

The Significance of Violated Assumptions on Core Analysis Results

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Abstract

Core analysis data, such as residual oil saturation and relative permeabilities, play an important role in reservoir engineering and decision making. In the traditional approach for determination of relative permeabilities from core analysis data, two main assumptions are made – namely that the capillary effect is negligible and that the core samples are homogeneous. The core analysis data gathered in the laboratory are usually influenced both by the capillary pressure and the heterogeneity pattern, and hence, both assumptions are frequently violated. In this paper, we study and demonstrate what effects violation of these assumptions have on the determination of the relative permeabilities and residual oil saturation. Utilizing a simulator, we generate unsteady state, centrifuge, and steady state data. The first two data sets are interpreted using the traditional Johnson, Bossler, Naumann (JBN) and Hagoort methods. Typically, we find that the JBN method over-estimate the residual oil saturation (in fact, frequently by as much as 10 saturation units) and under-estimate the oil relative permeability in the vicinity of residual oil saturation. As a result, the relative permeabilities seem to be rate and RPM dependent. As will be shown, this apparent rate and RPM dependency is due to not accounting for capillary effects in the interpretation procedure. Violation of the homogeneity assumption is demonstrated on steady state data. In the estimation procedure, one arrives at relative permeability estimates compensating for the violated homogeneity assumption. Hence, they differ significantly from the true curves.

Introduction

The relative permeabilities are defined through the system of equations describing flow through porous media. For isothermic flow of two incompressible, immiscible fluid phases, this system of equations may generally be written as (see Nomenclature section for notation):

$$\begin{aligned}\bar{v}_i &= \frac{\mathbf{K}_i}{m_i} \cdot (\nabla p_i - \mathbf{r}_i \bar{g}), \\ \frac{\partial(\mathbf{f}\mathbf{r}_i S_i)}{\partial t} &= -\nabla \cdot (\mathbf{r}_i \bar{v}_i), \\ P_c(S_w) &= P_{nw} - P_w, \\ S_{nw} + S_w &= 1.\end{aligned}\tag{1}$$

Here, the permeability of each fluid phase is typically represented as the product of the absolute permeability tensor (as defined for single phase flow) and the relative permeability of that phase (in this work the dependency of relative permeability on saturation history is neglected),

$$\mathbf{K}_i = \mathbf{K}k_{ri}(S_i).\tag{2}$$

In the traditional approaches for determination of relative permeabilities from core analysis data, the above system of equations is simplified. The reason for this simplification is to obtain computational advantages – certain simplifications make it possible to solve the system of equations analytically. The most common simplifications are to assume that the capillary pressure effects can be neglected (i.e., $dP_c / dS_w = 0$), and that the flow can be well represented assuming one-dimensional flow with a single permeability value (i.e., $\mathbf{K} = k$). With these assumptions, the system of equations may be inverted *explicitly*, and the relative permeabilities can be calculated directly from the time series of production and/or pressure drop data. The two most common examples are the determination of oil and water relative permeabilities from unsteady state data[5] (which will be considered in Example 1), and oil relative permeability from gas/oil centrifuge drainage data[4] (Example 2).

However, it is not always easy to perform the experiments in such a manner that these simplifications are justified. For example, to reduce the influence of capillary effects on the data one would typically perform unsteady state displacement experiments at a high injection rate. This could lead to situations for which this assumption is valid. On the other hand, if the injection rate is not sufficiently high, and/or the derivative of the capillary pressure with respect to the saturation is not negligible, the data may still be influenced by capillary effects. We study this through a series of different injection rates and RPM values for Example 1 and Example 2.

In this paper it will be demonstrated that experimental data influenced by capillary effects leads to relative permeabilities and observed residual oil saturations that appear to be severely rate dependent. Also, it typically leads to over-estimation of the residual oil saturation (frequently by as much as 10 saturation units or even more). As will be shown, this apparent rate and RPM dependency is due to not accounting for the capillary effects in the interpretation procedure.

The second assumption that will be discussed in this paper is the homogeneity assumption (discussed in Example 3). Assuming a single permeability value implies that the medium must be homogeneous. We investigate into this by generating “synthetic” experimental data using a simulator with a known heterogeneity; here the composite core case is investigated. The study is directed towards how the relative permeabilities estimated from such data depart from the true ones.

The Assumption of Zero Capillary Effects

We investigate into the assumption of negligible capillary effects through two examples; (1) determination of relative permeabilities of water and oil from time series of production and pressure drop data acquired from a water displacing oil flooding experiment, and (2) determination of oil relative permeability from time series of production data acquired from a gas displacing oil centrifuge experiment. In both cases, we utilize a simulator[3] to generate experimental data for some selected relative permeability and capillary pressure functions. The simulator has a fully implicit formulation, see, e.g., Aziz and Settari for a description [14]. From the set of “true” data, we calculate the relative permeabilities utilizing techniques assuming negligible capillary effects, and study how the resulting relative permeabilities depart from the true ones.

