RECENT APPLICATION OF SPECIAL CORE ANALYSIS TO FAULT ROCKS

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ABSTRACT
Faulted or fault zone rocks rocks often have a significant impact on fluid flow within petroleum reservoirs. Until recently, only their single-phase permeability values have been measured and the effects of their multi-phase flow properties on petroleum production have been neglected. Here we present results on the multi-phase flow properties of cataclastic fault rocks from Permo-Triassic sandstones found in outcrops of the UK, which are very similar to those found in the Rotleigend reservoirs of the UK southern North Sea. These fault rocks have single phase (brine and air) permeability values of around 0.002. Water saturations within these fault rocks have been varied using vapour chambers and their relative permeability to gas has then been measured using a pulse decay permeameter. The results indicate that if these fault rocks were present within the southern North Sea they would have maximum k_{rg} values of around 0.01. Incorporation of these new relative permeability and capillary pressure measurements into a simulation model for a Rotliegend reservoir in the southern North Sea can explain the reported 3700 psi (250 bar) cross-fault pressure differences that have been reported resulting from gas production. The standard practice of using transmissibility multipliers based solely on single phase permeability values cannot explain such large pressure differentials.

INTRODUCTION
Faults often act as barriers to fluid flow within petroleum reservoirs. It is therefore important to take into account their effects in production simulations models in order to achieve accurate production forecasts. Until recently, there was almost no data available on the permeability and capillary entry pressure characteristics of fault rocks. Consequently, the transmissibility of faults was often adjusted in an *ad hoc* manner (i.e. without serious scientific justification) to achieve a history match of production data. This often meant that cross-fault transmissibilities were adjusted in simulation models simply to compensate for other inadequacies in reservoir characterisation.

Recently, abundant data has become available on fault rock properties such as permeability, capillary entry pressure, fault thickness etc (see Fisher 2005). These data have allowed transmissibility multipliers to be calculated that can be applied to grid block faces adjacent to faults to account for the effects of faults on production (e.g. Manzocchi et al., 1999). Initial application of these new data appeared promising (e.g. Knai and Knipe, 1998). However, as more production data has become available, it is becoming increasingly obvious that the traditional way that transmissibility multipliers are calculated (i.e. based on single-phase permeability values) often make the faults too leaky to gain a history match. A potential reason why these transmissibility multiplier calculations often do not provide adequate results is that they do not take into account the relative permeability and capillary pressure characteristics of the fault (e.g. Fisher and Knipe, 2001; Manzocchi et al., 2002).

No measurements of the relative permeability of fault rocks have previously been made and therefore a large knowledge gap exists limiting our ability to accurately model fluid flow in reservoirs that are compartmentalised by faults (e.g. Al-Busafi et al., 2005). Here we attempt to partially fill this knowledge gap by presenting some data from gas relative permeability experiments undertaken on cataclastic fault rock obtained from an outcrop of Permo-Triassic sandstone in Scotland, UK. We show how incorporation of these results into a production simulation model of a southern North Sea gas field can dramatically improve the history match of the production data. The paper begins by describing the sample location and the experimental methodology used. The results from the experiments are then presented. Finally we show how incorporation of these results into a simplified production simulation model for a southern North Sea gas field produces a far better history match of production data than was achieved by only considering the single-phase permeability results.

FAULT LOCATION AND GEOLOGY

The extensional Lossiemouth fault zone, which lies on the southern margin of the Moray Firth, cuts through the Late Permian / Early Triassic Hopeman sandstone exposed in the Clashach Quarry near Burghead in Northeast Scotland, **Figure (1**). The main Lossiemouth fault slip plane trends E/W to WSW/ENE and dips to the south. The main phase of faulting probably occurred during the Late Jurassic development of the Inner Moray Firth rift. The Hopeman Sandstone is a clean, high-porosity yellow-brown sandstone of predominantly aeolian origin, which lies unconformably on Devonian sediments of the Orcadian Basin. It is approximately 70 m thick in this area, and in general dips at a shallow angle to north. A 15 cm x 15 cm x 30 cm block from the core of the Lossiemouth fault as well as a 10 cm x 10 cm x 10 cm block of undeformed Hopeman sandstone were obtained for microstructural and petrophysical property analysis. In total seven 2.0 inch long, 1.0 inch diameter cores were drilled perpendicular to the strike of the fault for the flow experiments reported here.

