Society of Petroleum Engineers

SPE 56484

A New Method of Measuring Relative Permeabilities for Calculating Gas-Condensate Well Deliverability

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This paper was prepared for presentation at the 1999 SPE Annual Technical Conference and Exhibition held in Houston, Texas, 3–6 October 1999.

Abstract

Well deliverability in most gas condensate reservoirs is reduced by condensate banking when the pressure falls below the dew point, but the impact of condensate banking may be reduced due to improved mobility at high capillary number in the near-well region.

Fevang and Whitson[1] have shown that the key parameter in determining well deliverability is the relationship between k_{rg} and the ratio k_{rg}/k_{ro}. They also suggested an experimental technique for measuring k_{rg} as a function of k_{rg}/k_{ro} using core plugs.

We have applied the experimental pseudo-steady-state technique proposed by Fevang and Whitson to long cores at high pressure and temperature, measuring relative permeabilites under conditions which are similar to the near-well region of a gas condensate reservoir. A gas condensate fluid is introduced into a core whose pressure is below the dew point of the fluid. The condensate saturation in the core builds up until it becomes mobile and a steady state is reached, reproducing the mechanism which occurs in the reservoir. By varying the fluid composition, core pressure and flow rate, it is possible to measure all of the relative permeability data needed to predict well deliverability, including the increase in mobility at high capillary number.

We describe the experimental techniques and present results for a sandstone core from a North Sea gas condensate reservoir, using a 5-component synthetic fluid. The results show a clear increase in mobility with capillary number, at flow rates which are typical of the near-well region.

The pseudo-steady-state technique measures relative permeabilities and does not require saturations to be measured. The dependence of k_{rg} on k_{rg}/k_{ro} can be used directly in pseudopressure methods to calculate well deliverability. We also describe how the data for k_{rg} versus k_{rg}/k_{ro} can be used to define parameters for empirical correlations of relative permeability versus saturation, so that the results can be used in reservoir simulators.

Introduction

Well deliverability is an important issue in the development of many gas condensate reservoirs. When the well bottom hole flowing pressure falls below the dew point, condensate liquid builds up around the well bore, causing a reduction in gas permeability and well productivity. The liquid saturation may reach values as high as 50 or 60 per cent, and the well deliverability may be reduced by up to an order of magnitude.

The loss in productivity due to this ‘condensate banking’ effect may be significant, even in very lean gas condensate reservoirs. For example, in the Arun reservoir[2], the productivity reduced by a factor of about two as the pressure fell below the dew point, even though the reservoir fluid was very lean with a maximum liquid drop out of only 1%.

Most of the pressure drop from condensate blockage occurs within a few feet of the well bore, where flow rates are very high. There is a growing body of evidence from laboratory core flood experiments to suggest that gas condensate relative permeabilities increase at high flow rates, and that these changes can be correlated against the capillary number[3,4,5,6]. The capillary number is a dimensionless number which measures the relative strength of viscous and capillary forces. The increase in mobility at high capillary number is sometimes termed ‘velocity stripping’.

There are several gas condensate fields where simulation with conventional relative permeability models has been found to underestimate well productivity[2,7,8]. To obtain a good match between simulation results and well test data, it was necessary to increase the mobility in the near well region, either empirically or through a model of the velocity stripping effect. Velocity stripping can increase well productivity significantly, and in some cases may eliminate most of the effect of condensate blockage.

Experimental Data Requirements

Fevang and Whitson[1] have shown that the key parameter in determining well deliverability is the relationship between k_{rg} and the ratio k_{rg}/k_{ro}. When velocity stripping is significant, the most important information is the variation of k_{rg} with k_{rg}/k_{ro} and the capillary number N_c. The relevant values of k_{rg}/k_{ro} are determined by the PVT properties of the reservoir fluids, but typical values might be 10 to 100 for lean condensates, 1 to 10 for rich condensates, and 0.1 to 10 for near-critical fluids.

There are various ways of defining the capillary number, but in this paper we use the definition

$$N_c = \frac{v_g \mu_g}{\sigma} \qquad (1)$$

so that the capillary number is proportional to flow rate and inversely proportional to interfacial tension (IFT).

The capillary numbers which are relevant for well deliverability depend on the flow rate, fluid type and well bottom hole pressure, but as a general rule, values between 10^{-6} and 10^{-3} are most important.

Experimental Methods

In a gas condensate reservoir, there are important differences between the flow regimes in the regions close to and far from the well. These different flow regimes are reflected in the requirements for relative permeability data for the deep reservoir and near well regions. Far from the well, flow rates are low, and liquid mobility is usually less important, except in reservoirs containing very rich fluids. In the near well region, both liquid and gas phases are mobile, flow rates are high, and the liquid mobility is important because of its effect on the relationship between k_{rg} and k_{rg}/k_{ro}.

'Depletion' Method. Relative permeabilities for the deep reservoir region are often measured in a core flood experiment, where the fluids in the core are obtained by a constant volume depletion (CVD) on a reservoir fluid sample. Relative permeabilities are measured at decreasing pressures from the fluid dew point, and increasing liquid saturation. In this type of experiment, the liquid saturation cannot exceed the maximum value in a CVD experiment, so that it is not possible to acquire data at the high liquid saturations which occur in the reservoir near to the well.

The 'depletion' experiment provides relative permeability data which are relevant to the deep reservoir, but there can be problems in interpreting the results due to the effects of IFT. Changes in liquid saturation are achieved by reducing pressure which results in a change of IFT. The increase in IFT as pressure falls may cause a large reduction in mobility, and Chen *et al*[9] describe an example where the condensate liquid relative permeability **decreases** with increasing liquid saturation

Steady-State Method. The steady-state technique can be used to measure relative permeabilities at the higher liquid saturations which occur in the near well region. Liquid and gas can be injected into the core from separate vessels, allowing relative permeabilities to be measured for a wide range of saturations. Results of gas condensate relative permeabilities measured by this technique have been reported by Henderson *et al*[3] and Chen *et al*[9].