Example 1: Relative Permeabilities From Unsteady State Experiments

To determine relative permeabilities from unsteady-state experiments, the Johnson, Bossler, Naumann (JBN) method[5] is typically utilized. This method is based on the Welge’s tangent technique[13], and utilizes production and pressure drop data after breakthrough of the displacing phase. In the JBN technique, the relative permeabilities and saturation are calculated as a function of time at the outlet phase *explicitly* (i.e., one relative permeability and corresponding saturation point for each measured point) from the production and pressure drop data along with its time derivatives.

In the JBN technique, the capillary pressure effects are assumed negligible, and the medium is assumed homogeneous and isotropic. We here investigate into the former assumption. To be able to neglect the capillary pressure effects, one must ensure that the viscous forces are much higher than the capillary forces, consequently the injection rate is typically set high. Although the system of equations is based on the rate

being sufficiently *low* (as this would ensure laminar flow)[1], we can assume that a low enough flow rate can be selected so that Darcy's law is valid at a condition for which the capillary effects are negligible. Several authors have been investigating into criteria for when the capillary effects can be neglected (see Lake [8] for an overview) typically through some capillary number, N_c . N_c quantifies the ratio of viscous to capillary forces. If N_c is high, the capillary forces are small compared to the viscous ones. One aim at keeping N_c sufficiently small to ensure that Darcy's law is valid, yet sufficiently high to avoid the influence of capillary forces on the data. One such criterion is to keep the Rapoport and Leas[9] number

$$N_{RL} = \left[\frac{f}{k} \right]^{\frac{1}{2}} \frac{m_i v L}{k_{rw}^0 f s_{wo} \cos \mathbf{q}} \quad (3)$$

larger than 3 (from Lake[8]). We consider a water-displacing-oil process for a porous medium described in **Table 1**. For this case (utilizing $k_{rw}^0 s_{wo} \cos \mathbf{q} = 1 \text{ mN} / \text{m}$ see Lake[8]), we should expect that the capillary effects would not affect a one-dimensional water-oil displacement provided that the selected flow rate is larger than 5 ml/min. However, a range of flow rates will be discussed in this paper.

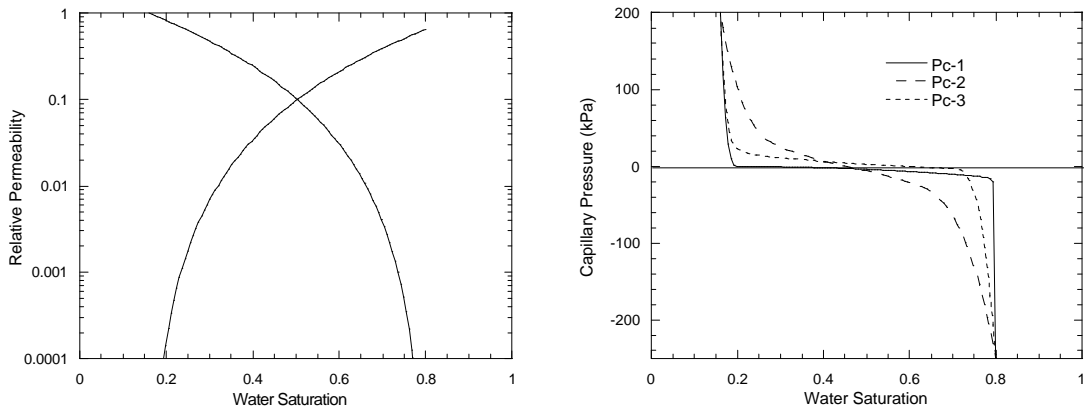


Figure 1: Relative permeability (left) and capillary pressure (right) functions used in Example 1.

Table 1: Core and fluid properties and flow rates.

	Example 1: Unsteady state	Example 2: Centrifuge	Example 3: Steady state
Core length	20.0 cm	4.84 cm	12.0 cm
Core diameter	3.78 cm	3.78 cm	3.78 cm
Absolute permeability	450 mD	253 mD	Core 1: 200 mD Core 2: 100 mD Core 3: 50 mD
Outer centrifuge radius	n.a.	9.38 cm	n.a.
Porosity	0.3	0.288	0.3
Water viscosity	0.42 cP	n.a.	0.66 cP
Oil viscosity	0.52 cP	1.25 cP	0.85 cP
Gas viscosity	n.a.	0.001 cP	n.a.
Initial water saturation	0.15	n.a.	0.1
Initial oil saturation	0.84	1.0	0.9
Residual oil saturation	0.2	0.062	0.1
Flow rates [ml/min]	0.5, 1.0, 2.0, 10.0, 20.0	n.a.	Oil: 0.95, 0.5, 0.0 Water: 0.05, 0.5, 1.0

n.a. = not applicable.

