Research Article
Effect of Some Input Parameters on 3D Basin and Petroleum Systems Modelling: A Case Study of the Norwegian Section of the Northern North Sea

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Abstract: The objective of this study is to test the influence of some key input parameters in basin modelling and to evaluate the resultant effect of varying these parameters on the model. 3D basin modelling and petroleum system analysis of the northern North Sea has been carried out using the PETROMOD software. The model was calibrated using well 34/8-7 in the Visund field. Different input parameters such as heat flow, source rock properties, fault properties, paleo water depth, source rock kinetics, migration methods and different erosion scenarios have been varied and their effects on the model assessed. The effect of the various input parameters has been assessed in terms of hydrocarbon volumes in the Kvitebjørn and Visund fields, source rock maturity, transformation ratios, hydrocarbon saturations and the time hydrocarbon generation began in the Draupne and Heather Formation source rocks. Increase in heat flow increases source rock maturity, the start of hydrocarbon generation, transformation ratios and results in the generation of a lot more gas than oil. Hydrocarbon generation starts at shallower depths with higher heat flow. Increasing Total Organic Content (TOC) and Hydrogen Index (HI) generally results in increase in the volume of hydrocarbons generated. The increase in HI, however, results in the generation of a lot more oil than gas. High TOC and HI also increase the hydrocarbon saturations in the source rock. Increasing Paleo Water Depth (PWD) has a marginal effect on the model. It increases the volume of oil and decreases the volume of gas marginally. Varying the PWD has no significant effect on source rock maturity, transformation ratios and hydrocarbon saturations. Opening the fault planes resulted in an increase in the volume of hydrocarbons generated. The increase was more evident in the volume of oil than gas. This increase in volumes is a consequence of additional migration pathways created by the faults. Varying the erosion thickness of the Draupne Formation did not have any effect on the model.

Keywords: Basin modelling, heat flow, input parameters, petroleum system modelling, source rocks

INTRODUCTION

Petroleum system and basin model: A petroleum system is a geologic system that encompasses the hydrocarbon source rocks and all related oil and gas and which includes all of the geologic elements and processes that are essential if a hydrocarbon accumulation is to exist (Magoon and Dow, 1994). A petroleum systems model is a digital data model of a petroleum system in which the interrelated processes and their results can be simulated in order to understand and predict them (Hantschel and Kauerauf, 2009). Basin modelling is dynamic modelling of geological processes in sedimentary basins over geological time spans (Hantschel and Kauerauf, 2009).

The geological processes calculated and updated at each step include deposition, erosion, compaction, heat flow analysis, expulsion, phase dissolution, hydrocarbon generation, accumulation and migration. These processes are simulated in a dynamic petroleum systems model in the assessments of exploration risks, migration scenarios and drainage areas. The model seeks to answer questions such as whether hydrocarbons have been generated, where they have been generated, when they were generated, the properties of the hydrocarbons generated and the prospects the hydrocarbons have migrated into. To achieve these results, a lot of data has to be inputted into the model before simulation. This data ranges from source rock properties, reservoir properties, heat flow,
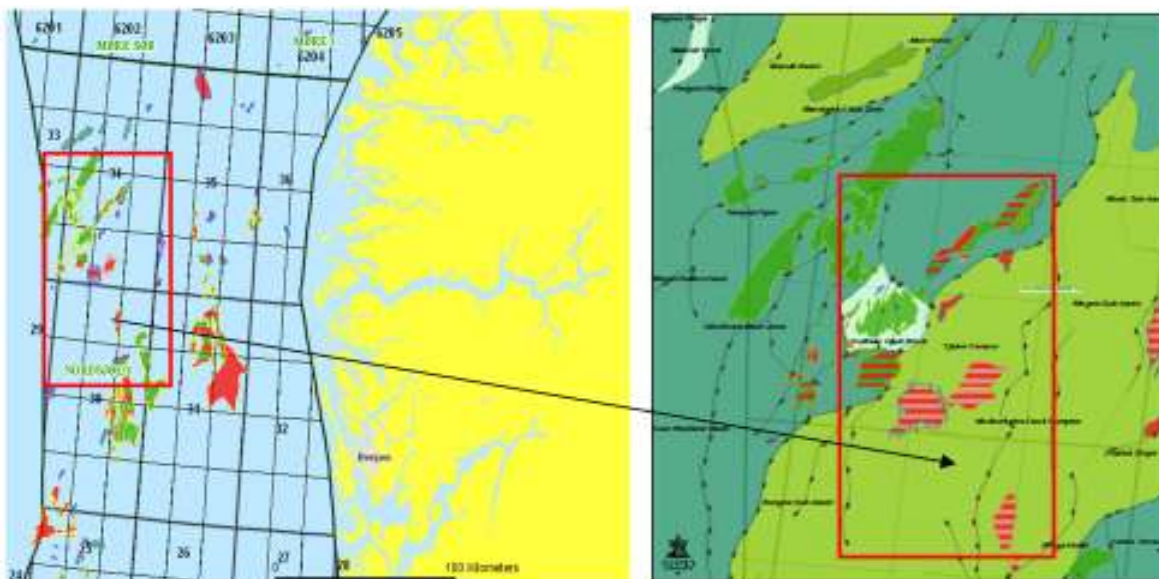
Fig. 1: Location map of study area modified from the Norwegian Petroleum Directorate (1996)

paleo water depth and sediment water interface temperature. Each of these parameters has a specific role it plays in the system. For example, heat flow is needed for the maturation of the source rocks and subsequent generation of hydrocarbons from it. The sensitivity of the petroleum system to each of these variables varies considerably. The objective of this study therefore is to test the sensitivity of the basin/petroleum system model to these input parameters in terms of maturity of source rock, start of hydrocarbon generation, volumes of hydrocarbon generated, hydrocarbon migration and accumulation using the Norwegian section of the northern North Sea as a case study.

Basin modelling history in the northern North Sea: Basin modelling in the northern North Sea has gradually been part of the general revolution in basin modelling from simple 1D model to present day complex 2D and 3D models. Most of the basin modelling was carried out from the early 1980's to the early 1990's. Several papers were published during this period. These include Goff (1983) paper on hydrocarbon generation and migration from Jurassic source rocks in the East Shetland Basin and Viking Graben and Lerche (1993) paper on theoretical aspects of problems in basin modelling. Other important publications on this topic include (Moretti and Deacon, 1995) 2D modelling of maturation and migration of the Tampen Spur area. An early example of 3D basin modelling in the northern North Sea was carried out by Schroeder and Sylta (1993) on 3D migration modelling of the northern North Sea using the SEMI modelling software and more recently Childs *et al.* (2002) paper on methods for including the capillary properties of faults in hydrocarbon migration models.

Geological setting: The study area is in the northern North Sea (Fig. 1). The structural configuration of the North Sea presently is largely a result of a Late Jurassic to Early Cretaceous rifting event. The rift axis for the Permo-Triassic rift is thought to lie beneath the present Horda Platform whereas the Late Jurassic rift was centered beneath the present Viking Graben (Zenella and Coward, 2003). The northern North Sea rift system is bounded in the west by the East Shetland Platform and in the east by the Horda Platform.

The North Sea rift system is a triple system that forms the Viking Graben, Central Graben and the Moray Firth basins (Zenella and Coward, 2003). One of the most recent and important events in the tectonic evolution of the northern North Sea is the Late Jurassic to earliest Cretaceous extensional tectonics. This event is extremely important for the petroleum geology of the northern North Sea because it led to the fault block rotations and the formation of major structural traps within and adjacent to the Viking and Central Grabens (Glennie and Underhill, 1998).

The northern North Sea petroleum system:
Source rocks: The petroleum system in the northern North Sea is characterized by two main source rocks: The Heather and Kimmeridge Clay/Draupne Formations. Maturity for oil generation was reached during the Late Cretaceous (early maturity at about 71 Ma, peak oil maturity at about 54 Ma) and the northern North Sea has been mature for significant gas generation since about 14 Ma (Fraser *et al.*, 2002). According to Fraser *et al.* (2002), Kimmeridge Clay in the northern North Sea typically has TOC contents around 6% locally reaching values in excess of 10% and can be as low as 2% with hydrogen indices varying between 200-400 mg/gTOC and can go up to about 600 mg/gTOC.
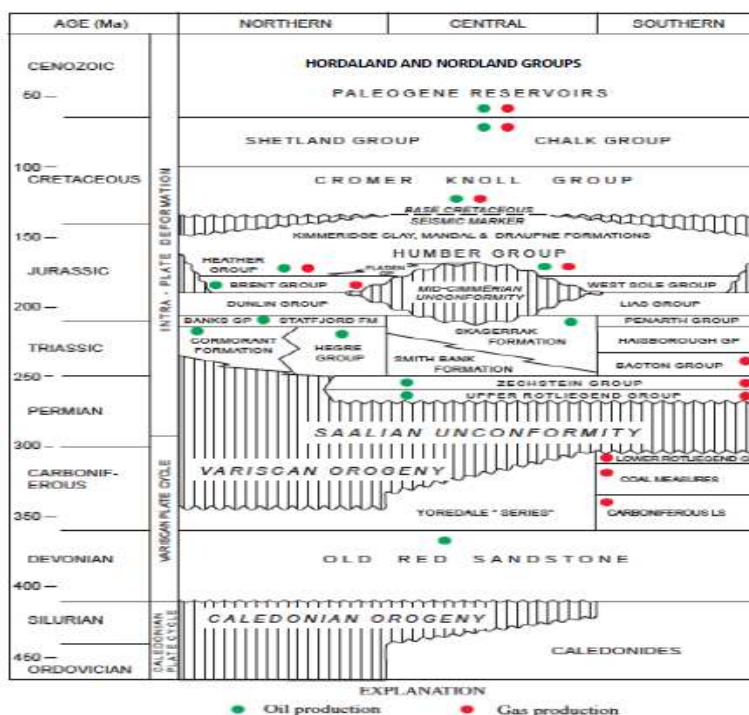
Fig. 2: Generalized stratigraphy of the North Sea modified from Brennand *et al*. (1998)

TOC contents of mudstones within the Heather Formation are typically lower than in the Kimmeridge Clay, at around 2-2.5% (Goff, 1983). Hydrogen indices from pyrolysis are commonly in the range 100-200 mg/gTOC but may be less than 100 mg/gTOC, mainly along the axial regions of the North Viking Graben where the Heather Formation is at a late-to-post-mature stage for oil generation (Fraser *et al*., 2002).

