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The incorporation of fault properties in flow models for hydrocarbon migration and reservoir production.

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Abstract
A key issue in geological model definition for hydrocarbon production and exploration evaluations is the accurate definition and modelling of both the geometry and the flow properties of faults. Concentrating on issues relating to the flow properties of faults, this talk considers the principal constraints and methods used for the inclusion of faults in reservoir production and hydrocarbon migration flow models. Two distinct strands of modelling are considered, those relating particularly to faulted clastic sequences in which faults are generally detrimental to fluid flow and those relating to so-called ‘fractured reservoirs’, in which faults are generally considered to be more conductive than their low poro-perm host rocks. This talk outlines the relatively recently developed methods for including faults in migration or production models for faulted clastic sequences and very briefly reviews the more mature methodologies for the inclusion of faults in production models of low-perm ‘fractured reservoirs’.

Faults that are detrimental to fluid flow

The treatment of so-called ‘sealing’ faults in flow modelling for hydrocarbon exploration and development has become more geologically-driven and more quantitative in recent years. Methods for the prediction of fault properties are now more refined and methods for their inclusion in flow models have, as a consequence, also improved. We outline the principal factors related to both the prediction and the incorporation of fault properties in migration and flow models. The methods described are relatively new and it is expected that ongoing and future application of these methods will identify essential refinements to these methods.

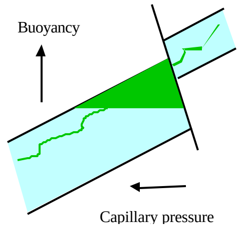
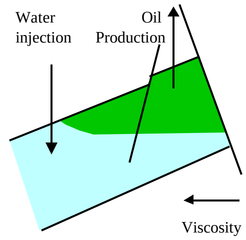
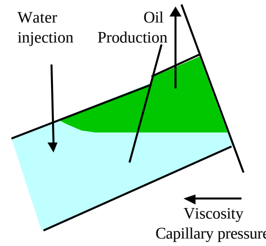
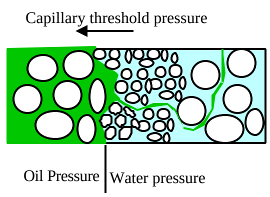
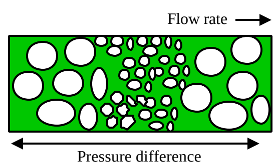
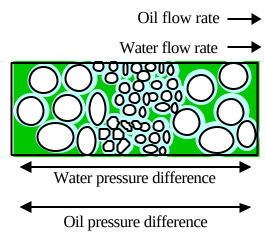
	Migration and accumulation	Conventional production simulation	Enhanced fault representation
Large scale process			
Implicit treatment	Two phase static	Single phase dynamic	Two phase dynamic
Driving force	Buoyancy	Pressure gradient	Pressure gradients
Resistance	Capillary pressure	Fluid viscosity	Fluid 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. From Manzocchi et al. (in press).

Migration modelling

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 carrier bed (e.g. 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. Crucially, an average fault property is of no value in determining the trapping potential of a fault, as leakage can occur through a focused flow path over geological time. In mature hydrocarbon provinces, however, empirical correlations between the limiting capillary pressure and specific details of the faulted succession observed in proven accumulations, have allowed an estimation of the likely column heights in undrilled prospects (Fisher & Knipe 1998; Fristad et al. 1997; Gibson 1994, 1998; Knipe et al. 1997; Sperrevik et al. in press; Yielding in press; Yielding et al. 1997). The most widely used predictive methods are variants on the SGR method (Shale Gouge Ratio method; Yielding et al. 1997, Yielding in press), in which fault properties are related to the clay content of the faulted sequence (Fig. 2). General support for the application of the SGR method is found from both detailed outcrop studies (e.g. Childs et al. 1997; Foxford et al. 1998) and from flow property data (e.g. core plugs/probe; Fig. 3) for fault rocks (e.g. Fisher & Knipe 1998; Sperrevik et al. in press). Here we describe a new method for incorporating the effects of fault seal, principally due to the presence of shaley fault rock, into migration modelling based on ray tracing methods (Childs et al. in press). The method is implemented within SEMI migration modelling software (Sylta 1991) and provides a means of testing the sensitivity of migration models to fault properties (Fig. 4). It is anticipated that future application of this or similar methods on both mature and immature petroleum provinces will provide an improved means of modelling migration in faulted basins than has hitherto been possible.