A schematic diagram of the equipment used by AEA Technology for these experiments is shown in Figure 1. At the start of the experiment the core contains gas condensate and connate water above the dew point pressure. The pressure is then reduced so that a liquid phase forms. Equilibrium gas and liquid are then injected into the core. (The gas and liquid are at equilibrium at the core pressure.) Different saturations are achieved by varying the proportions of gas and liquid. We have used this rig to measure relative permeability data with gas condensate fluids for a number of reservoir and outcrop cores, and have observed the increased mobility at high capillary number, first reported in Reference 2.

Pseudo-Steady-State Method. Fevang and Whitson[1] suggested an experimental technique for measuring k_{rg} as a function of k_{rg}/k_{ro} using core plugs. A similar method was also used by Asar and Handy[10] for measuring relative permeabilities of in a low IFT methane-propane system. We have applied this technique on a reservoir core of length 25 cm, although the equipment has been built to accommodate cores up to 1 m long.

The pseudo-steady-state technique is designed to measure relative permeabilities under conditions which are similar to the near-well region of a gas condensate reservoir. It determines k_{rg} as a function of k_{rg}/k_{ro} and capillary number, without the need to measure saturations directly. With this technique it is possible to measure all of the relative permeability data needed to predict well deliverability, including the increase in mobility at high capillary number.

Our apparatus for the pseudo-steady-state technique is shown schematically in Figure 2. The core is depleted to a pressure below the dew point, in the same way as for the steady-state method. The difference from the steady-state method is that the inlet accumulator contains the same gas condensate fluid but at a higher pressure. Only gas from the inlet accumulator is injected into the core, through a pressure reducing valve. The inlet accumulator represents conditions in the deep reservoir while the core represents conditions near to the well.

The experimental technique mimics the process in the near-well region, where rich gas flows into a region of lower pressure, condensing liquid and increasing the liquid saturation until it is mobile. After a time, steady-state conditions are reached when the flowing fluid composition at the outlet of the core is the same as the gas composition in the inlet accumulator. Further details of the experimental procedures are given by Cable *et al*[11].

Choice of Fluids. Measurements of gas condensate relative permeability can be carried out using reservoir fluid samples or with synthetic fluids. Experiments with reservoir fluid samples are more realistic but also more expensive and time consuming. The advantages of using synthetic gas condensate fluids are ease of handling, better characterization, and avoiding the need to work at very high temperatures and pressures.

For experiments relevant to near well conditions, an advantage of using reservoir fluids is that it avoids the need for accurate measurements of liquid viscosity, which are not made in routine PVT analyses of gas condensate samples. Simulator predictions of gas condensate well productivity are quite sensitive to liquid viscosity. However, if the relative permeability measurements are carried out with the same fluid, any errors in calculated liquid viscosity will cancel, as they will affect the reservoir simulation and the experimental interpretation in the same way.

Relative Permeability Measurements on North Sea Reservoir Core

Core Properties. The core used in this study to demonstrate the high rate, pseudo-steady-state method was a sandstone core from a North Sea gas condensate reservoir. The core properties are shown in Table 1. This core had previously been used for low rate depletion and steady-state relative permeability measurements using reservoir fluid samples, at conditions close to those in the reservoir, and the results of this earlier study are also summarized in this section.

Low Rate Relative Permeability Measurements. The low rate relative permeability measurements were carried out using a modified reservoir fluid at a temperature of 93°C. The fluid had a dew point of about 450 bar with the maximum liquid drop out in a CVD experiment of 25% occurring at about 200 bar.

Gas relative permeabilities were measured by the depletion method at pressures from 437 bar to 190 bar, followed by a small number of steady-state measurements at about 190 bar. The results are shown in Figure 3. The water saturation during these experiments was about 18%.

The unusual 'S' shape of the gas relative permeability curve suggests that gas relative permeability is affected by low values of IFT. At the highest pressures and lowest liquid saturations, the IFT is less than 0.02 mN/m, and the relative permeabilities lie on a straight line with an end point saturation of zero. For higher values of liquid saturation, the reduced pressure leads to an increase in IFT. The three measured points at high IFT lie on a Corey curve with an exponent of about 4 and a residual gas saturation of 49%. These two extremes are shown by the dotted lines on Figure 3.

Chen *et al*[9] present gas condensate relative permeability curves with a similar shape, and we have seen similar results in other measurements of gas condensate relative permeabilities using the depletion method.

During the 'depletion' measurements, the gas permeabilities were determined by measuring differential pressures at flow rates falling from 50 to 10 mL/hr. The pressure drop varied linearly with rate, indicating that there was no variation in relative permeability with flow rate

High Rate Experiments. A 5-component synthetic gas condensate was used for the high rate experiments. The composition of the fluid is given in Table 2. The properties of this fluid have been modeled with an equation of state at temperatures of 40°C, 60°C and 80°C to provide fluid characteristics, viscosity and interfacial tension. The fluid properties have also been measured. For this fluid, the IFT and maximum condensate saturation can be conveniently controlled by choice of temperature.

The experiments were carried out at a core temperature of 60°C. The dew point pressure at this temperature is about 212 bar.

Non-Darcy flow. An initial high rate experiment was carried out with the core pressure above the dew point pressure, in order to measure the gas permeability and non-Darcy flow coefficient at irreducible water saturation. The maximum rate was about 15 L/hr, measured at core conditions. Figure 4 plots the difference between the squares of the inlet and outlet pressures (P_{in}^2-P_{out}^2) against the flow rate. (We use P_{in}^2-P_{out}^2 rather than ΔP to allow for gas compressibility). With Darcy flow, these data should lie on a straight line, and the departure from a straight line is a measure of the effect of non-Darcy flow. Non-Darcy flow was apparent at rates above about 3 L/hr.

The measured pressure data were analyzed using the method of Evans *et al*[12], giving a gas permeability of 69 md and a non-Darcy flow coefficient (β) of 4.8 x 10^8 m^{-1}.

A large number of empirical correlations have been published for β as a function of effective permeability and porosity, giving a wide range of results which vary by at least an order of magnitude. The measured value of β is towards the lower end of the prediction from different correlations.

High Rate Relative Permeability Measurements. For the gas-oil relative permeability measurements the core pressure was reduced to about 160 bar, where the IFT was about 0.4 mN/m, and the liquid saturation in a CVD experiment was about 20%.

