EXPERIMENTAL INVESTIGATION OF UNSTEADY-STATE RELATIVE PERMEABILITY IN SAND-PACKS

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ABSTRACT

An experimental campaign consisting of over 80 separate water-floods in sand-packs and glass-bead packs was performed. A three-way study was carried out consisting of three levels of media permeability (11 μm^2, 47 μm^2, 207 μm^2), three levels of mineral oil viscosity (29 cp, 54 cp, 171 cp), and three levels of applied pressure drop across the media packing (~ 2.5 kPa, 5 kPa, 10 kPa). The sand packs were orientated vertically and water injection proceeded against gravity, producing oil, and later water, from the top of the sand- or bead-pack. One objective of this study was to demonstrate repeatability of experiments carried out under the same conditions with new packings made between experiments using new random samplings of the granular media; each experimental condition was tested at least three times. The end-point relative permeability of water was calculated directly from the experimental data and it was seen to be affected by differences in the level of media permeability, the viscosity ratio and the applied pressure drop. The main objective of the study was to ascertain, in a systematic and statistical fashion, the effects of media permeability, oil viscosity, and pressure drop on the oil and water relative permeability curves, as obtained by the Johnson, Bossler and Naumann (1959) method (JBN). The current study showed that the permeability of the porous medium has a dominant influence on the relative permeability for both oil and water. The effect of changes to the applied pressure drop or the viscosity of the oil on the relative permeabilities was found to be significant over specific saturation ranges, and particularly for the relative permeability of water. The pressure drop was seen to have less of a significant effect, overall, on the relative permeabilities compared to the viscosity ratio.

INTRODUCTION

Obtaining accurate relative permeability curves from core-flood experiments is imperative for characterizing a reservoir and for estimating its production capability. This paper is concerned with the unsteady-state relative permeabilities that are obtained from water-flood experiments conducted in a water-wet medium. The JBN method provides a convenient means for calculating the relative permeability curves from oil production and total fluid production data. The method also requires other data such as the measured flow rates of each fluid and the pressure drop across the core sample or sand-pack; this data must be smooth and continuous in its overall trend because the JBN method requires differentiation of either the total flow rate or the pressure drop. This study is concerned with identifying experimental variables that signficantly affect the relative permeabilities

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obtained by the JBN method. There are several investigations in the literature that directly or indirectly compare the relative permeability curves pertaining to disparate experimental conditions (*e.g.* different flow rates or different oil viscosities).

Of the literature surveyed, only two studies concluded that the viscosity ratio has no effect on the relative permeability curves; these were papers by Croes and Schwarz (1955), who calculated the ratio of relative permeabilities according to the theory of Buckley and Leverett (1942), and Johnson, Bossler and Naumann (1959). Johnson *et al.* reported that the effect of the viscosity ratio was to delineate different segments of the same set of relative permeability curves. However, other studies (see Table 1) have reported seeing a definite effect on the relative permeabilities due to the viscosity ratio; these include works by Lefebvre du Prey (1973), Singhal, Mukherjee and Somerton (1976) and Islam and Bentsen (1986). Lefebvre du Prey used oil-wet media in their experiments; Singhal *et al.* used mixed-wettability packings of glass beads and Teflon powder, and Islam and Bentsen performed experiments with unconsolidated silica sand. Islam and Bentsen found decreases in the effective permeability of water curves and increases in the effective permeability of oil curves, with increases in the viscosity ratio (oil to water).

There is also evidence in the literature that the rate of injection during a core-flood influences the relative permeability curves. Eight separate studies were identified (Table 1) that report on the effect of the flow rate on the relative permeabilities obtained by the JBN method. Delclaud (1972) injected a nitrogen gas at various pressures and displaced oil from sandstone cores. The curves for both gas and oil increased with increases in the pressure. Lefebvre du Prey (1973) reported differences in the relative permeability curves with changes to the inverse capillary number, $\sigma/\mu v$, whose value was changed mostly by changes to the flow rate. Sufi, Ramey and Brigham (1982) performed constant-rate experiments using sand-packs; the relative permeability of water was seen to increase with the rate, and the relative permeability of oil curve remained unchanged. The results of Islam and Bentsen (1986) depicted an increase in the effective permeability of water with the flow rate and a decrease in the effective permeability of oil. Peters and Khataniar (1987) conducted constant-rate experiments in sand-packs and they reported seeing an increase in the relative permeability of water curves and a decrease in the oil curves with increases in the flow rate. Qadeer, Dehghani, Ogbe and Ostermann (1988) conducted unsteady-state displacement experiments in Berea sandstone cores and studied the effect of flow rate on the relative permeability curves; an effect on the curves due to rate was reported. Mohanty and Miller (1991) also observed an increase in the relative permeability of water curve with increases in the flow rate; experiments were conducted on a consolidated core. Chang, Mohanty, Huang and Honarpour (1997) used consolidated cores and reported finding a difference in the relative permeability of oil curve between the two flow rates that were used in their experiments.

