3D basin and petroleum system modelling of the NW German North Sea (Entenschnabel)

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Abstract: 3D basin and petroleum system modelling covering the NW German North Sea (Entenschnabel) was performed to reconstruct the thermal history, maturity and petroleum generation of three potential source rocks, namely the Namurian–Visean coals, the Lower Jurassic Posidonia Shale and the Upper Jurassic Hot Shale. Modelling results indicate that the NW study area did not experience the Late Jurassic heat flow peak of rifting as in the Central Graben. Therefore, two distinct heat flow histories are needed since the Late Jurassic to achieve a match between measured and calculated vitrinite reflection data. The Namurian–Visean source rocks entered the early oil window during the Late Carboniferous, and reached an overmature state in the Central Graben during the Late Jurassic. The oil-prone Posidonia Shale entered the main oil window in the Central Graben during the Late Jurassic. The deepest part of the Posidonia Shale reached the gas window in the Early Cretaceous, showing maximum transformation ratios of 97% at the present day. The Hot Shale source rock exhibits transformation ratios of up to 78% within the NW Entenschnabel and up to 20% within the Central Graben area. The existing gas field (A6-A) and oil shows in Chalk sediments of the Central Graben can be explained by our model.

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The German North Sea (Fig. 1) covers an area of around 35 000 km² and about 80 exploration wells have been drilled. The NW part of offshore Germany referred to as the Entenschnabel (Ducks’s beak) has a size of approximately 4000 km² and contains about 29 exploration wells (Fig. 1a). Despite numerous petroleum discoveries in the neighbouring offshore areas, only two commercial petroleum fields have been discovered in offshore Germany: the Mittelplate oil field and the A6-A gas field. The latter is the only commercial natural gas field discovered in the Entenschnabel area so far (Fig. 1a), despite the fact that the geological structures are continuous from the Dutch to the Danish offshore sectors. Using the results from a recent detailed mapping campaign in the Entenschnabel area (Arfai et al. 2014) that was based on high-quality 3D reflection seismic data, we studied the petroleum generation and migration from three potential source rock formations. We constructed a 3D basin model that covers the basin’s structural development from the Devonian until the present day to reconstruct key elements and processes important for evaluating the petroleum systems in the study area. These key factors include: (a) the basal heat flow history; (b) the maturation history of potential source rocks; and (c) the timing of hydrocarbon generation.

Geological setting

In Figure 2, the main tectonic events of the study area are summarized in relation to the stratigraphic succession of the Entenschnabel.

The Entenschnabel area is tectonically subdivided by several graben and structural highs. The three major structural elements are the Schillgrund High, the Central Graben and the Step Graben System. These major structural elements are internally characterized by a number of minor structural features such as the John Graben, Clemens Basin belonging to the Central Graben, and the Mads Graben, Outer Rough High and the Outer Rough Basin of the Step Graben System (Fig. 1b) (Arfai et al. 2014). Important phases of the geodynamic history of the study area include the Saalian phase of uplift and erosion, Early Triassic extension and subsidence, Mid- and Late Cimmerian erosion and rifting, and Sub-Hercynian inversion phases (Ziegler 1990; Evans et al. 2003; Doornenbal & Stevenson 2010). During the Early Carboniferous, NW Europe, including the North Sea region, was located in the foreland basin of the Variscan Orogen (Ziegler 1990; Doornenbal & Stevenson 2010). As a result of the Carboniferous–Early Permian collapse of the Variscan Orogen, regional thermal uplift and concomitant erosion dominated parts of the Upper Carboniferous and Lower Permian deposits (Saalian unconformity; the ages of these tectonic events are discussed below) (Krull 2005; Ziegler 2005; Kombrik et al. 2012). Regional uplift was followed by late Early Permian thermal relaxation and subsidence. During this transtensional phase, voluminous volcanics were emplaced, as well as continental siliciclastic red-bed series of the Rotliegend strata which were subsequently buried by carbonates and evaporites of the Zechstein Group (Ziegler 2005; Kley & Voigt 2008; Stollhofen et al. 2008; Ten Veen et al. 2012). In the early Mesozoic rifting initiated, and the Central Graben developed as a half-graben from the Early Triassic (Sclater & Christie 1980; Frederiksen et al. 2001; Arfai et al. 2014). Salt tectonics have been active since the Late Triassic. As a result of thermal uplift related to the North Sea Dome (Mid-Cimmerian erosional phase: Underhill & Partington 1993; Graversen 2002, 2006), regional erosion affected Lower Triassic–Middle Jurassic sediments predominantly on structural highs in the Entenschnabel area (Arfai et al. 2014). During the Late Jurassic–Early Cretaceous, a major extensional phase (Late Cimmerian: Ziegler 1990) took place in combination with extensive reactive diapirism of Zechstein salt and deposition of clastic sediments. A change in the European stress pattern from an extensional to a compressional tectonic regime (Gemmer et al. 2002, 2003) in the Late Cretaceous resulted in inversion, accompanied by deep erosion of locally uplifted sedimentary deposits. Erosion affected mainly Cenomanian–Santonian sediments in the central and NW part of the Entenschnabel. Simultaneously, syn-inversion deposition of chalk and subsidence continued in the southern German Central Graben.

Seafloor spreading has taken place in the North Atlantic from the Eocene onwards and the North Sea Basin became tectonically
quiescent (Ziegler 1992). Subsidence started due to thermal relaxation and caused a regional transgression. The basin was progressively filled by clastic deposits of the surrounding landmasses (e.g. Vejbæk & Andersen 1987; Rasmussen 2009). During the Mid-Miocene, a transgression formed the Mid-Miocene Unconformity (MMU), on top of which more than 1 km of sediments have been deposited since the late Mid-Miocene (Thøle et al. 2014).

**Exploration history and hydrocarbon plays**

South of the central German North Sea, within the Dutch North Sea, numerous wells have been drilled and discovered economic natural gas reservoirs. Further, to the NW in the UK offshore, two oil fields exist within reservoirs in Upper Jurassic sandstones. In the Danish offshore to the north, numerous oil fields are exploited which have their reservoirs in Upper Cretaceous–Palaeogene Chalk sediments within the Tail End Graben. Despite the long period of exploration in the Entenschnabel since 1968, and the oil and gas fields in the neighbouring countries, only one natural gas field has been discovered (A6-A in 1974) accompanied by some minor oil shows within the Central Graben area. The gas field (A6-A) has a complex reservoir situation with accumulations in Rotliegend volcanics, Zechstein carbonates and Upper Jurassic sands, and is sourced by Carboniferous coals.

