TECHNIQUES TO HANDLE LIMITATIONS IN DYNAMIC RELATIVE
PERMEABILITY MEASUREMENTS

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Abstract

The objective of this work was to understand the limitations of the conventional methods of calculating relative permeabilities from data obtained from displacement experiments.

The Johnson, Bossler and Neumann (JBN) method is the industry standard for measuring relative permeabilities from field cores. It is known that the relative permeabilities calculated by the JBN method from low rate displacements are often in error due to the capillary forces. Sometimes history matching methods are used to calculate the relative permeabilities. Generally 1-D numerical models, that assume uniform initial saturation distribution, are used for this purpose.

The pressure drop and recovery data generated from 2-D, r-z numerical simulations were used to study the errors introduced in the calculated relative permeability curves when using the JBN method. The results indicate that, because of the saturation gradients in the core, the relative permeabilities obtained from the JBN method show large errors at low water saturations.

In this study, using the CT scanner to measure in situ saturations, it was observed that even at relatively high rates there are saturation gradients in the core after the drainage displacements. These saturation gradients cause additional pressure drop through the core. It is therefore recommended that control experiments should be conducted using some in situ saturation measurement technique to determine the extent of the end effects and the saturation gradients in the cores.

The Berea sandstone cores, used in this study even after baking to deactivate the clays, were found to be sensitive to the brine used in the experiments. It is therefore necessary to conduct the laboratory experiments using fluids which are compatible with the rock.

From the analysis of the experimental data using both the JBN and the history matching methods, it was observed that both the imbibition and drainage relative permeability curves and the end point saturations are functions of rate. It is therefore necessary to conduct relative permeability experiments at rates comparable to the expected reservoir flow conditions.

Results from the history matching technique have shown that it is necessary to start the simulations with the correct saturation distribution in the core. The imbibition permeabilities determined by the history matching method are poorly defined because of the piston like displacement in the strongly water wet system. The relative permeabilities obtained from the history matching method have also shown a strong dependency on the rate.

The comparison of the relative permeabilities obtained by the two methods have shown that the relative permeabilities of the non-wetting phase obtained by JBN were consistently lower than those obtained by the history matching method. This trend is even observed at the high rate displacements. The relative permeabilities curves for the wetting phase were almost identical, except that the JBN method only defines the curves for saturation values higher than that at the time of breakthrough.

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Chapter 1

Introduction

The fluid flow properties of reservoir rocks are the most important parameters required for reservoir engineering studies. These properties include the absolute permeability, the relative permeabilities to the fluids and the capillary pressure functions. The absolute permeability of a reservoir rock is defined as the ease with which a fluid, which completely saturates the medium, flows through the rock under an applied potential gradient. The absolute permeability, k , is the proportionality constant in Darcy's law. Darcy's law states that the flow of a fluid in a porous medium, q , is directly proportional to the applied potential gradient, $d\phi/dl$ and the area of the porous medium perpendicular to the direction of flow, A , and is inversely proportional to the viscosity of the fluid, μ , i.e.

$$q = -\frac{kA}{\mu} \frac{d\phi}{dl} \quad (1.1)$$

the potential gradient is given by:

$$\frac{d\phi}{dl} = \frac{dp}{dl} - \rho \frac{g}{g_c} \cos \theta \quad (1.2)$$

Here p is the pressure, θ is the angle between the direction of flow and the vertical taken in the downward direction, ρ is the fluid density, g is the gravitational acceleration and g_c is the constant in Newton's equation. Generally, flow experiments in the

laboratory are conducted in horizontal cores, and the gravity term drops out from Eq. 1.2. Darcy's law (Eq. 1.1) then reduces to:

$$q = -\frac{kA}{\mu} \frac{dp}{dx} \quad (1.3)$$

In this equation dp/dx is the pressure gradient in the direction of flow.

The concept of absolute permeability has been extended to multiphase flow by introducing the concept of effective permeability. The fluids present in the porous medium are often classified to be either wetting or non-wetting, depending upon their preferential ability to spread on the rock grains. Sometimes neither of the fluids is strongly wetting or non-wetting. In this case the system is said to have intermediate wettability. This condition is the most prevalent one in petroleum reservoirs.

The original work on the physics of two phase flow was done by Wyckoff and Botset (1936). They introduced the idea of using the effective permeability to each fluid present in the rock in Darcy's law to quantify the fluid flow behavior in the porous material. The effective permeability to each phase is defined by:

$$k_{ei} = \frac{q_i \mu_i}{A(dp/dx)_i} \quad (1.4)$$

In this equation k_{ei} is the effective permeability. The subscript, i , represents either the wetting or the non-wetting phase.

Chatenever and Calhoun (1952) concluded from visual studies conducted with glass bead micro models, that for a large range of flow rates the two fluids established their own independent paths. In their view, this confirmed the validity of Darcy's law for two phase flow.

The effective permeability to each phase increases as its saturation increases. It is zero at the irreducible saturation of the phase and is maximum at the maximum phase saturation. The effective permeability is usually converted to relative permeability by dividing it by a reference permeability. This allows the comparison of different systems with different absolute permeabilities. The choice for the reference permeability is arbitrary and can be any of the following:

1. Absolute permeability to one of the phases.
2. Klinkenberg corrected gas permeability.
3. Non-wetting phase effective permeability at irreducible wetting phase saturation.
4. Wetting phase effective permeability at irreducible non-wetting phase saturation.

Most often the non-wetting phase permeability is used as the reference permeability. Nevertheless it is important to state which reference permeability has been used to convert the effective permeabilities to relative permeabilities.

The relative permeabilities not only depend on the saturation of the phases but also on the saturation history. If the wetting phase saturation is increasing, the displacement process is termed imbibition. If the wetting phase saturation is decreasing, the process is called drainage. The difference between the drainage and imbibition permeabilities is called hysteresis.

Geffen et al. (1951) presented a comprehensive study on the different methods available for determining relative permeabilities of reservoir rocks. They divided the methods into the following four categories:

1. Estimation from past reservoir performance and extrapolation.
2. Use of published laboratory data from studies on similar porous media.
3. Deriving the flow equations, using known laws of fluid dynamics, and using some experimentally measurable characteristics of the reservoir rock, and
4. Direct measurement of the flow characteristics in the laboratory using representative rock and fluid samples.

They observed that the first three methods have shortcomings which make their use questionable. The reservoir performance data is only available for limited types of flow processes, and is not readily available during the early life of the reservoir. For the second method, the published data from other porous materials may not be applicable

to the reservoir under study. For the third method, the physics of fluid flow is not understood well enough to derive accurate mathematical equations describing flow in the complex pore geometry of porous media. Thus, they concluded that the direct measurement of the relative permeabilities in the laboratory, using representative core samples from the reservoir under study, is the only reliable method for obtaining relative permeability data. And even this technique can have some problems, as will be discussed latter.

Saraf and McCaffery (1981) published a comprehensive study of methods of determining two and three phase relative permeabilities. They agreed with the conclusions of Geffen et al. (1951) that, for two phase flow, experimentally measured relative permeabilities are better than the theoretically determined values. Recent developments in computer technology, resulting in faster and cheaper computers, have rekindled the interest in theoretically predicted relative permeability curves.

A brief review of the methods available for determining relative permeabilities from measured rock properties is presented next.

1.1 Mathematical Models for Calculating Relative Permeabilities

Engineers and scientists have attempted to develop equations, using basic laws of physics and fluid dynamics and some easily measurable properties of the porous media, to describe the flow of fluids through those media.

Purcell (1949) used a parallel capillary tube model of the porous media and presented an equation to calculate absolute permeabilities from capillary pressure data. The capillary pressure data is used to obtain the apparent pore size distribution. Poiseuilles' equation is then used to calculate the absolute permeability.

Gates and Lietz (1950) modified Purcell's model to calculate the relative permeability to the wetting phase by assuming that at any water (wetting phase) saturation only the smallest capillaries are filled with water. They derived the following equation:

$$k_{rw} = \frac{\int_0^{S_w} \frac{dS_w}{P_c^2}}{\int_0^1 \frac{dS_w}{P_c^2}} \quad (1.5)$$

where, k_{rw} is the relative permeability to the wetting phase, S_w is the wetting phase saturation, and P_c is the capillary pressure at that saturation.

Fatt and Dykstra (1951) included a tortuosity factor, τ , in the relative permeability equation. They assumed that the tortuosity varies inversely with the capillary radius, and can be calculated from pore radii r by

$$\tau = \frac{a}{r^b} \quad (1.6)$$

where a and b are constants for a particular medium. Their final equation is:

$$k_{rw} = \frac{\int_0^{S_w} \frac{dS_w}{P_c^{2(1+b)}}}{\int_0^1 \frac{dS_w}{P_c^{2(1+b)}}} \quad (1.7)$$

Their work indicated that the value of the constant b is around 0.5.

Burdine (1953) observed that the tortuosity factor, τ , depends on the saturation of the wetting phase. He developed the following equation to approximate the tortuosity factor:

$$\tau = \left(\frac{S_w - S_{wi}}{1 - S_{wi}} \right)^2 \quad (1.8)$$

Using this definition of tortuosity he developed the equations for the wetting and non-wetting phase relative permeabilities. His original equations were developed using the pore size distribution of porous media. Corey (1954) presented Burdine's equations in terms of the capillary pressures. The wetting phase relative permeability is then given by:

$$k_{rw} = \left(\frac{S_w - S_{wi}}{1 - S_{wi}} \right)^2 \frac{\int_0^{S_w} \frac{dS_w}{P_c^2}}{\int_0^1 \frac{dS_w}{P_c^2}} \quad (1.9)$$

here S_{wi} is the irreducible wetting phase saturation. The non-wetting phase relative permeability is given by

$$k_{rnw} = \left(\frac{S_n - S_{wi}}{1 - S_{nr} - S_{wi}} \right)^2 \frac{\int_0^{S_w} \frac{dS_w}{P_c^2}}{\int_0^1 \frac{dS_w}{P_c^2}} \quad (1.10)$$

In this equation S_n is the nonwetting phase saturation and S_{nr} is the irreducible non-wetting phase saturation.

Corey (1954) observed that there is a linear relationship between $1/P_c^2$ and the normalized saturation defined by

$$S_{we} = \frac{S_w - S_{wi}}{1 - S_{wi}} \quad (1.11)$$

Using this relationship in the equations given by Burdine he suggested using the following two equations for the wetting and non-wetting phase relative permeabilities.

$$k_{rw} = S_{we}^4 \quad (1.12)$$

and

$$k_{rn} = (1 - S_{we})^2 (1 - S_{we}^2) \quad (1.13)$$

Wyllie and Gardner (1958) concluded, from a randomized capillary tube model, that the tortuosity of any phase in the porous medium at any saturation can be approximated by the square of the normalized saturation of that phase. They suggested using the following equations for the relative permeability of the water, oil and gas phases, respectively:

$$k_{rw} = (S_w^*)^2 \frac{\int_{S_{wi}}^{S_w} \frac{dS_w}{P_c^2}}{\int_{S_{wi}}^{1.0} \frac{dS_w}{P_c^2}} \quad (1.14)$$

$$k_{ro} = (S_o^*)^2 \frac{\int_{S_{wi}}^{S_L} \frac{dS_w}{P_c^2}}{\int_{S_{wi}}^{1.0} \frac{dS_w}{P_c^2}} \quad (1.15)$$

and

$$k_{rg} = (S_g^*)^2 \frac{\int_{S_{wi}}^{1.0} \frac{dS_w}{P_c^2}}{\int_{S_{wi}}^{1.0} \frac{dS_w}{P_c^2}} \quad (1.16)$$

In the above equations they defined S_L to be the liquid phase saturation and S_w^* , S_o^* and S_g^* are the normalized water, oil and gas phase saturations. These saturations are given by

$$S_w^* = \frac{S_w - S_{wi}}{1 - S_{wi}} \quad (1.17)$$

$$S_o^* = \frac{S_L - S_w}{1 - S_{wi}} \quad (1.18)$$

and

$$S_g^* = \frac{1 - S_L}{1 - S_{wi}} \quad (1.19)$$

It should be noted that although they approached the problem using a very different method, for a two-phase systems, their results are identical to those give by Burdine.

Wyllie and Gardner simplified Eqs. 1.14 and 1.15 by assuming that there is a linear relationship between $1/P_c^2$ and S_w^* . Their resulting simplified equations are,

$$k_{rw} = (S_w^*)^4 \quad (1.20)$$

and

$$k_{ro} = (1 - S_w^*)^2 [1 - (S_w^*)^2] \quad (1.21)$$

These two equations are identical to those of Corey, i.e., Eqs. 1.12 and 1.13.

It is well known that the saturation history is an important parameter affecting multiphase flow in porous media. The above mentioned models work only for drainage displacements. For imbibition, these equations predict higher relative permeabilities for the non-wetting phase, than found experimentally.

Narr and Henderson (1961) developed a model for imbibition relative permeability for the non-wetting phase. They used a modified Wyllie and Gardner (1958) random capillary tube model to calculate the non-wetting phase saturation trapped during the imbibition process. They derived the following equation for normalized imbibition water saturation, $S_{w,imb}^*$, as a function of normalized drainage saturation, $S_{w,dr}^*$;

$$S_{w,imb}^* = S_{w,dr}^* - 0.5 S_{w,dr}^{*2} \quad (1.22)$$

This equation accounts for the trapping of the non-wetting phase in the imbibition process. They assigned the k_{ro} calculated at $S_{w,dr}^*$ to $S_{w,imb}^*$, and thus were able to calculate the relative permeability of the non-wetting phase for the drainage process as well.

Percolation theory was introduced by Broadbent and Hammersley (1957). In their work, the porous medium is represented by a network of interconnected channels. Simple flow equations are applied to each channel to describe fluid flow. The occupancy of the fluids (defined as the relative number of the channels filled with the particular fluid) in the channels determines their effective permeability.

Helba et al. (1992) have used percolation theory to model two phase flow in porous media using a Bethe network model. In this method the pore space is modeled with an endlessly branching structure, with no closed loops, that is characterized by a coordination number. The coordination number is defined as the number of bonds

that join at each interior node. The bonds are defined as the channels connecting different pores together and essentially are representative of the pore throats. They tested different pore throat radii distributions and coordination numbers to model porous media. They matched the experimental data with results from their model by changing the parameters which describe the flow properties of bonds. Although they showed a good match between experimental data and the relative permeabilities calculated by their model, the use of their model for predicting relative permeabilities is questionable because of the need to fit the results of the model to experimental data.

Blunt et al. (1992) reported that the percolation model does not represent the fluid connectivity properly. They presented results from a 3-D network model of the porous medium. In their model the porous medium is represented by a cubic lattice of spherical pore bodies interconnected with cylindrical tubes. Their model also took into account the flow in the thin films of wetting phase sticking to the grains. This 3-D model allowed them to study the effect of the force of gravity on displacements. They observed that the pore scale simulations provide a tool to understand the mechanics of multiphase fluid flow in porous media.

