Gravity Drainage during Gas Injection

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Abstract

The drainage of oil under gravitational forces has been an important mechanism in the production of many oil fields. In order to extend the economic implementation of gas injection into more marginal fields, a reduction in the uncertainties associated with gravity drainage is required. This paper describes a series of three tertiary, nitrogen experiments which investigated the effect of permeability on gravity drainage. The experiments were conducted at low pressure using long, vertical, water-wet sandstone cores and decane in the presence of connate brine.

The residual oil saturation following 62 days of nitrogen injection in a $0.37 \mu\text{m}^2$ core was 0.26. The residual oil saturation following 53 days of nitrogen injection in a $1.5 \mu\text{m}^2$ core was 0.10. The residual oil saturation following 63 days of nitrogen injection in a $2.0 \mu\text{m}^2$ core was 0.13. The variation of the oil and brine saturations were determined as a function of space and time for each experiment using a radioactive tracer technique. This independent measurement of both oil and brine in-situ saturations is a new development for the literature and enables core artefacts to be identified and relative permeabilities to be derived. Detailed analysis of the $2 \mu\text{m}^2$ experiment showed that the oil relative permeability was independent of position and

was only a function of oil saturation. The relative permeabilities are characterised by a zero asymptotic residual oil saturation and a Corey exponent of approximately four, which is higher than the value of three proposed from theoretical models of film drainage. A numerical simulation of this experiment gave a good match to the production and in-situ saturation data.

This paper presents the determination of oil and brine relative permeabilities under a flow regime which is representative of gravity drainage during gas injection. The method outlined thus gives added confidence when assessing field development options.

1 Introduction

Gas injection is a potentially attractive method of improving oil recovery as it can result in lower residual oil saturation than waterflooding alone. The high mobility of injected gas, however, can result in low sweep efficiencies. One situation where poor sweep efficiencies may not occur is during gravity stable gas injection. Under such circumstances, gravity forces can maintain a stable gas/oil interface. This process can result in very efficient oil recovery in both secondary and tertiary gas injection.

Relative permeabilities are a significant part of the input data required for field evaluation using numerical simulators. The uncertainties associated with these evaluations can be decreased by using relative permeabilities which are representative of the reservoir in question. Standard "special core analysis" methods do not establish the correct balance of gravity, viscous and capillary forces and the fluid distributions do not correspond to the film drainage flow regime associated with gravity stable gas injection. This paper describes a series of generic experiments which establish the principles and methodology required to generate representative data. A key feature of this approach is the use of three-phase in-situ saturation measurements which allow core artefacts to be identified and representative relative permeabilities to be derived.

A series of three low pressure, tertiary, nitrogen injection experiments are reported which investigate the effect of permeability on gravity drainage. The variation of the oil and brine saturations were measured for each experiment using a radioactive tracer technique. The in-situ saturation measurements were used to calculate the oil and brine relative permeabilities for the 2 μm^2 experiment. The results of the 2 μm^2 experiment (X1) were simulated.

2 Experimental Procedures

In all experiments, the cores were well-cemented aeolian sandstone from the Clashach quarry in Scotland, which is naturally water-wet, has well sorted grains and a low clay content. The cores were between 840 and 390 mm in length and were coated in epoxy resin. Some characteristics of the cores and the experimental parameters are given in Table 1.

The cores were vacuum saturated with brine containing 1% by weight sodium chloride and 0.3% potassium cobalticyanide and the absolute permeability determined. The cores were flooded to connate water with decane containing 1% by weight ferrocene. Water flooding was conducted by injecting at constant flow rate into the bottom of a vertical core. Gas injection was conducted by supplying nitrogen at a constant pressure to the top of a vertical core and extracting fluid at a constant volume flow rate from the bottom. A more detailed description of the flow circuit is given in Reference 1. In-situ saturations were measured along the length of the core during the experiments. Radioactive ferrocene containing gamma emitting iron-59 was used to label the oil phase. Radioactive potassium cobalticyanide containing gamma emitting cobalt-58 was used to label the brine

TABLE 1: SUMMARY OF CORE CHARACTERISTICS AND EXPERIMENTAL PARAMETERS

	Exp. A1	Exp. A2	Exp. X1
length (mm)	840	885	850
diameter (mm)	41.65	41.53	41.5
porosity	0.135	0.185	0.187
pore volume (mL)	154	221	214
abs. brine perm (μm^2)	0.37	1.47	2.0
connate water saturation	0.27	0.18	0.2
brine injection rate (mL/hr)	3	3	3
mean S_o to waterflood	0.52	0.31	0.43
nitrogen injection rate (mL/hr)	0.5	0.34	1
duration of gas inj. (days)	62	53	64
S_o at top of core at end of gas inj.	0.26	0.10	0.13

phase. The technique is discussed in References 2 and 3.