Investigations within the Danish Central Graben found a regional distribution of Lower Carboniferous deposits, comprising coal seams and/or thick sections of coaly shale (Petersen & Nytoft...
### Fig. 2. Simplified Stratigraphic Chart Showing the Age of the Main Depth Maps Used in the 3D Model (Dashed Lines)

<table>
<thead>
<tr>
<th>Time (Ma)</th>
<th>Era</th>
<th>Series</th>
<th>Stage/Age</th>
<th>Strati. Marker</th>
<th>Depth Maps</th>
<th>NL TNO</th>
<th>Tectonic Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.0 Ma</td>
<td>Cenozoic</td>
<td>Oligocene</td>
<td>Lower Cretaceous</td>
<td>q</td>
<td>SPBA</td>
<td>Kombink et al. (2012)</td>
<td>Upper North Sea Group</td>
</tr>
<tr>
<td>24 Ma</td>
<td>Cenozoic</td>
<td>Miocene</td>
<td>Lower Cretaceous</td>
<td>tnl</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>65 Ma</td>
<td>Cenozoic</td>
<td>Paleogene</td>
<td>Lower Cretaceous</td>
<td>tmR</td>
<td></td>
<td></td>
<td>Lower and Middle North Sea Groups</td>
</tr>
<tr>
<td>99 Ma</td>
<td>Cretaceous</td>
<td>Upper Cretaceous</td>
<td>Lower Cretaceous</td>
<td>tmR</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>142 Ma</td>
<td>Cretaceous</td>
<td>Lower Jurassic</td>
<td>Middle Jurassic</td>
<td>km</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>157 Ma</td>
<td>Jurassic</td>
<td>Upper Jurassic</td>
<td>Tithonian</td>
<td>jxPO</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>178 Ma</td>
<td>Jurassic</td>
<td>Lower Jurassic</td>
<td>Callovian</td>
<td>jxe</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>200 Ma</td>
<td>Jurassic</td>
<td>Cimmerian</td>
<td>Oxfordian</td>
<td>jok</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>235 Ma</td>
<td>Jurassic</td>
<td>Keuper</td>
<td>Muschelkalk</td>
<td>juhe</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>251 Ma</td>
<td>Jurassic</td>
<td>Rotliegend</td>
<td>Buntsandstein</td>
<td>suC</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>255 Ma</td>
<td>Permian</td>
<td>Zechstein</td>
<td>Upper Zechstein</td>
<td>Zs-7</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>285 Ma</td>
<td>Permian</td>
<td>Rotliegend</td>
<td>Lower Rotliegend</td>
<td>ra</td>
<td></td>
<td>Near base</td>
<td>Saalian</td>
</tr>
<tr>
<td>300 Ma</td>
<td>Palaeozoic</td>
<td>Stephanian</td>
<td>Lower Rotliegend</td>
<td>ra</td>
<td></td>
<td>Near base</td>
<td></td>
</tr>
<tr>
<td>328.5 Ma</td>
<td>Palaeozoic</td>
<td>Devonian</td>
<td>Westphalian</td>
<td>csl</td>
<td></td>
<td>Lower Rotliegend Group</td>
<td></td>
</tr>
<tr>
<td>358 Ma</td>
<td>Palaeozoic</td>
<td>Devonian</td>
<td>Namurian</td>
<td>sW</td>
<td></td>
<td>Lower Rotliegend Group</td>
<td></td>
</tr>
<tr>
<td>417.5 Ma</td>
<td>Devonian</td>
<td>Devonian</td>
<td>Tournaisian</td>
<td>d</td>
<td></td>
<td>Lower Rotliegend Group</td>
<td></td>
</tr>
</tbody>
</table>

The geological timescale after Menning (2012) was used. The chart also shows the Southern Permian Basin Atlas (Doozemval & Stevenson 2010) and the mapping study in the Netherlands North Sea sector after Kombink et al. (2012). The last column describes the main tectonic phases recognized within the 3D basin modelling study.
These could be a gas source for deep plays in the Danish Central Graben and extend into the Entenschnabel. Wells B-11-2, A-9-1 and B-10-1 (Figs 1a & 3) penetrate Lower Carboniferous (Namurian–Visean) sediments, containing coal seams (EBN 2015). Dinantian and Visean coals are also proven to the south of the study area and may have contributed to gas charge in the northern Dutch North Sea (De Jager & Geluk 2007). In the study area, the facies during the Early Carboniferous is characterized as being deltaic to fluvial lacustrine (Kombrink 2008). The coals which developed in this environment might also have contributed to gas accumulations within the Entenschnabel. Thus, we assume a coaly source rock facies at the boundary between the Visean and the Namurian. The reservoirs might be Rotliegend sandstones, similar to those in the Dutch North Sea which are sealed by Zechstein evaporites.

Three relevant hydrocarbon plays in the adjacent realms of the Entenschnabel area are known. The most important play within the Dutch North Sea is the Rotliegend play (De Jager & Geluk 2007), a sandstone reservoir with good properties, sealed by Zechstein salt and sourced by Carboniferous coals. Most traps occur at the edges of horst blocks. It has been speculated that the Rotliegend play might also be sourced by Namurian shales with kerogen type II, these are expected to generate gas under deep burial conditions (Abdul Fattah et al. 2012a, b). However, the main source rock is the Westphalian B coal-bearing layer (Kombrink 2008). These gas-prone Westphalian sediments, deposited in a lower delta-plain environment (Kombrink 2008), are characterized by a kerogen type III that reaches a maximum total organic carbon (TOC) content of 70% in the Dutch North Sea (Verweij et al. 2003). Uplift and erosion during the Late Carboniferous–Early Rotliegend in the Entenschnabel area is crucial in this regard as much, if not all, of the Upper Carboniferous source rocks may have been removed.

The second important hydrocarbon play is represented by the Upper Jurassic and Lower Cretaceous sandstone reservoirs which are sealed mainly by Lower Cretaceous marls. Traps occur as anticlines, formed in response to the Late Cretaceous basin inversion. Accumulated gas, which is preserved in Upper Jurassic and Lower Cretaceous plays, is partly fed from the Westphalian coal, similar to that of the Rotliegend play. Shales of the Lower Jurassic (Posidonia Shale and Aalburg Formation; De Jager & Geluk 2007) and/or from Upper Jurassic coal-bearing sequences additionally contribute to the reservoirs.

The oil plays are restricted to the Jurassic Central Graben system, with the Dutch Central Graben and the Danish Tail End Graben. The main source rock responsible for oil accumulations in the Dutch North Sea is the Toarcian Posidonia Shale. Its thickness ranges between 15 and 35 m, with an average TOC content of approximately 10% and a hydrogen index (HI) of up to 800 mg HC g⁻¹ TOC (Verweij et al. 2003; De Jager & Geluk 2007). Within the Dutch Central Graben, the Lower Jurassic Posidonia Shale is the main source rock for the Upper Cretaceous Chalk play (De Jager & Geluk 2007) and may also extend into the Entenschnabel.