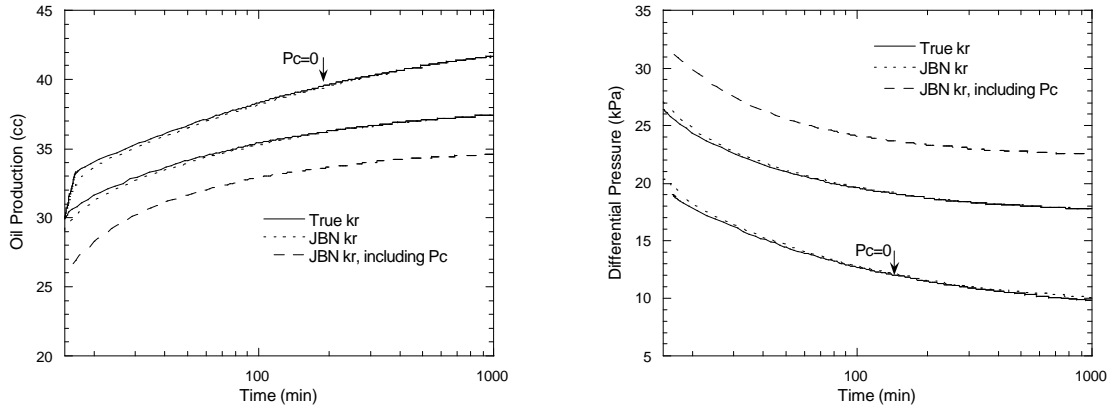


Figure 2: Solid lines are production (left) and pressure drop (right) data simulated using true relative permeabilities and for $P_c = 0$ and $P_c \neq 0$. Dotted lines are pressure drop and production data simulated using JBN relative permeabilities when $P_c = 0$ and dashed line for $P_c \neq 0$.

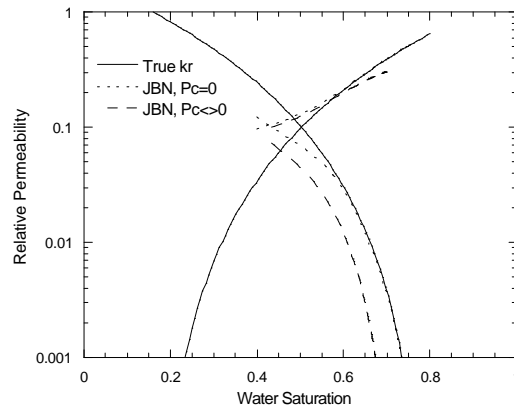


Figure 3: Relative permeabilities calculated using the JBN method for $P_c = 0$ and $P_c \neq 0$ cases.

Utilizing a series of different flow rates, the JBN method is used to determine the water and oil relative permeabilities from displacement data. We calculate the data using a simulator, compute the relative permeabilities using the JBN method, and compare the results to the “true” relative permeability functions. The true relative permeability and capillary pressure functions utilized are shown in **Figure 1**. The three capillary pressure functions (denoted P_{c-1} , P_{c-2} , and P_{c-3}) have different characteristics. P_{c-1} has a relatively small saturation region for which the spontaneous imbibition occurs. In the rest of the saturation range, the capillary pressure is negative. For P_{c-2} , the crossover point for spontaneous imbibition (i.e., the water saturation for which $P_c = 0$) is higher than for P_{c-1} , and the derivative (dP_c / dS_w) never becomes zero (or even close to zero), but has a certain magnitude over the entire saturation range. P_{c-3} has the highest water saturation at the crossover point, and only a small saturation region for which it is negative. The three curves may be regarded as reflecting typical wetting conditions in oil reservoirs.

We first performed a consistency check, highlighting the importance of quality assuring core analysis results. Utilizing P_{c-1} , an unsteady state experiment with an injection rate of 2.0 ml/min is simulated (see **Table 1** for details). **Figure 2** shows the simulated pressure drop and production data (solid line), the solid