Three series of experiments were carried out by varying the pressure in the inlet accumulator, which changed the composition of the flowing fluid and the values of the ratio k_{rg}/k_{ro}.

For the first test the inlet accumulator pressure was 170 bar, giving a reduction in pressure of about 10 bar across the inlet pressure reducing regulator. The displacement was continued until differential pressure, condensate production and total production rates reached steady-state conditions. Once steady-state values were measured, a new displacement rate was established by lowering the pressure by about 1 bar (using the outlet back-pressure regulator). New steady-state conditions were established rapidly. For the first test, relative permeabilities were measured at four displacement rates before the reservoir fluid expired.

Two further tests were carried out at inlet accumulator pressures of 190 bar and 224 bar, giving a richer injection gas.

For these tests it was possible to measure relative permeabilities at ten and fifteen displacement rates respectively, because experience with the first test had shown that steady-state conditions were achieved very quickly.

Between each test it was necessary to re-establish single phase conditions. This involved revaporizing all liquid components throughout the system and mixing the liquid with its associated gas. With the fluid revaporized, the core reference permeability and fluid CVD characteristics were measured as a means of quality checking.

During the second and third tests, some of the lower rate relative permeability measurements were repeated following the highest rate measurements. The results were consistent, with no indication of a 'hysteresis' effect resulting from the rate changes.

Figure 5 gives a plot of P_{in}^2-P_{out}^2 against flow rate for the high rate experiments below dew point, with three phases present. These results show a downward curvature at increasing rate, corresponding to an increase in mobility with flow rate. In contrast, the two-phase results in Figure 4 show an upward curvature, caused by an increase in mobility with flow rate. The downward curvature in Figure 5 shows that, for the rates in these experiments, the improvement in mobility due to changes in relative permeability with capillary number is greater than any loss of mobility due to non-Darcy flow.

Relative Permeability Results. Figure 6 shows the measured values of relative permeability, plotted in the form of k_{rg} and k_{ro} versus log of capillary number for each of the three tests. Each test aimed to keep a constant value of k_{rg}/k_{ro}, but in practice some variation in k_{rg}/k_{ro} occurred due to changes in the core pressure. The values of k_{rg}/k_{ro} were 13 to 17 in test 1, 3.6 to 4.3 in test 2, and 0.97 to 1.1 in test 3. The increase in mobility with capillary number is very clear, and there is relatively little scatter in the data. Note that the relative permeability data in Figure 6 are normalized to a value of k_{rg} = 1 when the condensate liquid saturation is zero.

The Pseudo-Steady-State Technique

An objective in this work is to develop an experimental procedure which can measure the relevant data for gas condensate well productivity on a routine basis. The pseudo-steady-state method has provided a very effective and practical means of measuring gas condensate relative permeability, including the effects of high flow rate. The simplicity of the technique enables data to be acquired very quickly, and there are significant advantages over conventional steady-state measurements. Some key points are

1. Steady-state is achieved quickly, typically in much less than 30 minutes, and it is straightforward to measure core differential pressure, steady-state liquid production and total displacement rate; the 3 parameters required for the calculation of k_{rg} and k_{ro}.
2. It is possible to select 'reservoir' and 'bottom hole' pressures to tailor flowing conditions to specific near-well situations, generating relative permeability data with the appropriate k_{rg}/k_{ro} ratio, flow rate and IFT.
3. The technique is a single pass operation; fluid recycling is not possible as the composition of the reservoir fluid changes from the inlet conditions to the core conditions. Large fluid volumes are therefore required. To obtain a data series of 5 to 10 steady-state points would require a reservoir fluid volume of approximately 5 to 10 L.
4. Although acquisition of data is very quick, fluid handling may prove to be expensive or time consuming for real reservoir fluid systems. These limitations may be reduced in time with more experience and specialized equipment tailored to the technique, such as the use of low diameter cores.

We are continuing to develop the pseudo-steady-state method by extending its use to low permeability cores and using in-situ saturation monitoring to give a better understanding of saturations in the core.

Interpretation of Relative Permeability Data

Models for IFT and N_c Dependence. A number of mathematical models have been proposed for representing the changes in gas and oil relative permeability with capillary number, all of which involve an interpolation between 'base' curves (at low capillary number) and straight lines representing 'miscible' conditions at high capillary number.

The gas phase relative permeability at capillary number N_c is given by

$$k_{rg} = f_g(N_c)k_{rg(base)} + [1 - f_g(N_c)]k_{rg(misc)} \qquad (2)$$

where $k_{rg(base)}$ is the relative permeability curve at low capillary number, and $k_{rg(misc)}$) is a straight line. f_g is an interpolation function, which can take values between 0 (at very high capillary number) and 1 (at very low capillary number). A similar expression is used for the oil relative permeability, although the parameters in the interpolation function are usually different for the oil and gas phases.

To avoid discontinuities in the critical saturation, the end points on both the base and miscible curves are usually scaled to a value of $f_g S_{gc}$.

The first model of this type was presented by Coats[13], with the interpolation based on IFT rather than capillary number. This model is used in many commercial simulators for modeling low IFT effects. The published models based on capillary number include those of Fevang and Whitson[14], Pope *et al*[15] and Danesh *et al*[16]. Blom and Hagoort[17] present a review of the different models, and list seven different options for the interpolation function f_g.

Modeling Low Rate Experimental Data. The gas relative permeabilities measured in the depletion experiment at low rate show dependence on IFT but not on flow rate. A reasonable fit to the data was obtained by using Equation 2 with the interpolation based on IFT, and the function f_g given by

$$f_g = \frac{1}{1 + (a/\sigma)^{1/b}} \quad (3)$$

where a and b are empirical parameters. This function is the same as in References 14 and 15, but using IFT rather than capillary number. Fitting this model to the experimental data, gave values for the parameters of $a = 0.057$ mN/m and $b = 0.72$, and Figure 7 compares the predictions of this model for gas relative permeability with the experimental data. The results show how the unusual 'S' shape of the measured relative permeability curve can be explained by including dependence on IFT.

Modeling High Rate Experimental Data. Fitting the high rate relative permeabilities to a theoretical model is more complicated as the saturations were not measured, whereas all of the published correlations calculate relative permeability as a function of saturation.