The Upper Cretaceous Chalk Group is the reservoir for several major oil fields in the Danish sector of the North Sea (e.g. Dan, Gorm, Skjold). The traps are mainly faulted anticlines formed...
during Late Cretaceous basin inversion. Within the Danish North Sea, the Upper Cretaceous play is sourced by excellent Upper Jurassic shales. The oil source rock is the Bo Member (Hot Shale) of the Farsund Formation in the Danish offshore, which is equivalent to the Kimmeridge Clay Formation in the British offshore and the Clay Deep Member in the Dutch North Sea (Ineson et al. 2003). A few wells encountered the Hot Shale layer in the Entenschnabel: for example, well DUC-B-1 (Fig. 1a) located south of the Outer Rough Basin. The thickness of the Hot Shale in DUC-B-1 is 85 m. Similar deposits within the Danish Central Graben are good to very good source rocks. This mudstone-dominated succession is typically 15–30 m thick, showing high HI values of between 200 and 600 mg HC g \(^{-1}\) TOC, and has a TOC content of 3–8%, although locally exceeding 15% (Ineson et al. 2003).

As described above, source rocks, as well as reservoirs, are present all around the German Entenschnabel (e.g. Lokhorst 1998; Ineson et al. 2003; De Jager & Geluk 2007; Kombrink 2008). This motivated the study of the petroleum potential of the Entenschnabel area using 3D basin and petroleum system modelling.

**Basin model: methods and database, input and boundary conditions**

**Methods and database**

3D petroleum system modelling was performed with the software PetroMod V. 14. The software calculates the evolution of a sedimentary basin from the oldest to the youngest event (forward modelling), and the processes of petroleum generation and migration (Hantschel & Kauerauf 2009). For the calculation of vitrinite reflectance from temperature histories, the EASY\%Ro algorithm of Sweeney & Burnham (1990) is used. This calculation method follows a kinetic reaction scheme, and is valid for calculated reflectance values between 0.3 and 4.5%. To depict the burial, thermal and maturity history of the study area, we used representative 1D extractions of the 3D model at well locations in the NW and central part of the Entenschnabel, as well as within the Central Graben area. Additionally, maps of calculated maturity and transformation ratios are presented.

Detailed mapping in the Entenschnabel (Arfai et al. 2014) provided the present-day stratigraphic and structural framework of the model from base Zechstein to Present. Fourteen depth grids (250 x 250 m cell size) and thickness maps of prominent seismic horizons were taken from this study. This was complemented with pre-Zechstein formations (358–260.5 Ma), including the Carboniferous–Rotliegend sedimentary successions adopted from literature (Krull 2005; Geluk 2007; Doornenbal & Stevenson 2010). For modelling purposes, information from 29 confidential wells covering the study area was used. Results of three wells with geological information and calibration data (vitrinite reflectance or temperature data) are shown in anonymized form, representing the two structural elements: the Central Graben and the Step Graben System, respectively. The well-penetration chart (Fig. 3) illustrates that most of the wells in the study area terminate either in the Mesozoic or within the Zechstein level. Consequently, temperature data from deeper stratigraphic units are restricted or even not available for the Central Graben area. Eight wells were drilled into the pre-Zechstein level located in the Step Graben System. Well B-11-2, drilled on a basement high, reached Namurian–Visean sedimentary sequences and is located in the immediate vicinity of the Central Graben area (Figs 1 & 3).

**Geological model**

The input model consists of 27 stratigraphic layers covering a time interval from the Early Carboniferous to the Present. A sedimentary basement of 2000 m thickness for the Dinantian and Devonian is added to extend the 3D model below the Upper Carboniferous. The latter is separated into the Stephanian, Westphalian and Namurian, whereby present-day and palaeothickness values are based on Krull (2005). The Namurian succession is assumed to have a constant thickness of 500 m in large parts of the study area. Locally, thicknesses of up to 920 m were assigned for the Namurian based on well data.

Lower Rotliegend distribution within the Entenschnabel area is taken from Geluk (2007). A present-day thickness of 100 m is assigned for the Lower Rotliegend layer, as Geluk (2007) assumed a similar value for the Lower Rotliegend Group within the Dutch North Sea. Upper Rotliegend depth and thickness maps are based on Doornenbal & Stevenson (2010). The thickness of the Upper Rotliegend ranges between 0 and 600 m. An initial depositional thickness of 700 m is assumed for the Zechstein layer. Salt movement is realized in such a way that parts of the overlying layers are replaced by salt lithology during subsequent time intervals (facies piercing), which mimics the evolution of salt bodies. Salt diapirism started in the Late Triassic.

For areas where the Triassic is completely eroded at the present day, a depositional thickness of 800 m is estimated based on structural maps and seismic data. The present-day thicknesses of Triassic sediments incorporated into the 3D model are taken from Arfai et al. (2014). The Lower Jurassic and the Upper Jurassic are divided into two units, respectively, to consider the source rock layers of each formation. The estimated total depositional thickness of the Lower and Middle Jurassic sediments is 465 m. The depositional thickness of the Upper Jurassic, Lower Cretaceous and Upper Cretaceous in eroded areas is interpolated using the thickness map from Arfai et al. (2014). Erosion maps for the main erosional phases (Triassic, Jurassic and Cretaceous) are illustrated in Figure 4.

Four erosional phases are included in the basin model: the Saalian (Late Carboniferous–Early Permian); the Mid-Cimmerian (Mid-Jurassic); the sub-Hercynian inversion (Late Cretaceous); and a final one during Mid-Miocene time (Fig. 2).

Upper Carboniferous sediments have not been encountered in wells and their sediment distribution is not indicated in the maps by Doornenbal & Stevenson (2010); therefore we assume that the Saalian erosion event removed previously deposited Stephanian and Westphalian sediments throughout the study area. The palaeothicknesses of the Westphalian and Stephanian sediments are each 500 m.

The domal uplift during the Mid–Late Cimmerian phase resulted in a widespread erosion in large parts of the study area. The intensity and amount of erosion varied in the area, depending on the structural elements (basin, high or platform). The erosion event began during the Bathonian (165 Ma) and ended in the Callovian (156 Ma). Layers that were affected by this erosional phase include the Lower and Middle Buntsandstein, Upper Buntsandstein, Muschelkalk, Keuper, Lower Jurassic, and Middle Jurassic.

A major Late Cretaceous inversion phase in the North Sea Basin resulted in uplift and erosion of the sedimentary fill in different pulses. Partly, Upper Jurassic, Lower Cretaceous and Upper Cretaceous sediments were eroded in the central and NW part of the study area. Here, erosion during the Late Cretaceous was active between 98 and 89 Ma. Therefore, subdivision of the Upper Cretaceous succession into three units (Cenomanian–Turonian; Coniacian–Santonian; and Campanian–Danian) was done to consider a local erosional phase in the NW on the Step Graben System during the Coniacian–Santonian. During this phase, sedimentation continued in the Central Graben.