Reservoir rocks: A common feature of the Triassic reservoirs of the northern North Sea is that they generally occur in tilted fault blocks with varying levels of Early to Middle Jurassic and Late Jurassic to Early Cretaceous erosion and varying degrees of Cretaceous onlap (Goldsmith *et al*., 2003). Majority of fields with Triassic hydrocarbon accumulations in the northern North Sea have most of their hydrocarbons in overlying Lower and Middle Jurassic reservoirs with the exception of the Snorre Field. The distal, cleaner and mature nature of the sands ultimately results in very good porosity ranging from 19-29% and permeabilities ranging from 300-500 mD (Goldsmith *et al*., 2003).

The Middle Jurassic Brent Group forms one of the most important stratigraphic units in the North Sea. It consists mainly of sandstones with interbedded siltstones, shales and interbedded coals. The Brent Group is made up of six formations namely Etive, Ness, Broom, Rannoch, Oserberg and Tarbert Formations (Vollset and Dore, 1984) (Fig. 2). These reservoirs have been characterized as having excellent porosity and permeability. The Brent Group sandstones were deposited in coastal-plain

and shallow-marine to near shore environments (Vollset and Dore, 1984).

Upper Jurassic hydrocarbon-bearing reservoirs are of two main types: shallow-marine/coastal-shoreface sandstones and deep marine-fan sandstones (Fraser *et al*., 2002). In the northern North Sea, Upper Jurassic shallow-marine reservoirs are rare, although localized, shallow marine sandstones occur along the Tampen Spur in the Snorre-Statfjord area as a result of footwall uplift and erosion during the early phase of rifting in the North Viking Graben (Solli, 1995).

Migration: In the northern North Sea, faults play a key role in controlling both hydrocarbon migration pathways and the distribution and magnitude of hydrocarbon accumulations. Faults modify migration routes and trap hydrocarbons by offsetting carrier units or, where carrier unit are juxtaposed across faults, by providing zones of fault rocks with high capillary threshold pressures (Childs *et al*. 2002). Vertical migration of hydrocarbons has occurred along the major graben-bounding faults in the northern North Sea. Where sandstones with the Mesozoic section terminate against faults, some leakage of hydrocarbons into the plane of the fault may have occurred, however, the bulk of the hydrocarbon would have been directed to follow structural contours along the plane of the fault towards structural culminations (Kubala *et al*., 2003). The main conduits for the migration of hydrocarbons within the Mesozoic section are sandstones of Middle or Late Jurassic age in the Brent Group of the Viking

Graben (Miles, 1990). Three main modes of migration from source to reservoir were identified by Curtin and Ballestad (1986) -intercalation of source and reservoir, juxtaposition of source and reservoir across faults and vertical migration through micro-fracture systems.

MATERIALS AND METHODS

The types of data used in building a model usually depend on the purpose of the model and the dimension (Ben-Awuah *et al*., 2013). The complexity and number of input parameters increase as you move from 1D to 3D models. Basin modelling workflows have been discussed by previous workers such as Hantschel and Kauerauf (2009), Waples (1994) and Tissot *et al*. (1987). The three major stages involved in this model building include the basin modelling stage, numerical simulation stage and calibration stage. The basin modelling stage is the foundation of the model and begins with the development of a conceptual model which has been subdivided into sequence of events (deposition, erosion and non deposition) of certain age and duration (Belaid *et al*., 2010). 3D modelling integrates seismic, stratigraphic and geological data with multi-dimensional simulations of thermal, fluid-flow, petroleum generation and migration.

The PETROMOD 3D software suite has been used in this modelling. A base model was first built using mainly the averages of most of the input data from diverse sources and then calibrated using wells from the northern North Sea. The key input parameters were then varied within the minimum and maximum threshold values and the effect on the base model in terms of maturity of the source rock, burial history, transformation ratio and saturation, start of hydrocarbon generation, migration and volume of hydrocarbon accumulations accessed.

Erosions (uplifts) are also defined in the age assignment table (Fig. 3). The deposition ages have been defined starting from the oldest to the youngest layer. The erosion has been defined between the period of 135-150 Ma, affecting the Draupne Formation. Varying thickness of the Draupne Formation has been eroded in different parts of the northern North Sea (Fig. 4). A simplified erosion model shown in Table 1 has been used and correlated with vertical depth.

|	Name	Color	Deposition Age from [Ma]	Deposition Age to [Ma]	Erosion Age from [Ma]	Erosion Age to [Ma]	Max. Time Step Duration [Ma]	Facies 1
15	Nordland Group		5.00	0.00	0.00	0.00	10.00	Nordland Group
14	Utsira Fm		20.00	5.00	0.00	0.00	10.00	Utsira Fm
13	Nordland Group		23.00	20.00	0.00	0.00	10.00	Nordland Group
12	Hordaland Group		55.00	23.00	0.00	0.00	10.00	Hordaland Group
11	Rogaland Group		71.00	55.00	0.00	0.00	10.00	Rogaland Group
10	Shetland Group		99.00	71.00	0.00	0.00	10.00	Shetland Group
9	Cromer Knoll Group		135.00	99.00	0.00	0.00	10.00	Cromer Knoll Group
8	Draupne Formation (Kimmeridge Clay)		155.00	150.00	150.00	135.00	10.00	Draupne Fm
7	Heather Formation		164.00	155.00	0.00	0.00	10.00	Heather Fm
6	Tarbert Formation (Top Brent)		168.00	164.00	0.00	0.00	10.00	Tarbert Fm
5	Ness Formation		172.00	168.00	0.00	0.00	10.00	Ness Fm
4	Etive Formation		175.00	172.00	0.00	0.00	10.00	Etive Fm
3	Rannoch Formation		178.00	175.00	0.00	0.00	10.00	Rannoch Fm
2	Dunlin Group		190.00	178.00	0.00	0.00	10.00	Dunlin Group
1	Statfjord Fm		203.00	190.00	0.00	0.00	10.00	Statfjord Fm

Fig. 3: Age and erosion assignment table
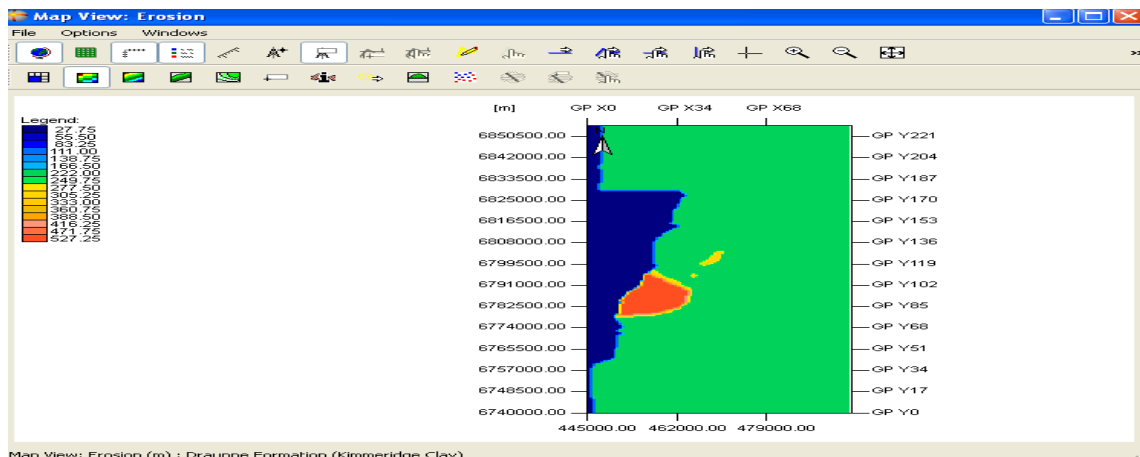
Fig. 4: Distribution of erosional thicknesses on the draupne formation

	Name	Petroleum System Elements	Color	Lithology Value	TOC Model	TOC Value [%]	Kinetics	HI Value [mgHC/gTOC]	HI Map	ID
1	Nordland Group	Overburden Rock		SHALE&SAND	Uniform	0.00	none	0.00	none	17
2	Utsira Fm	Overburden Rock		SAND&SHALE	Uniform	0.00	none	0.00	none	18
3	Nordland Group	Overburden Rock		SHALE&SAND	Uniform	0.00	none	0.00	none	19
4	Hordaland Group	Overburden Rock		SHALE&SAND	Uniform	0.00	none	0.00	none	20
5	Rogaland Group	Overburden Rock		SHALEsand	Uniform	0.00	none	0.00	none	21
6	Shetland Group	Seal Rock		SHALEcalc	Uniform	0.00	none	0.00	none	22
7	Cromer Knoll Group	Seal Rock		SHALEcalc	Uniform	0.00	none	0.00	none	23
8	Draupne Fm	Source Rock		SHALE	Uniform	6.00	Burnham(1989)_TII	400.00	none	24
9	Heather Fm	Source Rock		SHALE	Uniform	2.00	Burnham(1989)_TII	150.00	none	25
10	Tarbert Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00	none	26
11	Ness Fm	Reservoir Rock		SAND&SHALE	Uniform	0.00	none	0.00	none	27
12	Etive Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00	none	28
13	Rannoch Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00	none	29
14	Dunlin Group	Underburden Rock		SHALE&SAND	Uniform	0.00	none	0.00	none	30
15	Statfjord Fm	Reservoir Rock		SANDSTONE	Uniform	0.00	none	0.00	none	31

