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Characterization of Trapped Gas Saturation and Heterogeneity in Core Samples Using Miscible-Displacement Experiments

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ABSTRACT

Trapped gas saturation and permeability heterogeneity were evaluated in Berea cores at reservoir conditions, using standard miscible displacement experiments, with and without surfactants. Pressure and production history were influenced by core heterogeneity and foam lamellae formation when aqueous surfactant was present in the core.

A simple dispersion model and a three-coefficient dispersion-capacitance model (Coates-Smith) were fit to the experimental data. The dispersion-capacitance model successfully matched the experiments in which foam lamella formed, while the simple dispersion model was used only for determining initial core flow heterogeneity.

The objective of the dispersion-capacitance model was to estimate trapped gas saturations; however longitudinal dispersion and mass transfer also were examined. The results show that the dispersion-capacitance model accurately fits trapped gas saturation controlled by rock heterogeneities and foam lamellae for lamella generating mechanisms that allow a continuous gas phase (leave-behind lamellae). The practical applications resulting from this study can aid in core sample selection and scaling short laboratory corefloods to field dimensions for applications to foam stimulation and underground storage of natural gas.

INTRODUCTION AND BACKGROUND

When foam is generated in a porous medium, thin liquid films are formed between pore throats, which trap a substantial portion of the gas. Consequently, only a part of the gas flows through a reduced cross sectional area. This significant decrease in the pore space available for gas flow is considered to be one of the most important factors in the gas-phase mobility reductions associated with dispersed phase displacements in porous media [1]. Foams generated in porous media, can have a continuous or a discontinuous gas phase, depending on the lamellae generation mechanism. Leave-behind lamellae are produced when a gas phase displaces a surfactant solution in a core below some critical flow velocity. The main characteristic

of this lamellae formation mechanism is that the non-wetting phase remains continuous, unlike other mechanisms (snap-off or lamellae division) which create discrete gas bubbles. Flow visualization studies of leave-behind lamellae in glass bead packs [2] show that they are similar to bottle neck [3] structures that were previously used as physical pictures to model stagnant regions. Leave-behind lamellae generated in this way are used to divert acid into less permeable strata in matrix acidization treatments [4], in stopping the migration of natural gas from gas storage reservoirs [5], and in improved oil recovery processes [6].

Bernard, Holm and Jakobs [7] measured the trapped-gas saturation gravimetrically in different types of cores containing water or both water and oil. They concluded that foam formation increases the trapped-gas saturation in all cores, and that trapped-gas saturation is higher at higher surfactant concentrations. The presence of an oil phase reduced the amount of trapped gas.

Nahid [8] determined trapped-gas saturation during foam flow in a tracer experiment, by comparing the two "triangular" areas for each side of the "S" shaped curve of the tracer effluent concentration. Helium was the initial flowing fluid and a mixture of 80 percent helium and 20 percent methane was the tracer phase. The experiment was run at residual brine saturation. The amount of methane was determined at the outlet by a gas chromatograph, after a step change in concentration was injected into a Berea core. He found that approximately one-third of the gas in place was immobile when 1 percent surfactant was added to the water phase.

Friedmann, Chen and Gauglitz [9] performed gas-phase tracer (krypton) experiments in Berea core, at 150 °C with nitrogen as bulk gas phase. When 1 percent surfactant (Chaser SD 1000) was added to water, an earlier breakthrough time was recorded, indicating the presence of a stagnant-foam in the core. They also observed a considerable asymmetry of the effluent-concentration profile when foam was present, resulting from the diffusion of krypton across the liquid surfactant films in the trapped-gas phase. Breakthrough

times were compared when 10 percent of the injected krypton was detected in the gas phase. The flowing gas fraction was then determined as the ratio of gas pore volumes injected at breakthrough for foam flow and brine flow. For a range of frontal gas velocities of 25 to 130 m/day, they reported an average value of 0.15 for the flowing gas fraction. Gillis and Radke [10] developed a dual gas tracer technique for assessing gas saturation during steady-state foam flow through porous media. In this procedure, two tracer gases (methane and sulfur hexafluoride in nitrogen) with different liquid solubilities were injected with a step concentration change. The effluent concentrations were monitored by gas chromatography, then a simple mass transfer model that describes any partitioning between the mobil and trapped-foam phases was fit to the measured tracer histories. For true foam flow in Berea sandstone, at flow velocities between 0.5 and 4 m/day, the trapped gas fraction was over 70 percent, and in several cases, almost all the gas was blocked.