The final erosion during the Mid-Miocene, with a duration of 3 Ma, is included within erosion 30 m in thickness. Periods of sedimentation, erosion and non-deposition are summarized in Table 1.
An assigned lithology for each of the layers is based on generalized well descriptions within the study area (Table 1).

Three layers have been defined as source rocks in the model. Namurian–Visean coals are included as a gas-prone source rock. This source rock was assigned a thickness of 10 m, a TOC content of 30% and a HI value of 150 mg HC g⁻¹ TOC.

Two Jurassic layers are included as oil-prone source rocks, namely the Posidonia Shale and the Upper Jurassic Kimmeridge Clay (Hot Shale). A thickness of 15 m is assigned to the upper section of the Lower Jurassic formation. This thickness is described by De Jager & Geluk (2007) for the Posidonia Shale in the Dutch North Sea. The Posidonia Shale is characterized in our model with an average TOC content of 8% and an HI value of up to 400 mg HC g⁻¹ TOC. The thickness of the Bo Member (Hot Shale) of the Upper Jurassic varies strongly in the Danish Central Graben, from less than 10 m in the southern salt dome province to over 100 m in the western part of the Danish Central Graben, and extending into the Entenschnabel with about 85 m at the location of well DUC-B-1 (Ineson et al. 2003). In our basin model, the Upper Jurassic layer with a maximum thickness of approximately 2200 m is subdivided into two layers based on well analyses and literature. The upper layer has a thickness of 25 m for the Hot Shale source rock, and the lower layer has a variable thickness for the underlying Kimmeridgian and Oxfordian strata. The Hot Shale source rock is defined by a TOC content of 8% and an HI value of 430 mg HC g⁻¹ TOC.

Hydrocarbon generation for the Posidonia Shale and Hot Shale was calculated using the kinetic dataset TII North Sea of Vandebroucke et al. (1999). Hydrocarbon generation for the Lower Carboniferous gas source rock (Namurian–Visean coal) was calculated with the TIII kinetic after Burnham (1989). Additionally, kinetics based on Pepper & Corvi (1995) type TII, B and Di Primio & Horsfield (2006) for Kimmeridge Clay (BH263) were used to study the influence of kinetic datasets on hydrocarbon generation. Figure 5 shows a NW–SE-trending 2D cross-section through the 3D model with assigned source rock intervals, reservoirs and possible seals.

**Boundary conditions**

**Palaeowater depth (PWD).** The palaeowater depth (PWD) curve used in the model was constructed based on PWD trends of adjacent areas in the southern Dutch Central Graben (Verweij et al. 2009; Abdul Fattah et al. 2012a, b). The PWDs were allowed to vary in time but were kept constant over the entire area at a certain time. The PWDs range between 0 and 200 m, with peaks during...
the Early and Middle Jurassic (150 m), the Early Cretaceous (100 m), and the Late Neogene (200 m) (Fig. 6a).

**Sediment–water interface temperature (SWIT).** The palaeo-surface temperature at the sediment–water interface was calculated with an integrated software tool that takes into account the PWD and the palaeolatitude of the study area (Wygrala 1989) (Fig. 6b).

<table>
<thead>
<tr>
<th>Model layer horizon</th>
<th>Deposited from (Ma)</th>
<th>Deposited to (Ma)</th>
<th>Erosion start (Ma)</th>
<th>Erosion end (Ma)</th>
<th>Lithology</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Tortonian and Holocene</td>
<td>11.2</td>
<td>0.00</td>
<td></td>
<td></td>
<td>90% Shale (organic lean, silty), 10% siltstone (organic lean)</td>
</tr>
<tr>
<td>2. MMU and Serravallian</td>
<td>15.97</td>
<td>14.7</td>
<td>14.7</td>
<td>11.2</td>
<td>90% Shale (organic lean, silty), 10% siltstone (organic lean)</td>
</tr>
<tr>
<td>3. Lower Miocene</td>
<td>20.5</td>
<td>15.97</td>
<td></td>
<td></td>
<td>90% Shale (organic lean, silty), 10% siltstone (organic lean)</td>
</tr>
<tr>
<td>4. Oligocene</td>
<td>33.7</td>
<td>20.5</td>
<td></td>
<td></td>
<td>90% Siltstone (organic lean), 10% shale (organic lean, silty)</td>
</tr>
<tr>
<td>5. Eocene</td>
<td>54.8</td>
<td>33.7</td>
<td></td>
<td></td>
<td>70% Shale (organic lean, silty), 30% siltstone (organic lean)</td>
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<tr>
<td>6. Paleocene</td>
<td>65</td>
<td>54.8</td>
<td></td>
<td></td>
<td>90% Shale (organic lean, typical), 10% tuff (basaltic)</td>
</tr>
<tr>
<td>7. Campanian and Danian</td>
<td>83.5</td>
<td>65</td>
<td></td>
<td></td>
<td>Limestone (chalk, typical)</td>
</tr>
<tr>
<td>8. Coniacian and Santonian</td>
<td>89</td>
<td>83.5</td>
<td></td>
<td></td>
<td>Limestone (chalk, typical)</td>
</tr>
<tr>
<td>9. Cenomanian and Turonian</td>
<td>98.9</td>
<td>89</td>
<td>89</td>
<td>88.2</td>
<td>Limestone (chalk, typical)</td>
</tr>
<tr>
<td>10. Lower Cretaceous</td>
<td>142</td>
<td>98.9</td>
<td>88.2</td>
<td>87.6</td>
<td>65% Marl, 20% shale, 15% siltstone</td>
</tr>
<tr>
<td>11. Hot Shale (Upper Jurassic)</td>
<td>144</td>
<td>142</td>
<td>87.6</td>
<td>87.3</td>
<td>Shale (organic rich, typical)</td>
</tr>
<tr>
<td>12. Upper Jurassic</td>
<td>156.5</td>
<td>144</td>
<td>87.3</td>
<td>83.5</td>
<td>75% Shale (organic lean, typical) 25% sandstone (typical)</td>
</tr>
<tr>
<td>13. Middle Jurassic</td>
<td>178</td>
<td>165</td>
<td>165</td>
<td>163</td>
<td>50% Sandstone (typical), 50% Siltstone (organic lean)</td>
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<td>14. Posidonia Shale (Lower Jurassic)</td>
<td>180</td>
<td>178</td>
<td>163.9</td>
<td>163.8</td>
<td>Shale (organic rich, typical)</td>
</tr>
<tr>
<td>15. Lower Jurassic</td>
<td>200</td>
<td>180</td>
<td>163.8</td>
<td>161.8</td>
<td>75% Shale (organic lean, typical) 25% sandstone (typical)</td>
</tr>
<tr>
<td>16. Keuper</td>
<td>234</td>
<td>200</td>
<td>161.8</td>
<td>159.5</td>
<td>45% Shale, 35% marl, 10% sandstone, 10% anhydrite</td>
</tr>
<tr>
<td>17. Upper Buntsandstein and Muschelkalk</td>
<td>246</td>
<td>234</td>
<td>159.5</td>
<td>158.5</td>
<td>60% Shale, 35% siltstone, 5% sandstone</td>
</tr>
<tr>
<td>18. Lower and Middle Buntsandstein</td>
<td>251</td>
<td>246</td>
<td>158.5</td>
<td>156.5</td>
<td>60% Shale, 35% siltstone, 5% sandstone</td>
</tr>
<tr>
<td>19. Zechstein salt</td>
<td>258</td>
<td>251</td>
<td></td>
<td></td>
<td>Salt</td>
</tr>
<tr>
<td>20. Zechstein carbonate</td>
<td>260</td>
<td>258</td>
<td></td>
<td></td>
<td>20% Anhydrite, 80% carbonate (dolomite)</td>
</tr>
<tr>
<td>21. Upper Rotliegend</td>
<td>272.5</td>
<td>260.5</td>
<td></td>
<td></td>
<td>Sandstone (typical)</td>
</tr>
<tr>
<td>22. Lower Rotliegend</td>
<td>296</td>
<td>272.5</td>
<td></td>
<td></td>
<td>75% Siltstone (organic lean), 25% shale (organic lean, silty)</td>
</tr>
<tr>
<td>23. Stephanian</td>
<td>305</td>
<td>304</td>
<td>304</td>
<td>301.3</td>
<td>Sandstone (typical)</td>
</tr>
<tr>
<td>24. Westphalian</td>
<td>320</td>
<td>305</td>
<td>301.3</td>
<td>298.6</td>
<td>80% Shale (typical), 25% sandstone (typical)</td>
</tr>
<tr>
<td>25. Namurian</td>
<td>326.5</td>
<td>320</td>
<td>298.6</td>
<td>296</td>
<td>60% Shale (organic reach, typical), 40% sandstone (typical)</td>
</tr>
<tr>
<td>26. Namurian–Visean</td>
<td>330</td>
<td>326.5</td>
<td></td>
<td></td>
<td>50% Siltstone (organic reach, typical), 25% coal (silty), 15% sandstone (typical)</td>
</tr>
<tr>
<td>27. Sedimentary basement</td>
<td>380</td>
<td>330</td>
<td></td>
<td></td>
<td>Siltstone (organic lean)</td>
</tr>
</tbody>
</table>

