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**Evaluation of NMR and MRI Techniques for Use
in Special Core Analysis**

by

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ABSTRACT

Special core analysis, involving conduct and interpretation of dynamic displacement tests, has been the main source of relative permeability relationships. However, as a result of lack of knowledge about saturation distribution and saturation gradients in the core floods, laboratory displacement tests have for a long time been evaluated on the basis of assumptions such as the concept of one-dimensional diffuse flow, ignoring capillary pressure gradients and ignoring core scale heterogeneities. In an attempt to justify some of the assumptions, most laboratory tests are designed at flow rates which risk losing similarity with the reservoir displacement conditions and which in turn may lead to gross error in development of the relative permeability relationships. The one-dimensional relative permeability relationships are used to develop fractional flow forecasts and to predict multidimensional reservoir performance.

In this research a nuclear magnetic resonance (NMR) imaging (or magnetic resonance imaging (MRI) for short) technique has been evaluated and used to obtain knowledge about saturation distribution and saturation gradients in core floods. This allows evaluation of the contribution of both viscous and capillary forces to the results of laboratory displacement tests. The imaging was conducted with equipment comprising a nuclear magnetic resonance imager and an imaging console with computer software, plotter, hard disk, floppy disk and tape streaming facilities. The imaging equipment was used to complement the conventional core flood test experimental instrumentation, which for this purpose, was made using only non-magnetic material.

An important new contribution to knowledge which has resulted from this research is the demonstration that the MRI technique can be used successfully to enable a meaningful set of relative permeability curves to be obtained for a heterogeneous rock sample. This arises from the separation of viscous and capillary forces in the displacement process and the consequent opportunity for scale-up on

the basis of force ratios. The relative permeability relationships were calculated from a combination of the saturation distribution data provided by the imaging technique and the usual core flood data comprising the pressure and production history. An evaluation of the MRI technique for use generally in core analysis has also been undertaken and this generally indicates positive results.

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NOMENCLATURE

<u>Symbols</u>	<u>units</u>	<u>meaning</u>
A	cm^2	cross sectional area
A	%, fraction	NMR signal amplitude
B_o	T, G	static magnetic field of an NMR spectrometer
D	m	depth
G	G/cm	strength of magnetic field gradient
I		nuclear spin
I_r		relative injectivity
L	cm, mm	length
$M(t)$		transient magnetisation decay
M_o		equilibrium bulk magnetisation of a spin system
N_{pd}	PV	cumulative oil recovery
S_w	fraction	saturation of wetting phase or water
S_{we}	fraction	water saturation in producing well
S_{wf}	fraction	frontal water saturation
T_1	ms, s	spin-lattice or longitudinal relaxation time
T_2	ms, s	transverse relaxation times
T_2^*	ms, s	total dephasing time
T_2'	ms, s	T_2 contribution due to magnetic field inhomogeneity
T_e	ms	echo time
T_r	s	repetition rate
T_R	s	interpulse time spacing
W_i	cm^3	cumulative water injected
W_{id}	PV	dimensionless W_i
f	Hz, rad/sec	frequency per point
f_w	fraction	fractional flow of wetting phase or water
f_{we}	fraction	f_w at the producing end after breakthrough
g	m/s^2	acceleration due to gravity
k	darcy, md, m^2	absolute permeability
k_L	darcy, md, m^2	liquid permeability
k_r	fraction	relative permeability

p	atm, psi, Pa	pressure
p_c	atm, psi	capillary pressure
q	volume/time	flow rate
t	ms, s	time
t_e	ms	echo time
v	m/s, cm/s	flow velocity
$\vec{v}$	m/s	flow velocity vector
ν_i	Hz	Larmor frequency for the i^{th} nucleus
ν_j	rad/sec	Larmor frequency for the j^{th} nucleus
ω_o	rad/sec	the NMR frequency of the rf pulse
x, y, z		co-ordinates
x, y, z	m, cm, mm	length, distance
x_f	cm	distance from injection end to the flood front
Δ_x	mm	resolution
$\Delta\nu_{\frac{1}{2}}$	Hz, ppm	absorption mode linewidth

Greek letters

Φ	atm	datum corrected pressure
α	fraction	geometric factor
γ	rad s	the magnetogyric ratio of a nucleus
ϕ	fraction	porosity
μ	cp, Pa.s	fluid viscosity
ρ	g/cm^3	fluid density
σ	dynes/cm	interfacial tension
σ_j	ppm	shielding constant of nucleus j
θ	degree	angle

subscripts

bt	breakthrough
i	injection
nw	nonwetting phase
o	oil

w	water or wetting phase
t	total
x, y, z	components

superscripts

R	registered trade mark
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Abbreviations

CT	computerised tomography
VHF	very high frequency
1-D	one-dimensional
2-D	two-dimensional
3-D	three-dimensional
2DFT	two-dimensional Fourier transform
2DPE	two-dimensional phase-encoding
CSI	chemical shift imaging
EOR	enhanced oil recovery
FFI	free fluid index
G	Gauss
NMR	nuclear magnetic resonance
MRI	magnetic resonance imaging
PV	pore volumes
RCA	routine core analysis
S/N	signal to noise ratio
T	Tesla
ppm	parts per million
rf	radio frequency
ms	milliseconds

CHAPTER 1

GENERAL INTRODUCTION

1.1 Background

Crude oil held in pores of reservoir rocks is often recovered by displacing it by the accumulation of other fluids, normally gas or water. Hence considerable research work has been devoted to the study of mechanisms by which one fluid is displaced by another in a porous medium. A good part of the work is primarily concerned with studying the displacement of oil by water in reservoir rock materials since many reservoirs are produced by waterflooding. While oil and water are immiscible, it is well known that the displacement of one by the other is not really piston-like. Except at the irreducible or residual saturation of one of the fluids (end points), the two fluids appear to flow simultaneously within the porous medium with no mass transfer between them. An apparently irreducible fraction of each of the fluids is trapped in the porous medium. One of the fluids may wet a given medium more than the other. The amount and distribution of the movable and trapped fluids depend largely on the wetting preference of the porous medium. Water often appears to be the preferential wetting phase to reservoir rocks in a water-oil system. As such throughout this thesis water will be taken to be the wetting phase, unless otherwise specified.

Laboratory flow tests have been used for many years to study displacement mechanisms in reservoir rocks. Displacement experiments are frequently conducted with core plugs which are typically around 5 cm long by 3 cm in diameter. The results of such “linear” one-dimensional core floods are commonly interpreted for use in numerical simulation models in which domain cells typically have dimensions of 100 m by 100 m by 10 m. Most of the commonly utilised methods of interpreting dynamic displacement tests in “Special Core Analysis” studies invoke the assumption of diffuse flow, core homogeneity and absence of capillary pressure gradients. Such assumptions are often necessitated by the limited information available on the movement and distribution of the fluids inside the core. This is mainly due to the limited capability of the experimental instrumentation. It is not unreasonable to expect that if the assumed conditions are not true then such interpretation may lead to gross error in development of relative permeability relationships which usually forms the main purpose of displacement testing. The relationships are used in simulators which have the capability to represent full viscous / capillary / gravity force controls in developing fractional flow forecasts. The ideal way of obtaining information concerning displacement processes within

a core is to monitor the distribution and movement of the fluids inside the reservoir rock sample.

Imaging techniques such as those used in medical technology promise to be useful tools in petrophysical and reservoir engineering studies. There has been an advance in two-dimensional (2-D) interpretation of saturation distribution in cores utilising X-Rays (Hove et al., 1985; Withjack, 1987) and nuclear magnetic resonance phenomenon (Rothwell and Vinegar, 1985). The 2-D interpretation is based on computer aided creation of 'images' of saturation measurements and are called 'computerised tomography' (CT). These techniques are more powerful than the earlier imaging methods involving microwaves, VHF electrical properties, tracers in the fluid phases, radioactive sources outside the sample, X-rays and resistivity, which give only one-dimensional (1-D) information about fluid distribution.

1.2 Statement of the Problem

Appropriate laboratory core floods need to be evaluated in the light of knowledge about saturation distribution and saturation gradients in heterogeneous core in order to make meaningful interpretation of the results. This has led in recent years to the use of imaging techniques in core flood tests. Though history matching procedures for validating core flood simulators already exist (Archer and Wall, 1986), their use has been limited by a general lack of knowledge concerning the fluid displacement processes within the heterogeneous core. An X-ray tomography technique has been evaluated and is extensively used for performing core flood tests (Ringen and Hove, 1987). The limitations of the technique appear to reside in resolution of saturation, particularly where interests may lie at pore scales. Nuclear magnetic resonance (NMR) imaging or magnetic resonance imaging (MRI) for short also lends itself to tomographic imaging and medical applications of it hint that it might also be usefully applied to petrophysical and reservoir engineering studies.

There are only a few reports of the potential of the NMR technique (Rothwell and Vinegar, 1985; Vinegar, 1986; Williams et al, 1990) which suggest that the technique can complement the X-ray CT. It also has a number of important advantages over X-Ray CT and the 1-D imaging methods involving microwaves (Parsons, 1975), VHF electrical properties (Davis, 1980), radioactive tracers (Josendal et al.,

1952), etc. The limits of resolution of saturation in NMR imaging at individual pore level has not yet been reported but high resolutions down to few tens of microns have been achieved with high magnetic fields and gradients. The limits therefore appear to be controlled largely by the power of the equipment employed. MRI also opens the possibility of three-dimensional (3-D) visualisation of flow in porous media, and can image nuclear spin density, NMR relaxation times and chemical shifts.

In a porous rock, the spin density images show the spatial distribution of fluid-filled porosity. The transverse relaxation times T_2 show the physical nature of the pores, e.g., pore size or clay content. The ability to discriminate oil and water by MRI is based on the chemical shifts and differences in the relaxation times.

The research reported here concerns work to evaluate the potential of MRI methods in terms of resolution and discrimination of saturation, applicability to different reservoir rocks, ability to distinguish different fluid species, ability to 'visualise' flow in cores and to offer an opportunity to resolve saturation gradients in core floods in terms of viscous and capillary force terms. In the evaluation, suitable MRI methods are sought for studying particular displacement processes and several core displacement tests are performed and interpreted to demonstrate the usefulness and to identify the limitations of this technique.

1.3 Scope and Aims of this Research

The main aim of this research work is to investigate the potential of NMR and MRI techniques as a laboratory tool for studying core floods, especially with heterogeneous reservoir rock samples.

It also aims to provide insight into the fluid displacement processes within cores, and to evaluate the results of laboratory displacement tests in the light of the knowledge concerning saturation distribution and saturation gradients. This knowledge opens the possibility of resolving saturation gradients in laboratory core floods in terms of viscous and capillary force terms, hence the fractional flow equation can be solved to include the capillary pressure gradient term.

The findings of this work are used to enhance development of improved and reliable relative permeability relationships which are used in appropriate reservoir simulation models to predict reservoir performance.

1.4 Research Methodology

This project involved extensive experimental investigation and required characterisation of natural porous rocks of interest in petroleum reservoirs. To achieve the objectives set out above this work was organised in the following sequence.

1. Experimental methods were devised for conducting flow experiments inside the magnet of the NMR imager. This involved design and construction of special core holders with ancillary flow rig assemblies of non-magnetic material.
2. Routine core analysis (RCA) was employed to characterise the rock samples.
3. Each core was imaged using MRI methods while it contained oil or water or both in static or dynamic flow conditions. Fluid saturations were quantified by both material balance and NMR methods, and saturation distributions within the core sample were spatially mapped by 1-D and/or 2-D imaging.
4. Experimental data obtained from the imaging and the flood tests were combined and used in displacement calculations to obtain the relative permeability relationships.
5. The relative permeability relationships were validated by use in a multidimensional core flood simulator.

1.5 Thesis Outline

The content of the thesis can be summarised under three broad groupings. The first grouping is a general introduction which includes a statement of problem being investigated, i.e., why we seek to use MRI technique in core flood studies. A review of the theory of fluid displacement in reservoir rocks, with emphasis on previous core flood studies, comes under the second grouping. Also under this

grouping a brief review of the basic principles and theory of NMR and MRI, with their previous applications to petroleum engineering studies, is presented. Finally experimental results and their analysis, core flood simulation results, findings, conclusions and recommendations form the major and last of the groupings.

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CHAPTER 2

NUCLEAR MAGNETIC RESONANCE

2.1 Basic Principles

Nuclear magnetic resonance (NMR) spectroscopy has long been in use (since its discovery in 1946) in such diverse fields as organic and analytical chemistry, solid state physics, food science and petroleum engineering, hence its basic principles are well established and its theory is adequately described in several texts including Abragam (1961). The concept of nuclear magnetic resonance imaging (MRI), however, was developed later (Lauterbur 1973). Only a brief overview of the basic physical principles of NMR is provided here, with emphasis on the imaging principles. Detailed review and discussion on NMR and MRI can also be found in texts such as Mansfield and Morris (1982), McConnell (1987), and many others. NMR active nuclei, when placed in a magnetic field and irradiated by a pulse of radio frequency (rf), emit measurable rf signals. The rf field satisfies the resonance condition

$$w_o = \gamma B_o \quad (2.1)$$

where,

w_o is the NMR frequency of the rf pulse (in rad/sec),

γ is the magnetogyric ratio of the selected nucleus and is specific to the nuclear species considered, and

B_o is the strength of the applied magnet field.

The reason why some atomic nuclei are affected by a magnetic field is that they themselves behave in some respects like tiny magnets. In particular the proton in the nucleus of the hydrogen atom ^1H emits the strongest signal because it has by far the largest magnetic moment I . Other magnetically active nuclei include ^{19}F , ^{23}Na , ^{31}P , and ^{14}N . Prior to perturbing the magnetic environment of the atomic nuclei, the nuclear system is in thermal equilibrium with their surroundings (or lattice) and the bulk magnetisation M_o lies along the field direction B_o .

When a sample containing NMR active nuclei is placed in a magnetic field, the energy states of the nuclear spin become nondegenerate. Energy is exchanged with the lattice, and a net spin polarisation develops resulting in a new position of magnetisation. The equilibrium magnetisation can be perturbed by the application of an oscillating magnetic field rotating in phase with the precessing magnetisation. If a pulse of rf is applied the new position of the magnetisation can be resolved into component M_z parallel to B_o and transverse components M_x and M_y normal to B_o . When the system reaches a new steady state of equilib-

rium, the magnetisation components M_x and M_y are each zero. The nuclear spin system returns from the excited state to thermal equilibrium in a manner which can be modelled mathematically by exponential decays, with characteristic time constants T_1 and T_2 (Equations 2.2 and 2.3). These time constants known as relaxation times characterise the time dependent return of nonequilibrium spin systems to equilibrium.

$$M_z(t) = M_o[1 - \exp(-\frac{t}{T_1})] \quad (2.2)$$

$$M_{x,y}(t) = M_o \exp(-\frac{t}{T_2}) \quad (2.3)$$

where, t is the time from start of application of the pulse.

T_1 is known as spin-lattice or longitudinal relaxation time and characterises energy transfer from the nuclear spin system to the lattice, which results in return of the z component magnetisation M_z to M_o . The magnetisation M_z is parallel with the magnet field and hence does not generate signal in the direction perpendicular to the field.

T_2 is known as spin-spin or transverse relaxation time and characterises the interaction of the nuclear spins with one another, without transfer of energy to the lattice, which results in the change in M_x and M_y . Inhomogeneities in the magnetic field or strong local fields in the sample cause the transverse magnetisation M_x and M_y to decay more rapidly. Spin-spin interaction in this case is characterised by a total dephasing time T_2^* , which for a typical NMR experiment arises from the intrinsic T_2 and the contribution T_2' due to the magnetic field inhomogeneity. Equation (2.3) is therefore rewritten as

$$M_{x,y}(t) = M_o \exp(-\frac{t}{T_2^*}) \quad (2.4)$$

where,

$$\frac{1}{T_2^*} = \frac{1}{T_2} + \frac{1}{T_2'} \quad (2.5)$$

2.1.1 NMR imaging and methods

MRI was developed by Lauterbur (1973) when he demonstrated that by applying controlled magnetic field gradients, the spatial distribution of hydrogen-containing fluids could be mapped with NMR. By contrast with conventional high-resolution

NMR which requires the use of homogeneous magnetic fields (field is constant over the sample), MRI is accomplished by making the field inhomogeneous. For fluid identification and the study of immiscible fluid displacement in opaque porous rocks, where two or more fluid phases may be present it is necessary to have an imaging technique capable of readily distinguishing between fluids of different chemical composition. Chemical shift imaging (CSI) technique is well suited for the spatial mapping of water and hydrocarbon in porous rock (Hall et al., 1986). CSI measurements yield a chemical shift data set which has three dimensions. By phase-encoding spatial information along two of the three spatial axes the final display is a two-dimensional (2-D) display of the intensity distribution corresponding to a particular chemical shift. The display can be made on a gray scale. To encode spatial information into the signal a magnetic field gradient is superimposed on the static magnetic field. By combining a series of magnetic field gradient pulses and rf pulses in a particular way, it is possible to spatially encode phase or frequency on the time domain NMR signal. This information is then extracted back to the spatial domain by Fourier transformation. MRI can thus obtain a 2-D image of a three-dimensional (3-D) object and produce images from selected regions of the sample. Important hardware on an MRI system is schematically shown in Figure 2.1.

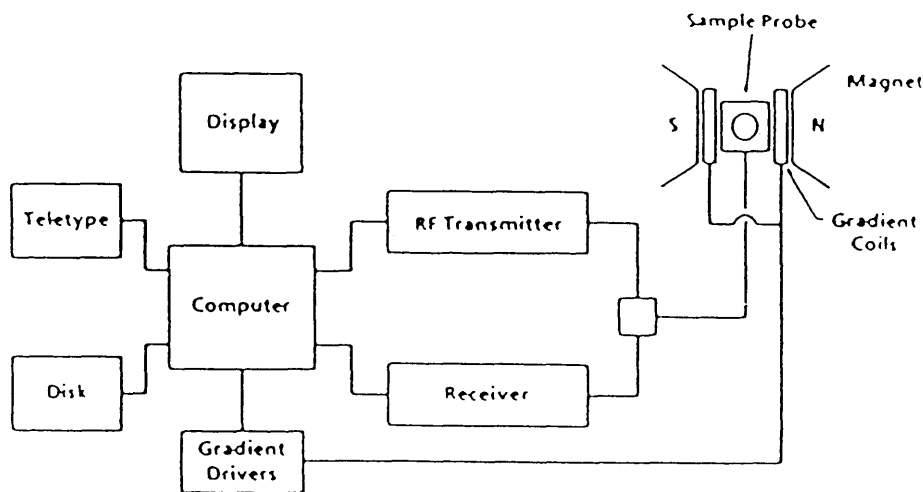


Figure 2.1 Schematic of basic hardware on an MRI system (after Rothwell, 1985)

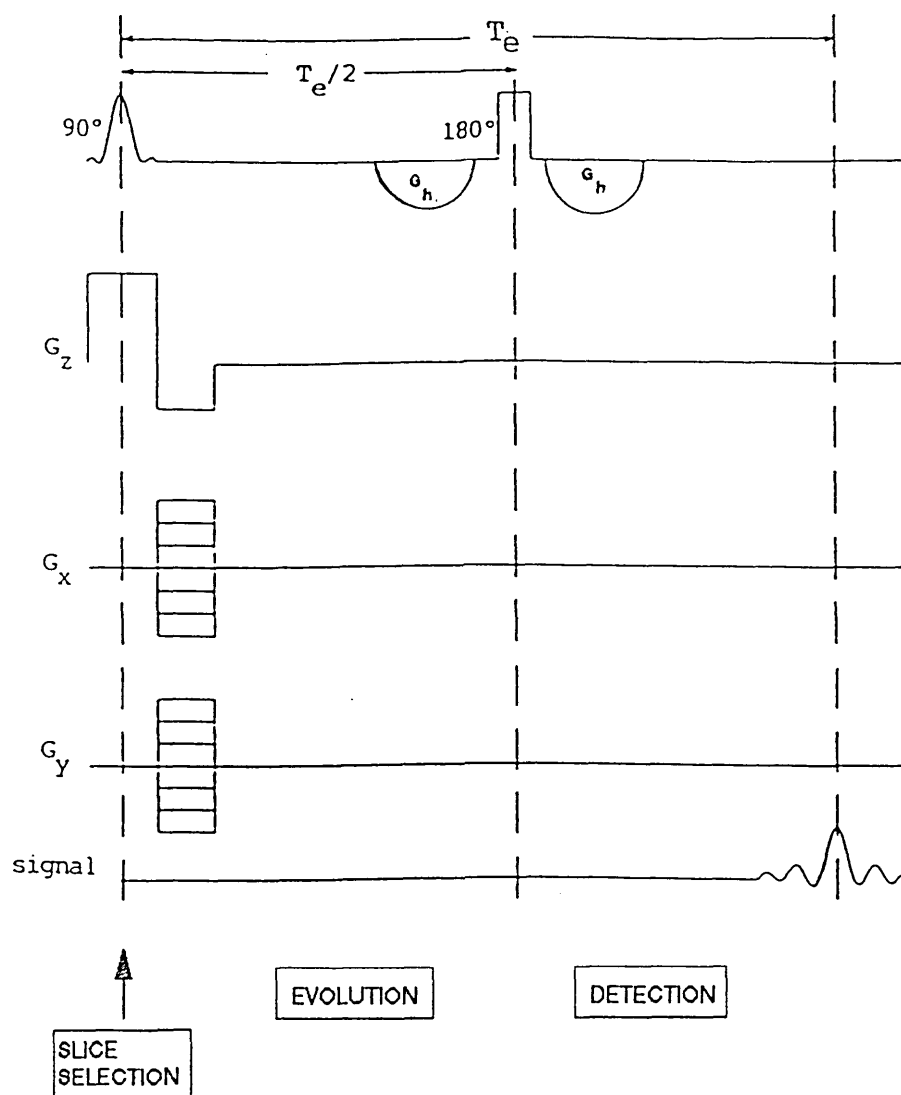
MRI methods have been extensively reviewed by Mansfield and Morris (1982) and will not be repeated here. However, the 2-D imaging method utilised in this work is briefly discussed. The imaging method involves a modification of the spin-warp imaging technique which uses a two-dimensional Fourier transform (2DFT) processing (Edelstein et al., 1980). Although the 2DFT imaging technique works well for a single resonance, it does not permit the measurement of the chemical shift spectra because the frequency-encoding gradient, applied during data acquisition, broadens the spectral line so that chemical shift information is irretrievably lost. This problem was overcome by modifying the technique as described below.

2.1.2 Chemical shift imaging

Figure 2.2 shows the gradient and rf pulse sequence used here. The technique is a modified two-dimensional phase-encoding (2DPE) sequence used to perform chemical shift imaging (CSI). In the Figure, the 90° rf pulse was combined with the gradient G_z and each selective 90° pulse was followed at time $\frac{T_z}{2}$ by a non-selective 180° pulse. The phase encoding rf pulses are used in both y and x directions, while homospoil gradients on the z direction are symmetric about the 180° rf pulse. To produce a 1-D image the phase-encoding gradient in the y -direction was removed.

Figure 2.3(a), in conjunction with Figure 2.2, illustrates the slice selection process. Slice selection was effected by applying a selective 90° rf pulse in the presence of the magnetic field gradient G_z . During the evolution period a reversed (rephase) gradient $-G_z$ was applied to refocus the excited magnetisation. A solenoid rf coil was used in the imaging and was oriented perpendicular to the static magnetic field. The coil was positioned parallel with the gradient G_z direction so slicing along x produced a circular cross section through a cylindrical core, and slicing along y (or z) produces a longitudinal cross section. The slice position was determined by the centre of the selective pulse. The slice thickness was determined by a combination of the bandwidth of the frequency components contained in the selective pulse and the applied gradient strength. A shape selective pulse, 1.5 ms Gaussian weighted, applied with 2.5 G cm^{-1} gradient (G_z) gives a slice thickness of about 4 mm.

The phase encoding process is illustrated in Figure 2.3(b). The phase encoding gradients G_x and G_y in Figure 2.2 were applied (switched on) in the same time period as the rephase gradient, i.e., during the evolution period. The non selective



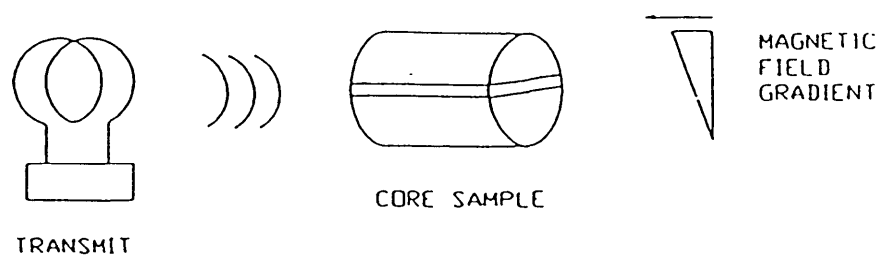
G_z - the observe magnetic field gradient

G_x & G_y - phase encoding gradients

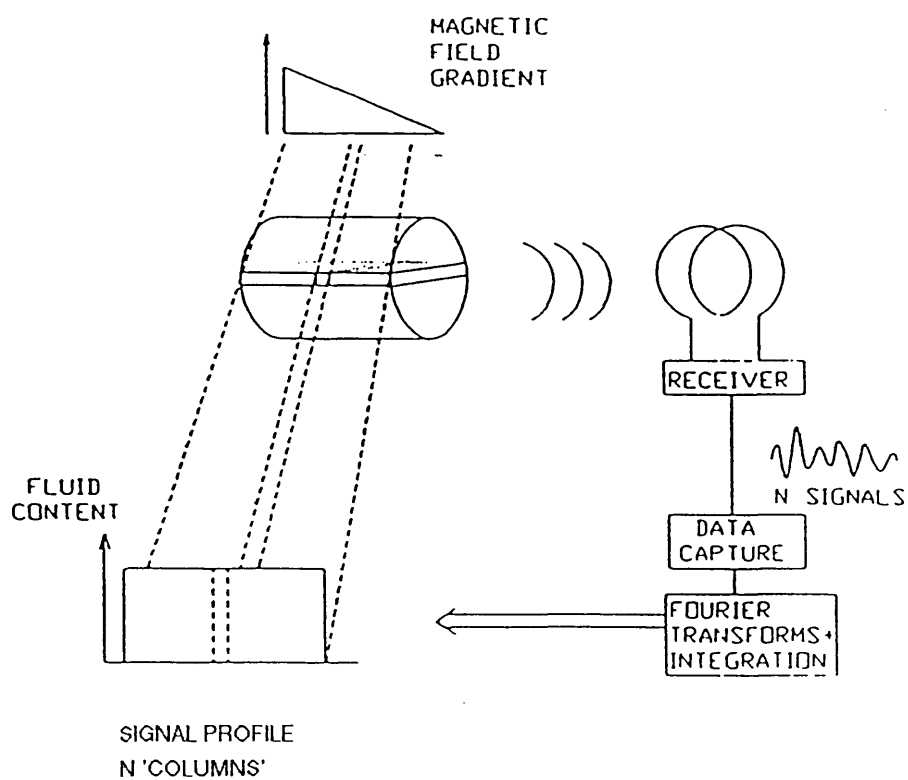
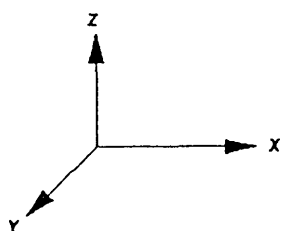
G_h - homospoil gradients

T_e - echo time (40 ms)

Figure 2.2 Modified 2DFT sequence for the chemical shift imaging



(a)



(b)

Figure 2.3 (a) Slice selection for imaging, and
(b) phase encoding the NMR signal

180° pulse generated out of plane image signal which was removed by application of a homospoil gradient and phase cycling. The imaging sequence was repeated $2n^2$ times (n is the number of pixels in x and y directions, 2 is a factor arising from the phase cycling). The result was a three-dimensional (3-D) data set with a chemical shift spectrum per image pixel (n^2 pixels in all). The repetition time of this sequence of CSI depends on T_1 and can be of the order of 2-4 seconds, as such about 4.5 hours was required for a 2-D 64 by 64 image array. The 1-D 64 points CSI required about 4 minutes to acquire. The length of the echo time T_e was chosen long enough to allow eddy current (generated in the system by gradient switching) to decay before data acquisition, therefore T_e depends on the equipment and its quality. The increase in imaging speed depends on field strength and relaxation times of the sample being imaged.

It is obvious from the length of time required to perform the 2-D CSI that it can only be used for static measurement of fluid distribution in core plugs. To effectively use 2-D CSI technique for dynamic flow imaging will require very fast switching times to reduce data collection time to a few minutes. 1-D CSI, however, was adequate for use to track flood movement at reasonably low flow velocities in the core plugs.

2.1.3 Linewidths and image resolution

The absorption mode linewidth $\Delta\nu_{\frac{1}{2}}$ in a CSI is related to the total dephasing time T_2^* in accordance with the expression

$$\Delta\nu_{\frac{1}{2}} = \frac{2}{\gamma T_2^*} \quad (2.6)$$

The linewidth $\Delta\nu_{\frac{1}{2}}$ is the full width at half-maximum of the spectral line, and can be measured directly by producing a plot of the NMR line from the Fourier transformation of the time domain signal or by measuring the time t taken for half the signal to decay. T_2^* can then be derived from the equation

$$t = 0.6937T_2^* \quad (2.7)$$

Assuming adequate signal to noise ratio S/N , the resolution of an NMR image Δ_x is governed by the strength of the applied gradient γG and natural linewidth $\Delta\nu_{\frac{1}{2}}$ of the species being imaged, and the appropriate expression can be derived on the basis that $\gamma G \Delta_x > \Delta\nu_{\frac{1}{2}}$.

In addition to gradient strengths and S/N, image resolution and fidelity can be affected by field stability and homogeneity, gradient linearity and orthogonality, inhomogeneity of the rf, and the quality of the imaging technique itself (Rothwell, 1985).

2.2 MRI Parameters

MRI can measure a multiplicity of parameters of which the most appropriate in rock-fluid systems are nuclear spin density (fluid concentration), relaxation times T_1 and T_2 (or T_2^*), and chemical shift. Two or more fluids present in a rock system can be distinguished by several MRI methods based on one or more of these contrast parameters. In particular oil and water can be distinguished by the chemical shift difference between their respective resonant frequencies.

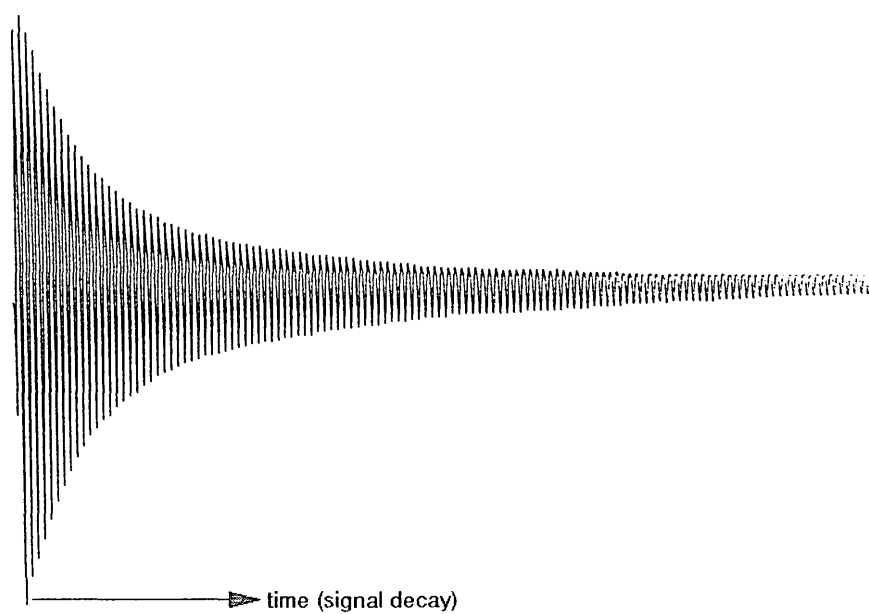
2.2.1 Nuclear spin density

The NMR signal strength is proportional to the nuclear spin density of the fluids in the core but also depends on relaxation effects. To perform an NMR experiment the fluid-filled sample is placed with a detector (rf coils) in a strong, uniform static magnetic field B_o . The fluid concentration can then be measured, e.g., by using the rf coils to apply an rf pulse of sufficient duration and rf magnetic field strength to tip the magnetisation by 90° into the xy plane perpendicular to the magnetic field direction. When the pulse is turned off the spins in this plane precess around B_o , and the magnetic field inhomogeneities cause various spin packets to have slightly different Larmor frequencies and hence precess at slightly different rates. A Larmor frequency is the frequency of precession of a magnetic moment about the applied magnetic field and is expressed in Hz as $\nu_i = |\frac{\gamma}{2\pi}|B_o$. A particular nuclear species precesses at a precise Larmor frequency proportional to the magnetic field strength, so that different nuclei can be studied by changing the operating frequency of the NMR system. One type of spectroscopy consists in irradiating the sample with a pulse that contains a range of frequencies covering the entire spectrum and monitoring the absorption from all the superimposed resonant lines as the signal decays with time due to various relaxation processes. The absorption is monitored by the rf coil detector. The result is a time domain NMR signal spectrum which typically has the appearance of exponentially decaying noise as illustrated in Figure 2.4(a). A computer is employed to Fourier transform this spectrum and thereby

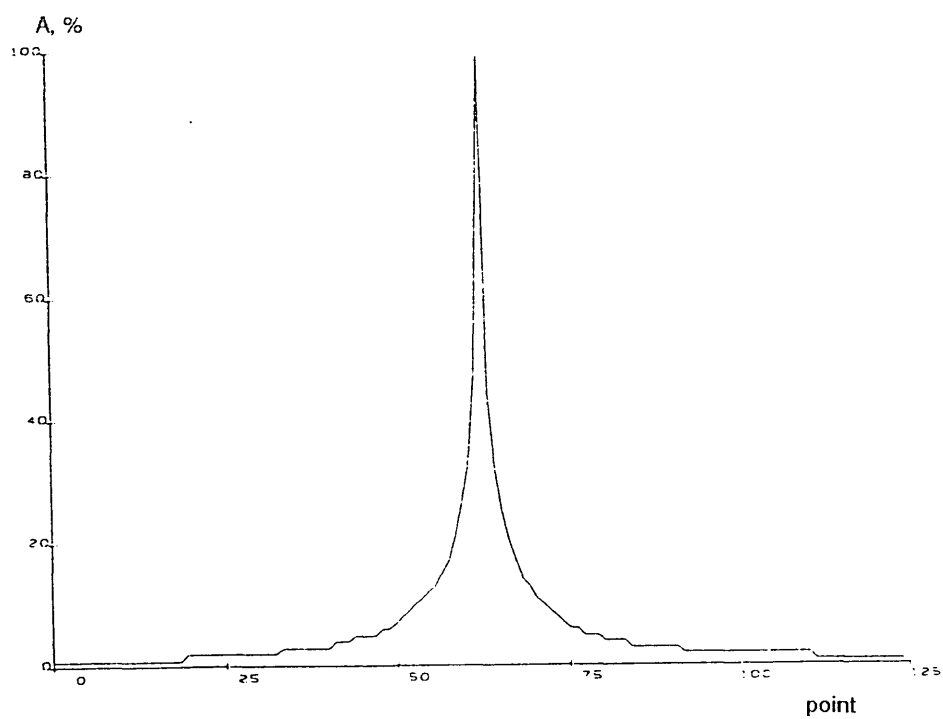
convert it to a more usual frequency domain type shown in Figure 2.4(b).