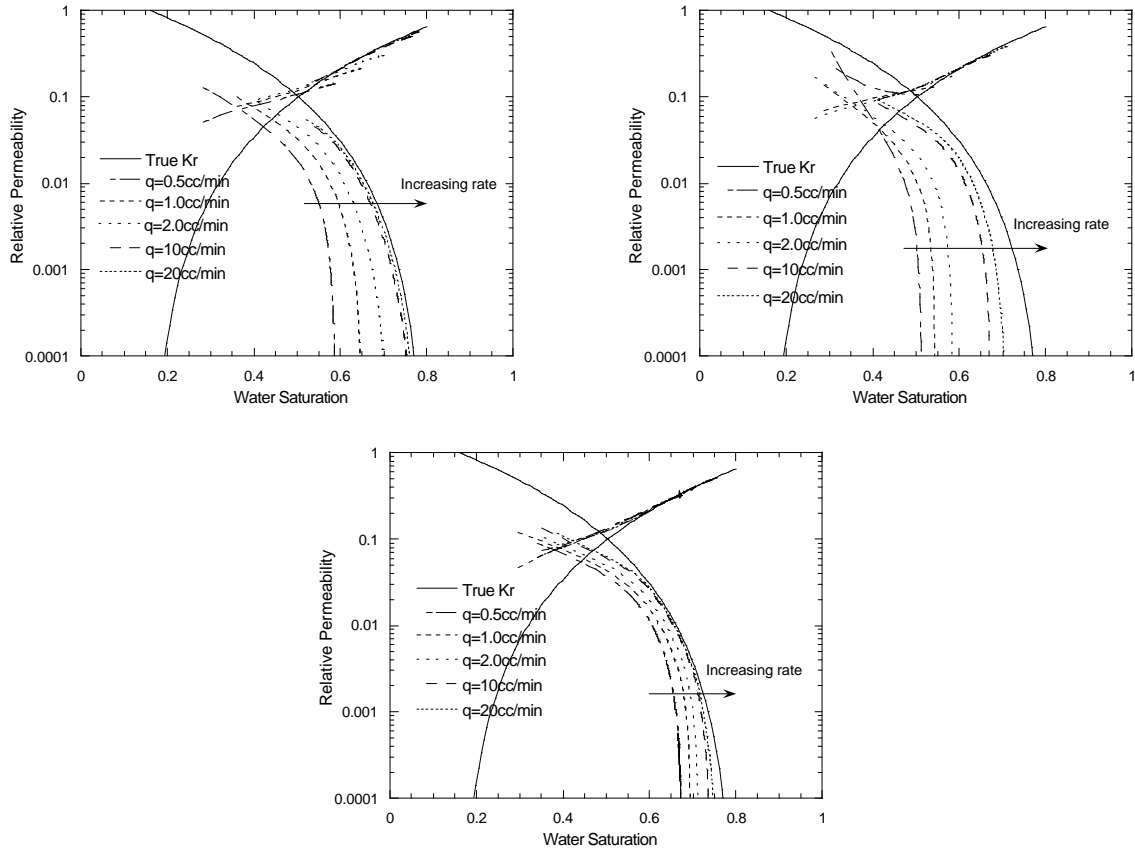


Figure 4: Relative permeabilities calculated using the JBN method. Upper left: P_c -1; Upper right: P_c -2; Lower: P_c -3.

line denoted $P_c = 0$ is production and pressure drop utilizing zero capillary pressure. Note that only post breakthrough data are shown, as these are the only one used in the JBN method. The true relative permeabilities utilized in this case are shown in **Figure 1**. Interpreting these data sets using the JBN method results in relative permeability curves as shown in **Figure 3**. This figure shows that the relative permeabilities computed using the JBN method when $P_c \neq 0$, deviate significantly from the true ones. However, inputting these curves into the simulator and utilizing a capillary pressure curve being identical to zero (as was the assumption), the resulting simulated data overlap the true data (see dotted line in **Figure 2**). Hence, *the capillary effects are incorporated in the relative permeability functions*. Simulating the pressure drop and production data utilizing the relative permeability obtained from the JBN method together with the true capillary pressure curve, results in production data being lower than the true ones, and pressure drop being higher (dashed line in **Figure 2**). As the capillary effects are now explicitly taken into account through the capillary pressure, the simulated data will depart from the true ones. In fact, this exercise can be utilized as a quality control procedure for unsteady state experiments, see also Maas et al.[6]. The same analysis has been performed for a case where the true capillary pressure function was identical to zero. The pressure drop and production data are plotted in **Figure 2** (solid line denoted $P_c = 0$), and the production data are now higher than for the first case while the pressure drop are lower. **Figure 3** shows that the relative permeabilities computed using the JBN method agrees well with the true relative permeabilities when $P_c = 0$, as expected. The consistency check has been applied for this case also; the true and the simulated data using relative

permeabilities generated through the JBN method coincides (see solid and dotted line in **Figure 2** for $P_c = 0$).

Production and pressure drop data were generated utilizing the three capillary pressure functions in **Figure 1** and the five flow rates in **Table 1**. The relative permeabilities were calculated utilizing the JBN method and the results are shown in **Figure 4** (one figure for each capillary pressure). The figure shows that for none of the cases, the simple Rapoport and Leas criterion (**Eq. 3**) would be sufficient, although for $Pc-1$, flow rates of 10 and 20 ml/min seem to yield relative permeabilities quite close to the true ones. Since the JBN method really neglects the derivative of the capillary pressure, the largest departure from the true curves should be expected in $Pc-2$, as this capillary pressure function has a non-negligible derivative for the entire saturation range. This is also what is observed. Even though the relative permeabilities are getting closer to the true ones as the flow rate is increased, the JBN curves are never overlapping. The results using $Pc-3$ exhibit an intermediate behavior. This was also expected from the shape of the capillary pressure curve.

