

Measurements of Relative Permeabilities for Calculating Gas-Condensate Well Deliverability

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Summary

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

This paper presents the results of relative permeability measurements on a sandstone core from a North Sea gas-condensate reservoir, at velocities that are typical of the near-well region. The results show a clear increase in mobility with capillary number, and the paper describes how the data can be modeled with empirical correlations which can be used in reservoir simulators.

Introduction

Well deliverability is an important issue in the development of many gas-condensate reservoirs, especially where permeability is low. When the well bottomhole flowing pressure falls below the dewpoint, condensate liquid may build up around the wellbore, causing a reduction in gas permeability and well productivity. In extreme cases the liquid saturation may reach values as high as 50 or 60% 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,¹ the productivity reduced by a factor of about 2 as the pressure fell below the dewpoint, even though the reservoir fluid was very lean with a maximum liquid drop out of only 1% away from the well.

Most of the pressure drop from condensate blockage occurs within a few feet of the wellbore, where velocities are very high. There is a growing body of evidence from laboratory coreflood experiments to suggest that gas-condensate relative permeabilities increase at high velocities, and that these changes can be correlated against the capillary number.²⁻⁸ The capillary number is a dimensionless number that measures the relative strength of viscous and capillary forces.

There are several gas-condensate fields where simulation with conventional relative permeability models has been found to underestimate well productivity.^{1,9,10} 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 increase in relative permeability at high velocity. This effect can increase well productivity significantly, and in some cases may eliminate most of the effect of condensate blockage.

Experimental Data Requirements

Fevang and Whitson¹¹ have shown that the key parameter in determining well deliverability is the relationship between k_{rg} and the ratio k_{rg}/k_{ro} . When high-velocity effects are 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 pressure/volume/temperature (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

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

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

The capillary numbers that are relevant for well deliverability depend on the flow rate, fluid type, and well bottomhole 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, velocities 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, velocities 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 coreflood 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 dewpoint, and increasing liquid saturation. In this type of experiment, the liquid saturation cannot exceed the critical condensate saturation or the maximum value in a CVD experiment, so that it is not possible to acquire data at the high liquid saturations that occur in the reservoir near to the well.

The "depletion" experiment provides relative permeability data that 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.*¹² 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 that 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.*^{2,6} and Chen *et al.*¹²

Fig. 1 shows a schematic diagram of the equipment used for steady-state experiments by AEA Technology. At the start of the experiment the core contains gas condensate and connate water above the dewpoint pressure. The pressure is then reduced so that a liquid phase forms by retrograde condensation. Equilibrium gas and liquid are then simultaneously injected into the core. (The gas and liquid are in equilibrium at the core pressure.) Different satu-

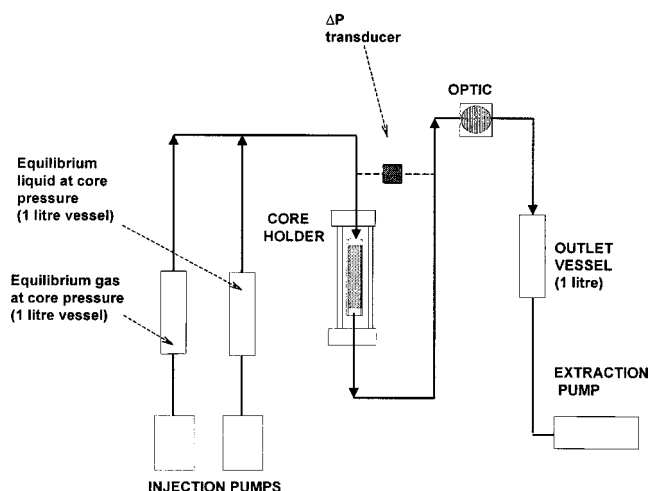


Fig. 1—Rig for steady-state relative permeability experiments.

rations 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 Ref. 2.