The match was achieved by setting up a spreadsheet to calculate a two dimensional table of k_{rg} versus k_{rg}/k_{ro} and capillary number, using a theoretical model of the form in Equation 2. From this table it was possible to calculate k_{rg} at the measured values of k_{rg}/k_{ro} and capillary number, and to compare predicted and measured values of k_{rg}. The model parameters were then adjusted to optimize the fit between predicted and measured values.

The 'base' relative permeability curves at low capillary number were estimated from the low flow rate data, taking account of the impact of low IFT on the gas relative permeability curve. As only a small number of steady-state measurements were made, it was difficult to estimate the 'base' oil relative permeability curve with any certainty. The base curves also allowed for the reduction in the water saturation during the high rate non-Darcy flow measurements.

The change in relative permeability with capillary number was modeled using the interpolation function [14,15]

$$f_g = \frac{1}{1 + (N_c/a)^{1/b}} \quad (4)$$

The parameters a and b were allowed to take different values for the oil and gas phase, and their values are listed in Table 3. Figure 8 compares the calculated and measured values of k_{rg}. The ratio of k_{rg}/k_{ro} is approximately constant during each of experiments, but slight variations in k_{rg}/k_{ro} occur, caused by small changes in the core pressure. The 'bumps' in the data for experiment 2 at a capillary number of about 3×10^{-5} are due to these variations in k_{rg}/k_{ro}.

The relative permeability data were also matched using two other choices of interpolation function; the model of Danesh *et al* [16], which uses different functions for interpolating relative permeability curves and end point saturations, and equation F-1 of Blom and Hagoort [17]. All of the models gave a reasonable match to the experimental data, but gave very different predictions when extrapolated to significantly higher capillary numbers.

Discussion. The relative permeability measurements on this core show different behaviour in the low rate, depletion experiments and in the high rate, pseudo-steady-state experiments. The low rate gas relative permeability data show an unusual behaviour which is probably caused by the effects of low IFT, but no variation with flow rate was seen. On the other hand, the high rate results show a definite increase in mobility with flow rate at a fixed value of IFT.

Most recent models for gas condensate relative permeability assume that the capillary number can be used as a single parameter to account both for the effects of flow rate and IFT. These results suggest that this model may not be valid for flows at low rate and low IFT. However, this type of flow regime only occurs in the deep reservoir at high pressure, and is of limited importance when calculating well productivity.

Another area of interest is the relationship between capillary number and inertial (non-Darcy) flow effects. A comparison of Figures 4 and 5 shows that capillary number effects have a significant impact at flow rates above about 2 L/hr, while inertial flow effects only become important at flow rates above about 5 L/hr. The highest flow rate in the relative permeability experiments was 5.6 L/hr, so it is difficult to draw any firm conclusions about the interaction of capillary number and inertial flow effects

Any inertial effect is included in the relative permeability results in Figure 6. As these results show an increase in mobility with flow rate, it appears that any reduction in mobility caused by inertial flow is less important than the increase due to high capillary number flow. However, this may not be the case at higher flow rates or for low permeability cores, where inertial flow effects may be more dominant. Further experiments at higher flow rates are needed to investigate the interaction between non-Darcy and high capillary number flow.

The highest flow rates in the relative permeability tests gave a superficial velocity of about 500 m/day. This velocity occurs about 1 foot from the wellbore in a reservoir producing 20 MMscf/d from a 100 foot column.

Simulation of Condensate Well Productivity

A common approach to modelling gas condensate well productivity in field scale simulation is to use single well models to estimate skin factors due to condensate blockage, and to use these skin factors in the field scale simulation. This is not ideal, as the skin factor may vary with pressure and flow rate, and there can be problems in ensuring consistent conditions between the single well and full field models.

Local grid refinement (LGR) can be used to model near well effects in field scale simulation, but results in a much more complex simulation model. Adding LGR to a simulation model can lead to a significant increase in run time, and may cause numerical problems in linking the solutions on the local and global grids.

A more practical alternative is to use a pseudopressure method to calculate gas condensate well productivity within a coarse grid simulation model[1]. This technique can be extended to include capillary number[14] and non-Darcy flow effects. Mott[18] compares results of fine grid simulation and coarse grid simulation with a pseudopressure integral. The pseudopressure method gives good agreement with fine grid simulation, including a case where the capillary number effect causes a significant improvement in well productivity. It is also possible to use the pseudopressure method in material balance models which calculate well productivity in a spreadsheet calculation, including the impact of capillary number and non-Darcy flow[18].

Pseudopressure models require permeabilities in the form of k_{rg} as a function of k_{rg}/k_{ro} and capillary number, so that the pseudo-steady-state method measures relative permeability data in the format needed for pseudopressure calculations. Figure 9 shows the results from the high rate experiments and the fitted theoretical model, plotted in this form.

The model predictions in Figure 9 show a large increase in mobility as the capillary number increases from 10^{-4} to 10^{-3}. This rapid change in mobility can occur with most of the interpolation functions which have been proposed for interpolating relative permeability with capillary number, and different interpolation functions can give very different results when used to extrapolate experimental data to higher capillary numbers. Further experimental data at higher flow rates are needed to choose the most suitable interpolation function for modeling capillary number dependence of relative permeability.

Conclusions

1. A new method, the pseudo-steady-state technique, has been used to measure gas condensate relative permeabilities under conditions relevant to the near well region. The new technique measures k_{rg} as a function of k_{rg}/k_{ro} and capillary number; this is the most important information for calculating gas condensate well productivity. The new method has the potential for measuring high rate gas condensate relative permeabilities on a routine basis.
2. High rate relative permeability measurements on a North Sea sandstone core show a significant increase in relative permeability with capillary number, confirming the effect seen by other researchers.
3. At the flow rates in the experiments, the increased mobility due to capillary number dominated any reduction in permeability due to inertial (non-Darcy) flow. Further experiments at higher flow rates are needed to understand the interaction between capillary number and inertial flow effects.
4. Gas relative permeability measurements were carried out using a ‘depletion’ technique on the same core at low flow rates. The results showed no rate dependency, but there was evidence for an increase in relative permeability due to low IFT.
5. A method has been devised for matching the results of the pseudo-steady-state technique (k_{rg} as a function of k_{rg}/k_{ro} and capillary number) to empirical correlations of relative permeability versus saturation.

