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Department of Earth Science and Engineering
Centre for Petroleum Studies

Numerical Investigation of Two-Phase Flow through a Fault

By

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DECLARATION OF OWN WORK

I declare that this thesis **Numerically Investigation of Two-Phase Flow through a Fault** is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

Signature: ....

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Numerical Investigation of Two-Phase Flow through a Fault

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Abstract

Faults are naturally occurring baffles or barriers to flow prevalent in hydrocarbon reservoirs which often affect reservoir performance predictions if their two-phase effects on fluid flow are not properly modelled. Realistic modelling of these effects in predictive flow simulation models offers the potential to understand their impacts on hydrocarbon production timescale and helping constrain development strategies. Single-phase flow effects of faults have been captured as transmissibility multipliers in conventional flow simulators but the realistic impacts of two-phase flow through faults cannot be approximated by these multipliers. This paper focuses on a series of numerical investigation of two-phase flow through a fault using conceptual models to capture the correct behaviour of fluid flow upstream of the fault.

In this study, we modelled two-phase (oil and water) flow through idealised one-dimensional (1D) conceptual models that mimic the reservoir/fault situations, and having different relative permeability and capillary pressure data for the fault and the reservoir rock. These data were derived from established correlations for qualitatative modelling. Realistic fault representation with explicit water-wet saturation functions was compared with the conventional field-scale fault representation where faults are treated as permeability baffles. Sensitivity studies on model grid size, fluid viscosity and interstitial velocity were conducted and the importance of fine grid modelling of two-phase flow properties through a fault to capture the correct mobility upstream of the fault was investigated.Waterflooding, a typical oil recovery process, is used in this study.

The results show that it is important to correctly model two-phase flow through faults in order to better predict reservoir performance, and to allow for sound reservoir management decisions. They can also be used to assist in the understanding of the actual flow behaviour upstream of the fault which is necessary to develop suitable fault-rock pseudo-curves that duplicate the realistic two-phase transmissibility multipliers.

Introduction

Faults in porous clastic reservoirs are generally baffles to flow which are known to strongly affect hydrocarbon reservoir connectivity and, hence reduced petroleum recovery. Most petroleum reservoirs, due to their natural geologic settings, have faults and several oil and gas fields that are currently being produced have experienced significant problems with reservoir performance predictions due to fault-related features (e.g Brent Province of the Northern North Sea) Jolley *et al.*, 2007. Accurately modeling the impacts of faults on field-scale simulation models is far from satisfactory due to the treatment of their dynamic two-phase properties in conventional flow simulators.This may result to significant uncertainties on flow behaviour predictions which may lead to costly reservoir management decisions (Walsh *et al.*, 1998; Knipe *et al.*, 1998). Available commercial field-scale flow simulators do not capture the correct behaviour of flow across these flow baffles and realistic modelling of fault flow properties in predictive reservoir models offers the potential to understand their impacts on hydrocarbon production timescale and helping constrain development scenarios.

Extensive research work by several authors (Bentley & Barry 1991; Fulljames *et al.*, 1997; Knipe, 1997; Foxford *et al*., 1998; Yielding *et al.,* 1998**;** Manzocchi *et al.,* 1999**)** on the baffling effects of faults to flow in reservoirs allows fault properties to be calculated and incorporated into the flow simulation model as transmisibility multipliers assigned to the grid blocks upstream of the fault (Knai & Knipe, 1998; Manzocchi *et al.*, 1999). A promising method for calculating and incorporating geologically-realistic fault transmissibility multipliers as a function of known properties of the reservoir model has been developed by Manzocchi *et al*., (1999). Although, their empirical method clearly shows the dependencies contained within fault transmissibility multipliers but dynamic data such as hydrocarbon column height, pressure differences across faults, well test pressure and production data, differences in fluid compositions within reservoirs where available must be used to condition the overall transmissibility assigned to the fault.The known limitation of fault transmissibility multipliers is that they do not take into account the two-phase behaviour of flow through fault rocks, whose relative permeabilities and capillary pressure curves can have different characteristics to their juxtaposed reservoir flow peroperties (Al-Busafi *et al*,. 2007).

The underlying assumptions and approximations of fault transmissibility multipliers are incorrect for dynamic two-phase flow through faults. In water-wet reservoirs, for example, fault transmissibilities multipliers, even if based on correct predictions of fault rock permeability and thickness, are too permissive to flow of oil and too restrictive to flow of water. In order to reflect two- phase flow through a fault, transmissibility multipliers should not only be phase specific, but should also change in value as a function of the water saturation present (Manzocchi *et al*., 2002). From the foregoing, it has been suggested on theoretical grounds that incorporating the two-phase fault rock properties explicitly in faulted reservoirs would have an increasingly significant role in obtaining improved flow simulation results as capillary effects become relatively more significant to viscous effects (Ringrose & Corbett 1994; Fisher & Knipe 2001; Manzocchi *et al*., 2002; Al-Busafi *et al*., 2005; Al-Hinai *et al.,* 2006). To date, however, incorporating fault rock properties in which there is more than one phase present has been a major challenge.

As a next logical step in coming up with two-phase fault transmissibility multipliers in commercial flow simulators, recent research has increased in such flow problems, notably in the oil and gas industries where two-phase mixtures are commonplace. Devising methods to arrive at a more realistic way of incorporating two-phase fault flow properties in routine flow simulation models is therefore still an active area of research (Manzocchi *et al.,* 2010). The concept of using pseudo-relative permeability function in the grid-block upstream of the fault to approximate two-phase flow behaviour through faults has been suggested. Manzocchi *et al.,* (2002) introduced the concept of relative transmissibility multipliers where they demonstrated the use of weighted potential dynamic scale-up methods (Christie, 1996) to upscale relative permeability and the use of coarse grid-block capillary pressure curve as an acceptable compromise to reproduce the fine-scale model using a simple one-dimensional (1D) numerical model. However, the implementation on a 3D complex fault model with different across-faults flow rates is a challenge because varying flow rates in two-phase simulation run require separate pseudo functions for the different rate. A more practical but similar method was used by Al-Busafi *et al.,* (2007) to generate the dynamic fault rock pseudos using in-situ fractional flows and compartmentalised phase pressures across fault faces in the non-neighbour connections. The in-situ generated pseudos takes advantage of dynamic flux/pressure boundaries preservation in splitting large models into small active regions to allow discrete inclusion of fault zones at a significantly low cost of simulation time. These methods, however, are often difficult to implement (Fisher & Jolley, 2007). The capillary entry height method as proposed by Zijlstra *et al.,* (2007) differs from the previous approaches in that they attempted to account for the two-phase flow properties of fault rocks in dynamic models of real producing reservoirs (Southern Permian Basin in the North Sea). Their method is rather simple but does not attempt to capture the full range of possible behaviour applicable to all situations in which two-phase properties may be important. The suitability of such an approach may vary over the life of a field. Determining the precise circumstances in which two-phase fault rock properties might be significant in production simulation has been studied by Al–Busafi *et al.,* (2005) and there are revealing.

Unfortunately, the progress from single-phase fault transmissibility multipliers to modelling two-phase flow properties through faults in the existing methods are plagued with problems. These difficulties frequently arise from not capturing the correct reservoir characterisation (e.g. across fault heterogeneities) and incomplete knowledge of the flow behaviour across a fault (Dawe *et al.,* 2010). In order to capture this flow behaviour in the flow simulation models, subgrid scales modelling that accurately represent the correct flow physics is required for the development of suitable pseudo functions. Upscaling therefore is required but the technique will not be optimal except the flow physics is well understood and reproduced in the coarse simulation model.

This study presents numerical investigation on the importance of modelling two-phase flow through a fault and the limitations of commercial flow simulators in capturing the correct flow behaviour. This is achieved through detailed numerical simulations using idealised one-dimensional (1D) reservoir-fault models having different relative permeabilities and capillary pressure curves for the fault and the reservoir rock. Sensitivity studies on model grid size, fluid viscosity and interstitial velocity are conducted.

Transmissibility and Fault Transmissilibity Multipliers

In reservoir simulation, the key is to determine the inter-block flow given the cell properties. Fluxes between pairs of grid-blocks in the discrete solution of flow equation are calculated as a function of a special conductance property called transmissibility. It represents the harmonic averaged permeability between two cell centres weighted by the distance separating their centres (Schlumberger Technical Description, 2010). In this work, we used Eclipse 100$^{\text{TM}}$ flow simulator to numerically investigate the impacts of incorporating two-phase fault properties explicitly at the juxtaposed interface.

Most naturally occurring reservoirs are heterogeneous in nature and sometimes with great difference in intrinsic rock properties of adjacent rock (e.g. fault superimposed on sedimentary heterogeneity). If the effects of such heterogeneities are not well incorporated into the simulation model to capture the correct flow displacement behaviour, reservoir management decisions made with such a model at the planning stage of oil recovery operation may be costly and the consequence become evident when it is too late to remedy.

The mass flux of component between two adjacent grid-blocks *A* and *B* is governed by the combination of Darcy's law and conservation of mass (ignoring gravity effect).

$$\mathrm{Q}_{AB} = \left(\lambda_p \mathrm{K}\right)_{AB} \left(\frac{\mathrm{A}_{AB}}{\mathrm{L}_{AB}}\right) (\mathrm{P}_B - \mathrm{P}_A)_p \quad \text{.....} \quad (1)$$

where λ_p is the mobility of phase *p*, *K* is the absolute permeability; P is the phase pressure; A_{AB} and L_{AB} are the area and length for the pressure gradient determination respectively. In Equation (1), the terms independent of pressure and saturation can be grouped in the form

$$\mathrm{Q}_{AB} = \mathrm{T}_{AB}\left(\lambda_p\right)_{AB} (\mathrm{P}_B - \mathrm{P}_A)_p \quad \text{.....} \quad (2)$$

where T_{AB} is called the transmissibility which is, therefore, defined as

$$\mathrm{T}_{AB} = \mathrm{K}_{AB} \frac{\mathrm{A}_{AB}}{\mathrm{L}_{AB}} \quad \text{.....} \quad (3)$$

It is evident from Equation (3) that interblock transmissibility is only dependent on grid block geometry and permeability.This does not take the mobility of flow at the interface into account.

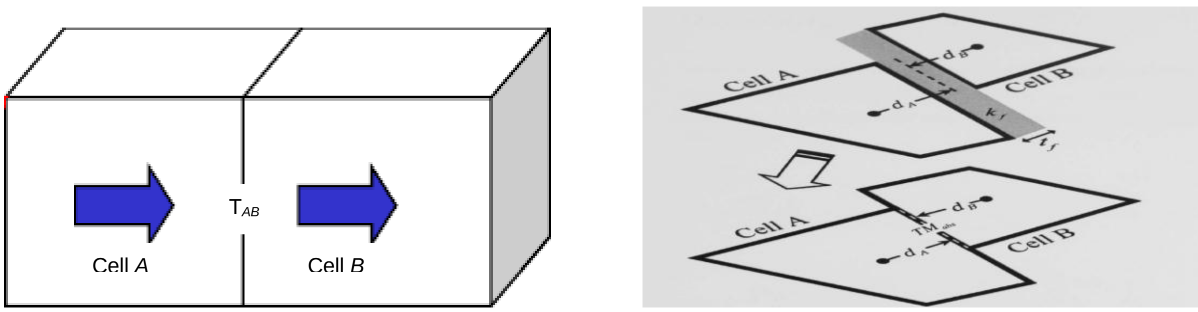

Figure 1: (a) Sketch of idealized grid-blocks. (b) Representation of a fault between grid-blocks *A* and *B*.