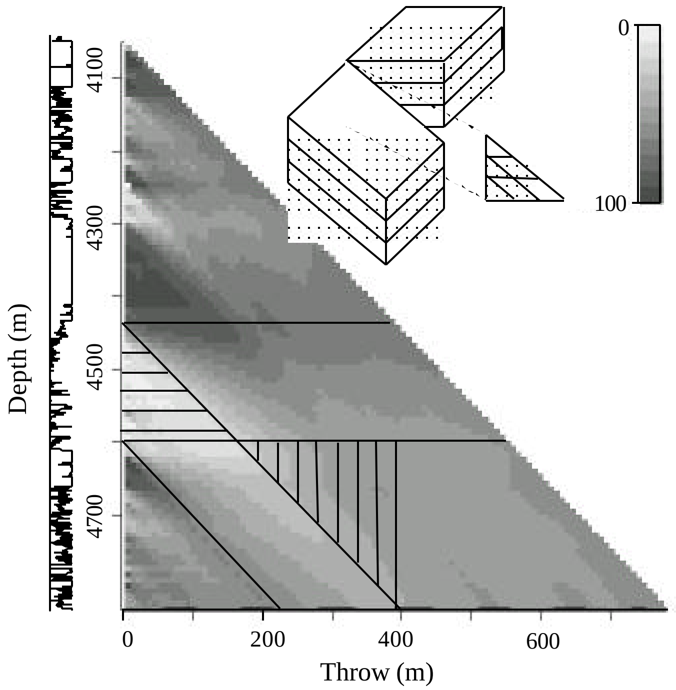


Figure 2. Sequence/throw juxtaposition diagram showing the variation in SGR (shale gouge ratio – the percentage of shale that has moved past each point on a fault) with fault throw for the vshale curve shown on the left hand side. The inset illustrates the construction method. Shale gouge ratio maps can be generated for faults incorporated in either migration or production flow models. Shale gouge ratio is taken as a proxy for the phyllosilicate content of related fault rocks, a property which from empirical data correlates with capillary entry pressure and negatively correlates with permeability. The particular juxtaposition diagram shown is for migration modelling using Semi (Childs et al. in press), in which the two horizontal lines show the elevation of the top and base of the carrier interval on the upthrown side of the notional fault and the diagonal lines show their downthrown elevations. The horizontal lined fill shows the area where the carrier interval is self-juxtaposed. The vertical lines show the area of the plot relevant to estimation of column heights when the carrier interval is self-separated and within which fault zone migration occurs.

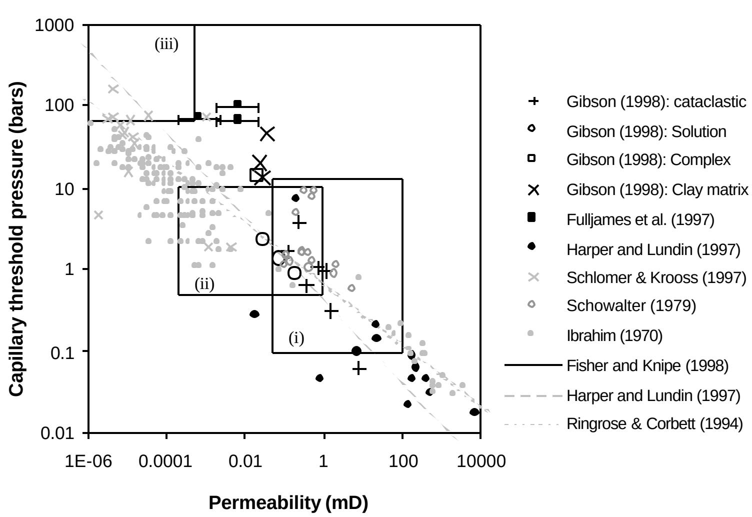


Figure 3. Capillary threshold pressure vs. permeability for fault samples (black) and unfaulted rock samples (grey) from a variety of lithologies. The boxes (Fisher and Knipe, 1998) are summaries of data from faults in clean sandstone (i), dirty sandstone (ii) and shale-rich fault gouge (iii). The grey 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^o.