Common to many of the published experimental investigations is a lack of quantity of evidence to support or deny claims that either the viscosity ratio or the flow rate affect the JBN relative permeabilities. The number of experiments conducted by many of the researchers in the literature typically ranges from just 2 (Chang *et al.*) to 10 (Singhal *et al.*); other researchers have done 3, 4 or 8 experiments. To clearly demonstrate the effect of the experimental parameters, or the lack of effect, on the relative permeabilities requires performing a suite of experiments that investigate a range of magnitude in the oil viscosity, flow rate (or pressure drop) and the absolute permeability. Furthermore, each experimental condition (combination of parameters) should be tested more than once to demonstrate repeatability of the data and to obtain confidence statistics on the relative permeability curves. The principal goal of the current research was to produce experimental data from three levels of magnitude of the experimental variables and to test their effect on the relative permeability curves as produced by the JBN method. The type of experiments that were performed were unsteady-state displacements of oil by water with the boundary condition of a fixed pressure drop. The ideal initial conditions of zero saturation of water and no aging of the oil-saturated pack were employed. The experiments discussed in this work are of a fundamental nature; the results presented may be influenced to some degree by the initial conditions but the effect of these will be consistent.

The relative permeability curves from the JBN method are functions that *interpret* the experimental data (the production of oil and water, the pressure drop or total flow rate). The relative permeability of water at the end of each experiment can also be calculated directly using the flow rate data and with accurate knowledge of the pressure drop through the injected water phase. Effects of the experimental parameters on the end-point relative permeability of water can be correlated with the effects seen with the JBN relative permeabilities of water.

EXPERIMENTAL METHOD

The water-flood experiments presented here were conducted with a vertical orientation to prevent gravity segregation of the oil and water in the porous medium; this orientation causes the oil that does not remain trapped in the pore spaces to exit the medium at the top end of the column. The cylindrical column (1.63 cm diameter, 27.5 cm length) was filled with one of the three granular media: Glass Beads (**GB**, average bead size approximately 600 μm), a medium-sized grain silica sand (**SM**, average grain size approximately 400 μm), and a finer-grained silica sand (**SF**, average grain size approximately 200 μm). These porous media provided three different measured absolute permeabilities, K, of 207 μm^2, 47 μm^2, and 11 μm^2. The schematic diagram of the apparatus in Fig. 1 shows the major components; it is a simple design that permits the use of a constant head of supply water from a large diameter tank (42 cm, with replenishment) and the simultaneous measurement of both the production of oil and of the total produced fluids during a water-flood experiment. The major components in the system were custom fabrications of glass. Mineral oils of three different viscosities were used to give the following viscosity ratios of oil to water, $\hat{\mu}$, of 29, 54, and 171. Monitoring of the amounts of oil and water accumulated during an experiment was done using two differential pressure transducers. Oil accumulations were detected by the difference in head through the oil line and water line (Fig. 1). The total accumulation of oil and water was measured through the change in static head of water collected in the accumulation cylinders. The signals from each of the transducers were monitored and recorded by a computer at desired time increments.

One of three experimental variables were altered at a time and a minimum of three experiments were performed with each set of conditions. The three variables varied were: (1) the absolute permeability of the medium, K, (2) the viscosity of the oil, μ_o, and (3) the total pressure drop across the column of sand or beads, ΔH. Each experimental condition was conducted once and repeated at least twice to give a total of three experimental data sets. A new packing of the porous medium was done between each run using fresh Glass Beads or Silica Sand and fluids; the apparatus was thoroughly cleaned between runs and rinsed with ethyl acetate. Distilled water was used as the injected wetting phase. Before any of the water-floods were done, an accurate estimate of the permeability of each medium was obtained by measuring the single-phase flow rate of water through several packings of each of the three media types, and applying Darcy's law. In sum, to produce all of the data for this experimental program required performing $3^4 = 81$ separate displacement experiments. The relative permeability curves were produced using the JBN method of data analysis. The multiple sets of relative permeability curves pertaining to each set of experimental conditions were then averaged, and the mean and standard deviation information, at regular saturation intervals, was obtained.

Charging of the porous medium was accomplished by first evacuating the test column of media of air down to approximately 65 to 70 cmHg vacuum. The dry sand or beads was then flooded with the desired oil at a controlled flow rate until full saturation with the oil was achieved. The pressure level for each experiment was set by measuring the difference in elevation between the level of water in the supply head tank (A) and the atmospheric outlet point (E) of the apparatus. This elevation difference provided the head of pressure for flow of water through the column of media. The actual value of pressure drop across the inlet and outlet of the test column (between points B and C) was calculated based on the total flow rate measurements. Head losses through line (2) into the test column and line (5) to the outlet cup, in addition to the head loss through the fluids riser tube (4), were all accounted for in the calculations of the pressure in the system. The pressure drop across the test column was calculated by solving a set of linear algebraic equations that approximate the flow in the tubing as Poiseuille type in each component of the apparatus (as a series of tubes), using the values of the measured flow rate. An experiment was deemed completed when oil production from the sand-pack became very sparse and the time increments between successive oil accumulations became very long compared to the overall run time of the experiment. Near the end of each experiment, the oil droplets were very small in size; the time span between droplets was typically 5 minutes for GB, 30 minutes for SM and 2 hours for SF.