Oil production during gravity stable gas injection is significantly reduced if the oil does not spread on brine in the presence of gas [4]. Spreading trials were conducted with the fluids used in these experiments and it was found that the oil spread on the brine in the presence of gas.

3 In-Situ Relative Permeabilities Of Experiment X1

Relative permeabilities were calculated from the in-situ saturation measurements of Experiment X1 using the method described in Reference 5. For example, in regions where capillary pressure can be neglected the oil relative permeability is given by:

$$k_{ro}(z,t) = - \frac{\mu_o}{K\Delta\rho g} \frac{\delta}{\delta t} \int_0^z \phi S_o(z,t) dz \quad (1)$$

where k_{ro} is oil relative permeability, z is distance from the top of the core, t is time from the start of the gas flood, μ_o is oil viscosity, K is absolute permeability, $\Delta\rho$ is difference between oil and gas densities, g is acceleration due to gravity, ϕ is porosity and S_o is oil saturation.

Phase saturation data derived from the experiment were in the form of discrete points for a particular position in the core and at a particular time. Thus to evaluate the derivative with respect to time interpolation or smoothing is required. Two possible methods of smoothing were recommended in Reference 4. The number of saturation points included in the smoothing may also be varied. No difference in the relative permeabilities calculated was found using either smoothing method or smoothing over seven or five time points at a time.

A Corey fit was made to the data for positions along the core to determine the Corey exponent n , and coefficient K_{ro}^o , assuming a

zero asymptotic residual oil saturation, $S_{org}=0$ using the Corey equation (2):

$$k_{ro} = K_{ro}^o (S_o - S_{org})^n \quad (2)$$

$$\text{where } K_{ro}^o = K_{ro}^o (1 - S_{wc} - S_{org})^{-n} \quad (3)$$

4 Simulation Of Experiment X1

Experiment X1 was modelled using a black oil simulator. The simulation study aimed to reproduce the physical effects observed during the experiment, particularly the development of the oil bank and the fluid saturation distributions after gas breakthrough. The variation in the initial saturation was not modelled and a uniform initial saturation was assumed.

The tertiary gas injection phase of Experiment X1 was modelled using a 1D vertical Cartesian grid. The core was represented by 171 grid blocks with a total volume of 214 mL, equal to the experimental value. A "buffer" of a further 10 blocks was added to the bottom (outlet) of the core to enable capillary end effects to be included. A total production rate of 1 mL/hr was imposed by placing a 'production well' in the bottom block of the buffer. A pressure constrained 'gas injection well' was placed in the top grid block of the model to replace voidage and maintain atmospheric pressure at the core inlet. The fluid properties used are given in Table 2.

TABLE 2: FLUID DATA
(at atmospheric pressure and temperature)

	Density (g/mL)	Viscosity (Pa.s) x10 ⁻³
Oil	0.732	0.907
Brine	1.006	1.0
Gas	0.0012	0.018

The oil relative permeabilities to gas, at low oil saturations, deduced from the in-situ saturations of Experiment X1 were used in the

simulation. The curve was extended to high oil saturations by adding smoothly a Corey curve to give the correct endpoint at connate water. Corey forms were used for the two phase oil/water relative permeabilities. Three phase oil relative permeabilities were represented using a Stones I model, with a linear interpolation between S_{orw} and S_{org} . The parameter values are summarised in Table 3. Capillary pressure curves derived from the final saturation profiles were used.