EXPERIMENTAL METHODOLOGY

The samples were scanned using an X-ray computed tomography (CT) system and their microstructure was analysed using a scanning electron microscope (SEM). All the samples were cleaned by Soxhlet extraction and dried before being tested. Porosity was measured using a helium expansion porosimeter. Gas and water permeability measurements were made using a variety of techniques described below.

To saturate the samples they were placed in a saturator under vacuum and left over night. The saturator was then flushed with CO_2, left for an hour and evacuated again to remove the CO_2. Deionised water was then allowed to drain into the chamber and the pressure was then increased to 2000 psi. The specimens were left to saturate at 2000 psi for 12 hours. The gas-air capillary pressure was measured using an ultracentrifuge. Gas relative permeability measurements were made on samples whose saturation was varied using vapour chambers. The methods are described in more detail below.

X-ray Tomography

The structure of the samples were examined using a Picker PQ 2000 dual energy CT scanner to check for fractures and to aid in selecting the best sample to core for this study. The CT images indicate the heterogeneity of these samples and highlight the existence of tight bands of cataclastic fault rock at different locations within the cores.

Microstructural Analysis

A polished block of the fault and a sample of the adjacent undeformed Hopeman sandstone were examined using a CAMSCAN CS44 electron microscope equipped with a secondary electron (SE) detector, a high resolution solid state four quadrant back-scattered electron (BSE) detector, a cathodoluminescence (CL) detector and an EDAX energy dispersive X-ray spectrometer (EDS). The images were saved in 8-bit (256 grey-levels) digital form, and then imported into an image analysis package. The BSE signal is proportional to the mean atomic number of individual minerals. The composition and porosity of the samples could therefore be established by carefully thresholding the images and using the image analysis package to calculate the area occupied by each mineral phase as well as porosity.

Single-Phase Permeability

The air permeability (permeability to gas) of the fault samples was measured by a Core Laboratories PDP-200 pulse decay permeameter, which is based on the method of Jones (1994). Helium gas was used in the tests. The permeability of selected fault samples and the undeformed Hopeman sandstone were also analysed using steady-state gas and brine permeameters. The gas permeability was calculated from the steady state flow rate of helium through the sample, and the associated pressure drop. Steady state is achieved when the upstream and downstream pressures and flow rate all become invariant with time. The measurements were taken at different mean gas pressures to obtain the Klinkenberg corrected gas permeability.

Brine permeability measurements were made using a custom-designed flow permeameter (Olson and Daniel, 1981; Olsen et al., 1991). This computerised permeameter, which uses an accurate constant-rate-of-flow pump and a highly linear differential pressure transducer, is capable of accurately measuring the permeability of samples in the range of 10 D to 0.001 mD. All samples were de-aired for a minimum period of 24 hours prior to testing. The sleeved samples were placed in a neoprene membrane and confined in a triaxial cell at a pressure of around 800 kPa to prevent leakage of brine between the sample and the confining sleeve. A back pressure of 260-270 kPa was used during testing.

Capillary Pressure Measurements

Air-water drainage capillary pressure curves were obtained from five samples of the Lossiemouth fault using an Optima L-100 XP ultracentrifuge. The ultracentrifuge can operate at up to 20,000 rpm but during our experiments we operated up to 15,000 rpm, which is equivalent to a capillary pressure of 1250 psi. Following saturation, the samples were placed in the centrifuge and their drainage air-water capillary pressures were determined by gradually increasing the speed of the centrifuge and measuring the amount of water expelled from the specimens as a function of time for each speed. The length of time required for the water saturation to reach equilibrium varied from sample to sample for each time-step. Samples HP2U and HP2V were left in the centrifuge for almost a month and run to a speed of 15,000 rpm. Other experiments were carried out over a 10-15 days period. The data were then analysed using the PORCAP software.