Nomenclature

a = parameter in interpolation function
b = parameter in interpolation function
f = interpolation function for relative permeability
k_r = relative permeability
N_c = capillary number
P_{in} = core inlet pressure
P_{out} = core outlet pressure
S = phase saturation
S_c = critical saturation
v = superficial velocity
β = non-Darcy flow coefficient
μ = viscosity
σ = gas-oil interfacial tension

Subscripts

g = gas phase
o = oil phase

Acknowledgements

AEA Technology is grateful for the financial support for this project from the UK Department of Trade and Industry, BP Amoco, Esso Exploration and Production UK Ltd, Marathon Oil UK Ltd, Mobil North Sea Ltd, Phillips Petroleum Company UK Ltd, Saga Petroleum a.s and Texaco Britain Ltd.

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TABLE 1 – RESERVOIR CORE PROPERTIES

Length (cm)	25.8
Diameter (cm)	3.80
Cross sectional area (cm^2)	11.3
Bulk volume (cm^3)	291.5
Pore volume (mL)	74.0
Porosity (%)	25.4
Absolute brine permeability (md)	102.4
Irreducible water saturation (Swi)	0.118
Gas permeability at Swi (md)	67.7

TABLE 2 - SYNTHETIC CONDENSATE COMPOSITION

Component	mol %
Methane	80.0
n-Butane	14.0
n-Heptane	4.0
n-Decane	1.4
n-Tetradecane	0.6

TABLE 3 – PARAMETERS IN EQUATION 4 FOR INTERPOLATING k_{rg} AND k_{ro}

a (gas)	7.2×10^{-5}
b (gas)	2.3
a (oil)	9.0×10^{-4}
b (oil)	0.20

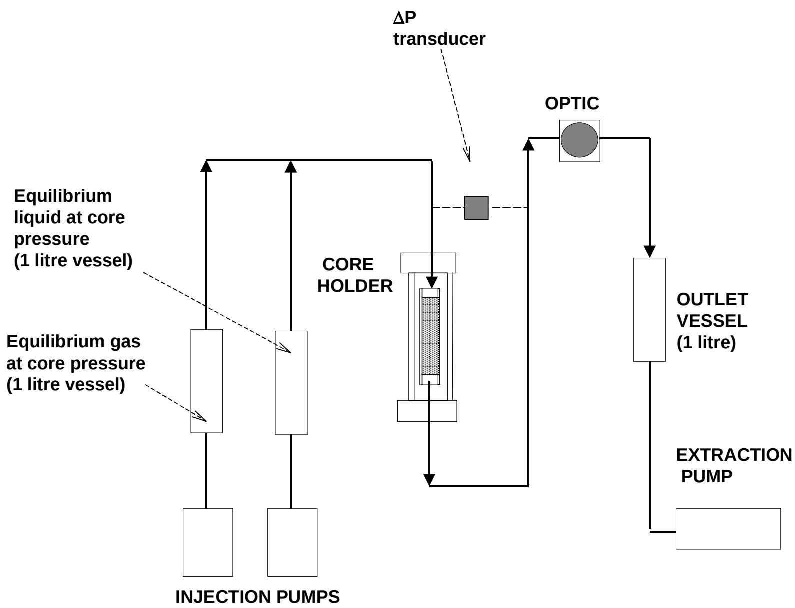

Figure 1. Rig for Steady-state Relative Permeability Experiments

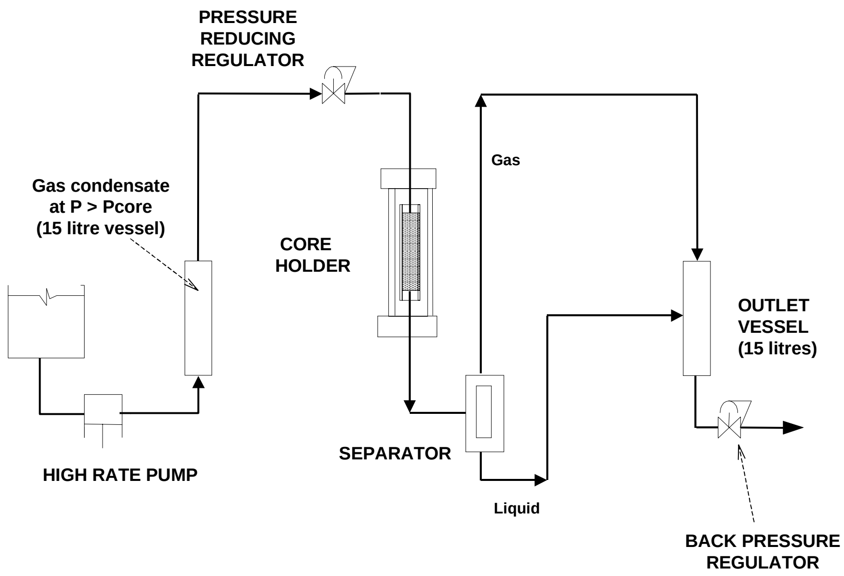

Figure 2. Rig for Pseudo--Steady-State, High Rate Relative Permeability Experiments