PseudoSteady-State Method. Fevang and Whitson¹¹ 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 Handy¹³ for measuring relative permeabilities 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 pseudosteady-state technique is designed to measure relative permeabilities under conditions that 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 pseudosteady-state technique is shown schematically in Fig. 2. The core is depleted to a pressure below the dewpoint, 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,

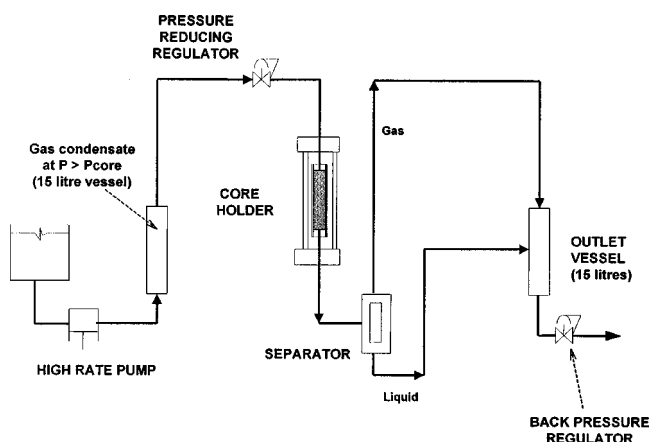


Fig. 2—Rig for pseudosteady-state, high-rate relative permeability experiments.

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 (S_{wi})	0.118
Gas permeability at S_{wi} (md)	67.7

through a computer-controlled 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.*¹⁴

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, pseudosteady-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.

A characteristic of this water-wet core is the relatively low value of gas permeability at S_{wi} . A very high proportion of the pores are interconnected by very small pore throats, so that a low water saturation blocks many of the flow paths of the gas phase.

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 dewpoint of about 450 bar with the maximum liquid drop out in a CVD experiment of 25% occurring at about 200 bar.

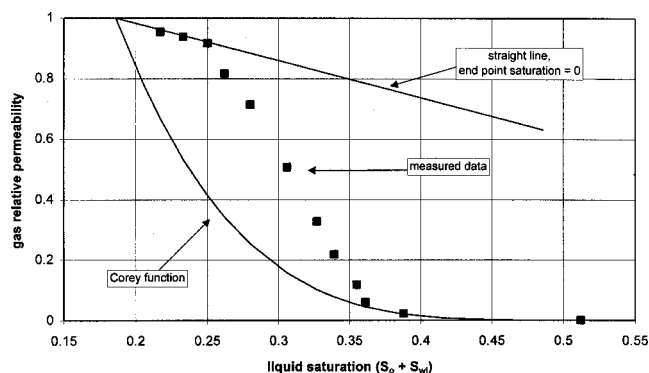


Fig. 3—Gas relative permeabilities measured in low-rate depletion experiment.

Gas relative permeabilities were measured by the depletion method at pressures from 437 to 190 bar, followed by a small number of steady-state measurements at about 190 bar. The results are shown in Fig. 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 endpoint 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 Fig. 3. Chen *et al.*¹² 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/h. The pressure drop varied linearly with rate, indicating that there was no variation in relative permeability with flow rate.

High-Rate Experiments. A five-component synthetic gas condensate was used for the high-rate experiments. Table 2 shows the composition of the fluid. The properties of this fluid have been modeled with an equation of state at temperatures of 40, 60, 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 dewpoint 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 dewpoint pressure, in order to measure the gas permeability and non-Darcy flow coefficient at irreducible water saturation. The maximum rate was about 15 L/h, measured at core conditions. Fig. 4 plots the difference between the squares of the inlet and outlet pressures ($p_{in}^2 - p_{out}^2$) against the