Source rocks are marked in italic.

**Basal heat flow.** One heat flow trend was assigned to the Step Graben System and a different one to the Central Graben. The thermal and maturity history of the Central Graben area includes a heat flow peak of 80 mW m$^{-2}$ during the Early Permian attributed to rifting and also manifested in volcanic activity in the Central European Basin, including the North Sea region (Fig. 6c). The value used is one according to Kearey et al. (2009) for a wide rift mode. During the Early–Late Triassic (246 Ma), a second peak
(70 mW m$^{-2}$) is included in the heat flow trend attributed to first post-orogenic (Variscan Orogeny) rifting phases. This rifting stage is characterized by the beginning of graben formation, and subsequent Triassic–Middle Jurassic tectonic subsidence and thickening of sediments within the Central Graben area. A third peak value (85 mW m$^{-2}$) during the Late Jurassic at 156 Ma represents the main heat flow event in the Central Graben area (Fig. 6c). This major extensional phase during the Late Jurassic formed the present-day Central Graben geometry. Subsequent Cretaceous and Cenozoic subsidence was largely controlled by a phase of post-rift thermal subsidence. The compressional stress regime resulted in several phases of basin inversion during the Late Cretaceous. However, this event had only a minor impact on the heat flow history and we assigned a heat flow value of 65 mW m$^{-2}$ for this time period. The present-day heat flow was calibrated based on temperature and vitrinite reflectance data.

The heat flow trend for the Step Graben System is the same as for the Central Graben until the Middle Jurassic. The Late Jurassic rifting of the Central Graben is omitted in the Step Graben heat flow trend (Fig. 6c, dotted line). The values decrease constantly from the Middle Jurassic to the present-day value of 52 mW m$^{-2}$.

Figure 7 shows the fit between measured and modelled vitrinite reflectance values for three wells with vitrinite reflectance values measured over a wide depth range.

**Results**

**Burial history**

The present-day German Central Graben area is dominated by major subsidence and sedimentation events during the Late Carboniferous, Late Permian–Early Triassic and the Late Jurassic. This is visualized by a 1D extraction of the burial history at the location of well C-16-1 (Fig. 8a). The presence of Zechstein evaporites greatly influenced the post-Permian structural and sedimentary development of the area (Fig. 5). The initial depositional thickness of the Zechstein Group in the 3D model is 700 m, while its present-day thickness varies from approximately 3000 m to only a few metres on structural highs. Significant subsidence occurred during the Late Jurassic (Fig. 8a). An additional, Late Cretaceous phase of rapid subsidence and sedimentation is distinct in the Central Graben area (Fig. 8a). The central and NW part of the Entenschnabel has undergone less burial than the rest of the area (Fig. 8b, c). The current burial of the source rock units shows a decreasing trend from the Central Graben area towards the NW. Thus, the burial depth of Lower Carboniferous source rocks (Namurian–Viséan) within the Central Graben at the present day shows a difference of approximately 3000 m to those preserved within the NW part of the Entenschnabel (Fig. 8a). Significant uplift occurred during the Late Jurassic visible in the NW part of the Entenschnabel at the location of well A-9-1 (Fig. 8c). As a result of significant pulses of inversion tectonics, a second important phase of tectonic uplift occurs during the Mid–Late Cretaceous (e.g. Fig. 8b).

**Thermal and maturity history**

**Thermal history.** The Namurian–Viséan unit reached a maximum temperature of up to 250 °C during the Late Jurassic (Fig. 8). This temperature is related to the burial depth of the formation, and the assumed heat flow value ranging between 80 and
85 mW m$^{-2}$ during the Late Jurassic–Early Cretaceous. The present-day temperature amounts up to 220°C within the Central Graben area (Fig. 8a). The overlying reservoir clastics of the Upper Rotliegend reach temperatures of around 220°C during the Late Jurassic–Early Cretaceous, while the present-day temperature field ranges between 200 and 210°C. During the Late Cretaceous, the temperatures of the formations decreased as a result of the Sub-Hercynian basin inversion phase. A second temperature peak is reached at the present day in the entire study area due to the maximum burial of the sediments (Fig. 8a–c). The present-day temperatures of the Posidonia Shale and the Hot Shale layer in the entire study area vary between 117 and 80°C (Fig. 8a–c).

