fig. 8. Biomarker variation of Well 15/3-5 and TOC-S2 plot (maturity corrected). The TOC-S2 plot shows that the average Hydrogen Index increases upwards from unit 3, the Heather Formation to Unit 1, the Upper Draupne Formation. Decrease of Pr/Ph ratio and increase of Homohopane Index indicate upward increase of anoxia. The abundance of the C_{27} diasteranes (triangular plot) increases upwards, indicating a shift towards a more marine dominated organic input independent of anoxia.

Evaluation of the vertical changes in the Upper Jurassic section in the Greater Balder Area showed that there is a great deal of variation, one typical example being Well 15/3-5 (Fig. 8).

The general observation in the study area is a Hydrogen Index increase upwards from the Heather Formation to the Upper Draupne Formation. This shift appears to be maturity-independent given the depth range of the analysed sections. This is visualized by the shift of the regression lines in the TOC-S2 plot from the upper left corner to the lower right corner (Fig. 8, inset). This general shift can be interpreted as an upward increase in Type II kerogen dominance and a shift towards a more marine environment. This shift can be observed in wells 24/9-1, 15/3-2, 26/4-1, 25/6-1, 25/10-8A and 15/3-5 (Fig. 8). A few kerogen typing results made available by Esso (not shown) support the fact that liptinite particles become more abundant upward and that the vitrinite content decreases. This general observation is also supported by the overall transgressive nature of the section (Rawson & Riley 1982; Haq *et al*. 1987). The development of a steady Hydrogen Index increase uphole with increasing marine dominance was also observed by other authors (Dahl & Speers 1985; Huc *et al*. 1985). Huc *et al*. (1985) studied the organofacies development of one well section in the Viking Graben, where they observed a Hydrogen Index increase from 200 in the Heather Formation to 600 kg HC/t C_{org} in the Draupne Formation. Dahl & Speers (1985) also observed vertical organofacies changes in the Upper Jurassic of the Oseberg area, from Hydrogen Index values of 300 kg HC/t C_{org} in the lower part of the Draupne Formation to 600 kg HC/t C_{org} in the upper part.

Five wells, four in the deep graben and one on the western flank of the Utsira High, do not show this simple upwards increase in marine influence: wells 15/2-1, 15/3-1S, 15/3-3, 25/7-2 and 24/12-1R. In these wells the general marine influence increases upwards, but there is a significant backshift to a more terrestrial influenced environment within the Upper Draupne Formation. This event could however not be correlated due to a lack of sequence stratigraphic data. One exception is Well 16/1-2 on the Utsira High, which even shows an increase in the terrestrial contribution upwards within the Draupne Formation.

The fact that this backshift occurs only in some wells may be due to the complex stratigraphic situation with missing and condensed sections and interfingering mass flows. In order to understand the complexity of organofacies variations in the study area, the geochemical data should have been interpreted in a sequence stratigraphic framework. This, however, was not feasible due to a lack of data. Wells 25/11-15, 25/8-9, 25/8-7, 16/1-3, 25/8-8S cover only one unit due to a lack of data.

Figure 9 shows a simple facies model for the study area based on the observations made and the average reconstructed Hydrogen Index. The model shows, in general, the upward increase in Type-II dominance for the basinal area. The deep basin, comprising blocks 15/2 and 15/3, also shows Type-III and -IV influence in the Upper and Lower Draupne Formation. Type-II kerogen on the flank of the Utsira High increases upwards. The analysis of each well section shows that this vertical change occurred at most locations in the basin. The same development is observed for the

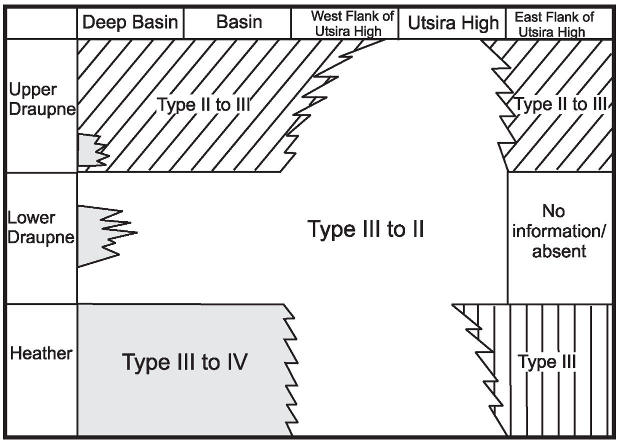

Fig. 9. Simplified organofacies model for the study area. The organofacies varies both vertically and horizontally. Type-II contribution increases upwards towards the part within Upper Draupne Formation. The influence of terrestrial and reworked organic matter is more dominant in the western part of the basin, decreases upwards and is related to the intra-Draupne Formation sands.

western (Well 25/10-8A) and eastern flank (e.g. Well 26/4-1) of the Utsira High. The Type-III content is higher in the Lower Draupne Formation in the western half of the study area, arguably due to the influence of the intra-Draupne Formation sands. Influence of terrestrial input on the western flank of the Utsira High seems to be less pronounced.