To apply the method of JBN to the experimental data, the data itself required smoothing so that meaningful flow rates of oil, Q_o, and of the total fluids, Q_t, could be calculated using differencing between time increments. Cubic B-splines were found to be best suited for characterizing the data; the splines provided an excellent curve-fit to the trends in the data

(Fig. 2) without introducing subtle fluctuations in curvature that tend to result with polynomial curve-fits. The JBN method is quite sensitive to fluctuations in the data, or a change in curvature of the fitting curve, because it involves taking the derivative of the inverse of the total flow rate, *i.e.*, the second derivative of the original total production data.

RESULTS AND DISCUSSION

A typical set of experimental data is shown in Fig. 2 along with the B-spline curves that match the data set. The data trends from three separate experiments, corresponding to the same experimental conditions, are shown in Fig. 3; in general, good reproducibility of the data was achieved in all of the experiments conducted in this study. Some disparity in the total production curves was expected because the volume of water through-put over time will tend to vary with small variations in the permeability of the sand- or glass bead-pack. Experiments with the Silica Fine sand (SF), using the heavy viscosity oil (HV) and at the lowest pressure level, had the greatest degree of disparity among the production curves. This observation was expected because viscous effects and local capillary pressure effects are dominant influences on the flow in finer-grained media and therefore amplify small variations in the permeability between packings. Variation in the permeability of the media between successive packings of the same media type was considered to be a likely source of error. From multiple tests of the permeability of each media type, the permeability was found to vary by ± 10 μm^2 (± 5%) for GB, by -1.5 to +0.6 μm^2 (-3% to +1%) for SM, and by -0.7 to +1.0 μm^2 (-6% to +9%) for SF. The accuracy of the fluid volume measurements was estimated to be within ± 0.2 ml for oil and ± 2 ml for water.

The volume of oil produced by the end of each experiment, V_{oe}, can be recast as the average saturation of water in the porous medium by dividing V_{oe} by the pore volume V_p to give the end-point saturation as $S_{we} = V_{oe} / V_p$. The end-point relative permeability of water was calculated by simply dividing the end-point flow rate by the calculated single-phase flow rate of water corresponding to the specific pressure level that was used during the experiment (Q_{we} and Q_w were values at the same pressure level): $k_{rwe} = Q_{we}/Q_w$. This data is shown in Fig. 4 for the Silica Medium experiments conducted. For each viscosity of oil used, there are distinct increases in the end-point saturations between the low and medium pressure levels, and increases in the relative permeabilities are also evident between all three pressure levels. With increases in the viscosity of oil, both the end-point saturation and relative permeability decreased. The data for the other media types were seen to be similarly behaved. The end-point relative permeabilities were also seen to be affected by the absolute permeability of the medium: in general, SF occupied a region lower on the relative permeability scale than the coarser media, SM and GB; the regions of saturation occupied by the three media types were distinct, with SF yielding the lowest values of end-point saturation.

At regularly-spaced intervals of saturation, the JBN relative permeability curves corresponding to a given experimental condition were averaged with the equation,

$$\overline{k}_r = \frac{k_r}{n}, \tag{1}$$

and the sample standard deviation was calculated as

$$s = \sqrt{\frac{n \quad k_r^2 - \left(\quad k_r \right)^2}{n(n-1)}}. \tag{2}$$

Using the sample mean and standard deviation of the relative permeability, each for that of oil and water, the t-statistic is suited for calculating a confidence interval for the true mean at each interval of saturation. A confidence interval of 95% was chosen and the interval limits were calculated using the expression,

$$\overline{k}_r \pm t_{\alpha/2} \cdot s/\sqrt{n}, \tag{3}$$

where $\alpha = 0.05$ level of significance and t is the statistic value corresponding to n-1 degrees of freedom. A typical set of mean relative permeability curves, along with the 95% confidence intervals, is shown in Fig. 5. The regions of the curves with narrow 95% confidence intervals indicate that the curves from all of the experiments for a particular set of conditions were quite close in agreement; regions of the curves with wide confidence intervals reflect a greater disparity among the individual relative permeabilities in the particular region of saturation.

A check was done, using the data in Fig. 3, to verify that the estimated average saturation at break-through using the fractional flow equation matched the experimentally observed saturation. The relative permeability values from the JBN method were used in the fractional flow equation (including the gravity component) and the fractional flow of water was plotted versus saturation. By graphical means, the average saturation value at break-through was obtained: a tangent line was drawn to the curve from the plot origin to a point on the f_w = 1 line. In all three experiments that were checked, the calculated saturations were slightly greater than the experimental saturation at break-through (*e.g.*, 0.430 from tangent vs. 0.399 from data). The slight discrepancy indicates that there was some degree of capillary end-effect, which the JBN method does not account for. The comparisons done in this work however were conducted using primarily the middle portions of the relative permeability curves; therefore any end-effect problem does not weaken the results presented here.