Multiplet structure is not evident on a time domain spectrum, hence it is mainly of interest as the raw data to be processed by the Fourier transform algorithm which converts it to a conventional spectrum and sometimes calculates line positions, line intensities, and chemical shifts. If two or more fluids containing the NMR active nuclei are present in the sample, a two- or multi-peak spectrum is obtained. A two-peak spectrum can be decomposed into two separate spectra by fitting two Lorentzian lineshapes to the spectrum if the linewidths of the fluids in the sample are sufficiently narrow. Fig.2.4(c) shows a two-peak spectrum for a rock sample saturated with oil and water and its decomposition into two spectra. The spectrum with the wiggly base is the original, and the two near-smooth spectral lines comprise the fitted spectra.

MRI obtains spatial localised information from the signal spectra in voxels of the sample by the combination of x, y, and z magnetic field gradients and rf pulses. These gradient fields, when applied, cause nuclei at different positions in the sample to precess at slightly different frequencies. The resulting localised frequency-modulated signal is Fourier-transformed to obtain the spatial distribution of fluid concentration. Oil and water in a rock, if spectroscopically resolvable, can be imaged separately using CSI techniques. Investigations involving oil-water systems with MRI require that the fluids in the rock have sufficiently narrow linewidths (about 3.7 parts per million (ppm) in this work) if oil and water are to be well resolved into separate spectra. This is the main criterion in choosing rock samples used in this research work.



(a)



(b)

Figure 2.4 NMR signal spectrum: (a) Time-domain and
(b) Frequency-domain

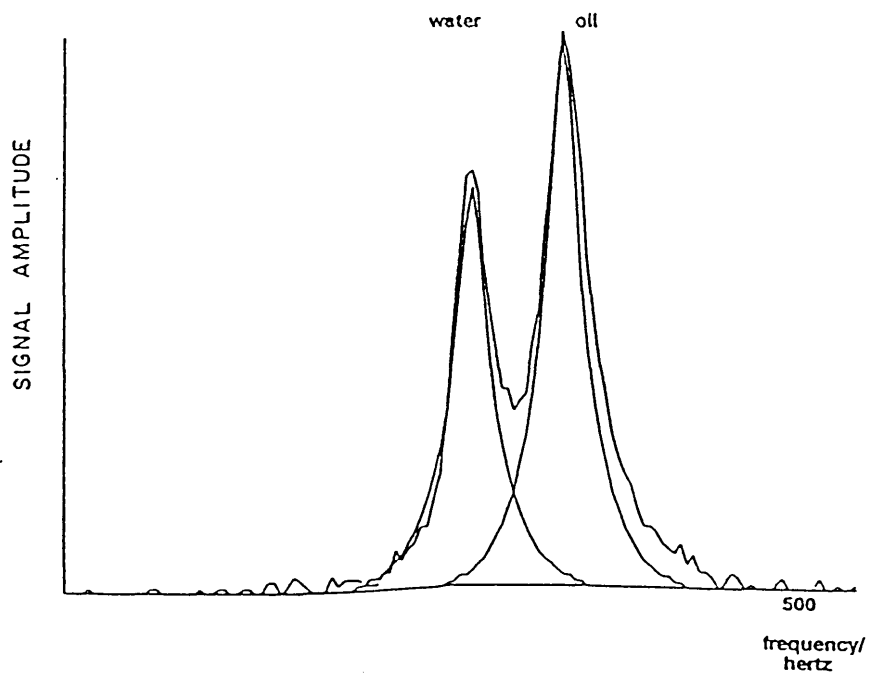


Figure 2.4(c) Example of deconvoluting two-peak spectrum into separate oil and water spectra

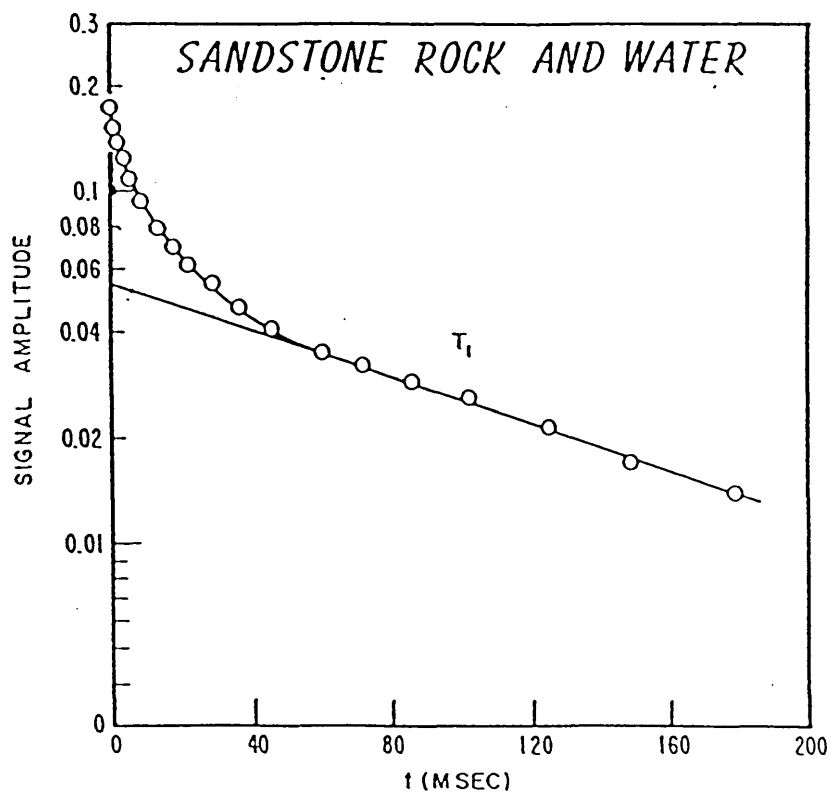


Figure 2.5 Determining relaxation time T_1 (after Seevers, 1966)

2.2.2 Spin relaxation times T_1 and T_2

Two widely used methods of determining relaxation times are the saturation method and the pulse method. Both methods and their various schemes are discussed in details by Poole and Farach (1987). If a spin system at thermal equilibrium is subjected to a 180° rf pulse, the resulting magnetisation M_z lies along the z axis and decays according to Equation 2.2. But the M_z does not generate a signal in the detection coil since it is parallel with the magnet field. To sample M_z a 90° rf pulse is applied at a time t after the 180° rf pulse to tip M_z into the xy plane, where it generates a signal in the detection coil proportional to $M_z(t)$. This sequence of rf pulses is known as inversion recovery sequence ($180^\circ - t - 90^\circ - T_r$). T_r is the repetition rate. To measure T_1 different values of time t are used and each time the amplitude of the signal is recorded. The repetition rate T_r is chosen such that equilibrium magnetisation M_o is reestablished along the z axis before the next inversion sequence is applied (usually $T_r > 5T_1$). The data is processed by fitting to Equation (2.2) as illustrated in Figure 2.5. The relaxation rate, which is the inverse of T_1 , is determined as the slope of the straight line portion of the curve (Seevers, 1966).

To sample the transverse magnetisation $M_{x,y}$ the dephasing after the 90° pulse due to field inhomogeneities can be refocussed by the application of a 180° pulse to produce a signal echo. T_2 can be determined by measuring the peak amplitude of a series of echoes produced. The repetition time of the sequence, T_r , must allow for the equilibrium magnetisation to be reestablished before the pulse sequence can be repeated (usually $T_r > 10T_1$). The data is fitted to Equation (2.4) in a similar manner as described above.

2.2.3 Chemical shift

The fundamental relationship between the Larmor precessional angular frequency w_o of a nuclear spin I placed in a static magnetic field B_o was given by

$$w_o = \gamma B_o \quad (2.1)$$

This expression assumes that the presence of the sample does not perturb the magnetic field, which is not strictly true. On the microscopic scale, the electrons in the vicinity of the nucleus shield it from the influence of the magnetic field.

The shielding may be taken into account by using an effective field at the nucleus given by

$$B = B_o(1 - \sigma) \quad (2.8)$$

Equation 2.1 can therefore, be rewritten in the light of Equation (2.8) as

$$w_j = \gamma B_o(1 - \sigma_j) \quad (2.9)$$

Where,

w_j refers to the Larmor frequency for the j^{th} nucleus (in rad/sec), and σ_j is a dimensionless small fraction, known as the shielding constant for the j^{th} nucleus.

Since the shielding effect is caused by the electronic environment, values of σ will vary with the position of the nucleus in the molecule and factors that affect electron density will affect σ . Variations in σ cause variations in resonance frequency and are the reason for the occurrence of chemical shifts. For example, σ for protons in water is less than that for aliphatic protons in hydrocarbon. Chemical shift differences are usually reported in ppm but they are obtained from measurements in Hz using a spectrometer. Water protons and aliphatic protons have a chemical shift difference of 3.7 ppm.

Since nuclei with different chemical shifts precess with different frequencies, the chemical shift produces a modulation of the time domain signal which on Fourier transformation reveals a number of peaks in the frequency (or chemical shift) spectrum. Nuclei of different elements or isotopes would give resonance in different parts of a spectrum due to variations in the magnetogyric ratio γ . The proportionality of intensity to concentration of nuclei for NMR is valid for comparison between different molecules, thus providing a rapid non-destructive method of obtaining concentrations of components in a mixture or compound. For a given compound the appearance of the spectrum is governed by intermolecular chemical shifts, i.e., differences in resonance frequencies for different nuclei of the same molecule. But for elemental analysis comparison of absorption of the very different frequencies involved is difficult. The frequency of ^{14}N absorption for solutions or liquids is known to depend on the chemical environment of the nucleus (Abragam, 1961). This feature, fortunately, has since been shown to be general, and such difference in resonance conditions is referred to as chemical shifts.

The existence of chemical shifts makes MRI molecular species specific and

therefore, a powerful tool for the discrimination of oil and water in the rock. The resonant frequencies of oil and water based fluids have a chemical shift difference of about 3.7 ppm, therefore oil and water inside a rock could be distinguished by chemical shift imaging (CSI) technique.

2.2.4 MRI of oil-water systems in rocks

There are several MRI methods, as already discussed, which can be used to distinguish oil from water in the porous media. However, CSI is particularly suitable as it is molecular species specific and could therefore be used to image simultaneously the distributions of oil and water and perhaps indicate, as well, the distribution of enhanced oil recovery (EOR) additives. CSI was therefore predominantly used in the experimental part of this research work. Relaxation times T_1 and T_2 of oil and water in rocks are usually dominated by the physical interaction of the fluids with the pore surface, hence these intrinsic parameters can not effectively be used on their own to discriminate between oil and water in rocks.

The CSI sequence illustrated in Figure 2.2 generates n spectra for each 1-D image or n^2 spectra for each 2-D image (n - number of pixels). Each spectrum can be integrated to give a value to the corresponding pixel of the image array which is a measure of the total fluid content of the sample voxel. By deconvolving the spectra, i.e., separating and integrating oil and water spectra individually, oil and water images can be produced. The success of deconvolution process would depend on factors such as

- the deconvolution technique,
- linewidth and line separation,
- relative peak amplitude from the fluids,
- noise level, and
- spectral resolution.

For any deconvolution technique used, the maximum values for oil and water peaks in the experimental spectra are found. The amplitude and spectra position are used to generate a lineshape, function which is given by

$$l(x) = \frac{1}{(1 + (2\pi f T_2^* x)^2)^{0.5}} \quad (2.10)$$

where, f is frequency per point and x is the spectral point.

x varies from 0 to 128 from our MRI system with a frequency 500 Hz. The value of T_2^* for the model line is set empirically to give the best fit (generally $T_2^* = 10$ ms). The fitted water (or oil) lineshape is then integrated over the 128 spectral points to give one pixel value in the water (or oil) image array. The number of points in the NMR spectrum determines the spectral resolution.

The deconvolution exercise is a curve fitting process as illustrated in Figure 2.4(c) above. In our work we set the spectrometer frequency experimentally to the resonance of water, so that the water line appears at the centre of the spectrum (point 64). The oil line is 3.5 ppm (or 60 Hz) away at point 80. The magnet can be shimmed over the entire core volume to less than 0.5 ppm which corresponds to ± 2 points accuracy in the spectra.

2.2.5 MRI and other imaging methods

Advance in recent years in imaging methods utilising X-rays (Withjack, 1986; Hove et al., 1985; Ringen and Hove, 1987) and now using MRI has led to 2-D interpretation of saturation distribution in cores. These techniques are more powerful than the earlier 1-D imaging methods involving microwaves (Parsons, 1975; Brost and Davis, 1981), electrical properties (Davis, 1980), radioactive tracers (Josendal et al., 1952). The application of computer aided tomography (CT) of X-rays requires that oil or water phase (usually the aqueous phase) is doped with, say, sodium iodide. The X-ray method is based on detection of density differences between the rock and fluids and between the fluid phases. Though the physical properties imaged by X-ray CT and MRI techniques are somewhat complementary, MRI has considerable advantages over the X-Ray CT in monitoring flow of oil and water in a rock sample. MRI obtains an image of the entire sample volume within the rf coil, while in X-Ray CT sample has to be moved through the scanner or vice versa to obtain sequentially images of cross sectional slices. The limitations of X-Ray CT technique appear to reside in resolution of saturation, particularly where interest may lie at pore scales. The limits of resolution of saturation in MRI have not yet been identified but appear to depend largely on the strength of the magnetic field and gradient employed. Chardaire and Roussel (1990) used a high magnetic field of 9.4 Tesla on a limestone sample saturated with a single fluid (water or oil) to obtain 512 by 512 images of a $50\mu\text{m}$ -thick slice.

Important characteristics of MRI in general can be summarised thus:

1. Multiphase flow can be imaged, with discrimination between oil and water on the basis of their chemical shift or difference in relaxation times.
2. It can be interpreted as molecular species specific.
3. It can be used to image flow velocities so that override or crossflow mechanisms can be studied directly.
4. It has potential for high spatial resolution, which could allow fundamental and detailed study of entrapment and mobilisation of residual fluids in realistic porous systems.
5. It adds the extra feature of planar and 3-D visualisation of fluids in porous media on very fine (micro) scale, thus providing 2-D interpretation of saturation distribution in cores.
6. It is 'transparent' to the rock matrix, yet the interaction between the rock pore surfaces and the mobile fluids is imaged.

2.3 Previous Petrophysical Applications of NMR

One of the early applications of NMR to petrophysical study reported in the literature is the study of fractional wettability using nuclear magnetic relaxation method made by Brown and Fatt (1956) on sand packs. Timur (1969) utilised a pulsed NMR technique to measure porosity and estimate permeability of sandstones. Nuclear magnetic logging has long been utilised to measure residual oil in reservoir rocks (Robinson et al., 1974). MRI, developed by Lauterbur, (1973) now provides the possibility of studying the spatial distribution of porosity, pore size and fluid saturations on core plug scale. In a recent work Edelstein et al. (1988) confirmed through experiments the accuracy, rapidity and non-invasiveness of NMR measurements of various petrophysical properties of reservoir rocks such as porosity and saturations.

2.4 Discussion

The CSI method, based on a modified 2DFT imaging technique, appears to be the best suited for distinguishing between oil and water in the rock. The imaging sequence, combined with the slice selection technique, permits the mapping of saturation distribution in a selected slice within a core plug. The 2DFT imaging sequence is used to obtain images involving single resonance, e.g., to map fluid dis-

tribution in water-filled samples for the purpose of deriving the fluid-filled porosity map.

Due to the length of time required to obtain an image, the 2-D CSI is better suited for imaging of fluid-filled core samples under static conditions. For example, a sample used in a core flood test would be imaged under static conditions prior to commencing and after completing the flood test. This would provide the saturation distributions at the initial and final stages of the flooding test - an information particularly useful in the history matching method of using a simulator to define appropriate relative permeability relationships from laboratory data. The time interval required to obtain an image with the 1-D CSI makes it suitable for measuring saturation in a core sample under dynamic flow conditions. In this work the 1-D CSI is used to image saturation propagation during core flood without having to interrupt the flow. This is a considerable advance in the application of magnetic resonance imaging to petrophysical studies. Such applications so far have involved measurements under static conditions in the main. The core flood imaging requires a balance between velocity of fluid advance and the imaging speed. With the imaging the fluid distribution is obtained in addition to the conventional data available from a core flood experiment. The determination of the fluid content and distribution is undoubtedly an important element in the interpretation of core-analysis data.

Since image resolution is also dependent on the natural linewidth of the species being imaged, different rock-fluid systems would be expected to provide different levels of image resolution. For the purpose of this study, therefore, rock-fluid systems that would provide a high quality of image resolution are selected on the basis of their linewidths. This is merely for convenience and ease in resolving oil/water images obtained with the CSI technique; the results of the investigation, never-the-less, would be equally applicable to any other rock-fluid systems. The ^1H proton is imaged in this work because oil as well as water contains the hydrogen atom and the atom is known to emit the strongest NMR signal. For other fluids, other magnetically active nuclei can be imaged, including ^{13}C , ^{19}F , ^{23}Na , ^{31}P , and ^{14}N .

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CHAPTER 3

IMMISCIBLE CORE FLOOD STUDIES

In this chapter some processes of oil displacement by water in laboratory core floods are discussed. Basic reservoir rock properties such as porosity, grain density, permeability, saturation and the routine methods of their determination are presented in Appendix 3. Capillary pressure characteristics and the concept of relative permeabilities necessary to describe the two phase flow of oil and water are also briefly presented in the Appendix.

3.1 Laboratory Core Floods

3.1.1 Basis for interpretation

Interpretation of unsteady state core flood tests is usually based on observed oil and water production from the outlet end of a core plug and the differential pressure across the core. These data are usually analysed for cores which are assumed to be homogeneous by solving the unsteady-state equations by the methods of Buckley-Leverett (1942), Welge (1952) and Johnson, Bossler and Naumann ((JBN) 1959); or the graphical techniques of Jones and Rozelle (1978). These methods, like that of Buckley and Leverett from which they derive, invoke the assumption of diffuse flow, core homogeneity and absence of dynamic capillary pressure gradients. When these conditions are not true, say in heterogeneous reservoir rock systems or water displacing a very light oil in a homogeneous sandstone, these interpretations are sometimes inadequate. Archer and Wong (1973) showed examples where the JBN method led to poorly defined or anomalous relative permeability curves at low and intermediate water saturations, and used a simulator model of the laboratory test to obtain a smooth set of the curves. The Archer-Wong history matching method of using a simulator to define appropriate relative permeability relationships for laboratory data has been developed further by Sigmund and McCaffery (1979) and more recently by Kerig and Watson (1986, 1987); Watson et al (1988); Richmond and Watson (1990).

Other writers, including Corey and Rathjens (1956), have also observed anomalous changes in relative permeability to water during flooding of heterogeneous carbonate core samples. Poorly defined or anomalous curves appear to reflect small-scale local heterogeneity in the core sample. Mixed wettability in a core, for example, may result in non-uniform saturation distribution within the sample which may invalidate the assumption of diffuse flow. Small-scale hetero-

geneity may result in an observed water breakthrough at the outflow end of the core ahead of the main flood front, then the relative permeabilities calculated by the JBN method will not represent the properties of the bulk of the core sample (Archer and Wong, 1973). In order to eliminate or minimize dynamic capillary pressure gradients it is common practice to use high flow rates. Huppler (1970) has shown that heterogeneous core floods can be sensitive to flooding rates. It would be intuitively obvious that in order to mimic field behaviour, a laboratory core flood should ideally be conducted at the same force ratios that exist in the field. However, as has been indicated, this can introduce capillary discontinuity problems in the laboratory experiments. In practice core floods are sometimes run at flood rates that introduce the presence of capillary pressure gradients. Without knowledge of the magnitude of the capillary pressure gradient term it is clear that erroneous interpretation will occur and hence there is a pressing need to evaluate the results of the core flood tests in the light of knowledge about saturation distribution and saturation gradients.

Core floods are normally considered to occur under a viscous-capillary flow regime and hence the fractional flow equation must include the capillary pressure gradient term. Capillary pressure controls the sequence of pore saturation change so long as viscous flow forces are not controlling. Viscous forces tend to control when the term $\frac{qD\mu D L}{A}$ in Darcy units is greater than about 2.0 (Rapoport and Leas, 1953). Quantitatively, it is difficult to allow for the capillary pressure gradient for, although the capillary pressure p_c curve may be available, the water saturation profile is unknown. Furthermore, the imbibition p_c curve is difficult to obtain. The water saturation profile is the required result of displacement calculations. Consequently, it is common practice to use high flow rates and to neglect $\frac{\partial p_c}{\partial x}$ in the fractional flow equation in the region behind the flood front, where it is normally considered that both $\frac{dp_c}{dS_w}$ and $\frac{\partial S_w}{\partial x}$ are small.

In this work we have set out to obtain the water saturation profile directly from saturation measurements using MRI technique. This is of considerable importance, especially, in heterogeneous core floods where capillary forces are most noticeable, and this offers the possibility to resolve saturation gradients in terms of viscous and capillary terms. For a homogeneous sample the unsteady state test is interpreted on the basis of the fraction water in the outlet stream f_{w2} (Welge, 1952). A heterogeneous core flood with variable permeability k_i , irreducible water saturation

S_{wi} , residual oil saturation S_{ori} and a capillary pressure - saturation relationship $p_c(S_w)$ would more appropriately be interpreted on the basis of the corresponding variable fraction water f_{wi} . This is achieved by the use of appropriate simulator such as CORSIM (1988) available in this Department.

The time of breakthrough is an important measurement used in the interpretation of core flood for the purpose of determining relative permeability by the unsteady state method, and by 'visualising' the core flood it can be determined with less ambiguity. The MRI method monitors the arrival of the frontal water saturation S_{wf} at the production end face of the core plug (breakthrough saturation) as demonstrated in Chapter 6 of this work. A possible source of experimental error in the steady state test is introduced by removing the test sample from the assembly and weighing it since a small amount of fluid may be lost because of gas expansion and evaporation. *In situ* saturation measurement using MRI appears to resolve this problem and is accurate within 0.03 saturation units.

3.2 Capillary Pressure and Relative Permeability

Detail discussion of the concept of capillary pressure for fluids in porous media and its application has been presented in the petroleum literature (Leverett, 1941; Morrow, 1970; Amyx et al., 1960). It has been shown that capillary pressure which is defined as the phase pressure difference at an immiscible fluid interface $p_c = p_{nw} - p_w$ is dependent on saturation and also depends on the following.

- size and distribution of the pores,
- wettability of the porous media,
- saturation history, resulting in hysteresis, and
- dip and fluid density resulting in gravitational effect.

Relative permeability relates the absolute permeability of a porous system to the effective permeability $k_e = k k_r$. Since effective permeability decreases with decrease in the phase saturation, it has been convenient to relate relative permeability also to saturation. But relative permeability also depends on several other factors, including wettability, saturation history and gravity. Most laboratory flow tests, however, are designed to eliminate gravity forces and they result in 1-D displacement under viscous-capillary control. A recent review of factors affecting relative permeability has been reported by Honapour et al. (1986).

3.2.1 Capillary pressure measurements

A number of methods are available in the petroleum literature for experimental determination of capillary characteristics of rock samples (Purcell, 1949; Hassler and Brunner, 1945; Brown, 1951). These methods define either imbibition or drainage capillary pressure curves and can be grouped as:

- static,
- dynamic, and
- restored state.

Equation (A3.2a) given in the Appendix forms the basis for a capillary pressure application and enables the laboratory-derived capillary pressure curve for any pair of fluids to be used to generate the equivalent oil reservoir condition pressure at the same wetting phase saturation. In this work drainage oil-water capillary pressure curve was generated from a laboratory-derived drainage capillary pressure curve for an air-water system using the relationship

$$p_{c(oil-water)} = p_{c(air-water)} \cdot \frac{[\sigma \cos \theta]_{(oil-water)}}{[\sigma \cos \theta]_{(air-water)}} \quad (3.1)$$

where

σ is the interfacial tension in dynes/cm

θ is the wetting contact angle in degrees

For an air-water system σ is well established and water is the strongly wetting phase ($\theta \approx 0^\circ$; $\cos \theta \approx 1.0$). Archer (1985) reported that the residual saturation inferred from mercury displacing air capillary pressure tests is rarely the same as the true wetting phase irreducible saturation and the mercury tests should be used mainly for pore size distribution measurement. The current status of core studies with MRI indicates that it can provide the possibility of studying the spatial distribution of pore size, porosity and fluid saturation on core plug scale. This area of work is further investigated here and by others (Howard and Kenyon, 1990).

3.2.2 Laboratory determination of relative permeability

Relative permeability is generally measured in the laboratory in special core analysis tests, conducted usually on core plug samples which are assumed to be 'homogeneous'. Tests may model displacement under steady state or unsteady state

conditions with reservoir or synthetic fluids at reservoir or room conditions of temperature and pore pressures. These tests and their limitations are discussed comprehensively by Archer and Wall (1986).

Steady state measurement of relative permeabilities involves flow of displacing and displaced fluids simultaneously through the core at a number of equilibrium phase ratios. At each flowing ratio from 100% displaced phase to 100% displacing phase an equilibrium condition must be reached at which the inflow ratio of fluids equals the outflow ratio, and at which the pressure gradient between inlet and outlet is constant. At such a condition the Darcy law equation is applied to each phase to calculate effective permeability at the steady state saturation. Between five to ten such stages are usually needed to establish relative permeability curves. Capillary pressure tend to be ignored because phase pressures cannot be determined individually. A major difficulty is the determination of saturation at each stage. This involves removing the sample from the flow assembly and weighing it after an equilibrium condition is reached. This procedure introduces a possible source of experimental error, since a small amount of fluid may be lost because of gas expansion and evaporation. This difficulty is overcome by *in situ* measurement of the saturation. Several methods have been used to accomplish this of which the best results have been obtained with X-ray CT and MRI. By scanning with X-ray CT during tests, Withjack (1987) determined saturations which differed from those determined by weighing within 2 saturation percent. A standard error estimate of 0.03 saturation units compared with mass balance value was obtained by Edelstein et al (1988) using MRI, which in addition provides the saturation distribution.

Measurement is more rapid by the unsteady state method in which the determination of relative permeability is based on observation of the fractional flow of displacing phase fluid from the outlet end of the core plug and its relation with saturation. An initial differential pressure drop across the core is measured at a base saturation (e.g. at the irreducible water saturation (IWS)). Then water is injected at a constant rate or pressure. For the constant rate test, oil production, together with the pressure drop across the core is monitored with time. The time of breakthrough of the displacing phase is noted and flooding is continued until residual oil saturation (ROS) is reached. The curve can be computed using the JBN method or by the graphical techniques of Jones and Rozelle (1978). The

history matching method of using a simulator to define the appropriate relative permeability relationships can be used (Archer and Wong, 1973; Sigmund and McCaffery, 1979; Kerig and Watson, 1986 and 1987).

The fractional flow equation discussed in the Appendix is the basis for interpretation of the unsteady state test. The fraction water in the outlet stream f_{w2} , with the corresponding saturation S_{w2} , is computed. The average saturation in the core S_{wav} and the cumulative water injected can be measured experimentally. From these data the relative permeabilities are computed, usually neglecting capillary pressure.

Interpretation of test results using these conventional methods may sometimes lead to gross error in development of relative permeability relationships in heterogeneous systems due to the assumptions inherent in their development. Simulation and history matching procedures have been used to model laboratory tests and to validate relative permeability curves (Archer and Wong, 1973; Sigmund and McCaffery, 1979; Kerig and Watson, 1987). But their use has been limited by a general lack of knowledge concerning the fluid displacement processes in the core. Visualisation of fluids in porous rocks, made possible utilising MRI and other imaging techniques, provides better knowledge of the processes of fluid displacement in cores than hitherto was available and can therefore enhance the history match approach originally introduced by Archer and Wong (1973). Spatial variations of permeability, capillary pressure - saturation relationship and saturations can be included in simulator for improved history match approach. Detection of breakthrough time of the displacing phase at the outlet core face, which is critical in the representation of relative permeability in the unsteady state core flood tests is greatly improved by imaging. MRI techniques can reveal the importance of capillary and gravity forces, as evidenced from their effect on fluid saturation distribution and saturation gradients during flow. This is demonstrated in Chapter 7 of this work where capillary pressure gradients during a core flood are determined.

3.3 Factors Affecting Core Flood Measurements

3.3.1 End effects

Core plugs taken from reservoir rock for laboratory tests exhibit some discontinuity

of properties as they are no longer surrounded by their native structures. At the outflow end of the core, there can be capillary discontinuity due to flow of fluids from regions of finite capillary pressure to a region of zero capillary pressure. During two-phase flow, this capillary pressure gradient results in higher wetting phase saturation at the outflow end than exists in the remainder of the core. At the inlet end, spontaneous, localised imbibition of the injected wetting phase may occur because it may first contact the inlet face of the core only at localised area. At the same time the non wetting phase counterflows from the core to replace the imbibed fluid.

Considerable research work has been devoted to the study of end effects, aimed at eliminating or minimizing them and the findings have been reported (Osoba et al, 1951; Geffen et al, 1951; Richardson et al, 1952; Kyte et al, 1958). This includes the use of a variety of designs of distributors at the ends of the core. Core flood visualisation using X-ray CT and now MRI provides information on fluid distribution and saturation gradient, hence non-linearity resulting from the effects can be assessed and accounted for in the interpretation of test results. Because the saturation profiles are obtained directly from measurement and not, as is the case without imaging, by calculation based on the assumption of diffuse flow, any saturation build up can be quantified as demonstrated by Figure 7.1 in Chapter 7 of this work.

3.3.2 Flow rate

Flow rates can alter the balance between viscous and capillary forces during core flood, hence its effect has long concerned laboratory investigators. A term *Capillary number* (N_c) is used to represent the ratio between viscous and capillary forces in core floods. At very low displacement rates, which may approach spontaneous imbibition, capillary forces are dominant and may control residual oil saturation S_{or} . Several opinions concerning effects of flow rate on core floods exist and some of them can be found in the review book by Honapour et al, (1986). High flow rates are commonly employed to minimize effect of capillary forces so as to assume diffuse flow. Flow rates have been chosen such that viscous forces predominate over capillary and gravity forces in accordance with the core flooding criteria of Rapoport and Leas (1953). However, Huppler (1970) found waterflood oil recoveries from cores with significant heterogeneities to be sensitive to flooding rate. This finding suggests the need to use the reservoir flow rates, which involve

competing displacement forces.

Laboratory tests should ideally be conducted at force ratios in the core plug which model the force ratios in the reservoir as represented in simulator grid cells. Because of inability to design such experiments the subject of viscous flow rates has been of great concern to reservoir engineers. Since the MRI technique lends itself to observations of flow processes involving viscous forces and capillarity, the saturation gradients can therefore be resolved in these terms in solving the fractional flow equation. A demonstration of such solution is provided in Chapter 7 of this work where both the capillary pressure curve and the saturation profile were obtained by measurements, and hence the capillary pressure gradients were quantified. The fractional flow equation which includes the capillary pressure gradient was then solved.

3.3.3 Saturation hysteresis

Capillary pressure and relative permeability characters depend in the main on saturation and also on the direction of saturation change, i.e., the relations also depend on whether during displacement processes the wetting phase saturation increases (imbibition) or decreases (drainage). This phenomenon, known as hysteresis, gives rise to curve characters as shown in Figure 3.1. This has been verified by Osoba et al (1951); Geffen et al (1951); and Levine (1954). It has also been shown that the hysteresis is more profound for systems with strong wetting preference and less in systems without strong wetting preference.

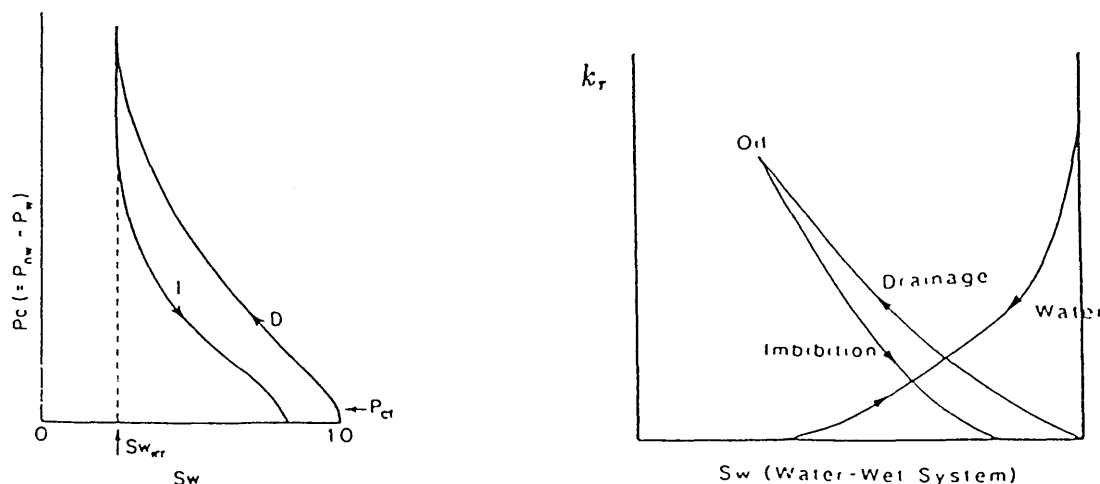


Figure 3.1 Capillary pressure and relative permeability hysteresis
(after Archer and Wall, 1986)

Although this phenomenon is not significant in linear systems or on a microdisplacement scale, they may be important when considering 3-D macro systems, or systems with potential gradient reversals. Huppler (1970) found that in the absence of time-dependent wetting effects, no saturation reversals occur during waterflooding. Pore-size distribution and cementation of rock grains are known to control the rate of saturation change in a given wettability system (Owens and Archer, 1971) and hence influence the hysteresis behaviour. In a water-wet system, prior to displacing the oil with water (imbibition) water is found to occupy the smaller pores and wet the grains while oil occupies the larger pores. At oil saturations which greatly exceed those which occur at the onset of continuity of a nonwetting phase, the oil phase appears as discontinuous globules trapped in the larger pores. Hence higher ROS results in the imbibition cycle than in the drainage cycle. Since MRI has potential for high resolution, down to micro scale, fundamental and detailed study of entrapment and mobilisation of residual fluids is thus possible.

3.4 Discussion

Laboratory core flood tests conducted at low flow rates with reservoir fluids at reservoir conditions of pressure and temperature appear to offer better representation of reservoir flow conditions. But such flow conditions may introduce the presence of capillary pressure gradients. The fractional flow f_w equation should therefore be solved to include the capillary pressure p_c gradient term. Such solution would require the knowledge of the magnitude of the p_c gradient term. In this work the p_c gradient term is quantified by combining the capillary pressure curve with the saturation profile obtained directly from measurements using MRI. The MRI method therefore offers the opportunity to resolve saturation gradients in core floods in terms of viscous and capillary terms. Without the prior knowledge of the saturation profile, it has hitherto been difficult to allow for the p_c gradient term; rather the saturation profile has been the required result of displacement calculations.

Relative permeability relationships are calculated from laboratory core flood tests using fractional flow f_w equation which assumes the absence of capillary pressure gradient term. Since the p_c gradient term tends to increase the f_w , its presence would be expected to result in different relative permeability relationships. With

MRI, information about the saturation distribution at different stages of the displacement process is obtained. This knowledge concerning the fluid distribution, combined with the production and pressure drop data obtained from the core flood, is an important element in the correct interpretation of core-analysis data. With appropriate simulation, these data should enhance the accuracy of the history match method first introduced by Archer and Wong (1973).