Fig. 5: Facies and petroleum system elements definition table

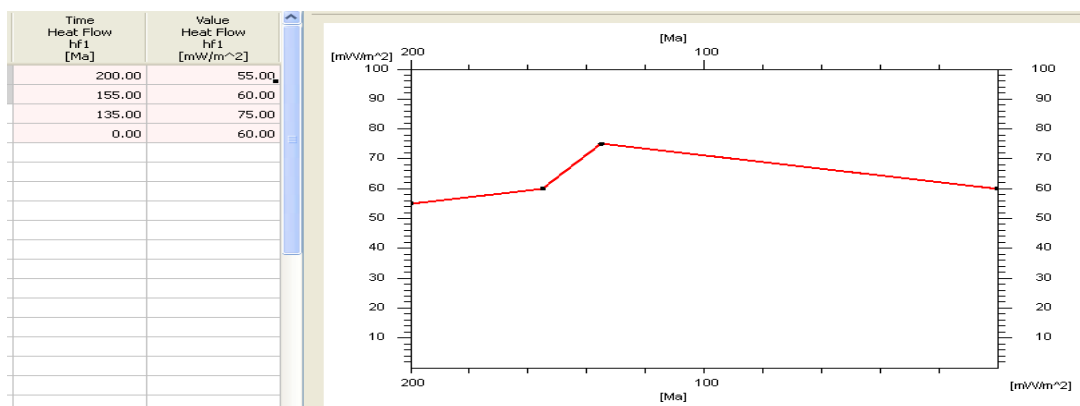| Time Heat Flow hf1 [Ma]	Value Heat Flow hf1 [mW/m^2]
200.00	55.00
155.00	60.00
135.00	75.00
0.00	60.00

Fig. 6: Heat flow distribution model over time in the northern North Sea

Table 1: Erosional thicknesses of the draupne formation correlated with depth

Depth (m)	Thickness eroded (m)
1500-2500	500
2501-3000	300
3001-5000	200

The facies and petroleum system elements also need to be defined. The main petroleum system elements to be defined are the source rock, reservoir and seal. Four reservoir rocks (Tarbert, Ness, Rannoch and Etive) of the Brent Group and two source rocks (Draupne and Heather) have been defined. The source rock properties (total organic content and hydrogen index) and reaction kinetics have been defined (Fig. 5). The Draupne Formation has a TOC of 6% and an HI of 400 mgHC/gTOC whereas the Heather Formation has a TOC of 2% and HI of 150 mgHC/gTOC.

Three main boundary conditions need to be defined namely Heat Flow (HF), Paleo Water Depth (PWD) and Sediment Water Interface Temperature (SWIT). Heat flow values in the North Sea vary between 50-75 mW/m^2 (Eldholm *et al*., 1999). Figure 6 shows the heat flow distribution used in this modelling. The highest value of 75 m W/m^2 has been assigned to periods of extensive rifting and faulting (135 Ma) whereas the

lowest heat flow values of 55 Ma is recorded around 200 Ma. The present day heat flow is 60 mW/m^2. The heat flow values have been calibrated using vitrinite reflectance data of well 34/8-7 in the Visund field.

SWIT trends have been preset in PETROMOD but the location of the basin has to be defined. The northern North Sea is in the Northern Hemisphere at latitude 61° N (Fig. 7).

The paleo water depth has been specified in Fig. 8 after the trend of Kjennerud *et al*. (2001).

Fault planes can be defined as open or closed depending on the permeability of the faults. An open fault is non-sealing and allows migration through it whereas a closed fault is sealing and does not allow migration through it. The Shale to Gouge Ratio (SGR) is also an option that is used to characterize the permeability or impermeability of the fault. Faults with SGR greater than 40 are impermeable whereas faults with SGR less than 20 are very permeable. The fault planes need to be assigned to a specific layer and in this modelling the faults have been assigned to the Brent Group reservoirs, Dunlin Group and Statfjord Formation and defined as closed (Ben-Awuah *et al*., 2013).
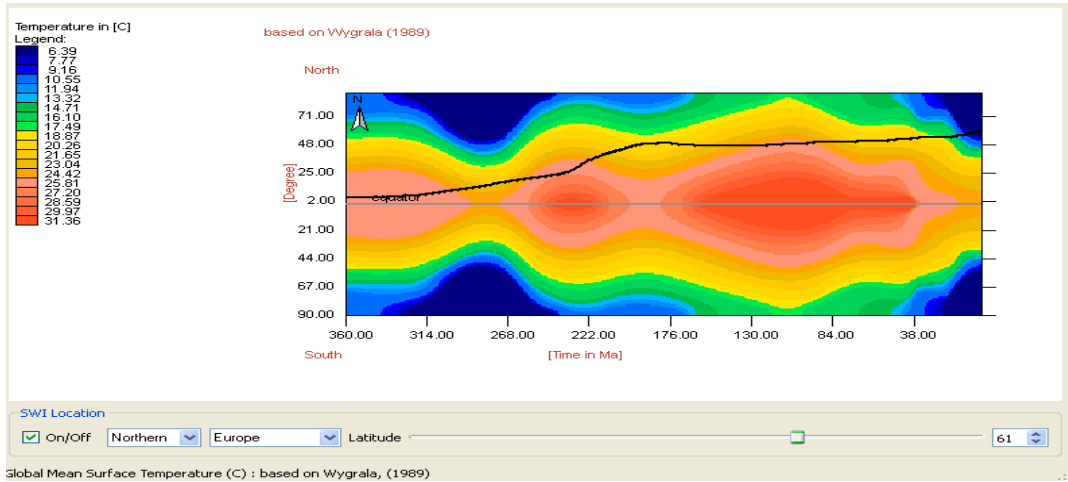
Fig. 7: Sediment Water Interface Temperature (SWIT) definition
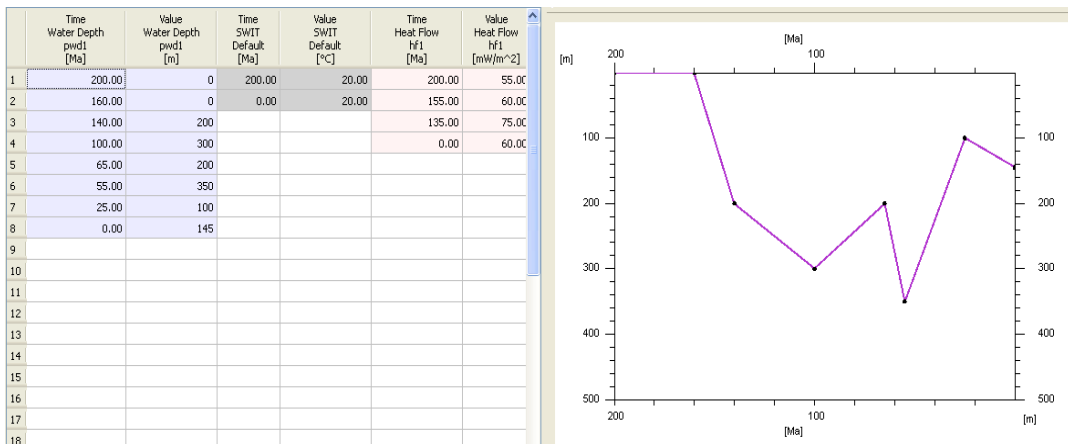

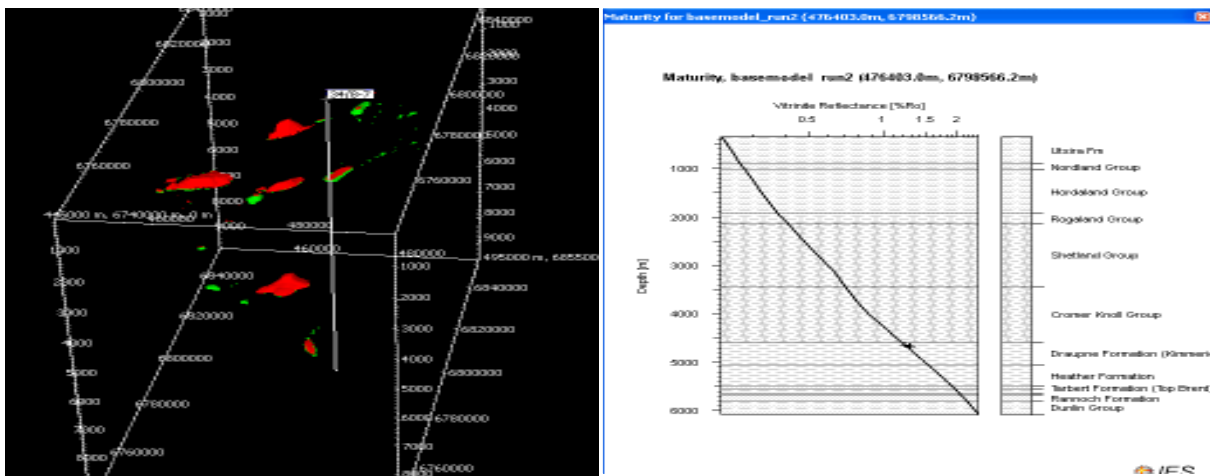Fig. 8: Paleo water depth distribution model over time

Fig. 9: (a) Location of well 34/8-7 in the model, (b) model calibration with vitrinite reflectance

