Complete gas-brine imbibition relative permeability curves increase confidence in gas field performance

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SUMMARY

The standard methods used for measuring gas relative permeability during brine imbibition have been found to be inadequate as the resulting curves are incomplete and may include invalid points. CSIRO, together with an industry partner, developed new methods to improve on existing special core analysis, and generate substantially more complete gas relative permeability curves for samples from a NW Shelf gas field and also a Berea sandstone sample considered as a laboratory standard.

The true relative permeability curve is typically 'S' shaped or has a rolling over, convex-up shape that is completely different from the concave-up shape of the Corey relperm curve usually fitted to SCAL test data and also assumed in reservoir simulations models as the default.

Using the complete and more accurate relative permeability curves can give reservoir engineers more confidence in field development planning, and along the life of the field should result in better history matching. There may also be an economic upside if the reservoir produces gas at a high rate for longer than was originally predicted based on the old relperm curves.

Key words: Petrophysics, reservoir characterization, permeability, gas reservoir engineering.

INTRODUCTION

When using standard test methods for measurement of imbibition gas-brine relative permeability (relperm) on reservoir core samples, e.g. as recommended by McPhee et al. (2015) it is very difficult to establish uniformly progressing brine saturation. This often leads to poor definition of the shape of the relperm function at lower brine saturations when gas has the highest mobility.

Typically, during co-current flow with forced imbibition of brine along with gas, the saturation within the sample does not advance uniformly along the sample length. Brine will bank up at the inlet end of the sample (Figure 1) and it takes a long time to redistribute along the sample length, even with high fractional flow of gas to brine of 400:1 or more. Moreover, the first reliable co-current gas-brine relative permeability point is often only attained after a brine saturation of around S_w=40% is achieved, leaving a data gap between S_{wirr} and this point (Figure 2).

The data in Figure 2 can be interpolated with a concave-up Corey function curve, but this may not be correct. The lack of valid data can lead to questionable inputs to (and outputs of) reservoir simulation models and flow on to uncertainty in the performance of gas reservoirs undergoing depletion drive with an encroaching aquifer, or subjected to a water flood.

Figure 1. Berea sandstone sample taken from test rig at the early stage of an imbibition relperm measurement using existing SCAL methods. A large brine bank has formed at the inlet that blocks the permeability to gas.

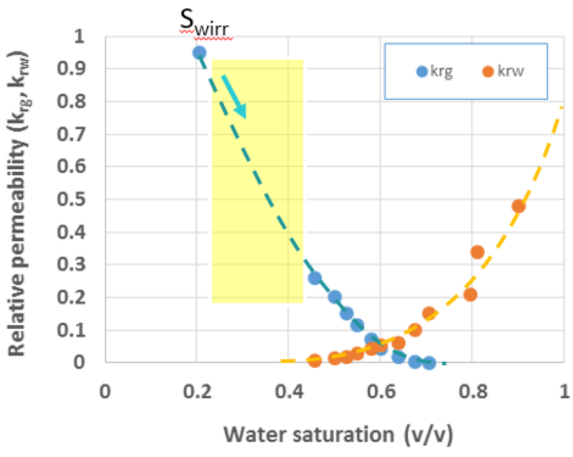

Figure 2. Example of a good quality, but incomplete imbibition relative permeability curve. There is a large data gap (yellow) in the gas relperm data between the gas-only flow point at S_{wirr} and the first co-current flow point at S_w=0.43. Data from Maloney et al. (1994).

The general problem of incomplete imbibition relperm curves available for conventional gas field development planning has been pointed out previously at an industry forum (e.g. Cense et al., 2016), but it has not so far been resolved in the form of a more practical measurement method that can obtain accurate and complete relperm curves.

In 2016 CSIRO was engaged by industry partners to investigate improvements to Special Core Analysis (SCAL) test methods for the purpose of reducing uncertainties in the development of major gas fields in the Northwest Shelf of Australia. During the ensuing research project, CSIRO worked with the operating company and in-house domain experts to devise and test new laboratory methods. We were able to collect a series of much more complete imbibition gas-brine relative permeability curves on several sandstone samples ranging in permeability from 10 mD up to over 600 mD. The methods were applied to NWS gas reservoir sands and also to a Berea sandstone, a well-known "standard" rock, which produced similar results.