In order to compare the mean relative permeabilities between the differing experimental conditions, a two-sample t test was performed using the averaged relative permeability curves and their corresponding standard deviations. In essence, inferences concerning two sample means (two at a time) were deduced by testing the null hypothesis that the two sample means are the *same* based on a chosen level of significance of $\alpha = 0.05$. To see if the null hypothesis can or cannot be rejected, a calculated *t*-statistic was compared against tabulated values for the $n_1 + n_2 - 2$ degrees of freedom, at each saturation value. If the calculated *t* value exceeded the tabulated $t_{\alpha/2}$ value then the null hypothesis was rejected and this showed that their was a significant difference between the two sample means at a particular saturation. The *t*-statistic, including the sample means and standard deviations, was calculated using the equation,

$$t = \frac{\overline{k}_{r1} - \overline{k}_{r2}}{\sqrt{(n_1 - 1)s_1^2 + (n_2 - 1)s_2^2}} \cdot \sqrt{\frac{n_1 \, n_2 \,(n_1 + n_2 - 2)}{n_1 + n_2}}, \qquad (4)$$

where the subscripts 1 and 2 refer to the sets of averaged relative permeability data. Null hypothesis testing was conducted over the common saturation ranges of two mean relative permeability curves at a time. For example, at a certain pressure level and viscosity of oil (say low pressure level and light viscosity oil) the relative permeabilities for Glass Beads (GB) were compared with those of the Silica Medium sand (SM). Then comparison was done with the relative permeabilities of Silica Medium sand (SM) and Silica Fine sand (SF); and finally the curves for the Glass Beads (GB) were compared against those of the Silica Fine sand (SF). Note that the relative permeability curves of oil and water were treated separately in the comparisons. This mode of comparing was done for each level of pressure (low, medium, and high) and viscosity of oil (light, medium, and heavy). In a similar fashion, null hypothesis testing was done to compare the relative permeability curves for differing oil viscosities (by keeping the permeability and the pressure drop the same in the comparisons), and then for the different pressure levels used (with the permeability and the oil viscosity kept the same in each comparison).

It was found that, as expected, differences in the absolute permeability (GB vs. SM, SM vs. SF, GB vs. SF) significantly affected the relative permeability curves about equally for oil and water (Fig. 6). The region of the curves where significant differences exist was seen to increase with higher levels of applied pressure; this occurred partly because more complete relative permeability curves tended to result with the higher pressure cases. It was observed that decreases in the permeability (GB→SM→SF) tended to shift the water curves lower on the relative permeability scale and toward slightly greater values of saturation (Fig. 6). The same trend was seen with the end-point relative permeability of water except that the saturation also decreased. The relative permeability of oil curves also shifted toward lower values with decreases in the permeability. Some literature has claimed that the permeability does not affect the relative permeability, but these authors (Wycoff and Botset, 1936; Muskat and Meres, 1936) based their conclusions on steady-state experiments, and more recent work (Peters and Khataniar, 1987) showed that steady- and unsteady-state relative permeabilities are not the same.

The viscosity of the oil used in the experiments was seen to influence the relative permeability curves that were compared in this study (Fig. 7). At the low pressure level, however, typically no comaparison was possible with the curves or no significant differences were seen in the ranges compared. A greater significant effect due to the oil viscosity was evident with the relative permeability curves of water over those for oil. Below the highest pressure level, significant effects in the oil curves were not seen, but some effect was evident at the medium pressure level with the Silica Fine sand. Typically the mid-saturation region of the curves is where significant differences are obtained in many of the statistical comparisons. The effect of increasing the oil viscosity was to cause a slight shift toward higher values of relative permeability of water for the Glass Beads and toward lower values of relative permeability of water for the Silica Medium (Fig. 7) and Silica Fine sands. Recall that a shift toward lower end-point relative permeabilities of water and saturations was seen with increases in the viscosity of oil. The effects of the viscosity ratio observed in the experiments lend support to the findings of other studies, such as the works of Lefebvre du Prey (1973), Singhal *et al.* (1976), and Islam and Bentsen (1986). Johnson *et al.* (1959) contended that the effect of the viscosity ratio was to delineate different regions of the same set of relative permeability curves; however, Peters and Khataniar (1987) maintain that using high-permeability media can lead to stable (no viscous fingering) displacements and hence produce no effect of the viscosity ratio on relative permeability. (Calculation of the Peters and Flock, 1981, stability number for the current set of experiments showed that all of the present water-floods were unstable.)