In summary, the investigators cited above have either studied trapped gas saturation in true foams with gas being trapped as a discontinuous phase or the reported values were significant for foam floods followed by a waterflood. In this paper the trapped gas due to leave-behind lamella formation is treated as a capacitance and the Coats-Smith dispersion-capacitance model is fit to measured effluent concentration profiles. We investigated the validity of the Coats-Smith model to predict the tailing and dispersion due to the trapped gas in leave-behind lamellae. We found that the Coats-Smith model may be used, although with some restrictions due to the possibility of other foam formation mechanisms and also due to the temporary nature of lamellae. Dispersion fits without capacitance proved totally inadequate when leave-behind lamellae were present.

ANALYSIS OF MISCIBLE DISPLACEMENT EXPERIMENTS

Microscopic flow heterogeneity in reservoir rocks can be estimated from data obtained in a tracer type or miscible type experiment. If a tracer is added at constant concentration (C_0) to the flowing phase at the entrance of the core, the ratio of tracer concentration in the effluent over that of initial concentration (C/C_0) will increase from zero to 1 [8]. The effluent concentration profile should be symmetrical and C/C_0 equal to 0.5 at one pore volume injected, only if all the fluid in the core is mobile. This process can be described by the simple dispersion equation [11]:

$$D \partial^2 C / \partial x^2 - u \partial C / \partial x = \partial C / \partial t \quad (1)$$

For a semi-infinite core and the following boundary conditions:

$$\begin{aligned} \text{at } x = 0, \quad C &= 1 \\ \text{and } x \rightarrow \infty, \quad C &\rightarrow 0, \end{aligned} \quad (2)$$

the solution is given by [11]:

$$C = 1/2 \operatorname{erfc} [(x-ut)/2\sqrt{Dt}] + 1/2 e^{ux/D} \operatorname{erfc} [(x+ut)/2\sqrt{Dt}] \quad (3)$$

where:

C = in situ concentration,
D = dispersion coefficient,
x = linear distance,
u = pore velocity and
t = time.

Therefore, if effluent concentration data are available, a value of dispersion coefficient D can be obtained from a fit of equation (3) to the data. However, it was observed [12,13] that trapping of the solvent in regions of dead-end pore volume or relatively stagnant flow contributes to the mixing-zone growth. This trapping, known as capacitance, can be

caused by liquid films, foam lamellae, or macroscopic rock heterogeneity. The prediction of the capacitance, a very significant effect in foam based process, is very important for the design of a such a process. Trapped foam lamellae can block large fractions of the cross sectional area available to gas flow, reducing the relative permeability to gas drastically. Another effect of the stagnant volume is the requirement of a larger amount of solvent than that predicted by the simple dispersion model. Accordingly, accurate modeling of data from short-core experiments can affect the mixed-zone volume predicted for long distances in a field application. A three-parameter equation was developed by Coats and Smith [12], which includes the flowing fraction, f ; the mass transfer coefficient, M ; and the dispersion coefficient, D :

$$D \partial^2 C / \partial x^2 - u \partial C / \partial x = f \partial C / \partial t + (1-f) \partial C^* / \partial t \quad (4)$$

A first order rate expression was assumed for transfer between the stagnant pore volume and the flow channels. The concentration in stagnant pores was defined as C^* , while $1-f$ represented the total stagnant volume:

$$(1-f) \partial C^* / \partial t = M(C-C^*) \quad (5)$$

For a semi-infinite system, with diffusion at the inlet face, the following boundary conditions result:

$$\begin{aligned} \text{at } x=0, \quad C_0 &= C - (D/u) \partial C / \partial x \\ \text{and } x \rightarrow \infty, \quad C(x,t) &\rightarrow 0, \end{aligned} \quad (6)$$

where C_0 is the feed concentration. With this set of boundary conditions, Coats and Smith [12] solved equations 4 and 5. In the present study, for interpreting the experimental data from miscible experiments, equations 4 and 5, with boundary conditions 6, were solved by the method of Laplace transforms. A NAGLIB routine available at Morgantown Energy Technology Center was used for the numerical inversion of the Laplace transform. Then, the parameters of the capacitance-dispersion model, f , M , and D , were adjusted to match an effluent concentration profile for each displacement experiment. Even though the initial intent was to calculate a value for the stagnant pore volume ($1-f$), due to the large amount of tailing observed, the values of the mass transfer and dispersion coefficient became equally important.