**Maturity history.** Thermal calibration of the 3D model is based on present-day temperatures of six wells mainly located within the Central Graben area and vitrinite reflectance measurements of 16 wells covering different structures in the study area. Figure 7 shows a comparison of measured (black dots) and calculated (line) vitrinite reflectance and temperature data with depth. Three of the confidential wells are shown in Figure 7. Two of them are located in the Central Graben (Fig. 7a, b) and one is from the Step Graben System (Fig. 7e). A very good match is achieved between measured and calculated vitrinite reflectance values for the wells in the Central Graben area and on the Outer Rough High (Fig. 7a, b, c). Good agreement is achieved between the measured temperature data and simulated results at the location of two wells covering the Central Graben (Fig. 7c, d). The maturity evolution (vitrinite reflectance) and the hydrocarbon zones are illustrated in Figure 9 at three well locations. In addition, hydrocarbon zones and transformation ratios of the Carboniferous and the Lower and Upper Jurassic source rocks are depicted in Figures 10–12 and, respectively, for four time steps in map view. The maturity history indicates that the deepest parts of the Namurian–Visean source rock unit had already entered the oil window during the Late Carboniferous (Fig. 9a). Maturity increased during the Triassic and the source rock reached the gas window during the Middle Triassic within the Central Graben (Fig. 9a). At the present day, the Lower Carboniferous Namurian–Visean layer is overmature in the John Graben (Figs 9 & 10). Within the central and northern parts of the Entenschnabel area at the locations of wells A-9-1 and B-11-2, the Namurian–Visean source rock layer only enters the main oil-window range (Fig. 9b, c). The latter is also reached on the structural highs (Outer Rough High, Mads High and Schillgrund High), whereby in the graben and basins in the north (Mads Graben and Outer Rough Basin) the gas window is reached (Fig. 10). During the Late Jurassic, the Posidonia Shale is mostly immature, with the exception of the John Graben where the early oil window is reached (Fig. 11a). Maturity increased during the Early Cretaceous and the wet-gas window was reached in the deepest parts of the John Graben (Fig. 11b); however, large parts of the Posidonia Shale in the Central Graben are still immature. From the Eocene onwards, most of the Posidonia Shale is in the oil window (Fig. 11c). Maximum maturity of the source rock in the whole study area is reached at the present day (Fig. 11d). The Upper Jurassic Hot Shale layer is in the oil window over the whole of the Entenschnabel at the present day, except for locally uplifted areas in the Central Graben where it is still immature (Fig. 12d). This source rock entered the oil window during the Late Cretaceous.
Fig. 7. Measured and modelled vitrinite reflectance and present-day temperature data in a selection of wells in the study area: (a, b) modelled vitrinite reflectance (line) and measured data (black dots) of the Central Graben area; (c, d) measured temperature data (dots) and modelled (line) of the Central Graben area for the same wells as shown in (a) and (b); and (e) measured (dots) and modelled vitrinite reflectance (line) of the Step Graben System – the dashed line shows the calculated vitrinite reflectance with the heat flow model of the Central Graben.
Fig. 8. The burial history of three 1D extractions from the 3D model: (a) 1D burial history at the location of well C-16-1 in the Central Graben; (b) of well B-11-2 in the central part; and (c) of well A-9-1 in the northern part of the Entenschnabel. Calculated present-day temperatures for the source rock units are annotated and temperature isolines are plotted for the three well extractions. Locations of the wells are shown in Figure 1a.
Fig. 9. The calculated maturity evolution is shown in wells C-16-1, B-11-2 and A-9-1 (from top to bottom), the same well locations as in Figure 8. The maturity modelling and colour scale are based on the Sweeney & Burnham (1990) kinetic model.
Fig. 10. Calculated maturity (vitrinite reflectance values; Sweeney & Burnham 1990) at the top of the Namurian–Visean unit over four time steps: (a) Late Carboniferous; (b) Late Triassic; (c) Late Jurassic and (d) the present day. (e)–(h) The calculated transformation ratios for the same time steps as above. The calculated transformation ratios are based on Burnham (1989) TIII for the Namurian–Visean source rock.
Fig. 11. Calculated maturity (vitrinite reflectance values: Sweeney & Burnham 1990) at the top of the Posidonia Shale unit over four time steps: (a) modelled maturity of the Posidonia Shale layer during the Late Jurassic; (b) the Early Cretaceous; (c) Eocene; and (d) the present day. (e)–(h) The calculated transformation ratios for the same time steps as above; (h) the framed inset shows the transformation ratio of the Posidonia Shale by assuming source rock facies for the whole Posidonia Shale layer. The calculated transformation ratios are based on Vandenbroucke et al. (1999) TII North Sea for the Posidonia Shale source rock.
Fig. 12. Calculated maturity (vitrinite reflectance values; Sweeney & Burnham 1990) at the top of the Hot Shale unit over four time steps: (a) modelled maturity of the Hot Shale layer during the Late Cretaceous; (b) Eocene; (c) Oligocene; and (d) the present day. (e)–(h) The modelled hydrocarbon generations for the same time steps as above. The calculated transformation ratios are based on Vandenbroucke et al. (1999) TII North Sea for the Hot Shale source rock.
(Fig. 12a) and later during the Oligocene (27 Ma) at the location of well C-16-1 (Fig. 9a). The maximum maturity (0.9% Ro) is reached in the Outer Rough Basin at the present-day.

On the Outer Rough High (Fig. 9c, well A-9-1), the Posidonia Shale was eroded by Mid-Cimmerian erosion and only the Hot Shale is preserved there, reaching the oil window first during the Late Miocene.

**Hydrocarbon generation history**

The transformation ratio is an indicator of hydrocarbon generation of the source rocks. The transformation ratios are calculated for the source rock units according to the assigned reaction kinetics (Vandenbroucke et al. 1999, TII North Sea; Burnham 1989, TIII), and are therefore more specific for source rocks than the general classification using oil and gas windows based on vitrinite reflectance values. Figures 10–12 show the transformation ratios (TR%) of the top of the three source rock layers for four time steps.

A remarkable difference is observed in the transformation ratio of the Namurian–Visean layer between the northern part (Outer Rough High), the Central Graben area and the southern part on the Schillgrund High (Fig. 10e–h). The model indicates that the total transformation of organic material into hydrocarbons is already reached within the Central Graben (John Graben) during the Late Jurassic (Fig. 10g). Eighty per cent are reached at the present-day within the Outer Rough Basin at the border with the Danish North Sea in the NE (Fig. 10b).

Up to 96% of the organic matter of the Posidonia Shale layer was transformed during the Late Jurassic–Early Cretaceous within the deepest parts of the John Graben (Fig. 11e, f). The maximum of 97% is reached at the present-day (Fig. 11b).

The Hot Shale source rock shows only low transformation ratios of less than 20% within the Central Graben area at the present day (Fig. 12e–h). There is a remarkable difference with the present-day transformation ratio of the Hot Shale layer in the Outer Rough Basin. Here, the transformation ratio reaches up to 78% (Fig. 12h). A significant increase in the transformation ratio is observed between the Oligocene (44%) and present day (Fig. 12f, g).