The mathematical models discussed in this section are tools to understand the mechanics of fluid flow in porous media. They use simplified geometry for representing the complex structure of pores and their interconnections. It is unlikely that these models can predict the relative permeabilities of the real porous media with any accuracy. As pointed out by Saraf and McCaffery (1981) the models have not been tested extensively against measured laboratory relative permeabilities. It is therefore advisable to use experimental methods to obtain specific relative permeability relationships for specific reservoir engineering applications.

1.2 Measuring Relative Permeabilities

A brief review of the methods used to measure relative permeabilities in the laboratory will be presented. These methods can be divided into three categories: (i) steady state methods, (ii) unsteady state or displacement methods, and (iii) centrifuge methods.

1.2.1 Steady State Methods

In the steady state method, generally both wetting and non-wetting phases are injected simultaneously into the core. The pressure drop and the saturations are measured when the system has reached steady state, i.e. the pressure drop across the core and the saturations are not changing with time. The pressure drop across the core along with the flow rates and fluid viscosities are used in the modified Darcy's law (Eq. 1.4) to calculate the effective permeabilities. The saturations of the phases are varied by changing the ratio of the flow rates of the fluids. Thus the relative permeability curves can be determined over a representative range of saturations.

The steady state method requires the determination of fluid saturations in the core as well as the pressure gradient in both phases and the individual phase flow rates. Ideally the pressure gradients and the saturations should be measured across a section of the core which has uniform saturation.

Leverett (1939) measured the relative permeabilities to oil and water in unconsolidated sands using the steady state method. He concluded that the capillary discontinuities at the ends of the core caused errors in pressure measurements, especially at low flow rates. He also concluded that the measured relative permeabilities were essentially independent of the viscosities of the fluids, but were related to the pore size distribution of the rock, the displacement pressure, the pressure gradient and the water saturation.

Since the early work on relative permeability measurements by Leverett indicated the presence of capillary end effects, researchers have tried to find ways either to eliminate or minimize these effects on measurements.

Hassler (1944) presented a method to measure gas and oil relative permeabilities in which semi-permeable plates are used at the ends of the core, allowing the fluids to flow separately outside the core. In this method the pressure drops in the gas phase are adjusted to equalize the capillary pressures at the inlet and outlet ends of the core. This procedure should result in a uniform saturation inside the core, thus eliminating the end effects. Osoba et al. (1951) reported that this method gives oil relative permeabilities which are consistently less than those measured by the dynamic and Penn State methods. In the dynamic method, as reported by Osoba et al. (1951),

both fluids are injected and produced from the same ports at the end of the core. The capillary effects are minimized by using high flow rates.

Morse et al. (1947), working at the Pennsylvania State University, developed a method in which three pieces of the core material are butted together in a core holder. The upstream piece acts as a mixing zone, where incoming wetting and non-wetting phases mix together. The pressure drop and the saturations are measured in the middle section. The capillary end effect is confined to the third, down stream, section. The saturations are measured by removing the central core from the core holder and weighing it after each saturation step. Caudle et al. (1951), Osoba et al. (1951), and Geffen et al. (1951) compared this method with others available at that time, and reported that it gives consistent and reliable results. It should be noted that the disassembly of the core after each saturation step can cause errors in saturation measurements, because of loss of fluids when isolating and weighing the core. Osoba et al. (1951) reported that the capillary contact between the three pieces of the composite core is also questionable. They also reported that the end effects may not be confined to the end plugs only.

Leas et al. (1950) used semi-permeable plates at both ends of the core to keep the liquid phase stationary, while flowing a gas phase through the core. The core was initially completely saturated with oil. The oil saturation was reduced by injecting gas into the core, bypassing the semi-permeable plates under a constant pressure difference between the oil and gas phases. After the equilibrium saturation had been achieved, the gas was injected through the core at a very low flow rate. The low flow rate helped in minimizing the saturation gradient in the core. This method could be used to measure the relative permeability of the gas phase only. The assumption of uniform saturation distribution throughout the core is questionable.

Rapoport and Leas (1951) used a similar method to measure the relative permeability to the liquid phase, while keeping the gas phase stationary. The gas was held in place by semi-permeable plates at both ends of the core. Loomis and Crowell (1962) used a combination of these two methods to measure the relative permeabilities of both phases. In this method, since one of the phases is not allowed to flow, the flow mechanism is unrealistic, and the results obtained are questionable.

Early researchers, Terwilliger et al. (1951), Richardson (1957), and Johnson et al. (1959), indicated that the steady state and the displacement methods (in which only one fluid is injected into the core and which will be discussed in the next section) give similar results. Latter Handy and Data (1966), and Amaefule and Handy (1981) concluded that because the saturation distributions differ in the steady state and displacement processes, the relative permeabilities also differ.

1.2.2 Unsteady State Methods

In unsteady state methods only one of the phases is injected into the core. The core is at the irreducible saturation of the displacing phase. The recovery and pressure drop across the core are recorded during the displacement process. The relative permeabilities are then calculated by either the Johnson, Bossler and Neumann (1959)(JBN) method or by the history matching techniques.

Buckley and Leverett (1942) developed the equations governing the displacement of one fluid by another in a porous medium. They assumed linear, incompressible flow, and negligible capillary forces.

Welge (1952) presented a method based on the Buckley–Leverett (1942) theory to calculate the ratio of relative permeabilities. He also presented a method for calculating the recovery from a reservoir under gas or water drive.

Johnson et al. (JBN) (1959), based upon Welge’s solution of the flow equation, developed for the first time a method to calculate the individual phase relative permeabilities from displacement data. The experiments need to be conducted at high enough flow rates so that the capillary forces can be neglected. The other assumption mentioned by the authors is that the flow rate is constant at all cross sections of the core, thus the flow is incompressible. Although not mentioned in their paper, an essential requirement for the method to work is that the core must have an initial uniform saturation distribution. This method requires the differentiation of the data to calculate relative permeabilities. This method generally gives relative permeabilities over a fairly small saturation range, which varies depending on the relative mobilities of the flowing fluids.

Jones and Roszelle (1978) presented an extension of the JBN method for calculating the relative permeabilities. They proposed a graphical technique to do the necessary differentiation of the production data required by the JBN method. Their method allows the analysis of the late time data. They also developed a graphical method to calculate individual relative permeabilities from the pressure/production history of the displacements. The JBN method can only be applied to constant rate displacements whereas the Jones and Roszelle method can also be used for displacements conducted at constant pressure drop across the core, or even when both rate and pressure drop vary with time.

Miller (1983) used a curve fit on the recovery and the pressure drop data from oil–water displacement experiments. He then used these curve fitted forms in the JBN analysis to calculate the relative permeabilities. He imposed the conditions that the equations describing the recovery and the pressure drop be smooth and monotonic, and that the resulting relative permeabilities should be smooth and look like conventional relative permeability curves. By imposing these conditions he also eliminated the possibility of any strange relative permeability curve shapes.

Archer and Wong (1973) reported that the JBN method gives erroneous results in mixed wettability and/or heterogeneous cores, because of the high flow rates required to eliminate the capillary end effects. They observed that for such systems the relative permeability curves obtained by the JBN method can have strange shapes. They proposed a computer model that could be used to history match the recovery and pressure drop data from low rate displacement experiments to obtain the relative permeabilities. They used a linear core model for their simulations. The history matching was done by a trial and error procedure. They assumed parametric forms for the relative permeability curves. In this way they eliminated any possibility of getting strange shaped relative permeability curves.

Sigmund and McCaffery (1979) proposed an automatic history matching technique. They proposed using a nonlinear method, like Gauss–Newton, to history match the data. They included the capillary pressure term and outlet capillary end effect in a numerical model, as suggested by Settari and Aziz (1974). This allows the buildup of wetting phase saturation at the outlet end. To properly include the

effects of capillary forces in a numerical model, the capillary pressure function must be evaluated independently in the laboratory.

Batycky et al. (1981) modified the method proposed by Sigmund and McCaffery (1979). They measured capillary pressure by the mercury injection method. Their history matching is done in two steps. During the first step the capillary pressure curve, applicable to the oil–water system under study, and the connate water saturation are determined. The assumption is made that, over the saturation range of interest, the oil–water and mercury–air curves scale linearly with the ratio of the interfacial tensions in the two systems. In the second step the relative permeability curves are determined by automatic history matching.

Evans, et al. (1985) included an inlet plenum in their numerical model, which they used for history matching laboratory displacement data. This geometry allowed for the water injection rate into the core to change over time rather than assuming a step change at the beginning of the injection.

Islam and Bentson (1986) measured the saturations and pressure profiles along the length of a sand pack. They measured the saturations by the microwave absorption method. The pressure profiles were measured by putting taps along the length of the core. They calculated local fractional flows by using the saturation profiles at different times. The local fractional flows and pressure drops in the water phase were used to calculate relative permeabilities. They claimed the method to be independent of the errors caused by the end effects. In their analysis they assumed the capillary pressure gradients were negligible.

Qadeer (1988) reported that these history matching methods do give satisfactory results for matching the recovery and pressure drop data in drainage displacements. In the case of imbibition displacements though, during the early stages of floods the history matched pressure drop data show some errors.

1.2.3 Centrifuge Methods

Centrifuges have been used to measure the capillary pressure of porous rocks since 1944 (Hassler and Brunner). Haggort(1980) used the data from gas–oil centrifuge

experiments to determine the oil relative permeability curves. He assumed that the capillary number N_{cg} defined by:

$$N_{cg} = \frac{\sigma \phi^{0.5}}{k \Delta \rho_{og} g L} \quad (1.23)$$

is small and the capillary forces behind the front, where the saturation gradients are small, can be neglected. In this equation σ is the interfacial tension, ϕ is the porosity, $\Delta \rho_{og}$ is the difference in the density of the gas and oil, and g is the acceleration due to gravity. In his derivation he also assumed that the mobility of the gas phase is much higher than that of the oil phase.

O'Meara and Crump (1985) obtained oil relative permeability and gas–oil capillary pressure from centrifuge experiments conducted at differing speeds. In their method the capillary pressure is determined by the data obtained at nearly stabilized conditions at the end of each run. The relative permeabilities are determined by history matching the transient production data from the centrifuge experiment. They concluded from their work that the history match gives a unique solution.

Firoozabadi and Aziz (1991) used a numerical simulator to history match data from centrifuge experiments to infer the relative permeabilities of both wetting and non–wetting phases. They concluded that for a fixed capillary pressure curve the solution for the relative permeabilities is unique. But, if the capillary pressure curve is changed a completely different set of relative permeabilities gives a similar match. They therefore concluded that simultaneous determination of capillary pressure and relative permeabilities from centrifuge data can give non unique solutions.

1.3 Measurement of Saturations

In any relative permeability measurement method it is important to know the saturations of the fluids in the core as accurately as possible. Earlier researchers have generally used gravimetric, electrical or volumetric material balance methods to evaluate the saturations. Recently methods which allow in–situ saturation measurements

are becoming more popular. These include radiation adsorption methods using, X-rays, gamma-rays or microwaves and nuclear magnetic resonance measurements.

Leverett (1939) used electrical conductivity measurements on various sections of the core to determine the saturation profile along its length. In this method the electrical conductivity of cores with known saturations is measured. These measurements are used to draw a calibration curve which is used in the experiments to find saturations from the resistivity measurements. Polarization of the electrodes can result in errors in these measurements.

In the Penn State method, after Morse et al.(1947), the saturations are determined by disassembling the core holder and weighing the core. The fluid loss and damage to the core during the disassembly and reassembly process can cause errors in the measured saturations and the resulting relative permeabilities.

The volumetric material balance has been a standard procedure in the industry for measuring the saturations during unsteady state displacements. The use of this technique has been further facilitated by Hvolboll (1978) who proposed a method of recirculating the fluids. In this method the fluids from the core are produced into a separator, and the separated fluids are reinjected into the core. The relative volume of the fluids in the separator are measured with time, and the saturations in the core are determined by volumetric balance.

The separator level can be measured visually as done by Miller(1983). Torabzadeh and Handy (1984), used a differential pressure transducer to determine the level of fluids in the separator. In their method the transducer response needs to be calibrated for each flow rate because flow rate effects the pressure drop across the separator.

Saraf et al. (1982) proposed a method in which the level of the fluids is measured by a computer controlled photometric scanner. This method has the advantage that calibration is not required at different flow rates, but suffers from the fact that the instrumentation is more involved.

Qadeer (1988) used a commercially available high temperature, high pressure separator to measure the saturations in dynamic displacement experiments. In this separator the liquid level is measured by the time taken for an ultrasonic wave pulse

to travel from one end of the separator to the liquid interface and back. Real time calibration uses simultaneous measurements of travel time for a known distance through one of the phases in the separator. Thus errors caused by the change in the sonic wave velocity, due to the changes in the density of the fluids, are eliminated.

Sufi and Brigham (1982) measured the oil recovery from displacement experiments by using a photo cell and a frequency counter. The frequency counter essentially measures the cumulative time the oil is flowing through the photo cell. By knowing the rate of injection into the core, total oil produced can be calculated as a function of time. This method has the advantage that a properly designed cell can be placed very close to the outlet of the core, thus avoiding errors associated with hold up of fluids in the tubing, and resulting material balance errors.

Saraf and Fatt (1967) used nuclear magnetic resonance (NMR) imaging to measure in situ saturations in three phase relative permeability experiments. In this method, certain molecules, e.g. hydrogen are excited by a strong external magnetic field. The molecules in turn emit electromagnetic radiation which is measured to determine the concentration of the particular molecule being tracked in the medium. In their experiments they used heavy water (deuterium oxide), kerosene oil (which contains hydrogen atoms), and nitrogen. They kept the saturation of water constant for a particular run by keeping the flow rate of water and the pressure drop constant. The saturation of the kerosene was determined by the NMR technique. Material balance calculations were used to determine the saturation of the gas phase.

Parson (1975), introduced the use of microwave absorption to determine the in-situ saturations in displacement experiments. His method used high energy microwave radiation and required the use of large slabs of material with a rectangular cross section. Brost and Davis (1981) improved on Parson's technique so the method could be used for saturation determinations in laboratory floods of field cores which have circular cross sections. They used carefully selected microwave frequencies which allowed them to use lower energy levels and thus smaller equipment. The field cores are potted in epoxy resin. Microwave absorber rods were embedded in the epoxy mold. These absorber rods prevented the microwave energy from reaching the detectors without passing through the core.

Davis (1983) included a computer controlled scanning mechanism to scan rectangular slabs of porous materials. The scanning mechanism moves the microwave source and detectors through a 2-D grid. Saturations were measured at known locations on the grid. This technique allows the construction of areal saturation maps in cores with rectangular cross sections.

Willington and Vinegar (1987) used a medical X-ray CT scanner to map saturations in cores during laboratory floods. The X-ray absorption coefficient of different materials is a function of the energy level of the X-rays. Thus by conducting the scans at two energy levels, it is possible to obtain the saturations of all three phases in 3-phase experiments. The scanner creates 2-D saturation maps at each scan location. 3-D saturation maps can be constructed by stacking the 2-D images along the third dimension. This method can also be used, in separate experiments, to determine the porosity, density, and atomic weight variations of the cores.

