THREE-PHASE RELATIVE PERMEABILITY

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ABSTRACT

The results of three-phase relative permeability tests on nine water-wet consolidated Berea sandstone samples are presented as composite ternary diagrams showing isoperms of oil, water and gas. Capillary pressure control was exercised over the flow of gas and oil in the presence of water. The water saturations ranged from 17 to 71 per cent pore volume.

A method of calculating both the oil and water permeabilities of a three-phase system from the easily measured gas relative permeability is presented.

EXPERIMENTAL PROCEDURE AND RESULTS

A renewed interest has been shown in three-phase relative permeability as a result of recent developments involving underground combustion processes, steam injection, and other multiphase displacement processes. The experiments and results described here involved simultaneous flow of oil and gas in consolidated Berea sand with brine present as the wetting phase.

Gas and oil relative permeabilities were measured on nine cores with CaCl₂ brine present as the wetting phase in saturations ranging from 17 to 71 per cent. The average residual liquid saturation of the cores was

approximately 20 per cent. In order to make certain that brine was the wetting phase, the test cores were saturated with brine before contact with hydrocarbons. As an added precaution to avoid having oil displace brine from the wetting position as a result of changing wettability, each core was only used twice, i.e., first with a fixed percentage of brine and then for a gas-oil permeability determination with no brine present. The results, therefore, are presented as composite ternary diagrams representing the flow tests on nine individual cores having very similar properties. All tests were made using a modification of the capillary pressure technique described elsewhere[1,2].

The effective oil permeability was measured before gas was introduced using a very small pressure gradient (a few centimeters of oil). This determination was made without selectively wet barriers in contact with the core. The cores were then placed between capillary barriers and gas-oil relative permeability curves obtained. The capillary barriers had been made water repellent with a silicone treatment.

In determining gas-oil-water relative permeability in this fashion, control was exercised over the capillary pressure existing between the gas and oil. No control was exercised over the pressure difference existing between the oil and water. Although an equal pressure gradient

was applied to the gas and the oil phases, this pressure gradient does not exist in the water phase. Since the pressure gradient across the core was always much less than the displacement pressure of the fully saturated core, the pressure gradient can have caused only a very slight distortion of the oil-water interfaces. This slight distortion of the oil-water interfaces had a negligible effect on the validity of the oil permeabilities measured. The oil permeability, measured in the presence of water but with no gas present, was in every case equal, within experimental error, to the gas permeability of the gas-oil system when the oil saturation was the same as that of the water.

Gas and oil relative permeabilities were plotted as a function of total liquid saturation. It was found that the gas relative permeability curves obtained on cores with brine present were identical with those obtained on the same cores with no brine present. The denominator for calculating oil relative permeabilities was the permeability found by extrapolation to infinite mean pressure (à la Klinkenberg).

Fig. 1 illustrates gas-oil relative permeability results obtained on a typical core. The solid permeability curves represent the experimental data. The dashed oil relative permeability curve was calculated

$$k_{ro} = \frac{(S_L - S_w)^3}{(1 - S_{Lr})^4}(S_w + S_L - 2S_{Lr})$$

. . . . (1)

FIG. 1—GAS-OIL RELATIVE PERME-
ABILITY CURVES FOR BEREA CORE
No. 10, 38.8 PER CENT BRINE
SATURATION.

FIG. 2—APPROXIMATE $(1/P_c^2$ vs $S_L)$
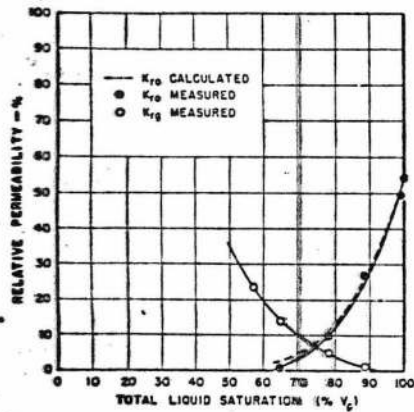FUNCTION FOR A CONSOLIDATED
SAND.

FIG. 3—GAS-OIL RELATIVE PERME-
ABILITY CURVES FOR BEREA CORE
No. 10, 0 PER CENT BRINE
SATURATION.