The effect of changes to the pressure drop across the sand- or bead-pack was, in general, seen to be weaker than the effects of the other two parameters. At the low pressure level, the effects of local capillary pressures on the flow were expected to be strong, especially in the Silica Fine sand where the pore sizes are small. It should be noted that the JBN method strictly does not apply to low pressure cases because the method assumes that capillary pressure gradients are small in comparison to the overall pressure gradient. The relative permeability curves were generated regardless to show comparisons between three pressure levels, knowing that restrictions apply regarding the validity of the curves for the low pressure cases. Throughout the statistical analysis, however, the relative permeability curves for the low pressure cases had high values of standard deviation and therefore precluded finding many significant differences between the curves. The effect of pressure was seen to be greatest for the silica-sand packs (SM and SF), and particularly with the relative permeability of water (Fig. 8). Some increases in the relative permeability curves were evident with the Silica Fine data due increases in the pressure level. There is consistent agreement in the literature stating that increases in the flow rate among experiments tends to increase the relative permeability of water (*e.g.*, Sufi *et al.*, 1982; Islam and Bentsen, 1986; Peters and Khataniar, 1987; Mohanty and Miller, 1991; Chang *et al.*, 1997). Observations from the current study confirm this trend regarding the relative permeability of water, although constant pressure was the prescribed boundary condition in the present experiments. The work of Peters and Khataniar indicated that the relative permeability of oil tends to decrease with increases in flow rate; evidence was seen in the current study that the relative permeability of oil increased with the pressure applied. This discrepancy may be the result of using a different boundary condition (constant pressure) compared to that used by Peters and Khataniar (constant flow rate). The end-point relative permeabilities and saturations in the current study showed definite increases in value with increases in the pressure applied, which supports the trend observed with the JBN relative permeability curves.

CONCLUSIONS

Statistical analysis of the JBN relative permeability curves produced from a suite of experiments demonstrated that the absolute permeability of the medium, the viscosity ratio of oil to water, and the level of pressure drop used, all contribute to significant differences in the relative permeability curves. Increases in the applied pressure drop tended to produce more extensive regions of saturation where significant differences were evident in comparisons performed with the permeability and the viscosity ratio. The permeability affected the relative permeability of oil and water equally. The viscosity ratio tended to significantly influence the relative permeability of water, and to a greater degree than on the relative permeability of oil. The pressure level, ΔH, was found to affect the relative permeabilities less extensively than the other parameters. However, a significant effect was noticed on the relative permeability of water with the silica sand media. Many of the observations from this study lend support to similar conclusions in the literature. Also, confirmation of the trends concerning the JBN relative permeability of water was seen from direct calculations of the end-point relative permeability of water.

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Table 1. Literature investigating the effect of experimental parameters on the JBN relative permeabilities.

Author(s)	Number of Experi-ments	Effect of Viscosity Ratio	Effect of Flow Rate or Pressure Gradient	Fluid Pair	Direction of Flood (I=imbibition, D=drainage)	Wetting Nature of Porous Medium
Croes and Schwarz (1955)	6	NO† (k_r ratio)	—	Water/Oil	I	Water-Wet
Johnson *et al.* (1959)	3	NO	—	Water/Oil	I	Water-Wet
Delclaud (1972)	4	—	YES	Gas/Oil	D	Oil-Wet
Lefebvre du Prey (1973)	6	YES	YES	Water/Oil	I & D	Oil-Wet
Singhal *et al.* (1976)	10	YES (k_r ratio)	—	Water/Oil	I & D	Mixed-Wet
Sufi *et al.* (1982)	4	—	YES	Water/Oil	I	Water-Wet
Islam and Bentsen (1986)	8	YES	YES	Water/Oil	I	Water-Wet
Peters and Khataniar (1987)	8	—	YES	Water/Oil	I	Water-Wet
Qadeer *et al.* (1988)	3	—	YES	Water/Oil	I	Water-Wet
Mohanty and Miller (1991)	3	—	YES	Water/Oil	I	Mixed-Wet
Chang *et al.* (1997)	2	—	YES	Water/Oil	I	Mixed-Wet

† used Buckley-Leverett equation.