TABLE 3: RELATIVE PERMEABILITY DATA

$S_{wc} = 0.2$
$S_{orw} = 0.43$
$S_{org} = 0.0$
$k_g(S_g=1.0) = 2.5 \mu m^2$
$k_{og}(S_o=1-S_{wc}) = k_{ow}(S_o=1-S_{wc}) = 1.75 \mu m^2$
$n_o = 4.5$
$K_{ro} = 0.053$
$n_g = 2$
$k_w(S_w=1-S_{orw}) = 0.085 \mu m^2$
$N_o = 1.9$
$N_w = 4$

5 Results And Discussion

5.1 Tertiary Gas Injection

The results of all the gas injection experiments are given in Table 1.

The variation of gas, oil and brine productions with total fluid production during the gas floods of Experiments A1, A2 and X1 are illustrated in Figures 1, 2 and 3 respectively. The fluid productions have been normalised by the water flood residual oil volumes of 81 mL, 68 mL and 93 mL respectively. During A1 only brine was produced until 28 hours after the start of the gas flood, gas breakthrough occurred after 30 hours. During A2 only brine was produced until 220 hours after the start of the gas flood, gas breakthrough occurred after 312 hours. During X1 only brine was produced until 26 hours after the start of the gas flood, gas breakthrough occurred after 62 hours.

FIGURE 1: EXPERIMENT A1
FLUID PRODUCTION DURING TERTIARY GAS INJECTION

FIGURE 2: EXPERIMENT A2
FLUID PRODUCTION DURING TERTIARY NITROGEN INJECTION

FIGURE 3: EXPERIMENT X1
FLUID PRODUCTION DURING TERTIARY GAS INJECTION

The spatial variation of oil and brine saturations during the gas floods of A1, A2 and X1 are illustrated in Figures 4 to 9. The mean water flood residual oil saturation of 0.31 obtained for A2 was significantly lower than for the other experiments. The residual oil distribution measured prior to the gas flood varied considerably along the length of the core. The unusual behaviour may have been caused by portions of the core drying out

FIGURE 4: EXPERIMENT A1
OIL SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

FIGURE 7: EXPERIMENT A2
BRINE SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

FIGURE 5: EXPERIMENT A1
BRINE SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

FIGURE 8: EXPERIMENT X1
OIL SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

FIGURE 6: EXPERIMENT A2
OIL SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

FIGURE 9: EXPERIMENT X1
BRINE SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

between a previous experiment performed on the same core and A2. It is interesting to note that the residual oil saturation to gas did not appear to depend on the residual oil saturation to waterflooding.

During A1 no oil bank was observed in contrast to A2 and X1 where an oil bank formed ahead of the gas front and was produced before gas breakthrough. The variation of oil and brine saturations during the start of gas injection of X1 are illustrated in Figures 10 and 11. Early gas breakthrough was observed during A1, the final oil at the top of the core after 62 days of gas injection was 0.26. The final oil saturation at the top of the cores during A2 and X1 was similar,

namely 0.10 and 0.13 after 53 and 64 days of gas injection respectively.

The residual oil saturation at the top of the lower permeability core A1 was significantly higher at 0.26. Significant capillary retention was observed for both the oil and brine phases during A1 see Figures 4 and 5. The high residual saturations for A1 are due to capillary forces dominating the core. During all the experiments the oil and brine continued to be produced after gas breakthrough. In water-wet cores with spreading oil it is believed that the brine forms a film on the surface of the rock and the oil forms a film

FIGURE 10: EXPERIMENT X1 OIL SATURATION DISTRIBUTION DURING START OF TERTIARY GAS INJECTION

FIGURE 11: EXPERIMENT X1 BRINE SATURATION DISTRIBUTION DURING START OF TERTIARY GAS INJECTION

FIGURE 12: EXPERIMENT X1 OIL RELATIVE PERMEABILITY

FIGURE 13: EXPERIMENT X1 BRINE RELATIVE PERMEABILITIES

between the brine and the gas. The brine and oil can therefore drain under the influence of gravity in their own film.

The mean oil saturation at gas breakthrough for Experiments A2 and X1 were 0.25 and 0.33 respectively. The lower oil saturation on gas breakthrough for Experiment A2 is consistent with the lower gas injection rate of 0.34 mL/hr compared to 1 mL/hr for Experiment X1. This result is consistent with the findings of Hagoort [6].