1.4 Effect of Capillarity on Fluid Flow

The problem of capillary pressure and associated saturation gradients within the core were recognized by early researchers in the petroleum industry: (e.g. Leverett(1939), Morse et al. (1947), and Rapoport and Leas(1951)). Some methods were developed to minimize the end effects. It was not until about 1953 that attempts were made by Rapoport and Leas to qualitatively understand the effects of capillary forces on the displacement process.

Rapoport and Leas (1953) introduced the scaling factor, $L_{\mu v}$, to define the range of flow rates in which the capillary forces affect flow in linear systems. They concluded that if the value of the scaling factor was greater than 10 cm-cp/min, the flood becomes stabilized, i.e. the recovery from the core becomes independent of the flow rate. In their view, at such conditions the Buckley–Leverett theory is applicable.

Moore and Slobod (1956) presented the concept of a pore doublet model to study the relative importance of capillary and viscous forces in imbibition displacement processes. Their results indicated that the recovery from a strongly water wet system is practically independent of the flow rate and the oil is trapped in the larger

pores. On the other hand, in a strongly oil wet system the oil is trapped in the smaller pores. They suggested using $v\mu L/\sigma\cos\theta$ as a scaling factor for intermediate wettability systems.

Hadley and Handy (1956) studied the effect of capillary forces on the steady state end effect. They observed the saturation gradients in both steady state and dynamic displacement experiments. They pointed out the need to measure the pressure drops in both phases for accurate determination of the relative permeabilities.

Kyte and Rapoport (1958) discussed the importance of conducting displacements at high pressure drops to minimize the errors caused by the capillary forces. They also pointed out that these high pressure drops and resulting high flow rates might cause instability and early breakthrough.

Douglas et al. (1958) were the first to present a finite difference method to solve the equations which included capillary forces. They simulated the flow of fluids in a linear system using a second order finite difference formulation.

Fayers and Sheldon (1959) compared the Eulerian and Lagrangian formulations of numerical solutions for linear flow problems. They observed that the capillary and gravity forces are important only at low flow rates. They stated that the Lagrangian method gives better results for calculating the shape of the saturation profiles, whereas the Eulerian method should be used for slow rate displacements in which accurate results near the inlet boundary are required.

Bentson (1978) investigated the flow conditions under which the capillary term can be neglected in flow equations. He used a numerical simulator to study displacements at differing flow rates. He postulated that if the value of the Capillary Number, N_c , defined as $\sigma Ak_{rw}/qL\mu_w$, is less than 0.01 the capillary forces can be neglected and the Buckley–Leverett solution can be used.

The effect of capillarity on fluid flow in one dimensional problems has been extensively studied. It is well recognized that capillary end effects cause errors in the analysis of displacement data by standard methods for the determination of relative permeabilities. Researchers have usually recommended that flow experiments be conducted at high rates to minimize these errors. Peters and Flock (1981) determined the flow conditions which will cause instability of flow. They based their analysis on

perturbation theory. From their analytical and experimental results they determined the critical value of a dimensionless stability number, I_{sc} , to predict the onset of instability in the displacement process. For horizontal, cylindrical cores the stability number is given by:

$$I_{sc} = \frac{(M - 1)v\mu_w D^2}{C^* \sigma k_{wor}} \quad (1.24)$$

where M is the mobility ratio, D is the diameter of the core, C^* is a wettability number to be determined experimentally, and k_{wor} is the water permeability at residual oil saturation. This analysis is valid for a water flood. Similar analysis can be done for an oil flood. In their analysis they neglected the effect of perturbations caused by non uniform injection at the inlet end. For their experiments, conducted on sand packs, the critical number was 13.56. They observed that if I_{sc} is greater than 13.56, the displacement is unstable.

Peters and Khatanier (1987), from an experimental study conducted on sand packs, concluded that the relative permeabilities calculated from the data obtained from displacement experiments are affected by the instability of the displacements. They compared the relative permeabilities calculated by the JBN method at different stability numbers. They observed that as the instability increases, in imbibition displacements, the calculated relative permeability to oil decreases and that of water increases. They recommended conducting laboratory experiments at stability conditions similar to those in the reservoir.

1.5 Related Work

Lefebvre du Prey (1973) did a comprehensive study of the effects of different rock and fluid properties on their relative permeabilities. He studied the effect of viscosity, interfacial tension and the fluid velocity through a dimensionless group, he called, π , defined as $\sigma/\mu v$. He varied interfacial tensions, viscosities and fluid velocities in his experiments. His work indicated that for a given porous medium the relative permeabilities are affected by the viscosities of the fluids and the interfacial tension

between them. He also observed that as π increases, the relative permeabilities to both fluids decrease at a given saturation.

Fulcher et al. (1983) studied the effect of the Capillary Number, N_c , and its constituents, (viscosity, flow velocity, and the interfacial tension) on relative permeabilities. They defined the capillary number as:

$$N_c = \frac{\mu v}{\gamma \phi} \quad (1.25)$$

where μ is the viscosity of the injected fluid, v is the velocity of fluids, γ is the interfacial tension, and ϕ is the porosity of the porous medium. They conducted steady state experiments using Berea sandstone cores. They came to conclusions similar to those of Lefebvre du Prey (1973). They further concluded that at very low interfacial tensions the relative permeability curves straightened out and approached the expected straight line shapes for completely miscible systems with unit viscosity ratio.

Heaviside et al. (1983) presented the results from an experimental and theoretical study of fundamentals of relative permeabilities. They concluded that the concept of relative permeabilities is only valid for drainage displacements. They stated that, for imbibition displacements, the displaced phase becomes discontinuous at high non-wetting phase saturation and thus the concept of relative permeabilities does not hold. They also observed that during the imbibition process there is counter-current flow of the phases.

Odeh and Dotson (1985) suggested a method for reducing the errors in drainage relative permeabilities caused by the capillary end effects in water wet systems. They observed that, at high oil saturations, the relative permeability curves measured at high flow rates are more or less independent of the flow rate. They also observed that a plot of the ratio of relative permeability to oil and the oil flow rate, k_{ro}/q_o , versus the average saturation, $\bar{S}_w$, was a straight line at high oil saturations. They assumed that, in this region, the oil relative permeabilities are not affected by the capillary end effect. They suggested that this line be extended over the entire saturation range for which the relative permeabilities are to be calculated. The corrected relative

permeabilities for the oil are then given by:

$$(k_{ro})_{cor} = k_{ro} \frac{(q_o/k_{ro})_C}{(q_o/k_{ro})_{SL}} \quad (1.26)$$

Here $(k_{ro})_{cor}$ is the corrected oil relative permeability, k_{ro} is the relative permeability to oil calculated by the JBN method, $(q_o/k_{ro})_C$ is the ratio of flow rate to the relative permeability of oil as calculated from the JBN method, and $(q_o/k_{ro})_{SL}$ is the value of this ratio as read from the straight line drawn in the first step. The corrected k_{ro} 's can then be plotted against the outlet saturation as used in the JBN method. They showed good agreement between relative permeabilities, corrected by their method, and steady state measurements. They presented similar equations for correcting water relative permeabilities. They observed that the imbibition relative permeabilities for water wet systems are essentially independent of rate.

1.6 Summary

It can be inferred from the above discussion that the following four methods have been in use for the determination of the relative permeabilities.

1. Mathematical Models,
2. Steady State Methods,
3. Unsteady State Methods, and
4. Centrifuge Methods.

The use of mathematical models suggested by Purcel in 1949 and improved by recent researchers still needs much more refinement, as the basic equations governing the flow in the individual pores and channels is not well understood. Even when the equations fully describe the complex flow system and are proven, there is still the need to know the actual flow geometry and the rock–fluid interactions in terms of, for example, interfacial tension, which are very difficult to understand.

The fluid flow in the reservoir is generally an unsteady state process, where one fluid is displacing the other. The representation of this by relative permeabilities measured in a steady state experiment is questionable. Other problems associated with the steady state experiments are the end effects caused by the capillary forces and the measurement of the saturations. Although modern techniques for measuring in situ saturations like CT scanners and micro waves, can be used, they are generally not available for routine experiments. There have been attempts made to reduce the end effects by using composite cores and taking the measurements on the central part of the core only, but it is difficult to ensure capillary contact between different pieces of the composite core and the confinement of the capillary end effect to the end piece of the core can not be guaranteed.

The unsteady state method is generally accepted as to be the closest to the flow mechanism in the reservoirs. The JBN method requires that the capillary effects should be minimized by conducting the experiments at high enough rates. However if the flow characteristics are not very similar in the experiments to those in the reservoir, the validity of the experimental data becomes questionable. Higher rates can cause unstable flow in the experiments and in such cases the concept of relative permeabilities does not hold.

The flow mechanism in centrifuge experiments is very different from that in reservoirs, except those going through gravity drainage. Therefore the use of this method for determining relative permeabilities for reservoir analysis has never gained popularity, although this method reduces the time to conduct experiments, especially on tight cores. This method also has the advantage that the experiments can be conducted using small core samples.

The objective of this study was to try to understand the problems associated with the unsteady state method of measuring relative permeabilities and to come up with possible solutions to these problems. In this study both numerical simulations and displacement experiments were conducted to achieve this goal. The numerical simulations and the analysis of the results obtained from them by JBN method were used to understand the flow mechanisms in the core at a much finer scale than was possible from the experiments and to quantify the errors associated with the JBN

technique of calculating the relative permeabilities. The experiments were conducted to understand the errors and associated problems.

The bulk of the work related to this dissertation was performed from 1989 to 1994. However due to a variety of circumstances it was not possible to complete the work at that time. The history matching runs were completed in the summer of 2001.

Chapter 2

Numerical Simulations and Error Analysis

In this study a commercial black oil simulator, ECLIPSE from GeoQuest (2000) was used. The simulator was used to study the flow geometry within the core, and also to obtain pressure drop and recovery predictions from known relative permeability and capillary pressure data. The details of the simulation study and the results from the JBN analysis conducted using the simulated data are presented in this chapter.

2.1 Numerical Simulations

It is important to select a proper gridding scheme to simulate laboratory core flood experiments. In this study cylindrical cores were used. In laboratory displacement experiments end plugs are used to distribute the fluids uniformly across the face of the core (see Chapter 3). To properly include the geometry of the distribution plugs in the simulations it is necessary to use a cylindrical grid. Preliminary simulations were conducted using a 2-D Cartesian grid to study the effect of gravity on the flow pattern. The saturation contours from one of these simulation runs are shown in Fig. 2.1. This run simulates a drainage displacement experiment conducted at an injection rate of 1.0 cc/min, the lowest rate used in the experiments. The contours clearly show that the effect of gravity is minor at these flow conditions. It was therefore concluded that

Figure 2.1: Saturation contours from 2-D, Cartesian grid simulation.

in the simulation runs the effect of gravity could be neglected, and a 2-D cylindrical grid, with the specific gravity of both oil and water equal to one, was used to simulate the laboratory floods.

The grid used is schematically shown in Fig. 2.2. It is a 2-D, r - z coordinate system. The z -axis runs through the axis of the core. After doing a sensitivity study it was decided, to use 16 grid blocks in the r -direction and 60 grid blocks in the z -direction. one additional grid block was added in the z -direction at each end of the core to simulate the distribution plugs. As it is much more convenient in the simulations to use a vertical z -axis, and the effects of gravity are negligible in the experiments, it was decided to use 2-D, r - Z simulations with a vertical z -axis. To completely eliminate the effects of gravity in this configuration, the specific gravity of both oil and brine were set to 1.0.

To study the effects of flow geometry on the results it is important to include the geometry of the end plugs in the simulations. The configuration of the distribution grooves in the end plugs used in the experiments is shown in Fig. 2.3. The fluids enter the end plug through a hole in the center, and distribute over the core face through the conducting radial and concentric grooves. This geometry is often used in relative permeability and other displacement experiments. These grooves were represented, at both ends of the core, by one layer of grid blocks with high permeability which was

Figure 2.2: Schematic of 2-D, r-z gridding for simulations.

ten times that of the core material, zero capillary pressure and straight line relative permeabilities. It should be realized that not all of the core face is open to flow. To take this into account, the permeability distribution in the z-direction, in the first and second last rows of blocks were set proportional to the surface areas of each groove, and not to the area of the face of the grid block representing the groove. The permeability of the second to last row was modified as upstream mobility is used in ECLIPSE to calculate the inter block transmissibilities. The appropriate portions of the radial lines in the “spider web” were also lumped into the transmissivity of the corresponding grid blocks. This permeability distribution is shown in Fig. 2.4. This arrangement permitted proper simulation of the nonuniform injection of the fluids in the core.

The relative permeability and capillary pressure data used in these simulations are shown in Fig. 2.5 and are tabulated in Appendix A. The relative permeability data were selected on a judgmental basis for these runs using representative end points for Berea sandstone. Note that water relative permeability is around 0.15 at irreducible oil saturation of 0.2, which is appropriate to a strongly water wet system. The capillary pressure curve was obtained by measuring the drainage capillary pressure for the high water saturations and by extrapolating some early information on the apparent connate water saturation from the displacement experiments. The connate

Figure 2.3: The groove pattern in the end plugs.

Figure 2.4: Permeability distribution used to represent the grooves in the end plugs.

Figure 2.5: Capillary pressure and relative permeability curves used in simulations.

water saturation was estimated from some preliminary experiments conducted to test and improve the design of the coreholder and the production system described in Chapter 3.

The sequence of simulated experiments is shown in Table 2.1. The simulations were started on a 100% brine saturated core. The first simulation was that of a primary drainage process at 8.0 cc/min. It was followed by an imbibition and drainage displacement cycle, both at 8.0 cc/min. These were followed by 4.0 and 1.0 cc/min. imbibition and drainage displacement cycles. The simulated time for each displacement was 24 hrs. It was observed that after 24 hrs of injection the fractional flow of

Displacement		Flow Rate (cc/min)
Primary Drainage	(PD)	8.0
Imbibition-1	(I1)	8.0
Drainage-1	(D1)	8.0
Imbibition-2	(I2)	4.0
Drainage-2	(D2)	4.0
Imbibition-3	(I3)	1.0
Drainage-3	(D3)	1.0

Table 2.1: Sequence of simulated displacements.

the displaced phase had dropped below 1.0E-6 and the pressure drop had stabilized.

2.2 Results from Simulations

The simulations provide insight at a much finer scale than the experiments. The saturation contours graphed at two different times for Imbibition-1 (8.0 cc/min) are shown in Fig. 2.6. The core inlet is at the bottom and the outlet is at the top of the figure. The center of the core is shown at 0.0 cm and the exterior radial boundary is at 2.44 cm in the figures. Comparing the position of the 65% and 70% saturation contours in the two graphs, it is obvious that the shapes of the contours change as they move through the core. This clearly shows that the flow pattern is not linear inside the core. The plots show that the flow lines are almost hemispherical near the faces of the core. The three “humps” in the 70% saturation profile in the 0.05 hr map correspond to the three concentric grooves of the inlet end plug. This clearly shows that the injected fluid predominantly enters the core through these grooves. The radial saturation gradient resulting from this uneven injection although not significant in this case may result in significant instability problems with fluids of unfavorable mobility ratio. Hence in such an unstable system, proper design of the end plugs could be quite important.