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CHAPTER 4

MRI OF CORE - FLUID SYSTEMS

4.1 The MRI System

The resolution and speed of response in magnetic resonance imaging (MRI) is controlled by the power of the magnet. The governing expressions are (Rothwell, 1985; Mansfield and Morris, 1982)

$$\gamma G \Delta_x > \Delta v_{\frac{1}{2}} \quad (4.1)$$

$$t_{vol} \propto 1/a^4 (rf)^{7/2} \quad (4.2)$$

where, γG is the strength of the applied gradient;

Δ_x is the required degree of spatial resolution (side of a cubic volume element);

$\Delta v_{\frac{1}{2}}$ is natural linewidth of the species being imaged;

t_{vol} is the time taken to achieve a particular S/N with given resolution;

a radius of the solenoidal coil;

(rf) is the radio frequency.

4.1.1 Experimental setup

The MRI system at the University of Surrey used in this study comprised a 120 mm diameter horizontal bore 0.4 Tesla Oxford Instrument magnet and an SMIS imaging console. The system specification is given in Appendix 4.1 and the block-scheme diagram of the MRI system, with the console, is shown in Figure 4.1. Figure 4.2 is a photograph of a radio frequency (rf) coil system used to apply rf pulse to excite the nuclei of hydrogen atoms (^1H) contained in oil and water. The coil also serves for detection of the transient NMR signal produced by the excited nuclei. Amplitude and frequency of the detected signal give information on the local chemical and physical environment of the nuclei.

The coils, with their associated tuning circuitry, used in this study have dimensions dictated by the size of sample object imaged so that there is a uniform magnetic field. In order that both transverse and longitudinal images can be produced with a coil with full coverage of the sample length the coil was made longer than the sample. A coil which accommodates an object of 34 mm diameter has the following dimensions:

- length - 79 mm
- internal diameter - 38 mm
- number of turns - 17
- wire size (enamelled) - 1 mm

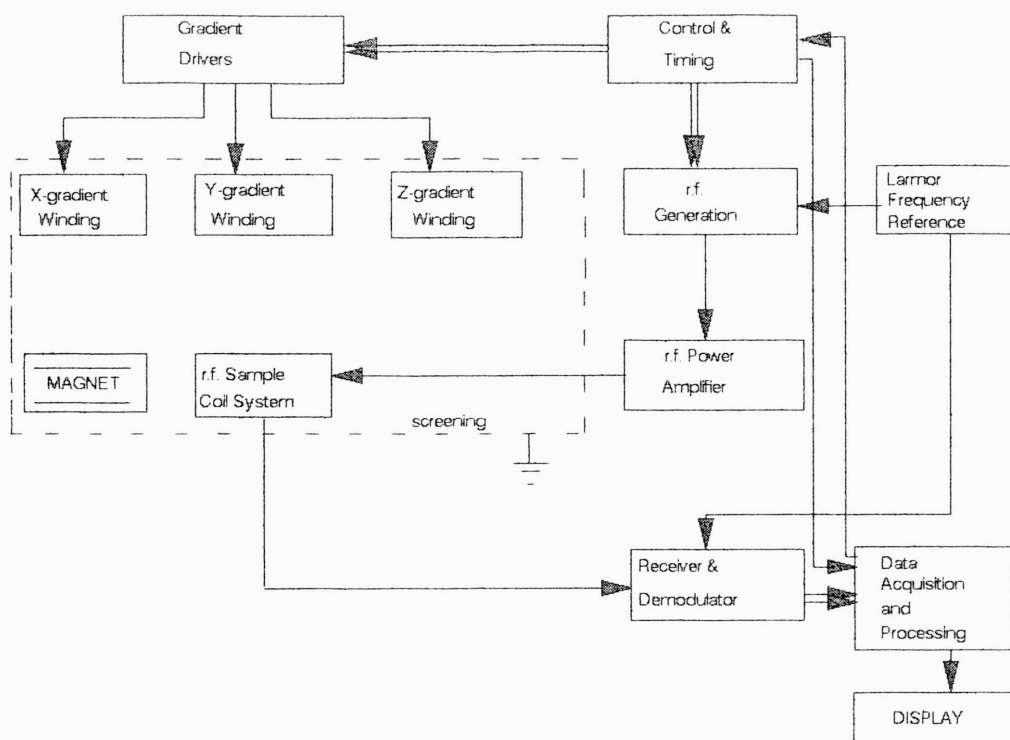


Figure 4.1 Block diagram of NMR imaging system

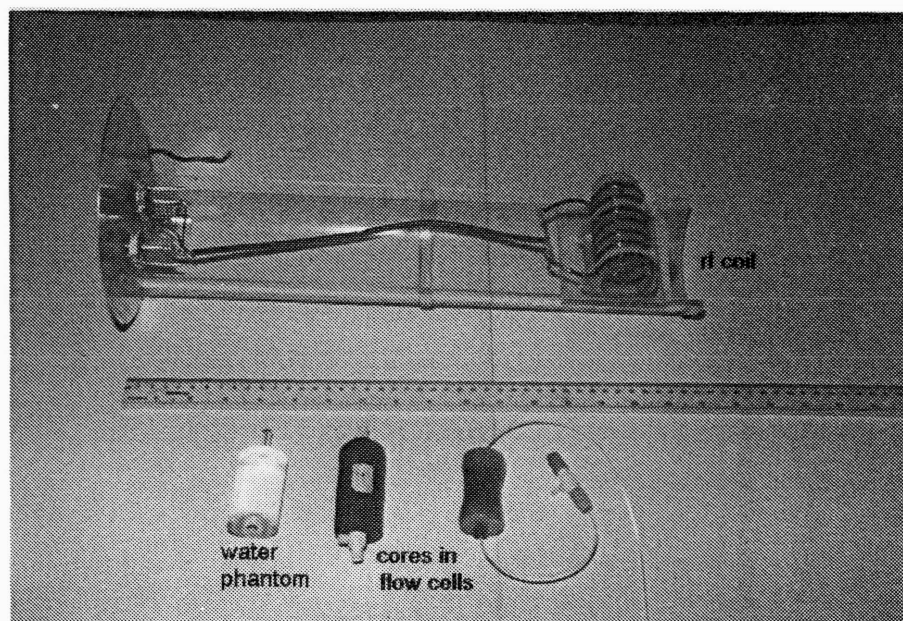


Figure 4.2 The rf coil assembly

4.1.2 Imaging procedure and data collection

The fluid-filled sample to be imaged is placed in the rf coil and the assembly is then placed in the field of the superconducting magnet to excite the nuclei to produce the recordable signal. To prevent movement of an object in the coil, soft tissue paper was used to wrap round the object to fill the annulus between object and coil. On the basis of S/N consideration solenoid coils were used in this work in preference to saddle or other configurations. Spatial information is encoded into the signal by superimposing magnetic field gradients on the static field. The two-dimensional Fourier transform (2DFT) technique is adequate for imaging a single resonance (e.g. single phase distribution), but to enable observation of only a single species during acquisition of a chemical-shift data set (e.g. in two phase distribution) the modified two-dimensional phase encoding (2DPE) sequence is used. Data acquisition and processing are performed by the computer interfaced with the console, and the data can be displayed as a "picture" by integrating each picture element, or *pixel*, in the frequency domain to produce one value per "picture". The CSI sequence used here generates 64 by 64 spectra for each 2-D image (64 spectra for each 1-D). Each spectrum can be integrated to give a value to the corresponding pixel of the image array which is a measure of the total fluid content of the sample voxel. A *voxel* is the optimal elementary volume defined by the resolution and contains a sufficient number of nuclei to be detected. If the spectrum is deconvolved, e.g., oil and water lines are separated and integrated, individual oil and water images can be produced.

The main factors associated with the experimental system which do influence pixel values of the NMR image are

- the operating conditions of the MRI system, and
- the magnetic field homogeneity.

For each set of experiments, the system parameters were optimised and the uniformity of the rf field with the end response of the coil was assessed by obtaining a 1-D profile from a doped water phantom. A uniform rf field with good end response of the coil was confirmed if the signal amplitude is fairly constant along the sample length. From the profile the object length per unit pixel was also determined as 0.94 mm. The optimised parameters for the saturation imaging experiments reported below are given in Appendix 4.2. The spectrometer frequency was experimentally set to the resonance of water, so that the water line appears at

the centre of the spectrum (point 64). The spectra produced have 128 points with a frequency width of 500 Hz. The oil line is 3.5 ppm (60 Hz) away at point 80. The magnet can be tuned over the volume of the core sample to be imaged to < 0.5 ppm, which corresponds to ± 2 points in the spectra. In water-oil saturation imaging, the best distinction of the two lines can be achieved by searching for the water line from point 0 to point 67, and that of oil from point 77 to point 128. This is illustrated in Figure A4.1 in Appendix 4.

4.2 Experimental Materials

Cores plugs were obtained by cutting samples from a variety of outcrop sandstones and limestones from various locations in the United Kingdom (Marsden, 1988). The cylindrical plug-size samples (about 5cm long by 3cm in diameter) were obtained by drilling into these rock samples with a laboratory hollow section drill pipe using appropriate drilling fluid to avoid clay effects. Samples were then dried in an oven at a temperature of 100°C until no further weight changes were observed. The main control on the sample selection was the paramagnetic mineral and shale content of the rocks since the samples were used in the investigations involving the MRI. The porosity and permeability of some of the rock types considered for selection were measured and are shown in Table 4.1. Fluids used were brine, n-decane, paraffin, and soltrol 130 but a variety of enhanced oil recovery (EOR) additives in water was also investigated. This included polymers, surfactants and co-surfactants. Distilled water was used in the selected samples which contained little or no clay minerals.

4.2.1 Core sample analysis

Characteristic plug porosities and permeabilities of the rock samples were measured by the routine core analysis (RCA) methods described in Appendix 3. Table 4.1 shows some sandstones and limestones tested with their porosity and permeability values. Mineralogical analysis made on samples of the various rock-types tested provided their composition. The result of the analysis is presented in Appendix 4.3. The NMR linewidths of rock samples saturated with either brine or oil were measured as described in section 4.2.4 below.

Artificial core samples made from uniform sized spherical-shape glass beads

were used to model uniform wettability and homogeneous porous media. The samples were made by packing the beads in special rubber tubes of similar length and diameter as those of the rock samples.

TABLE 4.1 Rock sample porosity and permeability

Sample code No.	Grain density, g/cc ρ_g	porosity, % ϕ	permeability, md k
Limestones:			
21"-5	2.31	12.0	30.0
18'-8	2.81	22.8	5.2
Sandstones:			
18-2	2.64	14.2	70.6
17-4	2.65	16.2	6.0
16-5	2.62	13.0	6.7
16-8	2.65	8.4	0.1
15-8	2.65	22.5	1000.0
18-1	2.7	20.9	55.3
19'-1	2.6	23.7	88.5
19'-2	2.6	22.1	71.1
19'-4	2.6	20.3	87.2
1-0	2.1	18.5	425.0
1-1	1.7	20.0	300.0

4.2.2 Fluid samples

The hydrogen proton (^1H) NMR imaging technique is insensitive to dry solid samples such as the rock matrix and glass beads. Signals are detected only when fluids (or fluid) are contained in the pores of the solid materials. The intrinsic parameters (T_1) and (T_2) of the fluids can be altered significantly by the effects of the confining solid surface, i.e., the interaction between the fluids and the rock matrix surrounding them. In rocks such effects result from the pore size and its

distribution, degree of compaction, wetting preference, clay content and magnetic susceptibility of the rocks.

A study of the relaxation times of some of the liquids and liquid-solid systems used was made. The relaxation times T_1 and T_2 were measured for bulk water, brine and decane to compare with the same fluids in the presence of glass beads and chips of Clashach sandstone. The results are shown in Table 4.2, and indicate that pure water has long T_1 (about 2.5 seconds) and T_2 (about 1.8 s) and correspondingly an extremely narrow linewidth. The natural linewidth of bulk water and oil measured with the imaging system is less than 0.2 ppm. The relaxation times of the fluid-bead systems were considerably shortened in comparison with those obtained from the bulk fluids. The fluid-rock systems give the shortest relaxation times. The measurements were made at resonant frequency of approximately 17.12MHz. The difference in resonance frequency of water and decane was 63Hz.

TABLE 4.2 T_1 & T_2 for bulk fluids and fluid-solid systems

System	T_2 , ms	T_1 , ms
Brine	1990	2630
n-Decane	408	1247
Water	1780	2460
Water - beads (grade 4)	488	1010
Water - beads (grade 6)	421	862
Water - beads (grade 9)	305	556
Brine - beads (grade 4)	583	1020
Brine - beads (grade 6)	361	842
Brine - beads (grade 9)	268	536
Decane - beads (grade 4)	334	1360
Decane - beads (grade 6)	278	1240
Decane - beads (grade 9)	288	1330
Decane - rock chips	-	496
Brine - rock chips	104	108
Water - rock chips	125	174

The bulk relaxation times of some EOR fluids in water were also measured and are shown in Table 4.3. The results show that the additives alter the T_1 and T_2 of water, and hence in bulk their presence in brine can be recognised on the basis of the relaxation parameters.

TABLE 4.3 T_1 & T_2 for EOR fluids in water

<u>EOR fluid</u>	<u>concentration</u>	T_2	T_1
Flocon	4.8%	1490	880
	2.4%	1860	1270
	1.0%	2090	1670
NaDBS	24%	2160	2100
	2.4%	-	2010
	1.0%	-	1870
	0.4%	-	1810
Alcoflood	150 ppm	2470	2050

4.2.3 Core sample preparation for imaging

Fluid-filled core samples for static measurements and imaging can simply be wrapped in a thin film of waterproof material. For imaging involving flow in a sample, the sample had to be sleeved to form a flow cell. A sleeved sample (flow rig) is shown beside the rf coil system in Figure 4.2. A flow assembly comprising core sample, special rubber sleeve and two end platens was made for the purpose of conducting flow through the sample while placed in the coil of the superconducting magnet. All components of the assembly had to be specifically made of non-magnetic materials because magnetic material around the core sample would reduce the S/N, and they were also non-reactive with oil and brine. These solid components did not produce a signal detectable by the imaging methods used here. Various core holders were constructed, tested and/or used and these are described

in Appendix 4.4.

4.2.4 Rock sample selection for MRI studies

As discussed previously many MRI methods can distinguish between fluid species with the rock matrix effectively transparent with regard to signal interpretation. One would then expect that the resulting image of fluid-filled rock sample should always be a representation of the fluid distribution. However, the nature of the rock influences the relaxation times of excited fluids and hence of imaging rates. This influence broadens the linewidth of the fluid in rocks. Fluids used were distilled water or brine, and decane. For two fluids such as water and oil in a rock, separate images of the two phases can easily and confidently be produced by the MRI technique only if their individual linewidths are sufficiently narrow for the MRI system used.

The linewidths of several sandstones and limestones saturated with water were measured. The cores were fully saturated with water by using vacuum pump to evacuate air from the pores, and then filling them with water. The purpose of the measurements was to select the core with the narrowest linewidth for the CSI technique. The exercise comprised measuring the total dephasing time T_2^* . The NMR linewidth was calculated in Hz as

$$\nu_{\frac{1}{2}} = 10^3 \cdot \frac{1}{\pi T_2^*}$$

or in ppm as

$$\nu_{\frac{1}{2}} = \frac{10^3}{17.12} \cdot \frac{1}{\pi T_2^*}$$

where 17.12 MHz is the resonant frequency at which measurement was made. The results are presented in Table 4.4, which shows that of all samples tested the Portland limestone gave the longest T_2^* of 6.4 ms. The range of values obtained for different rock types reflect the effect of the fluid interaction with the solid rock matrix. As discussed previously in Chapter 2, the relaxation parameters depend on the fluid in the rock and are also influenced by the effects of the confining solid surface on the fluid. Rocks with tightly binding matrix and/or containing shales usually tend to shorten the T_2^* and consequently exhibit broadened linewidths.

TABLE 4.4 Linewidths of water-saturated rocks

Rock*	Code No.	Type	T_2^* , ms	$\nu_{\frac{1}{2}}$, ppm
Clashach	1-0	Sandstone	3.9	5.0
Birkams	19'-4	Sandstone	1.0	18.6
Springwell	17-4	Sandstone	1.0	18.6
Crosland hill	16-5	Sandstone	2.5	7.4
Blaxter	15-7	Sandstone	2.8	6.6
Dolington	15-8	Sandstone	3.5	5.3
Lochaline	1-1	Sandstone	6.0	3.1
Gebdykes	18'-2	Limestone	2.5	7.4
Portland	21"-5	Limestone	6.4	2.9
Monks Park	21'-2	Limestone	4.0	4.6
Guiting	2-0	Limestone	1.5	12.4
Barton	15-11	Limestone	2.6	7.1

* Marsden (1988)

The main criterion for the selection of rock types for the MRI experiments was the linewidth value (the T_2^* value). The linewidths for the Portland limestone and the Lochaline sandstone were satisfactory for use with our MRI system. The Lochaline sandstone is a high quartz sand from a shallow marine depositional environment. Broad linewidths (or short T_2^*) would necessitate the use of faster gradient switching times and stronger magnetic field than obtainable from our imaging system. To effectively resolve the oil and water phases from the spectra the width of the individual line should be less than the chemical shift separation of the two lines. This difference is about 3.7 ppm (or 63 Hz) at an operating resonance frequency of 17.12 MHz.

The result of the mineralogical analysis in Appendix 4.3 shows that shaley sandstones and limestones with tightly binding rock matrix exhibit broadened linewidths. A similar broadening effect was also observed with samples containing paramagnetic minerals. The implications of this effect on the imaging technique have been discussed in Chapter 2. Although the magnet strength in these experi-

ments limited the use of some samples, more powerful imaging systems have not been successfully used for all core samples. The limiting factors include presence of shaley, magnetic and paramagnetic materials in rock samples. Some of these limitations may be overcome in a custom-built MRI system. Edelstein et al (1988) suggested that by refocussing part of the NMR signals in some shaley sandstones, they can be imaged with very fast data acquisition. There are already electronically enhanced fast imaging techniques designed for medical applications (Haase et al., 1986) which can be adapted to imaging core-fluid systems to take advantage of significantly faster gradient switching times. NMR capabilities can therefore be extended to shaley sandstones with short T_2^* and broad NMR linewidths and this is already arousing research interest.

4.3 Fluid Images

4.3.1 Thin-slice images

Conventional two-dimensional projection images of fluids in a core plug have been reported using a 2-D imaging sequence (Hall and Rajanayagam, 1987; William et al, 1990). They are obtained without slice selection and represent a projected view across the diameter of the sample. Much higher information content is obtained from thin-slice images. Slice selection techniques involve the application of a frequency-selective rf pulse in the presence of a magnetic field gradient. MRI with slice selection can proceed by defining a domain cell (thin-slice) of the core plug. The cell may be a circular cross section plane or a longitudinal section plane depending on the direction of gradients applied. Figure 4.3 illustrates the later. A preference for longitudinal thin-slice selection is indicated in the later part of this work for monitoring the process of a core flood along the core length. A plane can be divided into n_x grid blocks in a 1-D slice image or n_x by n_y blocks in a 2-D slice image. In the multi-slice technique 3-D cell grids (n_x by n_y by n_z blocks) are defined. Factors that determine slice thickness have been discussed in Chapter 2 of this work and elsewhere (Hall and Rajanayagam, 1987).

With a 1.5 ms Gaussian weighted selective pulse and 2.5 G cm^{-1} gradient, a slice width of 4 mm was determined. Unless otherwise specified slice images obtained and reported in this work have 4 mm width and represent the central

plane through the sample.

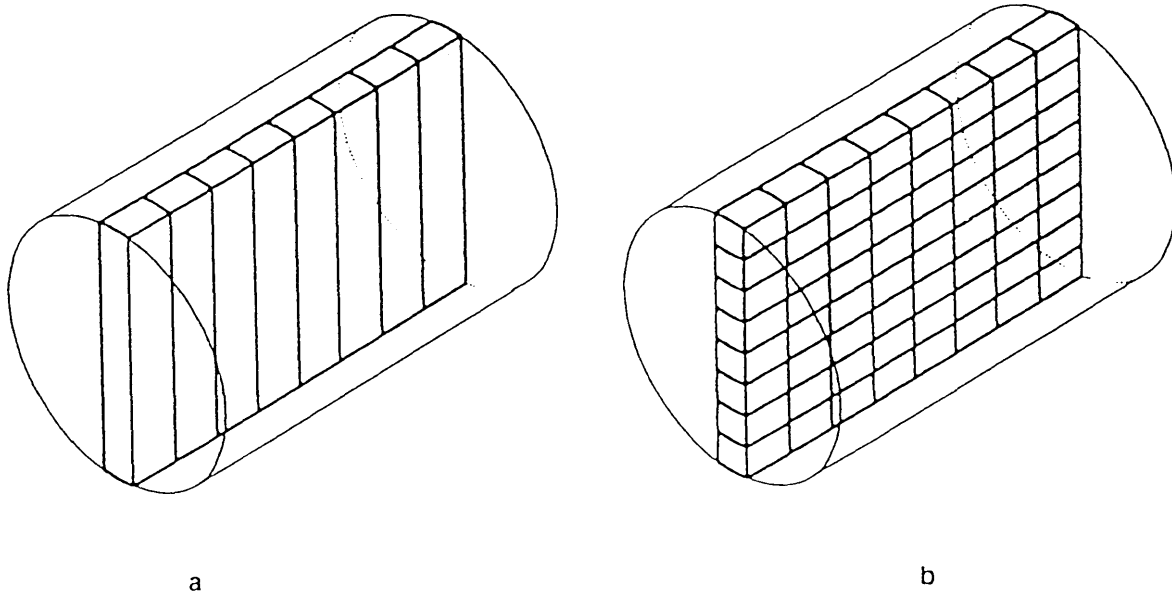


**Figure 4.3 Voxel arrangement in a longitudinal thin-slice
(a) 1-D image and (b) 2-D image**

4.3.2 Water image

To check the imaging system for magnetic field uniformity a water-filled phantom (2.5 cm diameter and 4.5 cm long) was first imaged. A cylindrical plastic canister of dimensions similar to those of the core plugs to be imaged is referred to here as a *phantom*. Figure 4.4 was typically obtained from the water phantom. Pure water has extremely narrow linewidth and so had to be doped with manganese chloride to mimic the line broadening effect similar to that produced by porous rock matrix. The doped water had T_2^* approximately 20 ms. The profile from the phantom serves to assess the uniformity of the radio frequency field and the end response of the detecting coil. The amplitude peak height A of the bulk NMR spectrum of water in the sample being imaged is taken as unity and the pixel amplitude peak height is recorded as fraction of the bulk A . Hence the amplitude peak height is presented in percent on the profile, from which the object length per pixel (each data point) was determined as equivalent to about 940 μm . The

doping agent reduces the water NMR signal in a similar manner to that of the effect of the confining rock matrix.

The 1-D image shown beside the profile in Figure 4.4 indicates, as expected, the same level of NMR signal intensity along the sample length. The image is a photograph of the display on the interfaced computer monitor and served as a quality control. The image was intensity-normalized in order to photographically reproduce it more effectively. Similar tests were performed with oil phantoms with consistent results.

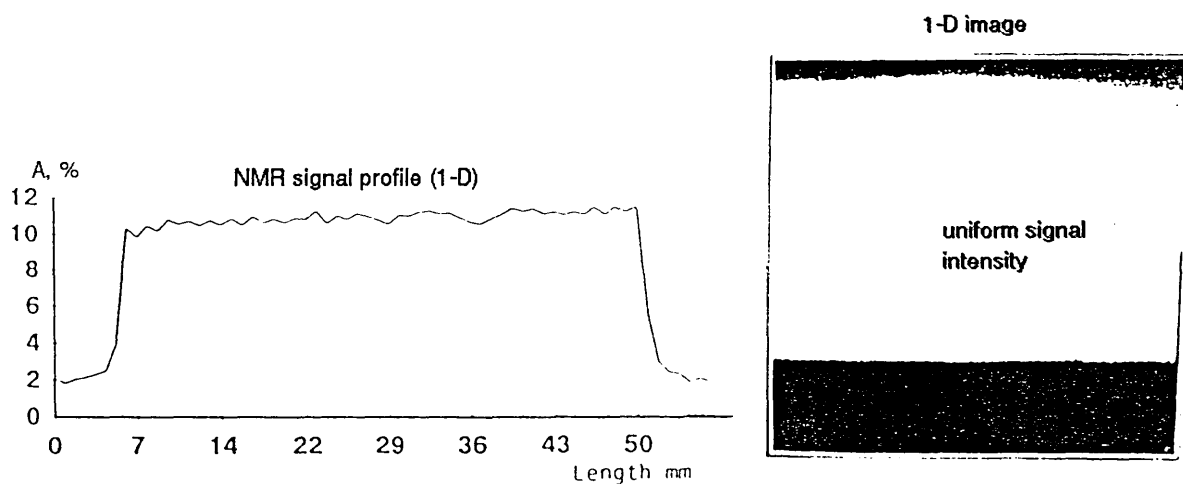


Figure 4.4 Image of doped water in a canister

4.3.3 Oil and water images

The chemical shift imaging technique was used to differentiate oil and water NMR signals in a porous material and separate images were obtained. Two bead packs, one fully saturated with water only and the other fully saturated with oil only, were imaged as a composite sample. There was no capillary contact between the two packs. The fluid-filled composite sample was imaged in 1-D and deconvolved into separate oil and water images. Figure 4.5 shows the oil and water profiles and also indicates the effectiveness of the deconvolution process - no oil signal in the water image and vice versa. The 1-D CSI image is acquired typically in 4.5 minutes. This potential for rapid NMR signal mapping was used in the later part of this work to monitor advance of flood fronts in core floods involving water and

oil.

Chemical shift imaging in two dimensions (2-D CSI) of oil and water in porous solid material was demonstrated with a glass bead pack. Figure 4.6 shows the separate oil and water images. The glass bead pack made from mono-size spherical beads was 4.5 cm long with 2.5 cm diameter and had a bulk porosity of 39.5%. The bead pack was fully saturated with water, and then oil (n-decane) was injected from one end until it just began to produce with water at the outflow end. The injection, represented on the figure as occurring from left to right, was then stopped and the images were obtained. The profiles on the left of the figure are plotted from the 1-D data. They reflect (as confirmed by the 2-D image photographs shown beside them) the predominance of oil in the part of the sample from which the oil was injected, likewise the predominance of water in the remaining part.

The image spectra from four pixels positioned along the selected longitudinal thin-slice are shown in Figure 4.7. The image spectra signals originate from the small sample voxels and indicate that

- for this particular oil/water/beads system good spatial and chemical shift resolution is feasible, and
- the voxels contain oil and water at different ratios

4.4 Discussion and Conclusions

The Portland limestone and the Lochaline sandstone, saturated with brine or oil, produced the narrowest NMR linewidths compared with the other rock types tested. The choice of rock types tested was based on availability. Imaging experiments involving the simultaneous presence of oil and water in the rock sample were conducted with samples cored from either of these two rock types. As discussed previously in Chapter 2, the selection of the rocks was purely for ease in resolving the oil/water chemical shift images or spectra into separate oil and water images or spectra. With the appropriate imaging equipment and methods, the MRI technique should be applicable to many other rock-fluid systems. The limiting factors are the presence of shaley, magnetic and paramagnetic materials in rock samples.

The rf selective pulse and gradient used in this work produce a 4-mm wide slice image. The duration of the rf pulse and the strength of the gradient determines

the width of the selected slice. In principle any slice width can be obtained by a combination of pulse and gradient. The rf selected plane width Δx defined by the expression (Rothwell, 1985)

$$\Delta x = 2\Delta w / \gamma G_x \quad (4.3)$$

where, Δw is the frequency offset and

γG_x is the strength of the applied gradient.

This implies modification in the imaging hardware which for the purpose of this work was not made. With the appropriate pulse and gradient it would be possible to select a slice as wide as the diameter of the sample being imaged. But for samples the size of typical laboratory core plugs, such a slice will undoubtedly compromise microscale observation of the saturation distribution, especially where interest may lie at the pore scale.

Figure 4.4 demonstrates the uniformity of the rf field and the end response of the detection coil used in the imaging experiments. Prior to conducting imaging experiments with real rock samples, such demonstration was conducted to ascertain the status of the imaging system. The rf field can be unsettled following interruptions in the electricity power supply (e.g., switch off and on). The magnet was shimmed over the water phantom volume to set the position of water peak amplitude on the spectrum. The position of the oil peak amplitude relative to that of the water on the spectrum is about 63 Hz away to the right. Figure A4.1 in the Appendix obtained for decane and water illustrates the positions.

The chemical shift imaging (CSI) technique has been used to obtain 1-D and 2-D NMR signal images of oil and water in porous media (bead packs), and obtain separate NMR signal profiles and images of oil and water simultaneously present in a bead pack.

Each image pixel length was determined as equivalent to 0.94 mm.

These results indicate that core samples containing no shaley, magnetic and paramagnetic materials can be used in special core analysis monitored with the MRI technique. The CSI technique measures chemical shift difference within 0.2 ppm accuracy, equivalent to about 0.05 standard deviation. The technique offers a reasonably good resolution of 0.94 mm. These results form the basis for the saturation imaging experiments with some rock samples and the study of water-oil displacement processes in the rock samples reported in the following part of this work.

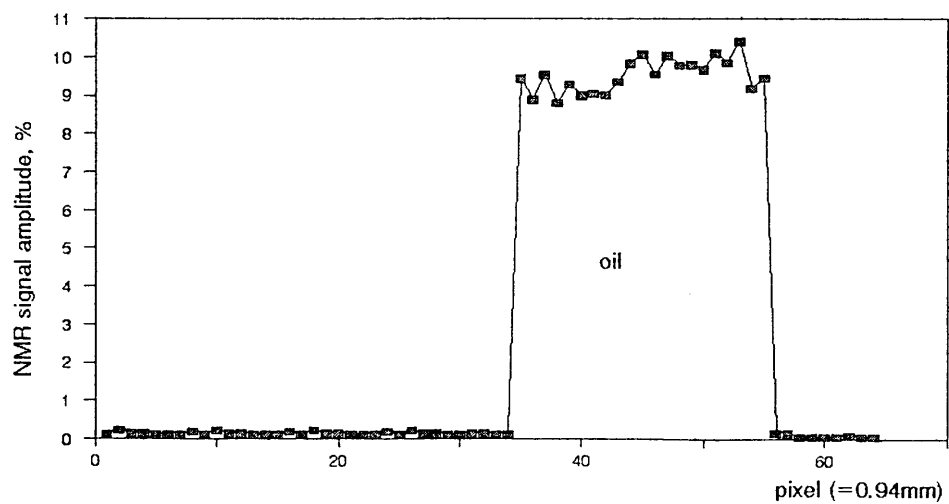
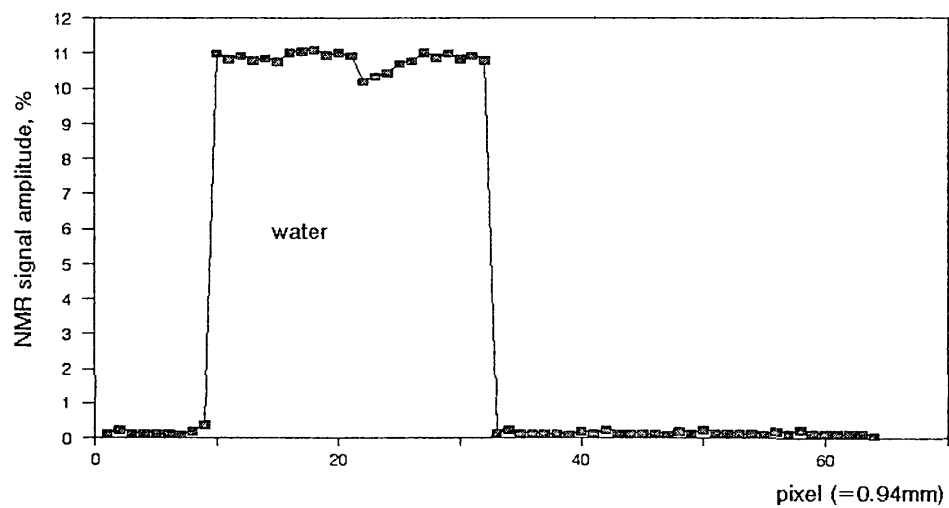
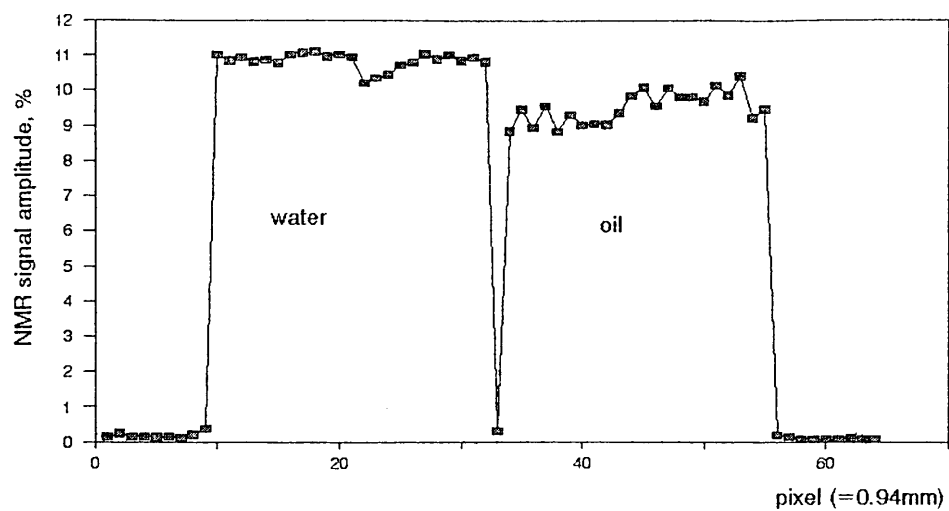


