Fault-rock capillary pressure: extending fault seal concepts to production simulation

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Single phase petrophysical properties of faults 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 which vary as a function of the saturation of the grid-blocks to which they are attached. Faults are represented in conventional 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.

Fault-rock properties and flow conceptualisations made in migration and production flow modelling are summarised on Figure 1. The most important fault property for migration and accumulation studies is the capillary threshold pressure of the fault rock. Buoyancy driven oil migration is stopped by a fault, and an accumulation forms behind it. As the accumulation grows, the capillary pressure in the sandstone adjacent to the fault will increase. Eventually, the capillary pressure in the accumulation (not necessarily equivalent to the across-fault pressure difference) will match the capillary threshold pressure of the fault, and an oil stringer through the fault will form allowing migration into the sandstone beyond. This kind of treatment assumes sufficient time is available for flow-related forces to be negligible, and is, therefore, a static treatment. The only significant force is capillary pressure, and the only significant fault property is the fault rock capillary threshold pressure.

The treatment of faults in production simulators is entirely different. The goal of successful production is to maximise flow by exploiting or applying pressure gradients. The resistance to flow is the viscosity of the fluid, and the coefficients relating viscosity and pressure gradient to flow rate, are permeability and length. Hence the most important fault properties for production are the permeability and thickness of the fault rock, and these properties are captured in the flow simulator as transmissibility multipliers (Manzocchi et al. 1999). Transmissibility multipliers do not incorporate any capillary properties of faults, and the capillary pressure curve of the fault rock is assumed to be the same as that of the reservoir rock. This is therefore a single phase treatment of the fault as the transmissibility multiplier acts indiscriminately on all fluid phases. This treatment cannot predict capillary trapping of oil behind faults: using the conceptualisation of a fault contained in a production flow simulator, it would not be possible to model a membrane fault sealing oil accumulation (i.e. one controlled by fault rock) and related upstream accumulations of residual oil. This trapped oil may be a target for new production wells, but any infill-drilling programme which is based on the results from the simulator would not identify the presence of this oil.

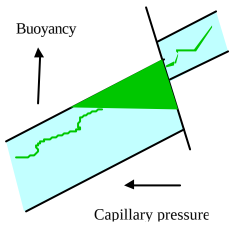
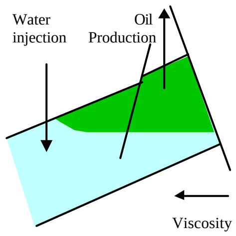
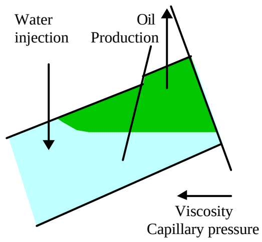
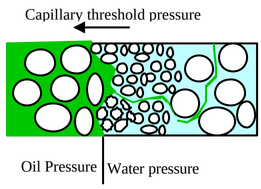
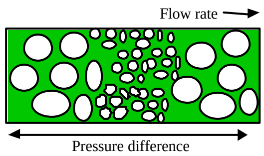
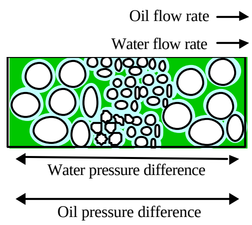
	Migration and accumulation	**Conventional production simulation**	**Enhanced fault representation**
Large scale process			
Implicit treatment	Two phase static	Single phase dynamic	Two phase dynamic
Driving force	Buoyancy	Pressure gradient	Pressure gradients
Resistance	Capillary pressure	Fluid viscosity	Fluid viscosities and capillary pressure
Small-scale process			
Principal fault rock properties	Capillary threshold pressure	Permeability and thickness	Permeability, thickness, relative permeability and capillary pressure curves
Governing Equations	Capillary pressure leakage criterion	Darcy's law	Two phase Darcy's law, Capillary pressure
Fault modelling properties	Capillary threshold pressure	Transmissibility multipliers	Relative transmissibility multipliers

Figure 1. Comparison of assumptions made about flow process and fault properties in migration studies and production simulation. Methods for determining geologically meaningful transmissibility multipliers for conventional production simulation exist. Enhanced fault representation for production simulation combines the conceptualisations made in the two modelling disciplines to develop the concept of the relative transmissibility multiplier. These are necessary if simulation models are to honour capillary pressure related hydrocarbon trapping during production, or fault trapping in a hydrodynamic regime (e.g. Heum 1996). Dark grey: hydrocarbon. Pale grey: water.

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 (T_{abs}) in a coarse scale model (Figure 2b). 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. In the regions immediately up-stream of the fault, the water saturation shows 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).