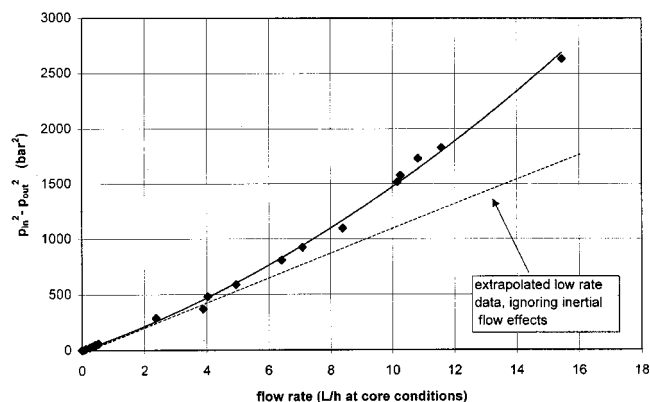


Fig. 4—($p_{in}^2 - p_{out}^2$) vs. flow rate for high-rate experiment, gas condensate, and water, to measure non-Darcy flow coefficient.

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/h.

The measured pressure data were analyzed using the method of Evans *et al.*,¹⁵ giving a gas permeability of 69 md and a non-Darcy flow coefficient (β) of $4.8 \times 10^8 \text{ m}^{-1}$.

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 range of predictions 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 and 224 bar, giving a richer injection gas. For these tests it was possible to measure relative permeabilities at 10 and 15 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 re-vaporizing all liquid components throughout the system and mixing the liquid with its associated gas. With the fluid re-vaporized, 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.

Fig. 5 gives a plot of $p_{in}^2 - p_{out}^2$ against flow rate for the high-rate experiments below dewpoint, with three phases present. These results show a downward curvature at increasing rate, corresponding to an increase in mobility with flow rate. In contrast,

TABLE 2—SYNTHETIC CONDENSATE COMPOSITION

Component	mol %
Methane	80.0
<i>n</i> -Butane	14.0
<i>n</i> -Heptane	4.0
<i>n</i> -Decane	1.4
<i>n</i> -Tetradecane	0.6

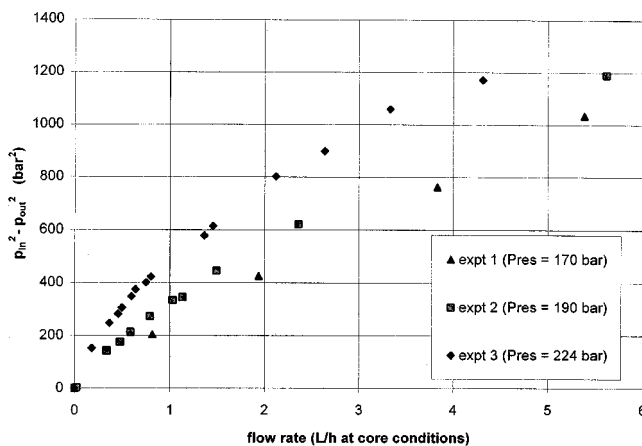


Fig. 5—($p_{in}^2 - p_{out}^2$) vs. flow rate for high-rate experiment, three-phase conditions, to measure high-rate relative permeability.

the two-phase results in Fig. 4 show an upward curvature, caused by a decrease in mobility with flow rate. The downward curvature in Fig. 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. Fig. 6 shows the measured values of relative permeability, plotted in the form of k_{rg} and k_{ro} vs. log of the 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 Fig. 6 are normalized to a value of $k_{rg}=1$ when the condensate liquid saturation is zero.

PseudoSteady-State Technique

An objective in this work is to develop an experimental procedure to measure the relevant data for gas-condensate well productivity on a routine basis. The pseudosteady-state method has provided a very effective and practical means of measuring gas-condensate relative permeability, including the effects of high velocity. 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:

- Steady state is achieved quickly, typically, in much less than 30 minutes, and it is straightforward to measure core-differential

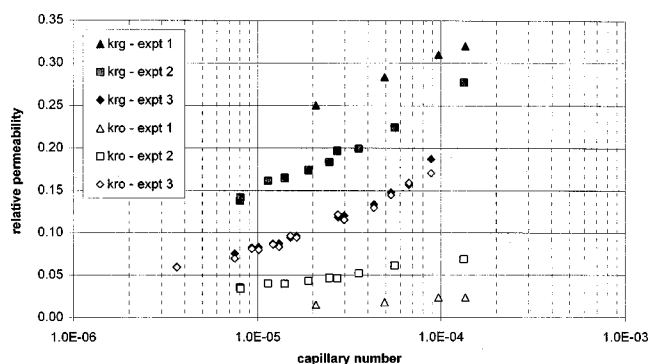


Fig. 6—Gas and oil relative permeabilities measured in high-rate experiment.

pressure, steady-state liquid production, and total displacement rate; the three parameters required for the calculation of k_{rg} and k_{ro} .