RESULTS AND DISCUSSION

Calibration: PETROMOD uses all the input data and together with the boundary conditions simulate all these processes within a specific time frame to give the output results. Errors in the input data and modelling means the model needs to be calibrated with known data to determine the accuracy of the modelling and its
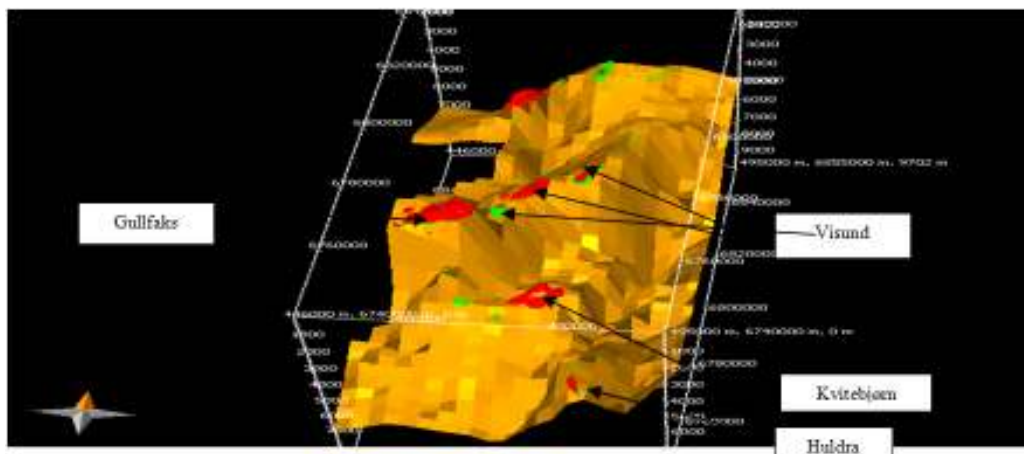
Fig. 10: Hydrocarbon accumulations in the tarbert formation

Table 2: Comparison of ROIP from the model and the Norwegian Petroleum Directorate (NPD)

HC type	ROIP from model (mmcmoe)	ROIP from NPD (mmcmoe)
Gas	130	139

Table 3: Comparison of ROIP from the model and the Norwegian Petroleum Directorate (NPD)

HC type	ROIP (mmcmoe)	ROIP (mmcmoe)
Gas	104	116
Oil	71	108

Table 4: Oil and gas windows of the draupne formation

Hydrocarbon window	Depth: from (km)	Depth: to (km)
Early oil	0.6	3.0
Main oil	2.6	3.6
Late oil	3.4	4.7
Wet gas	4.1	5.1

Table 5: Oil and gas windows of the heather formation

Hydrocarbon window	Depth: from (km)	Depth: to (km)
Early oil	0.9	2.5
Main oil	1.2	3.7
Late oil	3.3	4.0
Wet gas	3.9	5.5

results. In this study, vitrinite reflectance data from well 34/8-7 (Fig. 9a, b) in the Visund field has been used for the calibration.

Resources Originally in Place in base model (ROIP): The main accumulations in the model are found in the Gullfaks, Visund, Huldra and Kvitebjørn fields (Fig. 10). These accumulations are found mainly in the Brent Group reservoirs, specifically the Tarbert Formation. The focus of this analysis will be on the Visund and Kvitebjørn fields.

Kvitebjørn is a gas condensate field located in the eastern part of the Tampen area, in the North Sea. The reservoir consists of Middle Jurassic sandstones of the Brent Group. Table 2 gives accumulation in Kvitebjorn field in million cubic metres of oil equivalent (mmcmoe).

Visund is an oil field east of the Snorre field in the northern North Sea. The reservoirs are in Middle Jurassic sandstones in the Brent Group and Lower Jurassic and Upper Triassic sandstones in the Statfjord and Lunde Formations. As shown in Table 3 there is a significant difference between the volumes of ROIP obtained in the model and that put forward by the NPD. This difference can be attributed to two main reasons:

- The Lunde Formation which contains a significant amount of the oil in the Visund field is absent in the model due to data constraint.
- The Statfjord Formation which is one of the important reservoirs in this field does not contain any accumulation in the model. This is because only the top Statfjord Formation is present in the model. The base of the Statfjord was not defined due to data constraint.

Source rock maturity in base model: Both source rocks, Draupne and Heather Formations, have generated hydrocarbons. The start of the main oil and gas windows of the Heather Formation occurs at shallower depths than for Draupne Formation (Table 4 and 5). This is because the Heather Formation is buried deeper than Draupne Formation and attains maturity earlier than Draupne. The overlap between oil and gas generation at some depths represent simultaneous generation of oil and gas (Fig.11a and b).

Transformation ratios in base model: Transformation of kerogen to hydrocarbons begins at a depth of 2.2 km in the Draupne Formation and 1.5 km in the Heather Formation during the Upper Cretaceous (Fig. 12a, b). Figure 13a, b show hydrocarbon generation began at 80 Ma for the Draupne Formation and 90 Ma for the Heather Formation. Table 6 and 7 give the transformation ratio depths for the Draupne and Heather Formations, respectively.