The average saturation profiles from the same simulation are shown for various times in Fig. 2.7. In this and all subsequent figures only selected data points are

Time= 0.050 hr

Time= 0.250 hr

Figure 2.6: Saturation maps from simulated imbibition (8.0 cc/min).

graphed for the sake of clarity. The computed data points at each end in this figure and also in Figures 2.9 and 2.10 correspond to the end plugs. The sharp jump in the saturation between the core and the end plugs is due to the capillary discontinuities. Note that the saturation distribution at 0.03 hr in Fig. 2.7 shows the severity of the non-monotonic changes in the saturation in the core during imbibition displacement. The wetting phase saturation is decreasing through the first half of the core and then it increases in the other half. This violates the assumption of monotonic changes required by the JBN analysis. The calculated saturation maps from the 8.0 cc/min drainage simulations at two different times are shown in Fig 2.8. Again the curvature on the saturation contours is quite obvious at 0.01 hr. The corresponding average saturation profiles are shown in Fig 2.9. Similar behavior was observed during the other displacement simulations for both imbibition and drainage.

The average saturation profiles from two imbibition simulations at 0.114 PV injection at rates of 1.0 cc/min and 4.0 cc/min are shown in Fig. 2.10. As the two displacements start from slightly different initial conditions, the breakthrough for the lower rate imbibition is somewhat earlier than that of the higher rate.

Simulations were also run with an oil to water viscosity ratio of 5.0 at 8.0 cc/min. The results are shown in Figures 2.11 to 2.14. These are similar to those for the unit viscosity ratio.

The pressure and recovery data obtained from these simulation runs were analyzed by the Johnson, Bossler and Neumann (1959) method to determine the errors introduced in the relative permeabilities by the assumptions made in the JBN analysis. The JBN method and the error analysis are presented in the subsequent sections of this chapter.

2.3 The JBN Method

Johnson et al. (1959) presented a method for calculating the relative permeabilities from data obtained during displacement experiments. Their method is based upon the earlier work of Welge (1952). The basic assumptions in their method are: (a) the flow is linear and incompressible, and (b) the flow rate is high enough that the

Figure 2.7: Average simulated saturation profiles at different times. Imbibition (8.0 cc/min).

Time= 0.010 hr

Time= 0.070 hr

Figure 2.8: Saturation maps from simulated drainage (8.0 cc/min).

Figure 2.9: Average simulated saturation profile at different times. Drainage (8.0 cc/min)

Figure 2.10: Comparison of simulated saturation profiles, Imbibition, (1.0 and 4.0 cc/min).

Figure 2.11: Saturation maps from simulated imbibition viscosity ratio 5.0 (8.0 cc/min).

Figure 2.12: Average simulated saturation profiles at different times. imbibition, viscosity ratio 5.0 (8.0 cc/min).

Figure 2.13: Saturation maps from simulated drainage viscosity ratio 5.0 (8.0 cc/min).

Figure 2.14: Average simulated saturation profiles at different times. drainage, viscosity ratio 5.0 (8.0 cc/min).

capillary forces can be neglected. Although not mentioned in their paper, an important requirement for the method to work is that the saturations should change monotonically during the displacement process.

The data required for calculating the relative permeabilities from displacement experiments are the pressure drop, Δp , across the core and the cumulative recovery, V_p , of the the displaced phase as functions of the total fluid injected, V_i . The cumulative recovery is used to calculate the average saturation, $\bar{S}_w$, in the core and the fractional flow of oil, f_{o2} , at the outlet face by:

$$\bar{S}_w = S_{wi} + V_p \quad (2.1)$$

and

$$f_{o2} = \frac{d\bar{S}_w}{dV_i} \quad (2.2)$$

The water saturation at the outlet face, S_{w2} , is given by (Welge, 1952):

$$S_{w2} = \bar{S}_w - f_{o2}V_i \quad (2.3)$$

To calculate individual relative permeabilities the relative injectivity, I_r , is calculated from the pressure drop, Δp , and total flow rate, q , by:

$$I_r = \frac{(q/\Delta p)}{(q/\Delta p)_i} \quad (2.4)$$

where subscript, i , indicates the base (initial) conditions used to calculate the relative permeability. The relative permeability to oil, k_{ro} , is then given by:

$$k_{ro} = f_{o2} \frac{d(\frac{1}{V_i})}{d(\frac{1}{V_i I_r})} \quad (2.5)$$

The relative permeability to water, k_{rw} , can now be calculated by:

$$k_{rw} = \frac{(1 - f_{o2})}{f_{o2}} \frac{\mu_w}{\mu_o} k_{ro} \quad (2.6)$$

where μ_w and μ_o are the viscosities of water and oil.

All of these calculations are based on the measurement of pressure drop across the core and the cumulative production of oil and water. The individual k_r 's are calculated from the k_r ratios which in turn are directly related to the fractional flow at the outlet end. Both the pressure drop and the recoveries strongly depend on the saturation distributions in the core. In particular, it is necessary for the initial water saturation to be connate and uniform. Experiments and simulations have helped us to understand how the saturations change during displacements. In general it was found that uniform saturation is not seen at the start of displacement by water. See Fig. 2.10.

In the next section relative permeabilities calculated by the JBN method are compared with the values which were used to generate the simulated recovery and pressure drop data.

2.4 Error Analysis of JBN Method

The pressure drop and recovery data obtained from the simulations was used in the JBN analysis to calculate the apparent relative permeabilities. As we start with known relative permeabilities it is easy to quantify the errors introduced by the assumptions made in the JBN method. The saturation maps and the average saturation profiles have shown that the assumption regarding linear flow and monotonic saturation changes are violated even at high rate.

The original and the calculated relative permeabilities, from the 8.0 cc/min imbibition simulation are compared in Fig. 2.15. In this and all subsequent figures, the relative permeabilities used in the simulations are shown as solid lines, while the results calculated by the JBN analysis are shown as crosses and stars. It is observed that at the beginning of the displacement, when the water saturation is low and there are large saturation gradients in the core, the errors are quite large in the calculated

Figure 2.15: Relative Permeabilities (Imbibition, Rate=8.0 cc/min, $\mu_o/\mu_w = 1.0$).

k_{rw} . The errors decrease as the water saturation increases and the capillary effects are reduced. However all calculated k_{ro} values were much smaller than the input data. Figures 2.16 and 2.17 show the comparison for the 4.0 and 1.0 cc/min imbibition displacement simulations. The results obtained are similar to those at 8.0 cc/min.

The results from the Drainage displacement simulations are shown in Figures 2.18 to 2.20 at rates of 8.0, 4.0 and 1.0 cc/min. The errors in the oil relative permeability curves, though still significant are smaller than they were for imbibition. At lower water saturations, where both imbibition and drainage relative permeabilities can be obtained, the errors in the water relative permeabilities are smaller, but at higher

Figure 2.16: Relative Permeabilities (Imbibition, Rate=4.0 cc/min, $\mu_o/\mu_w = 1.0$).

Figure 2.17: Relative permeabilities (Imbibition, Rate=1.0 cc/min, $\mu_o/\mu_w = 1.0$).

Figure 2.18: Relative Permeabilities (Drainage Rate=8.0 cc/min, $\mu_o/\mu_w = 1.0$).

saturations they are similar to the errors in the imbibition curves. It can be seen from Figures 4.9 and 4.10 that, in both imbibition and drainage, high water saturations occur near the outlet of the core at times near breakthrough. These cause large pressure gradients due to the capillary end effect, resulting in larger calculated relative injectivity as defined in Eq. 2.4, and as a consequence giving erroneous value of k_{ro} as calculated from Eq. 2.5.

The result from higher viscosity ratio of 5.0 for 8.0 cc/min are presented in Figures 2.21 and 2.22. Contrary to expectations, the imbibition errors for both relative permeability curve were not much different than those at unit viscosity ratio. In the

Figure 2.19: Relative Permeabilities (Drainage Rate=4.0 cc/min, $\mu_o/\mu_w = 1.0$).

Figure 2.20: Relative permeabilities (Drainage Rate=1.0 cc/min, $\mu_o/\mu_w = 1.0$).

drainage displacements, the errors are similar at low water saturations, but at higher water saturations the data show double curvature, the calculated oil curve is concave upwards at lower saturations and downwards at higher water saturations.

One limitation of the JBN method is that, for imbibition, no information can normally be obtained when the water saturation is less than the Buckley Leverett cutoff value, S_{wf} , the point of first tangency to the fractional flow curve. For our input relative permeabilities, S_{wf} is 0.71 for a viscosity ratio of 1.0, and is 0.67 for a viscosity ratio of 5.0. Because capillary pressures smooth out the Buckley–Leverett front, it is apparently possible to infer relative permeabilities for S_w less than S_{wf} . Such results will always be invalid, for this range the data violates the assumptions in the JBN analysis.

Figure 2.21: Relative permeabilities (Imbibition Rate=8.0 cc/min, $\mu_o/\mu_w = 5.0$).

Figure 2.22: Relative permeabilities (Drainage Rate=8.0 cc/min, $\mu_o/\mu_w = 5.0$).

Chapter 3

Experimental Equipment and Procedure

This chapter describes the experimental equipment and the procedures. The experiments were conducted using the unsteady state method. This chapter is divided into two sections. In the first section the experimental equipment is described. In the second section the materials used in the experiments and the details of the experimental procedures are given.

3.1 Experimental Equipment

An experimental system was designed and constructed as part of this study. This equipment can be used to conduct unsteady state experiments on consolidated core samples. The core holder is designed so that the cores can be scanned by a CT scanner during the displacement process to measure the saturation distributions as a function of time. The core holder can accommodate consolidated cores of two inch diameter and up to 18 inches long. The system is shown in Fig. 3.1. By switching the appropriate valves, flow experiments can be conducted either by recirculating the fluids, or by flowing them through the core only once. The main components of the experiment are described in detail in the following sections.

Figure 3.1: The experimental system.

3.1.1 The Injection System

The injection system consists of two LDC Analytical liquid chromatography pumps, model Constametric 3200. These pumps are positive displacement dual cylinder pumps. They have been designed to minimize pulses in the flow. The flow rate can be varied between 0.0 to 10.00 cc/min. in increments of 0.01 cc/min. The fluid ends are made from Hastaloy and the plunger and other moving wetted parts are made from sapphire. The plunger seal is made from reinforced Teflon. There are flow channels behind the plunger seals for circulation of cleaning fluids. This helps in removing any salt build up behind the seals, which would otherwise greatly increase the abrasion of the plunger and the seals. The suction lines of the pumps can either be connected to the oil or brine reservoirs for initial filling of the system, or they can be connected to the separator (which is described latter) for recirculating the produced fluids.

3.1.2 The Core Holder

The core holder for these experiments was designed so as to facilitate the in-situ measurement of saturations during the experiments. The saturations are measured by a medical CT scanner. Thus the core holder needs to be made from materials

Figure 3.2: The Core Assembly.

Figure 3.3: The groove pattern in the distribution plugs.

which have low X-ray absorption coefficients. The parts of the core holder which come in contact with the fluids should be chemically inert. It is also important to eliminate any fluid bypass around the core. The core has a thin layer of epoxy and a heat shrunk Teflon sleeve around it. The epoxy used is Number 907 sold by Miller–Stephonson Inc. The epoxy is applied to eliminate fluid bypassing around the core. The Teflon sleeve also supports two stainless steel distribution plugs. The heat shrunk Teflon sleeve provides the mechanical strength. The distribution plugs have 1/16 in deep grooves in a spider web pattern. The pattern is shown in Fig 3.3. The core mounted assembly is shown in Fig. 3.2.

The core assembly is placed inside the core holder which is shown in Fig. 3.4.

Figure 3.4: Schematic of the core holder.

The core holder is fabricated from a PVC pipe. Two flanges were cemented to the ends of the pipe with PVC cement. These flanges hold the two plugs. The inlet plug has the injection port and a pressure tap for the differential pressure transducer. The outlet plug is hollow. These two plugs hold a two inch ID Viton rubber tube in place. The cavity between the Viton tube and the outer PVC pipe is filled with colored mineral oil to provide the overburden pressure. The radial clearance between the Viton tube and the PVC pipe is about half an inch. The outer PVC pipe has two taps for filling of the overburden fluid and one of the taps is connected to the overburden pressure source.

The core holder is assembled first and then the core assembly (described earlier) is inserted inside the core holder from the hollow plug at the end of the core holder. Then the outlet end plug which has the production port and a tap for the differential pressure transducer, is pushed against the core holder. This end plug is held in place by a spacer of appropriate length. This arrangement allows the use of this core holder for cores from six inches to eighteen inches in length.

3.1.3 The Production System

The fluids produced from the core holder pass through a dome type back pressure regulator. The back pressure regulator is a Mity Mite model SD-911W made by

Figure 3.5: The production system.

Grove Valve and Regulator Company The back pressure is controlled by applying gas pressure on a Teflon diaphragm. This regulator can be set for a back pressure of 25 to 400 psig. In these experiments the back pressure was maintained at 50 psig. The fluids from the back pressure regulator enter into a separator. The schematic of the separator and its auxiliary equipment is shown in Fig. 3.5.

The separator was first designed and built by Ameri and Wong(1985). In this study it has been extensively modified to improve the results. The separator consists of an outer glass vessel which has a cover at the top and appropriate openings for the inlet and outlet connections. There is an internal vessel into which the fluids produced from the core are discharged. At this point the produced oil and brine separate. Oil being lighter than water floats on top and is contained in the inner vessel. The produced brine can flow out of the inner vessel through the open bottom. The top cover has two openings. One opening has a glass tube attached to it so that excess brine can flow into a flask, thus maintaining a constant fluid volume in the separator. The brine produced into the flask can be recirculated back into the core.

The glass tube has a hole, as shown in Fig. 3.5, to break any siphon effect. This flask sits on an electronic balance. The weight of the flask is continuously recorded. Any leak in the system will result in a decrease in the weight of this flask or will be indicated by the decrease in brine level in the separator.

The inner separator vessel is suspended by stainless steel tubing to another balance. The tubing has a plug near the top end and is open inside the inner vessel. Any gas phase accumulated during the assembly of the separator or resulting from leakage in the back pressure regulator can be removed by loosening this plug. Any change in the oil water interface in the separator results in an apparent change in the weight of this vessel. This weight as indicated by the second balance, is also recorded continuously. The change in weight is directly proportional to the change in fluid saturations in the core. During the drainage displacement experiments the suction line of the oil pump is connected to the oil in the inner vessel of the separator. As the volume intake of the pump must equal the fluid produced into the separator, the volume of the fluids in the separator remains constant, and the brine doesn't overflow into the flask. In case of imbibition the suction line of the brine pump is connected to the brine in the flask. The volumetric balance ensures that the weight of the flask remains constant.