Figure 4.5 NMR signal profiles of oil and water in composite bead pack

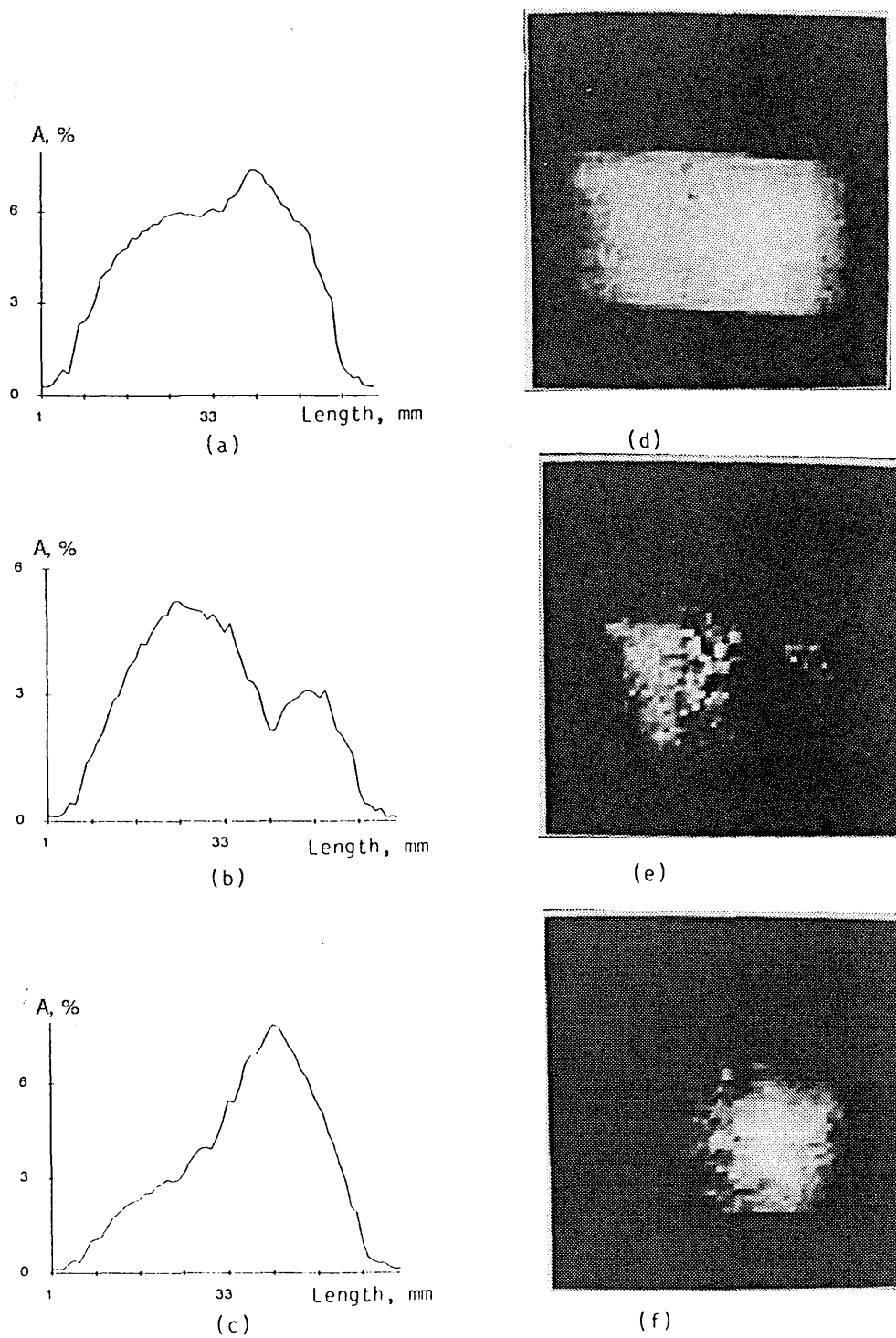
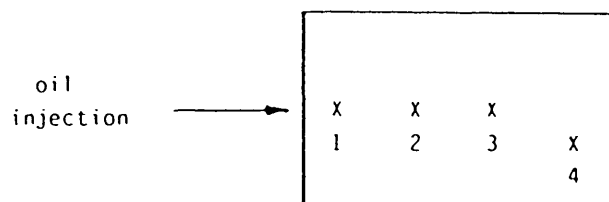
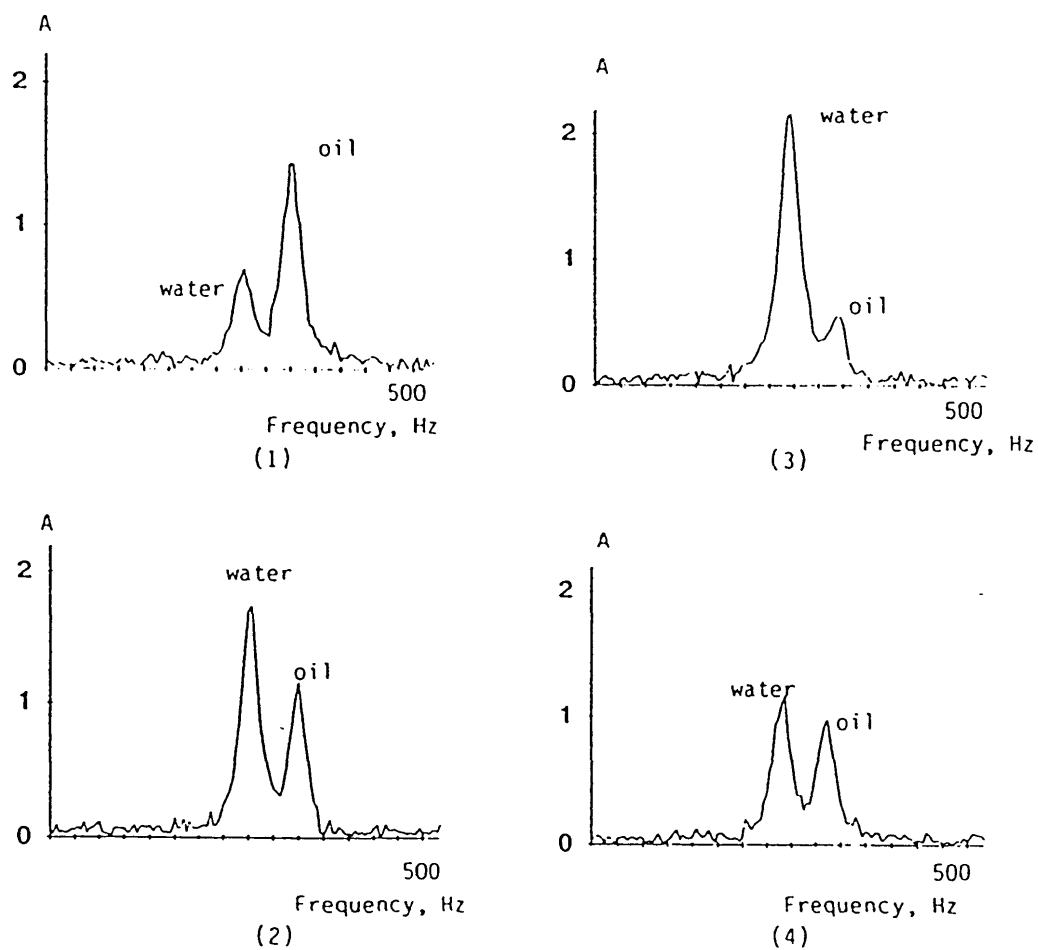


Figure 4.6 Separate CSI images of oil and water in bead pack
 (a) total fluid profile; (b) oil profile; (c) water profile; and
 2-D images of (d) total fluid; (e) oil; and (f) water.



Schematic diagram of the position of the bead pack spectra



A - Amplitude in %

Figure 4.7 The chemical shift spectra from the 2-D image of oil and water distributed in the glass bead pack.

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CHAPTER 5

CORE IMAGING

This chapter explores the potential of an MRI technique as a tool for visualising the spatial distribution of fluids in rock core plugs. One thin-slice, 4-mm wide in the longitudinal plane (or 4-mm thick circular cross section) through the centre of the core plug was selected and examined in each image. Some rock properties and their spatial distributions at small scale in the plane were revealed – in particular oil and water saturations, porosity and pore size distribution. Chemical shift imaging (CSI) methods were employed to distinguish oil from water in core plug samples. Single fluid distribution in the core plugs was measured by spin echo experiments. The radio-frequency (rf) pulse and gradient sequence used in the imaging has been described in Chapter 2. The slice images were obtained with an interpulse time spacing $T_R = 3.4$ s and echo time $t_e = 40$ ms. Three rock-types were examined.

5.1 Single-Phase Fluid-Filled Core

Hydrogen (^1H) proton NMR imaging is insensitive to the dry rock matrix, i.e., the solid matrix does not produce measurable signal. The core sample was imaged by this method only when it was saturated with fluid or fluids containing hydrogen protons such as those present in water and liquid hydrocarbons. The ^1H NMR signal is proportional to the number of protons in the sample.

Three rock samples, each about 1 inch in diameter, saturated with water were imaged at the same operating conditions as those used to obtain Figure 4.4 of Chapter 4. Mineralogical examination has shown these rocks to be almost clay-free, and therefore insensitive to water with regard to clay-water reaction. Hence distilled water was used in these tests. The presence of clay and shales in the rock samples would broaden the NMR linewidth and might alter the permeability and porosity of the samples by swelling in the presence of distilled water. The NMR signal profiles are shown in Figure 5.1 and indicate the one-dimensional (1-D) distribution of the water contained in the core plugs. A Portland limestone plug (sample PLS-08) of 16% porosity, 22 md permeability, with NMR linewidth of 2.9 ppm produced the profile shown in Figure 5.1(a). The sample was 3.88 cm long and 2.44 cm in diameter. Figure 5.1(b) shows the profile obtained from a plug sample of Lochaline sandstone (3.89 cm long and 2.38 cm in diameter) of 20% porosity, 223 md permeability with NMR linewidth of 3.1 ppm. A plug sample of Clashach sandstone (3.69 cm long and 2.44 cm in diameter), 19% porosity, 296 md

permeability with linewidth of about 5 ppm produced the profile shown in Figure 5.1(c). The bulk sample porosities of the samples were derived from the weight difference between the dry core plug and the fully saturated sample. The cores were saturated by placing dry plugs under vacuum to evacuate air, then sufficient air-free water was introduced to fully saturate the core.

By comparison with the water phantom profile of Figure 4.4 these profiles show fluctuation of NMR signal amplitude indicating unequal amounts of water in the volume represented in each of the pixels. The NMR signal amplitude A is proportional to the fluid proton density, i.e., the number of ^1H protons in the volume, but also depends upon relaxation parameters. Hence even where equal number water protons were held in pixels of different rocks the magnitude of the signal amplitudes were different. Since different fluid-filled rock samples have different relaxation parameters, this implies an important conclusion that each core plug needs to be specifically calibrated. However samples from a rock type often have similar bulk relaxation parameters.

Figure 5.2 shows the NMR water images from the water-filled Portland limestone sample (PLS-08). The images of the 4-mm wide longitudinal plane in the plug indicate the spatial distribution of the water contained in the core. Figure 5.2(a) is the 1-D image representation of Figure 5.1(a), showing the signal amplitude along the length of the sample slice. Pixels with high water content provide larger NMR signal in the images and are yellow in the colour representation. The blue regions correspond to smaller NMR signal amplitudes. The 2-D image of the same slice shown in Figure 5.2(b), as well as the 1-D image, has the signal amplitude per pixel scaled to the peak height of the bulk NMR spectrum of the sample. Hence the images and profiles show the signal amplitude variation from voxel to voxel as a percentage of the peak amplitude of the bulk spectrum. The water NMR images were obtained by spin echo experiments as described in Chapter 2 of this work.

Figure 5.3 shows 2-D cross section images from 4-mm thick planes in three different core plugs. The images were obtained from two Portland limestone core plugs and a Clashach sandstone plug and were NMR signal intensity-normalised in order to photographically reproduce more effectively. The 1" outer diameter (od) samples were fully saturated with decane, wrapped with thin-film waterproof material to avoid loss of fluid, and then placed in the rf coil to image.

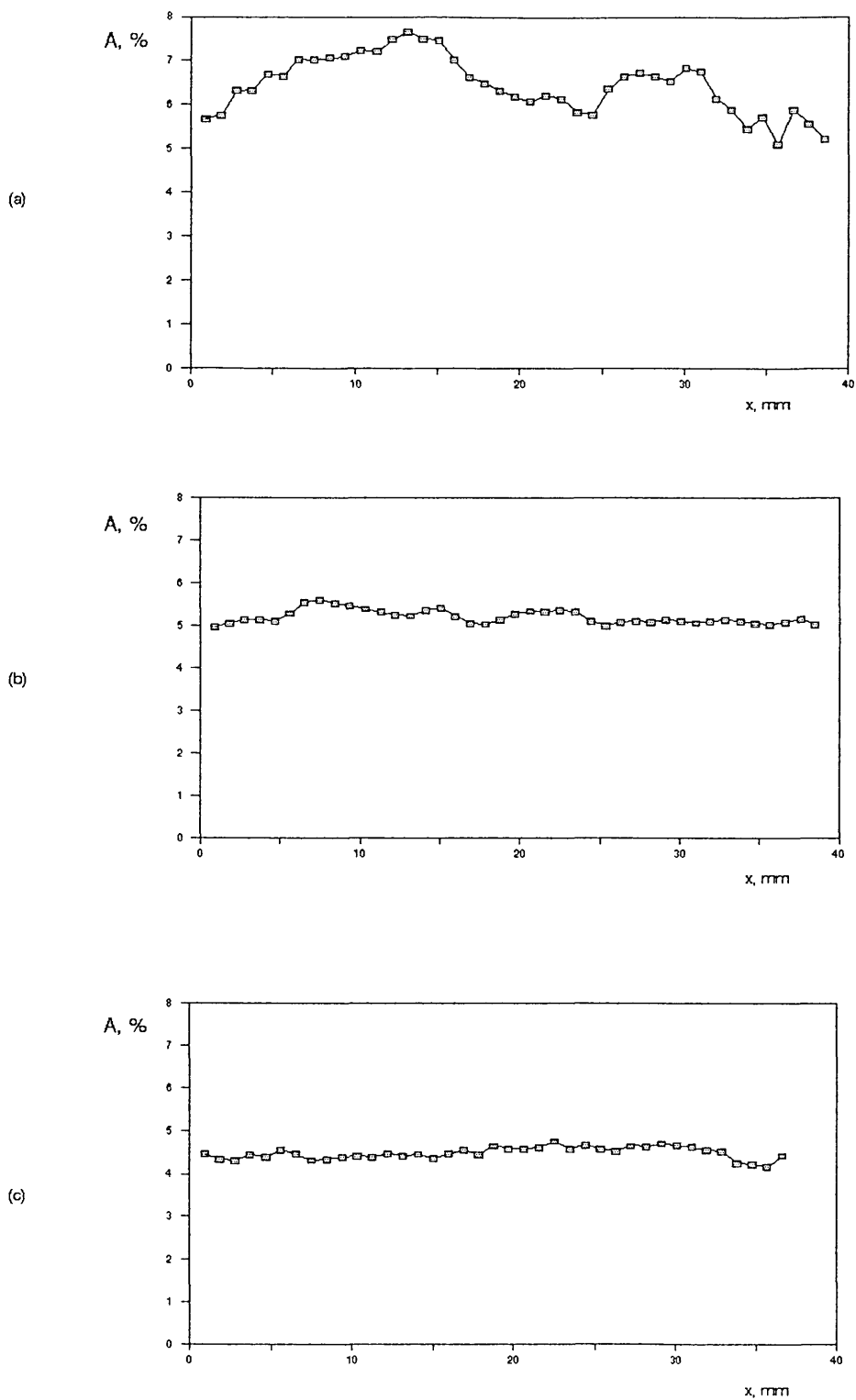
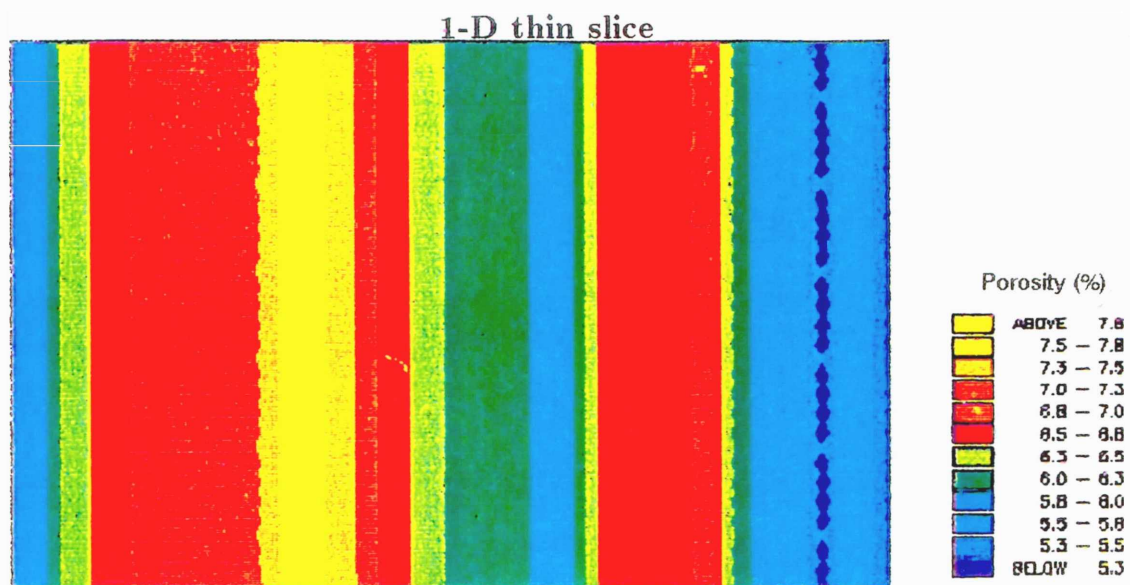
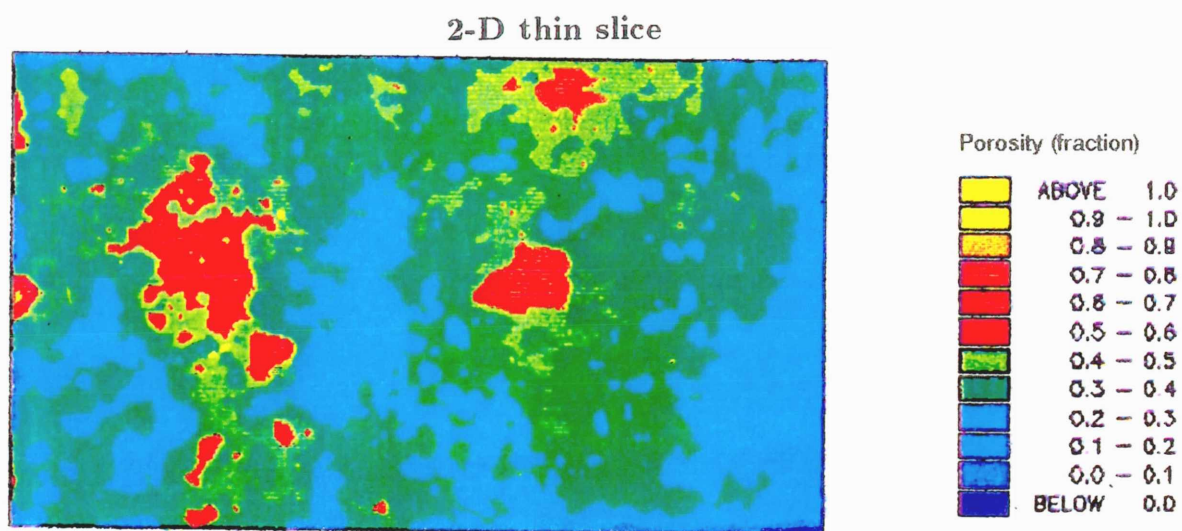


Figure 5.1 NMR signal from fluid-filled rock sample (1-D images)
 (a) Portland limestone; (b) Lochaline sandstone; (c) Clashach sandstone

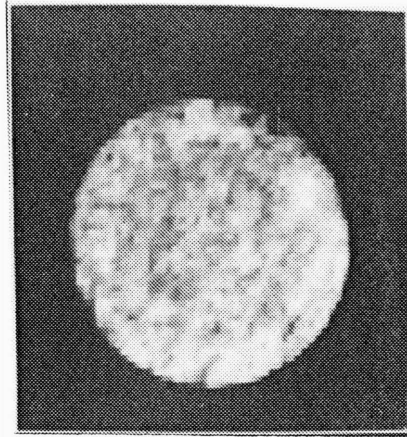


(a)



(b)

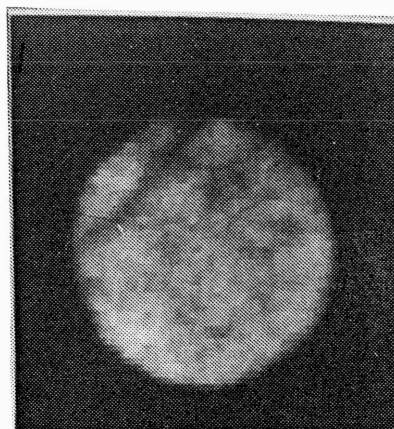
Figure 5.2 NMR signal images of water-filled samples



(a) Clashach sandstone



(b) Portland limestone



(c) Portland limestone

Figure 5.3 Cross section slice images of single fluid-filled samples

The image in Figure 5.3(a) was obtained from an apparently homogeneous Clashach sandstone sample. Most parts of the image appear bright (high NMR signal intensity) indicating similar fluid content. The slightly dark spots (low intensity) appear where the NMR signal from the n-decane decayed rapidly, usually in lower porosity regions. Figure 5.3(b) shows the image obtained from a sample slice of Portland limestone core plug, in which lower porosity regions in the sample appear as dark streaks. Another sample of Portland limestone produced the image shown in Figure 5.3(c) which reveals a dark streak on the top left corner of the image corresponding to a low porosity region.

5.1.1 Porosity mapping

Porosity images show details of exactly where the fluids are located in the core sample and what kind of porosity variations exist in it. Ways to get this kind of image using MRI techniques are varied and have been discussed elsewhere, including Edelstein et al (1988). Here we derived the spatial distributions of porosity from the distribution of a single fluid fully saturating the sample. The strength of the ^1H NMR signal emitting from localised fluid content at a given frequency is proportional to the number of the protons at the position. However the scale of the signal amplitude will depend upon the relaxation parameters of the rock. In general (Seevers, 1966),

$$Signal \propto \phi \sum_i f_i \exp\left(\frac{-t}{T_{1i}}\right)$$

where f_i is the fraction of the total porosity, ϕ , which has a relaxation time T_{1i} ; and t is the time.

For a given core plug with the same mineralogy throughout the sample, the local T_1 values are usually similar and hence can be assumed constant. Therefore the amount of fluid in the elementary volume (voxel) represented in each of the pixels is proportional to the signal amplitude. The distribution of the NMR signal amplitudes thus reflect the fluid distribution. For the sample fully saturated with water the voxel porosity ϕ_v was determined by dividing the volume of water filling the voxel PV_v by the bulk volume of the voxel V_v .

$$\phi_v = \frac{PV_v}{V_v} \quad (5.1)$$

Figure 5.4 shows the porosity profile derived from a 1-D image; and the porosity map and distribution determined from the 2-D image of the 4-mm wide plane

in the water-filled sample PLS-08. The pore volume (PV) of the core plug was determined as the weight difference between the dry core plug and the fully saturated sample. The bulk porosity of the sample was then determined by dividing the PV by the bulk volume of the core plug measured with the calipers ($\phi = 0.16$). For this water-filled sample the longitudinal relaxation time T_1 was fairly constant throughout the core ($T_1 = 883$) ms. So the porosity distribution was obtained from proportionality of the fluid volume with the measured NMR signal data. These data presented in Figure 5.4 indicate deviations of porosity around the bulk porosity value.

Porosity variations from about 0.12 to 0.2 were determined with the 1-D slice definition, and with the 2-D slice image the porosity differences span from about 0.02 to 0.3.

One of the more common forms of the characteristic distribution of porosity as observed in a reservoir is a normal distribution. Data from the 2-D porosity interpretation provided similar distribution as shown in Figures 5.4 to 5.6. This suggests that such characteristic distribution of porosity can also be observed at the core plug scale.

The NMR signal measured was that observed for times greater than the t_e . Error in signal measurement is associated with uncertainties in extrapolating the signal observed for $t > t_e$ back to zero echo time to obtain the absolute signal corresponding to the Free Fluid Index, FFI. This error was avoided since the porosity distribution was determined on the basis of weight difference between the dry sample and the fully saturated sample. Hence the accuracy of the estimates of the local porosities depends only upon the accuracy of the bulk porosity measurement which, by the method used here, is accurate within 5 percent.

Similar 2-D slice images were interpreted for sandstone samples and are shown in Figures 5.5 and 5.6. Figure 5.5 was obtained from a Clashach sandstone core plug and reveals porosity variations from 0.1 - 0.3. A sample of Lochaline sandstone produced the porosity map and distribution shown in Figure 5.6. Porosity variations, from about 0.1 - 0.3 are also evident.

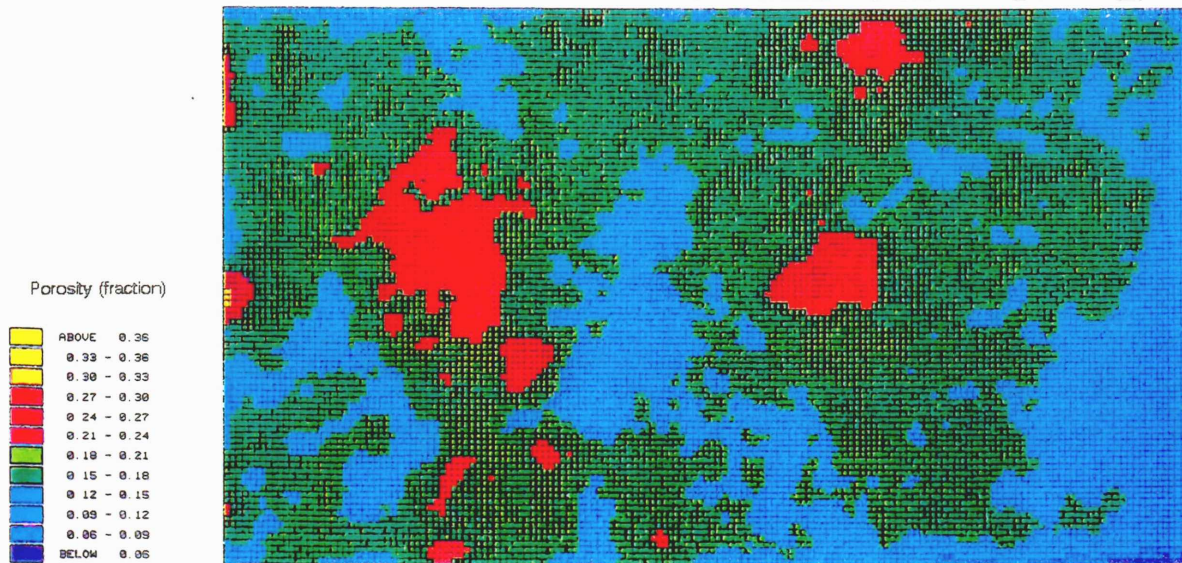
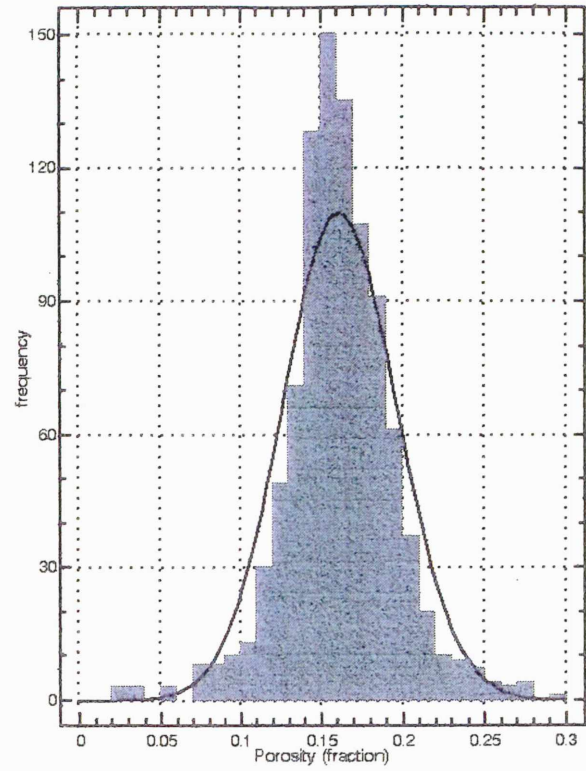
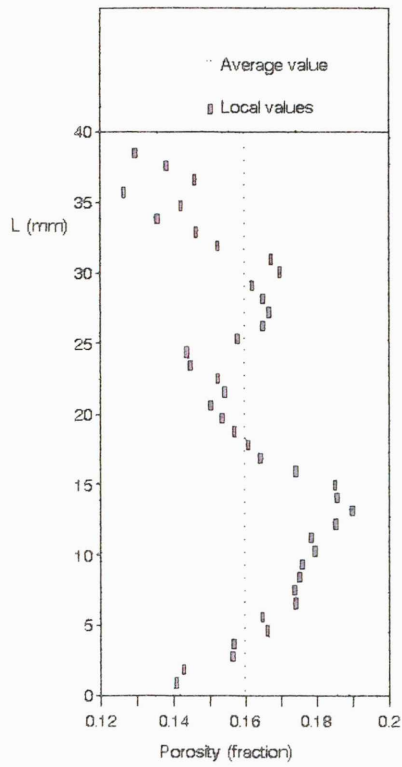


Figure 5.4 Porosity data for Portland limestone sample (PLS-08)

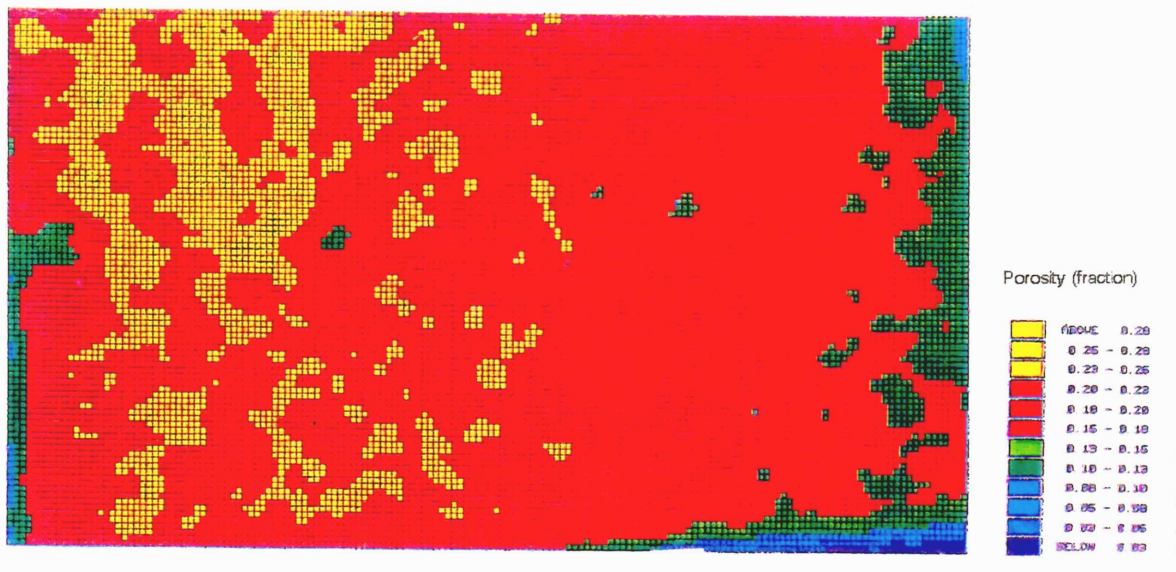
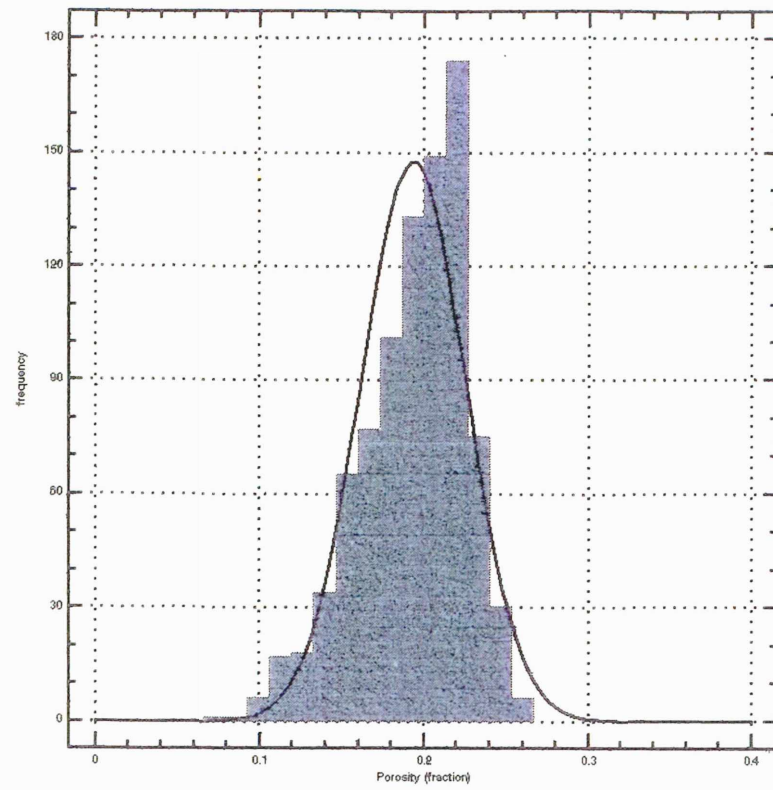


Figure 5.5 Porosity data for Clashach sandstone

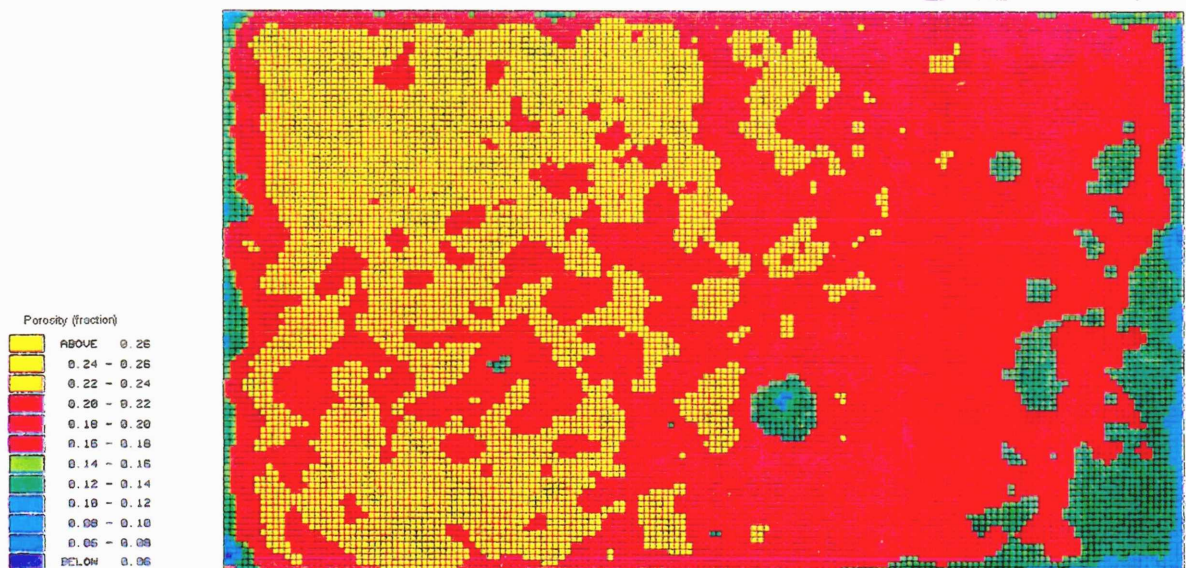
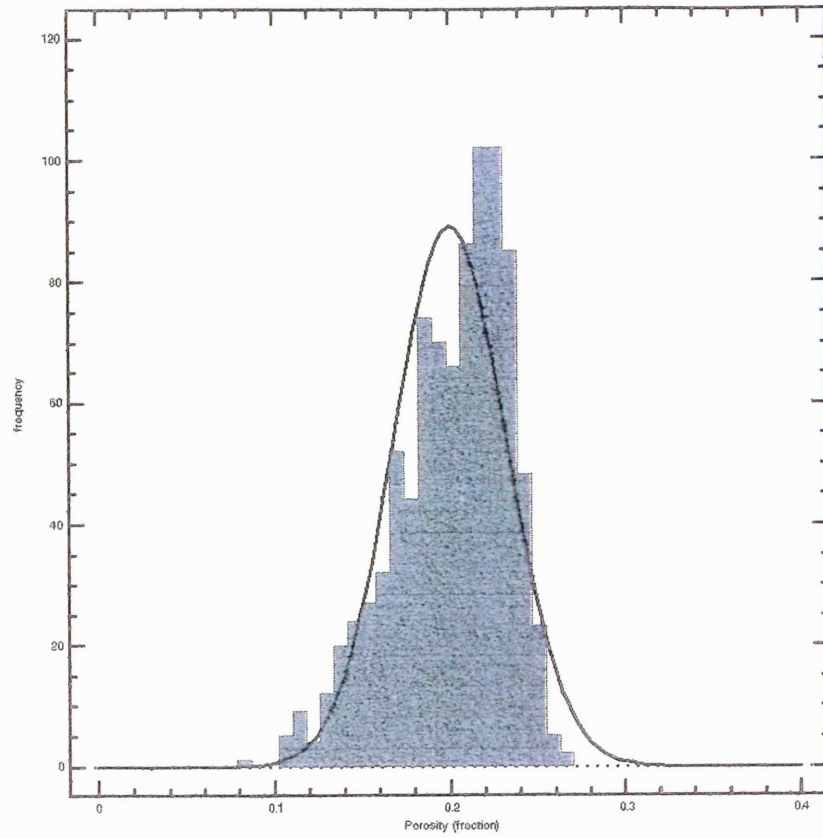


Figure 5.6 Porosity data for Lochaline sandstone

5.1.2 The profiles and maps

The profiles for the rock samples shown in Figure 5.1 show variation of the NMR signal amplitude along the rock samples length. Compared with the profile for the water phantom this variation reflects local variation in the water content and effects of the confining rock surface on it. However the NMR signal variation resulting from the effects of the confining rock surface is insignificant in relation to that caused by the water content. This has been confirmed with the experiments in the preceding chapter using glass beads. Hence the signal variation reflects local variation in porosity within the core samples. Each small volume represented in each of the pixels is equivalent to 0.094 cm by 0.4 cm by the core od (in cm).

