5-03 TOWARDS AN IMPROVED FAULT REPRESENTATION IN TWO-PHASE RESERVOIR SIMULATION

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Summary

The single phase petrophysical properties of faults (essentially fault zone permeability and thickness) can be included in reservoir flow simulation models using dimensionless transmissibility multipliers. Two phase flow, however, is governed by dynamic relative permeability and capillary pressure curves, and these properties are a function of the saturation of the grid-blocks to which they are attached. Faults are conventionally represented in simulation models not as volumes, but as 2D interfaces between grid-blocks, hence there is no simple method for including two-phase fault zone properties as a function of fault zone saturation. A method for including two-phase fault zone properties as a function of the up-stream grid-block saturation is presented, by introducing the concept of the relative transmissibility multiplier. This allows for more realistic models of hydrocarbon retention behind faults.

Introduction

Whilst it is routine to consider the capillary pressure of faults in exploration fault seal analysis, these properties are seldom included in production flow simulation models, and there is no straightforward method for doing so. Figure 1 gives a summary of available capillary threshold pressure data for faults, normalised for a moderately water-wet hydrocarbon-water system. Higher permeability faults have threshold pressures similar to unfaulted rock, and although clay-rich fault-rock values are somewhat higher than unfaulted rock with the same permeability, these differences are not extreme. For qualitative modelling purposes, therefore, the relationship between threshold pressure and permeability for both fault-rock and unfaulted rock can be considered the same (Figure 1). The capillary threshold pressure is the pressure needed for a non-wetting phase to form a connected passage through the sample, and is marked by the point of inflection of the drainage capillary pressure curve. For a water-flood in a hydrocarbon-filled water-wet reservoir, a typical displacement process considered in a production simulation reservoir model, the drainage capillary pressure curve is inappropriate and an imbibition curve is needed. Modifications to the relationships described by Ringrose and Corbett (1994) define imbibition capillary pressure and relative permeability curves applied to low permeability fault-rock and higher permeability matrix. These modified relationships are used in flow models to illustrate the method for incorporating saturation dependent fault properties.

Absolute and phase transmissibility multipliers

The issues involved in the representation of two-phase fault zone properties are illustrated using a simple 1D water-flood model consisting of a 20 cm thick, 1 mD fault contained in 1 D matrix. The fault is represented discretely in a fine scale model (Figure 2a) and as a transmissibility multiplier in a coarse scale model (Figure 2b). A method for estimating fault permeability and thickness in sub-surface reservoir models as a function of details of the faulted sequence and fault displacements has recently been described by Manzocchi *et al* (in press), and the fault transmissibility multiplier (T_{abs}) is given by:

$$T_{abs} = \left[1 + t_f \frac{\left(2/k_f - 1/k_i - 1/k_j\right)}{\left(L_i/k_i + L_j/k_j\right)} \right]^{-1}, \qquad (1)$$

where t_f is fault zone thickness, k_f is fault zone permeability, and k_i, k_j, L_i and L_j are the permeabilities and lengths of the grid-blocks on either side of the fault. In both representations the single-phase (or absolute) permeability structure is identical, but of course the relative permeability and capillary pressure curves for the fault can only be included in the fine scale model.