If one had investigated these results without knowledge of the capillary effects, one might have been misled to conclude that the relative permeabilities are rate dependent. However, the reason for this apparent rate dependency is that the JBN method produces relative permeabilities compensating for capillary pressure effects. In other words, whenever the data has capillary effects incorporated, the resulting JBN interpretation will too. As this capillary influence is a function of the rate, so will the JBN relative permeabilities. The effect of neglect of capillary effects on apparent residual oil saturation and water relative permeability endpoint is shown for all cases in **Figure 5**.

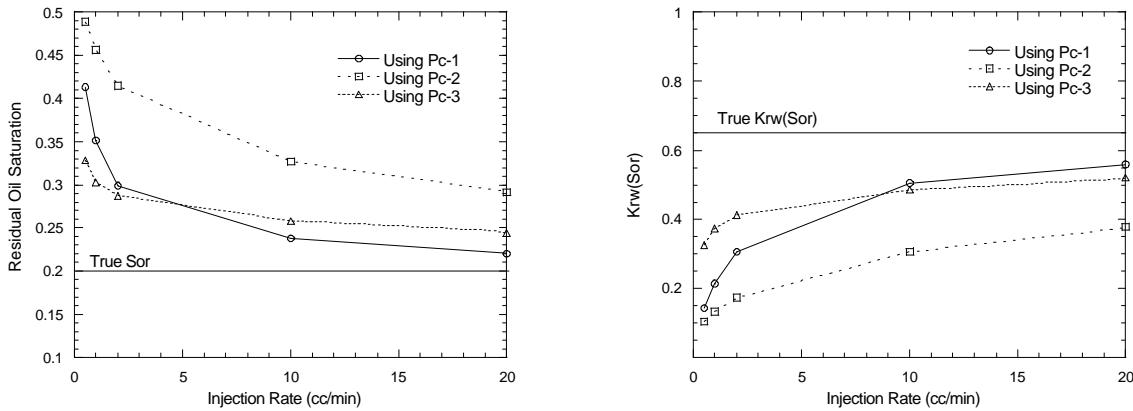


Figure 5: Residual oil saturation (left) and water relative permeability at residual oil saturation (right) as a function of flow rate.

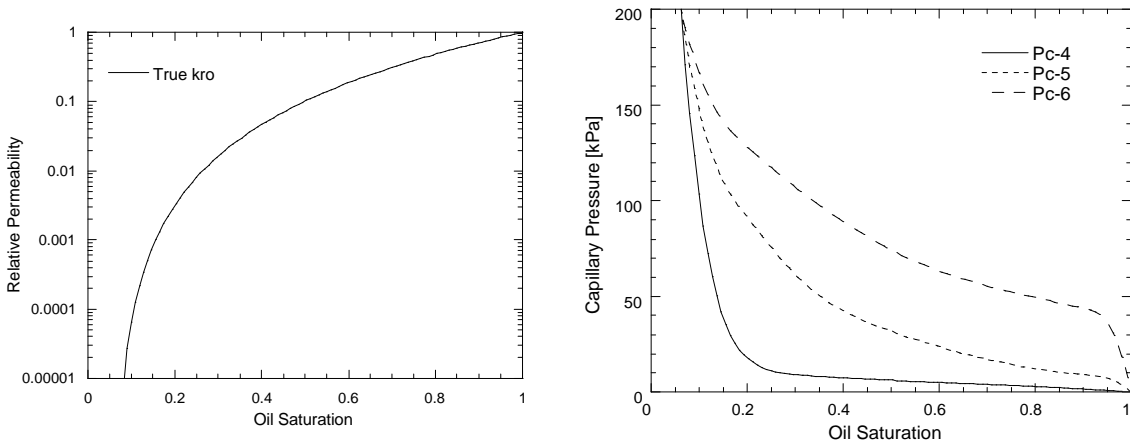


Figure 6: Relative permeability (left) and capillary pressure (right) functions used in this study.