Gas Relative Permeability Measurement

No previous attempts have been made to measure the relative permeability of cataclastic faults. It would clearly be far too time-consuming to undertake steady-state relative permeability measurements on such rocks. Therefore, it was decided to conduct pulse-decay permeametry on samples whose saturation was altered using the vapour chambers technique (e.g. Melrose, 1987; Collins, 1976; Calhoun et al., 1949). Three cores of the fault rock samples were placed in desiccators whose humidity was controlled by using different saturated salt solutions (ISO 483, 1988). The samples were weighed every 24 hours until equilibrium was achieved, e.g. constant weight. The weight difference between the sample after equilibration in the vapour chamber and its dry weight was used to calculate the water saturations. Then the effective gas permeability was determined in the pulse-decay permeameter. A desiccator containing a different salt solution (relative humidity) was used and the process of equilibration and gas permeability determination was repeated.

RESULTS

Petrographic Analysis And Structure Of The Samples

The undeformed Hopeman sandstone is a well sorted fine to medium grained sandstone composed of 86% quartz, 6% K-feldspar, 1% clay and has a porosity of around 11%, **Figure (2a)**. The main diagenetic process to affect the sample was the precipitation of mesocrystalline quartz cement, which makes up around 21% of the rock volume. It has been suggested that the silica may be hydrothermal in origin as the Lossiemouth Fault is a major basin bounding fault (Stuart Haszledine, Pers. Com. 2006).

The fault rock has clearly experienced a large grain-size reduction, **Figure (2b)**, as a result of the faulting-induced grain-fracturing. The faulting process has also clearly reduced the porosity dramatically and reduced pore-throat sizes.

The CT-images, **Figure (3),** show that the samples are highly heterogeneous and composed of alternating bands of low porosity cataclastic fault rock separated by lenses of relatively undeformed sandstone.

Single Phase Permeability Results

Pulse-decay permeametry results show that the gas permeability of the core samples varied between 0.001 and 0.006 mD, **Table (1)**. The pulse decay results are very consistent with the Klinkenberg corrected gas permeability as well as the steady-state water permeability results.

Capillary Pressure Curves Using Ultra-High Speed Centrifuge

The capillary pressure results processed using the Forbes second method algorithms within the PORCAP software are shown in **Figure (4)**. The results indicate irreducible water saturation was not reached, which is consistent with the findings of Morrow and Ward (1984) in their study of low permeability sandstone. Moreover, the minimum water saturation is defined with reference to the maximum speed of the centrifuge and it varies with the duration of the experiment significantly. Most of the samples have a minimum water saturation of > 40%, except sample HP2V, which behaves somewhat differently.

Relative Permeability Results

The results from the relative permeability experiments are shown in **Figure (5a).** They show that the effective gas permeability is reduced dramatically with increasing water saturation. Corey correlation has been used to extrapolate the gas relative permeability to a wider range of water saturations. The gas exponent represents a good fit through the data set, **Figure (5b)**. It should be noted that the gas relative permeability obtained extends beyond the minimum water saturation obtained from the centrifuge. On the other hand we still have no data for the water relative permeability, thus it was assumed that the fault is water-wet, which is a reasonable assumption for a gas reservoir.