In general an overall decreasing Pr/Ph ratio and increasing Homohopane Indices indicate a general upward increase in anoxia for the area. In most of the wells, however, e.g. wells 15/2-1, 15/3-3, 15/3-5 15/3-1S, 24/9-1, the topmost section of the Upper Draupne Formation was deposited under less anoxic conditions. This suggests that the type of organic matter exerts a stronger control on the oil and gas potential than the oxygen levels. This was already presumed by Isaksen & Ledje (2001). Well 16/1-2 is again an exception with increasing Pr/Ph ratios upwards (Fig. 10).

The C_{27}–C_{29} regular and diasterane ratio was also used to assess the degree of terrestrial vs. marine input. Well 15/3-5 (Fig. 8) shows a steady increase in the dominance of the C_{27} diasteranes over the C_{29} diasteranes, indicating a shift towards a more marine environment with increasing depth. The rest of the data set, however, shows rather little variation in regular and diasterane ratio and indicates a mixed input.

Due to the mixed input of organic matter and the resulting large variation in the absolute values of the biomarker parameters, it is very difficult to identify special value regimes for the Pr/Ph ratio, Homohopane Index and C_{27}–C_{29} steranes valid for all wells used in source rock–oil correlation. However the general differences of the three analysed formations define the following trends for the biomarker ratios: The Heather Formation products have low Homohopane Indices, higher Pr/Ph ratios and a strong terrestrial sterane signal, while the extracts of the Lower Draupne Formation have lower Pr/Ph ratios, higher Homohopane Indices and a more marine sterane signature. Highest marine input is typical for the Upper Draupne Formation, which also has the lowest Pr/Ph ratio and the highest Homohopane Index.