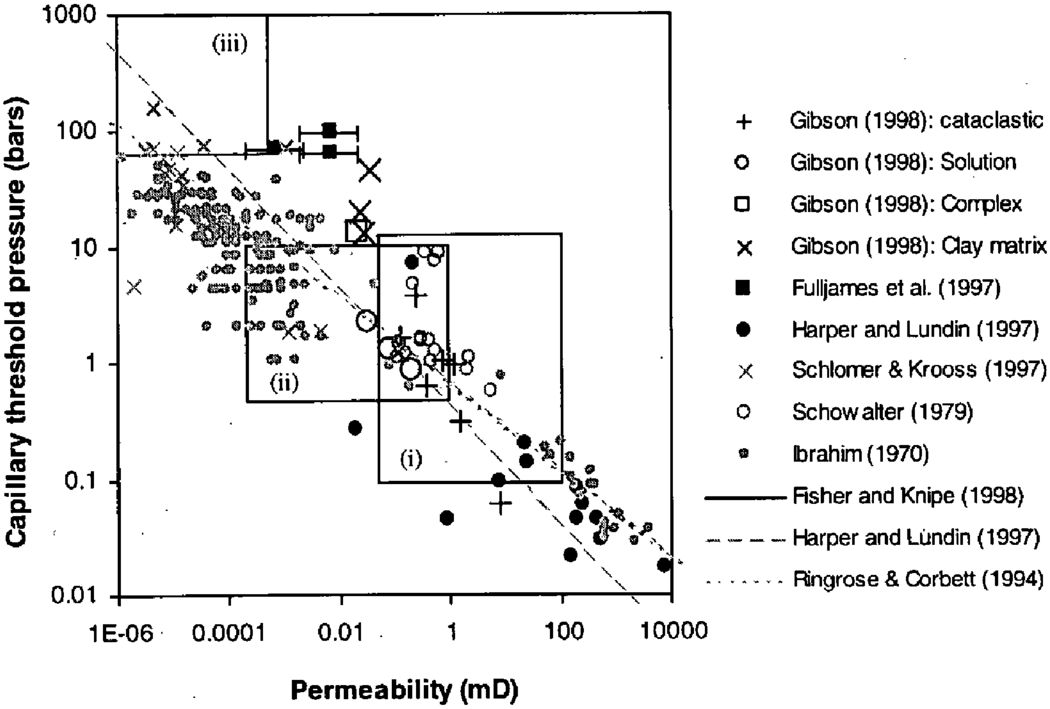

Figure 1. Capillary threshold pressure vs. permeability for fault samples (black) and unfaulted rock samples (grey) from a variety of lithologies. The boxes (Fisher and Knipe, 1998) are summaries of data from faults in clean sandstone (i), dirty sandstone (ii) and shale-rich fault gouge (iii). The grey lines are models. Capillary threshold pressure is calculated for a water-wet system with a hydrocarbon-water interfacial tension of 40 dynes/cm^2, and a contact angle of 30°.

In the regions immediately up-stream of the fault, the water saturation show a rapid increase as the water-front passes through the fault (Figure 2c). The residual oil saturation, however, is higher for the fine model (curves i and ii) than for the coarse model (curves iii and iv), reflecting the increase in capillary trapping close to the fault. There is no significant difference between the residual oil saturations in regions iii and iv, as both are determined only by the relative permeability and capillary pressure curves of the high permeability matrix. T_{abs} operates indiscriminately on both phases, while in reality fault transmissibility multipliers are phase-specific and vary throughout the course of the simulation run (Figure 2d).

Relative phase transmissibility multipliers

The water saturations observed in the fine model can be reproduced in the coarse model by introducing the concept of the relative transmissibility multiplier. A relative transmissibility multiplier (T_{rp}) for fluid phase p (p is oil or water) is defined as:

$$T_{rp} = T_p / T_{abs}, \tag{2}$$

where T_p is the phase transmissibility multiplier (Figure 2d) and T_{abs} is the absolute (single phase) transmissibility multiplier.

In the Eclipse two-phase flow simulator, the phase specific flow rate (q_p) between two blocks i and j is given by:

$$q_{pij} = T_{ij} T_{abs.} \frac{k_{rp}}{\mu_p} dP_p, \tag{3}$$

where T_{ij} is the absolute (i.e. single phase) transmissibility between the blocks, T_{abs} is the absolute transmissibility multiplier, k_{rp} is the relative permeability of the up-stream grid block, μ_p is viscosity and dP_p is the pressure difference between the blocks. Equation 3 does not give the correct phase fluxes through the fault (Figure 2c), as T_{abs} should be replaced by T_p (Figure 2d). By normalising T_p against T_{abs}, and reformulating it as a function of the water saturation observed in the region immediately up-stream of the fault, the relative transmissibility multipliers T_{rw} and T_{ro} are obtained (Figure 3a). Equation 3 may then be modified to include T_{rp}. This gives:

$$q_{pij} = T_{ij} T_{abs} T_{rp} \frac{k_{rp}}{\mu_p} dP_p . \tag{4}$$

Both T_{rp} and k_{rp} are functions of the water saturation of the block immediately up-stream of the fault, and therefore may be combined to give a pseudo relative permeability function k'_{rp}, where

$$k'_{rp} = T_{rp} k_{rp} . \tag{5}$$

In this way, Equation 3 becomes:

$$q_{pij} = T_{ij} T_{abs} \frac{k'_{rp}}{\mu_p} dP_p , \tag{6}$$

which contains the same number of terms as (3), but retains the saturation-dependent two-phase properties of the fault-rock within the coarse-grid model. Flow simulation results for the coarse model, using k'_{rp} in region iv, confirm the approach for this model (Figure 3b; *c.f.* Figure 2c).