- It is possible to select “reservoir” and “bottomhole” pressures to tailor flowing conditions to specific near-well situations, generating relative permeability data with the appropriate k_{rg}/k_{ro} ratio, velocity, and IFT.

- 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.

- 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.

We are continuing to develop the pseudosteady-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 these models involve an interpolation between “base” curves (at low capillary number, where flow is capillary dominated) and straight lines representing “miscible” conditions at high capillary number where flow is viscous dominated.

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

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

where $k_{rg(\text{base})}$ is the relative permeability curve at low capillary number, and $k_{rg(\text{misc})}$ 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 endpoints 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,¹⁶ 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,¹⁷ Pope *et al.*,¹⁸ and Danesh *et al.*¹⁹ Blom and Hagoort²⁰ 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 Eq. 2 with the interpolation based on IFT, and the function f_g given by

$$f_g = \frac{1}{1 + (c/\sigma)^{1/d}}, \quad (3)$$

where c and d are empirical parameters. This function is the same as in Refs. 17 and 18, but using IFT rather than capillary number. Fitting this model to the experimental data gave values for the parameters of $c=0.057$ mN/m and $d=0.72$, and Fig. 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.

The gas relative permeability curve in Fig. 7 shows a high residual gas saturation of almost 50%. Additional measurements

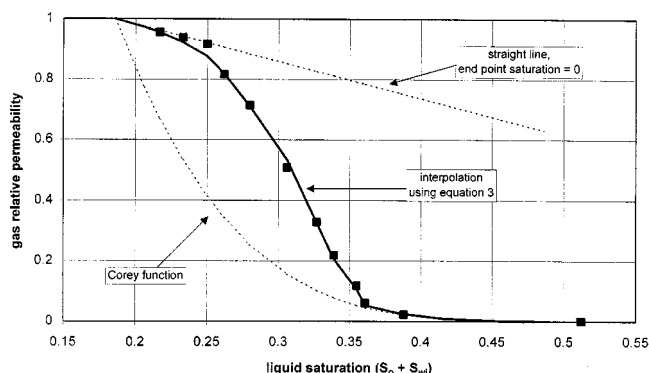


Fig. 7—Gas relative permeabilities measured in low-rate depletion experiment, and calculated values using Eq. 3.

showed the core to have a very high proportion of the pores interconnected by very small pore throats. The nonwetting gas phase would be effectively blocked at high saturation (in the largest pore spaces), while the wetting condensate flows via the small pore network and occupies the pore throat locations. Salino¹⁰ presents gas-condensate relative permeability data that also show a very high residual gas saturation.

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} vs. k_{rg}/k_{ro} and capillary number, using a theoretical model of the form in Eq. 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^{17,18}

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

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. Fig. 8 compares the calculated and measured values of k_{rg} .

The ratio of k_{rg}/k_{ro} is approximately constant during each series 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} .

TABLE 3—PARAMETERS IN EQ. 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

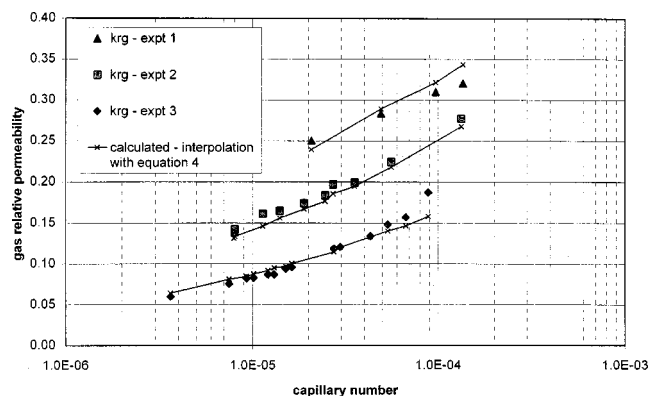


Fig. 8—Gas relative permeabilities measured in high-rate experiment, and predictions from theoretical model.