The flowing fraction of CO_2 was also estimated with a simple method developed by Friedman, et al [11]. They compared the breakthrough times of the tracer for cases with or without surfactant. Because mechanical dispersion dominates near initial breakthrough, a value of 10 percent injected tracer concentration detected in the effluent was chosen. The gas flowing fraction was then written as:

$$x_f = PV_{btfoam} / PV_{btbrine} \quad (7)$$

This ad hoc relationship, developed for evaluating trapped versus flowing foam, will be used as a qualitative comparison for our results.

EXPERIMENTAL METHODS

The experiments in this series can be categorized as step-input or tracer type experiments: CO_2 or CO_2 /decane displaced decane. First, a surfactant solution was displaced to an irreducible aqueous phase saturation producing leave-behind lamellae in parts of the porous medium, from which the aqueous phase was displaced. Decane was collected in graded tubes, while cumulative CO_2 produced was recorded with a digitized wet test meter able to measure 500 cm^3 /revolution. CO_2 was injected at a rate of 2 cm^3 /min at 1780 psi. At this pressure 1 cm^3 of CO_2 injected equals 484 cm^3 at lab conditions (atmospheric pressure, 21° C); thus, practically every cm^3 injected was recorded. The extent of the asymmetry in the resulting effluent concentration and the breakthrough of displacing fluid were also recorded. These results were compared with

simulations using a dispersion-capacitance model. The CO_2 flowing fraction was determined from the capacitance-dispersion model and also by the technique utilized by Friedman et al [9], presented in equation 7 of the previous section.

Materials. Two anionic, ethoxylated, commercial surfactants were used in this study. They were chosen based on predicted foaming ability, thermal and chemical stability, adsorption characteristics, availability and price. Alipal CD-128, produced by GAF Corporation, is an alcohol ethoxysulfate (chemical formula $\text{R}-(\text{OCH}_2\text{CH}_2)_2-\text{OSO}_3\text{NH}_4$). Avanel S-30, produced by PPG Industries, is an alcohol ethoxysulfonate (chemical formula $\text{R}-(\text{OCH}_2\text{CH}_2)_2-\text{SO}_3\text{Na}$). These surfactants were dissolved in brine containing 2 wt% NaCl at a higher concentration, usually 1% wt. Lower concentrations were prepared by diluting with brine. More information about the surfactants is given in Table 1. Decane (Fisher Scientific, 99.8 percent pure) was used in miscible displacement experiments.

Berea sandstone cut parallel to the bedding plane, with a porosity of about 21 percent and an absolute permeability to water of 500 mD was used as the porous medium.

RESULTS

The results are summarized in Table 1. The first run in this series, presented in Figure 1, was used to detect flow heterogeneities or dead-end pore volumes in the core before any lamellae were formed in the pores. Decane was used to displace brine to irreducible water saturation. CO_2 then displaced decane at a constant rate at the irreducible water saturation (no surfactant was added). Notice in Figure 1 that at 1.0 hydrocarbon pore volume, effluent concentration equals 0.54 instead of 0.5, which would correspond to perfectly homogeneous core. This is displayed by the simple dispersion model. The effluent concentration curve was then modeled very accurately with the capacitance-dispersion equation in Figure 2, and a flowing fraction of 96% was calculated. Hence, 4% of the porous medium was unavailable for flow; and implicitly no lamellae formation is expected in these pores. In the next experiment, (Run 2, Table 2) first decane displaced a 0.1 wt% surfactant solution until steady state was obtained. High pressure drops were observed during this stage (up to 100 psi/ft) due to the formation of an oil-water emulsion in the core, which partially blocked the pores. (The formation of a long-lived emulsion was observed in bulk by shaking decane and Alipal solution.) CO_2 was injected then in a miscible mode, the breakthrough and subsequent concentrations of CO_2 being monitored. Figure 3 shows a dispersion fit without capacitance which proves to be totally inadequate. Figure 4 presents the CO_2 effluent concentration curve, and an excellent fit by the dispersion-capacitance model. The early breakthrough time observed indicated the formation of stagnant phase in the core. Moreover, the large asymmetry of the effluent concentration profile indicates that a considerable amount of CO_2 was trapped in the core. When the values of trapped gas were calculated the result indicated 25% of HCPV with Coates-Smith's model and 36% with the approximate method of reference 9.

The following two runs were done with Avanel S-30, a surfactant that did not form an emulsion with decane in bulk. In Run 3, Figure 5, a 50% vol. Decane/50% vol. CO_2 mixture displaced CO_2 , which previously had formed leave-behind lamellae in the core displacing a 0.1 wt% Avanel S-30 solution. Decane breakthrough appeared at 0.28 HCPV of the mixture injected, and the 0.5 C/C₀ concentration was observed significantly before 1 HCPV at 0.68 HCPV. The capacitance-dispersion model could not reproduce exactly the experimental curve, because some of the leave-behind lamellae perhaps destroyed by the decane in the displacing fluid.