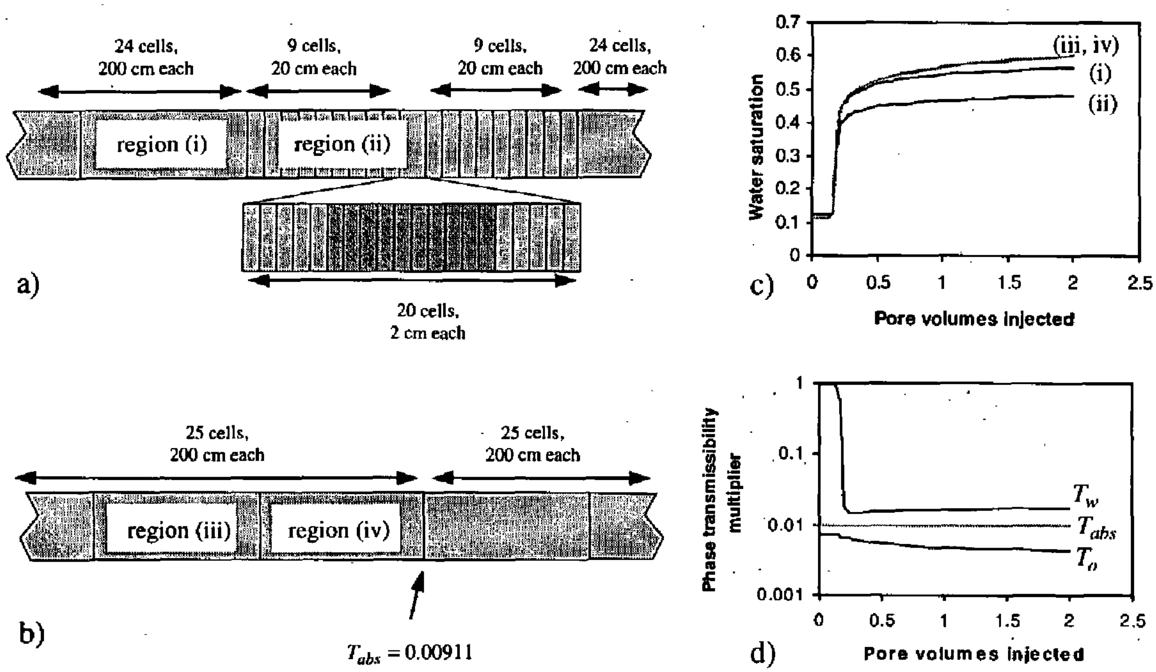

Figure 2 Flow simulation scheme used to illustrate the determination of the relative transmissibility multiplier. a) Fine grid model incorporating a discrete thickness of low permeability fault rock (dark cells). b) Coarse grid model, in which the fault is represented as a transmissibility multiplier T_{abs}. The regions (iii) and (iv) in the coarse model are the second and first grid-blocks up-stream of the fault, and occupy the same space as regions (i) and (ii) in the fine model. Water-flood is from left to right, with a frontal advance rate of 0.5 ft/day. Oil and water viscosities are 1 and 5 cp respectively. c) Water saturation in the four regions as a function of injected water volume. d) Oil and water phase transmissibility multipliers back-calculated from results of the fine scale run, as a function of injected water volume.

Applications

Relative transmissibility multipliers vary as a function of fault permeability and thickness, grid-block permeability and size (these factors also influence the single-phase transmissibility multiplier), as well as the relative permeability and capillary pressure curves, flow rates and fluid properties. As it is not practical to perform the dynamic up-scaling required to determine the relative transmissibility multipliers for each faulted grid-block in a reservoir simulation model, future work will investigate the possibility of defining a suite of relative transmissibility multipliers to be applied on the basis of likely fault structure and dynamic conditions within the reservoir. Defining such a suite of curves is considered feasible in view of the geometrical simplicity of the problem, which in a conventional faulted full-field simulation model involves only two grid-blocks at a time.

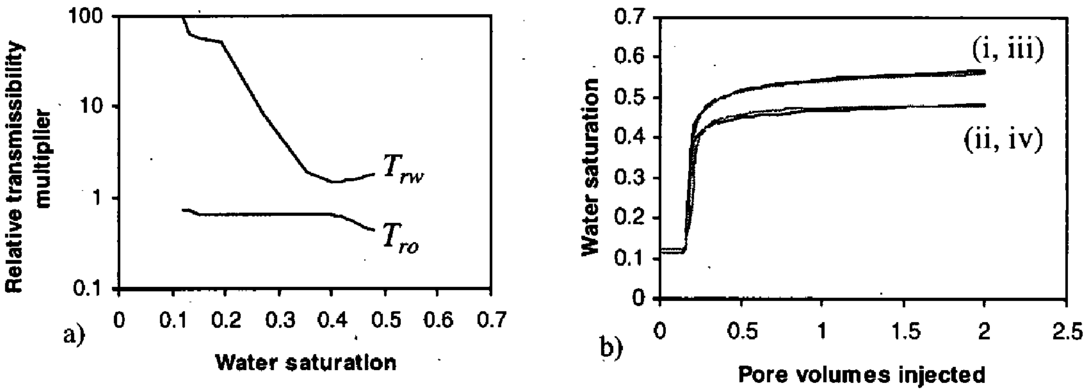

Figure 3 a) Relative transmissibility multipliers as a function of the saturation of region (ii). b) Water saturation in the four regions as a function of injected water volume, using the relative transmissibility multipliers to determine the properties of region (iv). Grey curves – coarse model. Black curves – fine model.

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