Fazed by three-phase relperms?

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Reservoir engineers might be forgiven for regarding three-phase relperm models as 'black-boxes' and trusting in simulator defaults, as there is little measured data. This article aims to demystify the 'black-boxes' a little and makes some recommendations for best practice, all without an equation in sight! Choice of model can significantly affect predictions of oil rates and recovery, which can be critical in deciding the future of a development.

Three-phase situations occur in practice when gas is injected, or when gas is released from solution as oil pressures fall below the bubble point. There are several gas injection projects in the North Sea where gas may not be fully miscible with oil, so modelling three-phase oil relative permeabilities (relperms) is potentially important. WAG (Water Alternating Gas) has been applied to several fields including Gullfaks, Snorre, Vesflefrikk and South Brae. An important example of a reservoir where three-phase regions will occur through gas being released from solution is Brent, for which a project to significantly depressurise the reservoir is underway.

Laboratory measurements

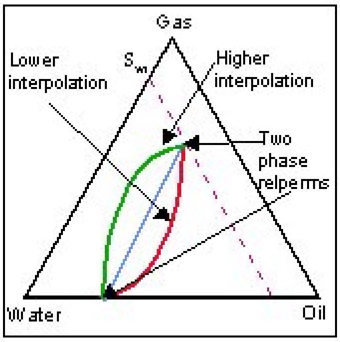
Valid two-phase relperm data is usually obtainable if best practice procedures are followed. However, if three phases are present, difficulties occur as follows:

- much higher mobility of gas compared with liquids (also relevant to gas and oil)
- the difficulty of controlling experiments to obtain a suitable range of results
- the lack of an appropriate analysis method
- the need for in-situ saturation measurements.

Hence laboratory measured three-phase oil relperm data are rare, sparse and may be prone to error.

Three-phase oil relperm models

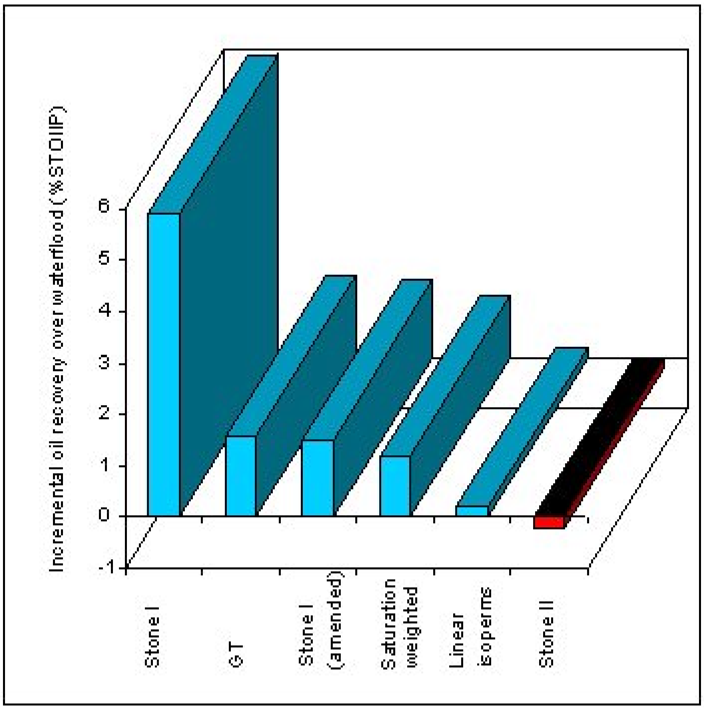
As there is little good measured data to constrain models, they have proliferated and many are available in reservoir simulators. Details of such models and greater explanation than appropriate here are given in [1]. The most popular models generally use conventional two-phase oil/water and oil/gas relperms to predict three-phase oil relperms. All the commonly used models 'hard-wired' into simulators are of this type. Although such models may look impressive, all that is really being done is some form of mathematical interpolation, with little physical input. Such models can be thought of as machines for predicting the oil relperm for different balances of water and gas, given the two-phase oil relperms. Figure 1 illustrates alternative constant relperm lines (isoperms) for



different interpolation models. Each vertex represents 100% saturation of a particular phase. Lines parallel to a straight line connecting the vertices opposite a particular phase vertex are lines of constant saturation for that phase. Note that there may be little or no three-phase data to constrain the model.

Predictions from commonly used models

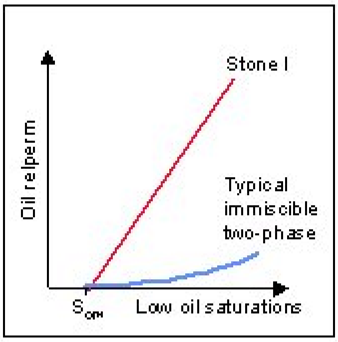
It might be hoped that the range of estimates from different models is not too large. To test this, the immiscible WAG process was simulated for a number of three-phase models on a fine grid assuming a typical North Sea geology and realistic well constraints. Predictions of incremental oil recovery over waterflood are shown in Figure 2.