MATERIALS AND METHODS

Experiments were conducted on reservoir sandstone samples ranging in dry gas permeability from 10 mD to around 760 mD, and with porosity ranging from 17% to 22%. The Berea sandstone outcrop sample used was quartz rich and well sorted with dry gas permeability of 665 mD and porosity of 21.8%. Core plugs of around 50-60mm length and 38 mm in diameter were cleaned prior to measurement, and then saturated with synthetic formation brine.

The samples were desaturated to irreducible brine saturation using a petrophysical centrifuge up to around 250 psi air-brine capillary pressure. The imbibition relperm experiments were commenced from close to the value of irreducible brine saturation S_{wirr}, which in the case of the Berea sample, was less than 2%, and for other samples ranged from 1.5 to 22%.

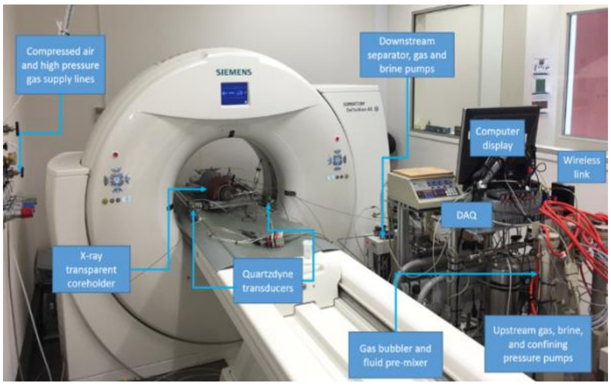

Figure 3. CSIRO X-ray CT monitored core flooding rig.

Samples were loaded into the CSIRO X-ray CT monitored core flooding rig (Figure 3). The system uses accurate differential and absolute pressure transducers capable of resolving a very small pressure drop across the sample, and gas and brine pumps with high accuracy and a wide range of allowable flow rates (0.001 to 120 cc/min). Flow into and out of the sample is by means of two porous end stones that are removable for cleaning and for controlling their initial brine content. The pressure drop for flow calculations is across the sample only, with the end stones bypassed by thin peek tubes and attached to the differential pressure transducer.

When using the standard technique of high gas fraction low brine fraction co-current flow to introduce the brine, we found the same problem arose that had been reported previously. A bank of brine built up at the sample inlet and only spread more uniformly after a brine saturation of around 40% had been achieved.

To overcome the problems described above we developed simple procedures to control the imbibition process in small increments of 5-10% S_w outside of the test cell, by blotting brine slowly into the sample from all sides with lint-free laboratory tissue, wrapping the sample plus tissue in impermeable film and allowing it to imbibe and redistribute evenly over a period of several hours to several days. Even brine saturation throughout the rock was validated using NMR T_2 spectroscopy and profiling along the axis of the film-wrapped sample (without tissue). The equilibrated samples were loaded into the rig and their properties measured under desired conditions: here a confining pressure of 2500 psi and a pore pressure of 500 psi were used. The gas used was nitrogen for safety reasons. A sodium iodide based brine was used to enhance X-ray contrast, though the overall composition was tested to be compatible with any clays in the rocks. With the blotting procedure a series of data points for gas-only flow was collected to fill in the data gap seen with the conventional method.

At low S_w, before brine became substantially mobile, we injected gas-only, at four or more rates, to define accurate gas relative permeability values that we also found to be highly repeatable. Once saturation had advanced sufficiently for brine to be detectably mobile, we progressed into co-current flows with the fractions of gas and brine adjusted to maintain near stable, but slowly advancing S_w. The use of paired syringe pumps at inlet and outlet allowed close control of both inflow and outflow brine rates, such that true steady state conditions were verified. The X-ray images of the experiments taken in the medical CT system included the end stones and this gave us advanced warning of potential saturation changes that could be balanced with a higher or lower brine flow rate. In this way, the progression of saturation was made as smooth as possible and the imbibition was controlled to be monotonic (meaning without any regressions in water saturation owing to too-rapid drainage of brine out of the sample).