5.2 In-Situ Relative Permeabilities for Experiment X1

Oil and brine relative permeabilities were calculated from the in-situ saturations measured during the gas injection of X1 and are illustrated in Figures 12 and 13 respectively. For positions near the top of the core the oil relative permeabilities lie approximately on a straight line indicating a zero asymptotic residual oil saturation.

It has been demonstrated that reliable relative permeabilities can be derived from in-situ saturation measurements. The oil relative

permeabilities of X1 were characterised by a zero asymptotic residual oil saturation, a modified Coefficient of 0.18 and a Corey exponent of approximately four, which is higher than the value of three proposed from theoretical models of film drainage. The relative permeabilities derived can then be used directly to simulate the experiment.

The oil relative permeabilities determined from the in-situ saturations were independent of position along the core and were only a function of oil saturation. This result is different from the results of previous experiments [5] which showed an increase in relative permeability with distance from the top of the core at a given oil saturation. More data points of a higher accuracy were obtained during X1 compared to the earlier results and may explain the difference in behaviour.

The water relative permeabilities curve towards the saturation axis at lower water saturations indicating connate water saturation. This effect is more pronounced lower down the core due to the effect of capillary pressure.

5.3 Simulation of Experiment X1

The results from running the simulation model are given in Figures 14-15. These figures show the oil and brine saturations in the early stages of the tertiary gas injection. The progress of the gas front was well matched. Similarly the development of the oil bank and its propagation down the core and the saturation of the oil bank were well matched at about 0.52, see Figure 10 and 11. The simulated oil and brine saturation distributions throughout the gas injection are illustrated in Figures 15 and 16 can be compared directly with the experimental results shown in Figures 8 and 9. Each profile tends towards a fixed distribution as time progresses. When comparing the saturation plots it must be remembered that an initial uniform saturation distribution down the core was assumed in the simulation, so the experiment and simulation profiles are somewhat different at early times.

The core simulation was in good agreement with the experimental results demonstrating that a Corey expression is applicable to the gravity drainage flooding regime present in X1.

FIGURE 14: EXPERIMENT X1 SIMULATED OIL SATURATION DISTRIBUTION DURING START OF TERTIARY GAS INJECTION

FIGURE 15: EXPERIMENT X1 SIMULATED BRINE SATURATION DISTRIBUTION DURING START OF TERTIARY GAS INJECTION

FIGURE 16: EXPERIMENT X1 SIMULATED OIL SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

FIGURE 17: EXPERIMENT X1 SIMULATED BRINE SATURATION DISTRIBUTION DURING TERTIARY GAS INJECTION

6 Conclusions

- 1) The independent measurement of oil and brine in-situ saturations enables core artefacts to be identified and relative permeabilities to be derived.
- 2) The residual oil saturation following 62 days of nitrogen injection in a $0.37 \mu\text{m}^2$ core was 0.26. The residual oil saturation following 53 days of nitrogen injection in a $1.5 \mu\text{m}^2$ core was 0.10. The residual oil saturation following 63 days of nitrogen injection in a $2.0 \mu\text{m}^2$ core was 0.13.
- 3) Detailed analysis of the $2.0 \mu\text{m}^2$ experiment showed that the oil permeability was only a function of the oil saturation. The relative permeabilities were characterised by a zero asymptotic residual oil saturation and a Corey exponent of approximately four, which is higher than would be expected from theoretical models of film drainage.
- 4) The relative permeabilities calculated from Experiment X1 were used successfully to simulate the fluid production and in-situ

saturation measurements obtained during the experiment.

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Nomenclature

g	acceleration due to gravity
K	absolute permeability
k	phase permeability
k_r	phase relative permeability based on gas absolute permeability

k_{og}	oil permeability (oil-gas 2-phase model)
k_{ow}	oil permeability (oil-water 2-phase model)
K_r	phase Corey coefficient
n	phase Corey exponent (oil-gas 2-phase model)
N	phase Corey exponent (oil-water 2-phase model)
S_{org}	residual oil saturation to gas
S_{orw}	residual oil saturation to water
S_{wc}	connate water saturation
t	time
z	distance from top of core
μ	viscosity
$\Delta\rho$	difference between oil and gas densities
ϕ	porosity

Subscript

g	gas phase
o	oil phase
w	water phase