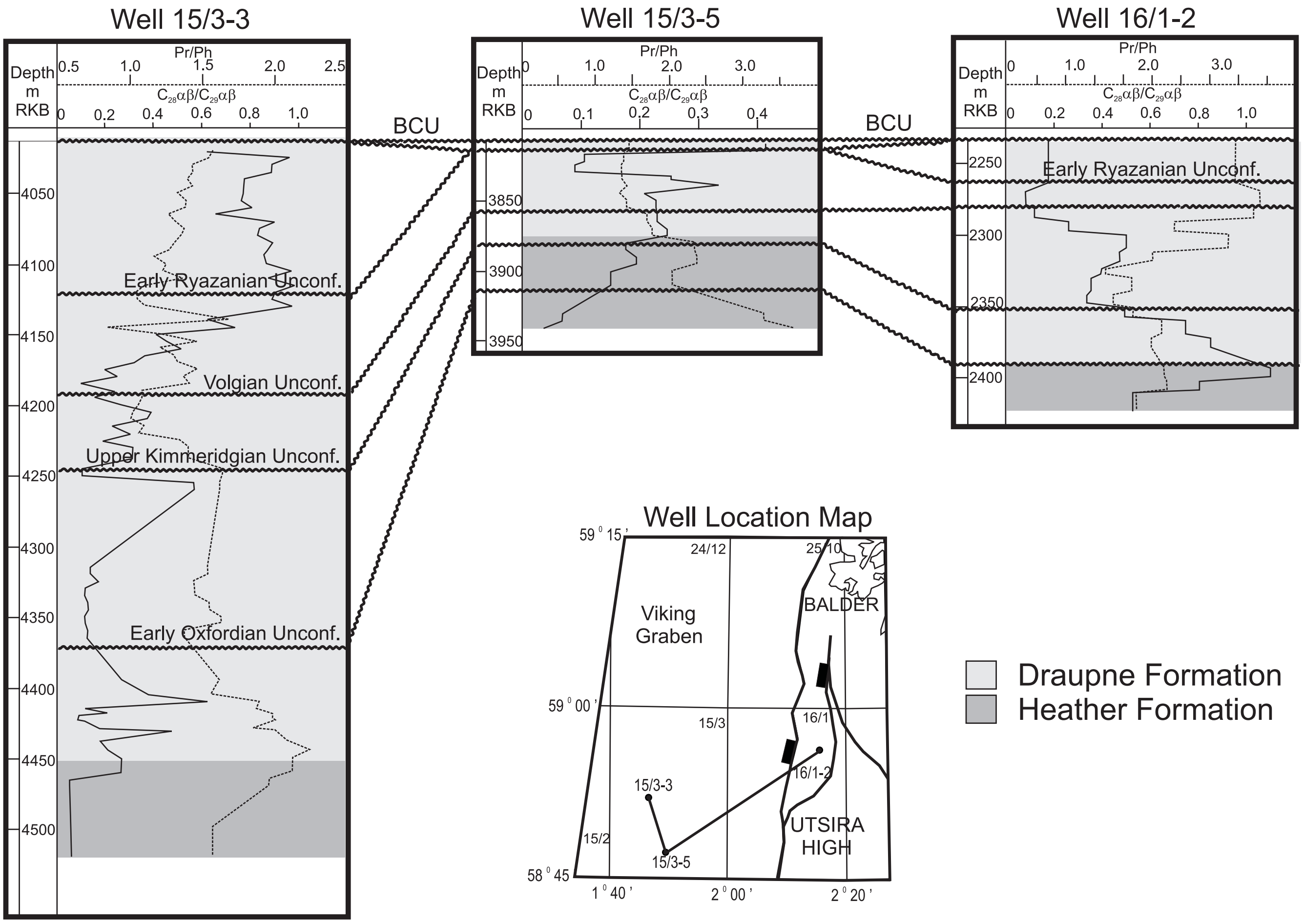

Fig. 10. Depth plots of the $C_{28}\alpha\beta/C_{29}\alpha\beta$ and the Pr/Ph ratio for the wells 15/3-3, 15/3-5 and 16/1-2. The $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratio cannot be used as stratigraphic marker in the area as the ratio does not change synchronously. Comparison of the $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratio with the Pr/Ph ratio, however, suggests dependency on depositional environment. Decreasing Pr/Ph ratios, indicating increase in anoxia, are accompanied by increasing $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratios and vice versa.

The Upper Draupne Formation is the most oil-prone section and products expelled from this formation will dominate over products expelled from Lower Draupne and Heather Formation. However, on maturity grounds, the earliest hydrocarbon products of the analysed section will derive from the Heather Formation, provided it is rich enough (>2 kg/t) to expel hydrocarbons. With ongoing subsidence and thermal maturation of the section, they will be diluted by products from the Lower Draupne and finally Upper Draupne Formation. Further investigation using quantitative biomarker measurements expressed as ng biomarker/g of extract and evaluation of expulsion efficiencies are necessary to deconvolve the impact of the three different sections.

Significance of bisnorhopane in the Upper Jurassic Section

Following the study in the Oseberg Area by Dahl (1987), it was attempted to test whether the vertical profiles of the ratio of $C_{28}\alpha\beta/C_{29}\alpha\beta$ hopanes (17α(H),21β(H)-28,30-bisnorhopane versus 17α(H),21β(H)-30-norhopane) could be correlated in a similar manner in the Greater Balder Area. Dahl (1987) studied a stratigraphically fairly complete Viking Group in the Oseberg Area and observed low values in the topmost section followed by high values (up to 10) between Early Ryazanian and Late Kimmeridgian.

The correlation of the three analysed sections (Fig. 10) shows that there is a general decrease in the $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratio downwards in wells 15/3-3 and 15/3-5, while values increase downwards in Well 16/1-2. The change in wells 15/3-3 and 15/3-5 does not occur synchronously. In contrast to the high values of up to 10, observed by Dahl (1987), the maximum values in the Grater Balder Area are around 1. Comparison of the Upper Jurassic section in the Southern Viking Graben is, however, complicated by the incompleteness and condensation of the section (Fig. 10). In addition, there is a considerable difference in sediment thickness. Based on results from these three wells it seems that the use of the $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratio as a stratigraphic marker, as demonstrated by Dahl (1987) in the Oseberg area, may be difficult in the Southern Viking Graben. In detail, what Dahl (1987) observed in the Northern Viking Graben may not apply to time equivalent sections in the study area. The fundamental differences between the basinal wells and the well on the high, however, suggest that the ratio is dependent on the environment. This is substantiated by comparison with the Pr/Ph ratio. Figure 10 shows that the $C_{28}\alpha\beta/C_{29}\alpha\beta$ and the Pr/Ph ratio for the three analysed wells co-vary. Decreasing Pr/Ph ratios, indicating increasing degree of anoxia, are accompanied by increasing $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratios and vice versa.