RESULTS

In all cases we found that the shape of the much more complete gas relative permeability curve, now extending through to low S_w values, is convex upwards and does not show the concave-up or "Corey" type profile that is conventionally expected. The gas relperm function may have an 'S' shaped form or simply roll over to a sharp drop-off without tapering at high S_w. Figure 4 shows the results for Berea sandstone.

The experimental gas relperm curves can be fitted with the *LET* function (Lomeland et al., 2005), while the water relperm curves still show a classic Corey function shape, as expected from established theory for strongly water wet conditions. When regressions in saturation occurred, the gas relative permeability for the subsequent point lay below the curve for progressive imbibition, suggesting that additional blocking of gas pathways by displaced brine was occurring. These points are shown in grey in Figure 4.

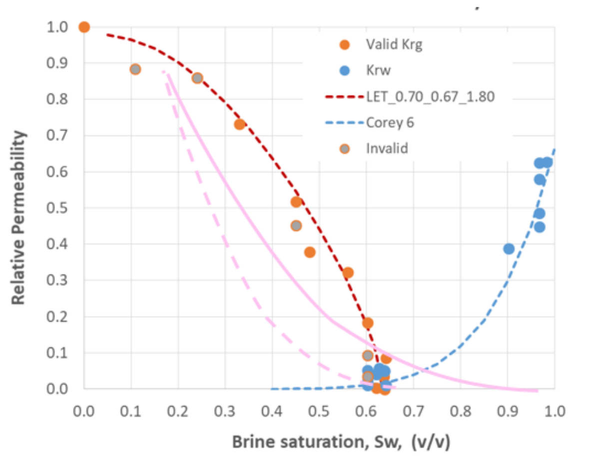

Figure 4. Gas relative permeability (orange dots are valid points) and brine relative permeability (blue dots). The red dashed line is the LET function fit. In pink is a default Corey function (solid- imbibition, dash- drainage).

DISCUSSION AND IMPLICATIONS

Our findings question the adequacy of relative permeability testing methods in SCAL programs for gas reservoirs and strongly suggest that the shape of gas-brine imbibition relative permeability curves should not be assumed to have a concave-up shape, at least for water wet systems such as those investigated in this research project. Considering that in a water wet rock, the brine has a strong affinity for surfaces, it is not surprising to us that the brine does not start to have a marked effect on the gas permeability until it has built up to a level where it blocks the gas pathways in the centres of pores and throat regions. Once the pathways start to block up however, the permeability to gas drops more precipitously in a process akin to the removal of bonds in a percolating network.

Our results apply to the water wet conditions tested in the gas-brine system in quartzo-feldspathic sandstones with variable proportions of clay, and moderate to high permeability. The prevailing conditions of our tests are representative of the interior of the reservoir (far from a well) and involve small capillary numbers (ratio of viscous (drag) forces to capillary (surface) forces of around 10^{-6} or 10^{-7}. At higher velocity and capillary number $>10^{-5}$ the viscous forces and momentum transfer will change the shape of the relperm curves, which are likely to straighten as the gas can more effectively push brine out of the way. Therefore, measurement of gas flow dynamics close to the wellbore would require a different style of testing and would most likely lead to differently shaped relperm curves.

Considering the true sigmoidal or roll-over profile of the gas relperm curves one can see that the gas flow rates predicted for the earlier stages of brine invasion into the reservoir (away from the near wellbore region) as it is depleted or swept, will be higher than would be predicted by defaulting to the concave-up “Corey” shape. (Figure 4 shows an example of one suggested Corey curve from a reservoir engineering manual). The Corey and *LET* type curves only merge towards the tail end of gas mobility, when the relative permeability is less than 10 percent of the starting values at S_{wirr}. Therefore, one would predict that higher gas flow rates are possible in the reservoir during the early stages of water ingress at least.

This new understanding of the true gas-brine relperm curve shapes may influence the development concept for gas reservoirs, the placement of wells and even the ultimate economics of a project. At the least, having complete and reliable relperm curves as inputs will improve the accuracy of reservoir simulation models and increase the level of confidence in their predictions of reservoir performance over time.

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