If there is any fluid gain or loss from the system, such as a leak from the overburden fluid into the core, or a leakage from the flow system, then either the weight of the brine in the flask will change or the level in the separator will drop. Thus any leak from the system during the experiments can be easily detected.

3.1.4 The Data Logging System

During the displacement experiments the recovery and pressure drop data are continuously monitored and recorded by a personal computer. The schematic of the data logging system is shown in Fig 3.6. The pressure drop data are recorded by three Celsco model DP-31 differential pressure transducers. The three transducers provided full scale reading of 1.0, 25.0 or 100 psi. Appropriate switching valves are provided, as shown in Fig. 3.1, to select the transducer most suitable for the differential pressure

Figure 3.6: Schematic of the data logging system.

being measured. Only two pressure transducers and their associated valves are shown in Fig. 3.1, for the sake of clarity. The third valve has similar plumbing. The output from the differential pressure transducers is a voltage signal which varies from zero to ten volts. This signal is fed to an HP 3497A high speed digital data acquisition and control unit (data logger). The signal from the transducers is converted to a digital form by the data logger. The data logger then transmits the digital output to the PC, over the HP-IB interface, which displays it in a graphical form in real time and also writes it to a file on the hard disk.

The balances used for measuring the recovery from the core transmit a digital signal directly to the PC over two serial lines. This data is also shown on the screen and recorded on the disk.

The program for data collection and real time display is written in C language. The program is menu driven and user friendly. It is an interactive program which allows the user to select the pressure transducer whose output is to be monitored and recorded. It also allows for selecting the time interval between each reading during the experiments. The pressure drop and the recovery data are displayed on the computer in real time. The scales of the real time plots generated can also be selected. During display the program automatically modifies the maximum time displayed to show the last data point. All programs which were developed and used in this study along with the data files are available on a CD from the SUPRI-A Program Office, Petroleum

Engineering Department, Stanford University. The contents of the CD are listed in Appendix E.

3.1.5 The CT Scanner

As mentioned previously, computerized tomographic imaging was used to measure the saturations during the displacement experiments. The principle of the CT scanning is well explained by Kak and Slaney (1988). The CT scanner used is a second generation machine, model EMI 5005. In this scanner the X-ray source and the detectors rotate and translate around the object to be scanned to get a two dimensional CT image. Initial experiments indicated strong beam hardening effects. These are caused by the polychromaticity of the X-rays generated by the source used in the scanner and by the sharp contrast in properties between the core and its surrounding materials. These caused strong artifacts in the CT data. Previously foam padding has been used in this lab to reduce this effect. The use of foam padding is very inconvenient if the location of the core has to be frequently changed in the scanner during the experiments. Repeatability was also a concern in the use of foam as a shielding material. A hollow doughnut was made from Plexiglas to filter the X-rays passing through the core holder. The doughnut is made in two separate identical sections to facilitate its installation and removal during the experiments. The doughnut is filled with distilled water during these experiments. This resulted in greatly improved CT data from the scanner. The doughnut can be filled with any other liquid which has the desired X-ray adsorption coefficient. The relative positions of the CT scanner X-ray source/detector, the doughnut, and the core holder are shown in Fig. 3.7.

The core holder is placed in the scanner on a pair of optical tables, so that it can be scanned at different locations during the experiments. The core holder can be placed in the scanner with an accuracy of ± 0.002 inches, and as a result, repeat scans at different times, can truly reflect the changes in saturations as the displacements proceed.

Figure 3.7: Positioning of the doughnut.

3.2 Experimental Procedures

This section describes the materials used in this study and the procedure employed to conduct the experiments. The core samples used in this study were from Berea Quarry. High permeability samples were selected which have relatively uniform properties and low clay content. Two inch diameter cores were selected so as to improve the visualization of the saturation distributions in the CT scanner. To improve the CT contrast between the brine and oil phases we chose to use a salt in the brine phase which had a high X-ray absorption coefficient. First 2% sodium iodide brine was tried as the wetting phase. But the iodide decomposed in light and caused problems. It was therefore decided to use 8% sodium bromide as the wetting phase. The higher concentration of sodium bromide was necessary because it has a lower CT number than sodium iodide. The non-wetting phase for this study was cyclohexane. At room temperature, the brine and cyclohexane pair had almost unit viscosity ratio. The details of the experimental procedure are presented in the subsequent sections.

3.2.1 Core Preparation

Cores two inches in diameter and about ten inches long were cut from the Berea sandstone. The cores were cut using tap water. After drying the cores at room temperature they were baked in a furnace at 400°C for six hours. This procedure reduced the reactivity of the clays. The cores were then slowly cooled to room temperature over a period of twenty four hours. The slow cooling was to reduce the possibility of cracking the cores due to high temperature gradients. The individual core is then clamped between the two distribution end plugs. A very thin layer of epoxy was applied over the core and the distribution plugs. The heat shrinkable Teflon sleeve was applied to this assembly before the epoxy was set. This procedure assures that the epoxy has a uniform thickness around the core, and that there are no channels for fluid flow around the core. The core assembly was kept in the clamps for twenty four hours to assure complete setting of the epoxy.

3.2.2 Initial Core Saturation

The core holder is assembled along with the core and is tested for leaks. The core holder is then placed in the CT scanner. The core is flooded with carbon dioxide at low rate to remove the air. It is then evacuated for 6 to 8 hours. This cycle is repeated two times to completely remove air from the core. The core is then scanned to measure the CT numbers of the dry core under vacuum. Any dissolved air from the brine is removed by placing it under vacuum for a short time. It is then allowed to flow into the core under vacuum. The brine is allowed to imbibe into the core for twenty four hours to assure complete saturation. The vacuum system is then disconnected and the flow lines and differential pressure transducer lines are connected to the core holder. Brine is injected through the core at a flow rate of 8 cc/min and the pressure drop is monitored. When the pressure drop is stabilized, the core is again scanned to get the 100% brine saturated CT numbers. At the same time the absolute permeability to brine is measured. The CT data obtained in these steps is used to calculate the porosity and also the brine saturations during subsequent displacement experiments. The details of these calculations and the description of the program developed for

Displacement		Flow Rate (cc/min)
Primary Drainage	(PD)	8.59
Imbibition-1	(I1)	8.43
Drainage-1	(D1)	8.60
Imbibition-2	(I2)	3.77
Drainage-2	(D2)	4.28
Imbibition-3	(I3)	1.04
Drainage-3	(D3)	1.07

Table 3.1: Sequence of displacement experiments.

this are given in Appendix B.

3.2.3 The Displacement Experiments

After measuring the absolute permeability of the core to brine, cyclohexane is injected at a rate of 8.59 cc/min for the primary drainage displacement. The injection is continued for about 24 hours at which time the fractional flow of brine becomes almost zero and the pressure drop across the core had stabilized. The sequence and the flow rates used in these experiments are given in Table 3.1. The core is scanned at appropriate locations and times to get in situ saturations during, and at the ends of, displacements. The results from these displacement experiments are analyzed in the next chapter.

During the later stages of the experiments it became obvious that the absolute permeability of the core used is higher for the oil phase than for the brine. The absolute permeabilities of Berea sandstone to nitrogen, cyclohexane and brine were measured on a one inch diameter core plug. The core plug was prepared in the same way as the cores used in the experiments. First the absolute permeability to nitrogen was measured. The core plug was then saturated with cyclohexane under vacuum and its permeability measured. The core plug was dried after measuring the permeability to cyclohexane and rebaked for an hour to completely dry it before saturating it with brine. The results are shown in Table 3.2. It is clear that even after baking the cores the clays are somewhat sensitive to the sodium bromide brine. The clays swell when

Fluid	Permeability md
Nitrogen	760
Cyclohexane	720
Brine	390

Table 3.2: Absolute permeability of Berea sandstone to different fluids.

they come into contact with brine resulting in a reduction in permeability.

Chapter 4

Data Analysis and Results

The methods used to analyze the experimental data and the results from this analysis are discussed in this chapter. The data was analyzed by both the more conventional method of JBN, and also by the less used history matching method. The results from the in situ saturation measurements are also given. The in situ saturation measurements helped in understanding the capillary end effects.

4.1 The JBN Analysis

The mathematical details of the JBN method are given in Chapter 2. The analysis requires the derivatives of the pressure drop and recovery data (See Eqs. 2.2 and 2.5). Because of the inherent noise in the experimental data the derivatives obtained from the raw data are never satisfactory. It was therefore decided to use the method proposed by Miller (1983). In this method the recovery and the pressure drop data are smoothed by fitting a curve through them. As proposed by him the equation used for fitting the recovery data is:

$$N_p = a_0 + a_1[\ln(V_i)] + a_2[\ln(V_i)]^2 \quad (4.1)$$

Since in the JBN analysis the derivative of $1/V_i$ with respect to $1/(V_i I_r)$ is needed, the injectivity data is smoothed by:

$$\ln(V_i I_r) = b_0 + b_1[\ln(V_i)] + b_2[\ln(V_i)]^2 \quad (4.2)$$

These equations gave a very good match for the drainage displacement data. It was however, observed that because of the drift in the measurement system the recovery curve started to drop down after the production of the displaced phase had ceased. An example of this behavior is shown in Fig. 4.1. In such cases the data up to the time when the recovery has become constant was used (In the example shown it was up to a time of about 6.0 hours). The data with matched functional form are shown in Figures 4.2 to 4.4. Only the post breakthrough data is used in this match. As the imbibition displacement in Berea sandstone is essentially piston like, there is very little production after breakthrough. The fitting procedure didn't work for the imbibition displacements. For the imbibition only the end point permeabilities could be calculated. This is expected from a strongly water wet system.

The fitted functional forms for these displacements were used to calculate the relative permeabilities by the JBN method. The results for the three displacement rates along with the corresponding imbibition permeabilities are shown in Figures 4.5 to 4.7. The flow rates, Rapoport and Leas number N_{rl} and the capillary number N_c are given in Table 4.1. Rapoport and Leas number, N_{rl} , ranges from a high of 10.07 to 1.21. The capillary number, N_c , has values between 0.011 to 0.260. From the limits given by Rapoport and Leas (1953) the results from these displacements should not be effected by the capillary forces. Also from the criteria given by Bentson (1978) the errors introduced by the capillary forces should be small.

The end point saturations and relative permeabilities are shown in Table 4.2. It is clear that the end point saturations and the relative permeabilities as calculated by the JBN method are a strong function of rate. It was observed from the saturation measurements that there are some heterogenities in the core. The porosity as measured by the CT scanner at different cross sections along the length of the core are graphed in Fig. 4.8. The saturation profiles as measured by CT scanner at the end of each displacement are shown in Figures 4.9 and 4.10. From Fig. 4.10 it is clear that at the end of the drainage displacements, there is a strong saturation gradient towards the end of the core, even at the high rate. This saturation gradient causes

Figure 4.1: The recovery data from drainage displacement at 1.07 cc/min.

Run	Flow Rate (cc/min)	N_{rl} ($cm^2 cp/min$)	N_c
PD	8.59	9.70	0.140
I1	8.43	10.07	0.011
D1	8.60	9.71	0.123
I2	3.77	4.50	0.015
D2	4.28	4.83	0.150
I3	1.04	1.24	0.038
D3	1.07	1.21	0.260

Table 4.1: Rapoport and Leas number and capillary number for the displacement experiments.

Figure 4.2: The injectivity and recovery data from drainage displacement at 8.60 cc/min.

Run	S_w	$K_{rend}(D)$	
		k_{rw}	k_{ro}
PD	0.322		0.390
I1	0.705	0.079	
D1	0.334		0.342
I2	0.699	0.051	
D2	0.414		0.208
I3	0.692	0.035	
D3	0.546		0.090

Table 4.2: End point saturations and relative permeabilities from JBN analysis.

Figure 4.3: The injectivity and recovery data from drainage displacement at 4.28 cc/min.

Figure 4.4: The injectivity and recovery data from drainage displacement at 1.07 cc/min.

Figure 4.5: JBN Relative permeabilities from imbibition (8.43 cc/min) and drainage (8.60 cc/min).

Figure 4.6: JBN Relative permeabilities from imbibition (3.77 cc/min) and drainage (4.28 cc/min).

Figure 4.7: JBN Relative permeabilities from Imbibition (1.04 cc/min) and drainage (1.07 cc/min).

Figure 4.8: CT measured porosity values of Berea sandstone core.

additional pressure drop through the core. Thus the results from the JBN analysis are questionable. By comparing Fig. 4.8 with Figures 4.9 and 4.10, it can be seen that the localized variation in porosity cause localized changes in saturations.

As was discussed in Chapter 2 the imbibition displacements don't start with a uniform saturation distribution. The saturation changes are non monotonic, thus the relative permeability data is questionable. Because of the strong wetting characteristics of the cores used, the only permeability data obtained from the imbibition displacements is the end point saturations and the corresponding relative permeabilities. The history matching method seems to be a better choice for such systems. The history matching algorithm used in this study and the results from the analysis are presented in the rest of this chapter.

Figure 4.9: Saturation profiles at the end of imbibition displacements.

Figure 4.10: Saturation profiles at the end of drainage displacements.

4.2 History Matching Method

As discussed in Chapter 1 the history matching method has been used to calculate the relative permeabilities from low rate displacement data. In this method the relative permeability curves are varied in the numerical model until a satisfactory match is obtained between the observed and the calculated response. In this study a commercial black oil simulator ECLIPSE (2000). has been used to model flow in the core. The model used is a linear 1-D simulator. The end effects are simulated by including blocks at the inlet and outlet of the core with zero capillary pressure and straight line relative permeability curves. Although the preliminary simulation studies (See Chapter 2) indicated the presence of non-linear flow near the inlet and outlet faces of the core, the effect of this non-linearity is small enough to be neglected. The model used has sixty grid blocks for the core and one at each end for the end plugs. Sensitivity studies indicated that any further refinement was unnecessary.

To automate the history matching procedure the Levenberg-Marquardt method as described by Press et al. (1992), was used in this study. In this method the merit function, χ^2 , defined by:

$$\chi^2 = \sum_{i=1}^N \left[\frac{y_i - y(x_i; a)}{\sigma_i} \right]^2 \quad (4.3)$$

is minimized. In this equation x_i represents the independent variable and y_i is the measured value of the dependent variables, $y(x_i; a)$ is the calculated value of the dependent variables, a is the vector of parameters used to fit the model. The original program as given by Press et al. (1990) works for only one independent and one dependent variable. In this study the variables fitted are the pressure drop, recovery data and the saturation distribution in the core at the end of each displacement. The program as given by Press et al. was modified to handle multiple independent and dependent variables.