The 2-D thin-slice images demonstrate good resolution (about 0.94 mm with a 4 mm slice width) and provide useful information. Only the MRI technique has been able to resolve fluid distribution in rocks on such a small scale. Multislice imaging techniques would define 3-D cell grids, i.e., a series of slice images of the entire core sample. A series of the image cross sections taken along the core length (or a series of longitudinal slice images taken along the core diameter) would provide a complete insight into the *in-situ* features otherwise ignored in routine and special core analysis. These data acquisition and processing methods however require a more powerful imaging hardware and computer capability than was used in this study.

The signals from the regions with the fast decay are never seen in the images because the MRI equipment had an echo time t_e of 40 ms. The reason for the choice of this long t_e lies in the equipment. It is the time required for eddy current generated as a result of gradient switching during the experiment to decay before the data are acquired. These regions with fast decaying signals are of very low porosity and in Figure 5.3 are dark in colour representation. The regions with more free fluid content provide a larger NMR signal in the images and are very bright on the image picture. They have higher fluid-filled porosity than the rest of the sample. Under similar imaging conditions, the brighter regions represent high porosity, i.e., the pores are larger, and correspond to long transverse relaxation time T_2 . Tightly bound fluid in small pores provide smaller signal amplitudes because most of the NMR signal from it decay rapidly due to short T_2 . Porosity variations revealed by the imaging indicate small-scale heterogeneities, which might affect corefloods as has been indicated by Huppler (1970).

The Lochaline and Clashach sandstones are usually uniform and are generally regarded to be homogeneous. The MRI approach revealed significant porosity differences, as evidenced from the fluid distribution. These imaging experiments show that MRI can ‘visualise’ single fluid distribution in rocks with reasonably good resolution $\Delta_x = 0.94$ mm.

5.2 Water/Oil in Core Plug

In Portland limestone water and oil NMR linewidths are narrow enough for their peaks to be spectroscopically resolvable. The CSI method was used in a Portland limestone sample (PLS-02) to distinguish the oil and the water signals. The core plug (2.44 cm in diameter and 3.58 cm long) had a bulk porosity of 17%. The Portland limestone samples when saturated with water had on the average an optimal total dephasing time $T_2^* = 6.4$ ms. The imaging was conducted with an echo time $t_e = 40$ ms, interpulse time spacing $T_R = 3.4$ s for reasons discussed below (see Discussion). The absolute signal ratio of oil to water corresponding to the zero echo time $t_e = 0$ was determined by comparing the peak heights of two NMR bulk spectra of the oil and water in the core, one obtained with $t_e = 40$ ms and the other with $t_e = 0$. This process is described in Appendix 5.1 and illustrated by Figure A5.1.

5.2.1 Water/oil NMR signal images

The sample, originally fully saturated with n-decane, was waterflooded until no more oil was produced. The core plug was contained in a flow cell made from perspex (Figure A4.4.2 in the Appendix) and water was injected at a constant flow rate of $0.7 \text{ cm}^3/\text{hr}$. Water injection was discontinued to obtain images, including 2-D, at a static condition. A 2-D image required about 4.5 hours to acquire as previously discussed, hence they were only suitable for obtaining saturation distribution at a static condition. This was a limitation of the particular imaging equipment used in this study. Figure 5.7 shows the profiles from 1-D imaging, and maps from the 2-D image of the water and the oil signals from the 4-mm wide plane in the core plug. The 1-D image was obtained immediately after the injection pump was stopped. The water injection was from right to left on the profile. In view of the long period of time taken to obtain the 2-D image with the University of Surrey equipment, some fluid redistribution may have occurred in

the core during the period of no fluid injection. For this reason it was not prudent to use the 2-D imaging during a core flood, except at initial (starting) conditions in the unsteady state flow tests. 1-D imaging which require only about 4 minutes to conduct was used later in this work for core flood imaging.

The bulk relaxation rates of the fluids in the core were determined for the whole core. The method of their measurement has been described in Chapter 2. The T_2 values were 50 ms for the decane and as well as for the water in the sample. $T_1 = 177$ ms for the water and $T_1 = 883$ ms for the n-decane, measured at 100% single-phase saturation in the Portland limestone.

5.2.2 Connate water saturation

A Portland limestone sample (PLS-15) with 0.15 porosity and 40 md permeability was imaged while it contained connate water (25% PV) and n-decane (75% PV). This was one of several imaging experiments with Portland limestone samples containing water at low saturations (up to 0.3) aimed at establishing the lower detection limit for water in the presence of oil. The core sample was first fully saturated and aged in water for four weeks to make it water-wet. The core was then partially desaturated to a connate water saturation of 0.25 using a centrifuge before it was resaturated with n-decane using a vacuum pump.

Figure 5.8(a) shows the bulk spectrum of the whole core plug containing 0.25 PV of water and 0.75 PV of oil. The spectrum was obtained immediately following the 90° pulse after excitation, and it shows only the oil spectral line. A similar spectrum was obtained for other samples with water saturation below 0.25. Apparently only the oil NMR signal was detected because the water NMR signal is smaller than the detection limit of the equipment. In a 2-D CSI of the sample only the oil NMR signal image was produced as shown in Figure 5.8(b). As in the bulk spectrum, the water NMR signal was not measurable.

The series of bulk spectra measurements and CSI experiments conducted with samples of the Portland limestone indicated that water produced a measurable NMR signal at saturations exceeding 0.3. This formed the lower detection limit of water signal for further imaging experiments with the Portland limestone samples on the MRI system used here. The limit depends mainly on the power of the imaging equipment. Connate water usually wets the rock and resides preferentially

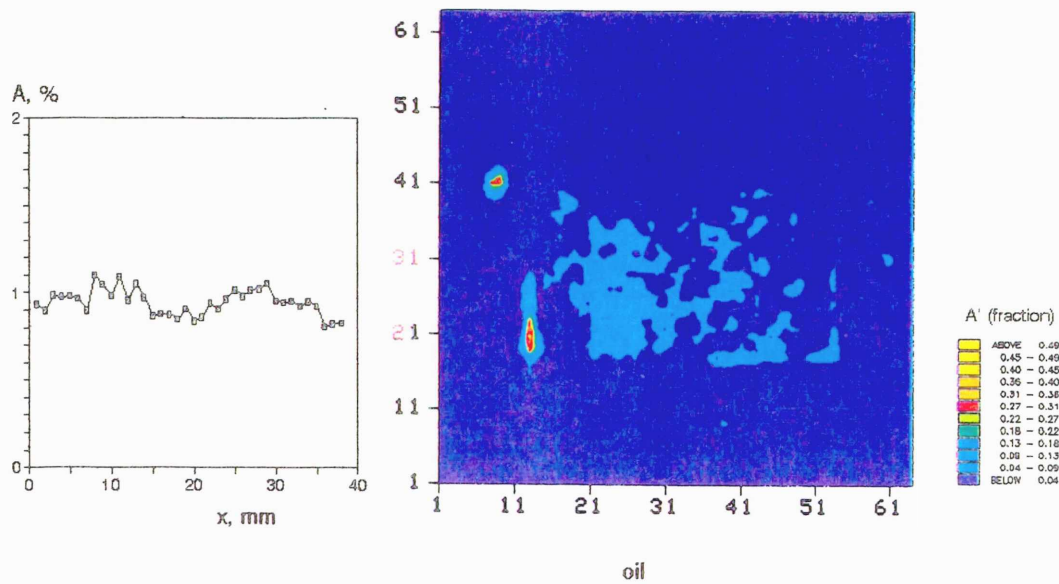
in the smaller pores, hence it can have very short transverse relaxation times T_2 close to those of solids and therefore the signal may not be detected with ^1H imaging. With imaging equipment capable of being exploited in such a way that the signal can be captured 1 or 2 ms after excitation (FLASH method), fast sequence can be used for rock-fluid systems with a high transverse relaxation rate. A very low detection limit (< 0.1) could perhaps be achieved.

5.2.3 Residual oil saturation

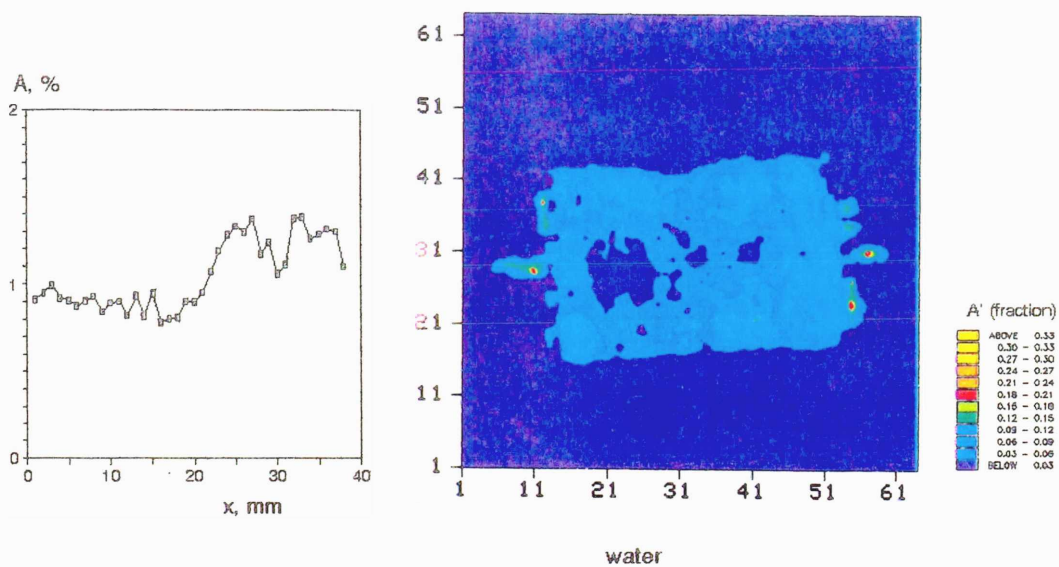
The lower detection limit on the MRI system for oil in the Portland limestone in the presence of water was also examined. Core samples with a range of oil saturation from 0 to 1.0 were imaged. The sample preparation was similar to that described above. The experiment that showed the lower limit, i.e., oil and water peaks were obtained, is reported here. The core sample contained approximately 0.7 PV of water and 0.3 PV of n-decane. Figure 5.9 shows the bulk spectrum and the 2-D signal images of the oil and water in a slice of the core plug. The residual oil produced a measurable signal at the low oil saturation of 0.3 as can be seen from the two-peak spectrum of the oil and water. Oil saturation below 0.3 was not detectable, hence 0.3 formed the lower detection limit of oil signal for further imaging experiments with the Portland limestone samples on the MRI system used here. The chemical shift images of the slice were well resolved to produce the water and the oil NMR signal images shown in Figure 5.10.

5.3 Discussion

The spin echo experiment to obtain the bulk spectrum at approximately zero echo time $t_e \approx 0$ does not measure the absolute signal per voxel, i.e., the total hydrogen content because the imaging equipment have a dead time (time required for the signal capture after excitation). The signal from the region with the fast decay are never seen. However by extrapolation of the signal observed for times greater than the dead time back to zero time one obtains the Free Fluid Index (FFI) which constitutes the movable portion of the total fluid content (Seevers, 1966). Similarly the CSI imaging technique does not measure the absolute signal per voxel, i.e., the total ^1H content because in addition to the dead time some time interval (echo time) is necessary to apply and interrupt (switch) the magnetic field gradients between the first excitation pulse and the signal capture.

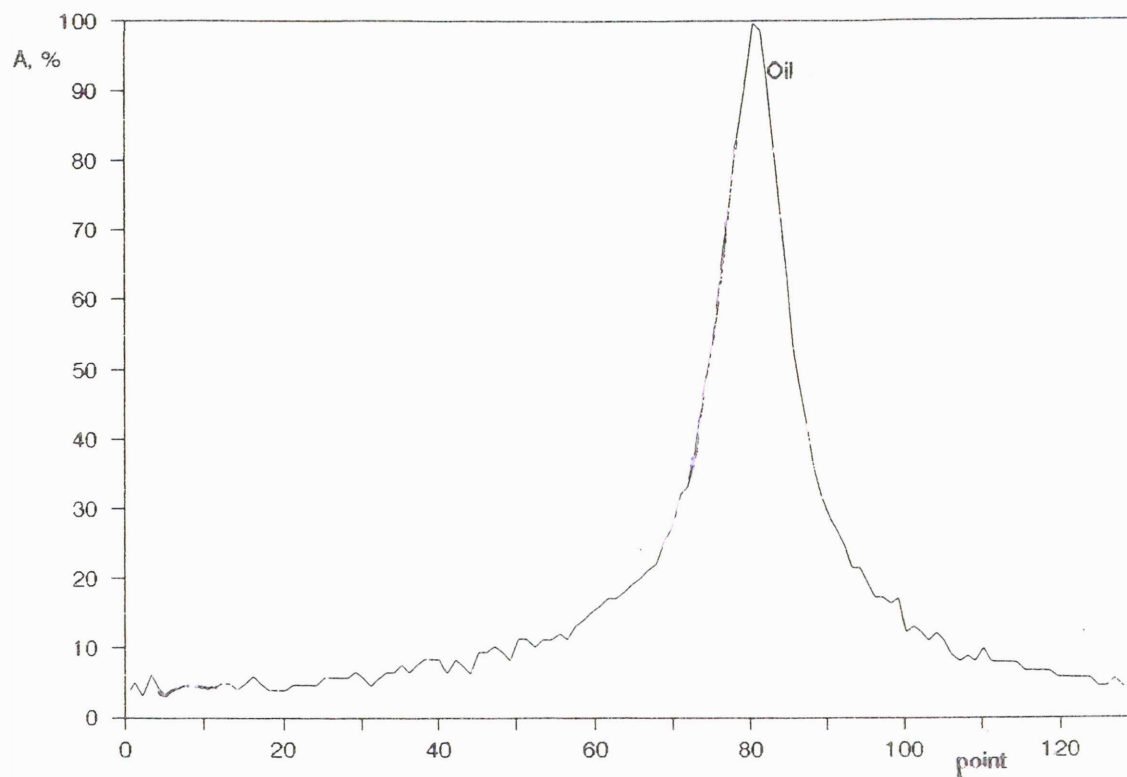


A' - fraction of the peak height of the oil spectrum

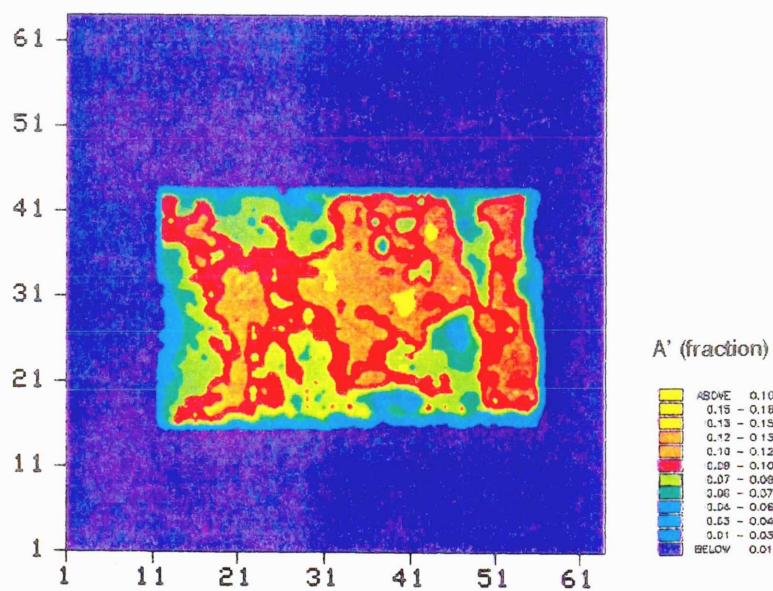


A' - fraction of the peak height of the water spectrum

Figure 5.7 Thin-slice images of oil and water in core plug

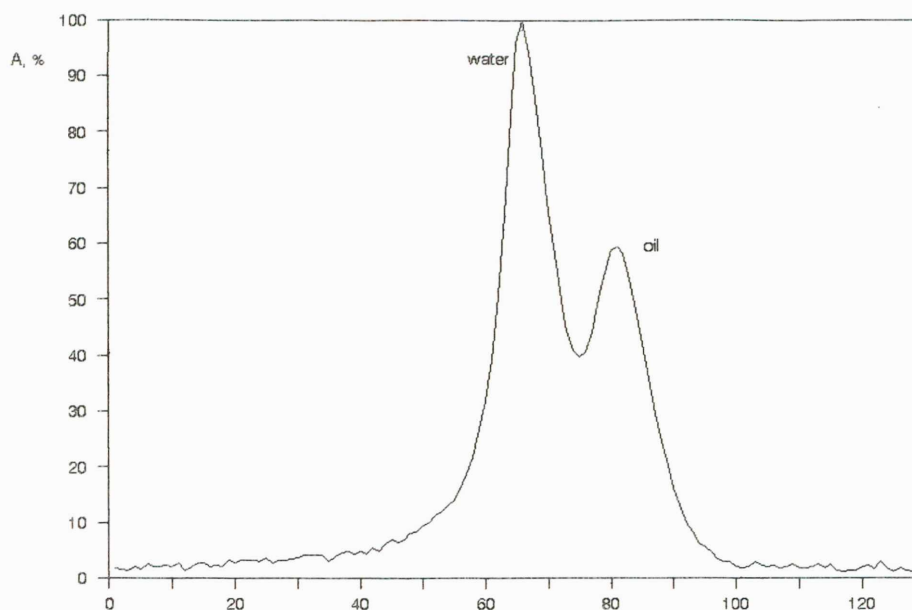


A - NMR signal amplitude peak is set at 100%



A' - fraction of the peak height of the spectrum

Figure 5.8 Spectrum and image of sample containing oil and immobile water



A-NMR signal amplitude (amplitude peak for water is set at 100%)

Figure 5.9 Spectrum of sample containing water and residual oil

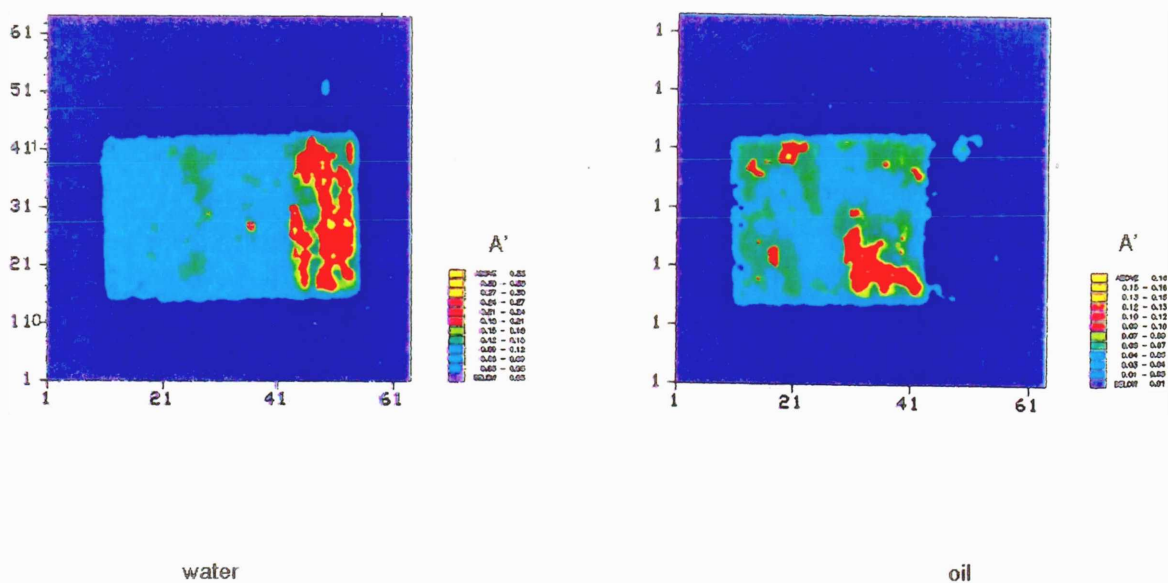


Figure 5.10 Slice images of sample containing water & residual oil

Echo time $t_e = 40$ ms was the optimum time required to let eddy currents decay in the gradient coils in order to allow relaxation of the fluid signals. The length of t_e , as well as the dead time, is dependent on the equipment. A short echo time of 5 ms was used with shielded gradients for rock imaging and this gave better signal to noise ratio than using long t_e with unshielded gradients (Edelstein et al, 1988).

Following the lower limits of NMR signal detection established from the experiments described above further imaging experiments with the Portland limestone on the imaging equipment used involved oil and water saturations between 0.3 and 1.0. This limitation is due to several factors, mainly

- the nature of the rock-fluid interaction reflected in the T_2 which characterises the extinction of the signal and the width of the frequency signal, hence the resolution of the method (the relaxation is governed by porosity, wettability and paramagnetic impurities);
- the length of the echo time and the dead time which depend on the imaging equipment. It is necessary to accord the echo time with the relaxation rate to obtain a signal.

5.4 Conclusions

The results of the investigations reported in the chapter show that the MRI technique can be applied to petrophysical study for the following purpose:

To 'visualise' a fluid and its distribution in rock samples by imaging the NMR signal produced by the fluid. Since the NMR signal is proportional to the fluid content, the NMR spectrum and signal image, for a given rock-fluid relaxation parameter, reflects the fluid content and its distribution. Variation in the mineralogical (species) content and effects of confining surface of the rock limits the accuracy of determining fluid content and distribution from the NMR signal. It is possible to measure the spatial distribution of the relaxation rates, which embodies the mineralogical and confining surface effects.

To provide porosity distribution within a rock sample, as evidenced from the distribution of a fluid with which the sample is completely saturated. This in turn may indicate porosity variations within the rock sample. Porosity measured in this way is the effective porosity and is accurate within 5%.

To indicate the presence and spatial positions of movable oil and water in rock samples by imaging their chemical shifts. The CSI method however, is limited in applicability to rock-types that exhibit narrow NMR linewidths when saturated with water or oil.

To distinguish between the oil and the water NMR signals and produce separate images showing the oil and water NMR signal distributions. By quantifying these signals in terms of the oil and water contents, as shown in the following chapter, the saturation distribution inside the core would be obtained. A limiting factor in determining oil and water content and distribution is that a part of the NMR signal from the immovable fraction of the fluid may not be detected. The lower detection limit of both the oil and the water saturations in the Portland limestone with the equipment used in this work is 0.3.

REFERENCES

- Edelstein, W.A., Vinegar, H.J., Tutunjian, P.N., Roemer, P.B. & Mueller, O.M. (1988): "NMR imaging for Core Analysis", SPE 18272.
- Seevers, D.O. (1966): "A Nuclear Magnetic Method for Determining the Permeability of Sandstones", Trans. SPWLA 6, section L.

CHAPTER 6

CORE FLOOD IMAGING

6.1 Introduction

This chapter reports core flooding experiments monitored using the MRI system. The test samples were sleeved, assembled in a flow cell, and then connected to a pump and a pressure transducer as described in Appendix 4.4. This multi-purpose flow cell and rig was used also for liquid permeability measurement. The main control in imaging of the immiscible water-oil displacement was a balance between velocity of fluid advance and imaging speed. The imaging speed depends on the imaging equipment and the sequence used. This has been discussed in the preceding chapter. For the CSI used to image oil and water simultaneously in the core sample, the slice images in 1-D required about 4.5 minutes. Flow in samples at low velocities was monitored and the saturations were imaged by the 1-D CSI without interrupting the flow. Thin-slice images were obtained from the central longitudinal plane, 4-mm wide, in the core plug.

The flood process was monitored using 1-D CSI with echo time $t_e = 40$ ms and interpulse time spacing $T_R = 3.4$ s. The t_e was selected as the optimum time required for eddy currents generated due to application and interruption of gradients to decay (refer to Figure 2.2), and was established for the Portland limestone through a series of experiments. Each image consisted of 64 pixels with a 128 point modulus spectra (with 500 Hz bandwidth) for each pixel. The T_R was selected on the basis of signal-to-noise ratio (S/N) as time required for the excited nuclei to relax before the imaging sequence was repeated ($T_R \approx 5T_1$). The 2-D CSI was used to obtain spatial fluid distributions at static condition (at initial and final flood stages).

In the Portland limestone samples oil and water linewidths were narrow enough so that the two-peak spectrum could be separated by simple spectroscopic techniques. Individual oil and water spectra were obtained by fitting two Lorentzian lines to the spectrum as shown in the example of Figure 2.4(c). The peak height of each of the spectra was measured. Lorentzian lines were used because they best fit the spectrum of bulk pure water.

The displacement tests were conducted under unsteady-state conditions with very low flow velocities and the capillary effects were assessed. In this approach, relative permeability can also be assessed. MRI offers the possibility of *in-situ* evaluation of the extent of the imbibition capillary pressure gradient prevailing in

the oil/water/rock system during immiscible displacement. Drainage and imbibition cycles of the unsteady state test were imaged and for both the monitoring and imaging processes were identical.

6.2 Flood Front Tracking

The unsteady-state displacement tests were conducted and imaged as follows. The core sample to be tested was first fully saturated with the wetting phase (often the aqueous phase) using a vacuum pump. The bulk porosity ϕ was determined gravimetrically, and compared with that obtained with the gas porosimeter. The porosities measured by the two methods agree within $\pm 1\%$. The liquid permeability K_L was measured by flowing the same fluid at constant flow rate and obtaining the pressure drop across the core sample length. The K_L for sample PLS-02 was not measured because the sample was used in the flow cell after it had been saturated with oil and water. The result of these measurements on the core samples used in these flow imaging experiments are shown in Table 6.1.

TABLE 6.1 Sample bulk porosity and liquid permeability

Rock	Sample No.	Gas ϕ fraction	Weight ϕ fraction	$(\phi_g - \phi_w)$	k_L md
Portland limestone	PLS-02	0.171	0.164	+0.007	-
Portland limestone	PLS-05	0.158	0.167	-0.009	22.0
Portland limestone	PLS-08	0.170	0.163	+0.007	21.8
Portland limestone	PLS-10	0.160	0.155	+0.005	33.0
Portland limestone	PLS-15	0.153	0.150	+0.003	39.5
Portland limestone	PLS-51	0.140	0.140	0.0	30.0
Clashach sandstone	CSS-1	0.193	0.190	+0.003	296.0
Lochaline sandstone	LSS-5	0.197	0.201	-0.004	223.0

Porosity distribution within the cores was obtained for the selected slice by imaging the single fluid phase distribution and this provided an assessment of the sample heterogeneity. Figure 6.1 shows the porosity variations along the length (within a slice) for some of the samples. The sandstone samples were apparently uniform to the eye and can be seen from the profiles to have only slight porosity heterogeneities along the length of the samples.

Five tests were conducted with oil displacing water in different rock samples, and as many with water displacing oil. In both cases the oil and water signals were not resolved in the sandstone samples, and hence no images were obtained with the CSI. One reason could be that the heterogeneity of local magnetic susceptibility in the sandstone samples were not compensated for by the CSI pulse sequence. The kind of pulse sequence that can be used is related to the MRI system hardware, modification of which was beyond the scope of this work. The conduct of the imaging tests with the limestone samples is reported below.

The deconvolution of oil and water NMR signal into separate signals was tested with the following experiment. A Portland limestone core plug was cut in two halves. One half was fully saturated with water and the other half was fully saturated with oil. The two halves were assembled into a composite core but with no capillary contact between them - a film of waterproof material was placed between the contacting faces. The composite core was imaged and the signal from the slice was deconvoluted into oil and water images and profiles as shown in Figure 6.2. This Figure shows the oil/water boundary clearly resolved and the profiles agree with the physical dimensions of the samples. The low water signal seen on the oil image and the low oil signal seen on the water image are consistent with the noise level in these experiments.

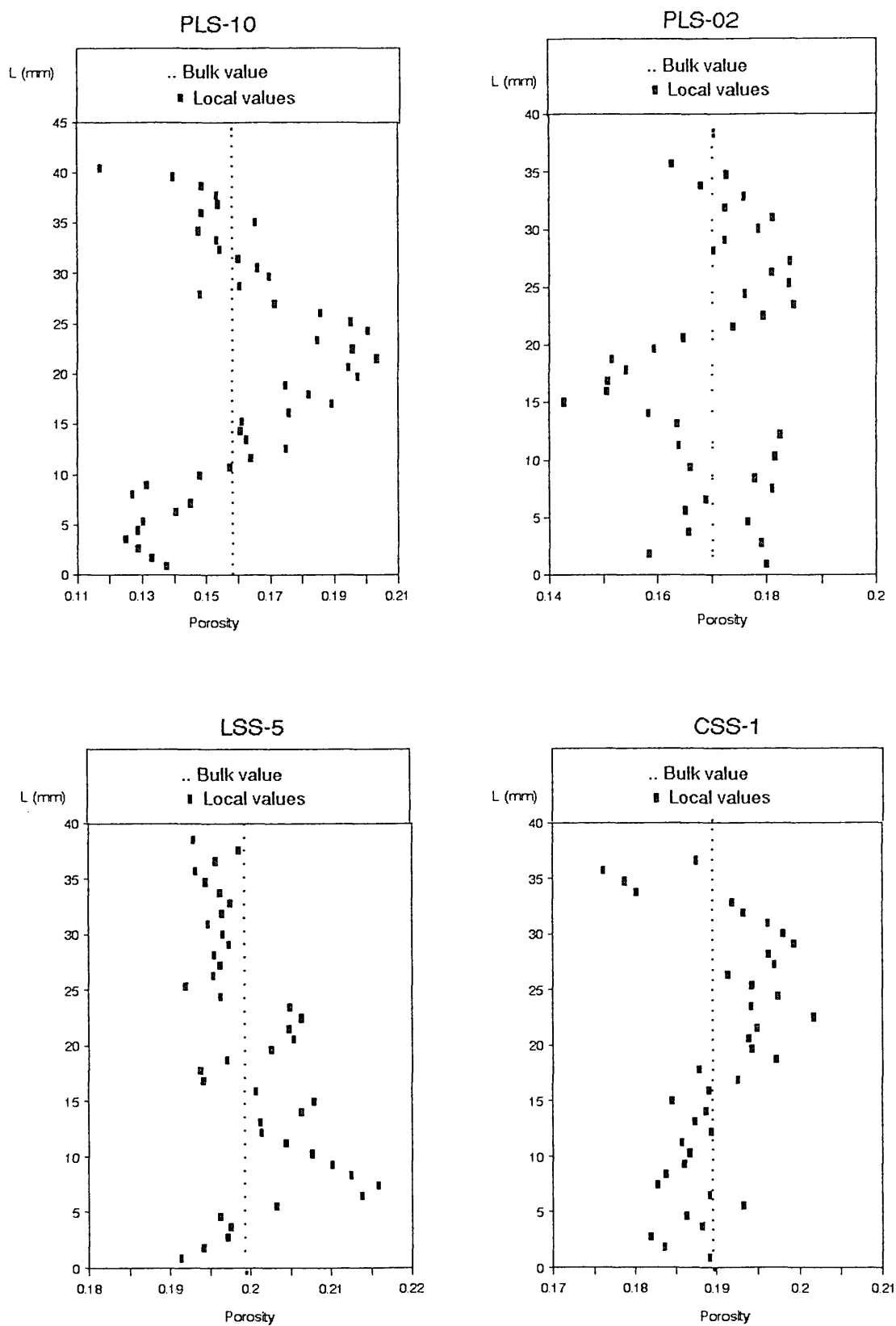


Figure 6.1 Porosity profiles on a 4-mm slice of rock samples

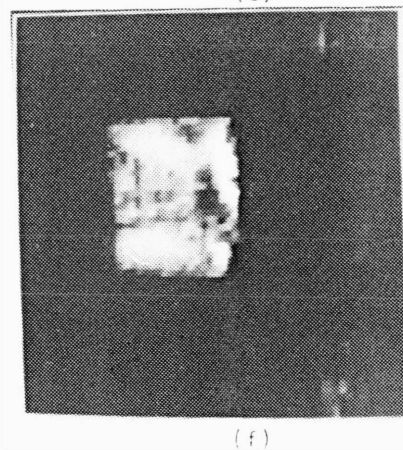
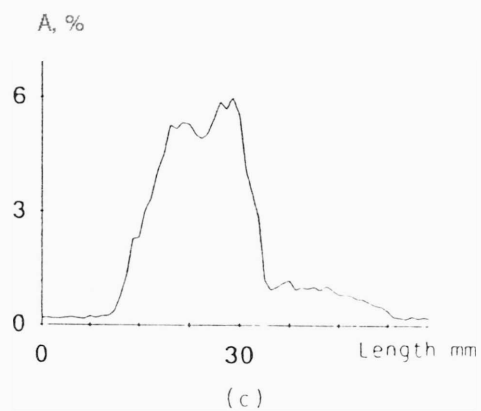
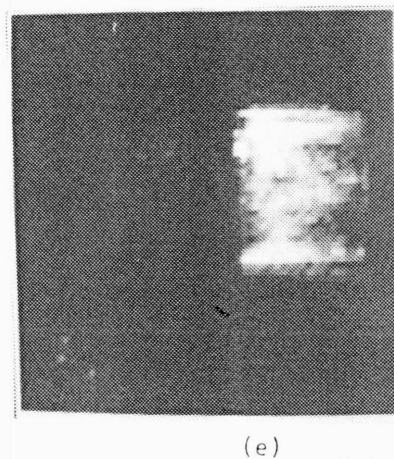
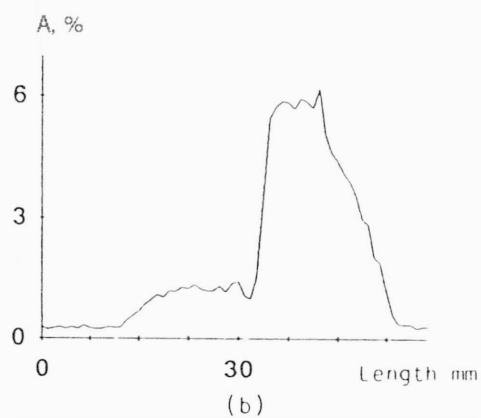
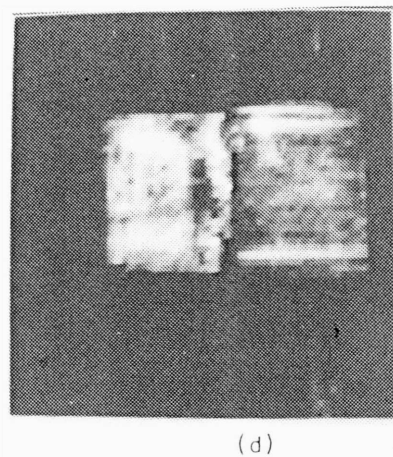
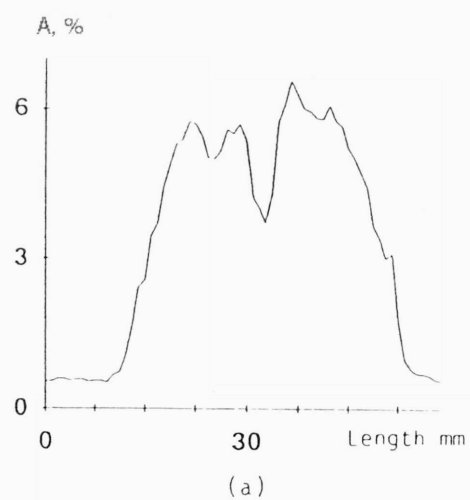


Figure 6.2 Composite sample of two Portland limestone plugs, one half fully saturated with oil, and the other - with water.
 (a) & (d) total fluid NMR signal profile and image;
 (b) & (e) oil NMR signal profile and image;
 (c) & (f) water NMR signal profile and image, respectively

6.2.1 Oil displacing water

The displacement of water by oil in a plug sample of Portland limestone (sample PLS-10) was imaged. The test started at saturation of distilled water $S_w = 1$, followed by flooding with Soltrol-130. The core sample was held in the multi-purpose flow cell described in Appendix 4.4. The oil was injected from one end of the core at a constant flow rate of 0.7 ml/hr (flow velocity ≈ 3.6 cm/day). The outflow end of the core was open to the atmosphere. The rock sample was initially fully saturated in water. The advance of the injected oil and the decrease of the water within the core plug was monitored using 1-D CSI. The NMR signal profiles on the 4-mm thick plane was obtained at three different flood stages before breakthrough of oil at the production end face and are shown in Figure 6.3. Each data point on the profiles represents a pixel-averaged NMR signal, i.e., signal emitting from a small volume 4 mm by 0.94 mm by 24.4 mm (the core diameter).