**Discussion**

The aim of this study was to reconstruct the maturity evolution and petroleum generation of three potential source rocks in the NW German North Sea. Uncertainties in the model are introduced from various sources but can be studied with scenario calculations. We addressed the uncertainty of the source rock distribution of the Posidonia Shale, the influence of different reaction kinetics on the marginally mature Hot Shale and the influence of initial salt thicknesses.

In the simulations, we assumed that the Namurian–Visean source rock is present across the whole study area (Fig. 10). We also assigned source rock properties for the entire Hot Shale layer, which is partly eroded in the Step Graben System (Fig. 12). The distribution of the Posidonia Shale was greatly reduced by erosion during the Mid-Cimmerian tectonic phase. In the Step Graben System, only erosional remnants of the Posidonia Shale occur within the Mads Graben. In the Central Graben, the Posidonia Shale is present to a large extent but was eroded towards the Schillgrund High (Fig. 11). In the base model, we only assigned source rock properties to the Posidonia Shale where the Middle Jurassic is also present, thus reducing the possible kitchen area.

**Burial history**

1D burial histories indicate that deepest burial is at the present day, and is associated with the maximum maturity of the source rocks in the NW and SE part of the study area (Figs 10–12). In the north, the current burial depth of the Lower Carboniferous source rocks is approximately the same as during the Jurassic (Fig. 9b, c).

Ten Veen et al. (2012) calculated an initial thickness of the Zechstein Group of about 700 m within the Dutch North Sea, and we used this value in our base model. From the Dutch North Sea in the north into the Entenschnabel and approximately along the German–Danish border, the salt basin margin is approached which leads to reduced Zechstein salt thicknesses. Therefore, we calculated models using different initial thicknesses of 500 and 900 m and the present-day thicknesses. The influence of different initial thicknesses on the present-day maturity of the three source rocks is negligible for all three models. Nevertheless, the salt thickness has an influence on migration, especially in the case of a thin salt layer which can be more easily eroded or mobilized.

**Thermal and maturity history**

The modelled present-day heat flow is calibrated using measured vitrinite reflectance and temperature data in wells covering the study area. The matches between the measured and modelled calibration data suggest that the combination of the present-day heat flow and the thermal conductivity of the major lithologies is acceptable (Fig. 7a, b, e). The derived present-day heat flow of 52 mW m–2 (Fig. 6c) in the main model scenario is similar to those used in publications of surrounding realms of the German Central Graben: for example, Beha et al. (2008: 52 mW m–2) from the Danish Horn Graben; Verweij et al. (2011: 55–58 mW m–2) and Abdul Fattah et al. (2012a) from the NW Dutch offshore sector and the southern Dutch Central Graben; and Heim et al. (2013: 55–58 mW m–2) on the Schillgrund High. Based on these data, the thermal history of the Central Graben in the SE portion of the Entenschnabel area is found to be distinctly different to that in the central and NW parts of the Entenschnabel area (Fig. 7e). Therefore, for reconstruction of the heat flow history from the beginning of basin formation until the present, two different scenarios for the Step Graben System and the Central Graben have been applied (Fig. 6c). The main difference is a Late Jurassic heat flow peak of 85 mW m–2 for the Central Graben, whereas the heat flow for the Step Graben System does not exceed 57 mW m–2 (Fig. 6c). Thus, using a decreasing heat flow during the Late Jurassic (Fig. 6c, dotted line) to a present-day value of 52 mW m–2 within the Step Graben System, the modelled results of the Namurian–Visean source rock interval (Fig. 7e, dashed line) show a better fit to measured vitrinite reflectance data (Fig. 7e, solid line). This shows that the Central Graben area has experienced higher heat flow values during rifting in the Late Jurassic than the central and NW parts of the Entenschnabel.

**Hydrocarbon generation (Central Graben)**

The Namurian–Visean source rock in the Central Graben entered the early oil window in the Late Carboniferous and reached an overmature state by the Late Jurassic within the John Graben (Fig. 10). This implies that, if there are gas accumulations from Namurian–Visean source rocks, the conditions for preservation of gas generated 150 myr ago must have been favourable for a very long time, and that the reservoirs were not destroyed by diapirism and inversion tectonics in the Late Cretaceous. Maturity and hydrocarbon generation models in the southern part of the Dutch Central Graben for the Carboniferous source rocks (Westphalian) describe a major phase of hydrocarbon generation during the Late Jurassic and Early Cretaceous times (Verweij et al. 2009). On the graben shoulder (Schillgrund High), a transformation ratio of around 60% is calculated at the present day. Similar transformation ratios were calculated for the Carboniferous source rocks on the
of this optimistic model are shown in Figure 11h (inset). It is possible that the Posidonia Shale is present, to be on the conservative side regarding the extension of the Posidonia Shale only where the Middle Jurassic sediments are preserved, a significant difference is calculated with the TIIB kinetics (dashed line) reaching 20% at the present day, and the kinetics BH263 (Kimmeridge Clay, dotted line) and TII North Sea (solid line) reaching 12 and 10%, respectively.

Schillgrund High, already reaching 50% during the Middle Permian (Heim et al. 2013). It is possible that gas accumulations exist below the Zechstein salt layer in Rotliegend sediments and/or volcanics at depths of generally more than 5500 m. These accumulations might have been affected by salt diapirism (>10 salt diapirs in the Central Graben) and Late Cretaceous inversion. This could lead to leaking and dismigration of gas through salt windows and faults or restructuring of reservoirs.

The calculated transformation ratios indicate that within the John Graben the Posidonia Shale starts generating hydrocarbons during Late Jurassic–Early Cretaceous times (Fig. 11a, b). During this time interval, almost maximum transformation ratios were reached just before Late Cretaceous inversion tectonics and associated tectonic uplift. This is also in agreement with the hydrocarbon generation results by Verweij et al. (2009) for the southern Dutch Central Graben. Hydrocarbon generation in the study area was resumed during the Paleocene because of continuous burial and continued until present.

For the base model, we assigned source rock properties for the Posidonia Shale only where the Middle Jurassic sediments are present, to be on the conservative side regarding the extension of the kitchen area (Fig. 11b). It is possible that the Posidonia Shale is present elsewhere as well, thus having a larger kitchen area. The results of this optimistic model are shown in Figure 11h (inset).