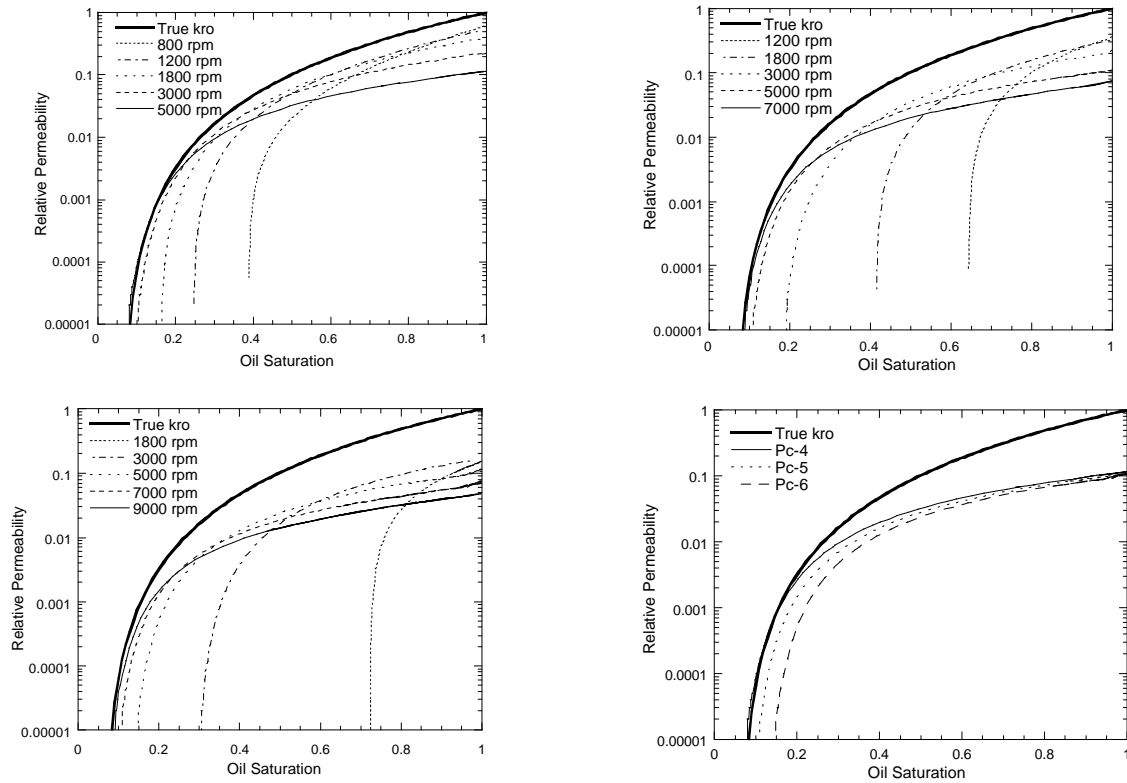


Figure 7: Relative permeabilities calculated using the Hagoort method. Upper left: $Pc-4$; Upper right: $Pc-5$; Lower left: $Pc-6$; Lower right: Speed 5000 RPM.

Example 2: Relative Permeabilities from Centrifuge Experiments

A similar analysis was performed for determination of oil relative permeability using the Hagoort[4] method on centrifuge data from a primary gas drainage process. Here, the oil is the wetting phase, and there is no water present. In this approach, the gas mobility is assumed large compared to that of oil, and the capillary pressure is neglected. As for the JBN method, this leads to a simple, closed-form equation for the pointwise calculation of oil relative permeability from time dependent production data[4]. However, for high oil saturation, the gas relative permeability will be low, and the assumption may break down. In addition, in the centrifuge, the equilibrium saturation profile for a given angular velocity (or RPM – Revolution Per Minute), will be uniquely determined by the capillary pressure. This is in conflict with the assumption of zero capillary pressure, and may result in that the relative permeabilities interpreted by the Hagoort method depart from the true ones. We now investigate how the assumption of zero capillary pressure influences the determination of relative permeability from gas/oil centrifuge data.

Table 1 shows the core and fluid properties for the centrifuge example. The centrifugal force will be proportional to the angular velocity (or RPM) squared, while the capillary forces depends on the capillary pressure function. The work has been directed towards studying the determination of oil relative permeability for a series of RPM values for three different capillary pressure curves. **Figure 6** shows the selected capillary pressure curves and true oil relative permeability. $Pc-4$ is relatively flat until close to residual oil saturation, while $Pc-5$ and $Pc-6$ have a non-zero derivative for all saturation values. For five RPM values for each capillary pressure curve, the production of oil from the centrifuge was calculated using a numerical simulator[14,3]. These production data were then interpreted using the Hagoort method. The results are shown in **Figure 7**. The relative permeability of oil approaches the true relative permeability for low oil