INCORPORATION OF FAULT MUTLI-PHASE PROPERTIES INTO A SIMULATION MODEL

The Rotliegend play in the southern North Sea consists of high net-to-gross aeolian sandstones of Late Permian age deposited on the southern edge of the Southern Permian Basin. The high net-to-gross Rotliegend reservoir sandstones directly overlie the prolific Carboniferous source rocks, and are generally sealed by a thick sequence of Zechstein evaporites. Compartmentalisation of the Rotliegend reservoirs is one of the key issues affecting their development and production. For example, van der Mollen et al., (2003) showed that a 250 bar pressure difference built up across a fault during production from a Rotleigend reservoir from offshore Netherlands. This fault clearly juxtaposed Rotleigend against Rotliegend suggesting that the presence of the fault rock itself was responsible for the compartmentalisation. In the following section we present some results from a simplified production simulation model, which show how the relative permeability and capillary pressure results presented above can help explain this level of compartmentalisation. We begin by describing the production simulation model and then compare the results from simulations. The multi-phase flow properties of the faults used in the production simulation model are compared with traditional methods which account for faults based on their single-phase permeability values.

Production Simulation Model Description

We have created a simplified production simulation model using Eclipse^{TM} 100 black oil simulator, **Figure (6)**, which has similar compartment sizes to the reservoir described by van der Mollen et al., (2003). Two distinct models were created. In the first, transmissibility multipliers (TM) were calculated to take into account the presence of the fault using the methodology described by Manzocchi et al. (1999). For this model, TM values were calculated from an average of the single-phase permeability values (i.e. 0.004 mD) presented above and assuming a fault rock thickness of 0.5 m. Second, the local grid refinement capabilities of Eclipse were used to include the fault discretely so that it could be given its own capillary pressure and relative permeability curves based on the results presented in this study. The basic model is 3000 m long, 4000 m wide and 660 m thick. The gas and water production is controlled by Bottom Hole Pressure (BHP) which was set to 50 bars. The gas water contact (GWC) was set at 3410 m.

Simulation Model Results

Overall, water and gas production did not seem to be overly retarded when the fault properties were incorporated using the methodology of Manzocchi et al., (1999) which is based on single-phase permeability values. After 20 years of production from one compartment, the predicted pressure in the other compartment was 96 bar when the fault is taken into account by TM. A particularly important result is that despite changing flow rates, and using reservoir permeabilities between 10 and 1000 mD we could not reproduce the 250 bar cross-fault production-induced pressure difference reported by van der Mollen et al., (2003). When the fault rock was given its own relative permeability and capillary pressure curves, consistent with the SCAL analysis results described above, the fault acted virtually as a total barrier to gas production and was able to reproduce the 250 bar pressure difference, **Figure (7)**, reported by van der Molen et al. (2003). The latter model matches almost exactly the real field data.

From the absolute permeability, capillary pressure, relative permeability values and modeling results it can be concluded that the Lossiemouth fault material acts as a seal.

DISCUSSION

Core analysis experiments conducted during this study have shown that low permeability fault rocks can have gas relative permeability values of <0.01 at reservoir conditions. These results help explain why Rotleigend reservoirs in the southern North Sea are often highly compartmentalised despite having very high net-to-gross ratios. The results highlight that it may be beneficial for Industry to invest more effort in measuring the multi-phase flow properties of fault rocks. These multi-phase flow properties will enable the simulators to better predict and model fluid flow within reservoirs that are compartmentalised by fault rocks with both low permeability and high capillary pressure values.

CONCLUSION

- We have provided data on the relative permeability of faults rocks to gas, which we believe are the first measurements ever published on this topic. The results should be viewed as an initial step towards a well designed and robust database on the relative permeability characteristics of fault rocks.
- The incorporation of these results into a production simulation model of a compartmentalised gas reservoir produced a history match that was much better then the classical method of treating the faults in production simulation models i.e. using transmissibility multipliers based on single-phase values. These new results may mean that we are now in a far better position to predict future production from gas reservoirs, which may lead to better day-to-day decision making.

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Table 1. Single-phase permeability results from the seven cores of the Hopeman fault rock analysed during this study.