The profiles of Figure 6.3(a) show the distribution of the NMR signal from both the water and the oil along the plane. The profile numbered 0 corresponds to image of the sample fully saturated in only water, i.e., before oil flooding started. Flooding is represented on the Figure as occurring from right to left. The profile numbered 1 corresponds to injection of 0.208 pore volume (PV) of oil. At this stage oil had advanced to a point about half-way along the sample, beyond which only water was present. The profile numbered 2 corresponds to injection of 0.248 PV of oil and the oil had further advanced to a point about two-third of the way along the sample. The profile numbered 3 coincides with injection of 0.33 PV of oil at which stage the signal value in the last pixel of the slice (in the direction of flow) had just changed. This preceded the breakthrough of oil at the exit end face of the sample. This stage is crucial in special core analysis and is better identified by the change in the local NMR signal of both fluids measured for the exit pixel than by monitoring individual fluid phase. In this way one avoids having to detect signal from low saturation of oil and water individually. As already discussed saturations below 0.3 are not directly detected in these tests.

The profiles of Figure 6.3(b) show the changes in the NMR signal at each pixel as flooding proceeded. They compare the signal amplitude A at each data point in the different flood stages to the signal amplitude at the data point before start of flood (i.e., profile number 0).

Flood front tracking experiments conducted with four other samples of the Portland limestone produced profiles similar to those in Figure 6.3. Signal profiles of the oil and water distribution during flow (in the direction of flow) were also obtained for a 4-mm thick slice. The NMR signal was imaged during the displacement of water by oil in the plug sample PLS-05. The sample was 3.95 cm long by 2.44 cm in diameter with bulk properties as given in Table 6.1. The test was conducted in the same way as described above. After the breakthrough of the Soltrol at the outflow end, injection of Soltrol was continued until no more water produced from the exit end of the core. The separate oil and water profiles obtained at this stage are shown in Figure 6.4. Flooding is represented on the Figure as occurring from left to right. At this stage saturations of oil and water over the length of the core exceeded 0.3 and hence the signals could be detected.

The monitoring process of the displacement in 1-D is illustrated in Figure 6.5. The porosity distribution and the permeability were measured with only water flowing in the water-filled core plug. The porosity profile on the thin-slice plane was determined from the profile numbered 0 and is shown in Figure 6.1. Then flooding was started. Arrival of oil in the inlet end face of the core results in a two-peak spectrum in the first pixel within the rock sample. Similarly, the occurrence of a two-peak spectrum in the last pixel within the rock sample (outflow end face) signals the breakthrough of the displacing phase. Each data point was equivalent to about 0.094 cm in the flow path and a 64-point 1-D chemical shift image of the slice required about 4.5 minutes to obtain. This is equivalent to 2 seconds for each experiment ($2n$ experiments in all where $n = 64$), i.e., time required to acquire a pixel image. In order to detect the breakthrough, the production end pixel was constantly monitored with the help of a computer interfaced with the imaging console.

The pressure drop response at the attainment of immobile water saturation during the drainage displacement (which constitutes the initial saturation S_{wi} for the subsequent imbibition cycle) was recorded. This information normally serves to determine one end-point relative permeability characteristic. A confining air pressure of 18 psi (an order of magnitude higher than the maximum injection pressure) was used to ensure no fluid slippage between the core sample and the rubber sleeve. The air was confined in the annulus between the rubber sleeve and the flow cell.

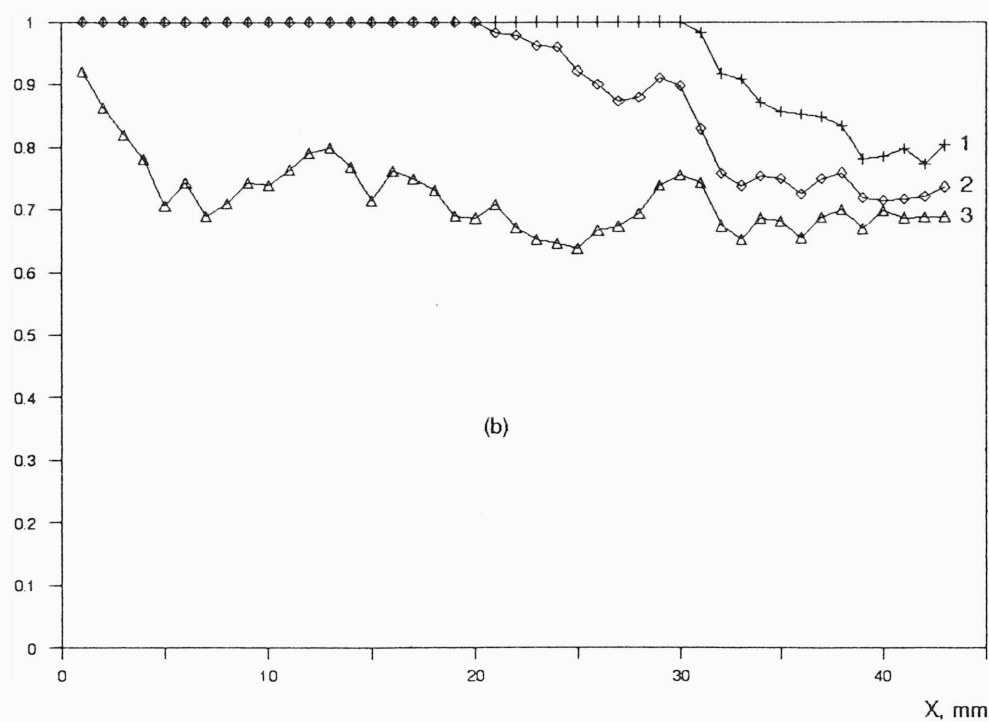
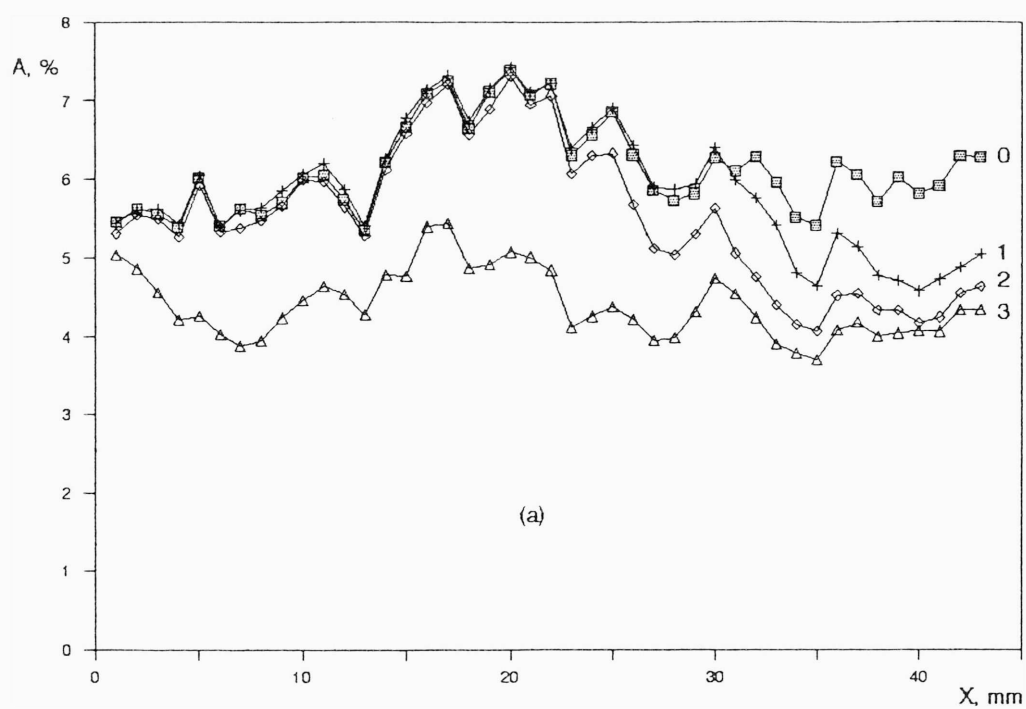


Figure 6.3 Oil and water NMR signal changes during flooding
 (a) at different flood stages
 (b) response relative to response at $t=0$

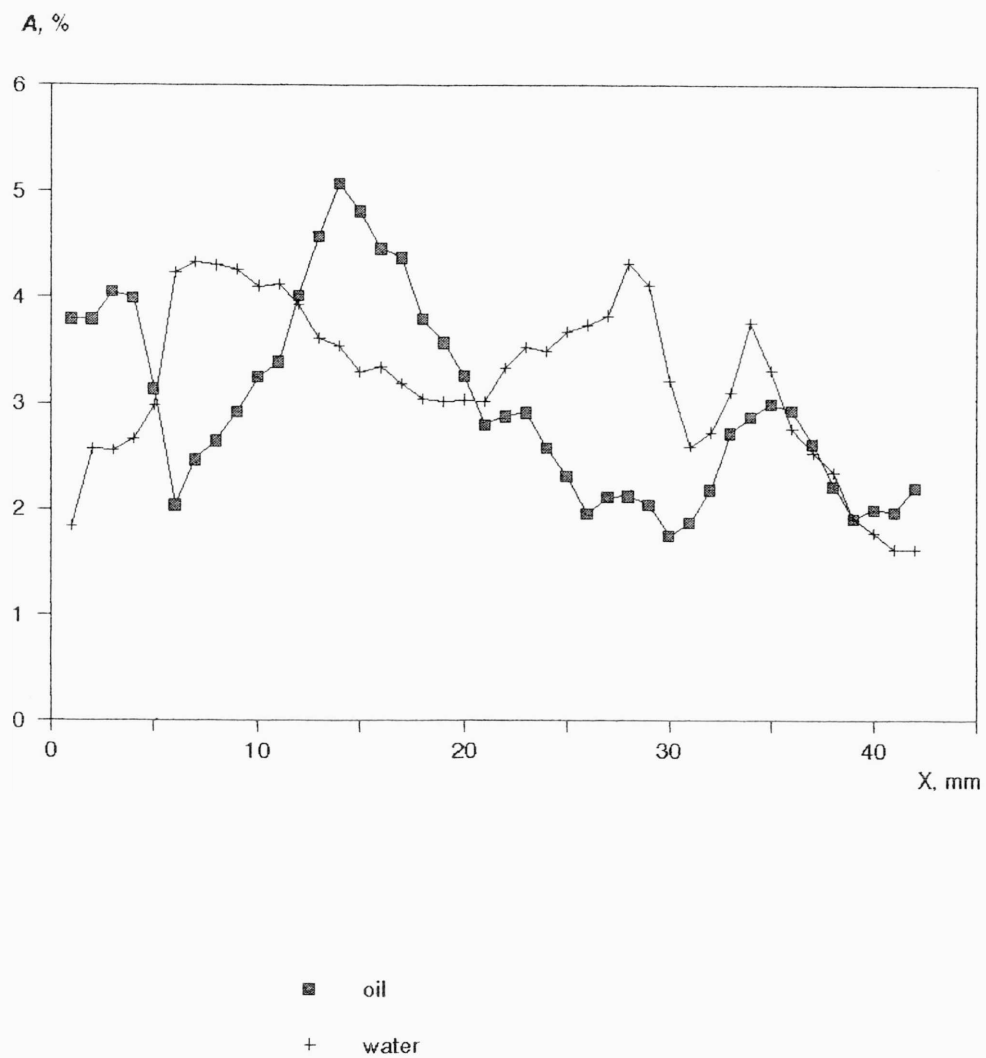


Figure 6.4 Oil and water signals during flooding
(at final stage of oil displacing water)

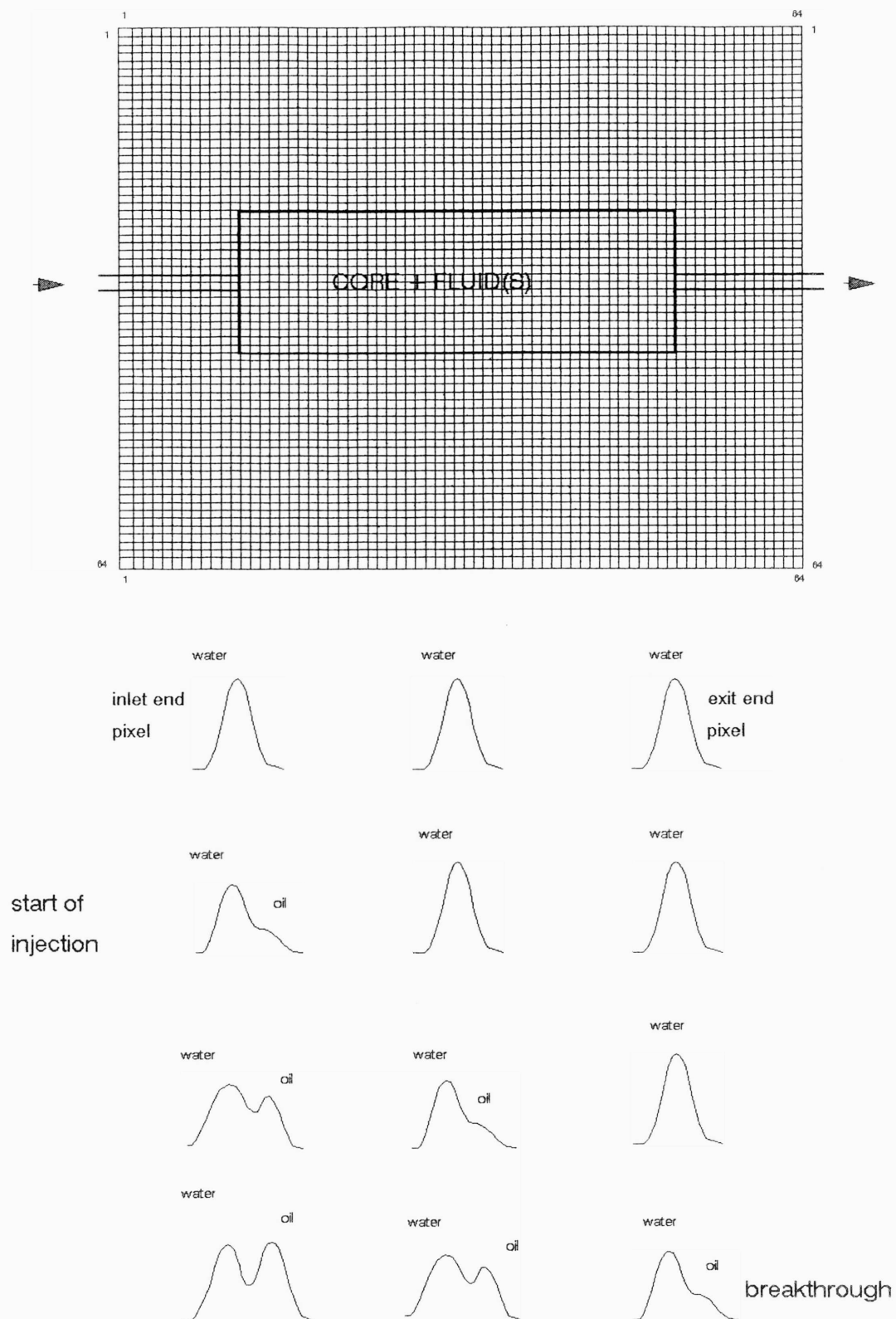


Figure 6.5 Illustration of saturation monitoring process

6.2.2 Water displacing oil

Flooding tests with water displacing oil in water-wet core samples were imaged. The Portland limestone core plug (sample PLS-02) contained connate water of 0.1, well below the detectable level. The sample was held in a flow cell made of perspex. First the core plug was fully saturated in n-decane, which was then displaced with distilled water injected at a constant rate of $0.3 \text{ cm}^3/\text{hr}$. The separate water and oil signal profiles obtained using 1-D CSI at several flood stages up to and beyond the water breakthrough time are shown in Figure 6.6. Flooding is represented on the Figure as occurring from right to left. The images were taken at intervals as presented in Table 6.2. The monitoring process was analogous to that illustrated with Figure 6.5. The profile numbered 8 was taken at the breakthrough stage, during which there was a period of build-up of water saturation at the production end face. The profiles numbered 9 was obtained after further injection of water for 15 minutes after the breakthrough.

TABLE 6.2 Flood stages corresponding to the profiles

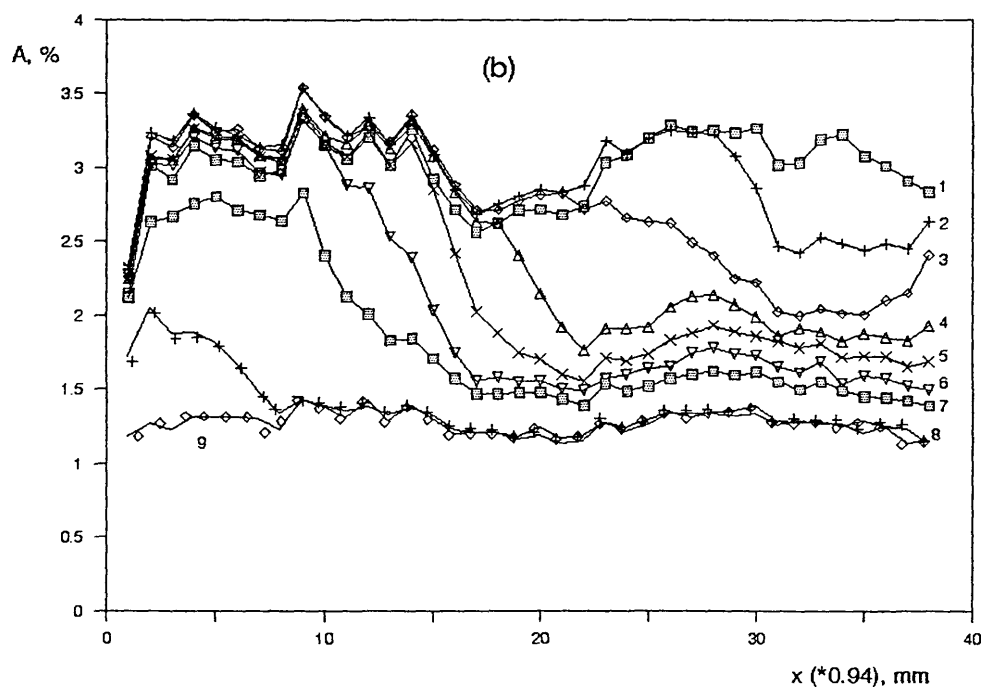
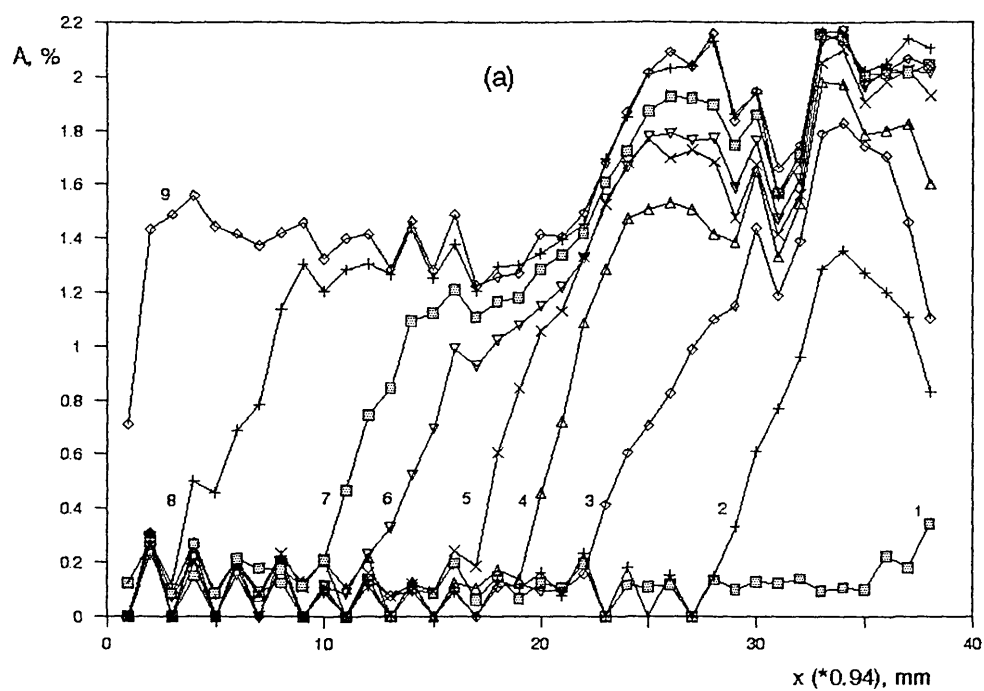
Profile No.	Time, min	Fractional breakthrough time
1	5	$\frac{5}{140}$
2	20	$\frac{20}{140}$
3	35	$\frac{35}{140}$
4	50	$\frac{50}{140}$
5	65	$\frac{65}{140}$
6	80	$\frac{80}{140}$
7	95	$\frac{95}{140}$
8	140	1.0
9	155	

In another imaging experiment the initial condition of the Portland limestone sample (PLS-15) consisted of 0.25 PV water and 0.75 PV n-decane. The core plug had first been fully saturated and aged in water for four weeks to make it preferentially water-wetting. The sample was assembled in a flow cell and the permeability was measured by flowing water at a fixed rate and recording the pressure drop across the core length. The permeability and fluid-filled porosity of the sample were 40 md and 0.15, respectively.

After the water content was reduced to a connate saturation of 0.25 by centrifuging, the core was resaturated fully with oil (n-decane) using a vacuum pump. The sample was then re-assembled in the flow cell and the effective permeability of the sample to the oil was measured by flowing the oil at a fixed rate and recording the pressure drop. The effective permeability at the connate water saturation was 22 md.

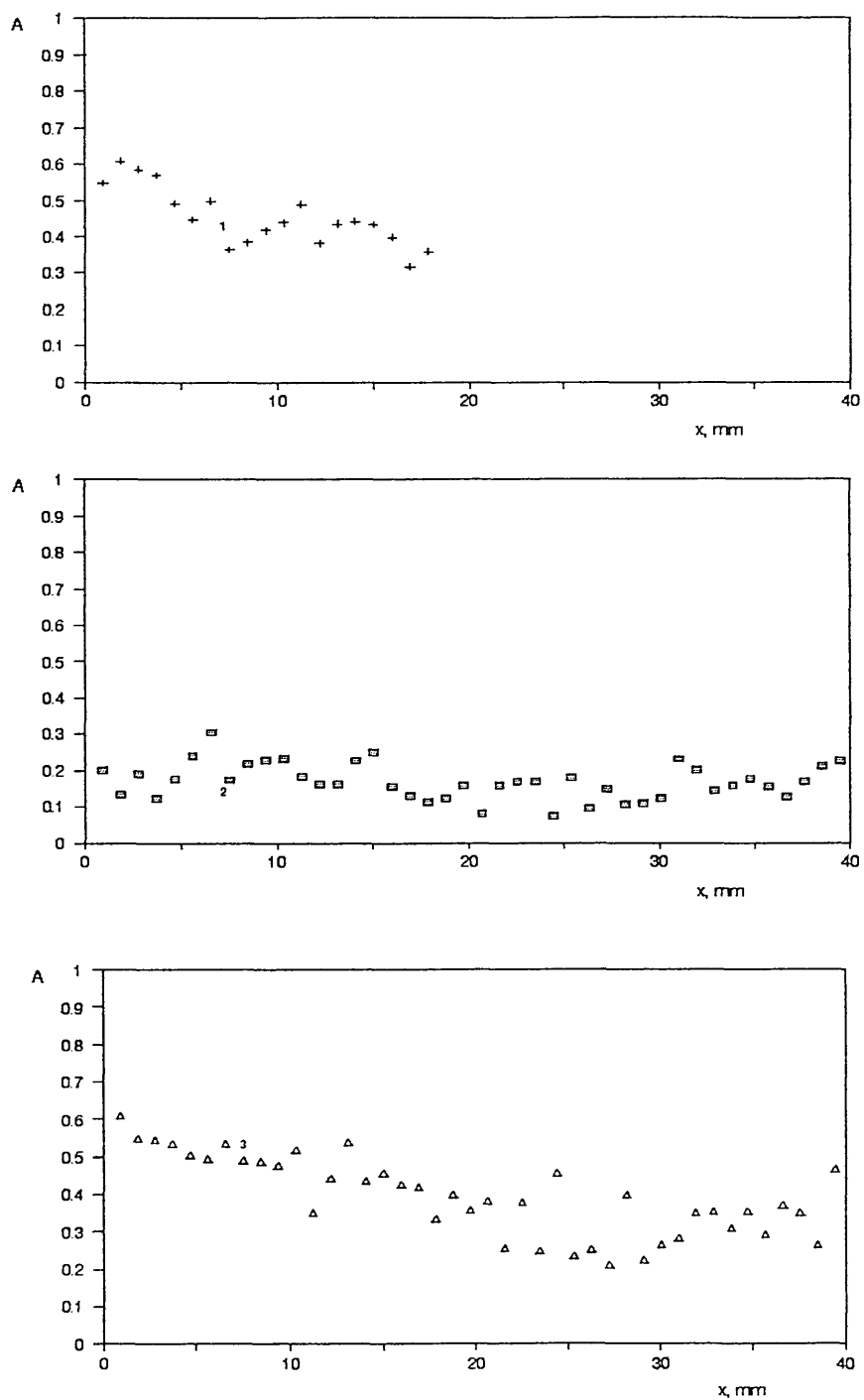
The oil was displaced with water by flooding at a constant flow rate of 0.3 cm³/hr (approximately 0.1 PV/hr), equivalent to a linear velocity of 0.15 m/D. The core flood process was imaged using 1-D CSI at two different stages under dynamic conditions. Figure 6.7 shows the water signal profiles. One profile (numbered 1) was obtained when the flood front was about halfway through the core, at which time 0.16 PV of water had been injected into the core. The flooding was then stopped for about 18 hours by shutting off the injection pump and closing the inlet and outlet valves. The objective of the stoppage was to assess the importance of capillarity in the system. Within the period of 18 hours pressure equilibrium was established and the water NMR signal distribution was imaged in 1-D, this time under static conditions. As the profile (numbered 2) shows, the water redistributed itself throughout the entire length of the core during this time, which is comparable to the experimental run time. Therefore the effect of capillary forces appears to be significant with respect to the viscous flow effects.

The flood experiment was resumed, now with an initial water saturation $S_{wi} = 0.41$ and the remaining oil $S_o = 0.59$. For this saturation level the water NMR signal was measured for the entire length of the slice. Another 1-D water NMR image of the core was obtained at the water breakthrough stage of the flood, corresponding to a total injection of 0.2 PV of water into the core. The signal profiles are also shown in Figure 6.7.



Key: numbers 1 - 9 represent flood stages

Figure 6.6 NMR signal changes during flooding: (a) water, (b) oil



- + (1) 0.16PV of water injected (image taken under dynamic flow conditions)
- ▣ (2) Image taken after redistribution of the 0.16PV of water (static)
- △ (3) Image at water breakthrough under dynamic flow conditions (0.2 PV injected)

Figure 6.7 Water NMR signal profiles for water displacing oil in PLS-15

6.2.3 Water saturation profile

The water saturation 1-D distribution shown in Figure 6.8(a) was derived from the water NMR signal profile (Figures 6.7(1)) obtained under dynamic flow conditions before water breakthrough. The conversion from signal to saturation was made on the basis of the material balance values of the oil and water in the sample. Water saturation below 0.3 might exist in the vicinity of the flood front but the NMR signal from it would decay prior to data acquisition, and hence could not be measured. This limitation was overcome by monitoring the oil signal in order to determine the flood front position x_f . The advance of the injected water into the unflooded parts of the sample cause the oil signal and the total fluid signal to change in a similar manner as demonstrated with Figure 6.3. $x_f \approx 1.786$ cm was estimated from the NMR signal profile corresponding to the position of detectable change in the total fluid NMR signal at the flood front. At this position the frontal saturation $S_{wf} = 0.53$. The water saturation distribution therefore depicts the situation after injection of 0.16 PV of water into the core originally containing the connate water $S_{wc} = 0.25$, when the flood front had moved a distance $x_f \approx 1.786$ cm measured from the injection end of the core.

The expected 1-D saturation profile was calculated on the basis of the non-capillary Buckley-Leverett theory assuming diffuse flow conditions. The relative permeability curves calculated from the laboratory waterflood history and the fractional flow curve are shown in Figure 6.8(b). The shapes of the relative permeability curves were adjusted using a simulator (CORSIM, 1988) in a history match procedure based on that suggested by Sigmund and McCaffery (1979). Up to the breakthrough stage, the average water saturation behind the flood front $\bar{S}_w$ was computed as

$$\bar{S}_w = \frac{W_i}{x_f A \phi} + S_{wc} \quad (6.1)$$

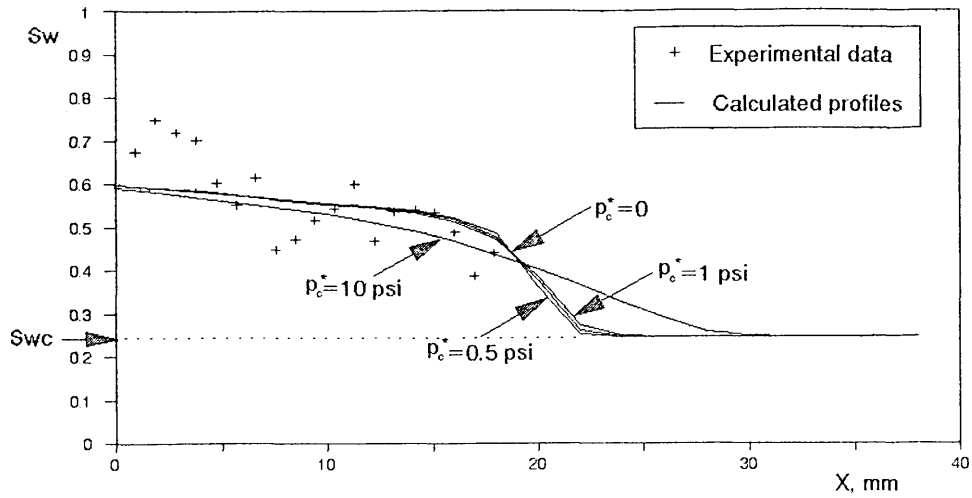
where

W_i - cumulative water injected, cm³

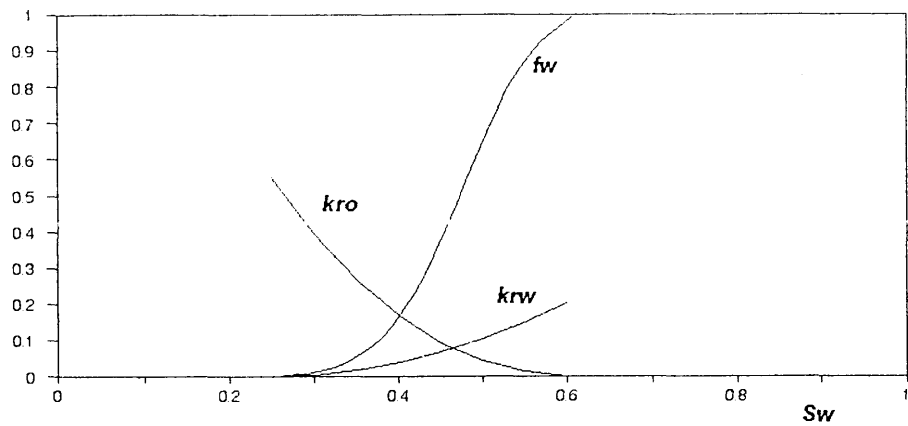
A - cross-sectional area, cm²

ϕ - sample porosity, and

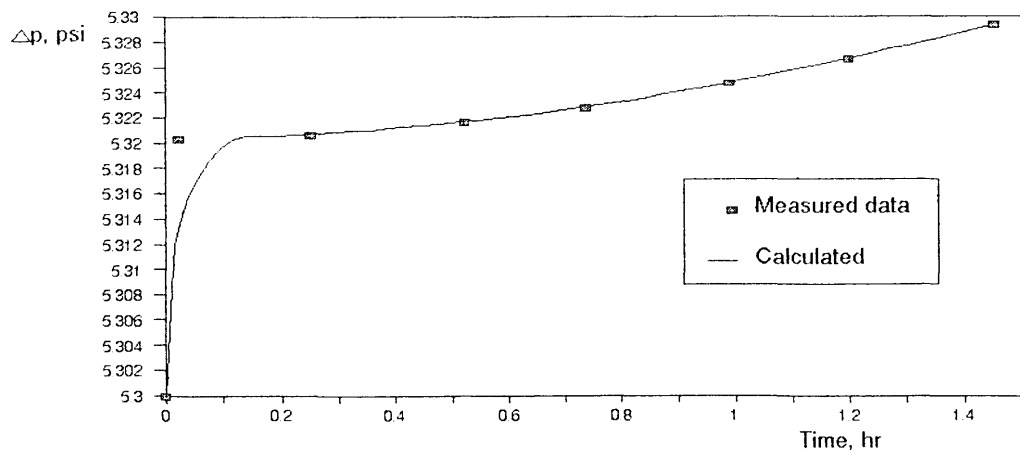
x_f - distance from injection end to the flood front, cm.