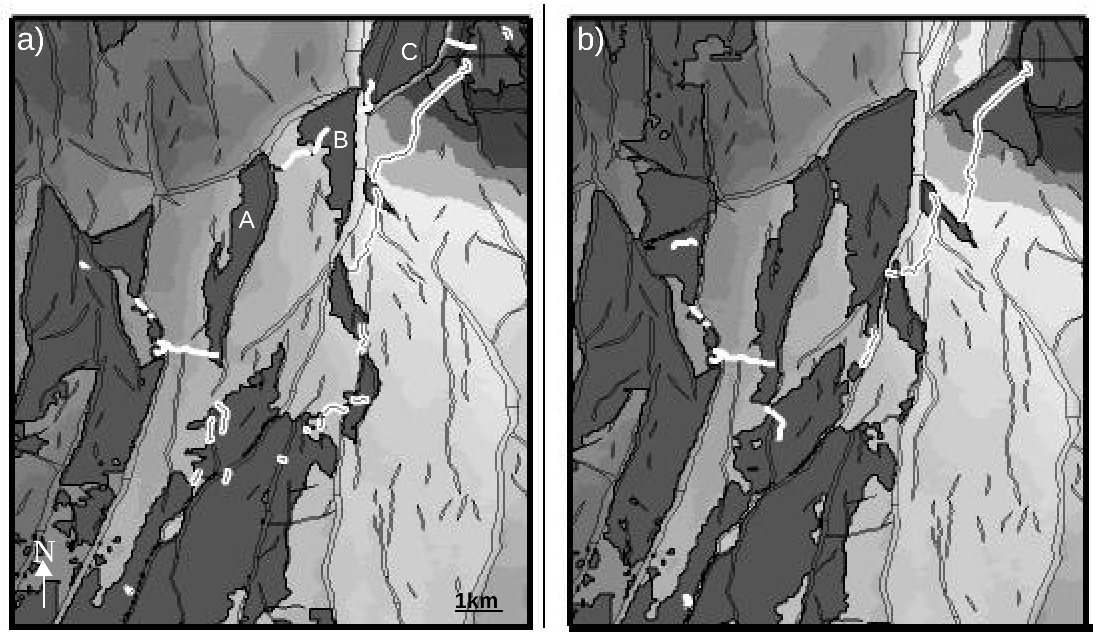


Figure 4. Top carrier structure contour map of part of the Oseberg Syd area, showing the sensitivity of hydrocarbon migration and trapping to different fault properties. The regional carrier dip is towards the west. Dark grey areas outlined in black are model hydrocarbon accumulations. A, B and C are progressively higher accumulations discussed in the text. Two migration arteries are highlighted in white and white with a black line; the flow direction is generally from the SW to NE. Fault seal capacities calculated for a) are lower than those for b) i.e. lower fault threshold pressures for a given SGR value.

Production flow modelling – seismically imaged faults

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. Until recently, the modelling of faults involved the 'ad hoc' tuning of constant transmissibility multiplier faults to provide history matches: this method can be shown to be entirely non-geological. New 'geologically-driven' methods have however been developed which allow the combined effects of permeability and thickness to be captured in the flow simulator as transmissibility multipliers (Manzocchi et al. 1999), using permeability predictors related to SGR or any other determinant (Fisher & Knipe 1998; Sperrevik et al. in press; Manzocchi et al. 1999) and using thickness predictions derived from outcrop data. By contrast with fault trapping, average fault properties can be utilised, with the most diagnostic measure of flow through heterogeneous faults being the arithmetic average of the permeability to thickness ratio (Walsh et al. 1998; Manzocchi et al. 1999). Transmissibility multipliers do not however 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 and cannot predict capillary trapping of oil behind faults. 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. We therefore outline a new method for including two-phase fault zone properties as a function of the up-stream grid-block saturation, by introducing the concept of the relative transmissibility multiplier (Manzocchi et al. in press). This method is underpinned by existing empirical fault property data (Fig. 3) and allows for more realistic modelling of hydrocarbon retention behind faults. Taken together, there has been a great improvement in our ability to model production-related fluid flow in faulted clastic reservoirs. Although the new methods provide an improved means of flow modelling and history matching in faulted clastic reservoirs, we expect significant improvements to arise from the continued application of these, and similar methods, in actual reservoirs.

Production modelling – sub-seismic faults

Methods for the prediction of sub-seismic faults are generally underpinned by the assumption that fault systems display fractal properties, with a self-similar geometry on a range of scales. In circumstances where this assumption is valid, the numbers of sub-seismic faults of different size (i.e. length and maximum displacement) can, in principle, be predicted. Significant uncertainties are however associated with the spatial distributions of sub-seismic faults, a feature which when combined with the relatively recent developments of incorporating geologically meaningful fault properties in flow models, is probably responsible for the relatively slow appearance of published case studies and the absence of a well-defined methodlogy for the inclusion of sub-seismic faults in flow models. It is anticipated that future studies will focus on a quantitative analysis on the impact of sub-seismic faults on hydrocarbon production.