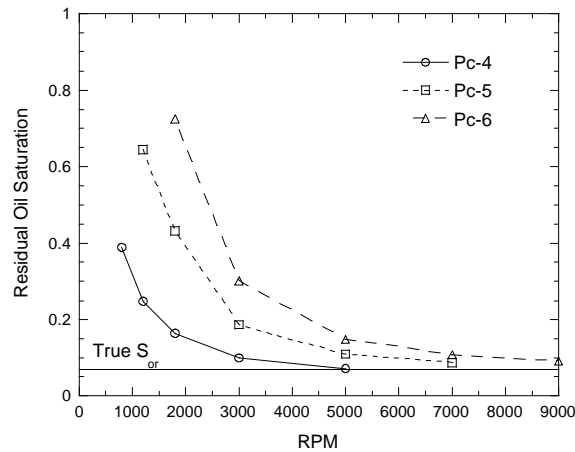


Figure 8: Residual oil saturation as a function of RPM

Saturation, as the RPM value is increasing. The saturation range for which the Hagoort method produces acceptable oil relative permeability values, is largest for *Pc-4*. This could be expected, as *Pc-4* is relatively flat and has a low capillary pressure value for a large saturation range, and hence, the capillary effects will be less pronounced than for the two other curves. Irrespectively of chosen capillary pressure curve, the oil relative permeability seems to be rate dependent. Obviously, this is an effect of the assumption in the analysis; as the RPM is increasing, we approach a situation for which the assumptions are met, at least for some saturation values. **Figure 7**, lower right, gives a direct comparison of the importance of the neglect of capillary pressure in the three cases with respect to expected residual oil saturation. **Figure 8** shows the residual oil saturation as a function of RPM.

The Homogeneity Assumption

Example 3: Composite Core

We next investigate the homogeneity assumption made in the determination of relative permeabilities from core analysis data. Even though one generally attempts identifying core samples that are homogeneous for analysis, a homogeneous sample may be hard to find. We will here only investigate into 1D heterogeneity and the impact of this on core analysis results; and refer to Mannseth et al.[7] for a discussion on 2D cases.

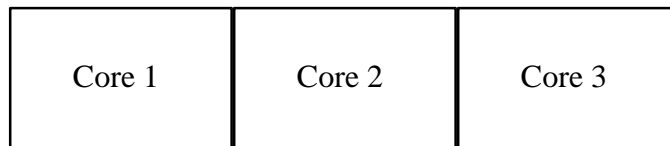


Figure 9: Composite core used in this study. Core 1, 2, and 3 has a mean permeability of 200 mD, 100 mD, and 50 mD, respectively.

The discussion is also restricted to the analysis of a case frequently occurring in core analysis, namely that of composite cores. Composite cores are used in core analysis basically to decrease the importance of end-effects, to decrease the relative error in the production measurements, and to obtain a high enough pressure drop across the core (both to avoid that small fluctuations in the line pressure impact the process and to have better accuracy in the measured data). The composite core consists of two or several samples butted together with capillary contact. Experiments have shown that it is reasonable to assume capillary continuity, with no internal end-effects between each core sample [10]. However, the individual cores may have different

properties. We here investigate the importance of a permeability contrast between the individual samples; actually we investigate the determination of oil and water relative permeabilities from a steady-state type process performed on three core samples butted together as illustrated in **Figure 9**; **Table 1** shows core and fluid properties. **Figure 10** shows the actual production and pressure drop data utilized. In the first rate step, water and oil are injected simultaneously into the composite core with a low water fraction. After some time, the water fraction is increased, and finally, the water fraction is set to unity.

The approach utilized in this work for determining the relative permeabilities takes the capillary pressure into account. A JBN-type interpretation technique could have been chosen, but it would then be hard to distinguish the effects from the neglect of capillary pressure and the assumption of homogeneous permeability on the estimated relative permeabilities. We therefore utilized a regression-based approach, in which the experimental data are reconciled by simulation[12,2]. In this approach, the capillary pressure as well as permeability contrast may be accounted for; see Sylte et al.[11].

Sylte et al.[11] have earlier demonstrated that utilizing composite cores will result in relative permeabilities deviating from the true ones, if the individual permeabilities of the cores are not taken into account. This is important in core analysis, as one typically will utilize the harmonic mean when estimating relative permeabilities from composite cores. (Utilizing the harmonic mean of permeability of the individual cores is equivalent to measure the permeability of the composite.) In fact, if not accounted for, small permeability contrasts (less than 10%) may result in estimated relative permeabilities deviating significantly from the true ones[11]. However, the permeability within each of the samples may well vary by 10%. A natural question then becomes: Would the permeability variation within the core sample have to be known in order to avoid erroneous relative permeabilities? We here investigate how such a local permeability variation impacts the estimation of relative permeabilities.

To investigate this, we study a 1D composite core case in which each of the three core samples in the composite is divided into 16 equally spaced zones. To assign a permeability value to each of the zones, we draw, from a normal distribution, 16 permeabilities for each of the three core samples. The mean of each of the three distributions, was the permeability values given in **Table 1**. We utilized a standard deviation of 10%. Experimental data were generated using the simulator and this true permeability distribution (random error with zero mean and a given standard deviation) were added to simulate the measurement process. The relative permeabilities were then (accounting for capillary pressure) utilizing two approaches: (1) By utilizing a single permeability value (the harmonic mean) to represent the permeability in the whole composite; and (2) By assuming that a harmonic mean within each of the individual core samples was sufficient. If (2) proves to be acceptable (i.e., relative permeabilities close to the true ones results), composite cores can be interpreted using a simulator including the permeability of each of the individuals in the estimation procedures. If (2) proves false, we would need to know the local permeability variation in order to calculate relative permeabilities. This would then impact all core analysis, as we would expect all samples to exhibit permeability fluctuations. Note that we have kept the capillary pressure constant and equal for all the zones. In practice, the capillary pressure will vary with varying permeability – here we have idealized the situation, studying the effect of permeability alone.