Migration in base model: The vectors represent migration from the source rocks to the reservoir. There is both vertical and horizontal migration of hydrocarbons from the Draupne and Heather
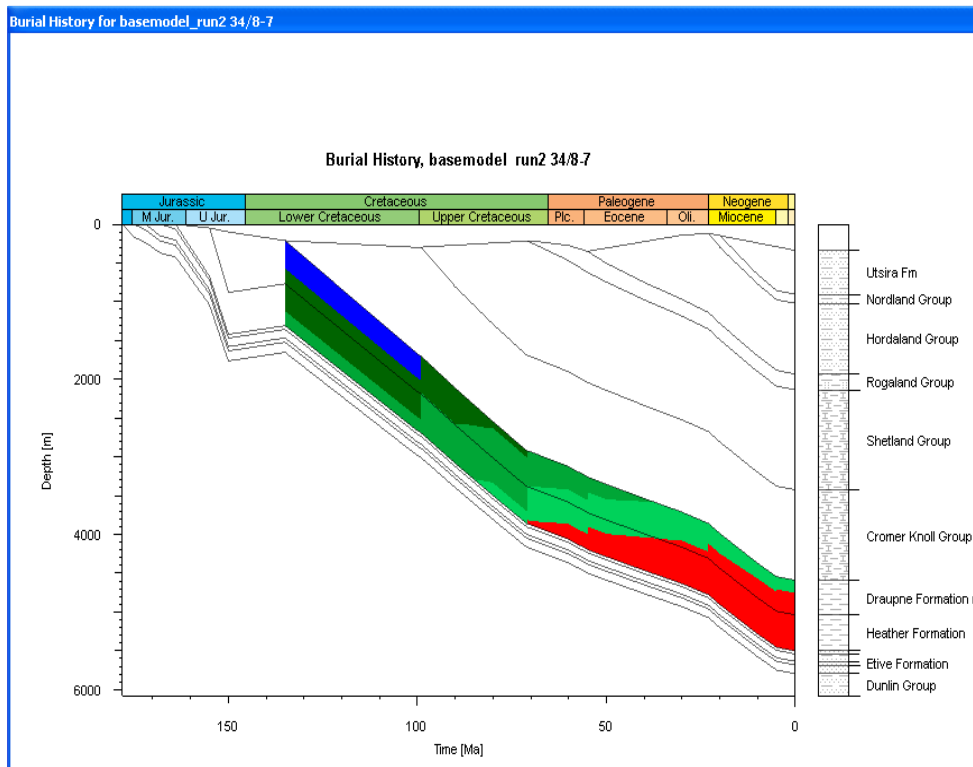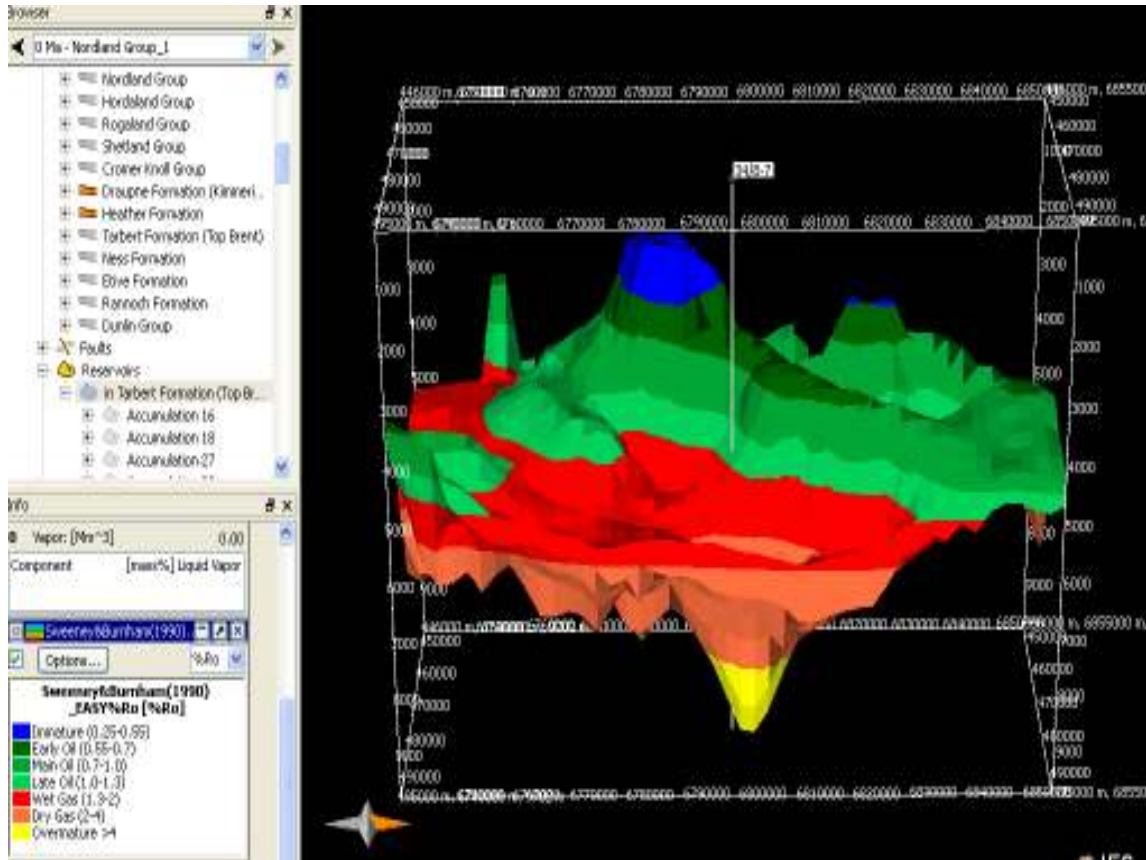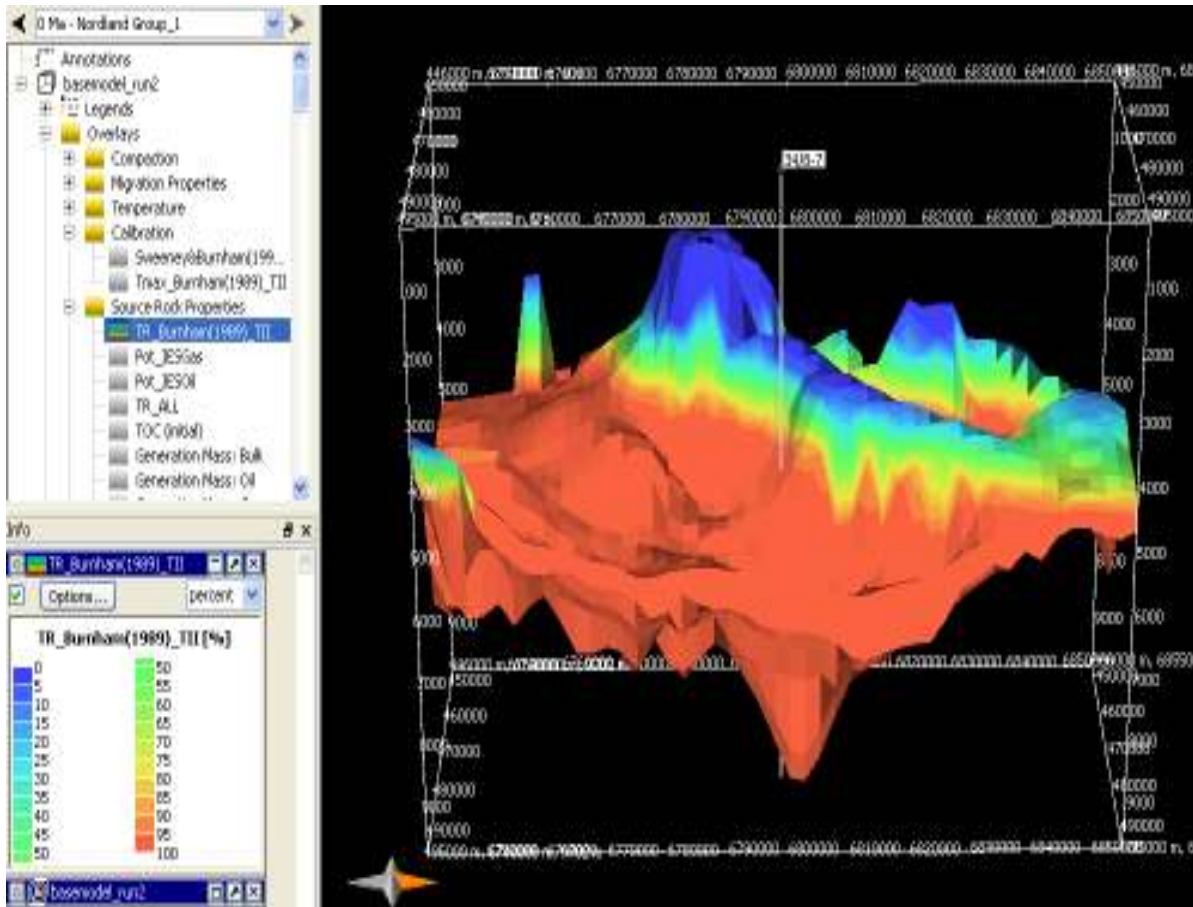
Fig. 11: Overlay of Sweeney and Burnham (1990) _easy % Ro calibration model of the source rocks in, (a) the 3D model, (b) burial history curves from 1D depth extraction of well 34/8-7
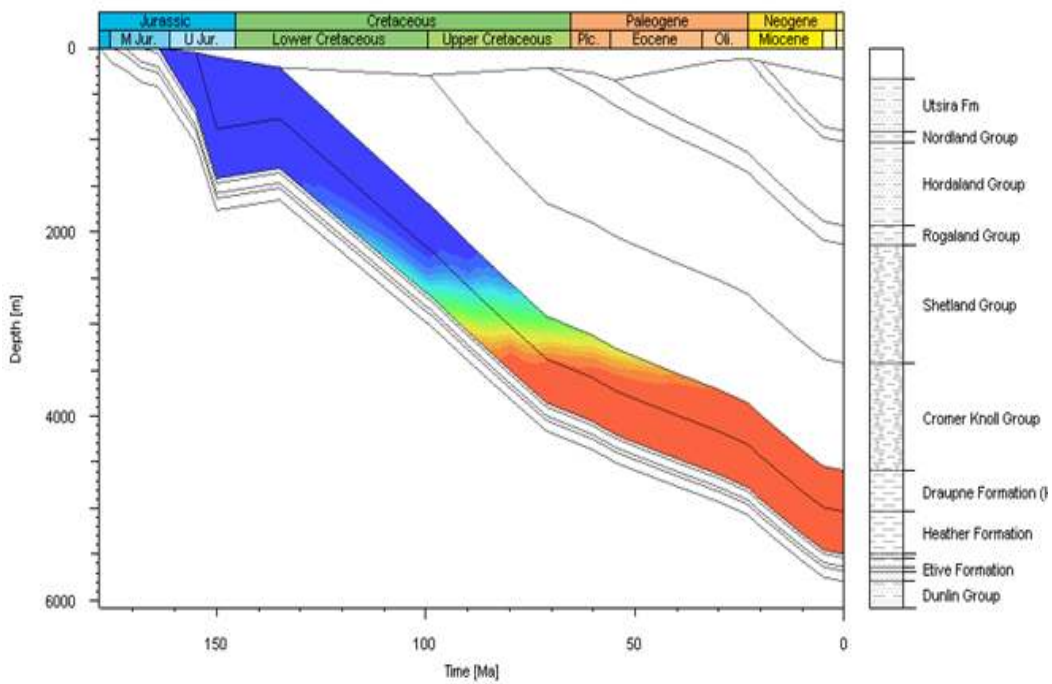
Fig. 12: Transformation ratios overlay of Burnham (1989) _TII (%) model on draupne and heather formations in, (a) 3D model, (b) burial history graph from 1D depth extraction of well 34/8-7
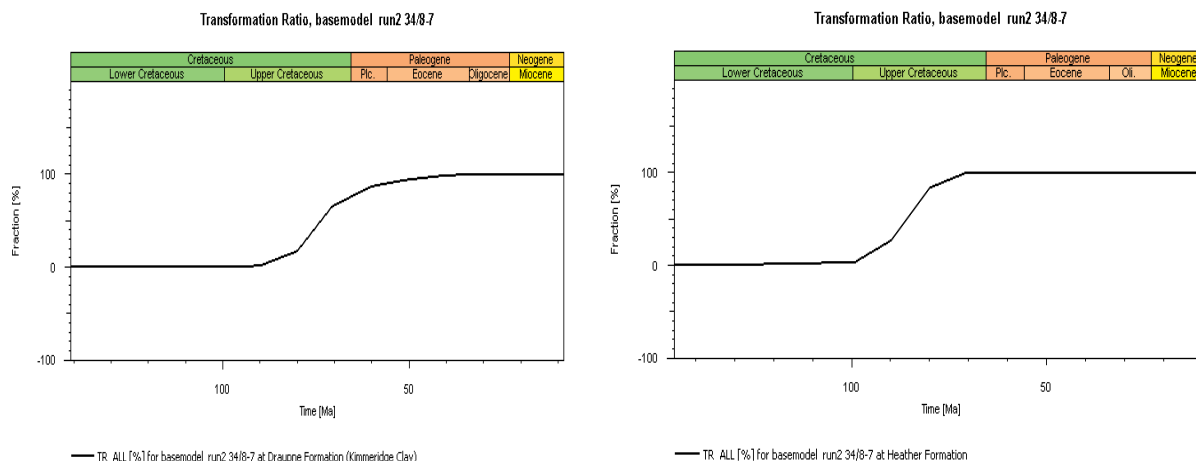
Fig. 13: (a) Transformation ratio time plot of the draupne formation, (b) transformation ratio time plot of the heather formation

Table 6: Transformation ratios of the draupne formation

Transformation ratio (%)	Depth: from (km)	Depth: to (km)
0-5	0.0	2.4
5-70	2.4	3.0
70-95	3.0	3.5
95-100	3.5	5.1

Table 7: Transformation ratios of the heather formation

Transformation ratio (%)	Depth: from (km)	Depth: to (km)
0-5	0.0	1.7
5-70	1.7	2.9
70-95	2.9	3.4
95-100	3.4	5.5

Table 8: Resources originally in place in the kvitebjørn field

HC type	ROIP (mmcmoe) from base model	ROIP (mmcmoe) from high heat flow scenario
Gas	130	131

Table 9: Resources originally in place in the visund field

HC type	ROIP (mmcmoe) from base model	ROIP (mmcmoe) from high heat flow scenario
Gas	104	111
Oil	71	62

Formations to the Tarbert reservoir. The red vectors represent gas migration whereas the green vectors represent oil migration (Fig. 14a).

Hydrocarbon saturation in base model: The Draupne Formation has higher hydrocarbon saturation than the Heather Formation (Fig. 14b). The Draupne is generally a richer source rock than the Heather and this is evident in the saturation distributions. The highest saturations are found in the Draupne Formation from 2 to 4.5 km (Fig. 14b). The saturations at this depth interval range averages about 70%. Hydrocarbon migration is mainly vertically upwards as represented by the vectors in Fig.14a.