The merit function for this study is given by:

$$\chi^2 = \sum_{i=1}^{N1} \left[\frac{\Delta p_i - \Delta p_c}{\sigma_i} \right]^2 + \sum_{i=1}^{N1} \left[\frac{R_i - R_c}{\sigma_i} \right]^2 + \sum_{i=1}^{N2} \left[\frac{(S_w)_i - (S_w)_c}{\sigma_i} \right]^2 \quad (4.4)$$

here Δp is the pressure drop across the core, and R is the recovery. Both of these are measured as a function of time. S_w is the saturation of brine at specified cross sections, measured as a function of distance from the core inlet at the end of a displacement run. The subscript i represents measured values and subscript c is for the calculated values. The term σ is the standard deviation of the measured values, $N1$ is the number of pressure drop and recovery data points, and $N2$ is the number of cross sections at which the saturations are measured. As in the displacement experiments it is not easy to assign values to σ_i 's, the stabilized values of Δp , R and the final saturation were used for σ 's in the above equation. Press et al. (1990) have recommended that in the absence of known values of σ any arbitrary but constant number can be used for this analysis. In the displacement experiments the values of Δp , R and S_w are quite different from each other. Same constant value for these three matched parameters would have resulted in a different weight being given to each one of them. In this study about 2000 data points (Δp and R) were collected during each displacement experiment. The small time increment required to match all of these points would have resulted in excessive computer time. It was therefore decided to use about 200 data points ($N1$) for each displacement experiment. This was achieved by averaging about 10 consecutive data points and assigning that value to the middle point. The saturations were measured at 19 cross sections equally spaced along the length of the core. The value of ($N2$) was therefore always nineteen.

The parametric form of the relative permeability curves for the wetting and non-wetting phases used in this study is based on a normalized form of the saturation defined by:

$$S_{ws} = \frac{S_w - S_{wc}}{1 - S_{or} - S_w} \quad (4.5)$$

The relative permeability curves for the wetting and non-wetting phases are defined by (Fayers, 1993):

$$k_{rw} = k_{rwe} * \exp(-A_w * (S_{ws})^{-\alpha_w}) \quad (4.6)$$

and

$$k_{rn} = k_{rne} * \exp(-A_n * (S_{ws})^{\alpha_n}) \quad (4.7)$$

In these equations k_{rw} and k_{rn} are the relative permeabilities to the wetting and non-wetting phases, k_{rwe} and k_{rne} are the corresponding end point relative permeabilities. The value of k_{rwe} is taken at the irreducible oil saturation S_{or} , and the value of k_{rne} is at connate water saturation S_{wc} . The parameters A_w , α_w , A_{nw} and α_{nw} control the shape of the relative permeability curves. This functional form gives large flexibility in the shape of the relative permeability curves (Fayers, 1993). As will be seen in the results obtained from the history matches, the curves can be concave downwards, concave upwards or S-shaped. Two sets of the relative permeabilities are used, one for the imbibition displacements and the other for the drainage displacements. In this program all variables, and the parameters defining the relative permeability curves, can be changed by the history matching routines until a match is achieved. The use of the program, including sample input data files, is explained in Appendix C. The program is available on a CD that can be obtained from the SUPRI-A Program Office, Department of Petroleum Engineering, Stanford University.

The history matching method requires the use of measured capillary pressure data. The drainage capillary pressure was measured by the porous plate method. It was in good agreement with the capillary pressure measured by centrifuge (Qadeer, 1988) for similar Berea sandstone cores. It was therefore decided to use the imbibition capillary pressure from Qadeer (1988). The capillary pressure data used in this study is shown in Fig. 4.11 and tabulated in Tables 4.3 and 4.4.

As discussed previously, the imbibition displacements don't start with a uniform saturation distribution. It is therefore necessary to have the proper saturation distribution in the simulation model at the beginning of the imbibition displacement calculations. The restart feature of the simulator, which allows the input of saturation and pressure data from the previous runs was used to assure that the imbibition displacements start with the correct saturation distributions.

Berea sandstone is known to show different flow characteristics during the primary drainage displacement than in subsequent flow cycles (Brigham, 1992). Thus the

Figure 4.11: Capillary pressure used in history matching.

Water Saturation	Capillary Pressure (atm)
0.1100	2.7265
0.1150	2.0357
0.1447	0.3749
0.1743	0.2184
0.2040	0.1568
0.2337	0.1234
0.2633	0.1023
0.2930	0.0876
0.3227	0.0768
0.3523	0.0686
0.3820	0.0620
0.4117	0.0566
0.4413	0.0522
0.4710	0.0484
0.5007	0.0452
0.5303	0.0424
0.5600	0.0399
0.5897	0.0378
0.6193	0.0358
0.6490	0.0341
0.6787	0.0325
0.7070	0.0000

Table 4.3: Drainage capillary pressure data used in history matching.

Water Saturation	Capillary Pressure (atm)
0.1100	2.7265
0.1150	0.2165
0.1412	0.0490
0.1675	0.0286
0.1937	0.0200
0.2199	0.0151
0.2461	0.0119
0.2724	0.0097
0.2986	0.0080
0.3248	0.0067
0.3510	0.0056
0.3773	0.0047
0.4035	0.0040
0.4297	0.0034
0.4560	0.0028
0.4822	0.0024
0.5084	0.0019
0.5346	0.0016
0.5609	0.0012
0.5871	0.0009
0.6133	0.0007
0.6395	0.0004
0.6658	0.0002
0.7060	0.0000
1.0000	0.0000

Table 4.4: Imbibition capillary pressure data used in history matching.

primary drainage data was used only to match the starting point for the subsequent displacements, i.e. matching the pressure drop and the recovery data at the end of the primary drainage displacement.

4.2.1 Results from History Matches

After getting a good match of the recovery, pressure drop and the saturation data at the end of the primary drainage displacement, see Figures 4.12 and 4.13 the match for the first imbibition displacement was tried with the full set of data. However it was observed that the pressure drop match at the early stages of the flood, i.e., before and just after the breakthrough, was not acceptable. The poor match was due to the fact that most of the data points recorded during the experiments are after breakthrough and thus the history matched solution is heavily weighted towards the end of the displacement experiments. A two step approach was therefore deemed necessary to properly match the data. In this method, the first history match is attempted using the early data. This was done by using the data from the first two hours from each displacement. In this match all parameters in the relative permeability equations 4.5 to 4.7, including the end point relative permeabilities and saturations, were allowed to change. This approach generally gave a good match for the early data. Some times however, even this approach didn't give a reasonable match to the very early pressure drop data. Where this occurred, end point relative permeability of the displaced phase was adjusted to match the experimental and simulated pressure drop at the start of that particular displacement. Once the early time data had been matched the starting end points, i.e. k_{rwe} and S_{or} for the drainage, and k_{rne} and S_{wc} for the imbibition, were held constant and the remaining parameters were allowed to change until a good match had been obtained between the simulated and the experimental data using the complete data set. This two step approach has given good history matches as will be described in the following discussion.

The first imbibition displacement after the primary drainage was done at a rate of 8.43 cc/min. The pressure drop and the recovery match for this displacement using the early time data is shown in Fig. 4.14.

Figure 4.12: Pressure drop and recovery match for primary drainage (Rate = 8.59 cc/min).

Figure 4.13: Measured and simulated saturation profiles for 8.59 cc/min primary drainage.

Figure 4.14: Pressure drop and recovery match for 8.43 cc/min imbibition using early data.

The corresponding match between the measured saturations and the simulated saturations is shown in Fig. 4.15. The relative permeability curves, which gave this history match are graphed in Fig. 4.16.

The results obtained from the history match using the complete set of data for this imbibition are shown in Figures 4.17 to 4.21. Figures 4.17 to 4.19 show the same history match data, but have been graphed at different time scales to more clearly show the quality of the match. It is to be noted here that in Fig. 4.19 only every 10th measured data point has been graphed for the sake of clarity. The same is true for all subsequent figures where the time scale is from 0-25 hours. It is observed from these figures that there is an apparent mismatch between the measured and the history matched recovery data. However the difference between the two is only about one cc. This is well within the expected experimental error in the data. This is further confirmed by the measured and simulated saturation profiles for this displacement as shown in Fig. 4.20, which shows a good match. The small mismatch between the

Figure 4.15: Measured and simulated saturation profiles for 8.43 cc/min imbibition using early data.

Figure 4.16: Imbibition relative permeabilities obtained from the history match using early data for 8.43 cc/min.

Figure 4.17: Pressure drop and recovery match for 8.43 cc/min imbibition using complete data set (Time = 0-1 hrs).

measured and the matched pressure drop just after the breakthrough (See Fig. 4.17) will be discussed in detail latter in this chapter.

As is apparent from the pressure drop, recovery and the saturation plots that there is little recovery after the breakthrough in this experiment. Therefore the results from the matches obtained using the early time data and the full data set are almost identical. As a consequence of the very little recovery after the breakthrough the shapes of the relative permeability curves cannot be defined uniquely from this experiment but the end points can be reasonably well defined. However, by fixing the capillary pressure data and the parametric equations, which define the relative permeability curves, the history matching solution becomes unique. In this study capillary pressure data measured from core samples, very similar to the ones used in the displacement experiments, were used. The parametric equations for relative permeability curves are also fixed. Therefore, the relative permeability curves from the history match are unique. However, if a different form of the equations is used,

Figure 4.18: Pressure drop and recovery match for 8.43 cc/min imbibition using complete data set (Time = 0-5 hrs).

Figure 4.19: Pressure drop and recovery match for 8.43 cc/min imbibition using complete data set (Time = 0-25 hrs).

Figure 4.20: Measured and simulated saturation profiles for 8.43 cc/min imbibition using complete data set

Figure 4.21: Imbibition relative permeabilities obtained from the history match for 8.43 cc/min using complete data set.

Figure 4.22: Pressure drop and recovery match for 8.60 cc/min drainage using early data.

a different pair of relative permeability curve will be obtained.

The next experiment in the series was a drainage displacement at a rate of 8.6 cc/min. The simulations used the pressure and saturation distributions from the previous imbibition run to ensure that the initial conditions in the simulation are as close as possible to those in the experiments. The results from this displacement using the early time data are shown in Figures 4.22 to 4.24. Using the relative permeability curves given in Fig. 4.24 and keeping the k_{rwe} and S_{or} fixed to the values obtained from Fig. 4.24 the full data set was used and the results are shown in Figures 4.25 to 4.29.

It is to be noted that unlike the imbibition displacement, there is considerable production of the displaced brine, after breakthrough. Even then a history matching run using the early time data was required for a good overall match.

The match between the measured and the history matched saturation profiles is shown in Fig. 4.28. The apparent difference between the measured and the matched

Figure 4.23: Measured and simulated saturation profiles for 8.60 cc/min drainage using early data.

Figure 4.24: Drainage relative permeabilities obtained from the history match using early data for 8.60 cc/min.

Figure 4.25: Pressure drop and recovery match for 8.60 cc/min drainage using complete data set (Time = 0-1 hrs).

Figure 4.26: Pressure drop and recovery match for 8.60 cc/min drainage using complete data set (Time = 0-5 hrs).

Figure 4.27: Pressure drop and recovery match for 8.60 cc/min drainage using complete data set (Time = 0-25 hrs).

Figure 4.28: Measured and simulated saturation profiles for 8.6 cc/min drainage using complete data set.

Figure 4.29: Drainage relative permeabilities obtained from the history match for 8.60 cc/min using complete data set.

profile can be attributed to the difference in the material balance recovery and the saturation values measured by the CT scanner. The recovery from the core was measured using the separator described in Chapter 3. As the difference in the specific gravity of brine and oil is only 0.28 gm/cc therefore an error in the weight measurement of the separator of only 1 gm will result in an error in recovery of about 3.6 cc. The mismatch is therefore well within the measurement error. However the difference in the trends in the curves near the outlet of the core is most likely due to the manner in which the capillary end effect is simulated by suddenly changing the P_c to zero is the end block in the numerical model. The ECLIPSE simulator does not honor the capillary end effect directly. In the results reported here the outlet end effect is mimicked by setting the capillary pressure in the block which represents the outlet end plug equal to zero. This creates large capillary pressure gradient near the outlet end. A rigorous way to simulate the correct boundary condition is discussed by Settari and Aziz (1974).

Another factor in the mismatch between the simulated and measured saturation profiles is that there are only 19 measured value of the saturations, whereas the number of data points for the recovery and pressure drop are around 200. As a consequence the history matched solution is heavily weighted towards the recovery measurements. Although it is possible to numerically force the solutions to weigh the two measurements equally but this was not done, because during most of the measurements done in the laboratories in situ saturation measurements are not available, and only the recovery data is available for history matching.

These high rate runs were followed by the medium rate, 3.77 cc/min imbibition and 4.28 cc/min drainage runs. The final results from the matches obtained using the full data set are shown in Figures 4.30 to 4.32 for the imbibition and Figures 4.33 to 4.35 for the drainage displacement. The matches for the early data and expanded match for the full scale data are shown in Appendix D.

It was observed that the recovery data for the 4.28 cc/min drainage displacement experiment had stabilized after about 5 hours. It was therefore decided to use the data up to 5 hours only for the match. After getting a good match using this data, ECLIPSE was run for the total duration of the experiment, i.e., 24 hours. The match

Figure 4.30: Pressure drop and recovery match for 3.77 cc/min imbibition using complete data set (Time = 0-25 hrs).

between this extended run and the experimental data as graphed in Fig. 4.33 shows a total difference of about 7.5 cc at the end of the run, which corresponds to about 2.1 gm in term of the weight measurements. It is suspected that in this case the weight measurements are in error due to the sticking of the inner vessel to the side of the outer vessel in the separator. This error is small when compared to the total weight of the inner vessel which was around 150 gm. The experimental data was not discarded as good data is available up to 5 hrs and can be used for history matching. Furthermore it was not possible to completely eliminate such errors in this design of the separator. The quality of the data is further confirmed by the match of the saturation profile as shown in Fig. 4.34. As in the previous high rate drainage displacement the mismatch in the trend of the saturation profiles near the outlet end of the core is obvious.

The next experiment in the sequence was an imbibition displacement at a rate of 1.04 cc/min. The results from the match using the first 2 hours of data are shown in Figures 4.36 to 4.38. It is obvious from the recovery and pressure drop matches

Figure 4.31: Measured and simulated saturation profiles for 3.77 cc/min imbibition using complete data set.

Figure 4.32: Imbibition relative permeabilities obtained from the history match for 3.77 cc/min using complete data set.

Figure 4.33: Pressure drop and recovery match for 4.28 cc/min imbibition using data up to 5 hrs (Time = 0-25 hrs).

Figure 4.34: Measured and simulated saturation profiles for 4.28 cc/min drainage using complete data set.

Figure 4.35: Drainage relative permeabilities obtained from the history match for 4.28 cc/min using complete data set.

Figure 4.36: Pressure drop and recovery match for 1.04 cc/min imbibition using early data.

shown in Fig. 4.36 that the match is not so good near and after the breakthrough. The matches using the complete data set are graphed in Figures 4.39 to 4.43. From Figures 4.39 to 4.41 it is clear that the match from right after the break through to about 4 hours is not good. The reason for this is explained in the next paragraph.