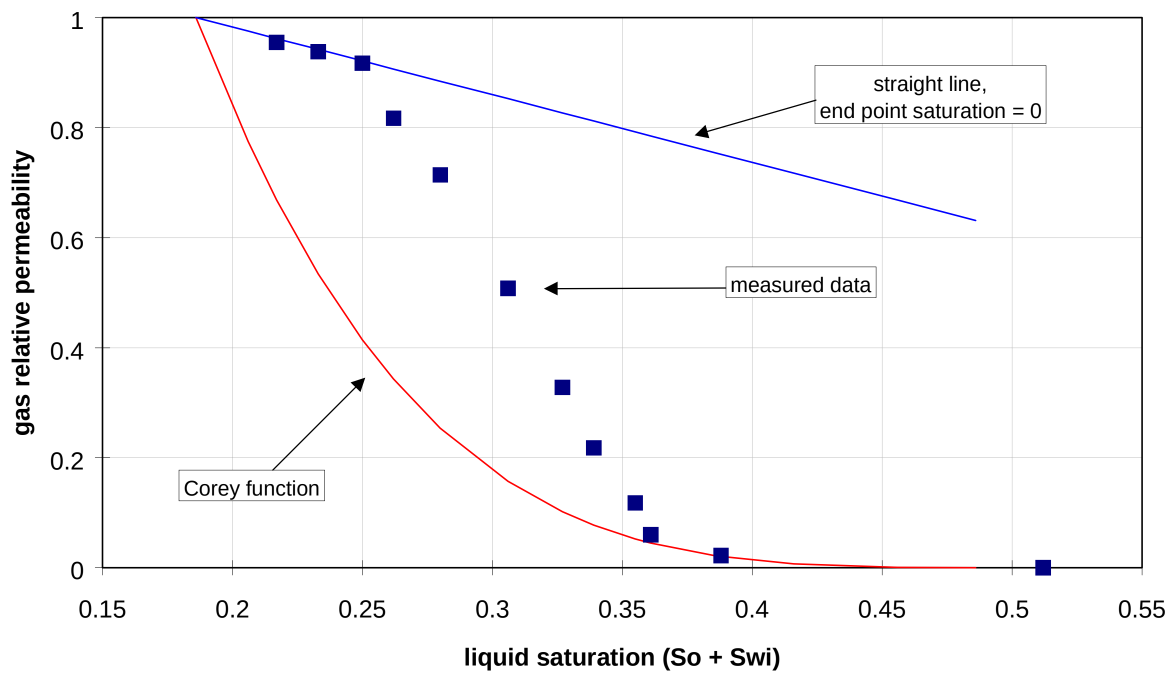

Fig.3 – Gas relative permeabilities measured in low rate depletion experiment.

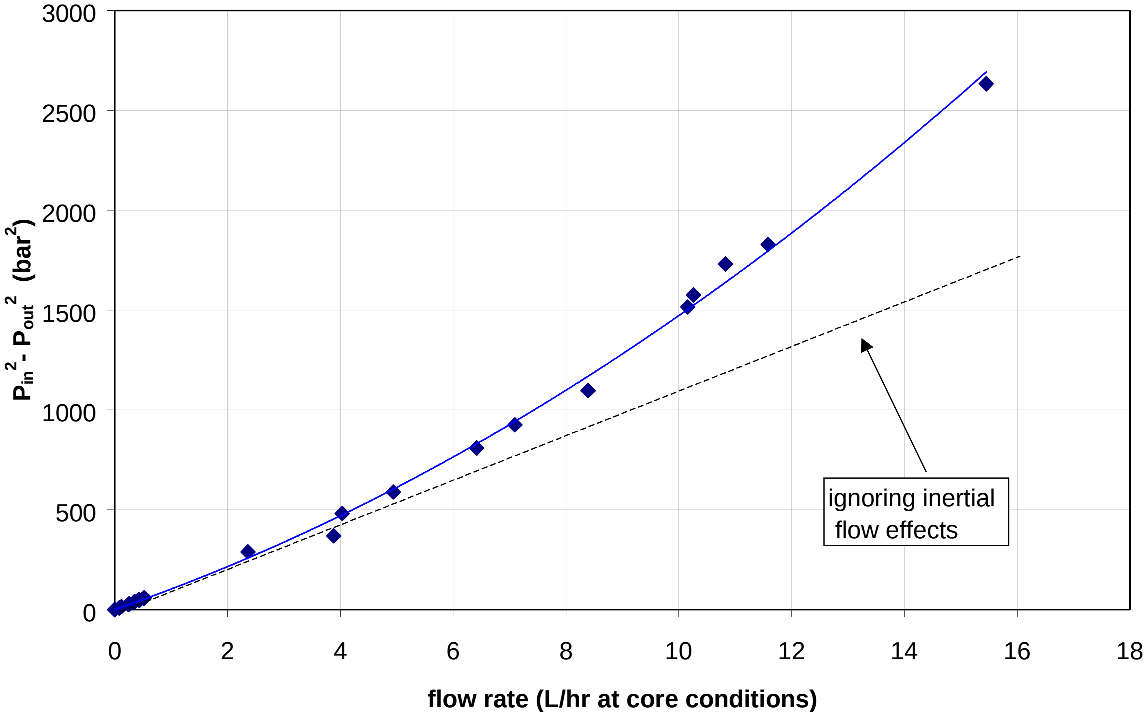

Fig.4 – (P_{in}^2 – P_{out}^2) versus flow rate for high rate experiment, gas condensate and water, to measure non-Darcy flow coefficient.