The experiment was repeated by injecting first the 50 vol% CO_2 /50 vol% decane mixture, followed by CO_2 .

A very early breakthrough (0.2 HCPV) was observed, and the 0.5 C/C₀ concentration appeared at about 0.59 HCPV. Figure 6 shows a poor fit of experimental data with the capacitance-dispersion model. A possible explanation may be derived from observing the experimental behavior of pressure drop in the core after the injecting fluid was switched from the CO_2 /decane mixture to CO_2 . Observed almost immediately was a rise in pressure drop at the beginning of CO_2 injection. This behavior could have been caused by snap-off foam bubble generation. (Leave-behind lamellae cannot be generated if liquid does not invade the porous medium again.) Consequently, the model cannot simulate trapping of the solvent in bubbles generated by other generation mechanisms.

The values of flowing fraction obtained by the two methods follow the same trend, the capacitance-dispersion model being more conservative. The values of the dispersion coefficient D and mass transfer coefficient M do not seem to have a clear physical significance. They have to be correlated with field data. Thus, it is good to look at the laboratory dimensionless rate group $a = \text{ML}/v$ [13], which may be small to result in a significant contribution to mixing by capacitance effects. In the field, L is hundreds of times larger and, consequently, will affect the mass transfer in the stagnant volume. Also, at field dimensions, capacitance effects might not cause asymmetry or mixing, but they remain important in scaling laboratory to field data.

CONCLUSIONS

1. The dispersion-capacitance model can be used successfully, although with some limitations, to model gas trapped by leave-behind lamellae in porous media.
2. Miscible displacements indicated that one-third to two-thirds of the pore volume was filled with CO_2 and was not contributing to flow.
3. Employed methods do not give a clear-cut distinction between capacitance effects due to heterogeneities and lamellae trapping, but they seem to be additive.
4. The dispersion coefficient increases with the increase of trapped gas i.e., with the lamella formation, more than one order of magnitude. The use of simple dispersion model can give large values of the dispersion coefficient because it adds capacitance and dispersion contributions.

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NOMENCLATURE

a	= dimensionless rate group, ML/v (Damkholer number)
A	= area, cm^2
C	= concentration, vol.%
C*	= trapped gas concentration, vol.%
C ₀	= feed concentration, vol.%
D	= dispersion coefficient, cm^2/sec
HCPV	= hydrocarbon pore volume
f	= flowing fraction in dispersion-capacitance model
1-f	= stagnant fraction
L	= core length, cm
M	= mass transfer coefficient, $(\text{sec})^{-1}$
PV	= pore volume, cm^3
q	= flow rate, cm^3/min
t	= time, minutes
u	= $q/\Phi A$ pore velocity, cm/min
v	= q/A Darcy velocity, cm/min
V	= volume, cm^3
x	= linear distance, cm
x _f	= flowing gas fraction method of ref.9

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Table 1. Surfactant Properties

Surfactant	Type	Ph	Avg. M_w	CMC Range	% Active
Alipal CD-128	Anionic	3.32	352	.01-.05%	58
Avanel S-30	Anionic	6.8	420	.08-.1	25.1

Table 2 Miscible Displacement Experiments Summary

Run No.	Displacing Fluid	Displaced Fluid	Surf. and Conc.	f	x_f	$M \cdot 10^3$ s^{-1}	$D \cdot 10^3$ cm^2/s
1	CO ₂	Decane	0.0%	.96	1	.28	27
2	CO ₂	Decane	0.1% Alipal	.75	.64	.18	1.39
3	50% CO ₂ 50% Decane	CO ₂	0.1% Avanel	.67	.64	.23	8.7
4	CO ₂	50% CO ₂ 50% Decane	0.1% Avanel	.5	.34	.22	35

Figure 1. Simple Dispersion Model and Effluent Concentration Profile for Run 1

Figure 4. Dispersion Capacitance Model and Effluent Concentration Profile for Run 2

Figure 2. Dispersion Capacitance Model and Effluent Concentration Profile for Run 1

Figure 5. Dispersion Capacitance and Effluent Concentration Profile for Run 3

Figure 3. Simple Dispersion Model and Effluent Concentration Profile for Run 2

Figure 6. Dispersion Capacitance Model and Effluent Concentration Profile for Run 4