Eclipse 100$^{\text{TM}}$ flow simulator calculates interblock transmissibility based on the type of grid used i.e. Cartesian, modified Cartesian and corner point grid). For a pair of grid-block illustrated in **Figure 1a**, Eclipse simulator calculates interblock transmissibility as:

$$\mathrm{T}_{\mathrm{AB}} = \frac{\mathrm{C}_{\mathrm{D}}\ \mathrm{T}_{\mathrm{mult}}}{\left(\frac{1}{\mathrm{T}_A}\right)+\left(\frac{1}{\mathrm{T}_B}\right)} \quad \text{.....} \quad (4)$$

where C_D is the Darcy's unit conversion factor (0.00853 in metric units, 0.001127 in field units), T_{mult} is the user-defined transmissibility multiplier included for changing the calculated transmissibility value to account for features that enhance or resist flow (e.g. faults, fractures). T_A and T_B are the inner transmissibilities for cell *A* and *B*, respectively, defined by

$$\mathrm{T}_A = \mathrm{K}_A . \mathrm{N}_A \left(\frac{\mathrm{A}_A}{\mathrm{L}_A}\right) \text{.....} \quad (5)$$

$$\mathrm{T}_B = \mathrm{K}_B . \mathrm{N}_B \left(\frac{\mathrm{A}_B}{\mathrm{L}_B}\right) \text{.....} \quad (6)$$

where K in the intrinsic permeability and N is the net-to-gross ratio for each cell.

The effect of fault on flow arising from fault-rock petrophysical properties can be taken into account in flow simulators by applying transmissibility multipliers to the face of grid blocks adjacent to the fault Manzocchi *et al.*, (1999). In this approach, the fault zone structure and content, basically permeability and thickness are captured and represented as a single and absolute value. This value is termed an absolute transmissibility multiplier and it replaces the user-defined multiplier, T_{mult}, to give the overall flow resistance between faulted cells without the need to include the fault zone explicitly. To capture the static properties of the fault zones and content, knowledge of both the permeability and thickness of the fault rock and the undeformed sand of the grid-blocks adjacent to the fault are required. Readers are referred to Manzocchi *et al.* (1999) for detailed discussion.

The fault absolute transmissibility multiplier, TM_{abs}, is defined as the ratio of the interblock transmissibility between two cells with the fault present to the transmissibility without the fault. It is calculated using:

$$\mathrm{TM}_{abs} = (\mathrm{T}_{AB})_f / \mathrm{T}_{AB} \quad (7)$$

where T_{AB} is the interblock transmissibility between cells *A* and *B* given by Equation 4 and $(\mathrm{T}_{AB})_f$ is the analogous definition to T_{AB} when the static properties are taken into account. The transmissibility between the grid blocks *A* and *B* across a fault of thickness tf and permeability kf (Figure 1b) is calculated using:

$$(\mathrm{T}_{AB})_f = \frac{\mathrm{C_D}\ \mathrm{T_{mult}}}{\left(\frac{1}{\mathrm{T}_A}\right)_f + \left(\frac{1}{\mathrm{T}_B}\right)_f} \quad (8)$$

Here $(\mathrm{T}_A)_f$ and $(\mathrm{T}_B)_f$ are the inner transmissibilities of each cell incorporating half of the fault thickness and they are calculated as follows (Al-Busafi *et al.*, 2007):

$$(\mathrm{T}_A)_f = a_A \mathrm{T}_A \quad (\mathrm{T}_B)_f = a_B \mathrm{T}_B \quad (9)$$

where T_A and T_B are the cells without the fault defined in Equation (5).

The factors a_A *and* a_B are calculated by attributing half of the unit of the fault thickness to each cell and calculating the harmonic average permeability across the merged cell and fault.

$$a_A = \left[1 + \left(\frac{t_f}{2d_A}\right)\left(\frac{k_A}{k_f} - 1\right)\right]^{-1} \quad (10)$$

$$a_B = \left[1 + \left(\frac{t_f}{2d_B}\right)\left(\frac{k_B}{k_f} - 1\right)\right]^{-1} \quad (11)$$

Combining Equation (4) with Equations (7 to 9) gives the absolute transmissibility multiplier TM_{abs} between two fault-juxtaposed cells as

$$\mathrm{TM}_{abs} = \left(\frac{1}{\mathrm{T}_A} + \frac{1}{\mathrm{T}_B}\right) / \left(\frac{1}{(\mathrm{T}_A)_f} + \frac{1}{(\mathrm{T}_B)_f}\right) \quad (12)$$

Equation (12) gives an absolute value determining the resistance or conductance of a fault.

It is important to note that the absolute transmissibility multiplier are independent of pressure and saturation, and hence they represent a pure single-phase treatment of the fault, as the multiplier acts indiscriminately on all fluid phase (Manzocchi *et al.*,1999). The numerical investigation, however, shows that this conventional treatment of faults may not always be valid to approximate two-phase immiscible flow through faults.

Simulation Model Description

During this study, we considered two simple 1D models for investigating the importance of modelling two-phase flow effects through a fault contained within the reservoir sand in order to correctly predict fluid mobility and hence pressure drop between the wells on the either side of the fault.Waterflooding, a typical oil recovery process, is used in our study. We assumed constant rate two-phase (oil and water) flow displacement where fluids are considered immiscible and hence, there is no mass transfer between the phases. This is to ensure there is no interference between phases that might result in reduction of total flow for a given pressure drop. Two vertical wells –a producer and an injector were defined in each of the models and the injection well was located in the first grid-block while the producing well was located in the last grid-block of the models. Both wells were controlled by reservoir volume to achieve 100% voidage replacement and differential pressure created between the wells was mainly achieved due to source-sink potential. Buoyancy force can have a significant impact on the fault-rock capillary pressure (Manzocchi *et al.*, 2002, Al-Busafi *et al.*, 2005, and Zijlstra *et al.*, 2007). For our models, however, the tops of the conceptual models were located 2500m above the oil-water contact where both oil and water phases are mobile within the fault-rock and the fault-rock water saturation is determined both by the local capillary pressure and by the shape of the fault-rock capillary pressure curve throughout the simulations. This makes the fault-rock acts as a permeability baffle or barrier that can influence cross-fault flow between juxtaposed permeable rocks.

Immiscible displacements bring into any analysis the problems created by capillary pressure and relative permeability phenomena. These have the further dimension requiring the knowledge of saturation distribution, saturation gradients, wettability effects and positions of residual and mobile phases.To provide a firmer understanding of the dynamics of capillary end effects behaviour of two-phase immiscible flow, essentially during co-current waterflood displacement in a faulted reservoir, we started with a numerical investigation of a 1D conceptual model comprising two different rock types (strongly oil-wet and strongly water-wet) butted together in series, which explains the saturation distribution process due to capillary heterogeneity at a discontinuous interface. The discontinuity was created by wettability difference in the two homogeneous rock type having a uniform porosity value of 20% and permeability value of 100mD in all directions. The model dimension is 480m ×1m divided into 40 uniform size grid-blocks with an injection well in block (1, 1) and a producing well in block (40, 1). The model was filled with oil with no oil-water contact and the wells were operated at constant rate. We assigned oil-wet relative permeability and capillary pressure to the first 20 grid-blocks and water-wet relative permeability and capillary pressure to the last 20 grid blocks. Grid sensitivity analyses on various field parameters were conducted to justify the number of grid cells required in the fine-scale model used in this study. We concluded based on the simulation sensitivity studies (APPENDIX C) that about 320 cells will give the most realistic saturation distribution profile. A common assumption of any upscaling study is that high-resolution model gives the most realistic result.

Based on our preliminary study, we built two conceptual heterogeneous models having low permeability fault-rock contained within the reservoir sand with dimensions of 5m × 1m. The fine-grid model is made up of 360 cells (corresponding to 360 × 1 × 1 grid-blocks in the x-, y- and z- directions respectively) designed such that the grid-blocks sizes get gradually smaller when approaching the fault-rock while the coarse model has 5 cells (corresponding to 5 × 1 × 1 grid-blocks in the x-, y- and z- directions respectively) without any refinement. These models are illustrated in **Figure 2.**

The following simplifying assumptions were made:

1. grid-block dips are ignored,
2. the grid block net-to-gross ratios and across-fault juxtaposition areas are all taken as unity, and
3. all non-fault grid-blocks have the same properties.

These parameters influence flux calculation between grid-blocks but we make these simplifications to focus on the impacts of two-phase fault-rock properties on flow mobility across the permeability boundaries. The conceptual models were specifically designed as described above to mimic reservoir-fault situations which are ideal for incorporating the fault-rock capillary pressure and relative permeability data explicitly and to allow for a thorough investigation into the impacts of these properties on flow mobility and hence pressure drop between the wells on the either side of the fault.

In this study, the fault-rock properties were defined explicitly using a 1m thick fault characterised with an assumed permeability of 0.1 mD contained within a 5m long, 100mD grid-blocks. We used an interstitial flood velocity of 0.3 m/day corresponding to a well injection rate of 0.06 m^3/day for all the simulation models. Water and oil viscosity are 0.5 cp and 1 cp respectively.

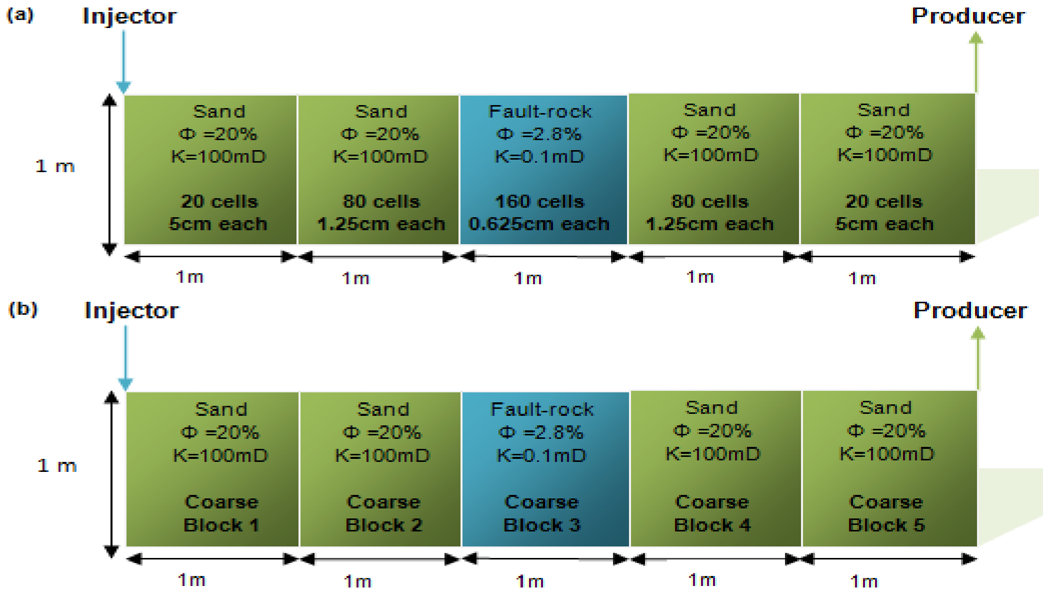

Figure 2: Sketch of the conceptual simulation models used in this study. (a) fine-grid model; (b) coarse model.

Methodology

In order to achieve our objectives, reservoir simulations were conducted using the models to investigate the importance of modelling two-phase flow properties through a fault and the limitations of commercial flow simulators in predicting the correct flow behaviour.We simulated these effects on two types of reservoir: mixed-wet and oil-wet reservoirs. Wettability is defined as the preferential affinity of the porous medium for a particular fluid (Dake, 1978). Rock is defined as water-wet if the rock has (much) affinity for water than for oil, and if it is oil the rock is oil-wet. Hydrocarbon reservoirs are commonly mixed-wet where part of the rock surfaces (usually the large pore spaces) are preferentially oil-wet with oil film being continuous while the remaining parts (fine pores and grain contacts) are preferentially strongly water-wet. The relationship between the capillary pressures and the wetting phase saturation in a porous media is known as the capillary pressure curve (Amyx, 1960) and are determined for various rock types by the equations defined in Equations (13 to 15) for our qualitative modelling. Imbibition is defined as an increase in the wetting phase saturation, and drainage is defined as a decrease in the wetting phase saturation

Oil-water relative permeability in an implicit function of wettability.In practice, the most generally accepted two-phase analogue of the single-phase transmissibility multipliers is to incorporate a water-wet fault with water-wet saturation functions explicitly into a flow simulation model (Manzocchi *et al.* 2002). We used this approach in our numerical investigation. Explicitly incorporating water-wet fault into our test cases is termed the **“realistic method”** while explicitly incorporating either oil-wet or mixed-wet fault which is analoguous to the conventional fault transmissibility multipliers in available commercial flow simulators is termed ***"TM".*** This is to represent the conventional field-scale practice where faults are treated as permeability barriers. Comparisons are made between these two representations.