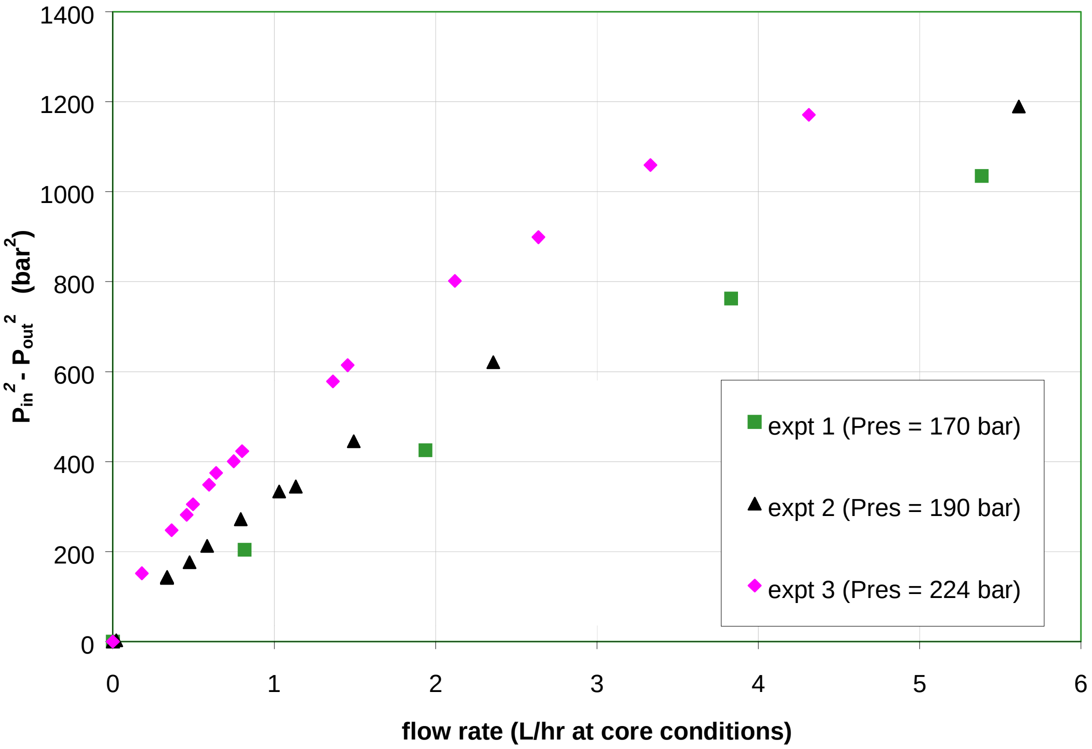

Fig.5 – (P_{in}^2 – P_{out}^2) versus flow rate for high rate experiment, three-phase conditions, to measure high rate relative permeability.

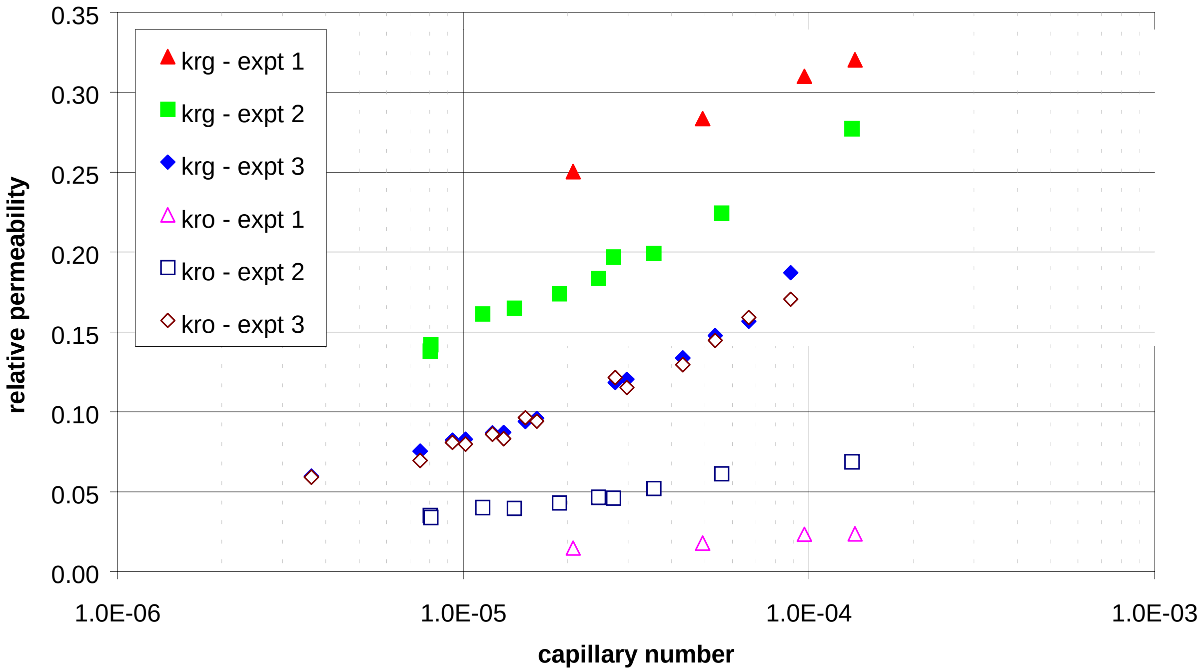

Fig.6 – Gas and oil relative permeabilities measured in high rate experiment.

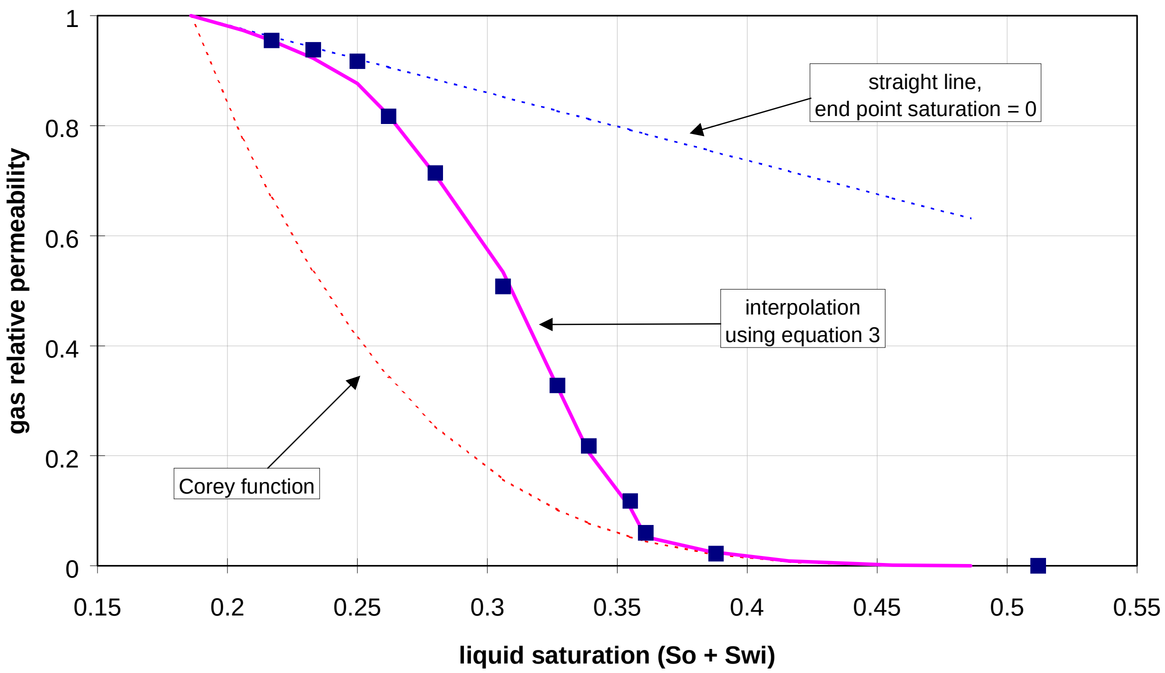

Fig.7 – Gas relative permeabilities measured in low rate depletion experiment, and calculated values using equation 3.