Effect of increasing heat flow: The effect of heat flow on basin models was tested by building a new model

and increasing the heat flow as compared to what was used in the base model. A higher heat flow model for the Viking Graben as proposed by Lucazeau and Le Douaran (1985) and Schroeder and Sylta (1993) is used in this new model (Fig. 15). The highest heat flow value of 88 mW/m^2 is recorded at 135 Ma when extensive rifting occurred. All other input parameters have been kept constant relative to the base model.

Resources Originally in Place in high heat flow scenario (ROIP): There is an increase in volume of gas generated whiles volume of oil decreases (Table 8 and 9). The high heat flow increases maturity of source rocks resulting in increased generation of gas.

Source rock maturity: Using the same well, 34/8-7, as used in the base model for calibrating the maturity of the Draupne Formation, it is found that the Draupne is more mature in this high heat flow scenario than in the base model (Fig. 16a). Hydrocarbon generation in the Draupne Formation began at 0.6 km in the base model and 0.4 km in the high heat flow model (Fig. 16b). Generation in Heather Formation began at 0.9 km in the base model and 0.8 km in the high heat flow model (Fig. 16b). This is evidence that source rocks mature at shallower depth with high heat flow. Another distinct difference in hydrocarbon generation between the two models is the generation of dry gas in the Heather Formation in the high heat flow model. Generation of dry gas requires a more mature source rock which is provided by the high heat flow. The hydrocarbon generation windows in this high heat flow scenario are given in Table 10 and 11.

Transformation ratios: Higher transformation ratios are recorded at shallower depth compared to the base model (Fig. 17). Transformation of kerogen to
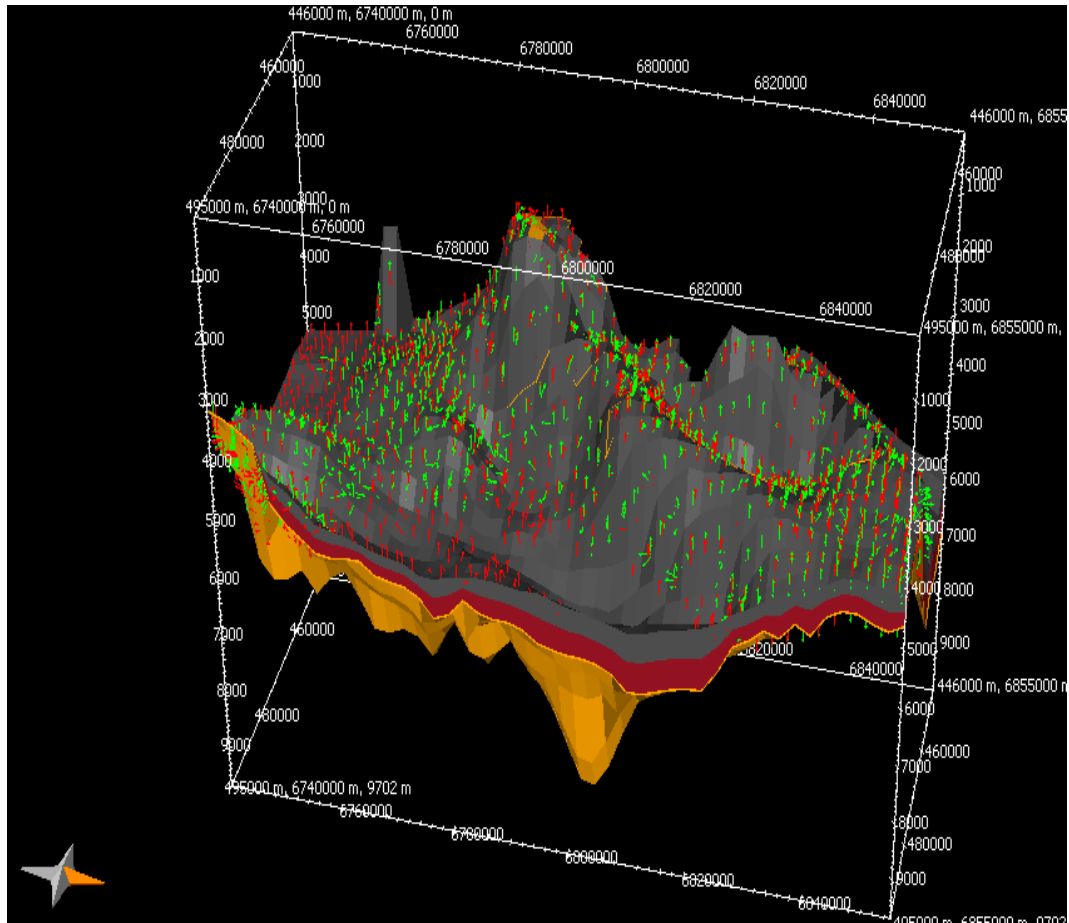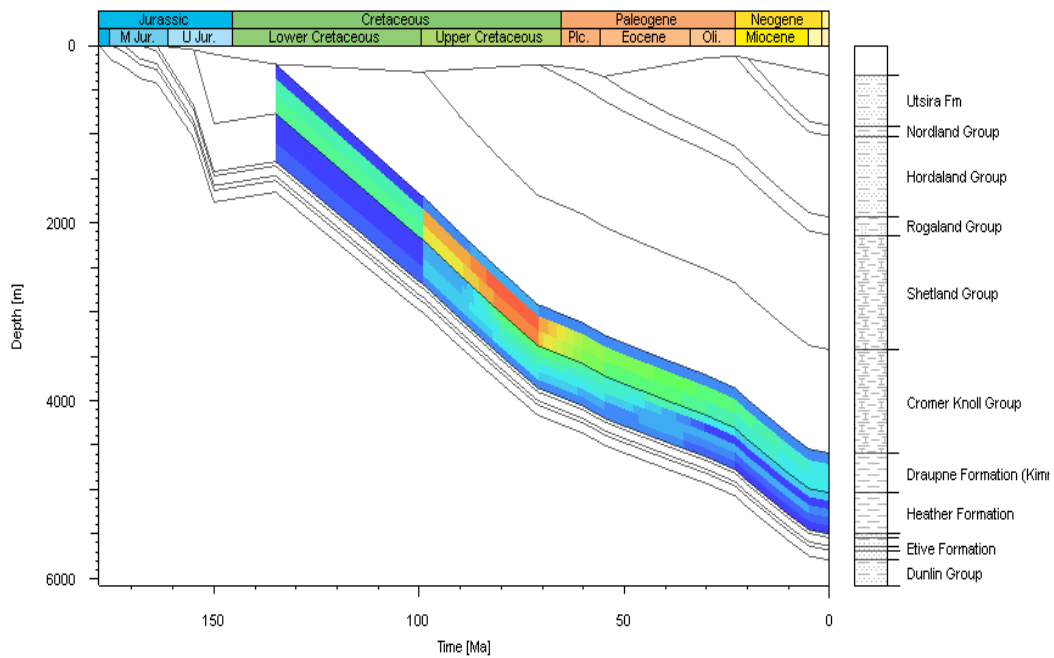
Fig. 14: (a) Migration vectors of hydrocarbons from the draupne and heather source rocks to the tarbert reservoir, (b) hydrocarbon saturation distributions on the draupne and heather formations from 1D depth extraction of well 34/8-7
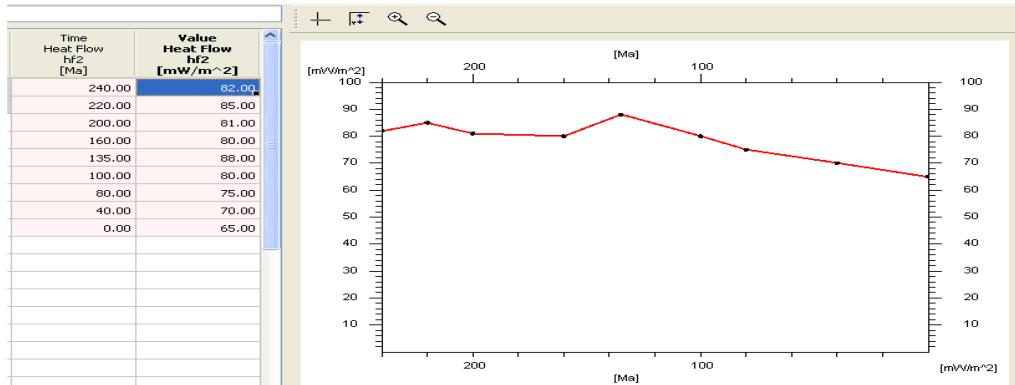
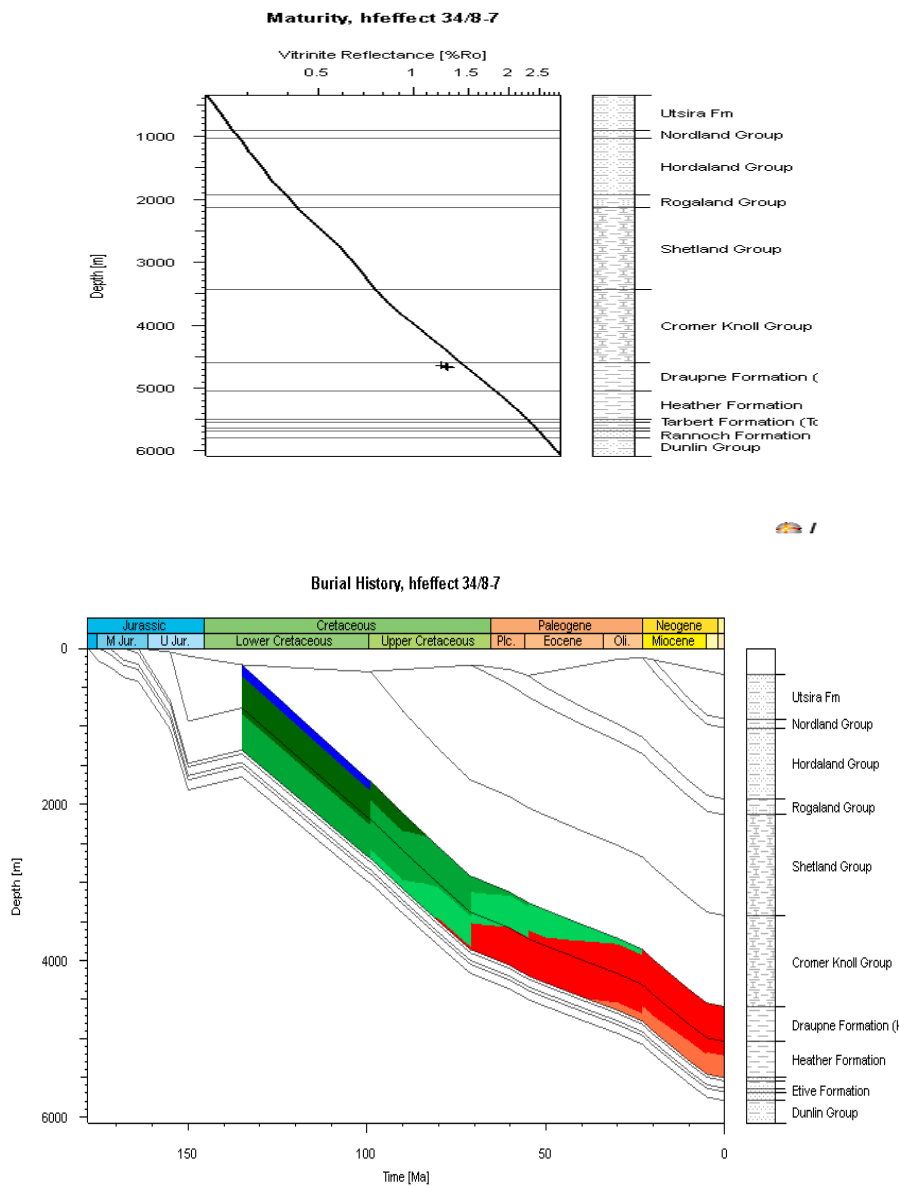Fig. 15: High heat flow scenario