Locally, within the Central Graben, where Triassic–Jurassic fault systems were reactivated accompanied by salt tectonics during the Late Cretaceous inversion phase, the Hot Shale was not buried deep enough to reach a mature state for hydrocarbon generation (Fig. 12d, blue coloured areas). Within the Central Graben area, the Hot Shale Formation generally shows only low transformation ratios (<20%: Fig. 12c–h). High transformation ratios of up to 60% are calculated only locally in rim synclines around salt diapirs in the Central Graben, reflecting the high thermal conductivity of the Zechstein salt (Fig. 12e–h). Thus, only local expulsion from the Upper Jurassic Hot Shale source rock can be expected, which might be enough to explain local oil shows in wells. The transformation ratio in the base model was calculated according to the kinetic TII, North Sea by Vandenbroucke et al. (1999). To assess the influence of the reaction kinetics on the transformation ratio we calculated two additional models using the TIIB (Pepper & Corvi 1995) and BH263 (Kimmeridge Clay: Di Primio & Horsfield 2006) kinetics. All three kinetics calculate transformation ratios of between 3 and 8% up until the Miocene. From the Miocene to present, a difference is calculated with the TIIB kinetics (dashed line) reaching 20% at the present day, and the kinetics BH263 (Kimmeridge Clay, dotted line) and TII North Sea (solid line) reaching 12 and 10%, respectively.

**Maturity and hydrocarbon generation (Step Graben System, central and NW Entenschnabel)**

In the NW part of the study area, the Mesozoic formations are less thick, and the degree of uplift and erosion of Mesozoic strata was more pronounced compared to the Central Graben area (Fig. 8a–c). This resulted in maturity variations over the area mainly attributed to differences in the burial depth history of the source rocks (Fig. 9a–c). In the NW part of the Entenschnabel, the Namurian–Visean source rock shows a present-day maturity in the range of 0.85–3% Ro (Fig. 10c). The calculated transformation ratios between wells A-9-1 and B-11-2 range between 65 and 75% at the present day. Values of about 88% are reached in the Mads Graben and 80% in the Outer Rough Basin (Fig. 10b). We assigned the Namurian–Visean source rock as a fluvial and deltaic kerogen type III facies with coal-bearing sediments.

Lower Jurassic sediments, including the Posidonia Shale, are only preserved within the Mads Graben and are elsewhere widely eroded within the Step Graben System as a result of the Mid-Cimmerian erosional events. Only in the southern Mads Graben does a small part show transformation ratios above 20%.

The maturity of the Hot Shale source rock increases from the Central Graben area towards the NW. Within the Outer Rough Basin, the Hot Shale is buried deeper than in the Central Graben and therefore reaches the highest maturities there. This is in contrast to the other two source rocks (Namurian–Visean and Posidonia Shale) which reach highest maturities in the Central Graben. Together with the distribution of the Bo Member interpreted by Ineson et al. (2003), which extends into the Entenschnabel area and is verified by well DUC-B-1 (Fig. 14, dashed red line), a part of the Outer Rough Basin can be considered as a hydrocarbon kitchen. So far this part of the Outer Rough Basin has not been targeted by wells.

**Migration of hydrocarbons**

Detailed petroleum migration and volumetric analyses were beyond the scope of this paper because a more detailed model...
would be needed that includes faults and more petrophysical data of carrier and reservoir layers, which were not available. Nevertheless, the results of the migration model give important information about where to focus more detailed studies. The simulation results indicate that the expulsion of gas from the potential Visean–Namurian source rock initiated in the Late Carboniferous. Peak expulsion of gas occurred before the Late Cretaceous inversion. The Lower Carboniferous source rock extends over the whole study area and petroleum generation led to the formation of numerous gas accumulations in the Upper Rotliegend below the sealing Zechstein salt. The Upper Rotliegend is assigned as a typical sandstone lithology, thus forming an excellent reservoir layer. By increasing the lithology porosity of the Zechstein carbonate layer, the model produces gas accumulations at the location of the present-day A6-A gas field. This suggests that the present-day reservoir at the location of the A6-A gas field, which is located on the Mads High, was probably charged by the Namurian–Visean source rock. The sealing Zechstein layer prevents any migration of Carboniferous gas from the Rotliegend into Triassic sediments in our model.

The Posidonia Shale expelled about 90% of the generated petroleum into the overlying sediments in the Central Graben. Expulsion initiated during the Late Jurassic and increased until present. Expulsion of hydrocarbons from the Hot Shale source rock started during the Late Cretaceous. A more detailed study that includes faults and their properties, as well as a complete migration simulation, is required to simulate migration and trapping.

Conclusions

Structural data from the Entenschnabel, which is the NW part of offshore Germany, are used for a 3D reconstruction of the burial and temperature history, source rock maturity, and timing of hydrocarbon generation. The study focused on three potential source rock intervals: the Lower Carboniferous (Namurian–Visean) coal-bearing source rocks; the marine Lower Jurassic Posidonia Shale; and the Upper Jurassic Hot Shale:

- The basin modelling, calibrated with vitrinite reflectance data from 16 wells and temperature data from six wells, resulted in a present-day basal heat flow of 52 mW m⁻² for the whole model area. The thermal history of the Central Graben in the SE portion of the Entenschnabel area is distinctly different to that in the central and NW parts. Therefore, two different heat flow scenarios for the Step Graben System and the Central Graben, respectively, have been applied. The main difference is a Late Jurassic heat flow peak of 85 mW m⁻² for the Central Graben, whereas the corresponding value during the Late Jurassic for the Step Graben System does not exceed 57 mW m⁻².
- The Namurian–Visean source rock had already entered the hydrocarbon generation zones during Late Carboniferous times throughout the area. Within the John Graben of the Central Graben, the overmature state was reached in the Late Jurassic. The Carboniferous source rock charged the A6-A gas field in the northern Entenschnabel, and the gas accumulation could

Fig. 14. Merged map showing the Late Jurassic tectonic framework of the Danish Central Graben after Ineson et al. (2003) and locations of released wells where the Bo Member is present. The thickness (in metres) of the Bo Member at well locations and the lateral distribution of this member (blue) as deduced from well and seismic data are illustrated. The extent of the Bo Member into the Entenschnabel (dashed red line) is verified by well DUC-B-1 (below). The present-day transformation ratio of the Hot Shale layer is shown, as also demonstrated in Figure 12h.
The calculated transformation ratios indicate that the Posidonia Shale source rock starts generating hydrocarbons within the deepest portions of the Central Graben in Late Jurassic times, with transformation ratios reaching their maximum values before Late Cretaceous inversion tectonics. Subsidence since the beginning of the Cenozoic enlarged the petroleum kitchen area and led to transformation ratios of more than 50% for almost the whole John Graben.

The potential Upper Jurassic Hot Shale source rock shows transformation ratios in the Central Graben of up to 10–20% depending on the reaction kinetic model used. Therefore, it is important to use source rock specific kinetics to determine the exact transformation ratio and to calculate volumes of generated petroleum.

High transformation ratios of the Hot Shale in the Outer Rough Basin, together with the inferred distribution of this source rock (Bo Member) and reservoirs in the chalk or Cenozoic, could constitute a working petroleum system.

The mature Posidonia Shale or early mature Hot Shale can explain oil shows in Upper Cretaceous sediments of the Central Graben.

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