Using the fine-grid model ($360 \times 1 \times 1$), four test cases are presented.

Case A: mixed-wet fault (160 cells, 0.625 cm each) contained within mixed-wet reservoir sand. This illustrates the conventional field scale simulation in which the fault is acting as a permeability barrier in a mixed-wet reservoir.

Case B: water-wet fault (160 cells, 0.625 cm each) contained within mixed-wet reservoir sand. This illustrates the realistic two-phase fault representation in a mixed-wet reservoir.

Case C: oil-wet fault (160 cells, 0.625 cm each) contained within oil-wet reservoir sand. This illustrates the conventional field scale simulation in which the fault is acting as a permeability barrier in an oil-wet reservoir.

Case D: water-wet fault (160 cells, 0.625 cm each) contained within oil-wet reservoir sand. This illustrates the realistic two-phase fault representation in an oil-wet reservoir.

We repeated our simulations using the coarse model ($5 \times 1 \times 1$) and the aim is to justify the need for fine-grid modelling which fully captures the correct flow behaviour across the fault for the development of suitable pseudo-relative permeability functions.

Using the coarse model ($5 \times 1 \times 1$), four test cases are presented.

Case E: mixed-wet fault (100cm thick) contained within mixed-wet reservoir sand. This illustrates the conventional field scale simulation in which the fault is acting as a permeability barrier in a mixed-wet reservoir

Case F: water-wet fault (100cm thick) contained within mixed-wet reservoir sand. This illustrates the realistic two-phase fault representation in a mixed-wet reservoir.

Case G: oil-wet fault (100cm thick) contained within oil-wet reservoir sand. This illustrates the conventional field scale simulation in which the fault is acting as a permeability barrier in a mixed-wet reservoir.

Case H: water-wet fault (100cm thick) contained within oil-wet reservoir sand. This illustrates the realistic two-phase fault representation in a mixed-wet reservoir.

Sensitivity analyses on fluid viscosity ratio and interstitial flood velocity were conducted for all the test cases. Simulation results from (Eclipse 100 **TM**) for our test cases were analysed and discussed. Fortran 90 external code was provided by Rashid Bilal (private communication) to extract the water saturation values from the Eclipse restart files for all the test cases. These values are then taken to Microsoft Excel (2007 version) to plot the saturation distribution profiles (water saturation versus model length) for our discussion. Reservoir geometry, rock and fluid data for the models are summarised in **Table 1**.

Table 1: Reservoir rock and fluid properties for the sand-fault model.

Reservoir and grid blocks data	Reservoir sand	Fault rock
Model dimensions	5m × 1m × 1m	5m × 1m × 1m
Reservoir sand properties	∅ =20%, *k*=100mD	∅ =2.8%, *k*=0.1 mD
Number of grid blocks	5× 1 × 1	360 × 1 × 1
Grid type	Cartesian	Cartesian
Depth to reservoir top	1585 m	1585 m
Production rate	0.06 (m/day) controlled by reservoir voidage	0.06 (m/day) controlled by reservoir voidage
Injection rate	100% voidage replacement	100% voidage replacement
Time step size	20 (steps) × 0.69 (days)	20 (steps) × 0.69 (days)
Rock compressibility	1.42E-05 (1/bars)	1.42E-05 (1/bars)
Fluid data		
Reference pressure	240 (bars)	
Bubble point pressure	80 (bars	
FVF at reservoir pressure	1.01 (rm3/sm3)	
Oil viscosity	1.0 (cp)	
Water viscosity	0.5 (cp)	
Oil compressibility	2.9E-05 (1/bars)	
Water compressibility	3.0E-05 (1/bars)	
Oil density	740 kg/m3	
Water density	1000 kg/m3	

For qualitative modelling purpose, the capillary pressure curves for each reservoir rock type and discrete fault-rock used for all our test cases are derived using the same empirical relationship between capillary pressure, permeability and porosity as that used by Manzocchi *et al.*, (2002) with necessary modifications to account for different rock types

$$\mathrm{P}_{C\,imb} = \mathrm{C}'\,\sigma\,\mathrm{Cos}\theta\,(1 - S_e^5)S_e^{-\frac{2}{3}}\sqrt{\frac{\phi}{\mathrm{k}}}\ , \qquad (\mathrm{C}' = 0.318, \sigma = 20\,\frac{\mathrm{mN}}{\mathrm{m}}, \theta = 20^0) \ldots\ldots (13)$$

$$\mathrm{P}_{C\,drai} = \mathrm{C}'\sigma\,\mathrm{Cos}\theta\,S_{eo}^{-\frac{2}{3}}\sqrt{\frac{\phi}{\mathrm{k}}}\ , \qquad (\mathrm{C}' = 0.318, \sigma = 20\,\frac{\mathrm{mN}}{\mathrm{m}}, \theta = 160^0) \ldots\ldots (14)$$

$$\mathrm{P}_{C\,mixed} = \mathrm{C}'\sigma\,\mathrm{Cos}\theta\,(1 - S_e^5)S_e^{-\frac{2}{3}}\sqrt{\frac{\phi}{\mathrm{k}}} + \mathrm{C}'\sigma\,\mathrm{Cos}\theta\,S_{eo}^{-\frac{2}{3}}\sqrt{\frac{\phi}{\mathrm{k}}} \ldots\ldots (15)$$

where $\mathrm{P}_{C\,imb}$, $\mathrm{P}_{C\,drai}$, $\mathrm{P}_{C\,mixed}$ are capillary pressures for imbibition, drainage and mixed processes, C' is a constant depending on the unit system employed (for metric units, P_C in Bars, k in mD, C' = 0.318), σ is interfacial tension, θ is the contact angle, ϕ is the porosity, k is the absolute (intrinsic) permeability in mD.

We defined the water-wet and oil-wet effective wetting phase saturations as:

$$\mathrm{S_e} = \frac{\mathrm{S_w} - \mathrm{S_{wi}}}{1 - \mathrm{S_{wi}} - \mathrm{S_{or}}} \ldots\ldots (16)$$

$$\mathrm{S}_{eo} = \frac{\mathrm{S}_o - \mathrm{S}_{or}}{1 - \mathrm{S}_{wi} - \mathrm{S}_{or}} \ldots\ldots (17)$$

where S_w is the water saturation, S_o is the oil saturation, S_{wi} is the initial water saturation (typically connate or irreducible value), S_{or} is the residual oil saturation (i.e. the oil saturation that is reached after spontaneous imbibitions only).

A modified connate water saturation (S_{wi}) function (Manzocchi *et al.*, 2002) was used and we varied S_{or} for different rock type.

$$\mathrm{S}_{wi} = \mathrm{S}_{wor} - 10^{-0.6\exp(-0.5\log(\mathrm{k}))} \ldots\ldots (18)$$

Reservoir sand porosity value of 20% was assumed and the fault rock porosity from the assumed fault permeability was determined using an empirical relationship used by (Manzocchi *et al.* 2002).

$$\phi = 0.05\mathrm{k}_f^{0.25} \ldots\ldots (19)$$

Relative permeability curves for each rock type in the model were generated from Corey's correlations (Brook and Corey, 1964) as outlined below.

$$\text{water} - \text{wet:} \quad K_{rw} = K_{rw}^{e}(S_e)^{N^w}; \qquad K_{ro} = K_{ro}^{e}(1 - S_e)^{N^o} \quad \ldots\ldots \quad (20)$$

$$\text{oil} - \text{wet:} \quad K_{rw} = K_{rw}^{e}(1 - S_{eo})^{N^w}; \qquad K_{ro} = K_{ro}^{e}(S_{eo})^{N^o} \quad \ldots\ldots \quad (21)$$

$$\text{mixed} - \text{wet:} \quad K_{rw} = K_{rw}^{e}(S_e)^{N^w}; \qquad K_{ro} = K_{ro}^{e}(1 - S_e)^{N^o} \quad \ldots\ldots \quad (22)$$

where K_{rw} and K_{ro} are the water and oil relative permeability respectively, and K_{rw}^{e} and K_{ro}^{e} are the water and oil relative permeability endpoint respectively. N^w and N^o are Corey's exponents for water and oil respectively. S_e and S_{eo} are the water-wet and oil-wet effective saturations as defined in Equations 16 and 17.

Table 2: Relative permeability (Brook-Corey) parameters for rock type used.

Parameters	Water-wet rock	Mixed-wet rock	Oil-wet rock
K_{rw}^{e}	0.2	0.6	0.7
K_{ro}^{e}	1.0	0.7	1.0
S_{wor}	0.8	0.9	0.7
N^o	2.0	4.0	4.0
N^w	4.0	3.0	2.0

Endpoint saturations, relative permeabilities and Corey's exponents for each rock type are summarised in **Table 2** and we used endpoint scaling option in all the simulation runs.

Resultant relative permeability and capillary pressure curves used in the simulations are shown in **Figures 3 and 4.**

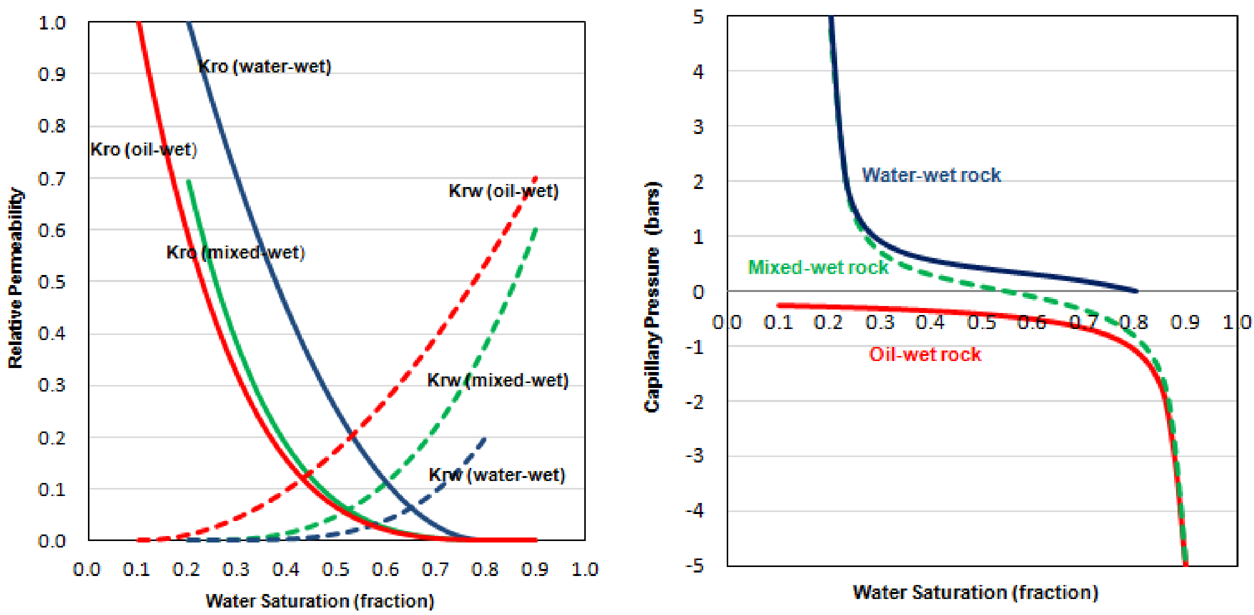

Figure 3: Rock relative permeability and capillary pressure curves.