A relative transmissibility multiplier (T_{rp}) for fluid phase p (p is oil or water) is defined as $T_{rp} = T_p / T_{abs}$, where T_p is the phase transmissibility multiplier (Figure 2d) and T_{abs} is the absolute (single phase) transmissibility multiplier. If T_p is tracked over the course of fine-scale simulation run, and then reformulated as a function of the saturation of the up-stream grid-block, the relative transmissibility multipliers T_{rw} and T_{ro} are obtained (Fig. 3a). Relative transmissibility multipliers act on the relative permeability functions of the up-stream grid-block, and when the modified curves are included in the coarse simulation model, a good match to the fine-scale model results are obtained (Fig 3b; *c.f.* Fig 2c).

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.

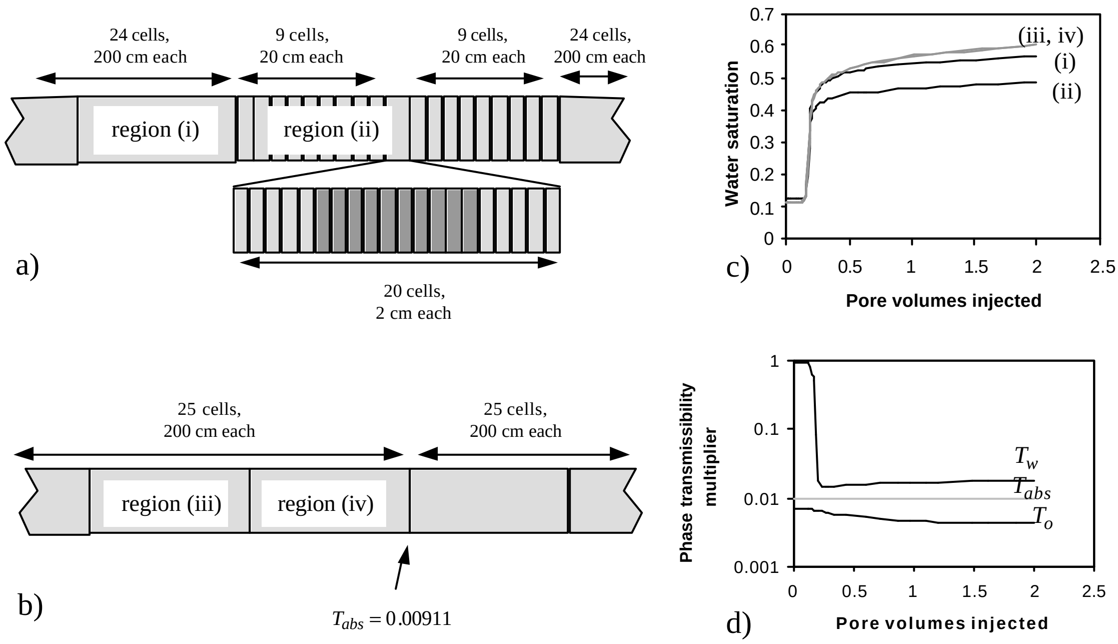


Figure 2 Flow simulation scheme used to illustrate the determination of the relative transmissibility multiplier. a) Fine grid model incorporating a discrete thickness of low permeability fault rock (dark cells). b) Coarse grid model, in which the fault is represented as a transmissibility multiplier 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.

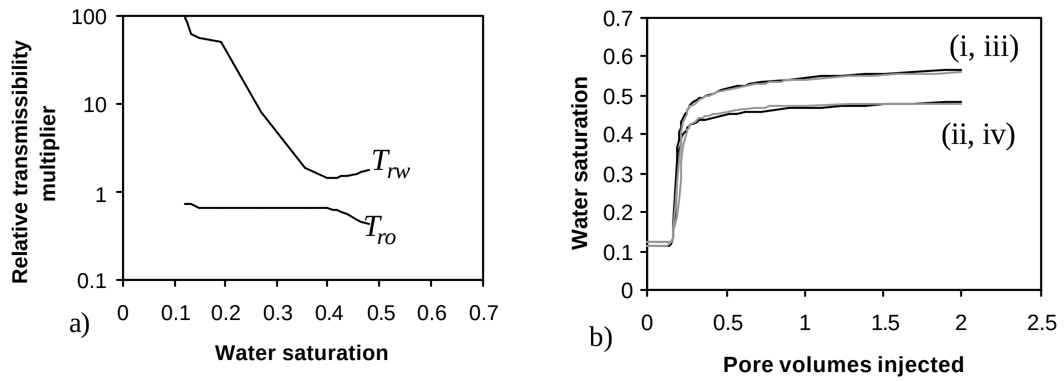


Figure 3 a) Relative transmissibility multipliers as a function of the saturation of region (ii). b) Water saturation in the four regions as a function of injected water volume, using the relative transmissibility multipliers to determine the properties of region (iv). Grey curves – coarse model. Black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

Heum, O. R., 1996. A fluid dynamic classification of hydrocarbon entrapment. Petroleum Geoscience, 2, 145-158.

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