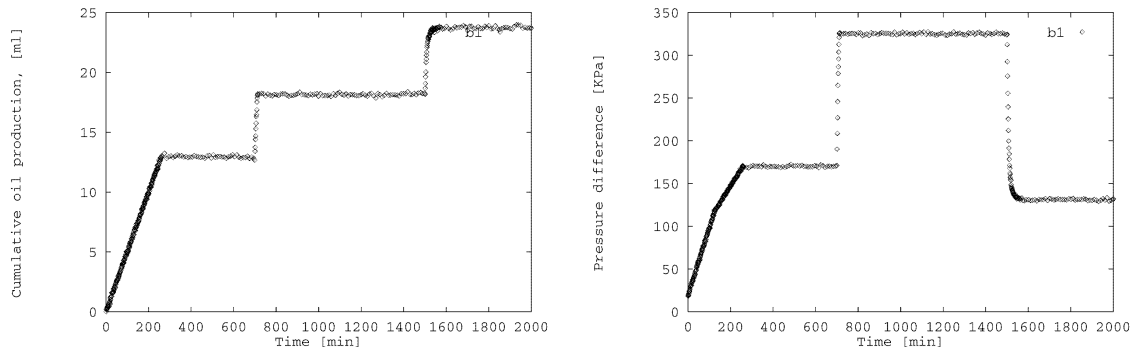


Figure 10: Production (left) and pressure drop (right) data used in the analysis.

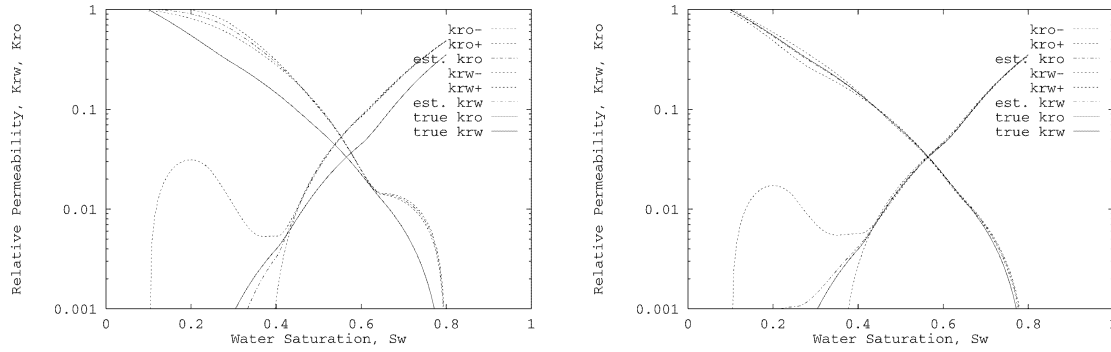


Figure 11: Estimation of relative permeabilities using a single permeability value (left) and a permeability value for each sample in the composite (right).

Figure 11 shows the results. As can be expected from the analysis in Sylte et al.[11], using only one permeability value leads to estimates of the relative permeabilities deviating significantly from the true ones, in fact over the entire saturation range. However, accounting for the major permeability variation using the harmonic average of each of the individual samples, gives relative permeabilities more or less coinciding with the true ones. This indicates that the effect of local permeability variation will not impact the estimation of relative permeabilities, at least not for modest permeability variations.

Conclusions

1. We have illustrated the seriousness of the neglect of capillary effects on the estimation of relative permeabilities using the JBN and Hagoort methods. It has been showed that an apparent rate and RPM dependency and over-estimation of residual oil saturation are due to not accounting for the capillary in the interpretation procedure.
2. We have demonstrated that local permeability variations within a core sample will not influence the estimation of the relative permeabilities provided that the length of the permeability variation is small compared to the length of the sample. On the other hand, utilizing a single permeability value for a composite core leads to large errors in the estimated relative permeabilities.

Nomenclature

\vec{g}	Gravity	\mathbf{r}	Density
f	Porosity	S_i	Saturation of phase i
K	Absolute permeability tensor	\mathbf{s}_{wo}	Interfacial tension, water and oil
k_{ri}	Relative permeability of phase i	v	Darcy velocity
L	Length of core		
\mathbf{m}_i	Viscosity		Subscript/superscript
N_c	Capillary number	nw	Nonwetting phase
N_{RL}	Capillary number [9]	o	Oil
P_c	Capillary pressure	w	Wetting phase/ water
p	Pressure		

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