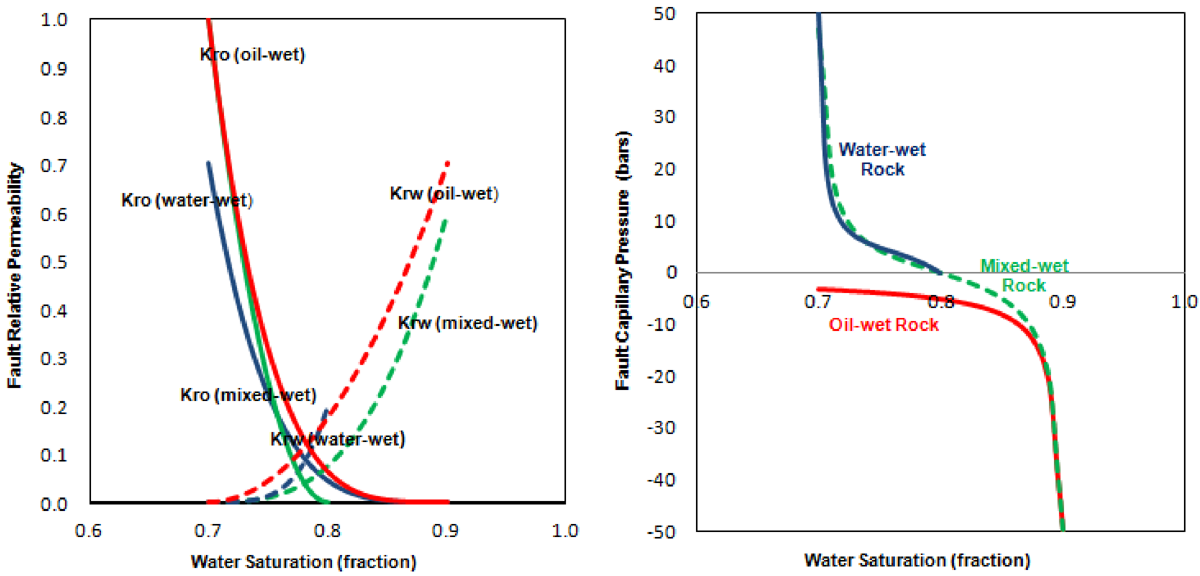

Figure 4: Fault-rock relative permeability and capillary pressure curves.

Results and Discussion

Simulation results for various test cases on the impacts of modelling two-phase flow effects through a fault are presented in **Figures 5 to 15** and the discussion is majorly focused on the behaviour of flow observed upstream of the fault block and its impacts on pressure distribution within the models. This is to see the importance of modelling two-phase flow effects of fault on water saturation distributions which in turn affects the fluid total mobility and hence pressure drops between the wells on the either sides of the fault. Fault-related compartmentalisation in hydrocarbon reservoirs is one of the key issues that can severely affect pressure distribution within a field (Rotlingend Reservoir in the Southern North Sea) and correctly modelling their two-phase effects on oil and gas field development is crucial (Zijlstra *et al.*, 2007). Although, the simulation results show the effects of modelling two-phase flow through faults on other reservoir parameters (sand oil-initially-in place and field oil recovery) but these effects would be minimal on a field-scale simulation model as the actual pore volume of faults compared with the main reservoir sand would be negligible.

Water saturation distribution profiles obtained from the fine-scale model test **cases (A-D)** at 0.4 and 0.6 pore volumes of injected water at constant rate are shown in **Figures 5** and **6**. Waterflooding is from left to right in all the simulation runs. As expected, the fine-scale model runs with explicit two-phase water –wet fault (realistic representation) has low water saturations (indicating high residual oil build-up upstream of the fault–rock zone) due to capillary trapping of the non-wetting fluid while this effect is not reproduced upstream of the fault in the model runs where faults are represented conventionally (**TM**) as permeability barrier. These observations clearly show the limitation of commercial flow simulators, including Eclipse flow simulator used in this study (Schlumberger Geoquest 2010), of modelling two-phase flow effects through faults correctly. Our result confirms the statement of (Manzocchi *et al.*, 2002) that treatments of flow through a fault in commercial flow simulators are captured as transmissibility multipliers which act indiscrimately on all fluid phases. This presents a problem of practical interest in effective development strategies. To date, there is no straightforward method of implementing the realistic two-phase transmissibility multiplier in commercial flow simulators. An alternative approach to the problem is to develop appropriate fault-rock pseudo curves for the fault-adjacent cells in the full-field simulation model.

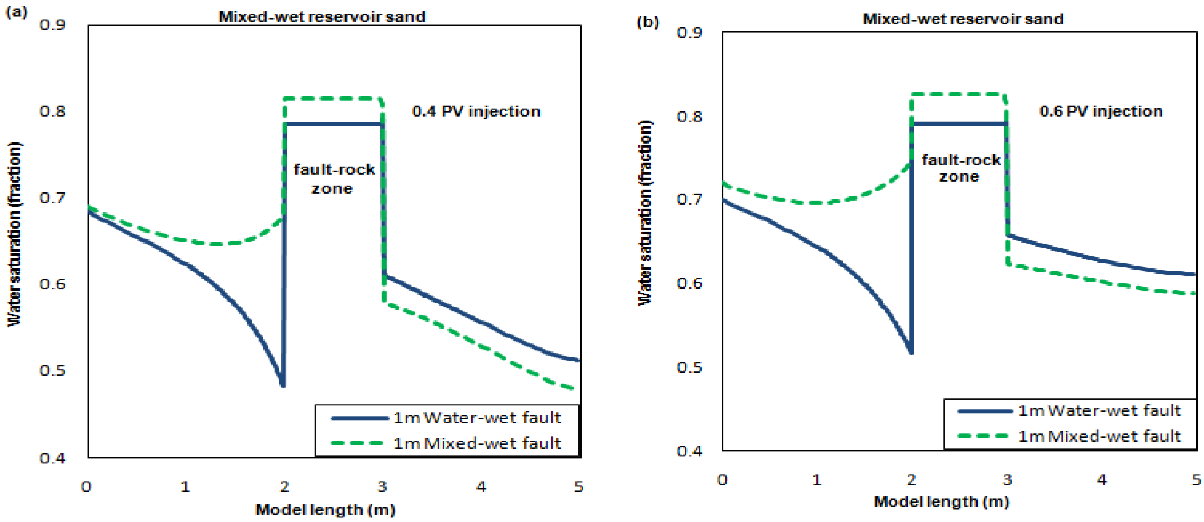

Figure 5: Water saturation distribution against model length (mixed-wet sand). (a) 0.4 PVI; (b) 0.6 PVI.

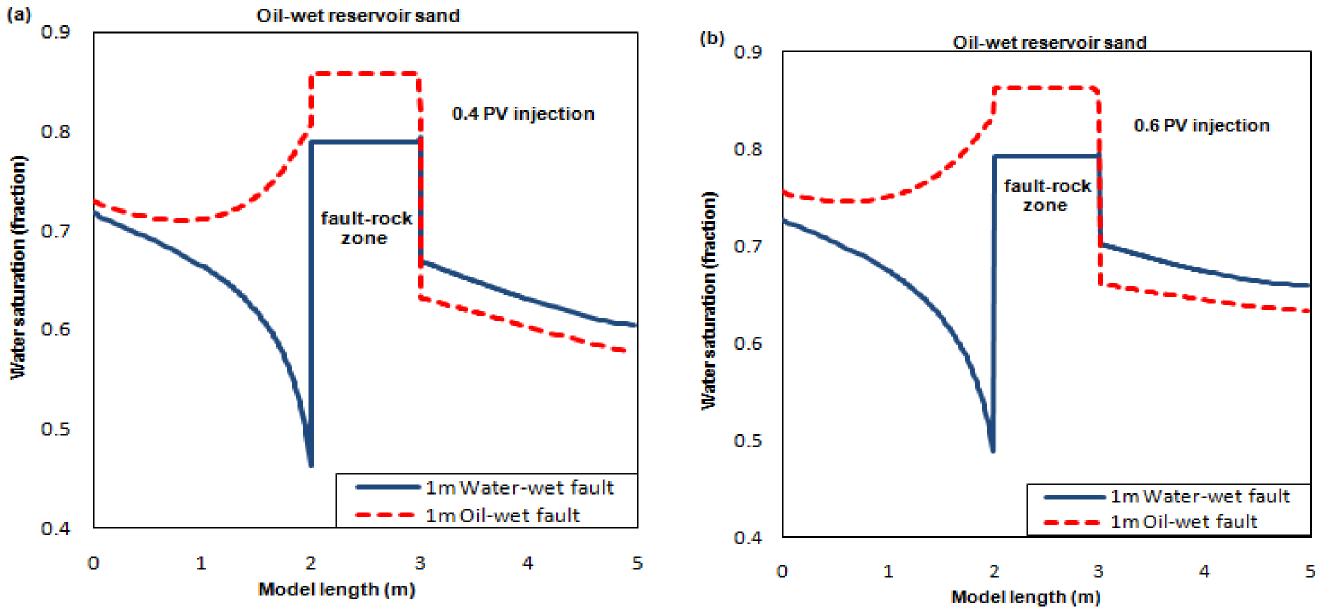

Figure 6: Water saturation distribution against model length (oil-wet sand). (a) 0.4 PVI; (b) 0.6 PVI.

Fine-grid field average pressures for the mixed-wet and oil-wet rock types are plotted in **Figures 7a** and **7b** respectively.It is interesting to note that large differences exist between the fault representations in in terms of their predictions of the field average pressures. One reason for this observation is that, macroscopically, fluid flow in porous media is controlled by reservoir heterogeneity and mobility of the fluid phase present.The ratio of rock permeability to fluid viscosity defines mobility, which largely controls pore-fluid motion and pore pressure in a porous medium. The fine-grid model runs with explicit two-phase water –wet fault (dashed lines) for both mixed-wet and oil-wet sands (**Figures 7a** and **7b**), predicts similar field average pressure distribution which is around 30 bars higher than the models in which the faults are treated as transmissibility multipliers (solid lines). These results clearly suggest that accurately modelling two-phase floe properties through a fault is important in predicting pressure distribution within a field.This as well shows the limitation of commercial flow simulators in capturing the two-phase flow effects through faults correctly. The field average pressure distributions (**Figures 8a** and **8b)** under the same flooding conditions using the coarse model **(Cases A-D)** shows reduction in fluid mobilities hence a larger pressure drop. These two effects cancel out and hence gave the same recoveries in the two rock types. It is well known that boundary condition affects two-phase behaviour, investigating the observation in **Figures 12a** and **12b** at varying injection rate i.e. constant pressure drop boundary condition might be interesting but is beyond the scope of this work. However, the general observation is that flow mobilities and pressure distributions are not preserved in the coarse model. Hence, the need for fine-scale modelling to capture the right physics of flow in a faulted reservoir simulation. Not capturing the correct mobility difference can severely impact the efficiency of waterflooding in a faulted reservoir.

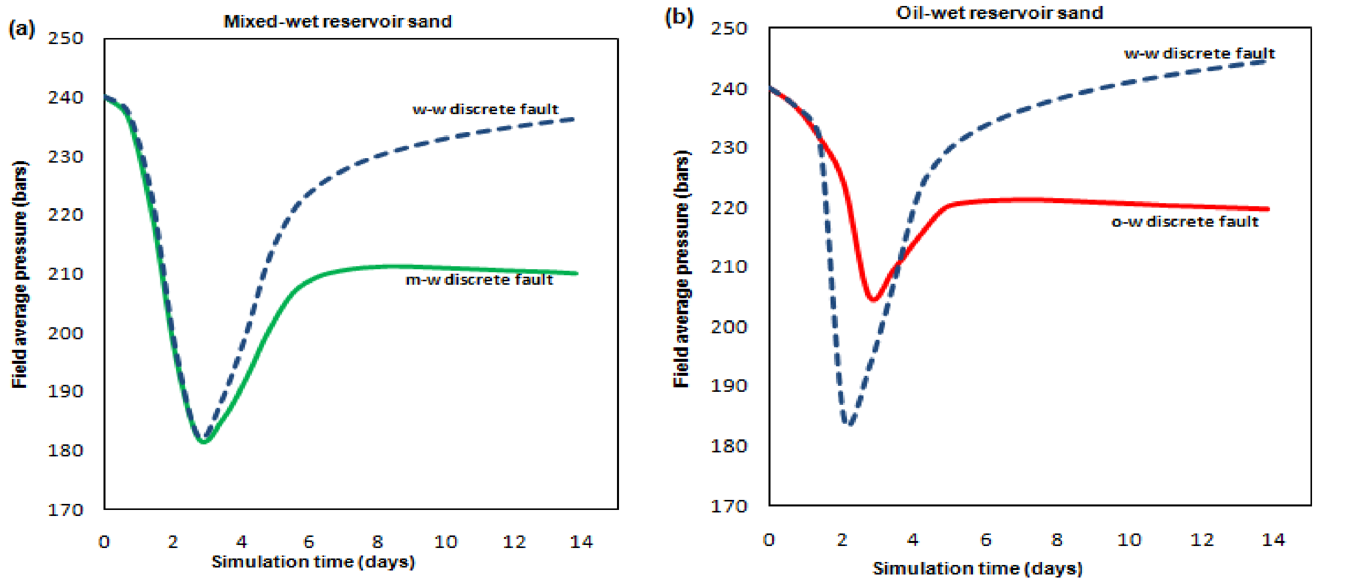

Figure 7: Field average reservoir pressure versus simulation time for the fine-scale model.(a) mixed-wet rock ;(b) oil-wet rock.