The saturation profiles in the core from the simulated data obtained using the relative permeability curves after the match at two different times are graphed in Fig. 4.44. The profile at a time of 0.5 hours is just before the breakthrough. It can be inferred from this figure that most of the core is at a brine saturation of about 0.7. To get a better match we should only change the values of the relative permeabilities very close to a brine saturation of 0.7. The relative permeability curves for brine and oil obtained from the match are graphed in Figures 4.45 and 4.46. In the same figures the relative permeabilities calculated by perturbing the parameters a and α , in Equations 4.6 and 4.7, by 10 % for the respective phases have also been graphed. It is obvious from these two figures that small perturbations in the values of a and

Figure 4.37: Measured and simulated saturation profiles for 1.04 cc/min imbibition using early data.

Figure 4.38: Imbibition relative permeabilities obtained from the history match using early data for 1.04 cc/min.

Figure 4.39: Pressure drop and recovery match for 1.04 cc/min imbibition using complete data set (Time = 0-1 hrs).

Figure 4.40: Pressure drop and recovery match for 1.04 cc/min imbibition using complete data set (Time = 0-5 hrs).

Figure 4.41: Pressure drop and recovery match for 1.04 cc/min imbibition using complete data set (Time = 0-25 hrs).

Figure 4.42: Measured and simulated saturation profiles for 1.04 cc/min imbibition using complete data set

Figure 4.43: Imbibition relative permeabilities obtained from the history match for 1.04 cc/min using complete data set.

Figure 4.44: Saturation profiles from simulated data after the match form imbibition displacement at 1.04 cc/min.

α result in changes in relative permeabilities over a much wider range of saturations than desired. It can therefore be concluded that the parametric representation of the relative permeability curves as given in Equations 4.5 to 4.7 is not flexible enough to give good match for the low rate experiments around the breakthrough time.

The last run in the sequence of experiments was a drainage displacement at a rate of 1.07 cc/min. The match obtained by using the early time data is shown in Figures 4.47 and 4.48. The corresponding relative permeabilities are graphed in Fig. 4.49. It is to be noted that the match of the pressure drop data from the beginning of the displacement to about 0.5 hours is bad. All attempts to get a better match by fixing the k_{rw} at the initial conditions failed. The match using the data up to a time of 10 hours is shown in Figures 4.50 to 4.52 at different time scales. It is quite obvious from Fig. 4.50 that in this case although the match using the data up to 10 hours did give a little better match than the one from short time data match but, neither is good enough. The reason for this mismatch is the same as explained earlier for the

Figure 4.45: Matched and perturbed wetting phase relative permeabilities.

Figure 4.46: Matched and perturbed non-wetting phase relative permeabilities.

Figure 4.47: Pressure drop and recovery match for 1.07 cc/min drainage using early data.

imbibition displacement in the previous paragraph. The saturations in the core only vary from about 0.6 to 0.7. Any attempt to change the relative permeability curves in this range changes them at saturations much lower than 0.6, which results in the simulated data to be much different after the breakthrough.

It has been demonstrated from this analysis that the parametric form of the relative permeability curves used in this study gives a reasonable match for high and medium rate displacement experiments. However it fails to properly model the flow for low rate floods where the capillary forces become more important. It may also be the case that the measured capillary pressure data are not strictly valid for the flow experiments, since capillary pressures are measured by ensuring equilibrium but the same may not be true during displacement experiments.

Figure 4.48: Measured and simulated saturation profiles for 1.07 cc/min drainage using early data.

Figure 4.49: Drainage relative permeabilities obtained from the history match using early data for 1.07 cc/min.

Figure 4.50: Pressure drop and recovery match for 1.07 cc/min drainage using complete data set (Time = 0-1 hrs).

Figure 4.51: Pressure drop and recovery match for 1.07 cc/min drainage using complete data set (Time = 0-5 hrs).

Figure 4.52: Pressure drop and recovery match for 1.07 cc/min drainage using complete data set (Time = 0-25 hrs).

Figure 4.53: Measured and simulated saturation profiles for 1.07 cc/min drainage using complete data set

Figure 4.54: Drainage relative permeabilities obtained from the history match for 1.07 cc/min using complete data set.

4.3 Comparison of JBN and History Matched Results

In this section the relative permeability curves calculated from the JBN method and those obtained from the history matching technique are compared. The comparison of the relative permeabilities obtained by the two methods for the three imbibition displacements are presented in Figures 4.55 to 4.57. It is interesting to note that in all these displacements only the end point relative permeabilities, at S_{or} , could be calculated by the JBN method. However, using the history matching method the complete relative permeability curves can be generated, and the values generated by the two methods are in good agreement. This is expected as there is neither a saturation gradient, nor any capillary end effect at the end of the imbibition displacements in the core. However because of the flat nature of the recovery and the pressure drop curve in the imbibition displacement experiments, the uniqueness of the curves obtained from the history match is questionable.

Similar data for the three drainage displacements is presented in Figures 4.58 to 4.60. Here the errors caused by the saturation gradients and the capillary end effects in the JBN method are quite noticeable. The oil relative permeability calculated by the JBN method is consistently lower than that by the history match by about the same amount in all three experiments. Contrary to the expectations, rate does not effect the apparent errors in these calculations. The brine relative permeabilities calculated by the JBN method are slightly higher than those from the history match. This could be a result of the poorer definition of the history matched curves in that saturation range as discussed in the last section. From this analysis it is quite clear that the JBN analysis in systems similar to those in this study give erroneous results even at high rates, where the capillary forces are in general, assumed to be negligible.

From the figures presented here it is also obvious that just like in the JBN method the relative permeabilities obtained by the history matching method are also dependent on the rates, higher the rate, higher are the relative permeabilities.

Figure 4.55: Comparison of imbibition relative permeabilities calculated from JBN and history match methods (Rate = 8.43 cc/min).

Figure 4.56: Comparison of imbibition relative permeabilities calculated from JBN and history match methods (Rate = 3.77 cc/min).

Figure 4.57: Comparison of imbibition relative permeabilities calculated from JBN and history match methods (Rate = 1.04 cc/min).

Figure 4.58: Comparison of drainage relative permeabilities calculated from JBN and history match methods (Rate = 8.60 cc/min).

Figure 4.59: Comparison of drainage relative permeabilities calculated from JBN and history match methods (Rate = 4.28 cc/min).

Figure 4.60: Comparison of drainage relative permeabilities calculated from JBN and history match methods (Rate = 1.07 cc/min).

Chapter 5

Conclusions and Recommendations

5.1 Conclusions

In this study both numerical simulations and experimental techniques have been used to get a better understanding of the problems and limitations associated with the determination of relative permeability curves from displacement experiments. The experiments were conducted using relatively high permeability Berea sandstone. This material is known to be homogeneous and strongly water wet. However it was observed from the CT scanner measurements of the porosity that some heterogeneities do exist even in these Berea sandstone samples. Berea sandstone is strongly water wet. Most reservoirs are known to be of intermediate wettability, it is therefore recommended that similar studies should be conducted on such systems. From the simulated and experimental data and the results obtained from relative permeability calculations in this study, the following conclusions can be drawn:

- In homogeneous cores, with the conventional spider web grooves in the end plugs, the flow near the ends of the cores is not uniformly distributed. It is nearly hemispherical in nature. However, with these fairly long cores (25 cm) this had only a minor effect on the displacement process.
- In case of drainage displacements, there are large saturation gradients in the core, even at high rates, which in certain cases can extend throughout the core.

These can effect the results obtained using standard analysis methods.

- As a result of the non-uniform entry of the fluids in to the core, and high saturation gradients, the basic assumptions made in the Johnson, Bossler and Neumann (JBN) method may be violated. These assumptions are: (a) the flow is linear, and (b) the saturations change monotonically.
- Due to the capillary end effect, the non-linear flow and the saturation gradients, large errors exist in the relative permeabilities calculated by the JBN method.
- The relative permeabilities calculated by the JBN method and by using the history matching technique, from the experimental data are rate dependent in the range of flow rat.
- The shapes of the relative permeability curves obtained from history matching are much different from those obtained by the JBN method.
- The relative permeabilities calculated by the JBN method had large errors even at high rates.
- The match between the measured and simulated data was generally acceptable. However, it was observed in the low rate experiments that the match between the simulated and the measured early time pressure data was not good.
- The parametric form of the relative permeability curves used in this study didn't give a satisfactory match for the low rate displacements. In this form the permeability to each phase is represented by two parameters a and α other parametric forms use only one parameter to describe the shape. These curves are not flexible enough to properly model the flow under all conditions. A different functional relationship is needed for low rate experiments.

5.2 Recommendations

- The CT scanner, that was used in these experiments completed one scan in about 45 seconds. Another 45 seconds were required to store the data. Thus

giving a total time of 1.5 minutes between scans. It was thus not possible to get a static picture of the saturation profiles and use that in the analysis. It is recommended that for such experiments a scanner which can take planner views covering the entire length of the core be used for such experiments.

- The equipment used to measure the recovery from the core in displacement experiments needs improvement. The recovery measurement system should be designed, to be placed as close as possible to the outlet of the core.
- The simulator used in this study uses tabulated relative permeability curves. In any automated history matching process the relative permeabilities are represented by equations. A simulator should be developed, which uses such equations. The simulator should properly model the inlet and outlet end plugs including the capillary end effect and non-linear nature of the flow near the ends.
- This study was conducted using Berea sandstone, which is strongly water wet, homogeneous and sensitive to brine even after baking. Further studies should be conducted on systems which have intermediate wettability, and are not sensitive to brine.
- The parametric relative permeability equations, used in this study didn't properly model the flow behavior of low rate displacements. Other functional forms of the equations, representing the curves need to be explored.

Nomenclature

English Symbols

A	area perpendicular to the flow
A	parameter in the relative permeability equations
a	vector of parameters
C^*	dimensionless stability number
D	diameter of the core
f_{o2}	fractional flow of oil at the outlet
g	gravitational acceleration
c_c	constant in Newton's equation
I_r	relative injectivity
I_{sc}	dimensionless stability number
k	absoulte permeability
k_e	effective permeability
k_r	relative permeability
L	length
l	length
M	mobility ratio
N_c	capillary number
N_{cg}	capillary number in centrifuge experiments
P_c	capillary pressure

p	pressure
q	flow rate
R	recovery
r	capillary radius
S_g^*	normalized gas saturation
S_L	liquid saturation
S_n	non wetting phase or oil saturation
S_{nr}	irreducible non wetting phase saturation
S_o^*	normalized oil saturation
S_w	water or brine saturation
S_{wf}	water saturation at the Buckley–Leverett front
S_w^*	normalized water saturation
$\bar{S}_w$	average water saturation
S_{wc}	connate water saturation
S_{we}	normalized water saturation
S_{wi}	irreducible water saturation
v	velocity
V_p	cumulative recovery
V_i	cumulative injected volume
x	distance or length
y_i	the i th measured value
$y(x_i, a)$	the i th calculated value based on parameter vector a

Greek Symbols

α	parameter in the relative permeability equation
χ^2	error function
Δ	difference between two values
γ	interfacial tension
θ	angle
θ	interfacial contact angle
μ	viscosity
ρ	specific gravity or fluid density
σ	interfacial tension
σ_i	standard deviation
τ	tortuosity
ϕ	porosity
ϕ	potential

Subscripts

c	calculated value
dr	drainage
i	measured value
imb	imbibition
n	non wetting phase
o	oil
w	wetting, water or brine

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Appendix A

Data Used in Numerical Simulations

The relative permeability and capillary pressure data used in the simulated experiments described and analyzed in Chapter 2 are tabulated in the following tables and are graphed in Fig. 2.5. As explained in the Chapter 2 these were estimated values for Berea sandstone of permeability similar to the one used in this study. It may please be noted that the capillary pressure data used in the history matching of the experimental data in Chapter 4 was measured in the laboratory and is tabulate in Table 4.3 and 4.4.

Water Saturation	Brine Relative Permeability	Capillary Pressure (atm)
0.400	0.000E+00	1.000E+00
0.430	0.263E-04	0.419E+00
0.445	0.173E-03	0.289E+00
0.460	0.534E-03	0.220E+00
0.475	0.116E-02	0.177E+00
0.490	0.209E-02	0.147E+00
0.505	0.331E-02	0.125E+00
0.520	0.482E-02	0.109E+00
0.535	0.664E-02	0.955E-01
0.550	0.875E-02	0.848E-01
0.565	0.112E-01	0.759E-01
0.580	0.139E-01	0.684E-01
0.595	0.169E-01	0.619E-01
0.610	0.203E-01	0.563E-01
0.625	0.240E-01	0.514E-01
0.640	0.281E-01	0.471E-01
0.655	0.327E-01	0.432E-01
0.670	0.378E-01	0.398E-01
0.685	0.434E-01	0.366E-01
0.700	0.498E-01	0.338E-01
0.715	0.570E-01	0.312E-01
0.730	0.654E-01	0.289E-01
0.745	0.753E-01	0.267E-01
0.760	0.875E-01	0.247E-01
0.775	0.103E+00	0.228E-01
0.790	0.128E+00	0.200E-01
0.800	0.176E+00	0.200E-01
1.000	1.000E+00	0.200E-01

Table A.1: Brine Relative Permeability and capillary pressure data for drainage displacements.

Water Saturation	Brine Relative Permeability	Capillary Pressure (atm)
0.400	0.000E+00	1.000E+00
0.430	0.263E-04	0.163E+00
0.445	0.173E-03	0.110E+00
0.460	0.534E-03	0.814E-01
0.475	0.116E-02	0.638E-01
0.490	0.209E-02	0.517E-01
0.505	0.331E-02	0.428E-01
0.520	0.482E-02	0.360E-01
0.535	0.664E-02	0.307E-01
0.550	0.875E-02	0.263E-01
0.565	0.112E-01	0.227E-01
0.580	0.139E-01	0.196E-01
0.595	0.169E-01	0.170E-01
0.610	0.203E-01	0.147E-01
0.625	0.240E-01	0.127E-01
0.640	0.281E-01	0.110E-01
0.655	0.327E-01	0.940E-02
0.670	0.378E-01	0.799E-02
0.685	0.434E-01	0.673E-02
0.700	0.498E-01	0.558E-02
0.715	0.570E-01	0.454E-02
0.730	0.654E-01	0.358E-02
0.745	0.753E-01	0.270E-02
0.760	0.875E-01	0.189E-02
0.775	0.103E+00	0.114E-02
0.790	0.128E+00	0.438E-03
0.800	0.176E+00	0.000E+00
1.000	1.000E+00	0.000E+00

Table A.2: Brine relative permeability and capillary pressure data for imbibition displacements.

Brine Saturation	Oil Relative Permeability
0.8	0.000E+00
0.745	0.143E-02
0.73	0.565E-02
0.715	0.144E-01
0.7	0.283E-01
0.685	0.476E-01
0.67	0.720E-01
0.655	0.101E+00
0.64	0.134E+00
0.625	0.170E+00
0.61	0.209E+00
0.595	0.251E+00
0.58	0.295E+00
0.565	0.341E+00
0.55	0.389E+00
0.535	0.438E+00
0.52	0.489E+00
0.505	0.541E+00
0.49	0.595E+00
0.475	0.651E+00
0.46	0.709E+00
0.445	0.770E+00
0.43	0.834E+00
0.415	0.906E+00
0.4	1.000E+00

Table A.3: Oil relative permeability data for drainage displacements.