Sample	Length (cm)	Diameter (cm)	Pore volume (cm^3)	Porosity (%)	Pulse decay (mD)	Klinkenberg Permeability (mD)	Water Permeability (mD)
HP3b	5.08	2.49	2.23	9.02	0.003	0.004	0.003
HP3a	4.89	2.47	1.88	8.02	0.001	0.002	0.003
HP2U	4.94	2.49	1.45	6.03	0.006	0.006	-
HP2V	4.75	2.49	1.39	6.01	0.003	-	-
HP2X	4.79	2.5	1.53	6.49	0.005	-	-
HP2Y	4.77	2.5	1.27	5.41	0.002	-	-
HP2Z	4.84	2.5	1.54	6.47	0.004	-	-

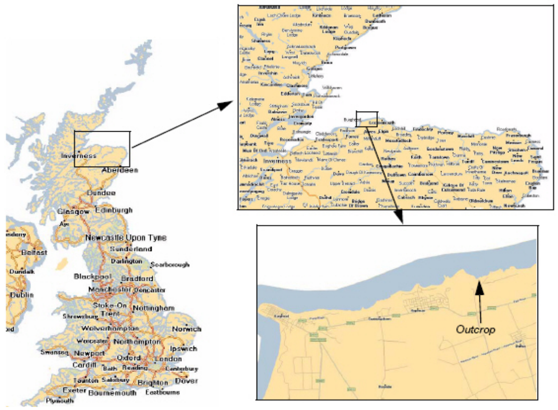

Figure 1. Location of the Clashach Quarry, near Burghead, Scotland.

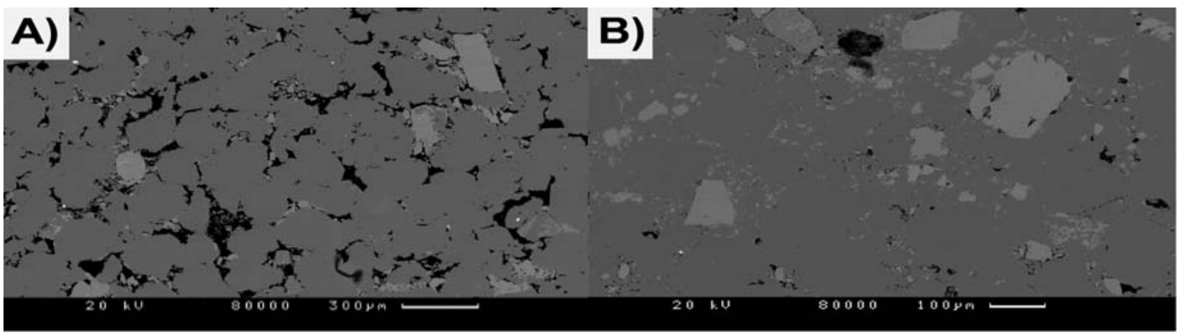

Figure 2. BSE images of a) the undeformed Hopeman sandstone and b) the cataclastic fault rock from the core of the Lossiemouth Fault. Note the fine grain-size of the fault, its low porosity and small pore-size.