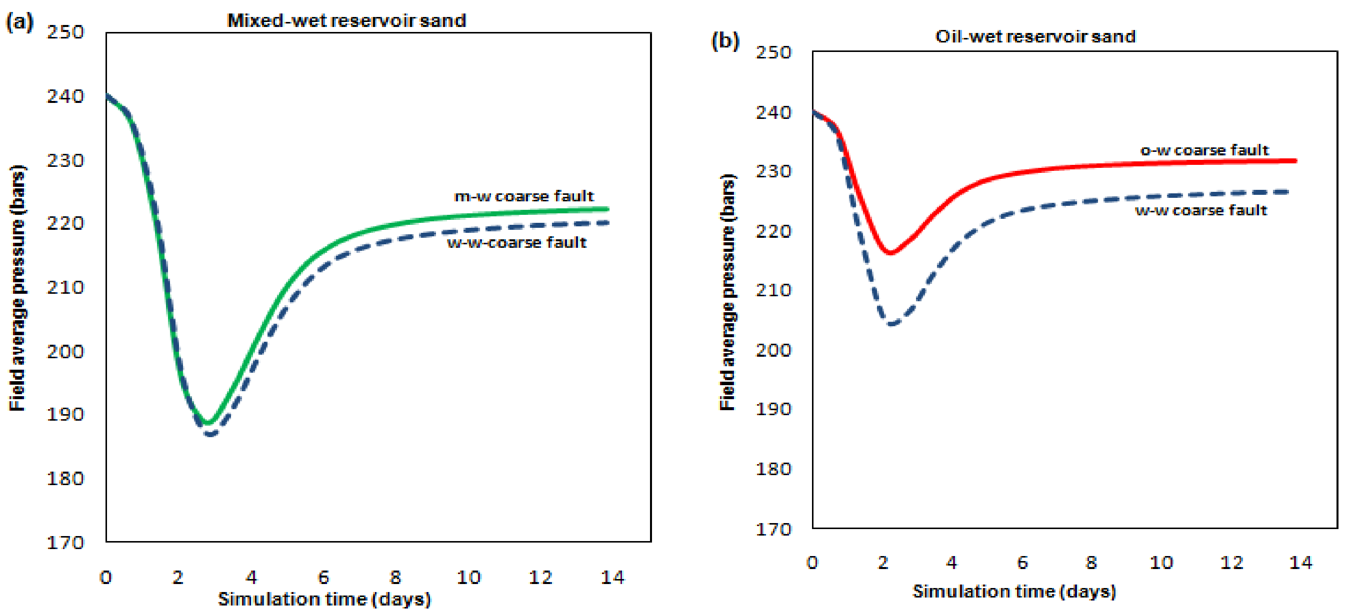

Figure 8: Field average reservoir pressure versus simulation time for the coarse model. (a) mixed-wet rock; (b) oil-wet rock.

Fine-grid bottom-hole pressures for the mixed-wet and oil-wet reservoirs are plotted in **Figures 9a** and **9b** respectively. Large differences exist in terms of bottom-hole pressure distributions between the two rock types. It appears that in mixed-wet reservoir (**Figure 9a**); accurately modelling two-phase flow effects through a fault when predicting bottom-hole pressure within the producing well is not significant. However, large difference in bottom-hole pressure distribution (50 bars) exists for an oil-well reservoir (**Figure 9b**). Similar trend is observed for the coarse grid model (**Figures 10a** and **10b)**.

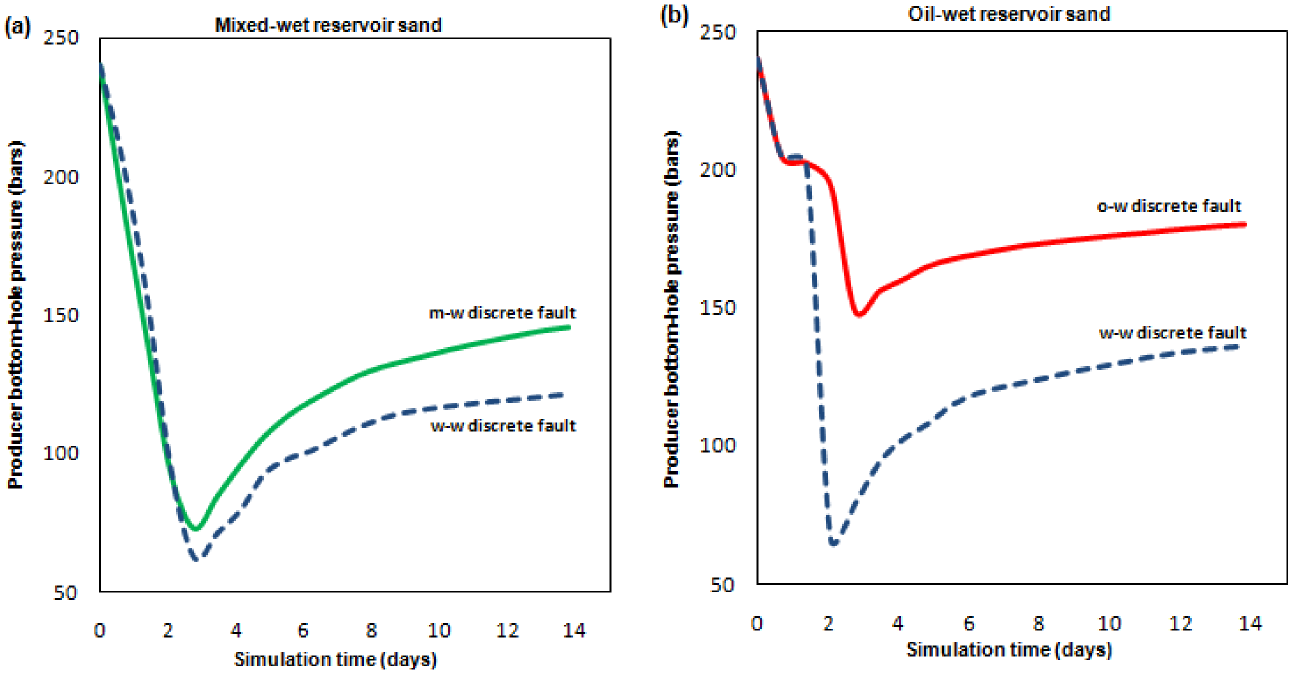

Figure 9: Producer bottom-hole pressure versus simulation time for the fine-scale model. (a) mixed-wet rock; (b) oil-wet rock.

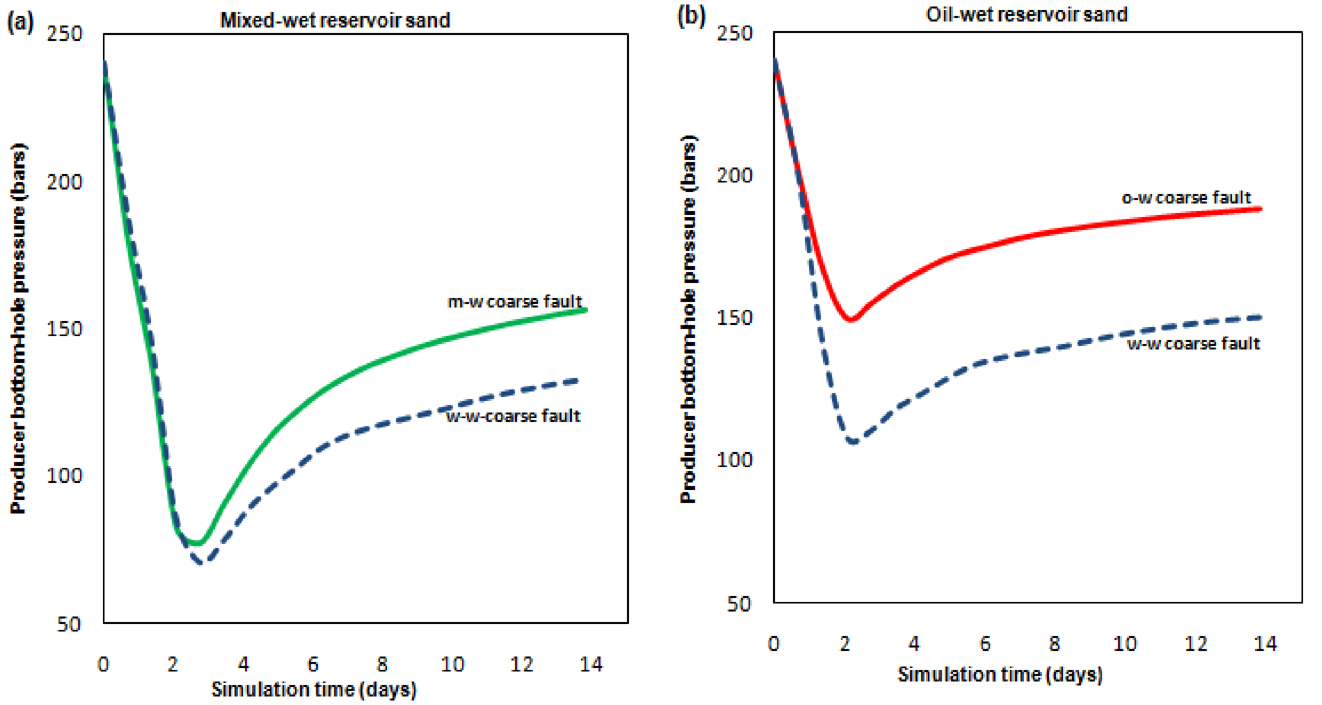

Figure 10: Producer bottom-hole pressure versus simulation time for the coarse model. (a) mixed-wet rock; (b) oil-wet rock.

Fine-grid field oil recoveries for the mixed-wet and oil-wet reservoirs are plotted in **Figures 11a** and **11b** respectively. Accurately modelling two-phase flow through a fault has a slight effect on hydrocarbon recovery (sweep efficiency). In practice, the actual pore volumes of faults compared with the main reservoir sand is negligible and fault transmissibility impacts is less noticeable at low flow rates. The coarse model simulation (**Figures 12a** and **12b**) results show reduction in fluid mobilities hence, a larger pressure drop between the wells on the either sides of the fault. These two effects cancel out and hence gave the same recoveries in the two rock types.