(a) Water saturation profile before breakthrough (0.16PV of water injected)



(b) Calculated fractional flow and relative permeability curves



(c) The imbibition pressure drop response data

Figure 6.8 Measured and calculated characteristics of core flood

Figure 6.8(a) compares the experimentally measured saturation distribution with the expected 1-D calculated water saturation profiles. The continuous lines are the calculated saturation profiles. For one case diffuse flow conditions and zero capillary pressure ($p_c = 0$) were assumed. The other curves were obtained from calculations including capillary pressure with maximum values p_c^* of 0.5, 1.0 and 10 psi. The main core flood characteristics are compared below

	S_{wf}	x_f , cm	$\bar{S}_w$
Experiment	0.53	1.786	0.6
Calculation	0.55	1.886	0.58
for $p_c^* = 10$ psi	0.45	1.886	0.58

The measured saturation profile shows higher gradient than the calculated profiles. This is because the calculation is based on the end point saturations (S_{wi} and $1-S_{or}$) which are average values for the whole core. The relative permeabilities are defined within this saturation range. The measured profile on the other hand reflect local average saturations for small equal volumes of the core. Since the saturation was imaged during a period of fluid injection the inlet end has higher saturation of the injected water. As shown above the average saturation is close for the measured and calculated profiles. The capillary pressure tends to cause the saturation gradient to increase (the gradient is negative). For the cases of p_c^* values of 0.5 and 1.0 psi, the influence of the capillary pressure is very minimal. The viscous flow forces dominate over the capillary pressure forces hence the profiles are close to the profile for the case of $p_c = 0$. The influence of capillary pressure is significant for $p_c^* = 10$ psi, and cannot be ignored without error in the displacement calculations.

6.3 Discussion

The accuracy of MRI measurements has since been confirmed through experiments (Edelstein et al, 1988). The saturation interpretation from NMR signal data was

based on the material balance values of the fluids in the core obtained as laboratory core flood data. The measured saturation shown in Figure 6.8 was made on a selected slice 4-mm wide through the center plane in the rock sample. The slice was assumed to be representative of the whole core plug following ‘visualisation’ of single phase water distribution in several similar slices. The reproducibility of the measurements was assessed by repeat measurements on sample PLS-05 containing water and Soltrol at static conditions. Using the same operating parameters of the imaging system to image the same slice, the NMR signal per pixel was exactly the same. Similarly the sample bulk spectrum measurements were exactly reproduced in several runs.

The calculated and measured core flood characteristics compared above indicate close agreement and there is a common trend in the course of the saturation distribution. The measured pixel-averaged saturation data displays fluctuation but on average behind the flood front is comparable with the calculated value. The local variation in saturation (somewhere significant like the dips) indicate rock and flow property variation such as capillarity. The actual fractional flow in the core flood would be higher than was used in calculating the water saturation profile by a factor contributed by capillarity. This is demonstrated in the next chapter where the assessment of the capillary pressure gradient term in the fractional flow analysis of the core flood is presented.

6.4 Conclusions

The experiments reported in this chapter have shown that the MRI technique of imaging chemical shift can be employed in core flood test to

- track a flood front under dynamic flow conditions; and hence determine experimentally the time of breakthrough of the displacing fluid at the production end of the core. The breakthrough stage is crucial to the proper interpretation of coreflood tests as discussed in Chapter 3.
- ‘visualise’ the actual process of displacement, with the possibility of revealing poorly distributed fluids and saturation build up due to end effects as demonstrated by Figure 6.7. The lack of this knowledge has been a potential source of error in the interpretation of core flood tests.

- derive saturations and obtain saturation profiles at any stage of the core flood directly from measurements of the NMR signal produced by the fluids in the core sample. Without imaging, the saturation profile would be unknown and hence would be the required result of displacement calculations. Therefore, quantitatively it has previously been difficult to allow for capillary pressure gradient. As a consequence, common practice has been to use high flow rates, which may not be representative of the reservoir flow conditions, in order to swamp the capillary pressure gradient.
- detect saturation gradients during flooding on the basis of the derived saturation profiles. This is demonstrated in the next chapter where the fractional flow that includes capillary pressure gradient is also analysed.

The limitations of using the MRI technique to monitor the core flood test are

- It was possible to measure separate oil and water NMR signals for saturations of oil and water in excess of 0.3 in the Portland limestone samples. Signal from saturation below 0.3 was not detectable with the equipment used. With a more powerful equipment lower saturation detection limit down to 0.1 could perhaps be achieved.
- Oil and water NMR signals were not resolved in the Lochaline and Clashach sandstones. One reason could be that the heterogeneity of local magnetic susceptibility in the sandstone samples were not compensated for by the CSI pulse sequence. The use of an appropriate pulse sequence and a powerful magnet could compensate this phenomenon.
- In order to achieve a balance between velocity of fluid advance and the imaging speed very low flow rates were used. The range of flow rates can be widened with the use of fast imaging techniques in a more powerful equipment.
- Images were obtained for a slice 4 mm wide due to the capability of equipment used here. A whole core plug can be selected as a slice with appropriate combination of rf pulse sequence and magnetic field strength.

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CHAPTER 7

LABORATORY INVESTIGATION OF FRACTIONAL FLOW UNDER VISCOUS - CAPILLARY CONTROL

7.1 Introduction

The fractional flow of oil and water in core plugs under the control of viscous and capillary forces was examined. In the laboratory core flood tests influence of gravity, the third of the three forces which control flow in porous systems, was considered negligible for horizontal systems. The full form of the fractional equation has been derived in Appendix 3 where the nomenclature and units have been defined, and without the gravity term can be expressed as

$$f_w = \frac{1 + \frac{k k_{ro} A}{q_t \mu_o} \left(\frac{\partial p_c}{\partial x} \right)}{1 + \frac{\mu_w}{k_{rw}} \cdot \frac{k_{ro}}{\mu_o}} \quad (7.1)$$

The capillary pressure gradient term $\frac{\partial p_c}{\partial x}$ in the x -direction (linear) was interpreted by expressing it as

$$\frac{\partial p_c}{\partial x} = \frac{dp_c}{dS_w} \cdot \frac{\partial S_w}{\partial x} \quad (7.2)$$

$\frac{dp_c}{dS_w}$ on the right hand side of Equation (7.2) represents the gradient of a capillary pressure curve $p_c(S_w)$ at any position x which should normally be an imbibition curve for the test oil and water. But in this work imbibition capillary pressures for the test oil and water were not measured due to inadequate equipment and capillary pressure hysteresis was assumed to be insignificant. Hence a drainage curve measured using an air-brine fluid pair was used after scaling it to the oil-water fluid pair. The decision to neglect hysteresis is believed to be justified since the gradients are being compared over small pore diameter distances on a microdisplacement scale (Archer and Wall, 1986). The magnitude of the difference between the drainage and the imbibition capillary pressures $\Delta p_{c(D-I)}$, i.e., the hysteresis, would be negligible in comparison with viscous force pressure gradients. $\frac{\partial S_w}{\partial x}$ representing the water saturation gradient was obtained directly from measurement using the CSI technique described previously. Due to the limitation of the MRI system hardware, the profile was obtained on a 4-mm thick plane in the core plug. It would be possible with more appropriate hardware to obtain the profile on the whole plug. It is assumed here therefore, that the saturation distribution in 1-D in the plane is representative of that in the entire core plug. This assumption was verified to be close to the truth by on-screen examination of different planes in the sample using the computer and monitor interfaced with the MRI system.

7.2 Capillary Pressure Gradient Interpretation

7.2.1 Water saturation profile

The water saturation profiles shown in Figure 7.1 were derived from the two dynamic 1-D images of water NMR signals (shown in Figure 6.7), measured under dynamic flow conditions, on the basis of the material balance values of the oil and water in the sample. The water saturation profile '1' depicts the situation after injection of 0.16 PV of water into the core originally containing the connate water $S_{wc} = 0.25$, when the flood front had moved about halfway through the core. This profile has been discussed in the preceding chapter. For the purpose of obtaining the saturation gradient data $\frac{\partial S_w}{\partial x}$, continuous line curves were fitted to the discrete experimental data points. The continuous line curve was fitted to the data points of profile '1' by regression of the S_w on x using the method of least squares and fits the equation

$$S_w = 0.7188 - 0.1845x + 0.0469x^2 \quad (7.3)$$

The second profile depicts the situation after a total injection of 0.2 PV of water into the core containing initial water $S_{wi} = 0.41$, when the flood front has moved the full length of the core ($x_f = L$), and water was about to start producing at the exit end (breakthrough). The fitted curve, also obtained by regression using the method of least squares, matches the equation

$$S_w = 0.6977 - 0.2022x + 0.0289x^2 \quad (7.4)$$

7.2.2 The capillary pressure curve

The drainage capillary pressure - saturation relationship was obtained for small core samples of the Portland limestone and the Lochaline sandstone using an air-water fluid pair. The approach used to measure the capillary pressures of the fluids in the plug was similar to the method proposed by Leverett (1941) and by Bruce and Welge (1947) known as the "restored state" technique. The water-wet samples, saturated fully in water, were placed individually on a water-filled porous porcelain diaphragm permeable to only water. Then a known pressure was applied to the air confined above the diaphragm and a portion of water was expelled from the core sample. By applying successively higher pressures in this procedure, the

curves for the air-water fluid pair shown in Figures 7.2 and 7.3 were obtained. To obtain the final water saturation usually defined by the imbibition condition $p_c = 0$, the applied air pressure was removed so that both the air and the water were at atmospheric pressure. Hence water imbibed back into the core sample until no further weight increase was observed in the sample. The water saturation in the Portland sample at this condition was 0.6.

7.2.3 Determining the term $\frac{\partial p_c}{\partial x}$

Figure 7.4 illustrates the approach to quantify the capillary pressure gradient $\frac{\partial p_c}{\partial x}$ term in the fractional flow equation. By determining the gradient $\frac{dp_c}{dS_w}$ on the capillary pressure curve and the gradient $\frac{\partial S_w}{\partial x}$ on the saturation profile for given saturation values the capillary pressure gradient $\frac{\partial p_c}{\partial x}$ were obtained in accordance with Equation (7.2). The calculation procedure for obtaining the $\frac{\partial p_c}{\partial x}$ is presented in Appendix 6. For the capillary pressure curve the gradient [in psi] was determined by differentiating the equation of the fitted curve

$$\frac{dp_c}{dS_w} = 35.16S_w - 37.37 \quad (7.5)$$

Similarly for the saturation profiles, Equations (7.3) and (7.4) were differentiated. The result is presented in Tables 7.1 and 7.2. Table 7.1 also compares the viscous pressure gradient ($\frac{dp}{dx}$) with the capillary pressure gradient distribution for $S_w > S_{wf}$, and shows the importance of the later in the core flood test.

TABLE 7.1 Capillary pressure gradients before breakthrough

x , cm	S_w	$\frac{\partial S_w}{\partial x}$, cm^{-1}	$\frac{dp_c}{dS_w}$, psi	$\frac{\partial p_c}{\partial x}$, atm/cm	$\frac{dp}{dx}$, atm/cm
0.094	0.701871	-0.17567	-12.6921	0.151680	0.026294
0.188	0.685773	-0.16685	-13.2582	0.150485	0.023683
0.282	0.670503	-0.15802	-13.7950	0.148297	0.021271
0.376	0.656064	-0.14920	-14.3027	0.145169	0.019048
0.470	0.642454	-0.14037	-14.7813	0.141152	0.017004
0.564	0.629673	-0.13155	-15.2306	0.136300	0.015127
0.658	0.617722	-0.12272	-15.6508	0.130665	0.013408
0.752	0.606600	-0.11390	-16.0419	0.124300	0.011835
0.846	0.596308	-0.10507	-16.4037	0.117256	0.010399

0.940	0.586846	-0.09625	-16.7364	0.109587	0.009088
1.034	0.578213	-0.08742	-17.0400	0.101345	0.007892
1.128	0.570409	-0.07860	-17.3143	0.092582	0.006801
1.222	0.563435	-0.06977	-17.5595	0.083352	0.005803
1.316	0.557291	-0.06095	-17.7756	0.073707	0.004889
1.410	0.551976	-0.05212	-17.9625	0.063698	0.004048
1.504	0.547491	-0.04330	-18.1202	0.053380	0.003270
1.598	0.543835	-0.03447	-18.2487	0.042803	0.002543
1.692	0.541008	-0.02565	-18.3481	0.032021	0.001857
1.786	0.539012	-0.01683	-18.4183	0.021087	0.001202

TABLE 7.2 Capillary pressure gradients at breakthrough

x , cm	S_w	$\frac{\partial S_w}{\partial x}$, cm^{-1}	$\frac{dp_c}{dS_w}$, psi	$\frac{\partial p_c}{\partial x}$, atm/cm
0.094	0.678948	-0.19677	-13.4981	0.180688
0.188	0.660706	-0.19135	-14.1395	0.184057
0.282	0.642973	-0.18592	-14.7630	0.186725
0.376	0.625751	-0.18050	-15.3685	0.188714
0.470	0.609038	-0.17508	-15.9561	0.190042
0.564	0.592836	-0.16965	-16.5258	0.190730
0.658	0.577143	-0.16423	-17.0776	0.190797
0.752	0.561960	-0.15880	-17.6114	0.190263
0.846	0.547287	-0.15338	-18.1273	0.189148
0.940	0.533123	-0.14796	-18.6253	0.187472
1.034	0.519470	-0.14253	-19.1054	0.185255
1.128	0.506326	-0.13711	-19.5675	0.182516
1.222	0.493692	-0.13169	-20.0117	0.179276
1.316	0.481568	-0.12626	-20.4380	0.175554
1.410	0.469954	-0.12084	-20.8463	0.171370
1.504	0.458850	-0.11541	-21.2368	0.166744
1.598	0.448255	-0.10999	-21.6093	0.161695
1.692	0.438171	-0.10457	-21.9638	0.156244
1.786	0.428596	-0.09914	-22.3005	0.150411
1.880	0.419531	-0.09372	-22.6192	0.144215

1.974	0.410976	-0.08830	-22.9200	0.137676
2.068	0.402931	-0.08287	-23.2029	0.130814
2.162	0.395395	-0.07745	-23.4678	0.123649
2.256	0.388369	-0.07202	-23.7149	0.116201
2.350	0.381854	-0.06660	-23.9440	0.108489
2.444	0.375848	-0.06118	-24.1551	0.100533
2.538	0.370352	-0.05575	-24.3484	0.092354
2.632	0.365365	-0.05033	-24.5237	0.083970
2.726	0.360889	-0.04490	-24.6811	0.075403
2.820	0.356922	-0.03948	-24.8205	0.066671
2.914	0.353465	-0.03406	-24.9421	0.057794
3.008	0.350519	-0.02863	-25.0457	0.048793
3.102	0.348081	-0.02321	-25.1314	0.039688
3.196	0.346154	-0.01779	-25.1992	0.030497
3.290	0.344737	-0.01236	-25.2490	0.021241
3.384	0.343829	-0.00694	-25.2809	0.011940
3.478	0.343431	-0.00151	-25.2949	0.002614
3.572	0.343544	0.003904	-25.2909	-0.00671
3.666	0.344165	0.009328	-25.2691	-0.01603
3.760	0.345297	0.014752	-25.2293	-0.02531
3.854	0.346939	0.020175	-25.1716	-0.03454
3.920	0.348396	0.023984	-25.1203	-0.04098

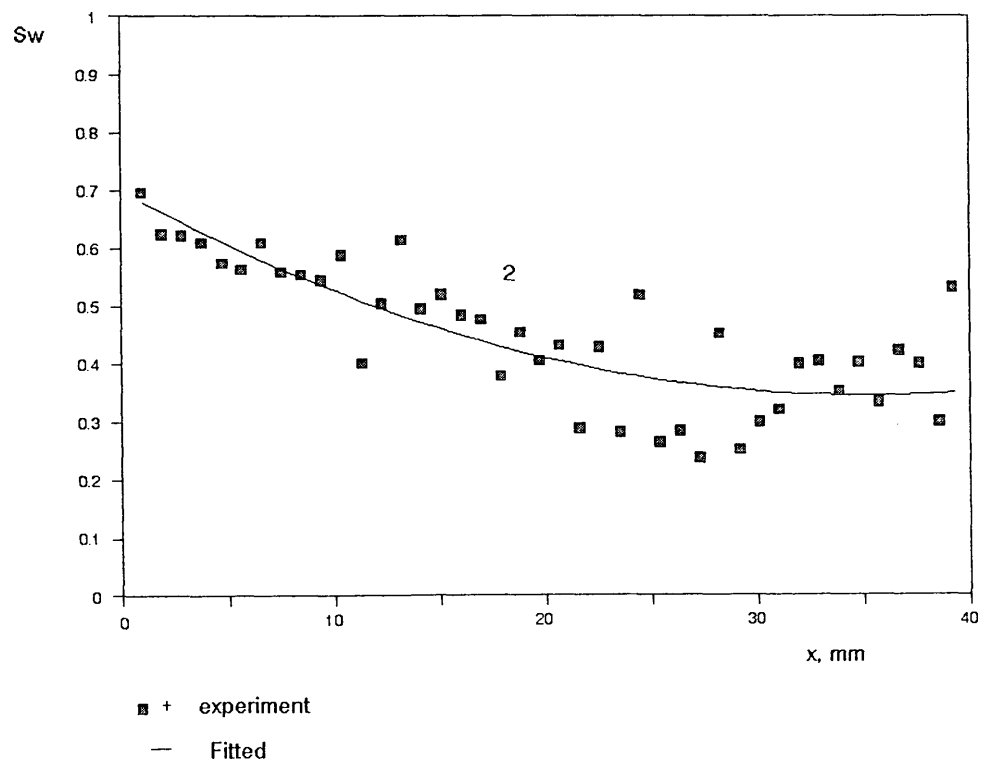
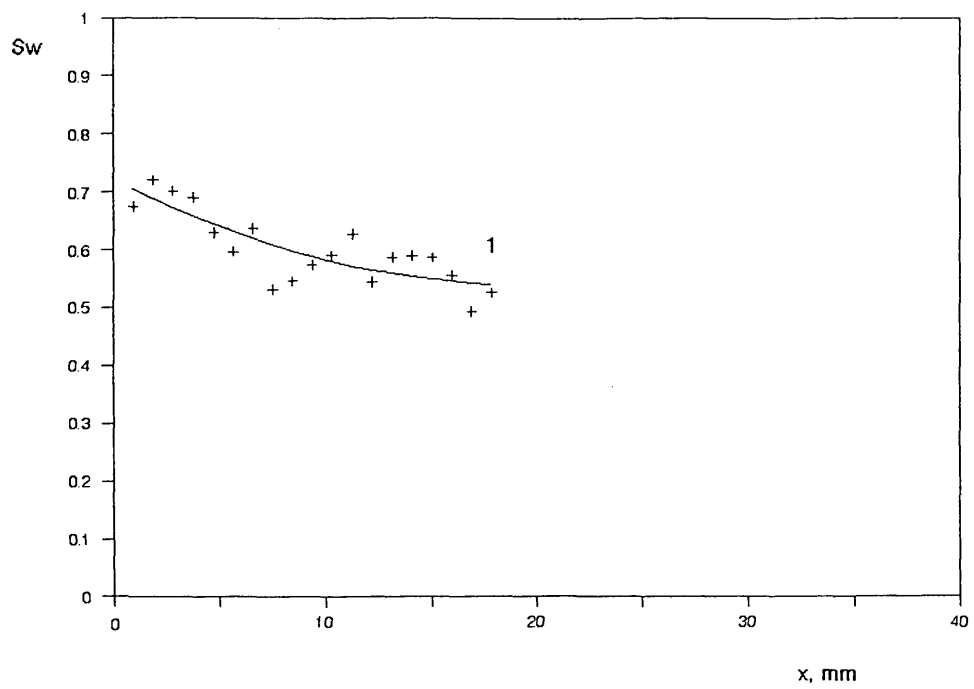


Figure 7.1 The water saturation profiles before '1' and at '2' breakthrough

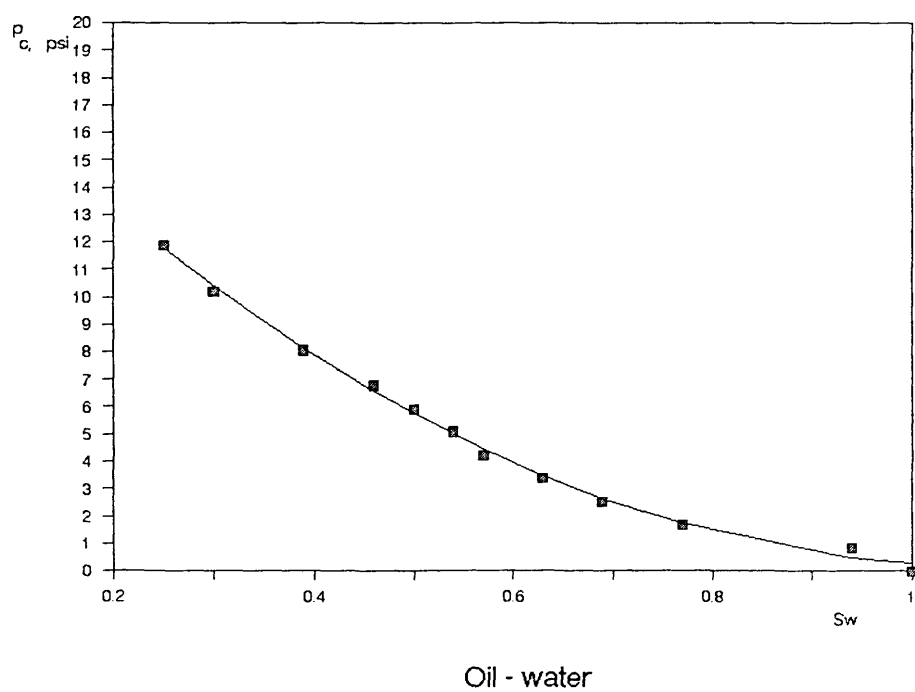
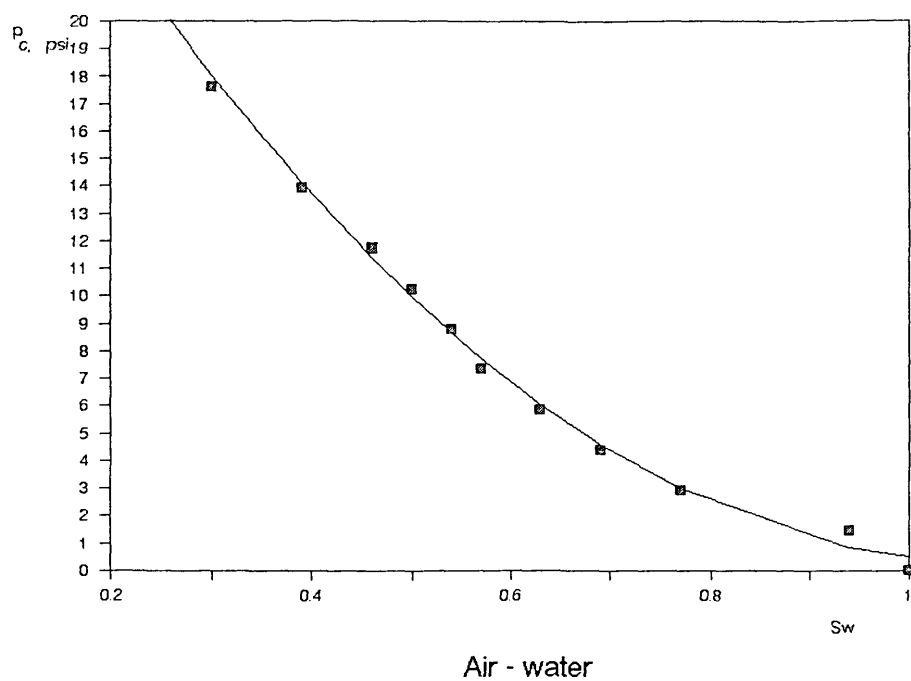


Figure 7.2 Drainage capillary pressure curve for the Portland limestone

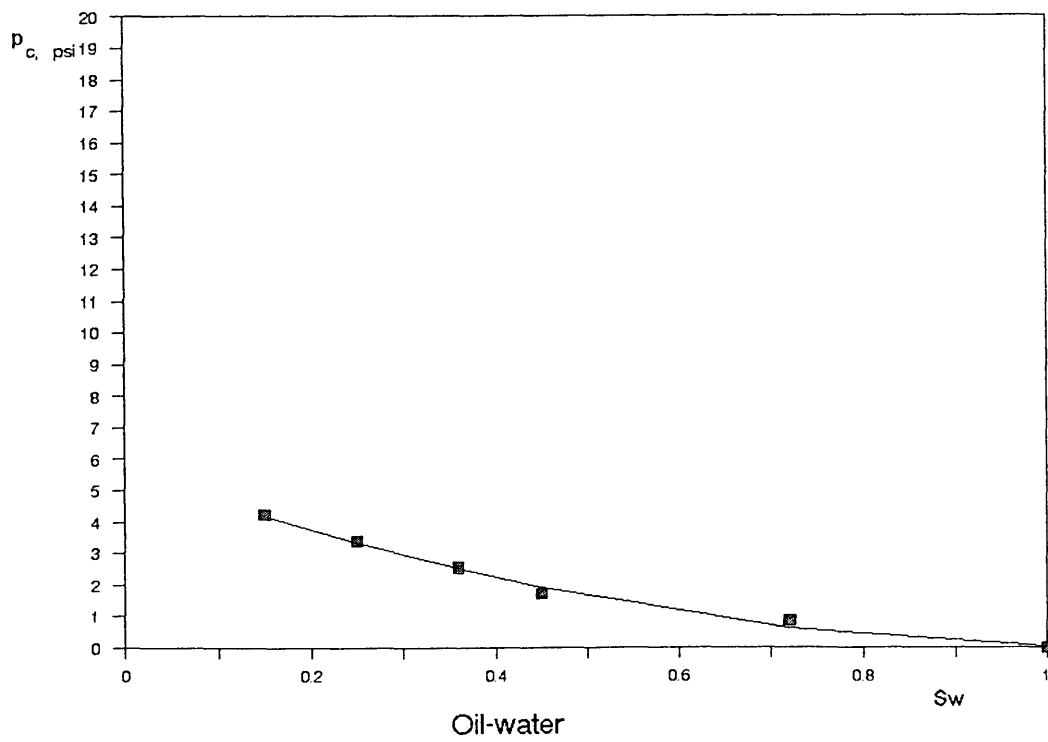
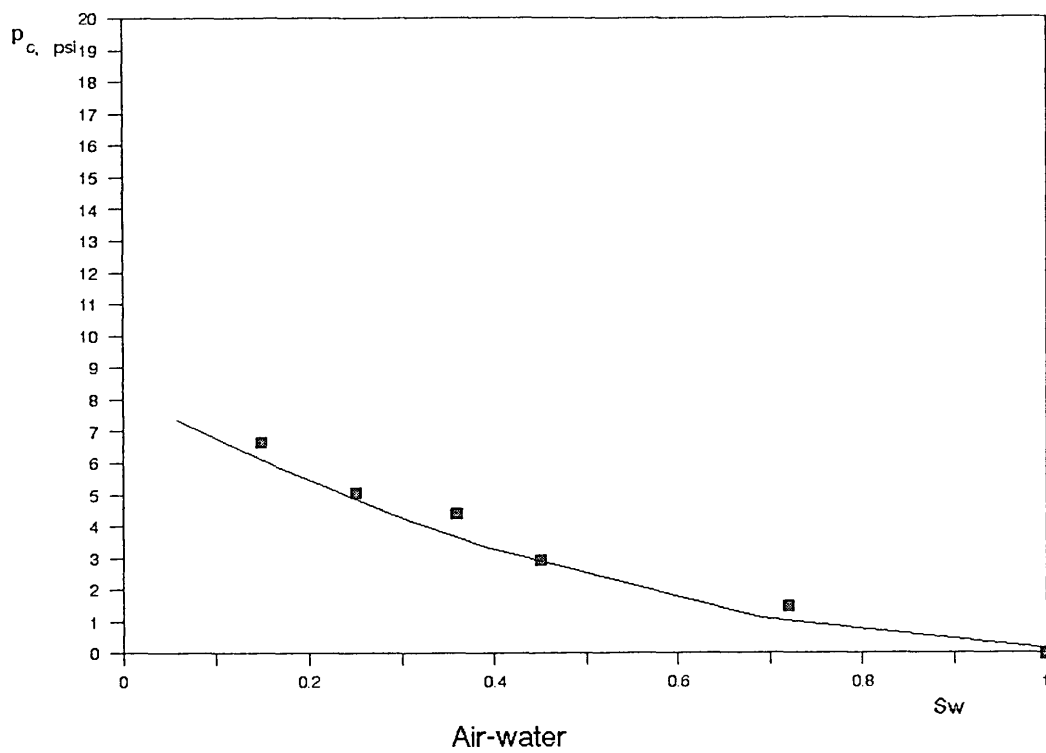
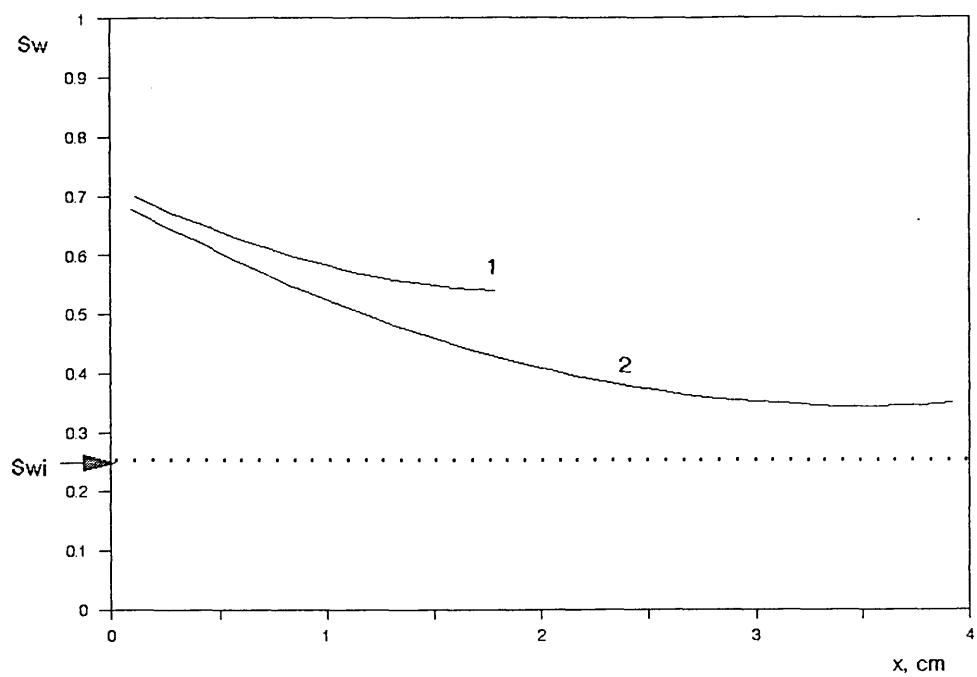
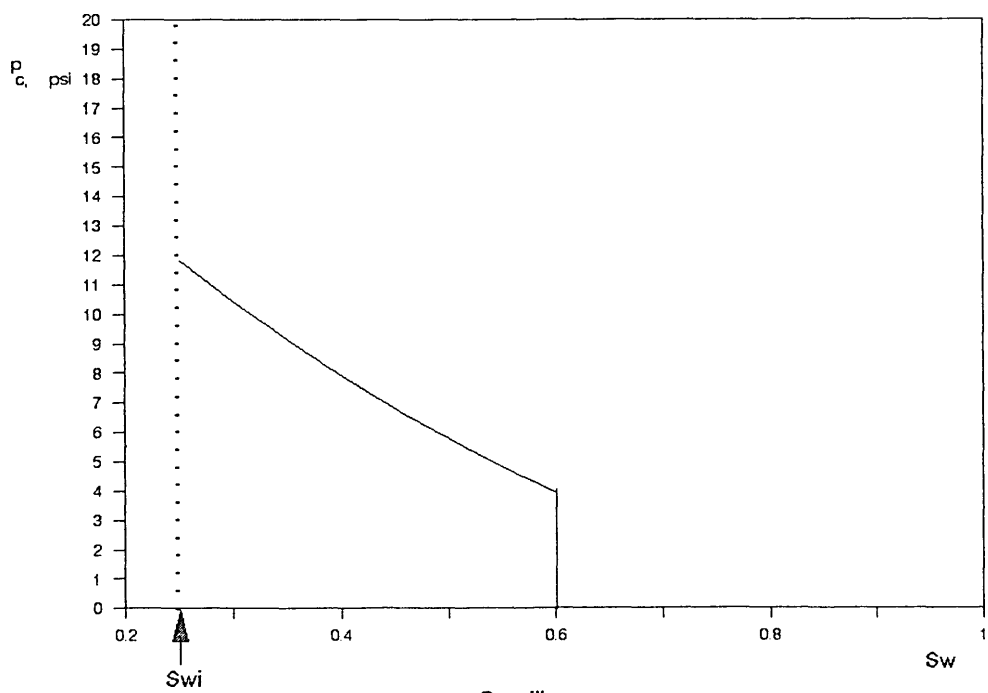


Figure 7.3 Drainage capillary pressure curve for the Lochaline sandstone



(a) Water saturation profile



(b) Capillary pressure curve

Figure 7.4 (a) Water saturation profiles and (b) capillary pressure curve used to determine capillary pressure gradients

7.3 Interpretation of Core Flood

7.3.1 Fractional flow and relative permeabilities

In a linear flood Welge analysis method makes use of the fractional flow curve at a saturation greater than the frontal saturation to obtain the saturation profile. It relates the calculated average saturation to its fractional flow saturation gradient. The reverse of this approach is applied in this analysis with the saturation distribution obtained directly from measurements, i.e., the saturation profile is used to define the fractional flow curve for saturation greater than the frontal saturation S_{wf} (detail in Appendix 7). The fractional flow f_w and relative permeability k_r curves obtained from the core flood on the basis of the non-capillary Buckley-Leverett theory have been presented in Chapter 6 (Figure 6.8). Figure 7.5 shows these relationships obtained from the saturation profile numbered '1' in Figures 7.1 and 7.4 for the saturations greater S_{wf} . Welge (1952) demonstrated that the part of the f_w curve for saturation less than S_{wf} is virtual, and hence the first real point on the curve has the coordinates $S_{wf}, f_w|_{S_{wf}}$ corresponding to the shock front. The equation derived by Johnson, Bossler and Naumann (1959) was used to calculate the individual relative permeabilities.

$$\frac{d(\frac{1}{W_i I_r})}{d(\frac{1}{W_i})} = \frac{f_w}{k_{rw}} \quad (7.6)$$

where

W_i - the cumulative injection in pore volumes,

k_{rw} - the relative permeability to water,

f_w - the fractional flow of water,

I_r - the relative injectivity,

$I_r = \frac{\Delta p_i}{\Delta p}$ which is the ratio of the pressure drop measured at start of injection to that measured at a given core flood stage. Figure 7.6 shows the core flood pressure response data.

7.3.2 The pressure response during the core flood

The flood test started with injecting water from one end of the cylindrical plug (3.92 cm long by 2.44 cm diameter) at a constant flow rate of 0.3 cm³/hr to displace the oil from the other end. The pressure drop response, measured across the core

plug up to this flood stage is shown in Figure 7.6. As the water injection was initiated the pressure drop Δp increased and only oil was produced from the core until after breakthrough of water at the exit end of the core.