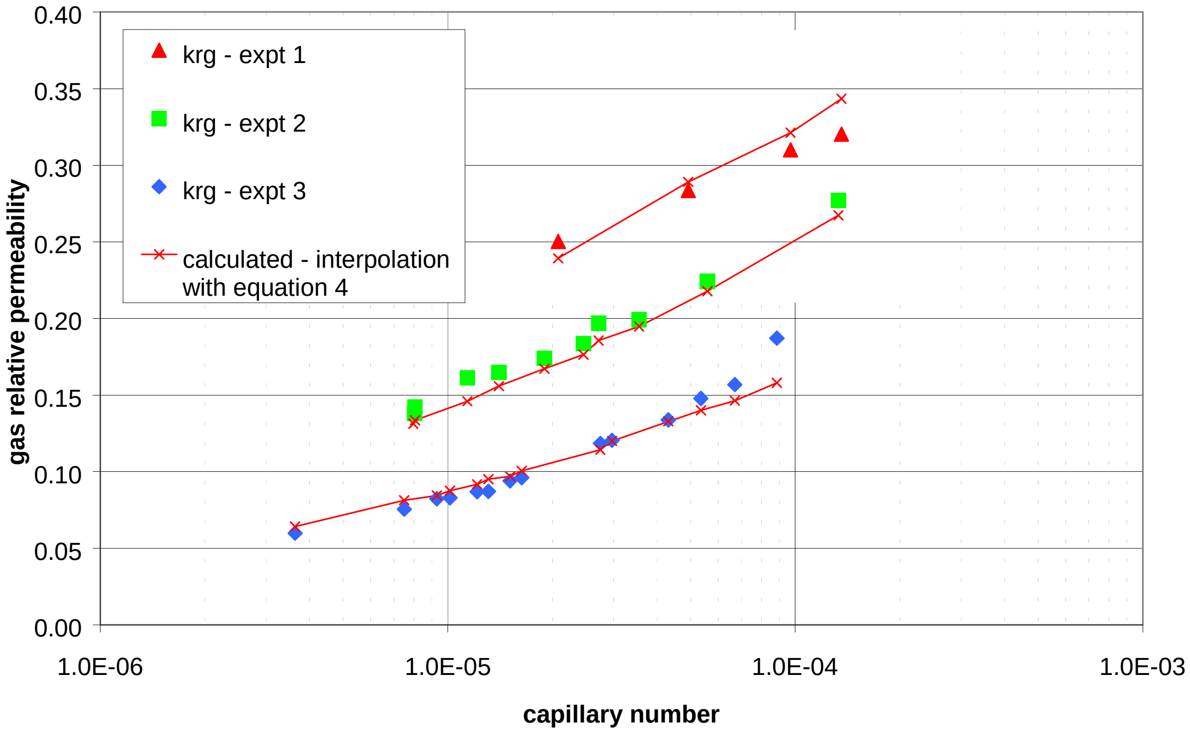

Fig.8 – Gas relative permeabilities measured in high rate experiment, and predictions from theoretical model.

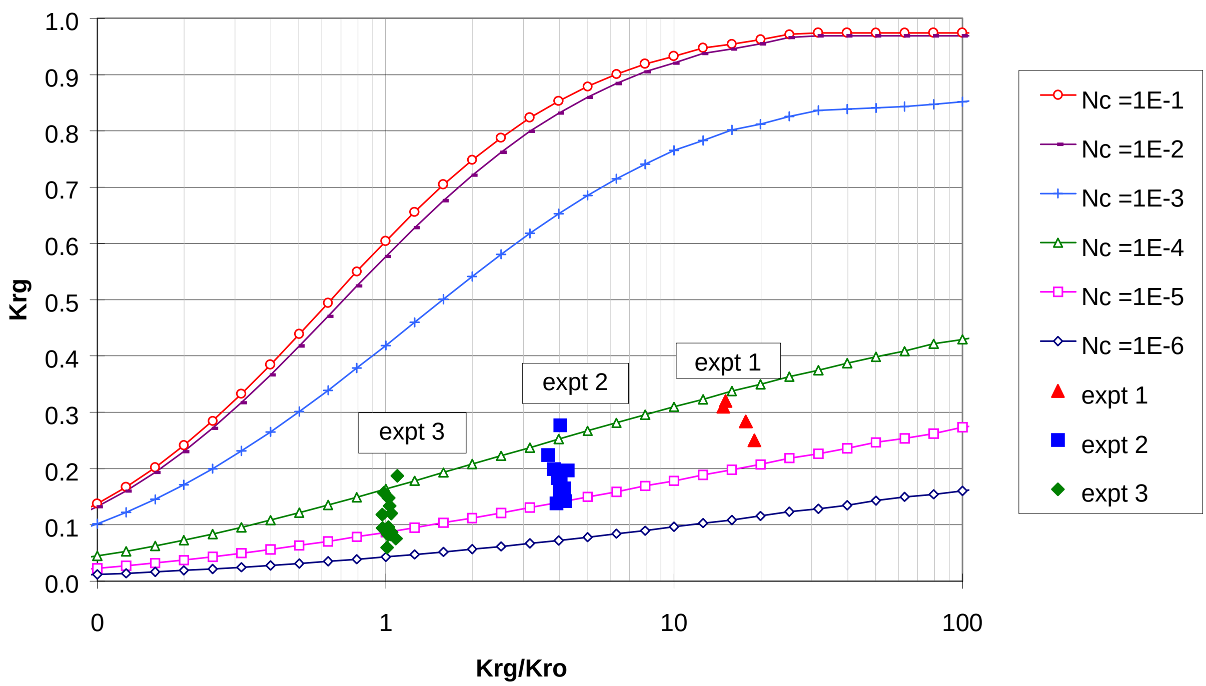

Fig.9 – K_{rg} versus k_{rg}/k_{ro} - permeabilities measured in high rate experiment, and predictions from theoretical model.