Brine Saturation	oil Relative Permeability
1	0.000E+00
0.715	0.189E-02
0.7	0.528E-02
0.685	0.116E-01
0.67	0.216E-01
0.655	0.357E-01
0.64	0.544E-01
0.625	0.778E-01
0.61	0.106E+00
0.595	0.138E+00
0.58	0.176E+00
0.565	0.217E+00
0.55	0.263E+00
0.535	0.312E+00
0.52	0.366E+00
0.505	0.424E+00
0.49	0.486E+00
0.475	0.552E+00
0.46	0.623E+00
0.445	0.700E+00
0.43	0.783E+00
0.415	0.877E+00
0.4	1.000E+00

Table A.4: Oil relative permeability for imbibition displacements.

Appendix B

Saturation Calculations

This appendix gives the details of the saturation calculations from the CT measurements. As stated in Chapter 3 the CT number of the core at different saturation stages is measured during the course of the experiments. The CT numbers of the core are measured at predetermined cross sections when the core is dry, and also when the core is 100% saturated with brine. Then during the runs, these are measured at whatever flood stage the saturations are to be determined. If we let CT_{dry} and CT_{100br} be the CT numbers of the core when dry and when 100% saturated with brine at any volume element in the core; Then, if the CT number of the brine itself is CT_{br} , the porosity, ϕ , of that volume element is given by:

$$\phi = \frac{CT_{100br} - CT_{dry}}{CT_{br} + 500} \quad (B.1)$$

To calculate any intermediate saturation of the core we need the CT number of the core when it is 100% saturated with oil. As we do not saturate the core 100% with oil during the experiments to avoid obvious experimental complications, this number is calculated by:

$$CT_{100oil} = CT_{dry} + \phi CT_{oil} \quad (B.2)$$

In this equation CT_{100oil} is the CT number of the 100% oil saturated core and CT_{oil} is the CT number for the oil itself.

Now if the term, CT , is the measured CT number of the core at any intermediate water saturation, S_w , the saturation can be calculated by:

$$S_w = \frac{CT - CT_{100oil}}{CT_{100br} - CT_{100oil}} \quad (B.3)$$

All of these equations assume that the CT number of the core varies linearly with the saturation. This assumption was verified by comparing the average brine saturations obtained from CT scans and those obtained by volumetric material balance.

Two program were developed to automate all of these calculations at each volume element of the core for which the CT data is obtained. The first program is used to calculate the porosity ϕ , and the CT values for the 100 % oil saturated core CT_{100oil} . The second program uses this data and the CT values measured by the scanner at different times and cross sections, and calculates the brine saturations. The use of these two programs with sample data files is given in the following sections.

B.1 Program for Porosity Calculations

This program was written using the C language. It requires just one input data file, a sample of which is given below:

```
/home/pete/suhail/TAPE/PROCESS/C3
/home/pete/suhail/TAPE
12000
6775.0 -2500.0
121 121 190 190
TAPE12/c3a_1 TAPE12/c3a-100%_1
TAPE12/c3a_2 TAPE12/c3a-100%_2
TAPE12/c3a_3 TAPE12/c3a-100%_3
TAPE12/c3a_4 TAPE12/c3a-100%_4
TAPE12/c3a_5 TAPE12/c3a-100%_5
TAPE12/c3a_6 TAPE12/c3a-100%_6
```

TAPE12/c3a_7 TAPE12/c3a-100%_7
TAPE12/c3a_8 TAPE12/c3a-100%_8
TAPE12/c3a_9 TAPE12/c3a-100%_9
TAPE12/c3a_10 TAPE12/c3a-100%_10

The structure of this input file is given below;

1. The first record in this file is the name of the directory where the processed files are to be stored.
2. The second record is the name of the directory from which the raw CT files are to be read.
3. The third record is a threshold CT number. Only the CT values in the scans which are greater than this value are processed. This is done to avoid getting negative numbers in the calculated values.
4. This record has the CT values of Brine and Oil.
5. The four numbers in this record give the minimum and maximum coordinates in the scan for the area of interest. They are xmin, ymin, xmax, ymax respectively.
6. All subsequent lines have two file names, one for the dry core and the other for the 100% brine saturated core at the same cross section.

The program processes all the pairs of files and generates two files from each pair. The first one is the porosity map and has the suffix “.por” attached to the file name given for the dry scan. The second is a file containing the calculated CT values if the core was 100% saturated with oil, and has the suffix “_oil” attached to the file name given to the dry scan.

B.2 Program for Saturation Calculations

This program was also written in C, and requires one input file for processing the CT scans. An example file is given below.

```

/home/pete/suhail/TAPE/PROCESS/C3
/home/pete/suhail/TAPE
13000
127 123 200 196
TAPE8/c2a_100%_1 PROCESS/c2a_dry_1_oil 4
TAPE9/c2a_d1_28 TAPE9/c2a_i1_28 TAPE9/c2a_i2_28
TAPE9/c2a_pd_29
TAPE8/c2a_100%_2 PROCESS/c2a_dry_2_oil 4
TAPE9/c2a_d1_29 TAPE9/c2a_i1_29 TAPE9/c2a_i2_29
TAPE9/c2a_pd_30

```

1. The first record in this file is the name of the directory where processed files are to be stored.
2. The second record is the directory from which the CT scan files are to be read.
3. The third record is a threshold CT number. Only the CT values in the scans which are greater than this value are processed. This is done to avoid getting negative numbers in the calculated values.
4. The four numbers on this line give the minimum and maximum coordinates in the scan for the area of interest. They are xmin, ymin, xmax, ymax respectively.
5. This record contains the name of the CT files that contain the CT_{100br} and CT_{100oil} values. The last field is an integer N , the number of scan data files which are to be processed using these two CT files. This is followed by N file names which are the CT files containing the scans for which the saturations are to be calculated. This sequence is repeated for as many files as necessary.

Appendix C

Programs for History Matching

The use of the history matching program along with the sample input data files, is explained in this appendix.

C.1 Main input file

The input data file for the first drainage displacement is reproduced below:

```
DIREC
D
initial lamda
0.0001
MA MAXITER
16 30
lista
1 2 3 4 5 6 7 8 9 0 1 2 3 4 5 6
0 0 0 0 1 1 1 1 0 0 0 0 1 1 1 1
parameters      min      guess    max
c1      swci      0.11     0.3147  0.5
c2      Sori      0.100    0.2528  0.272
c3      Krwroi    0.01     0.0821  0.1
```

c4	Krocwi	0.1	0.3035	0.800
c5	swcd	0.11	0.236	0.5
c6	Sord	0.1	0.293	0.4
c7	Krwrod	0.05	0.088	0.1
c8	Krocwd	0.3	0.341	1.0
c9	awi	0.01	9.448	10.0
c10	ani	0.01	0.0667	5.0
c11	alphwi	0.5	4.786	6.0
c12	alphni	0.100	2.703	5.0
c13	awd	1.5	5.450	15.0
c14	and	0.1	0.264	5.0
c15	alphwd	0.100	0.5458	3.0
c16	alphnd	0.10	1.958	5.0

atol
0.001

sig1 sig2 sig3 nwt wtf
37.0 10.0 0.30 40 1.0

--pcfile
pc_11_2n.dat

-- t_init
47.826

--datafile
c4ad1_avg.pv

--satfile
c4ad1.sat

--ecl_file
R1DD1

Each of the lines in this file is a record read by the program. Each of the records are explained below:

1. Comment
2. Either a 'D' or an 'I' for drainage or imbibition
3. Comment
4. Initial value of the λ , which determines the step length in the Levenberg–Marquardt algorithm.
5. Comment
6. Number of parameters and the maximum number of iterations.
7. Comment
8. Comment
9. A list of 0's and 1's corresponding to each parameter in the model. A '1' will make the parameter to be used in the history match, while a '0' will keep that parameter constant.

Records 11 to 26 are the minimum value, the first guess and the maximum value for the parameters in the model.

27. Comment
28. Tolerance for the match
29. Comment
30. The values for the standard deviations
31. Comment
32. Name of the file containing the capillary pressure data
33. Comment
34. Starting time for the simulation. It is the total time for the sequence of experiments up to the beginning of this displacement.

35. Comment
36. Name of the data file that contains the recovery and pressure drop data.
37. Comment
38. Name of the file containing the measured saturation profile.
39. Comment
40. Name of the ECLIPSE data file.

The program initializes all basic parameters required for the history match by reading this file. This input file also provides the program, the names of files containing the data required for the match, like the capillary pressure, the recovery and production data to be matched, the measured saturation profile and the ECLIPSE data file. These files are described in the following sections.

C.2 Capillary Pressure Data File

This file is in two sections. The first section is for the drainage capillary pressure data and the second is for imbibition data. The first record in each section is a comment, the second is the number of data points in that section, this is followed by pairs of saturation–capillary pressure data one on each line. an example file is given below:

```
# Drainage
22
0.110000000 2.7265400
0.115000002 2.03569818
0.144666672 0.374925911
0.174333334 0.218436062
0.203999996 0.156828821
0.233666658 0.123407431
0.263333321 0.102269858
```

0.292999983	0.0876256824
0.322666645	0.0768459737
0.352333307	0.0685595274
0.381999969	0.0619789958
0.411666632	0.0566190295
0.441333294	0.0521636531
0.470999956	0.0483980626
0.500666618	0.0451709554
0.530333281	0.0423726067
0.559999943	0.0399214253
0.589666605	0.0377554558
0.619333267	0.0358267725
0.648999929	0.0340977125
0.678666592	0.0325382426
0.707000000	0.0000000000

Imbibition

25

0.1100000	2.72654
0.1150000	0.2164655
0.1412273	4.9049303E-02
0.1674545	2.8596550E-02
0.1936818	1.9983370E-02
0.2199091	1.5115105E-02
0.2461363	1.1943240E-02
0.2723636	9.6938200E-03
0.2985909	8.0057979E-03
0.3248181	6.6867559E-03
0.3510454	5.6242072E-03
0.3772727	4.7477311E-03
0.4034999	4.0108669E-03
0.4297272	3.3816448E-03

0.4559545	2.8373017E-03
0.4821817	2.3611686E-03
0.5084090	1.9407370E-03
0.5346363	1.5664278E-03
0.5608636	1.2307758E-03
0.5870909	9.2786970E-04
0.6133182	6.5296423E-04
0.6395455	4.0220562E-04
0.6657728	1.7242739E-04
0.7060000	0.000000
1.0000000	0.000000

C.3 Saturation Data File

This file contains the saturation data in distance–saturation pairs starting at record 3. The first record is a comment and the second record is the number of data points in the file. An example data file is given below:

```
# % Drainage -1 core 4
19
2.28 0.329
3.55 0.333
4.82 0.316
6.09 0.33
7.36 0.313
8.63 0.301
9.90 0.324
11.17 0.283
12.44 0.334
13.71 0.33
```

14.98	0.324
16.25	0.33
17.52	0.334
18.79	0.326
20.06	0.341
21.33	0.348
22.60	0.366
23.87	0.412
24.58	0.44

C.4 The ECLIPSE Data file

This is a standard ECLIPSE data file, that describes the core geometry, flow rates etc. The relative permeability, capillary pressure and the time steps required for the simulation are not given in this file, but are generated by the program and included in this file by ECLIPSE. Please refer to the ECLIPSE users guide for complete details.

Appendix D

Results from History Matches

The comparison of simulated and the experimental results using the early time data and the expanded scale graphs of the final matches, which were not included in Chapter 4 are presented in this appendix. Figures D.1 and D.2 show the pressure drop, recovery and saturation profile matches for the 3.77 cc/min imbibition displacement. The resulting relative permeability curves are graphed in Fig. D.3. The expanded scale match of the recovery and pressure drop data are presented in Figures D.4 and D.5. As discussed at length in Chapter 4 there is some mismatch in the pressure drop just before and after the breakthrough.

The match, using the early time data for the 4.28 cc/min drainage displacement, and the measured pressure drop, recovery and the saturation profiles are graphed in Figures D.6 and D.7. The relative permeability curves obtained from this match are graphed in Fig. D.8. The expanded scale graphs of the match using the complete data set for this displacement experiment are shown in Figures D.9 and D.10

Figure D.1: Pressure drop and recovery match for 3.77 cc/min imbibition using early time data.

Figure D.2: Measured and simulated saturation profiles for 3.77 cc/min imbibition using early time data.

Figure D.3: Imbibition relative permeabilities obtained from the history match for 3.77 cc/min using early time data.

Figure D.4: Pressure drop and recovery match for 3.77 cc/min imbibition using complete data set (Time = 0-1 hrs).

Figure D.5: Pressure drop and recovery match for 3.77 cc/min imbibition using complete data set (Time = 0-5 hrs).

Figure D.6: Pressure drop and recovery match for 4.28 cc/min drainage using early data.

Figure D.7: Measured and simulated saturation profiles for 4.28 cc/min drainage using early data.

Figure D.8: Drainage relative permeabilities obtained from the history match for 4.28 cc/min using early data.

Figure D.9: Pressure drop and recovery match for 4.28 cc/min drainage using complete data set (Time = 0-1 hrs).

Figure D.10: Pressure drop and recovery match for 4.28 cc/min drainage using complete data set (Time = 0-5 hrs).

Appendix E

Contents of the CD

All programs and data from this work has been put on a CD that is available from the SUPRI-A Program Office, Petroleum Engineering Department, Stanford University. The contents are organized in two directories named “prog” and “data”. The root directory also contains a file named LSLR, which contains the complete listing of the files on the CD. A brief listing of the contents is given below:

```
CD--|
    |-LSLR
    |-data
    |   |-hismat
    |   |   |-d1
    |   |   |   |-long
    |   |   |   |   |-input
    |   |   |   |   |   |-R1DD1.DATA
    |   |   |   |   |   |-c4ad1.in
    |   |   |   |   |   |-c4ad1.sat
    |   |   |   |   |   |-c4ad1_avg.pv
    |   |   |   |   |   |-pc_11_2n.dat
    |   |   |   |   |   |Repeated for
    |   |   |   |   |   |the seven
    |   |   |   |   |   |displacements
    |   |   |   |   |-ouput
```

```

|      |      |      |      |-ECL_AVSAT.dat      |
|      |      |      |      |-ECL_KRPC.dat       |
|      |      |      |      |-c4ad1.out          |
|      |      |      |      |-fort.9             |
|      |      |      |      |-fort.99            |
|      |
|      |
|      |-JBN
|          |-d1
|              |-input
|                  |-c4ad1.pv                      |
|                  |-ejbnd1.in                      |
|                  |
|              |-output                            |Repeated for
|                  |-c4ad1.inj                      |the six
|                  |-c4ad1.inj_fit                   |displacements
|                  |-c4ad1.kr                        |
|                  |-c4ad1.out                       |
|                  |-c4ad1.rec                       |
|                  |-c4ad1.rec_fit                   |
|                  |
|
|
|- prog
|
|      |-ctcalc (Programs for porosity and saturation calculations)
|      |-datalog ( Data logging program)
|      |-histmatch ( Programs used in the history matching package)

```