Note that these results should not be used on their own to decide on the efficacy of immiscible WAG as a process, as they are for just one choice of reservoir description. Other choices may change predicted recoveries significantly. With the exception of GT (Goodyear-Townsley) and Stone I amended, these are probably the four most commonly used models in simulators. The range of predictions is large, from a significant incremental recovery to less than nothing! This could be the difference between a viable economic project and one not even technically viable. However, by understanding the main reasons for the different predictions, some models can be discarded. The results can be grouped into three, a high prediction from Stone I, low predictions from Stone II and linear isoperms and a middle group.

Reason for high prediction from Stone I

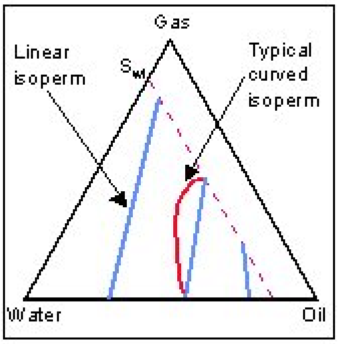
One of the critical factors affecting recovery predictions is the behaviour at low oil saturations. This is because the three-phase benefit from gas injection over waterflood mostly occurs from oil being more mobile at low oil saturations, when some gas is present. Typically immiscible two-phase oil relperms behave as shown by the curve in Figure 3.



The relperm increases quite slowly at low oil saturations. However, for Stone I, the three-phase relperms are *forced* to be linear at low oil saturations, as shown in Figure 3. At low oil saturations, the three-phase relperms predicted by Stone I are therefore relatively much greater than typical two-phase relperms. They are also relatively greater than predicted by the other models considered, except for Stone II. None of the other models, except Stone II, are constrained to be linear in this way. The amended Stone I model has the linearity at low oil saturations removed and therefore gives a much smaller value in line with the middle group.

Reason for low prediction from linear isoperms

The linear isoperm model is a straightforward mathematical interpolation, illustrated in Figure 4. Linear isoperms are obtained by connecting two-phase points with the same relperm. The reason why this model typically predicts less than the others is that they tend to have curved isoperms which increase the oil relperm as illustrated in Figure 4. The linear isoperm model is therefore a simple choice with conservative results.



Reason for low prediction from Stone II

Of the models considered Stone II is the only one which cannot be easily modified to enable the residual oil saturation (S_{om}) to be specified when three phases are present. For Stone II S_{om} is implied by the model, so it cannot be fitted to measured S_{om} data. The predictions in Table 1 were all made assuming a linear variation of S_{om} between the two-phase residuals, except for Stone II. Typically reservoir simulators do not output S_{om} implied by Stone II. This is unfortunate since it is difficult to calculate, so the models's implications are not transparent. An example of a badly-behaved S_{om} curve predicted by Stone II assuming two-phase relperms of Corey type is shown in Figure 5. The two-phase residual was set at 0.3 for zero gas saturation and zero at maximum gas saturation. The problem is that Stone II typically predicts a sudden large rise in S_{om} when entering the three-phase region. For zero gas the initial rise is only five percentage points, whereas it is almost forty at maximum gas saturation. Note that the choice of zero S_{om} at maximum gas saturation is not the cause of the large rise. The S_{om} implied by Stone II is typically much larger than the two-phase residuals, which can make a lot of difference to recovery predictions. This explains why, for the example quoted, Stone II predicts an oil recovery for WAG less than for waterflood, despite the enforced linearity at low oil saturations.

Recommendations for best practice

In the absence of reliable three-phase measurements, the following proposals are made for best practice:

- Use transparent and readily understandable three-phase relperm models without unwarranted physical assumptions or mathematical problems. In particular, don’t use either of Stone’s models. They both assume the oil relperm increases linearly at low oil saturations and, furthermore, Stone II tends to predict high residual oil saturations.

- Calculate a range of estimates, not only from different models, but also from alternative physical assumptions, for example, three-phase residual oil saturation. The linear isoperm model tends to be conservative and is therefore suitable for lower estimates. Any of the mid range models such as saturation-weighted or GT, could be used for a higher estimate.

- It is best to choose models which allow the three-phase residual oil saturation to be specified, or can be modified to do so. GT allows this directly and linear interpolation and saturation-weighted can be modified to do so.

Acknowledgements

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Reference

[1] Key characteristics of three-phase oil relative permeability formulations for improved oil recovery predictions, Balbinski, E F , Fishlock, T P, Goodyear, S G and Jones, P I R, Proceedings of the 9th European Symposium on Improved Oil Recovery, The Hague, October 1997, paper number 42. An expanded version of this paper is due to be published in Journal of Petroleum Geoscience.

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Figure captions

Figure 1: Schematic of interpolation for constant relperm lines in three-phase

Figure 2: Comparison of predictions of incremental oil recovery for immiscible WAG example

Figure 3: Behaviour predicted by Stone I model for low oil saturations

Figure 4: Linear isoperm contours

Figure 5: Typical residual oil saturation curve implied by Stone II