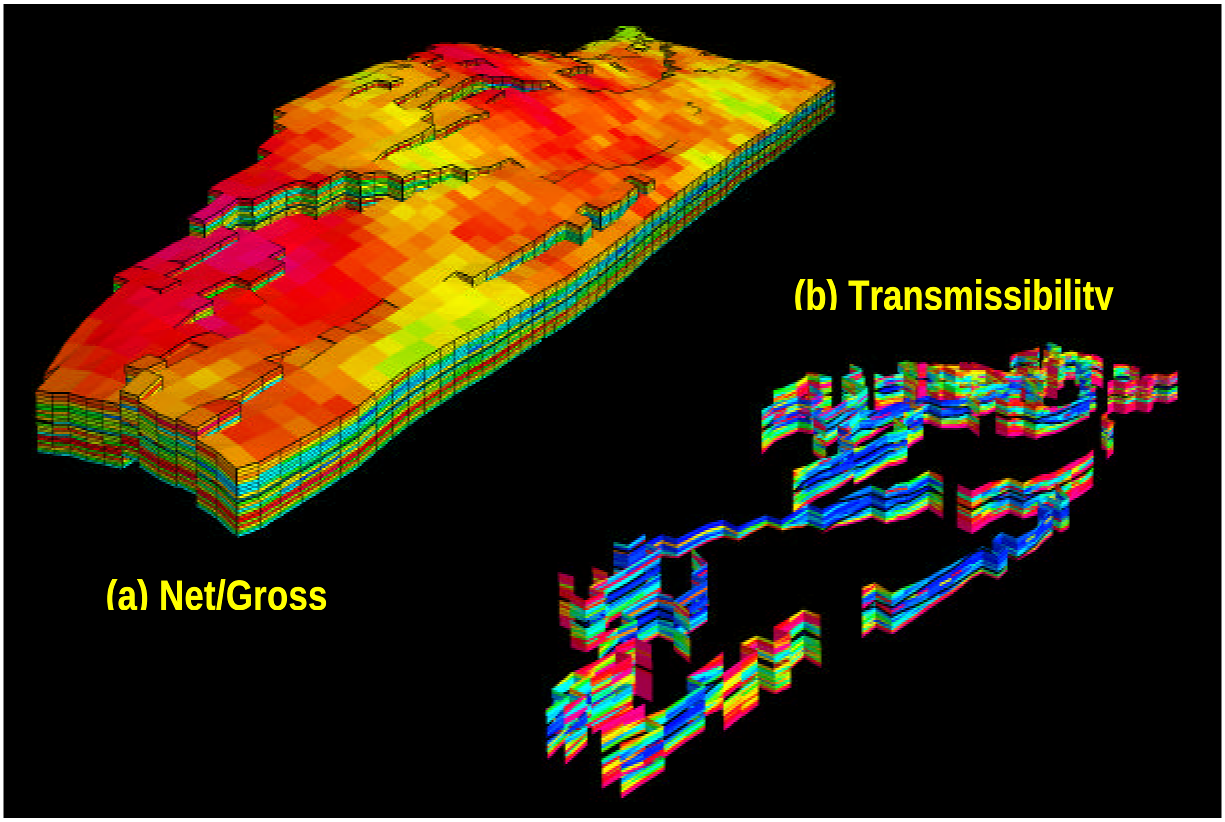


Figure 5. (a) Model of a clastic reservoir containing faults which offset a Brent-type sequence: cells are colour-coded for net:gross, with hot colours denoting high net:gross. (b) Fault transmissibility multipliers generated using the method of Manzocchi et al. (1999). Models were generated using the Transgen software package (Badley Earth Sciences, UK).

Faults in fractured reservoirs

Although the flow modelling of fractured reservoirs is, in some respects, relatively mature compared to that of faulted clastic reservoirs, the principal shortcoming of existing methods is the paucity of basic geological constraints and the complexity of flow in conductive fracture systems. Although a broad range of fracture types may exist within a given fractured reservoir, larger scale (e.g. seismically imaged) faults are generally considered to have the greatest impact on flow, sometimes representing the main conduits for fluid flow even in circumstances where the reservoir capacity is dominated by other types of fracture. Flow modelling in such dual porosity-dual permeability reservoirs generally involves the explicit inclusion of large faults with the implicit incorporation of smaller displacement faults or other fracture types as upscaled properties. The latter are generally computed by an iterative process of linking the flow response of discrete fracture models (e.g. FracMan models) generated from geological constraints (i.e. well data, sub-seismic fault predictions etc.) with those of well production tests or curves. Significant uncertainties are however associated with: (i) The application of an REV (Representative Elementary Volume) approach to certain small-scale fracture systems. (ii) The nature of both single phase and multi-phase flow in fracture networks. (iii) Definition and modelling of the heterogeneous nature of the poro-perm properties of individual faults, not to mention fault networks. (iv) Stress-dependence of fracture poro-perm properties. Following a brief description of the basic methodologies usually employed, some of the principal requirements for improved modelling of fractured reservoirs are illustrated using outcrop analogue data.

Conclusions

Definition and modelling of the hydraulic properties of faults in both migration and production flow models is a relatively immature area of research and application particularly in relation to so-called sealing faults. New geologically-driven methods for attaching fault properties in flow models represent a significant improvement on pre-existing, non-geological, methods. The progressive refinement and further development of these methods will benefit from their application in different petroleum provinces and reservoirs. Sensitivity analysis conducted on well-constrained case studies represent the most direct means of refining existing methods for use in either immature petroleum provinces or in newly discovered reservoirs.

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