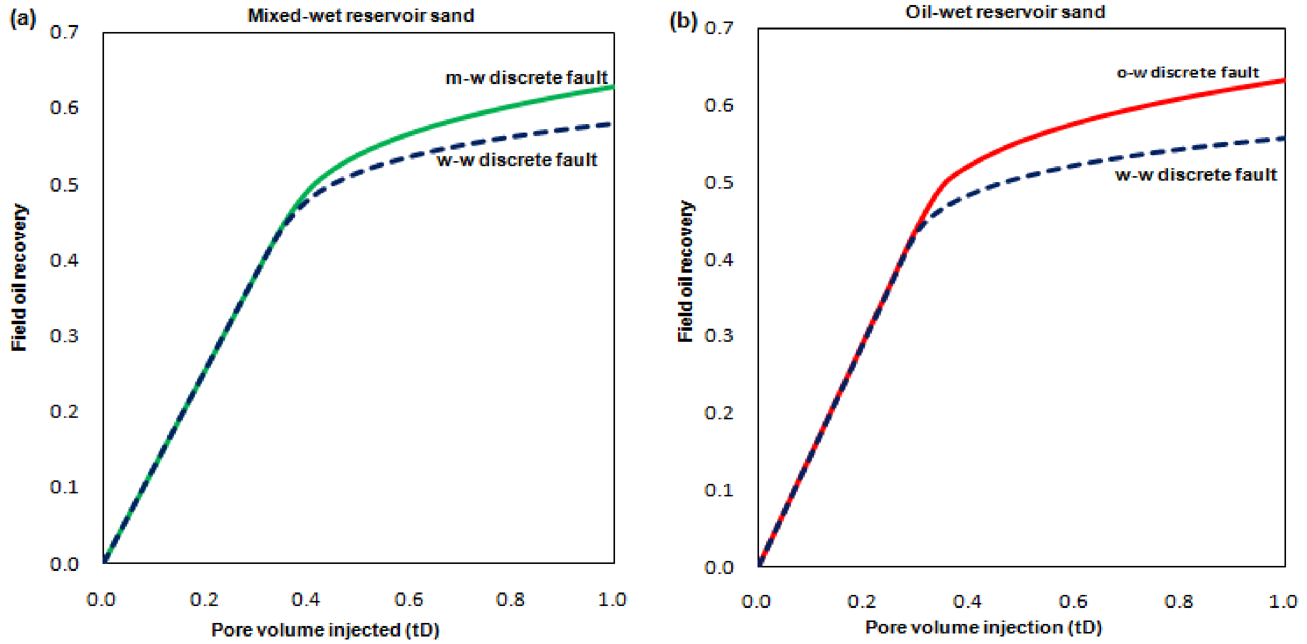

Figure 11: Field oil recovery versus PVI for the fine-scale model. (a) mixed-wet rock; (b) oil-wet rock.

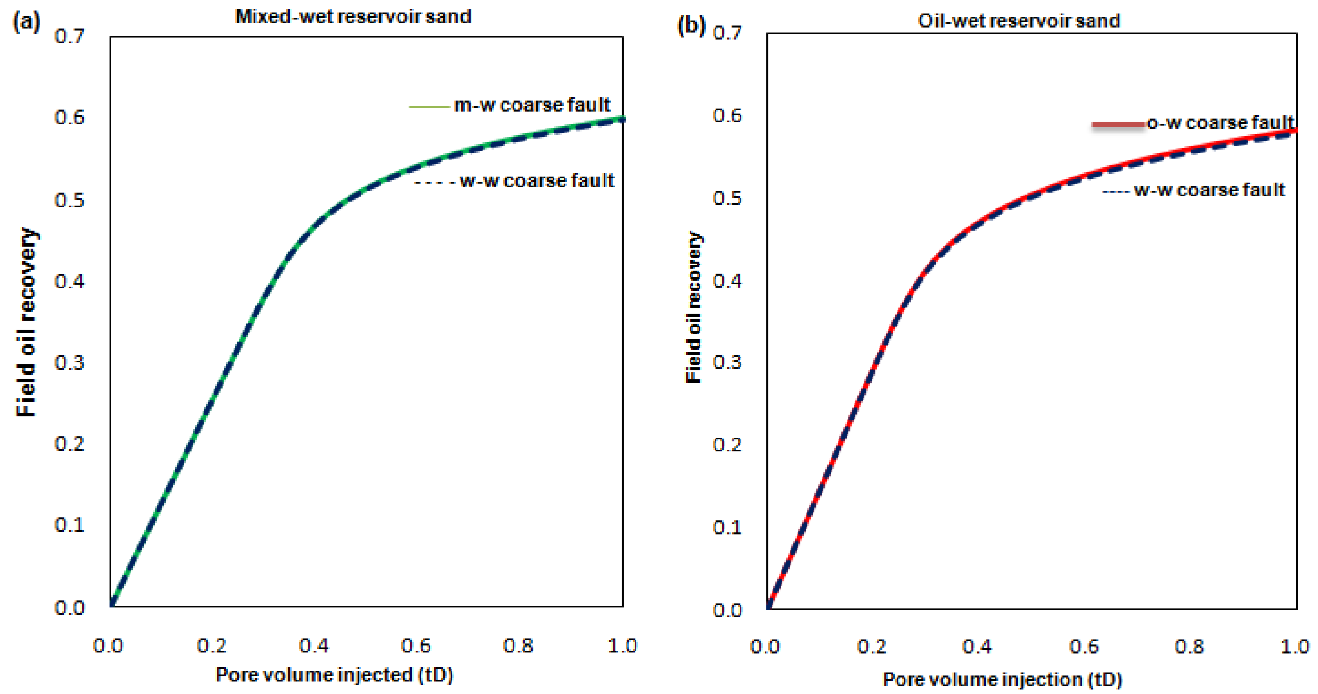

Figure 12: Field oil recovery versus PVI for the coarse model. (a) mixed-wet rock; (b) oil-wet rock.

Effects of viscosity ratio on fluid flow across a fault

Sensitivity analyses on viscosity ratio of the fluids **(Figures 13 and 14)** show that the realistic representation of fault with explicit water-wet saturation functions is showing low water saturation (capillary trapping phenomena) upstream of the fault for all the viscosity ratio while the conventional fault representation **(TM)** saturation distributions are not. Viscosity ratio values of oil to water used were 0.5cp, 1cp and 5 cp respectively.

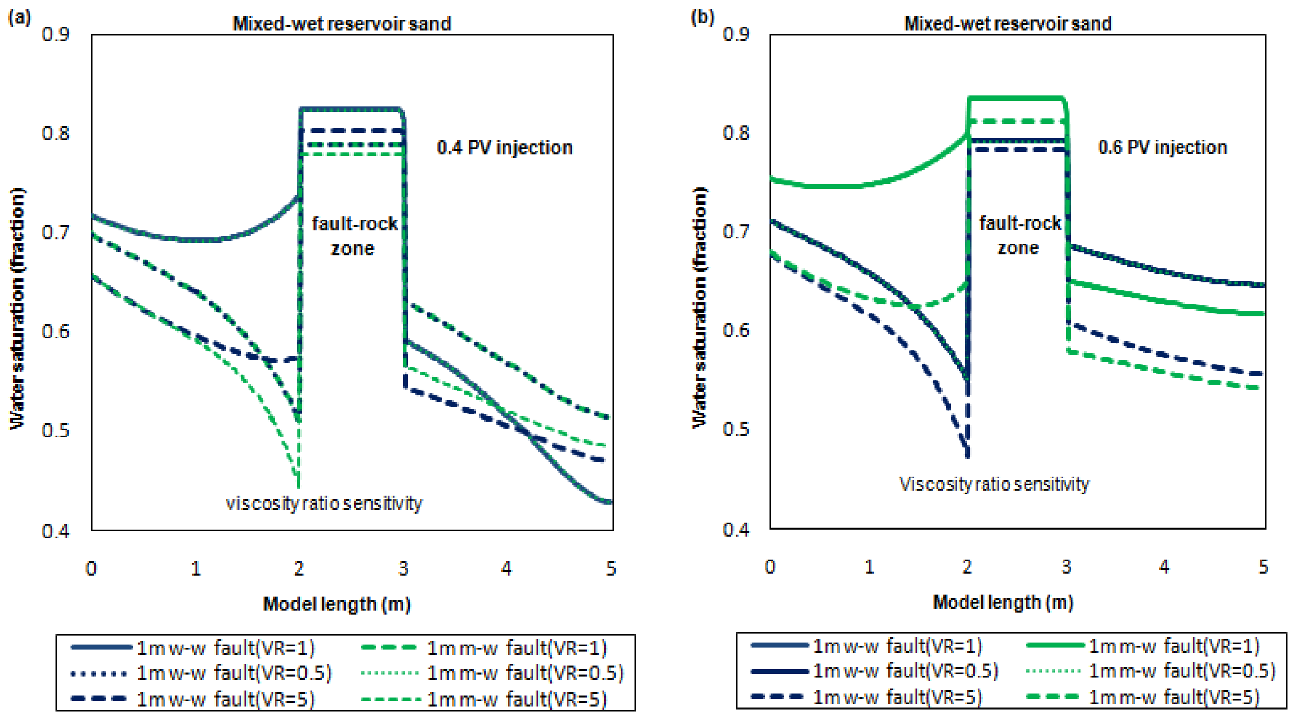

Figure 13: Water saturation distribution against model length for different viscosity ratio. (a) 0.4 PVI; (b) 0.6 PVI.

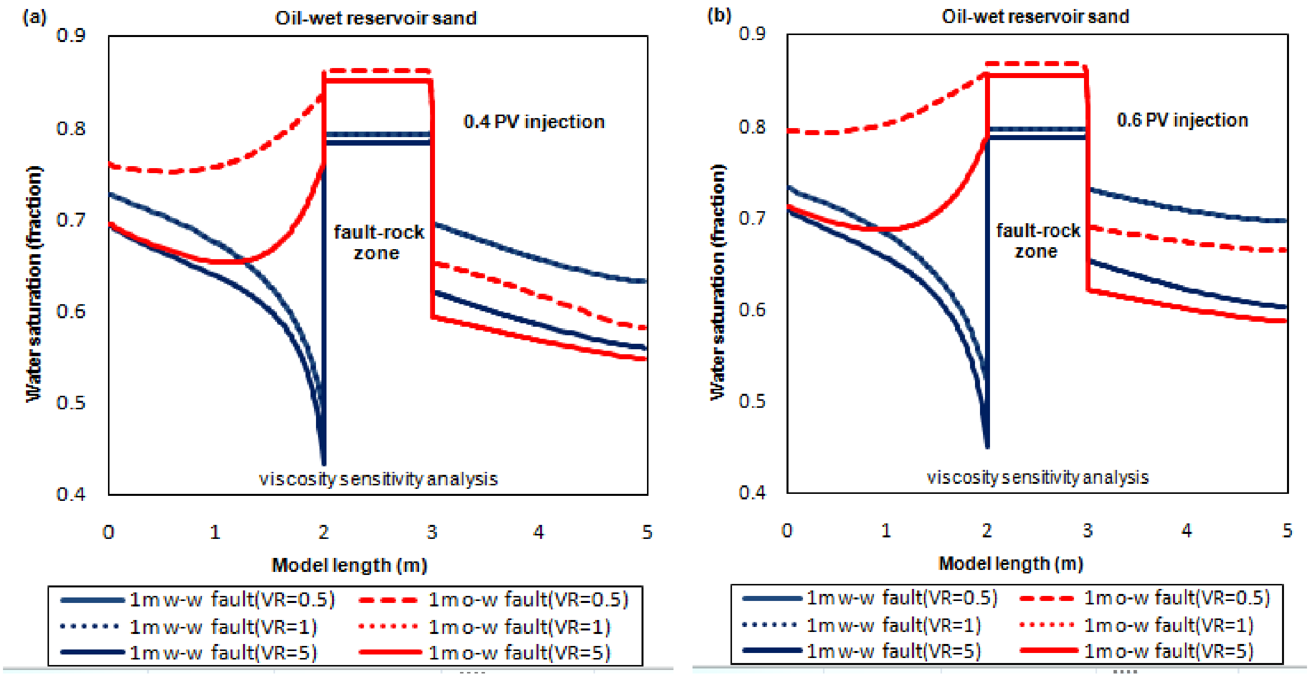

Figure 14: Water saturation distribution against model length for different viscosity ratio. (a) 0.4 PVI; (b) 0.6 PVI.

Effects of interstitial velocity on two-phase flow across a fault

Figures 15a and **15b** show the plots of undeformed sand oil-in-place as a function of pore volume injected (PVI) into the fine model at three different interstitial velocities (q) namely 0.3 m/day, 0.03m/day and 0.003m/day. The simulation is performed to test the ability of the transmissibility multiplier **(TM)** fault representation to reproduce the realistic model fault representation both in mixed-wet and oil-wet reservoirs respectively. The TM model results (solid lines) shown in (**Figures 15 a** and **15b)**, for all flood rates show less difference between them than the realistic (dashed lines) results do. This can be explained by the saturation distribution behaviours observed at the upstream of the fault in each representations as shown in (**Figures 5** and **6**). Low saturation (capillary trapping phenomena especially at low flow rates) is observed upstream of the fault in the realistic representation of fault which affects the total mobility of flow while the effect is less noticeable in the TM fault representation. The common observation in both plots (**Figures 15 a** and **15b)** is that as the flow rate increases, the difference between the realistic and the fault TM representations decreases. This clearly shows that the treatments of faults in conventional flow simulators do not account for the two-phase effects of faults on fluid flow.