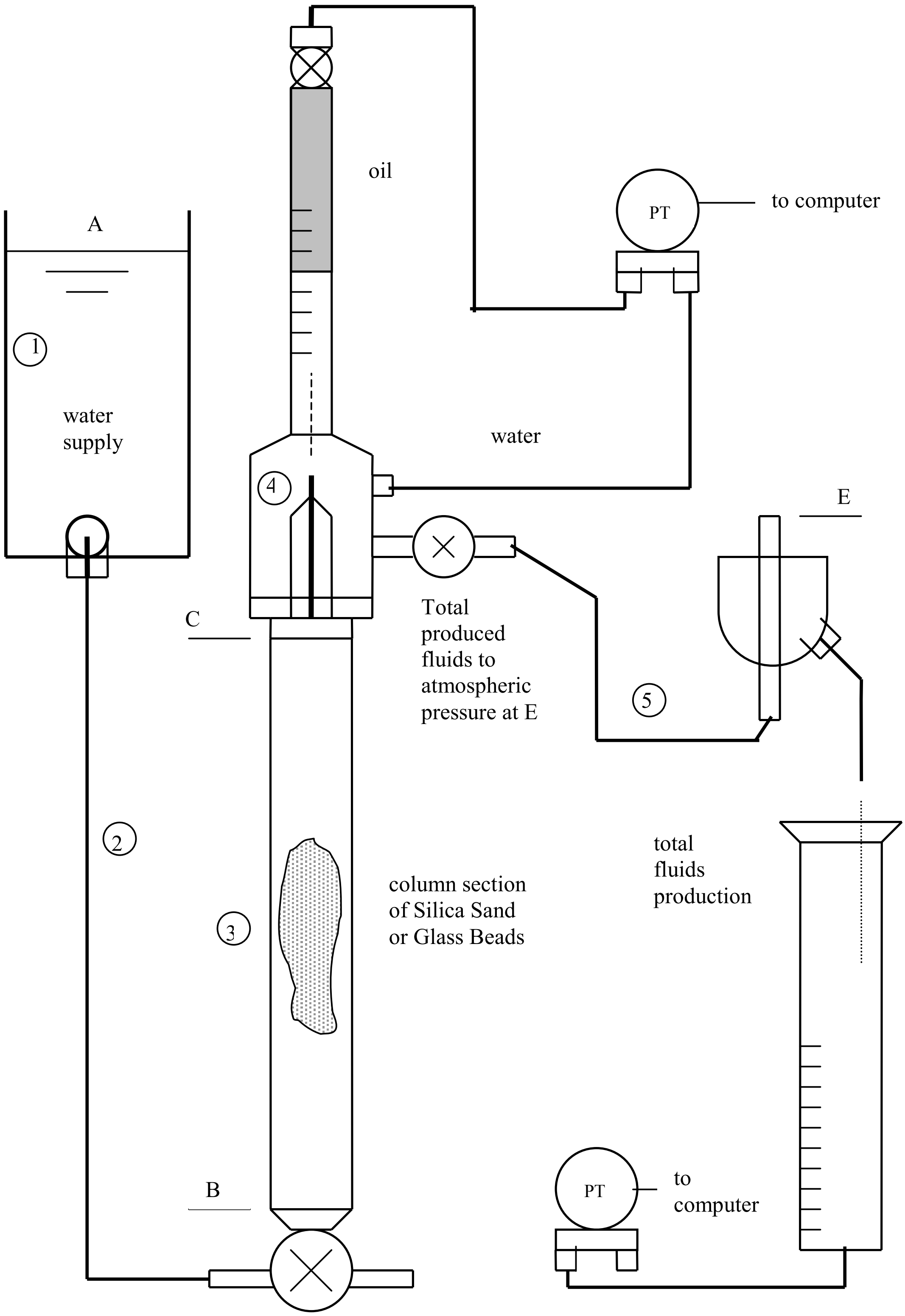

Figure 1: Schematic diagram of the experiment apparatus.

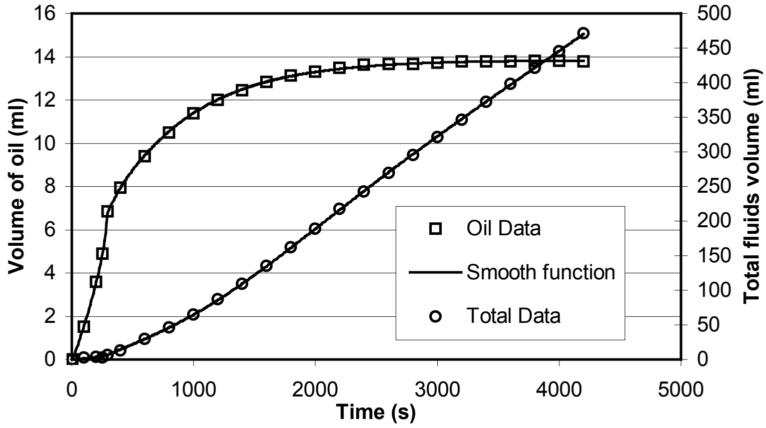

Figure 2: Example of experimental data and smoothing curves; SM, light oil, high ΔH.

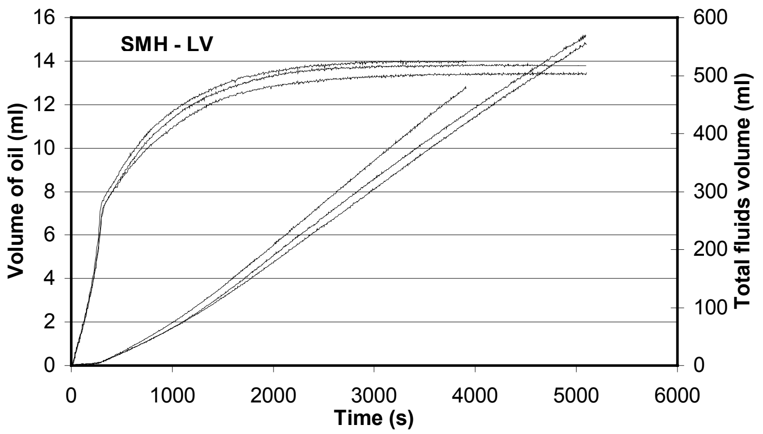

Figure 3: Example of data from three experiments corresponding to the same conditions.