Eq. 1 was derived in the following manner to give k_{ro} directly for the three-phase system in terms of the saturations. However, it assumes that the gas-oil capillary pressure curve for a three-phase system may be approximated by the relation:

$$\frac{1}{P_c^2} = \begin{cases} C\,(S_L - S_{Lr}) \text{ for } S_L > S_{Lr} \\ 0 \text{ for } S_L \leqslant S_{Lr} \end{cases}$$

$$. \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (2)$$

This is illustrated in Fig. 2. S_{Lr} refers to the residual liquid saturation left in the port space, which contributes negligibly to the permeability, and is considered numerically equal to S_{or} for a two-phase (oil-gas) system; S_w and S_L are the water and total liquid saturations, respectively.

A substitution by Corey[2] of Burdine's[3] tortuosity in the equations of Wyllie and Spangler[2] leads to the following equation for oil relative permeability:

$$k_{ro} = \left(\frac{S_o - S_{or}}{1 - S_{or}}\right)^2 \frac{\int_0^{S_o} dS_o/P_c^2}{\int_0^1 dS_o/P_c^2}$$

$$. \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (3)$$

Here oil was the wetting phase in a gas-oil system. Applied to the three-phase systems employed here, this equation should be modified to:

$$k_{ro} = \left(\frac{S_L - S_w}{1 - S_{Lr}}\right)^2 \frac{\int_{S_w}^{S_L} dS_L/P_c^2}{\int_0^1 dS_L/P_c^2}$$

$$. \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (4)$$

Eq. 4 is analogous to Eq. 3 but

considers that only pores not filled with water can be filled with oil or gas. It assumes that the water is present in two positions: completely filling small pores and as pendular rings in the interstices of larger pores. As a corollary to this assumption it follows that when gas displaces oil from pores containing residual water, the oil will be displaced completely except for a remanent film. This assumption is reflected in the tortuosity term of the equation. Its validity is supported by the precision with which calculations based on the equation match the experimental data.

The ratio of integrals in Eq. 4 can be evaluated from the ratio of the areas as seen in Fig. 2. This ratio simplifies to:

$$\frac{\int_{S_w}^{S_L} dS_L/P_c^2}{\int_0^1 dS_L/P_c^2} = \frac{A_{II}}{A_I + A_{II} + A_{III}} =$$

$$\frac{(S_L - S_w)}{(1 - S_{Lr})^2}(S_w + S_L - 2S_{Lr}) \quad . \quad (5)$$

Substituting Eq. 5 in Eq. 4 gives Eq. 1.

Fig. 3 shows the gas-oil curves obtained on the same core with no brine present. The residual oil saturation is 19 per cent, as determined from the gas relative permeability curve by a procedure outlined previously by Corey[2]. Briefly, values of $\overline{S}_{oc}$, corresponding to measured values of K_{rg} and S_o, are obtained by using the approximation:

$$k_{rg} = (1 - \overline{S}_{oc})^2(1 - \overline{S}_{oc}^2) \quad . \quad (6)$$

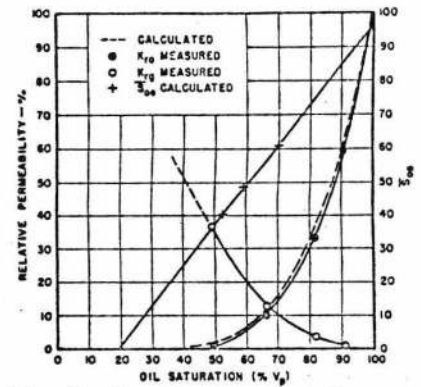and are plotted as a function of S_o. Extrapolation of this line to $\overline{S}_{oc} = 0$ gives S_{or}, which in turn is used to obtain values of oil relative permeability from the relationship,

$$k_{ro} = (S_{oc})^4 \quad . \quad . \quad . \quad . \quad (7)$$

Isoperms were plotted on trilinear paper, as shown in Figs. 4, 5 and 6. The oil isoperms exhibit a marked curvature, as shown in Fig. 4. An increase in oil permeability for a given oil saturation occurs when the water saturation is increased at the expense of gas saturation. This effect is most pronounced in the region of low water saturations.