Fig. 16: (a) Calibration of the draupne formation with well 34/8-7, (b) overlay of Sweeney and Burnham (1990) _Easy % Ro calibration model on the draupne and heather formations from 1D depth extraction of well 34/8-7
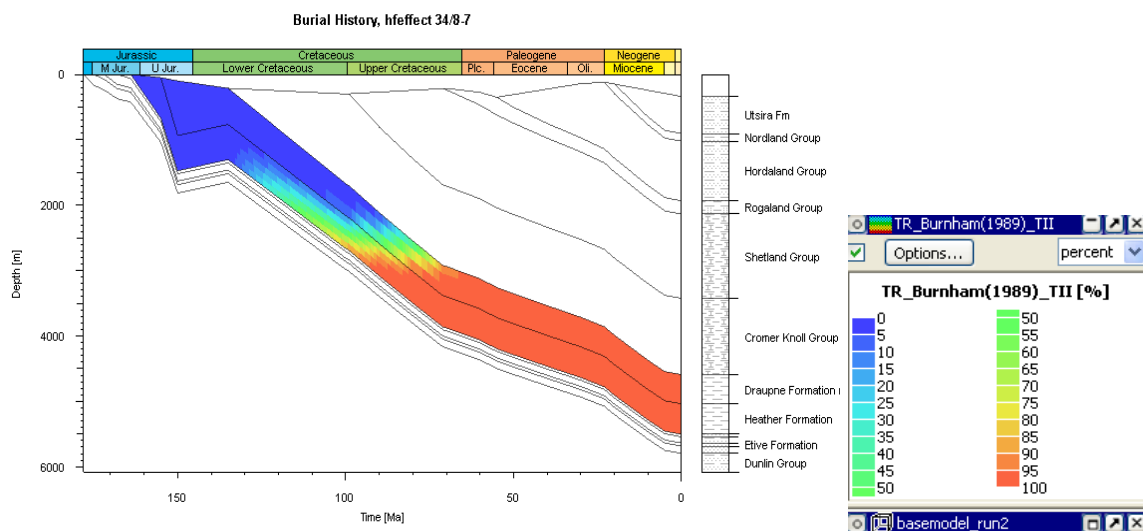
Fig. 17: Transformation ratios overlay of the Burnham (1989) _TII (%) model on the draupne and heather formations from 1D depth extraction of well 34/8-7

Table 10: Oil and gas windows of the draupne formation

Hydrocarbon window	Depth: from (km)	Depth: to (km)
Early oil	0.4	2.4
Main oil	2.0	3.4
Late oil	3.1	3.9
Wet gas	3.6	5.1

Table 11: Oil and gas windows of the heather formation

Hydrocarbon window	Depth: from (km)	Depth: to (km)
Early oil	0.8	2.2
Main oil	0.9	3.4
Late oil	2.6	3.8
Wet gas	3.5	5.2
Dry gas	4.5	5.5

Table 12: Transformation ratios of the draupne formation

Transformation ratio (%)	Depth: from (km)	Depth: to (km)
0-5	0.0	2.1
5-70	2.1	2.7
70-95	2.7	3.1
95-100	3.1	5.1

Table 13: Transformation ratios of the heather formation

Transformation ratio (%)	Depth: from (km)	Depth: to (km)
0-5	0.0	1.2
5-70	1.2	2.5
70-95	2.5	3.0
95-100	3.0	5.5

Table 14: Resources originally in place in the kvitebjørn field

HC type	ROIP (mmcmoe) from base model	ROIP (mmcmoe) from high TOC and HI
Gas	130	130

Table 15: Resources originally in place in the visund field

HC type	ROIP (mmcmoe) from base model	ROIP (mmcmoe) from high TOC and HI
Gas	104	106
Oil	71	80

hydrocarbons began at a depth of 2.1 km in the Draupne Formation and 1.2 km in the Heather Formation (Table 12 and 13) during the Upper Cretaceous. Hydrocarbon generation began at 90 Ma for the Draupne Formation and 100 Ma for the Heather Formation (Fig. 18a, b). In both source rocks, hydrocarbon generation started 10 million years earlier in this high heat flow model than the base model. This is an indication that higher heat flow causes hydrocarbon generation to start much earlier in source rocks. Figure 18a, b also show steeper transformation ratio curves than in the base model.

Hydrocarbon saturation: The higher heat flow results in higher hydrocarbon saturations in both the Draupne and Heather Formations at much shallower depth than in the base model. The highest saturations are recorded in the Draupne Formation from 0.4-4.5 km (Fig. 19).

Effect of varying source rock properties (TOC and HI):

The high TOC and HI scenario: In this scenario, all other input parameters are kept constant and the source rock properties (TOC and HI) for both Draupne and Heather Formations were varied relative to the base model based on values from Fraser *et al.* (2002). This scenario is to test the effect of varying the source rock properties on a basin model. TOC and HI were increased from 6 to 10% and from 400 to 600 mgHC/gTOC, respectively for the Draupne Formation. For the Heather Formation, TOC was increased from 2 to 2.5% and HI was increased from 150 to 200 mgHC/gTOC.

Resources originally in place (mmcmoe): The increase in TOC and HI resulted generally in an increase in the volume of hydrocarbons generated. This increase is more evident in the oil volumes than gas as shown in Table 14 and 15. The volume of oil
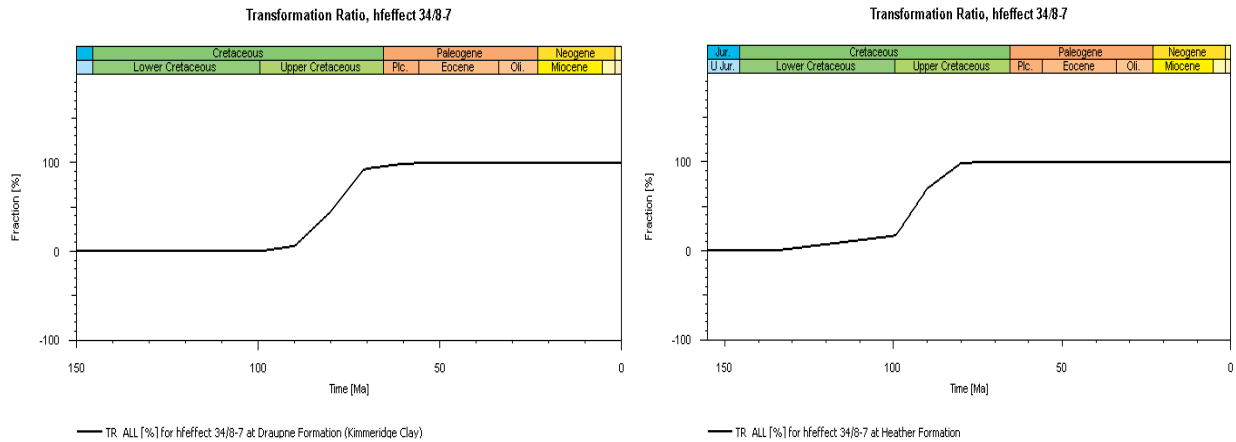
Fig. 18: (a) Transformation ratio time plot of the draupne formation, (b) transformation ratio time plot of the heather formation
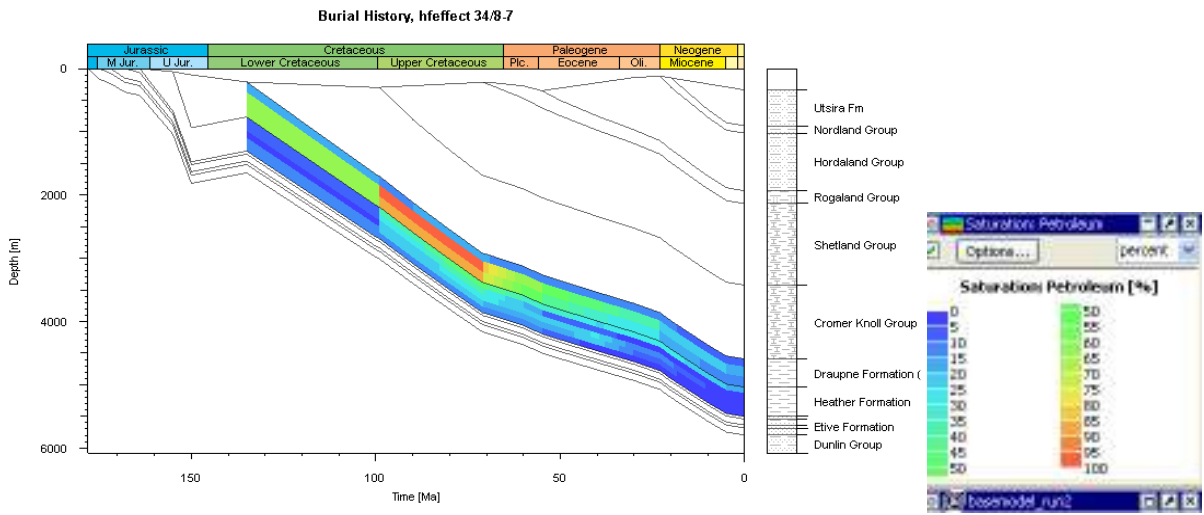