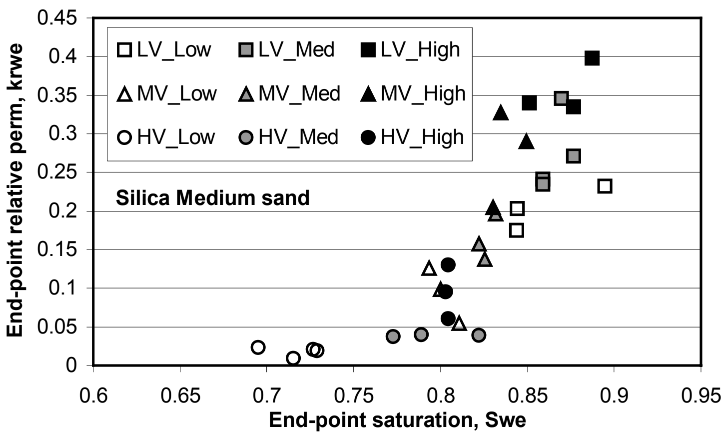

Figure 4: End-point relative permeability of water and average saturation; SM sand, data for three pressure levels (low, medium, high ΔH).

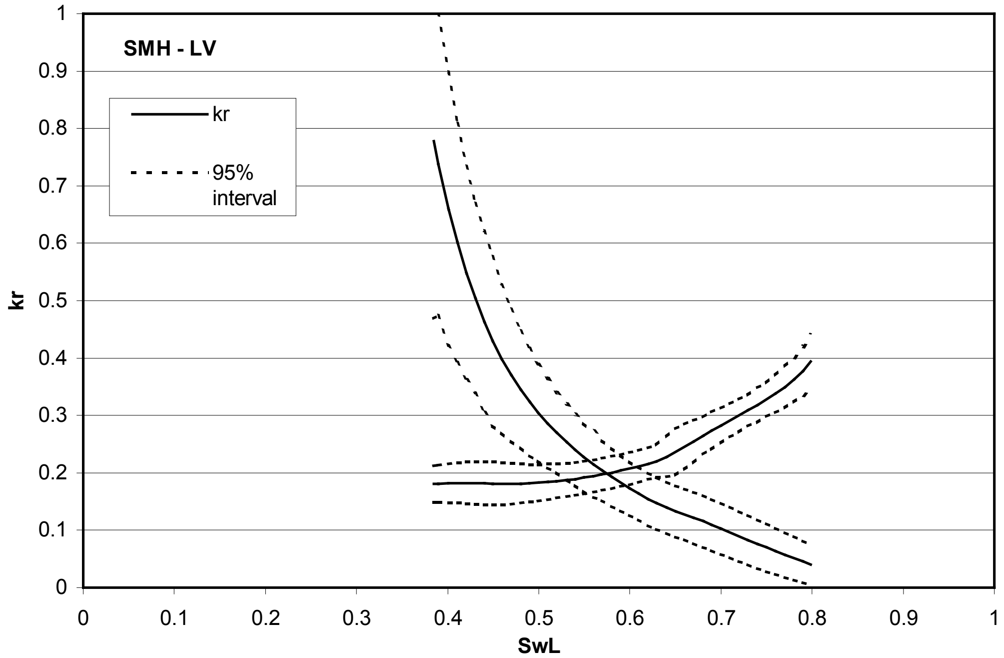

Figure 5: Mean relative permeability curves with 95% confidence intervals.

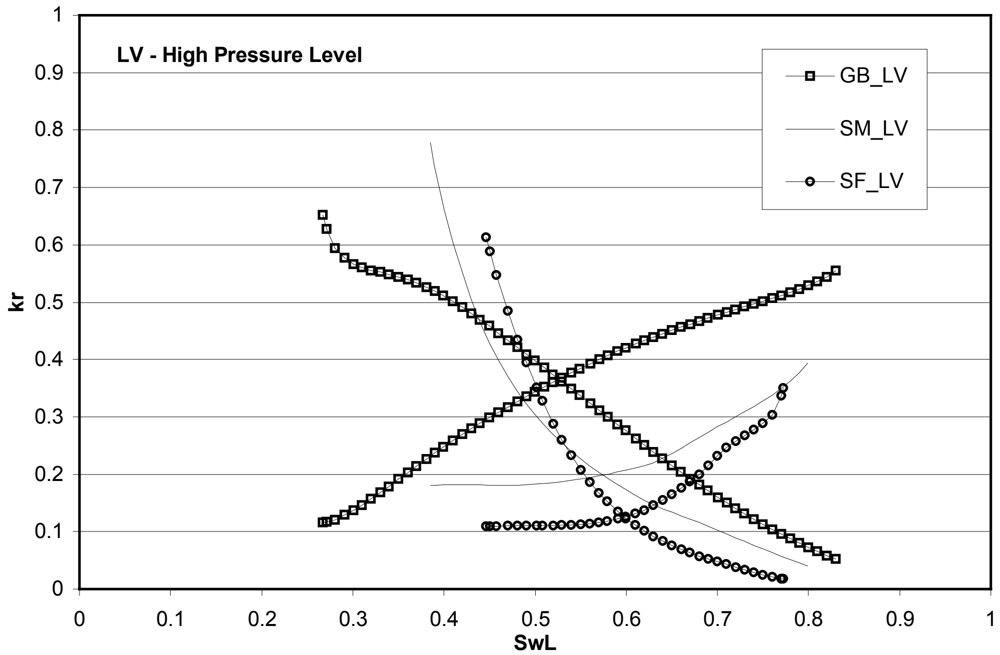

Figure 6: Comparison of mean relative permeability curves for three media permeabilities: Glass Beads (GB), Silica Medium sand (SM), and Silica Fine sand (SF).