The relative permeability data were also matched using two other choices of interpolation function; the model of Danesh *et al.*,¹⁹ which uses different functions for interpolating relative permeability curves and endpoint saturations, and Eq. F-1 of Blom and Hagoort.²⁰ 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 behavior in the low-rate, depletion experiments and in the high-rate, pseudosteady-state experiments. The low-rate gas relative permeability data show an unusual behavior, 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 Figs. 4 and 5 shows that capillary number effects have a significant impact at flow rates above about 2 L/h, while inertial flow effects only become important at flow rates above about 5 L/h. The highest flow rate in the relative permeability experiments was 5.6 L/h, 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 Fig. 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/d. This velocity occurs about 1 ft from the wellbore in a reservoir producing 20 MMscf/D from a 100-ft column.

Simulation of Condensate Well Productivity

A common approach to modeling 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

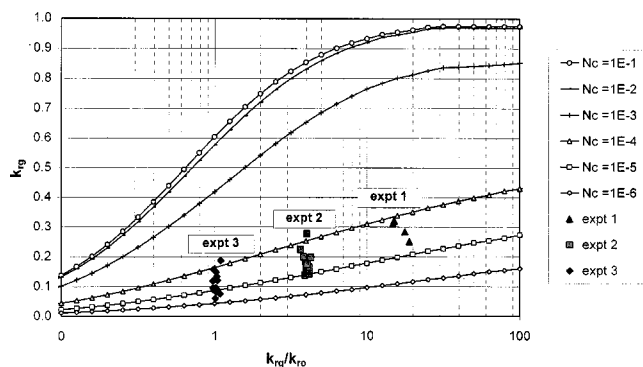


Fig. 9— k_{rg} vs. k_{rg}/k_{ro} —permeabilities measured in high-rate experiment, and predictions from theoretical model.

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.¹¹ This technique can be extended to include capillary number¹⁷ and non-Darcy flow effects. Mott²¹ 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 that calculate well productivity in a spreadsheet calculation, including the impact of capillary number and non-Darcy flow.²¹

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

The model predictions in Fig. 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 that 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

A pseudosteady-state technique has been used to measure gas-condensate relative permeabilities under conditions relevant to the near-well region. This technique measures k_{rg} as a function of k_{rg}/k_{ro} and capillary number, the most important data for calculating gas-condensate well productivity.

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.

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.

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.

A method has been devised for matching the results of the pseudosteady-state technique (k_{rg} as a function of k_{rg}/k_{ro} and capillary number) to empirical correlations of relative permeability vs. saturation.

Nomenclature

- a = parameter in interpolation function (Eq. 4)
- b = parameter in interpolation function (Eq. 4)
- c = parameter in interpolation function (Eq. 3), mN/m
- d = parameter in interpolation function (Eq. 3)
- f = interpolation function for relative permeability
- k_r = relative permeability, md
- N_c = capillary number
- p_{in} = core inlet pressure, bar(a)
- p_{out} = core outlet pressure, bar(a)
- S = phase saturation
- S_c = critical saturation
- S_{wi} = irreducible water saturation
- v = superficial velocity, m/d.
- β = non-Darcy flow coefficient, m^{-1}
- μ = viscosity, cp
- σ = gas-oil interfacial tension, mN/m

Subscripts

- base = base relative permeability
- g = gas phase
- misc = miscible relative permeability
- o = oil phase

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SI Metric Conversion Factors

bar	× 1.0*	E+05	= Pa
cp	× 1.0*	E-03	= Pa·s
ft	× 3.048*	E-01	= m
ft ³	× 2.831 685	E-02	= m ³

*Conversion factors are exact.

SPERE

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