Conclusions

(1) Methods for correcting measured TOC and Hydrogen Index to their original prematuration values were reviewed and applied to 21 wells in the Greater Balder Area, Viking Graben. In addition, a method for determination of the oil and gas potential, summarized herein, was applied to the Upper Jurassic source rocks of the same wells.

(2) The total restored TOC content distribution in the area appears to be strongly related to the preservation of organic matter in the sediment, itself a function of depositional environment, sea floor topography, anoxia and the dilution of marine by terrestrial organic matter by input via mass flows.

(3) The postrift Upper Draupne Formation of Mid Volgian to Ryazanian age has high potential for oil and gas, while the Oxfordian to Mid Volgian Lower Draupne Formation mostly exhibits gas potential.

(4) The distribution of oil and gas potential is a function of the varying degree of dilution of marine oil-prone organic matter with terrestrial gas-prone material.

(5) Exceptionally high oil potential is encountered on the flank of the Stord Basin, on the Utsira High and in Block 25/7. High-quality source rocks were not only deposited in the deep basin, but also during transgression on the Utsira High and its flanks during deposition of the Upper Draupne Formation.

(6) The distribution of TOC IV in the entire section reflects the influence of mass flows.

(7) The general observation in the study area is a Hydrogen Index increase upwards from the Heather Formation to the Upper Draupne Formation, independent of maturity. This increase is the result of an upward increase in Type-II kerogen and a shift from a more terrestrial towards a more marine kerogen source, but all within a marine depositional environment

(8) An increase in Pr/Ph ratio in the Upper Draupne Formation suggests that the type of organic matter exerts stronger control on the oil and gas potential than the degree of anoxia.

(9) Large variation of the absolute values of the selected biomarker ratios complicate the identification of special value regimes for the Pr/Ph ratio, Homohopane Index and $C_{27}-C_{29}$ regular and diasteranes that are valid for all wells. However, the general differences of the three analysed formations allow some general assumptions on the molecular content of HC products to be made from the analysed section.

(10) An attempt to use the $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratio as a stratigraphic marker within the Upper Jurassic in the Grater Balder Area failed. Results from the Greater Balder Area suggest the $C_{28}\alpha\beta/C_{29}\alpha\beta$ ratio is related to the environment of deposition.

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Appendix 1. Used biomarker ratios

Pristane/Phytane Ratio (Pr/Ph): This ratio is used as an indicator for the depositional environment. Pr/Ph ratios less than unity indicate anoxic deposition/marine origin, whereas oxic conditions and land plant input are indicated by ratios >1 (Brooks *et al.* 1969).

C_{35} Homohopane Index: This index is used as indicator for the redox potential of marine sediments during diagenesis (Peters & Moldowan 1993). The ratio is given as a percentage, and high C_{35} values indicate a highly reducing environment during deposition (Peters & Moldowan 1993).

$$\frac{C_{35}\,\text{homohopane s}}{C_{31}-C_{35}\,\text{homohopane s}}$$

C_{27}:C_{28}:C_{29} Regular Steranes: The C_{27}, C_{28}, C_{29} steranes are the fossil precursor molecules of C_{27} to C_{29} sterols (Peters & Moldowan 1993) and are valuable for the interpretation of the depositional environment. C_{27} sterols dominate in marine plankton and invertebrates, whereas C_{29} sterols are predominant in higher plants and animals (Huang & Meinschein 1976). The $C_{27}-C_{29}$ steranes are therefore used to determine the input of marine versus terrestrial organic matter. The $C_{27}-C_{29}$ steranes were identified in the *m*/*z* 218 fragmentograms.

Value for the C27 corner of the triangular plot:

$$\frac{27\beta\beta R+27\beta\beta S}{27\beta\beta R+27\beta\beta S+28\beta\beta R+28\beta\beta S+29\beta\beta S+29\beta\beta R}$$

The C_{28} and C_{29} values are calculated in an analogous fashion.

C_{27}:C_{28}:C_{29} Diasteranes: The C_{27}, C_{28}, C_{29} diasterane relation is used in an analogous way to the normal C_{27}, C_{28}, C_{29} regular sterane ratios (Peters & Moldowan 1993).

Value for the C27 corner of the triangular plot :

$$\frac{27\mathrm{d}bR + 27\mathrm{d}bS}{27\mathrm{d}bR + 27\mathrm{d}bS + 28\mathrm{d}bR + 28\mathrm{d}bS + 29\mathrm{d}bS + 29\mathrm{d}bR}$$

The C_{28} and C_{29} values are calculated in an analogous fashion.

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