Fig. 19: Hydrocarbon saturation distributions in the draupne and heather formations from 1D depth extraction of well 34/8-7
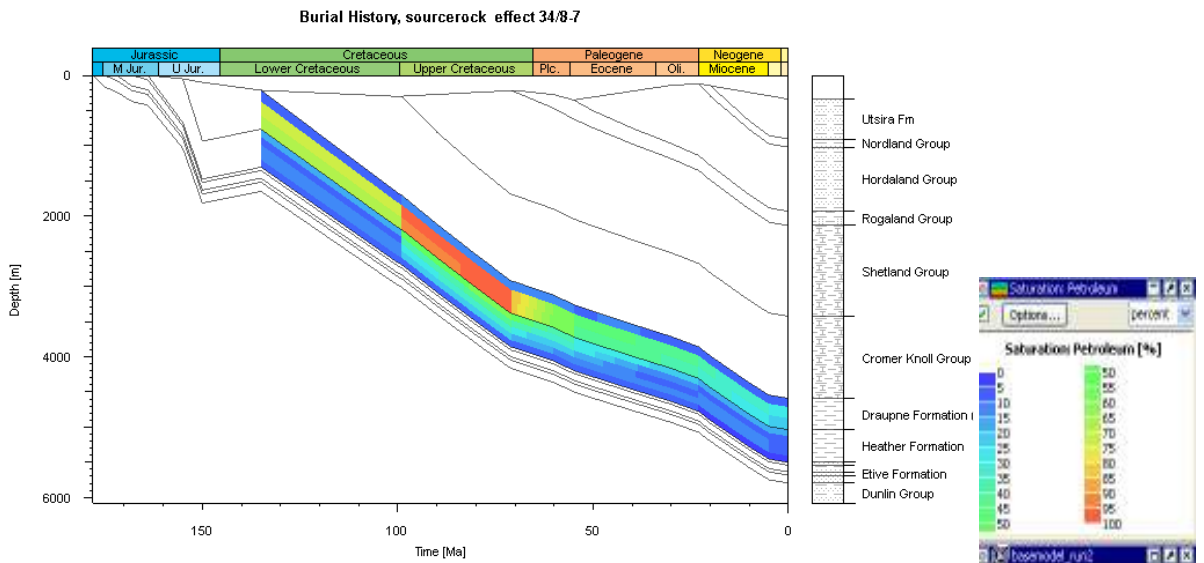

Fig. 20: Hydrocarbon saturation distributions in the draupne and heather formations from 1D depth extraction of well 34/8-7
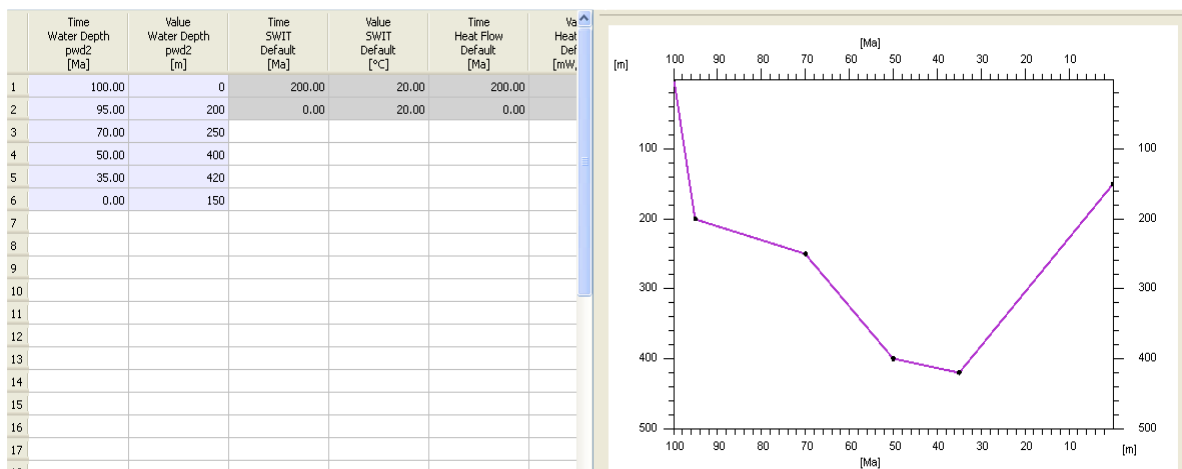
	Time Water Depth pwd2 [Ma]	Value Water Depth pwd2 [m]	Time SWIT Default [Ma]	Value SWIT Default [°C]	Time Heat Flow Default [Ma]	Va Heat Def [mW,
1	100.00	0	200.00	20.00	200.00	
2	95.00	200	0.00	20.00	0.00	
3	70.00	250				
4	50.00	400				
5	35.00	420				
6	0.00	150				
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						

Fig. 21: High paleo water depth scenario

Table 16: Resources originally in place in the kvitebjørn field

HC type	ROIP (mmcmoe) from base model	ROIP (mmcmoe) from high PWD scenario
Gas	130	129

Table 17: Resources originally in place in the visund field

HC type	ROIP (mmcmoe) from base model	ROIP (mmcmoe) from high PWD scenario
Gas	104	97
Oil	71	77

increased from 71 million m³ of oil equivalent in the base model to 80 million m³ of oil equivalent in this scenario. Higher HI values generally generate higher amounts of oil than gas.

Burial history and source rock maturity: There is no change in the maturity and hydrocarbon generation windows of the source rock in this model and in the base model. Increasing the TOC and HI therefore has no effect on the maturity of source rocks.

Transformation ratios: There is no change in the transformation ratios of the source rocks in this scenario as compared to the base model. Increasing the TOC and HI therefore has no effect on the transformation ratios of source rocks and the time hydrocarbon generation begins.

Hydrocarbon saturation: The higher TOC and HI values result in higher hydrocarbon saturations in both the Draupne and Heather Formations relative to the base model. The highest saturations are recorded in the Draupne Formation from 0.4-4.2 km as shown in Fig. 20.

Effect of Paleo Water Depth (PWD): The increase in Paleo water depth has a marginal effect on source rock maturity. There is a marginal decrease in the volume of gas generated and a marginal increase in the volume of

oil generated (Table 16 and 17). There are, however, no significant differences in transformation ratios and saturations in this high Paleo water depth model compared to the base model. The new Paleo water depth scenario is shown in Fig. 21.

Effect of faults: The faults in the base model were defined as closed from the start of basin formation to present day. The effect of faults on basin modelling is tested by using two different fault scenarios. One scenario has all the fault planes defined as open and the other scenario has SGR values defined for the fault planes during specific periods. There was an increase in the volume of oil in the Visund field from 71 to 77 million m³ of oil equivalent in both scenarios. This increase is attributed to additional migration pathways created by the permeable faults in both cases compared to the base model. The source rock maturity, transformation ratios and saturations were not affected by the change in fault properties.

CONCLUSION

- Hydrocarbon generation began later in the Draupne Formation (80 Ma) than the Heather Formation (90 Ma). It began in the Upper Cretaceous for both formations and reaches maximum generation in the Eocene for the Draupne and Paleocene for the Heather Formation. The Draupne is generally a richer source rock than the Heather and has higher hydrocarbon saturations.
- The gas in the model is generated mainly by the Heather Formation whereas the Draupne Formation generates most of the oil. The main oil and gas windows began at deeper depths in the Draupne Formation (2.6 and 3.4 km, respectively) than the Heather Formation (1.2 and 3.3 km), respectively. This is an indication that the Heather is more matured than the Draupne.

- There is both lateral and vertical migration of hydrocarbons from the source rock to the reservoirs in the basin.
- Increase in heat flow increases source rock maturity, the start of hydrocarbon generation, transformation ratios and generally results in the generation of a lot more gas than oil. Generation also starts at shallower depths with higher heat flow.
- Increasing TOC and HI generally results in an increase in the volume of hydrocarbons generated. The increase in HI, however, results in the generation of a lot more oil than gas. High TOC and HI also increase the hydrocarbon saturations in the source rock. The increase in TOC and HI has no effect on transformation ratios and source rock maturity.
- Increasing PWD has a marginal effect on the maturity of source rocks in the model. It increases the volume of oil and decreases the volume of gas marginally. Varying the PWD has no significant effect on transformation ratios and hydrocarbon saturations.
- Opening the fault planes resulted in an increase in the volume of hydrocarbons generated. The increase was more evident in the volume of oil than gas. This increase in volumes is a consequence of additional migration pathways created by opening the faults.
- Varying the erosion thickness of the Draupne Formation did not have any effect on the model.

ACKNOWLEDGMENT

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