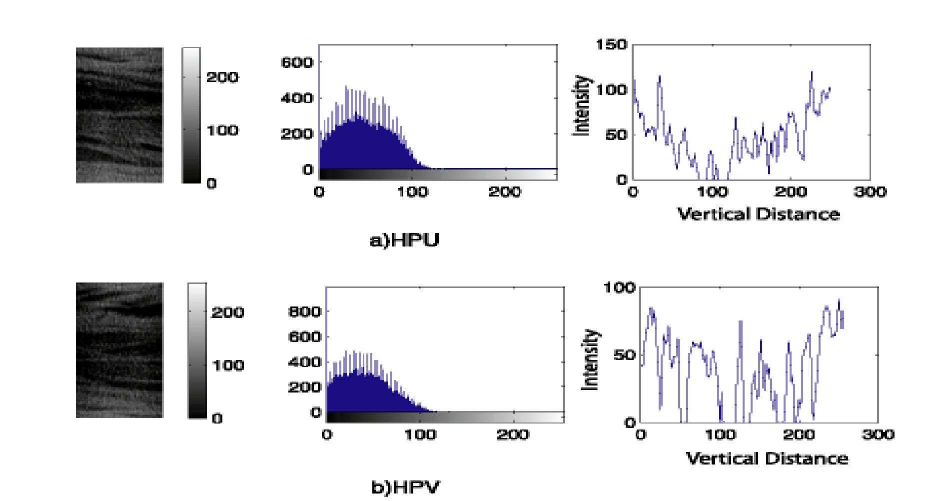

Figure 3. X-Ray tomography of two cataclastic fault rocks. Note the heterogeneity variation along the length of the sample which is clearly shown in the right hand plot.