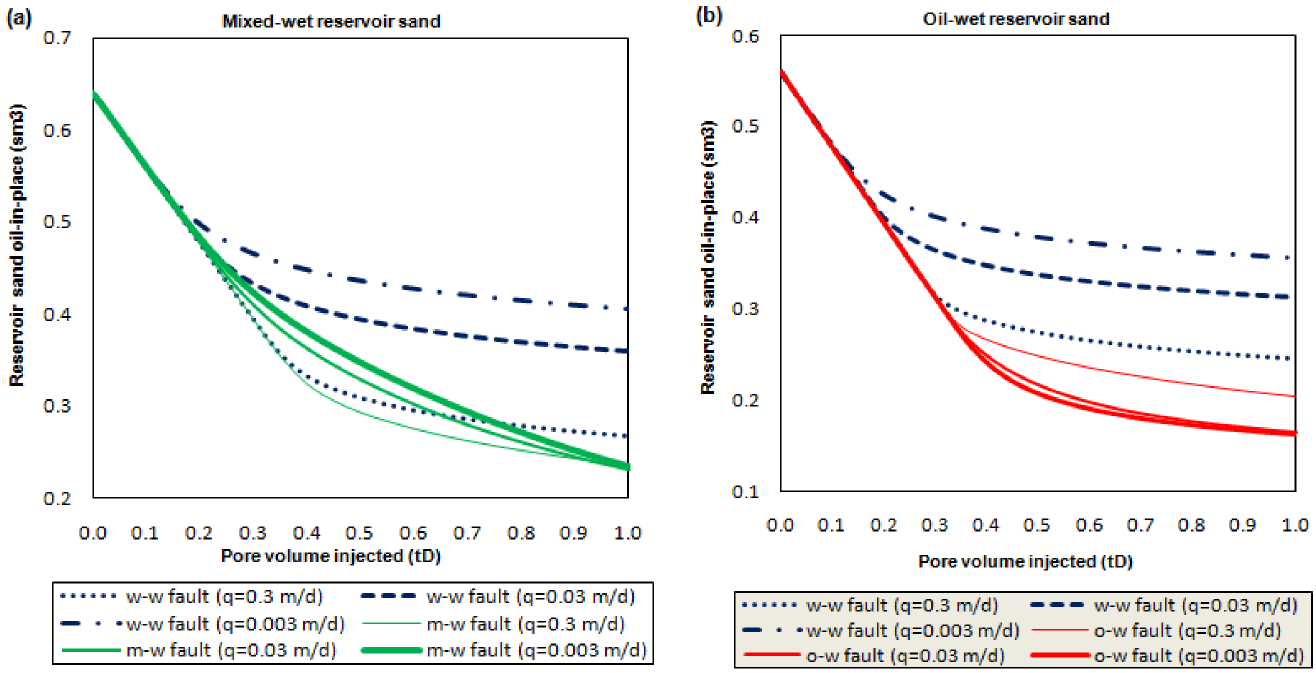

Figure 15: Reservoir oil-in-place versus PVI at different interstitial rates. (a) mixed-wet rock; (b) oil-wet rock.

Summary and Conclusions

In this study, we have investigated the importance of modelling two-phase properties of faults on fluid flow with a particular focus on total mobility upstream of the fault-rock and pressure drops between the wells on the opposite sides of the fault. Fine-grid and coarse grid models were built to mimic the reservoir-fault situations for our numerical investigation and eight test **cases (A-H)** are presented. Different fault representations were used for the test cases presented using water-wet fault with explicit water-wet saturation functions termed **realistic** representation of two-phase flow effects through a fault and we mimicked the conventional field-scale representation of fault using both mixed-wet and oil-wet saturation functions to show the limitation of treating a fault as a permeability barrier (**TM).**

Simulation results for various test cases using both models are analysed in terms of observed saturation distributions and pressure distribution within the models.Our results show that to accurately duplicate the correct total mobility and pressure distribution when developing fault-rock pseudos suitable to mimic flow behaviour upstream of the fault, fine-grid modelling is required. Using the coarse model to develop the pseudo functions indexed to the fault- adjacent grid-block will not properly model capillary trapping phenomena upstream of the fault. Therefore, fine-grid two-phase flow modelling is necessary to capture the correct water saturation distribution upstream of the fault which in turn affects the total mobility and hence, pressure drop prediction within the field. In field-scale simulation models, the actual pore volume of a fault compared with the main reservoir sand is negligible, so their effects on sweep efficiency would be minimal. The most important parameter therefore is to correctly predict pressure drops in fault-related compartments.

The following specific conclusions are drawn from this investigation:

1. The two-phase flow effects through faults have significantly influence on average pressure distribution within the faulted reservoir but less impact on sweep efficiency.
2. Fine-grid modelling is needed to correctly capture the two-phase flow effects through faults which are necessary to duplicate the appropriate flow behaviour on the coarse grid simulation.
3. The use of fault pseudo-relative permeabilities upstream of the fault grid-block to incorporate their two-phase effects as suggested by Manzocchi *et al.*, (2002) is a practical approximation of realistic two-phase flow transmissibility multipliers.

The suggestions for further works are:

1. Future research work on 1D analytical solution of the expected saturation distributions at constant rate condition is required to validate the numerical solution.
2. Development of appropriate fault-rock pseudo-relative permeability curves to duplicate the realistic flow behaviour upstream of the fault in simulation grid models.

Nomenclature

C_D = Darcy's unit conversion factor
k = Absolute permeability (mD)
k_r = Relative Permeability
l = Length (m)
N = Corey's exponent
P_{CI} = Imbibition capillary pressure (Bars)
P_{CD} = Drainage capillary pressure (Bars)
P_{CM} = Mixed capillary pressure (Bars)
q = Intestitial rate (m/day)
S_w = Water saturation (fraction)
S_o = Oil saturation (fraction)
S_e = Effective saturation (fraction)
S_{or} = Residual oil saturation (fraction)
S_{wi} = Initial water saturation (fraction)
T_{mult} = User-defined transmissibility multiplier
T_A = Inner transmissibility, cell A
T_B = Inner transmissibility, cell B
TM = Transmissibility multiplier
PVI = Pore volume injected (dimensionless)
VR = Viscosity ratio

Greek Symbols
Φ = Porosity, fraction
μ = Viscosity, (cp)
λ = Mobility ratio.
σ = Interfacial tension (mN/m)
θ = Contact angle

Subscripts
o = oil
w = water

Superscripts
e = endpoint

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APPENDIX

APPENDIX A: Milestones Table

MILESTONES ON MODELLING THE IMPACTS OF TWO-PHASE FLOW THROUGH FAULTS

Table A-1: List of milestones in the study of modelling the impacts of two-phase flow through faults

Papers	Year	Title	Authors	Contribution
Soc. Pet. Eng. Journal 25 (6)	1985	"Water/oil Displacement Characteristics in Cross-bedded Reservoir Zones"	Kortekaas, T.F.M.	First to develop a procedure for calculating dynamic directional-dependent pseudo relative permeability and capillary pressure for proper description of the effect of crossbedding on water/oil displacement characteristics on a reservoir scale.
Petroleum Geoscience Vol.5, Issue 1	1999	"Fault Transmissibility Multipliers for Flow Simulation Models"	Manzocchi, T. Walsh, J.J. Nell, G. Yielding, G.	First to develop geologically-driven conceptualisations of fault zone structures and content into a predictive method for calculating fault transmissibility multipliers as a function of known properties of the reservoir model.
Petroleum Geoscience Vol.8, Issue 1	2002	"The Representation of Two-Phase Fault-Rock Properties in Flow Simulation Models"	Manzocchi, T., Heath,A.E., Walsh,J.J., Childs, C.	Derivation of pseudo-relative functions including two-phase fault-rock properties as a function of the upstream grid block saturation which can be incorporated directly into conventional flow simulators.
Marine & Pet. Geology Vol.22, Issue 3	2005	"The Importance of Incorporating the Multi-phase Flow Properties of Fault Rocks into Production Simulation Models"	Al-Busafi,B., Fisher, Q.J Harris, S.D.	First to incorporate multi-phase fault rocks properties discretely into simulation models to investigate their impacts on field parameters.
Society of Core Analyst 2006-15	2006	"Recent Application of Special Core Analysis to Fault Rocks"	Al-Hinai, S. Fisher, Q.J. Al-Busafi, B. Guise, P. Grattoni, C.A.	First to provide data on relative permeability of cataclastic fault rocks to gas obtained from an outcrop of Permo-Triassic sandstone in Scotland, UK.
Geo. Soc. Lon. Special Pub. Vol. 292	2007	"Incorporation of Fault Properties into Production simulation Models of Permian Reservoirs from the Southern North Sea"	Zijlstra, E.B Reemst,P.H.M Fisher, Q.J.	First to incorporate multi-phase fault rock properties using capillary entry height method to a gas reservoir.
SPE 105100-MS	2007	"Incorporating Multiphase Behaviours in Dynamic Simulation Models Using In-Situ Generated Pseudofunctions"	Al-Busafi, B. Al-Siyabi, Z. Fisher, Q.J.	Determines a more practical pseudoisation approach to generate two-phase fault-rock pseudo-curves for a faulted flow simulation model in the form of in-situ pressures and saturations.
Transport in Porous Media 87:335-353	2010	"Immiscible Displacement in Cross-Bedded Heterogeneous Porous Media"	Dawe, R.A Caruana, A. Grattoni, C.A.	Generated benchmark data to validate commercial numerical simulator by using coloured (dyed) fluids and injection streamlines in synthetic cross-bedded models (stripes) for ready visualisation and characterisation of heterogeneous porous media.

APPENDIX B: Critical Literature Survey

Transport in Porous Media 5:399-420 (1990)

Capillary Effects in Steady-State Flow in Heterogeneous Cores

Authors: Yortsos, Y.C., Chang, J.

Contribution to numerical investigation of two-phase flow through a fault:
They provide a cursory overview of using saturation response profile and compositional path in the fractional flow diagram to understand the physics of flow across 1D heterogeneous media under steady state condition.

Objective of the Paper:
1. To systematically study the capillary effect on saturation response profile in a 1D steady state, immiscible displacement.

Methodology used:
1. The method used qualitative trends to examine two different models that allow for exact solutions, a linear (ramp) and a piecewise linear, periodic (sawtooth) variation in capillary variables.
2. Numerical simulations were used to illustrate the effects of randomness and variously correlated spatial variations in heterogeneities.
3. Permeability changes were used as a descriptor of heterogeneity in capillarity under the postulated assumption that relative permeabilities and Leverett functions are unaffected.

Conclusion reached:
1. The approximate solution errors involved in using permeability as a descriptor of heterogeneity while keeping the dimensionless functions unchanged do not alter the qualitative features of the steady state saturation response, in particular the fractional flow compositional path.
2. The magnitude and the phase lag of saturation response depend significantly on pore size distribution, and indirectly on the displacement properties (mobility ratios, etc).

Comments
A practical question that may arise in the simplifying assumption is the use of saturation profiles at steady-state to uncover capillary (possibly, permeability) heterogeneity since regions of constant permeabilities are connected by sharp but continuous linear transitions. The steady state approach taken seems to be too restrictive.

Transport in Porous Media 26:229-260 (1997)

Effective Relative Permeabilities and Capillary Pressure for One-Dimensional Heterogeneous Media

Authors: Dale, M., Ekrann, S., Mykkeltveit, J.

Contribution to numerical investigation of two-phase flow through a fault:
This work shows that in 1D, an analytical solution exists for rate dependent steady state pseudo-relative permeability and capillary pressure functions; hence fine-scale flow simulation may not be necessary to determine the pseudos.

Objective of the Paper:
1. The objective of the paper is to fill the gap between capillary limit and viscous limit effective parameters, by constructing effective parameters for intermediate values of the total velocity u, under separation of scales condition for one-dimensional heterogeneous media.