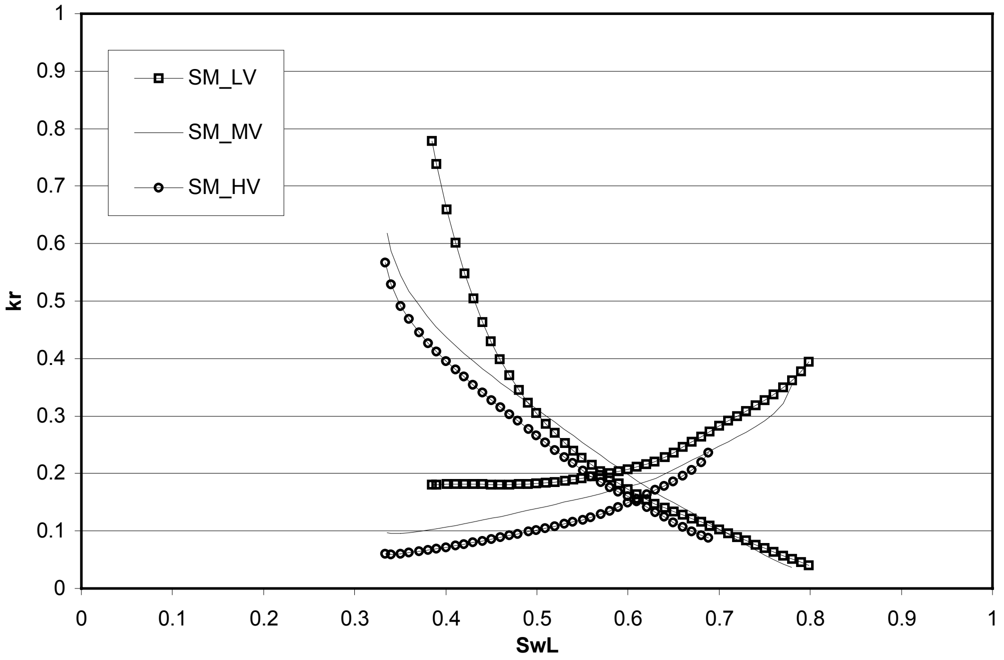

Figure 7: Comparison of mean relative permeability curves for three viscosities: light (LV), medium (MV), and heavy (HV), all at the highest pressure level.

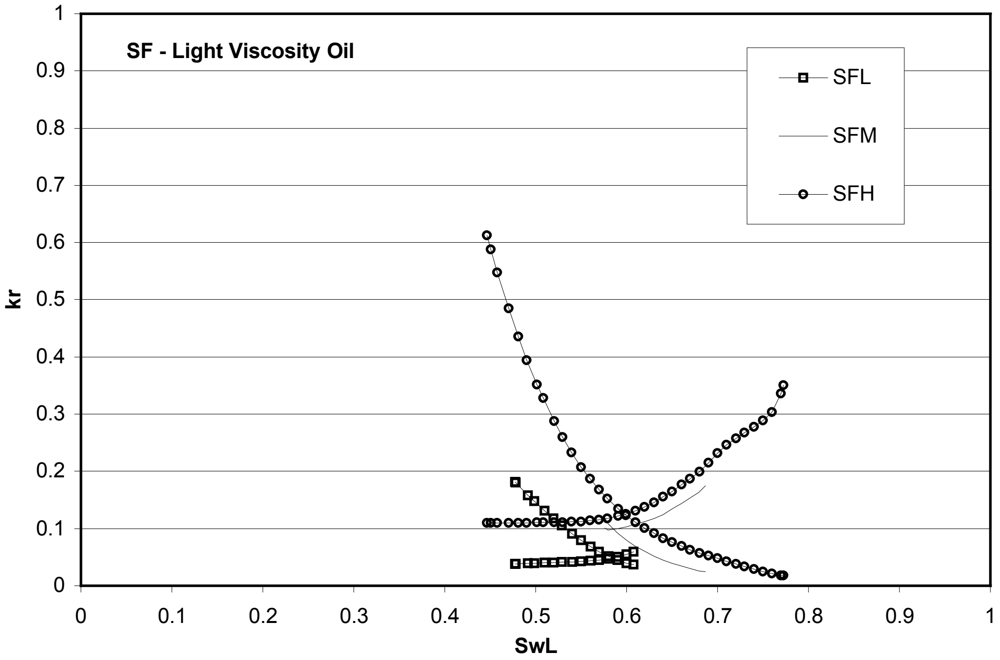

Figure 8: Comparison of mean relative permeability curves for three pressure levels: low pressure (ΔH = 2.5 kPa), medium pressure (ΔH = 5 kPa), and high pressure (ΔH = 10 kPa); Silica Fine sand, light viscosity oil.

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