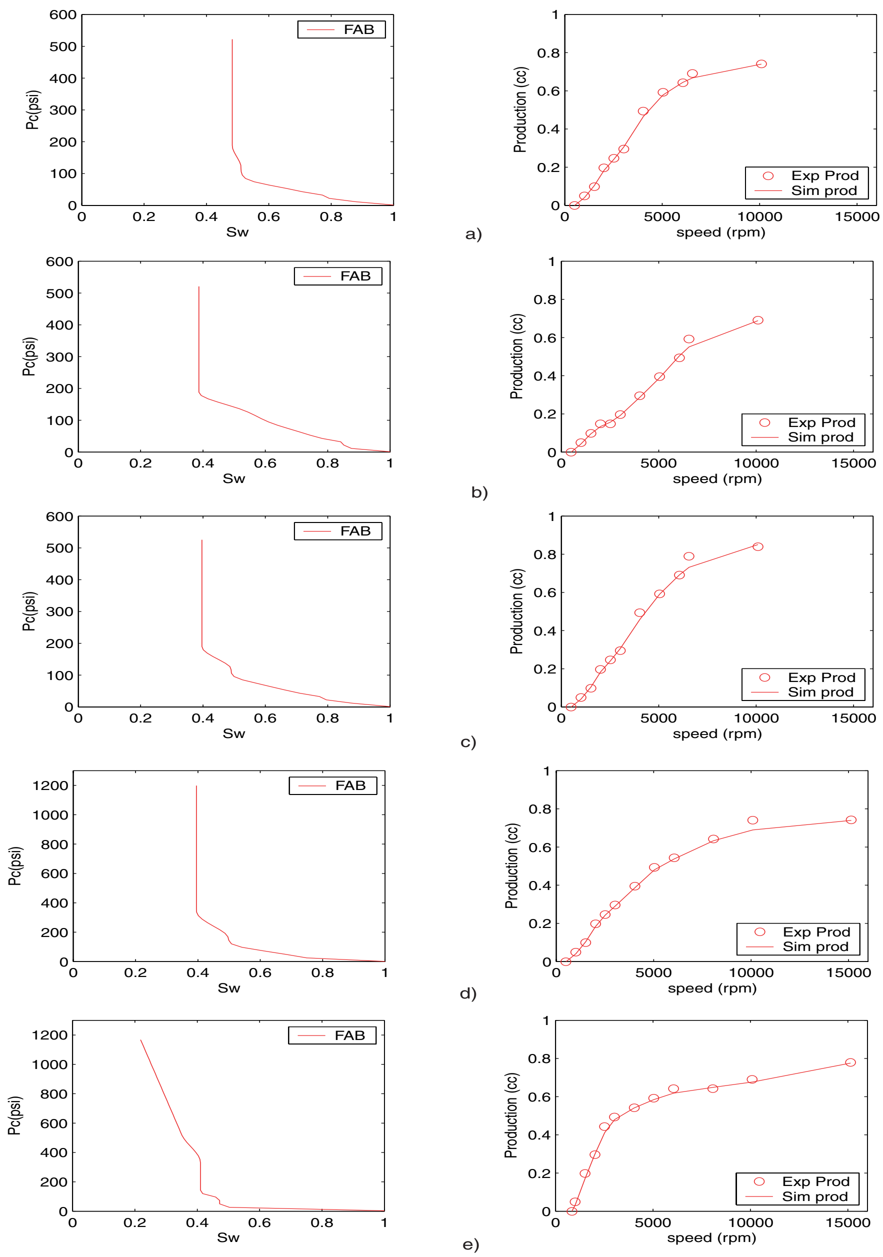

Figure 4. Air-water capillary pressure drainage curves for five samples of the Lossiemouth fault from the Clashach Quarry. Maximum centrifuge speed was 10000 rpm for HP2X (a), HP2Y (b), HP2Z (c) and a maximum speed of 15000 rpm for HP2U (d) and HP2V (e).

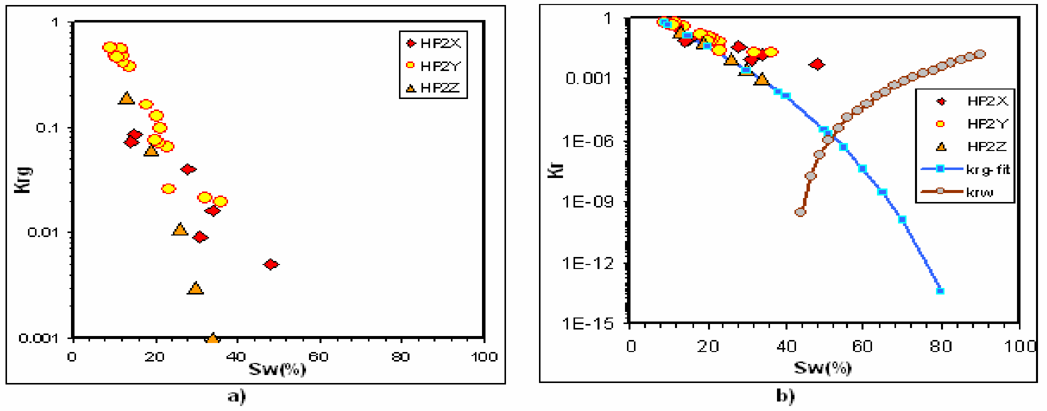

Figure 5. a) Experimental K_{rg} results for three samples of the Lossiemouth fault; b) Relative permeability curve used for modelling using Corey functions.

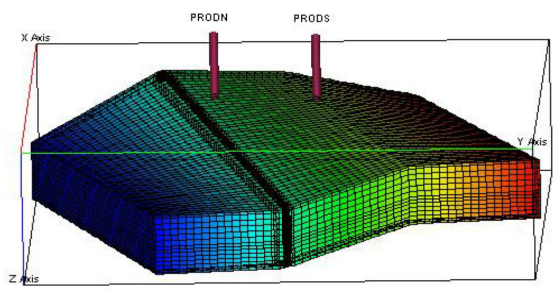

Figure 6. Model geometry with local grid refinement representing the fault. The fault cuts the entire model, splitting it into two compartments with possible communication.