Methodology used:
1. 1D analytic approach was used to determine small-scale saturation distributions by a balance between viscous and capillary forces.
2. At a particular case of rate dependence, the directional dependence behaviour of flooding a heterogeneous medium was examined for different composite core.
3. The methodology of using effective parameters in dynamic displacement situations was demonstrated by comparing the fine-gridded simulations in the original heterogeneous media with simulations in their homogeneous (effective) counterparts.

Conclusion reached:
1. The main practical advantage offered by effective parameters is the possibility to handle small-scale heterogeneities accurately within coarse numerical grids. However, effective parameters are material properties, defined without any reference to numerical grids or to numerical simulation.
2. The performance of effective parameters is quite satisfactory, even with strong fronts present, thus violating the separation of scales condition.
3. The effective parameters are applicable when the spatial separations of scale conditions are satisfied, and the flow is sufficiently slowly varying.

Advances in Water Resources 21, 451-461 (1998)

Similarity Solution for Capillary Redistribution of Two-Phases in a Porous Medium with a Single Discontinuity

Authors: Van Duijn, C.J., de Neef, M.J.

Contribution to numerical investigation of two-phase flow through a fault:

1. They provide a semi-analytical solution for time-dependent countercurrent flow in one-dimensional heterogeneous media with one discontinuity in permeability.
2. They introduced conditions to account for saturation discontinuity and capillary entry pressure at the interface of different rock types.

Objective of the Paper:

1. To construct a time-dependent similarity solution describing the 1D redistribution of two immiscible and incompressible phases in a heterogeneous porous medium.

Methodology used:

1. The method adopted two homogeneous porous media of infinite extent butted together, so that permeability and porosity have a jump discontinuity at the interface.
2. Two conditions of flux continuity and the so-called “extended pressure condition” which strongly depend on the qualitative behaviour of the capillary pressure were imposed at the interface.
3. The original initial value problem was transformed into a boundary value problem consisting of ordinary differential equations which lead to a unique solution for the interface conditions applied.
4. The similarity solution was used to validate numerical algorithm describing two phase flow in porous media with discontinuous heterogeneity.

Conclusion reached:

1. The interface conditions of flux continuity and extended pressure condition gave a unique similarity solution appropriate for both zero and positive entry pressure.
2. The similarity solution has free boundaries (as $s \uparrow 1$ and $s \downarrow o$) for all values of pore size distribution and independent of the mobility ratio M.
3. The extended pressure condition is equally appropriate for unsaturated water flow (limit case of two-phase flow for a negligible non-wetting phase viscosity) when the entry pressure is positive.

Petroleum Geoscience Vol.8, Issue 1 (2002)

The Representation of Two-Phase Fault-Rock Properties in Flow Simulation Models

Authors: Manzocchi, T., Heath, A.E., Walsh, J.J., and Childs, C.

Contribution to numerical investigation of two-phase flow through a fault:
Derivation of appropriate relative transmissibility multipliers which includes the properties of the upstream grid-block and of the fault-rock to approximate the two-phase flow effects of faults on fluid.

Objective of the Paper:
1. To show that the two-phase effects of fault on fluid flow can be accurately approximated in conventional faulted flow simulation models, without representing the faults as discrete grid blocks.

Methodology used:
1. Phase transmissibility multiplier for each fluid phase was developed using a one-dimensional model.
2. Dynamic weighted potential pseudoisation method was used to generate pseudo-relative permeability function from the fine-scale model.
3. The generated pseudo-relative permeabilities were indexed to the saturation of the fault upstream grid block.
4. Two-phase version of the single-phase transmissibility multiplier was then back-calculated from the grid block oil and water pseudo-relative permeability

Conclusion reached:
1. The 1D host-rock model having discrete grid blocks to represent the faults is the closest two- phase analogue of the single phase transmissibility multipliers but their implementation in conventional simulators is unreasonably complex, as it depends on two well-defined, but different, saturation averaging volumes.
2. The phase-specific relative transmissibility multipliers are practical but not completely analogous of two-phase fault-rock properties.

Comments:
The proposed pseudos are less satisfactory, particularly in systems with larger grid blocks, narrower faults and stronger contrasts between grid block and fault-rock properties. Further work is needed to identify the optimal pseudoization method for to capture the two-phase effects of faults on fluid flow.

SPE 83671 (2003)

A New Streamline Method for Evaluating Uncertainty in Small-Scale, Two-Phase Flow Properties

Authors: Hastings, J.J., Muggeridge, A.H., Blunt, M.J.

Contribution to numerical investigation of two-phase flow through a fault:
The major contribution of the work is to present a new, semianalytical way of upscaling total mobility in 1D for the case of spatially varying relative permeability. It was achieved by tracking values of fractional flow, rather than saturation, in line with Holden's (1997) fractional flow upscaling.

Objective of the Paper:
1. To develop a novel, semianalytical streamline method that allows the impact of small-scale uncertainties on waterflood performance to be evaluated rapidly, using Monte Carlo approach.

Methodology used:
1. The method assumed separation of scales condition for the large and small-scale heterogeneities to rapidly evaluate the effect of uncertainty.
2. Average total mobility for flow through a series of different rock-types with different relative permeability was upscaled using single set of streamlines, with constant, upscaled flow properties, throughout the displacement.
3. A stochastic model of a cross section through a synthetic fluvial reservoir is used to demonstrate the validity of the assumption.

Conclusion reached:
1. The new 1D streamline method fully allows for variations in relative permeability, which is vital in capturing the effects of small-scale heterogeneities at scale at or below the simulator gridblocks.
2. The uncertainty caused by small-scale heterogeneities around a coarse grid in a conventional finite difference simulator can be calculated easily using proposed 1D semianalytical solution in lesser time.

Comments:
Generally, the results are very promising but the separation of scales condition is overly severe. Further work will involve developing direct methods for combining the small-scale uncertainties with those at coarse scales (i.e., the variation in streamline lengths caused by different arrangement of the heterogeneities)

SPE 105119 (2007)

Incorporating Multiphase Behaviours in Dynamic Simulation Models Using In-Situ Generated Pseudofunctions

Authors: Al-Busafi, B., Al-Siyabi, Z., and Fisher, Q.J.

Contribution to numerical investigation of two-phase flow through a fault:
Developed a more practical pseudoisation approach for generating two-phase fault pseudo-curves to approximate two-phase effects of fault on flow using in-situ pressures and saturations from the simulation model output.

Objective of the Paper:
1. To develop a more efficient solution to approximate the realistic two-phase effects of faults on flow obtained from high resolution numerical model run in which faults are included discretely.

Methodology used:
1. The full-field simulation model is divided into sub-domains of pressure or flow inter-connected regions
2. Fault zones were included with their independent properties and saturations functions using a stable local grid refinement scheme.
3. Dynamic fault-rock pseudo-curves for every fault-adjacent cell in every active region were generated.
4. The generated fault pseudo-curves are attached to their corresponding regions and fault-adjacent cells in the original full-field simulation model based on the transmissibility multipliers representation.

Conclusion reached:
1 The in-situ generated pseudoisation method offers a different practical approach, yet a similar principle to the work of Manzocchi *et al*., (2002) on incorporating two phase behaviour of faults in real simulation model. The method takes into account in-situ fractional flows and compartmentalised phase pressures across fault faces between non-neighbour connections.

Comments:
The pseudo method reads all the input variables that affect the pseudo-curves generation in-situ which greatly reduces uncertainties in the parameters required for their generation. The in-situ pseudoization code developed can also upscale zig-zag faults with directional-dependent fault-pseudo curves which allow local grid refinement and hysteresis options.

Advances in Water Resources 31, 56-73 (2008

Numerical Modelling of Two-Phase Flow in Heterogeneous Permeable Media with Different Capillary Pressures

Authors: Hoteit, H., Firoozabadi, A.

Contribution to numerical investigation of two-phase flow through a fault:

1. Developed new 3D numerical formulation for accurate approximation of flow-lines and flux calculation in modelling two-phase flow in heterogeneous media with contrast in capillary pressure.
2. The new formulation reduced numerical dispersion better than the conventional finite difference method found in most conventional simulator

Objective of the Paper:

1. To developed a new consistent formulation which combines Mixed Finite Element (MFE) and Discontinuous Galerkin (DG) to solve the pressure and saturation equations respectively in a numerical simulator.
2. To develop a method applicable for two-phase flow in multidimensional, heterogeneous and unstructured gridding, with discontinuity in saturation arising from distinct capillary pressure functions.

Methodology used:

1. The method approximated flux by discretising the velocity and volumetric balance equations individually.
2. The saturation was approximated by discretising the Discontinuous Galerkin (DG) method and a multidimensional slope delimiter was developed to prevent spurious oscillations in saturation.
3. The mobilities at the interface of distorted unstructed gridding were approximated to account for discontinuity in saturation arising from different capillary pressure functions.
4. The total velocity is then expressed in terms of capillary potential gradient and wetting-phase potential gradient. The coefficient of the wetting potential gradient is in terms of the total mobility which is smoother than the wetting mobility.

Conclusion reached:

1. The proposed mixed finite element overcomes the deficiencies of the fractional flow formulation in heterogeneous media which cannot correctly describe the discontinuity in the saturation arising from difference in capillary pressure functions and the discontinuity in capillary pressure from the threshold capillary pressure.
2. The numerical results show that the MFE-DG method has better shock capturing features and less numerical dispersion than the Finite Difference method found in conventional flow simulator.

APPENDIX C: Preliminary Sensitivity Analysis.

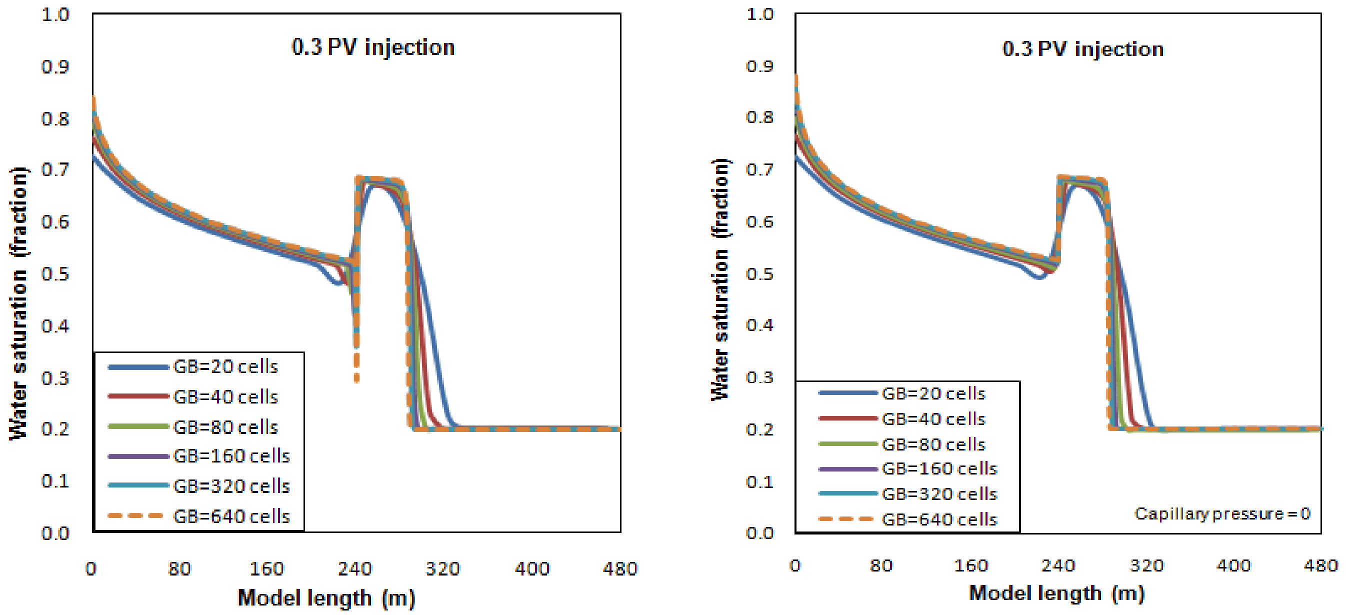

Figure B- 2: Grid sensitivity analysis to justify the number of grid-blocks used in the fine-scale model. (a) with capillary pressure; (b) without capillary pressure.