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Numerical and geological advances in fault handling for production flow simulation

T. Manzocchi[1], J. J. Walsh[1], C. Childs[1] & A. E. Heath[2].

[1]Fault Analysis Group, Department of Geology, University College Dublin, D4, Ireland.
[2]Fault Analysis Group, Department of Earth Sciences, University of Liverpool, UK

Outcrop studies have shown faults to be highly complex heterogeneous and anisotropic volumes with abundant displacement partitioning (e.g. Foxford et al. 1998), yet empirical approaches have shown that valuable predictions may be made concerning overall fault hydraulic properties from simple geological criteria (amount of shale in the faulted sequence; burial depth syn and post faulting; e.g. Yielding et al. 1997, Fisher and Knipe 2001). These methods have been adapted to derive a geologically and numerically meaningful method for including the petrophysical properties of faults (fault rock thickness and permeability) in production simulation models (Manzocchi et al. 1999). Implicit in the method are several simplifying assumptions which are addressed in the present work to derive methods which improve and broaden the scope of fault handling in production simulation of clastic reservoirs. These new methods additionally allow inclusion, at the resolution of a conventional faulted simulation model, of two phase fault rock properties, of more accurate across-fault transmissibility, and of complex sub-resolution fault zone structure.

Faults are represented conventionally in production simulation models as planar surfaces offsetting the model layers. Their geometrical properties are considered to be captured by the cell corner points, and their petrophysical properties by assigning multipliers to the transmissibility between juxtaposed cells. One way of constraining fault-related uncertainties in reservoir production is to ensure that the conceptualisations contained in the simulation model are plausible geologically - the practice of assigning a constant multiplier to an entire fault, for example, seldom represents a credible reservoir geology. Allied to this is the necessity that the numerical implementation reflects the conceptual geological and hydraulic model of the fault. For example it is well known that transmissibility multipliers do not allow inclusion of fault-parallel flow, and if such flow is considered important in a particular reservoir, it must be modelled in some other fashion. More insidious are conclusions derived from simulation results calculated with black-box implementations believed to be numerically correct, but that in fact are not.

Three assumptions commonly made in flow simulation of faulted reservoirs are addressed:

(i) The assumption that the transmissibility multiplier is sufficiently versatile to describe flow through fault rock.
(ii) The assumption that a transmissibility multiplier of unity implies that the fault rock is hydraulically neutral.
(iii) The assumption that the simulation model geometry adequately describes fault juxtapositions.

The first assumption is incorrect for two phase flow. 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. It is impossible to implement these requirements directly using transmissibility multipliers, however the effects can be included in pseudo-relative permeability functions attached to the grid-blocks upstream of faults (Figure 1; Manzocchi et al. 2002).

A more surprising result is that the second assumption is also incorrect. The standard grid-block to grid-block transmissibility equation hardcoded into commercial flow simulators is only correct in a homogeneous sequence, and will generally underestimate across-fault flow. Hence a hydraulically neutral fault usually requires a multiplier > 1. This error arises from the assumption that the correct area term in the transmissibility equation is the juxtaposition between the two grid-blocks. This ignores tortuous flow within the grid-blocks which can increase significantly the transmissibility between high permeability grid-blocks with realistic aspect ratios, particularly if one of the blocks is also juxtaposed against an inactive or very low permeability block. There appears to be no simple analytical solution to this problem, and it may be that approximate empirically derived solutions are required.

The first two assumptions, though of practical relevance to production geology, are essentially numerical, but the third is wholly geological. Fault zones in outcrop commonly are characterised by paired or multiple slip surfaces accommodating different portions of the total displacement. If the separation between these surfaces is smaller than the dimensions of the grid-blocks, the juxtaposition geometry, even if known, cannot be included in the flow model, and so the fault-related flow calculated by the simulator as a function of the model geometry will be incorrect. Geometrical up scaling methods have been developed to deal with such circumstances (e.g. Figure 2). In these methods the full geometrical description of the fault zone is used to calculate transmissibilities, which are forced to overwrite the juxtapositions present at the resolution of the simulation model.

Outcrop studies support conceptual fault growth models (Childs et al. 1996) in revealing the existence of a hierarchy of fault zone architectural components with geometrical properties linked to fault throw. Often a fault zone component, such as a relay zone, is known or expected to be present at a particular position on a fault from seismic attribute mapping or from dynamic reservoir flow behaviour. More commonly however, the existence and perhaps frequency of such features might be deduced logically by analogy with other, better-characterised faults, but their precise locations are unknown in the reservoir. Hence while it will never be possible to build an accurate deterministic reservoir fault model from available subsurface information (seismic and wells), it is potentially possible to define stochastically a range of plausible faulted models. Using the methods developed, this fault zone complexity can be modelled in two-phase reservoir uncertainty or history matching studies in an analogous manner to the methods used to model spatially unpredictable yet geologically plausible and potentially significant sedimentary heterogeneity.

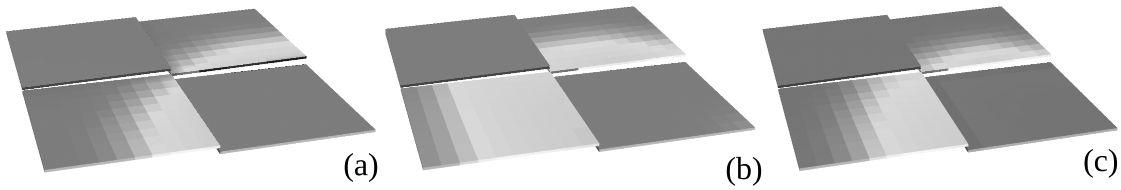

Figure 1. Implementation of two phase fault rock properties. Water saturation for the middle layer in a 13 layer faulted model during a water-flood. (a) Modelled with the two phase fault rock properties included explicitly, requiring grid refinements to represent the faults. (b) The conventional representation which ignores two-phase fault rock properties. (c) With the properties incorporated as up scaled pseudo-functions attached to the grid-block upstream of the faults. The model contains a producer in the left corner, and an injector in a higher layer in the right corner. Pale colours: high water saturation.

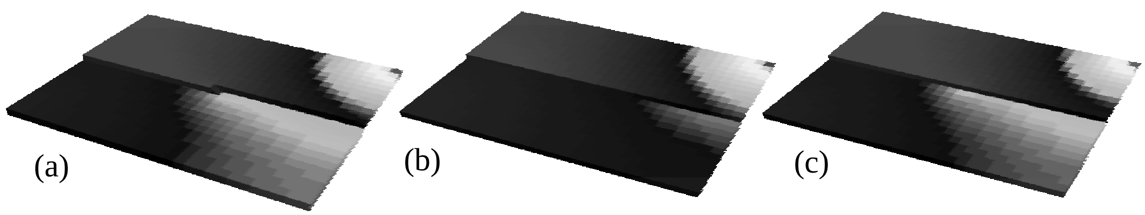

Figure 2. Implementation of sub-resolution fault zone structure. Pressure for the third layer of a 4 layer model including a relay zone on the fault. (a) Modelled with the relay zone geometry explicitly included, requiring grid refinements to represent the juxtaposition geometry. (b) The conventional representation which ignores sub-resolution fault zone structure. (c) With the relay zone incorporated implicitly using the geometrical up scaling method. The model contains a producer in the left corner of a higher layer, and an injector in the right corner. Pale colours: high pressure.

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