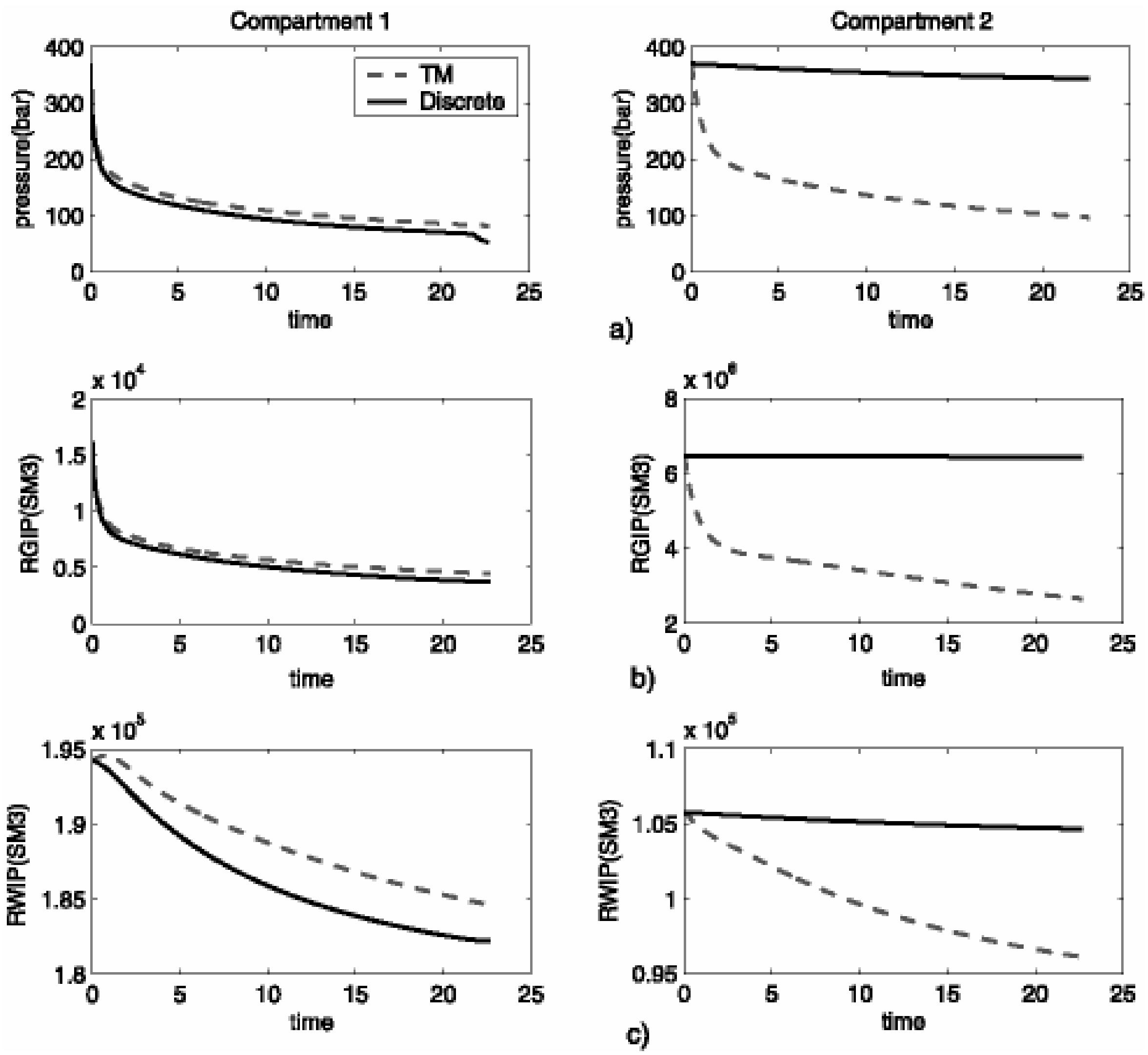

Figure 7. Some simulation results to compare the TM and the discrete model for Compartment 1 and compartment 2. a) Pressure in the compartment as a function of time. b) Region gas in place as a function of time. c) Region water in place as a function of time. The initial state of the reservoir before any production, the pressure in both compartments was 370 bar. After 20 years of production from one compartment, the predicted pressure in the other compartment was 96 bar when the fault is taken into account by TM, whereas when taking into account the multi-phase flow properties of fault, i.e. by including the relative permeability curve for fault in the simulation model, the pressure was 343 bar. The latter model matches almost exactly the real field data.