Since no water relative permeabilities were measured in this experiment, the water isoperms (Fig. 5) were calculated by making two assumptions: (1) water permeability is dependent on water saturation only [as found by Leverett and Lewis[1]] and (2) water permeability in a water-wet system is the same as the oil permeability in an oil-wet (oil-gas) system. It may be well to emphasize that the curves of Figs. 4, 5, and 6 normally apply to an oil drainage history where oil is replaced by gas and that the water isoperms are subject to the two limiting assumptions noted above. However, if these two limiting assumptions are satisfied, as the water saturation is increased the oil permeability for a given saturation will increase since the oil must of necessity occupy larger pores.
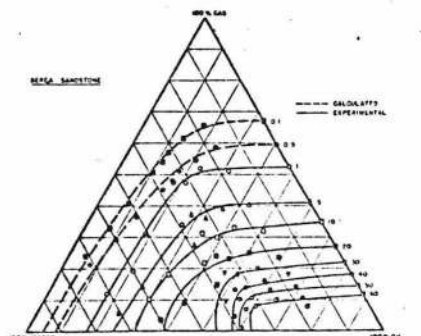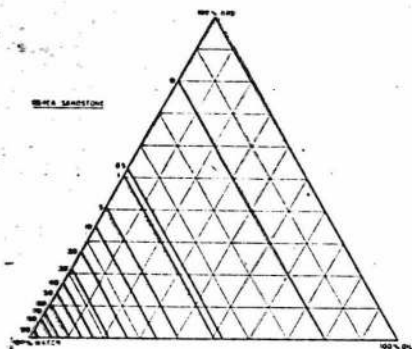

FIG. 4—OIL ISOPERMS.

FIG. 5—WATER ISOPERMS.

FIG. 6—GAS ISOPERMS.

FIG. 7—$1/P_c^2$ VS S_L FOR (a) CON-
SOLIDATED SAND AND (b) UNCONSOL-
IDATED SAND.

Two of the cores had gas relative permeability curves which differed from those of all other cores, particularly in the high liquid saturation region. Therefore, data from these cores were not used in constructing the gas isoperms (Fig. 6). For the gas relative permeability at zero water saturation, the arithmetic mean of the data for all cores was taken. The scatter in the data through which the gas isoperms are drawn undoubtedly reflects the result of using several different cores to represent one medium. It has been repeatedly observed that the gas (nonwetting phase) flow behavior is much more sensitive to changes in pore geometry than is the response of the wetting phase.

The results of these tests compare surprisingly well with the data of Leverett and Lewis' secured by flowing through an unconsolidated sand pack. As anticipated from theoretical consideration the curvature of the oil isoperms in regions of low water saturation is considerably greater for the consolidated core data. In consolidated cores, as shown by Fig. 2, the plot $1/P_c^2$ vs S_L approximates a triangle, while for unconsolidated cores of more uniform pore size the plot approximates a rectangle [cf. Wyllie and Spangler[5]]. Thus in a water-wet system, as oil is displaced by water, the oil moves into larger pores at the expense of gas, the lat-
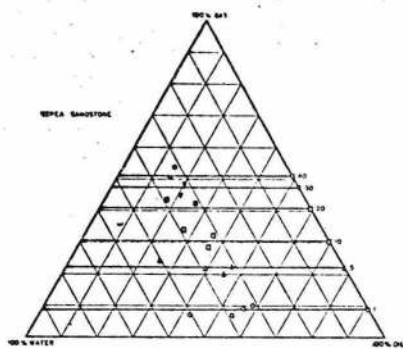
ter being displaced from the system. Since the oil permeability depends upon the ratio

$$\int_{S_w}^{S_L} dS_L/P_c^2 \Bigg/ \int_0^1 dS_L/P_c^2$$

the increase in permeability is greater for a triangular than a rectangular $(1/P_c^2 - S_L)$ plot. This is shown schematically in Fig. 7. However, the tendency of the Leverett-Lewis oil curve to parallel the oil iso-saturation lines is also evident in the data reported here. This is contrary to the behavior exhibited by the dynamic system studied by Caudle et al[6].

Using careful capillary pressure control to insure an unqualified "drainage" history, no evidence has been found to suggest that the gas relative permeability is sensitive to the saturation ratio of the two liquids occupying the wetting position. For this reason, the gas isoperms are represented as straight lines parallel to the gas iso-saturation values.

The foregoing theoretical considerations and experimental results lead to the conclusion that it is feasible to calculate both oil and water relative permeabilities from measured gas relative permeabilities. All that is required is acceptance of: (1) the hypothesis that residual oil saturation resulting from a desaturation of a system containing water $\geq S_{Lr}$
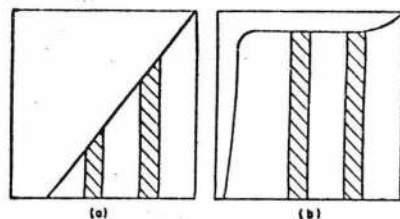
will be zero and (2) the water permeability of a three-phase, water-wet system is a function of saturation only and will equal the permeability at this saturation when only two phases are present.

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