7.3.3 The Buckley-Leverett/Welge analysis

A saturation distribution measured before breakthrough has been compared in Chapter 6 with calculated 1-D saturation profile. The core flood analysis involved using the fractional flow curve and relating the calculated average saturation to its fractional flow saturation gradient. Figure 7.7 compares the fractional flow and relative permeability curves calculated in this way from the core flood data with the fractional flow and relative permeability derived from measured saturation distribution for saturation greater than the S_{wf} . The relative permeability ratio curves may be compared in Figure 7.8.

7.4 Discussion and Conclusions

In the absence of an actual imbibition capillary pressure curve part of the drainage capillary pressure curve obtained for the Portland limestone has been used in the illustration. The drainage capillary pressures were measured on sample PLS-25 (taken adjacent to the test sample). Due to the experimental difficulties in determining the definition of the imbibition direction capillary pressure curve, and of using the information in reservoir simulation models, it is a common practice by many reservoir engineers to assume that, for practical purposes, capillary pressure hysteresis is relatively insignificant. As indicated by Archer and Wall (1986) the assumption is close to the truth in systems without strong wetting preference and with monosize pores and the magnitude of the difference $\Delta p_{c(D-I)}$ may often be negligible in comparison with viscous force pressure gradients. The capillary pressure gradient are considered here over small pore diameter distances on a microdisplacement scale, hence the assumption of negligible $\Delta p_{c(D-I)}$ reasonably applies.

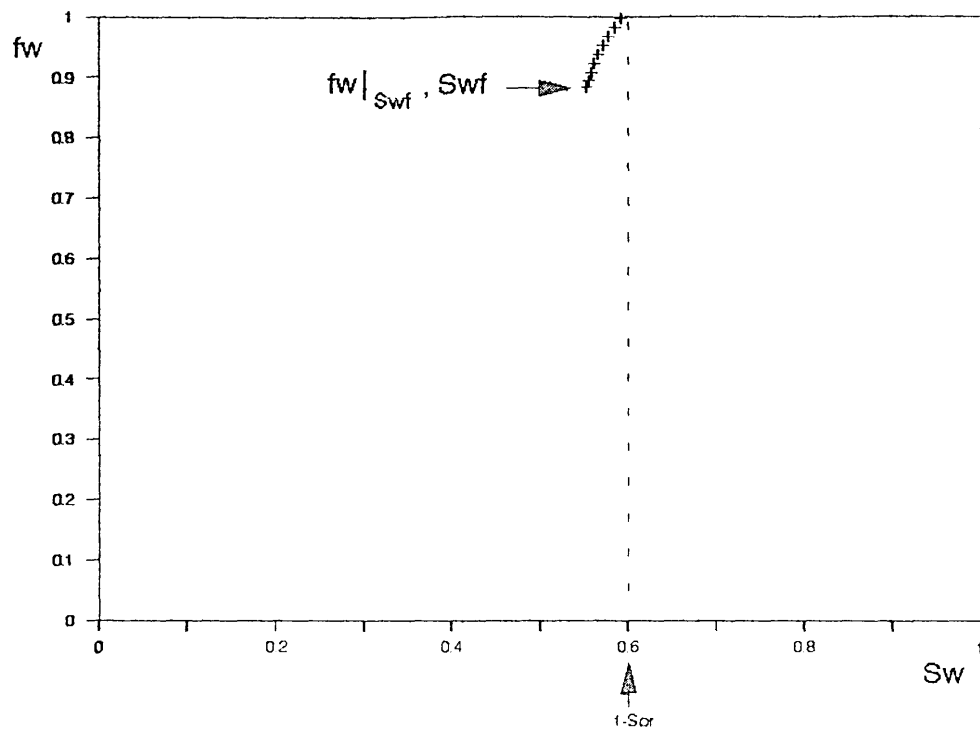
The gradient $\frac{\partial S_w}{\partial x}$ is negative except at the exit end for the profile measured at breakthrough which shows evidence of end effect. The gradient $\frac{dp_c}{dS_w}$ is always negative. The presence of a positive capillary pressure gradient $\frac{\partial p_c}{\partial x}$ term tends to increase the fractional flow of water f_w . Conversely, the presence of a negative

$\frac{\partial p_c}{\partial x}$ caused by the end effect tends to decrease the f_w .

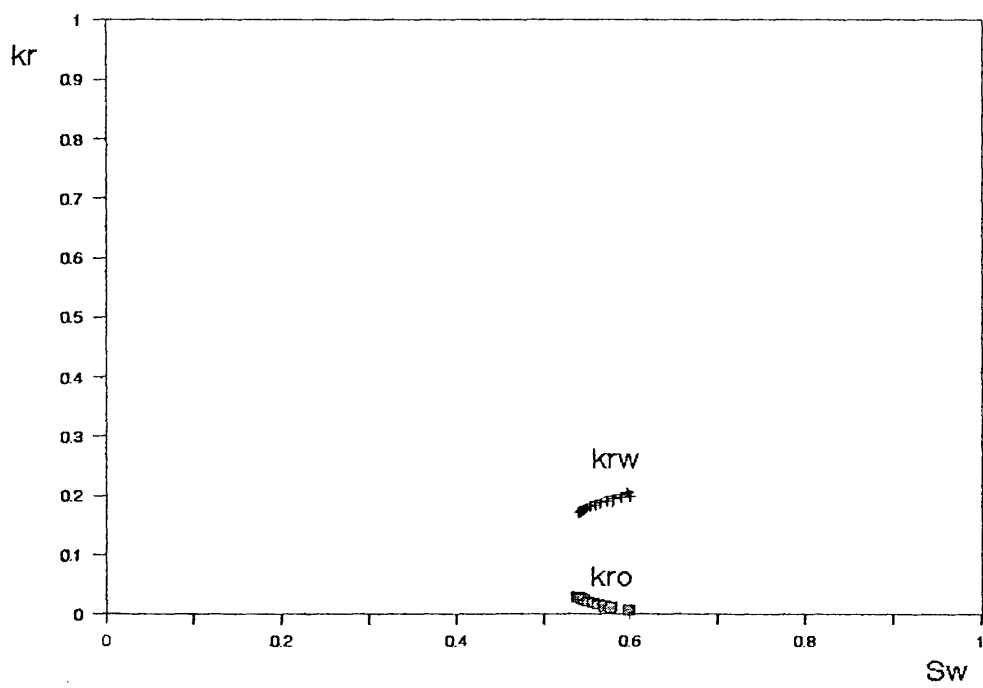
A complementary technique to the conventional method of core flood interpretation has been provided by an MRI imaging method. The technique has provided saturation distribution in a rock core plug by measurement, from which relative permeability relationships for the sample have been obtained. The relative permeability curves have been compared with smoothed curves interpreted using a simulator (CORSIM, 1988) from laboratory waterflood history using a history-match technique (Figures 7.7 and 7.8). Though only part of the curves were derived from the measured saturation distribution, namely, the part for saturation greater than S_{wf} , the other part is virtual. Due to limitation in the pulse and gradient strength used, only a plane 4 mm wide in the core plug was imaged. This limitation has been discussed in Chapter 4 where the governing equation can be found. It is possible with adequate combination of pulse and gradient to select a plane the size of a laboratory core plug during core flood.

With the aid of the MRI technique it has been shown that

- saturation gradients in core floods can be successfully resolved in terms of viscous and capillary terms. Before breakthrough the saturation gradient (in the Portland limestone sample flooded at a rate of 0.1PV/hr) decreased from -0.02 to -0.18 cm⁻¹ with the increase in S_w from 0.54 to 0.70 behind the flood front. In this region $\frac{dp_c}{dS_w}$ increased from -18.4 to -12.7 psi (-1.25 to -0.86 atm) with the increase in S_w .
- capillary pressure gradient can be quantified, hence a rational assessment can be made regarding the importance of capillarity in relation to the viscous flow forces. Before the breakthrough in the case examined here the capillary pressure gradient increased from 0.02 to 0.15 atm/cm with the increase in S_w behind the flood front.

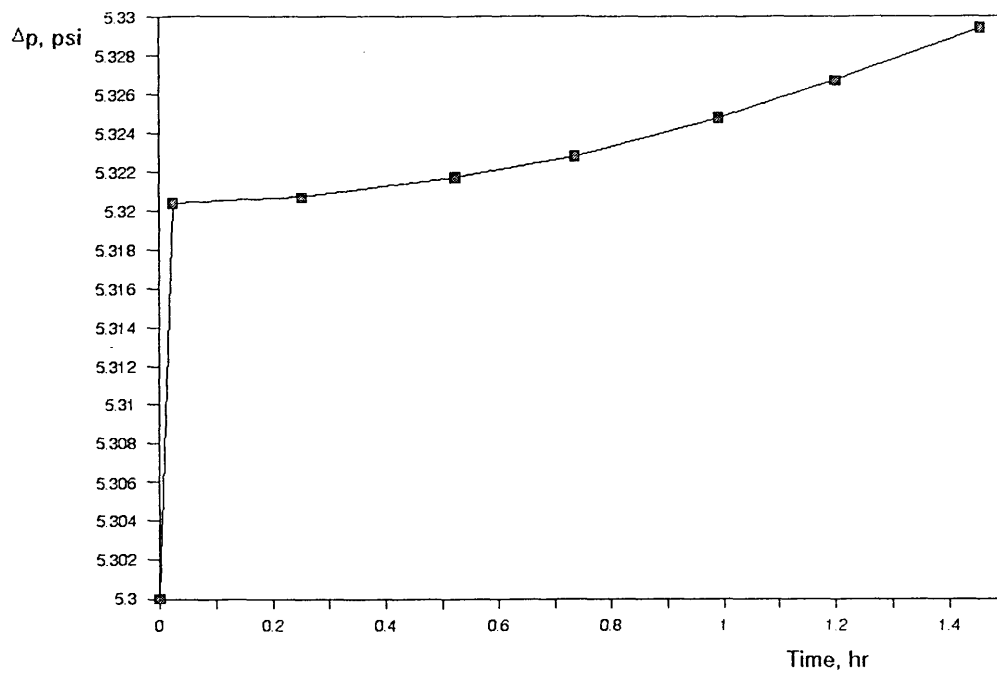


The fractional flow curve

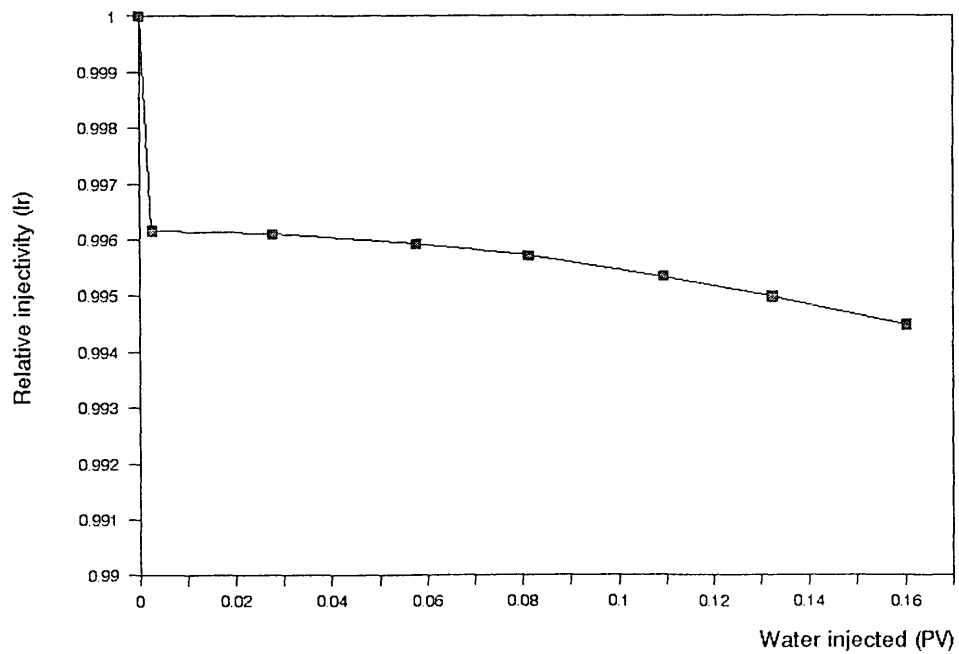


The relative permeability curves

Figure 7.5 Fractional flow and relative permeability curves for $Swf < Sw < 1 - S_{or}$

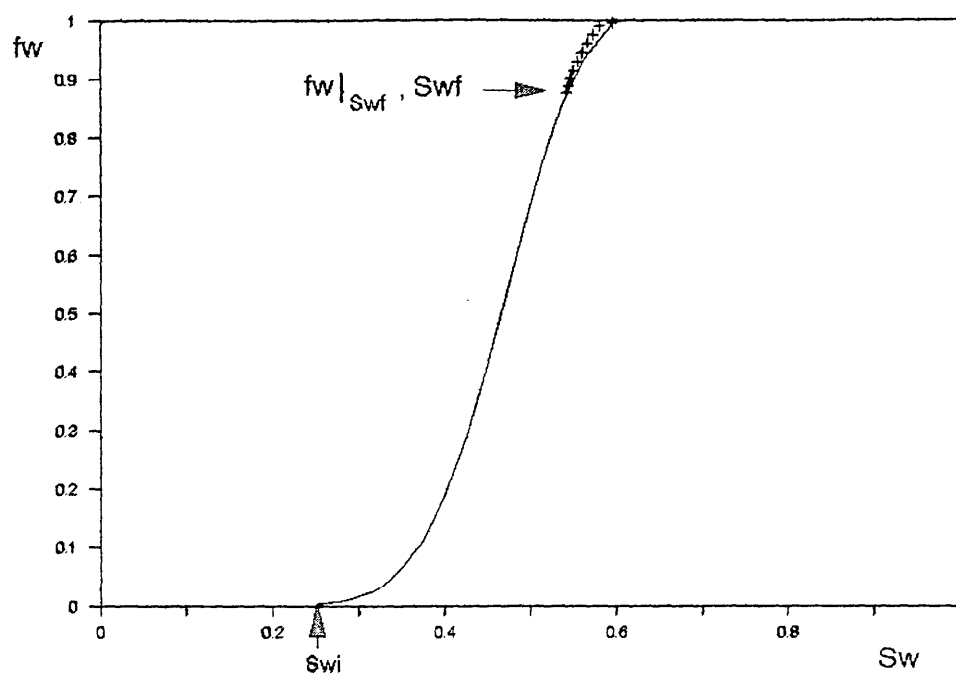


The imbibition pressure drop response

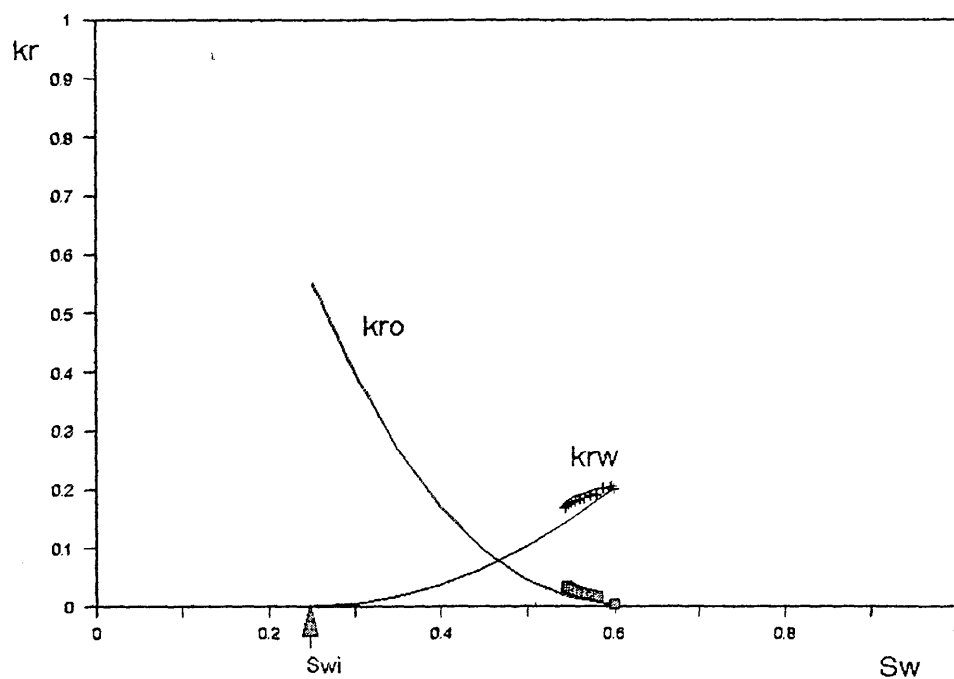


The relative injectivity curve

Figure 7.6 The core flood pressure and rate data



The fractional flow curves



The relative permeability curves

- + ■ derived from measured saturation profile
- derived from core flood data

Figure 7.7 Comparison of f_w and k_r curves

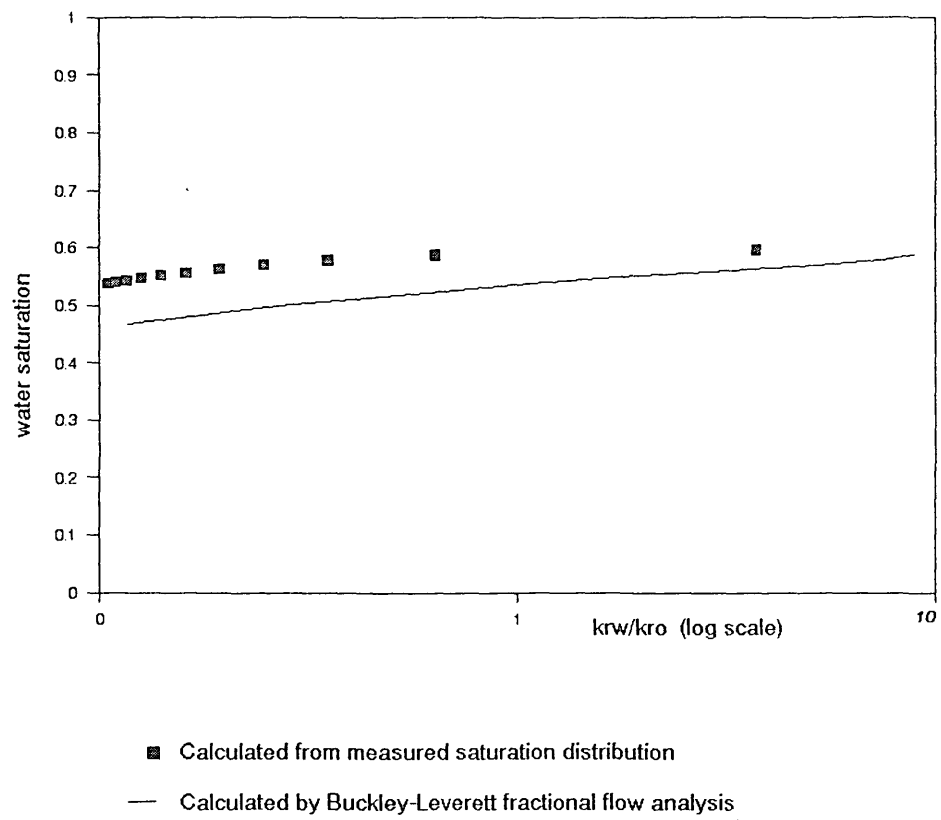


Figure 7.8 Comparison of the relative permeability ratios

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CHAPTER 8

CONCLUSIONS AND RECOMMENDATIONS

In this chapter the main conclusions drawn from the results of this research work are presented. Some suggestions and recommendations regarding further work in the application of magnetic resonance imaging (MRI) to petrophysical studies are also made.

The research concerned evaluation of nuclear magnetic resonance (NMR) imaging for use in special core analysis. Several rock samples saturated with water or oil were imaged using different MRI methods to obtain the fluid distribution in the samples. The chemical shift imaging method of the MRI technique was used to image several rock samples saturated with two immiscible fluids (oil and water) to obtain separate distribution of each fluid in the samples. Data from the core imaging was used to complement core flood data in the interpretation of the core flood tests. These investigations have provided several results that show the benefits of using the MRI technique in special core analysis in particular, and in core analysis in general.

The main new contributions to knowledge which have emerged from this work are

- (i) the identification of the advantages and limitations of MRI methods in multi-dimensional interpretation of saturation distributions in special core analysis displacement tests;
- (ii) the development of relative permeability relationships from laboratory tests which yield information on both viscous and capillary forces;
- (iii) the potential for scaling-up relative permeability data from laboratory tests to simulator-scale grid blocks using displacement force ratios.

8.1 The MRI Technique

An evaluation of nuclear magnetic resonance measurement and imaging techniques as a tool for use in conventional and special core analyses has been conducted. The technique has been used to image the effective porosity distribution, as evidenced from the fluid distribution in a rock slice 4 mm thick, with a resolution of 0.94 mm by 0.94 mm. It appears that such a high image resolution has so far been achieved in core analysis only with the MRI technique. The potential of the MRI

technique for ‘visualising’ a fluid and its distribution in rock samples has been demonstrated. The imaging equipment used was an *Oxford Instrument*^R with a superconducting magnet at 0.4 Tesla.

The chemical shift imaging (CSI) method of the MRI technique has been used to discriminate and image saturations of oil and water simultaneously present in artificial and real rock samples. The movable fraction of the oil and water in rock samples, constituting a saturation greater than 0.3 in the Portland limestone, was measured and resolved into separate images to obtain the saturation distribution. Two-dimensional, as well as one-dimensional, saturation distribution in porous media was obtained by the CSI under static conditions. Core floods at very low flow rate were imaged under dynamic flow conditions and saturation profiles at various stages of the flooding process were obtained. Low flow rates are often more representative of the reservoir flow conditions than high flow rates very often used in core floods. The imaging of core floods in this work was limited to very low flooding rates due the imaging speed capability of the MRI system used. It could be possible to widen the range of flooding rates by using appropriate combination of gradient and pulse sequence in a more powerful equipment.

The limitations in signal resolution and detection in a given rock type lie in the equipment power and in the speed of data acquisition. The *Oxford Instrument*^R used was a medical imager and was not custom-built or modified for core analysis. It used field gradient strength of only 2.5 Gauss/cm. Theoretically a strength as high as 50 G/cm can be used for core imaging, to obtain a resolution several times better than obtained in this work. Some more modern imaging equipment than that used in this work permit the use of a pulse sequence known as Flash method, in which the signal can be captured 1 or 2 ms after excitation. Such method would certainly improve the limits of resolution of saturation especially for a rock-fluid system with a high transverse relaxation rate (short T_2^*). A custom-built Magnetic resonance imager that includes the specifics of rock-fluid systems would enhance the potential of the MRI technique as a powerful tool for use in petrophysical studies.

8.2 Core Flood Interpretation

The MRI technique has been employed in core flood tests to show that

- flood fronts can be tracked under dynamic flow conditions, and hence visual observation of the breakthrough stage of the core flood process can be achieved;
- the actual process of displacement throughout the core sample can be visualised; this can reveal poorly distributed fluids and saturation build up due to end effects;
- saturations and saturation profiles can be derived at any stage of the core flood directly from measurements;
- saturation gradients can be detected during flooding on the basis of the derived saturation profiles.

This research work has shown that saturation distributions in core floods can be obtained from MRI measurements at **dynamic** flow conditions. Previous petrophysical studies with MRI have only been applied to immiscible fluids in porous media at **static** conditions. Core floods can now therefore be interpreted in the light of the more detailed saturation distribution; this takes special core analysis displacement tests into the multidimensional domain. The combination of a measured saturation profile with a rock imbibition capillary pressure curve for the test fluid pair, makes it possible to quantify the capillary pressure gradient. Hence it has been possible with the use of MRI to resolve saturation gradients in core floods in terms of the viscous and capillary terms.

8.3 Fractional Flow in Core Floods

The use of the MRI technique in core analysis offers the opportunity to quantify a capillary pressure gradient prior to performing the displacement calculations. As a consequence, it has been shown how the relative importance of capillary forces compared to viscous flow forces can be assessed in a core flood. The fractional flow equation can then be solved to include the capillary pressure gradient term. This represents an important new opportunity in the interpretation of immiscible displacement in core floods.

A novel approach has been used to obtain the fractional flow curve for saturations greater than the frontal saturation from the measured saturation profile. The

approach follows the Welge analysis in reverse and is referred to in this work as “reverse Welge analysis”. The fractional flow curve obtained in this way includes the contribution due to the capillary pressure gradient term.

8.4 Relative Permeability Relationships

The MRI technique has been used to complement conventional core flood testing techniques and thereby enhance unsteady state core flood interpretation by providing saturation distribution in a rock core plug. Meaningful relative permeability curves for a sample have been obtained. The relative permeability curves for saturations greater than the frontal saturation appear to have been validated since they compare favourably with smoothed relative permeability curves obtained using a simulator to model the laboratory test in a history-match approach.

8.5 Future Directions

- Immiscible displacement by the steady state process can be investigated by the MRI method and comparison with the unsteady state flooding process can be made.
- The MRI technique can be utilised to investigate the influence of wettability modification in rock cores on saturation distribution.
- The MRI technique also lends itself to the study of miscible displacement processes in reservoir rock samples. In miscible core floods gravity override may thereby be revealed.
- The MRI technique is known, from its medical applications, for having the potential to be made molecular species specific. It can therefore be used to image the distributions of certain components in chemical enhanced floods and in liquid-liquid miscible fluid systems.

Appendix 3

Basic Properties of the Rock - fluid System

The porous rock materials used in these investigations were either saturated with a single liquid or two immiscible liquids (water and oil based). When two phases (one wetting and the other nonwetting) jointly fill the void space, then

$$S_{nw} + S_w = 1 \quad (A3.1)$$

and

$$p_c = p_{nw} - p_w \quad (A3.2)$$

where,

subscripts nw and w refer to the nonwetting and wetting phases, respectively, S and p are saturation and pressure, respectively, and p_c - the capillary pressure is the difference between the non-wetting phase and the wetting phase pressures.

Water-oil capillary pressure is defined as the pressure in the oil phase minus the pressure in the water phase, or

$$p_c = p_o - p_w$$

Hence, the capillary pressure can have either positive or negative value, depending upon the wettability preference of the rock. For an immiscible fluid pair confined in a circular cross-section pore radius r , the capillary pressure can be defined as

$$P_c = \frac{2\sigma \cos\theta}{r} \quad (A3.2a)$$

where,

σ is the interfacial tension,

θ is the contact angle, measured through the wetting phase fluid, and

r - the radius of the circular cross-section pore.

The angle θ is influenced by the wettability preference of the rock. The capillary pressure forces that influence allowable saturation change in pores of a given size are thus directly influenced by wetting character.

Relative permeability k_r is a concept used to describe the flow resistance for each fluid phase present in multiphase flow through porous media, and it is defined as

$$k_{rnw} = \frac{k_{nw}}{k} \quad (A3.3a)$$

and

$$k_{rw} = \frac{k_w}{k} \quad (A3.3b)$$

A3.1 Routine Core Analysis

A3.1.1 Saturation determination

Accurate determination of the fluid content and distribution is an important element in the interpretation of core-analysis data. Important flow parameters such as capillary pressure and relative permeability are dependent upon phase saturations. The determination of saturation distribution in core floods is one of the aims of evaluating the MRI technique in this work for use in special core analysis.

A3.1.2 Porosity Determination

The helium gas expansion porosimeter supplied by ITR^R was used to obtain the bulk porosities of samples used in this study. It basically consists of a sample chamber and a reference chamber among other things as shown in Figure A3.1. The measurement of grain volume involves three steps:

1. The reference chamber was charged with helium up to a pressure p_R while the sample chamber contained dummy cores (steel cylinders) of approximately the size of the rock sample and kept at atmospheric pressure p_o . The gas in the reference chamber is then expanded and the equilibrium pressure monitored.
2. The procedure is repeated with no dummy or core sample in the sample chamber.
3. Then the actual sample was placed in the sample chamber and the procedure was repeated.

The reference chamber pressures p_R and volume V_R , equilibrium pressures p_e and volumes V obtained in the three steps are used to calculate the grain volume V_g .

Applying Boyle's law to step 1

$$p_R V_R + p_o V_1 = p_e (V_R + V_1) \quad (A3.4)$$

As p_o is atmospheric Equation (A3.4) can be rewritten as

$$(p_R + B)V_R + B V_1 = (p_e + B)(V_R + V_1) \quad (A3.5)$$

where B is the barometric pressure. Also

$$p_e V_1 = V_R (p_R - p_e)$$

Or

$$V_1 = V_R \left[\frac{p_R}{p_e} - 1 \right]_1 \quad (A3.6)$$

Similarly in step 2, upon expansion of gas in the reference volume when the sample chamber was empty

$$V_2 = V_R \left[\frac{p_R}{p_e} - 1 \right]_2 \quad (A3.7)$$

And upon expansion of gas in step 3 when core sample was in place

$$V_3 = V_R \left[\frac{p_R}{p_e} - 1 \right]_3 \quad (A3.8)$$

If we denote

$$\left[\frac{p_R}{p_e} - 1 \right] = R$$

The dummy volume is then

$$V_2 - V_1 = V_R [R_2 - R_1]$$

Since the dummy volume is known

$$V_R = \frac{V_2 - V_1}{R_2 - R_1}$$

The grain volume V_g is given by $(V_2 - V_3)$, so that

$$V_g = V_R (R_2 - R_3) \quad (A3.9)$$

Porosity is calculated as

$$\phi = \frac{V_B - V_g}{V_B} \quad (A3.10)$$

A3.1.3 Permeability Determination

Permeability can be determined only by a flow experiment and the data analysed by employing Darcy's law. Darcy's law for the viscous flow of a fluid through permeable media may be stated in general terms as

$$v_s = \frac{Q}{A} = -\frac{k}{\mu} \left[\frac{dp}{ds} - \rho g \frac{dz}{ds} \right] \quad (A3.11)$$

where in Darcy unit of permeability (the unit adopted in the oil industry),

v_s - volume flux across a unit area of the porous medium in unit time,

Q - volume rate of flow is in cm^3/s ,

A - average cross-sectional area perpendicular to lines of flow is in cm^2 ,
 s - distance along the direction of flow is in cm ,
 z - vertical coordinate directed downward,
 ρ - the density of the fluid is in g/cm^3 ,
 g - acceleration of gravity is in cm/s^2 ,
 $\frac{dp}{ds}$ - pressure gradient along s at the point to which v_s refers is in atm/cm ,
 μ - viscosity of the fluid is in cp ,
 k - permeability of the medium is in Darcy.

The minus sign in front of the right side of Equation (A3.11) indicates that v_s should be positive if the fluid is flowing towards increasing values of the coordinates. Dry gas is usually used (air, N_2 , He) as fluids in permeability measurements, and the liquid permeability in some cases is obtained by correction.

Permeability in a rock may be homogeneous or heterogeneous and isotropic or anisotropic (i.e. directional). However, the direction of greatest interest in reservoir samples is that parallel to the applied pressure gradient. Equation (A3.11) may be reduced to a simpler form for the case of horizontal isothermal steady state flow of gas through permeable rock core sample as

$$\frac{Q}{A} = -\frac{k}{\mu} \cdot \frac{dp}{dx} \quad (\text{A3.12})$$

where x denotes the direction of flow. For gas flow where flow rate is measured at standard (or base) conditions, the relationship between rate and pressures is given by $pQ = p_b Q_b$. Hence Equation (A3.12) becomes

$$\frac{Q_b}{A} = -\frac{k}{\mu} \frac{p}{p_b} \frac{dp}{dx} \quad (\text{A3.13})$$

the integral over the length of the sample L of which is

$$\frac{Q_b}{A} = \frac{k(p_1^2 - p_2^2)}{2\mu L p_b} \quad (\text{A3.14})$$

where p_1 and p_2 are the terminal (inlet end and outlet end) pressures, and Q_b is the volume rate of flow measured at the base pressure p_b . Solving for k yields

$$k = \frac{2\mu Q_b p_b L}{A(p_1^2 - p_2^2)} \quad (\text{A3.15})$$

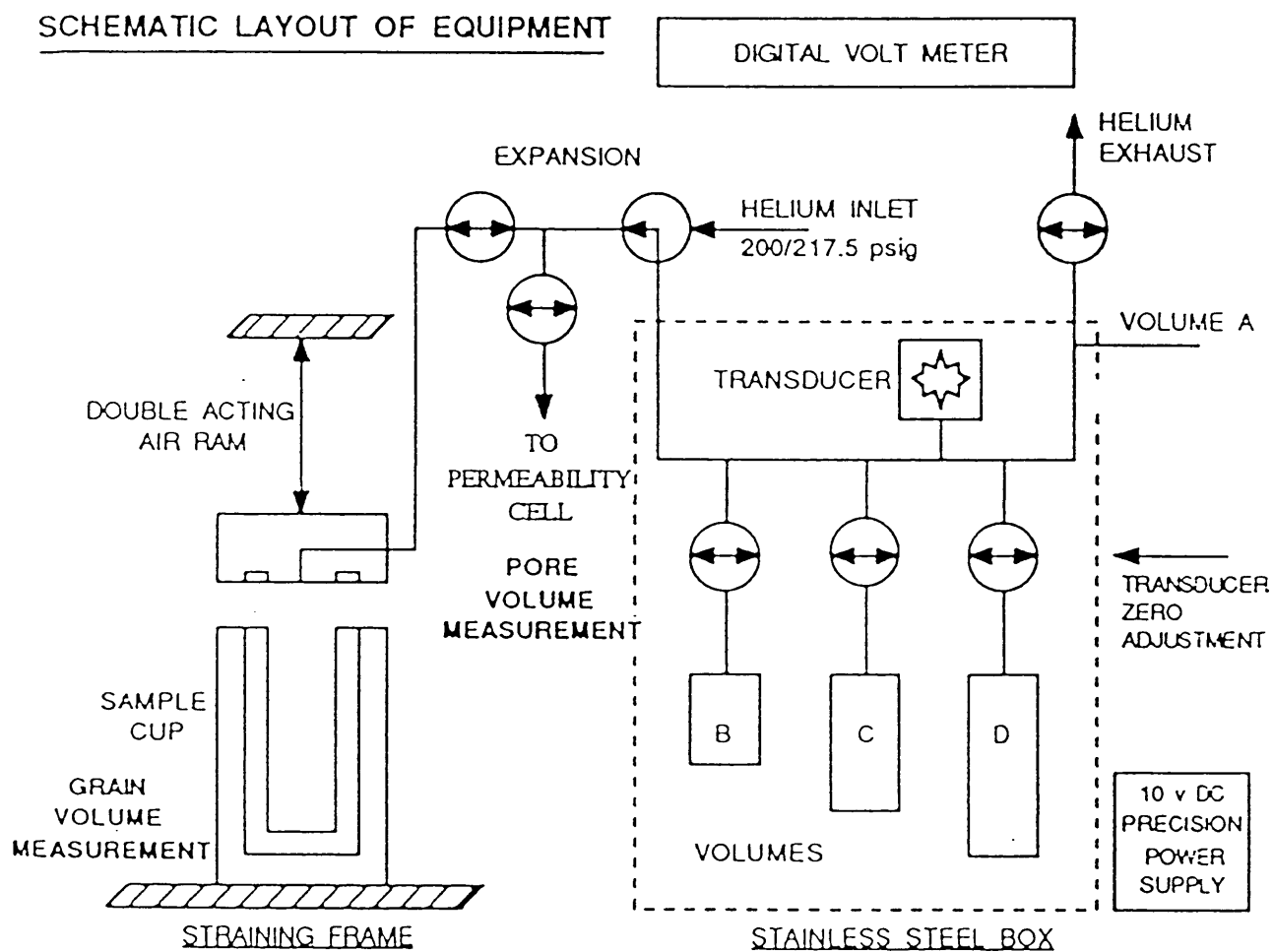


Figure A3.1 Schematic arrangement of the helium gas expansion porosimeter

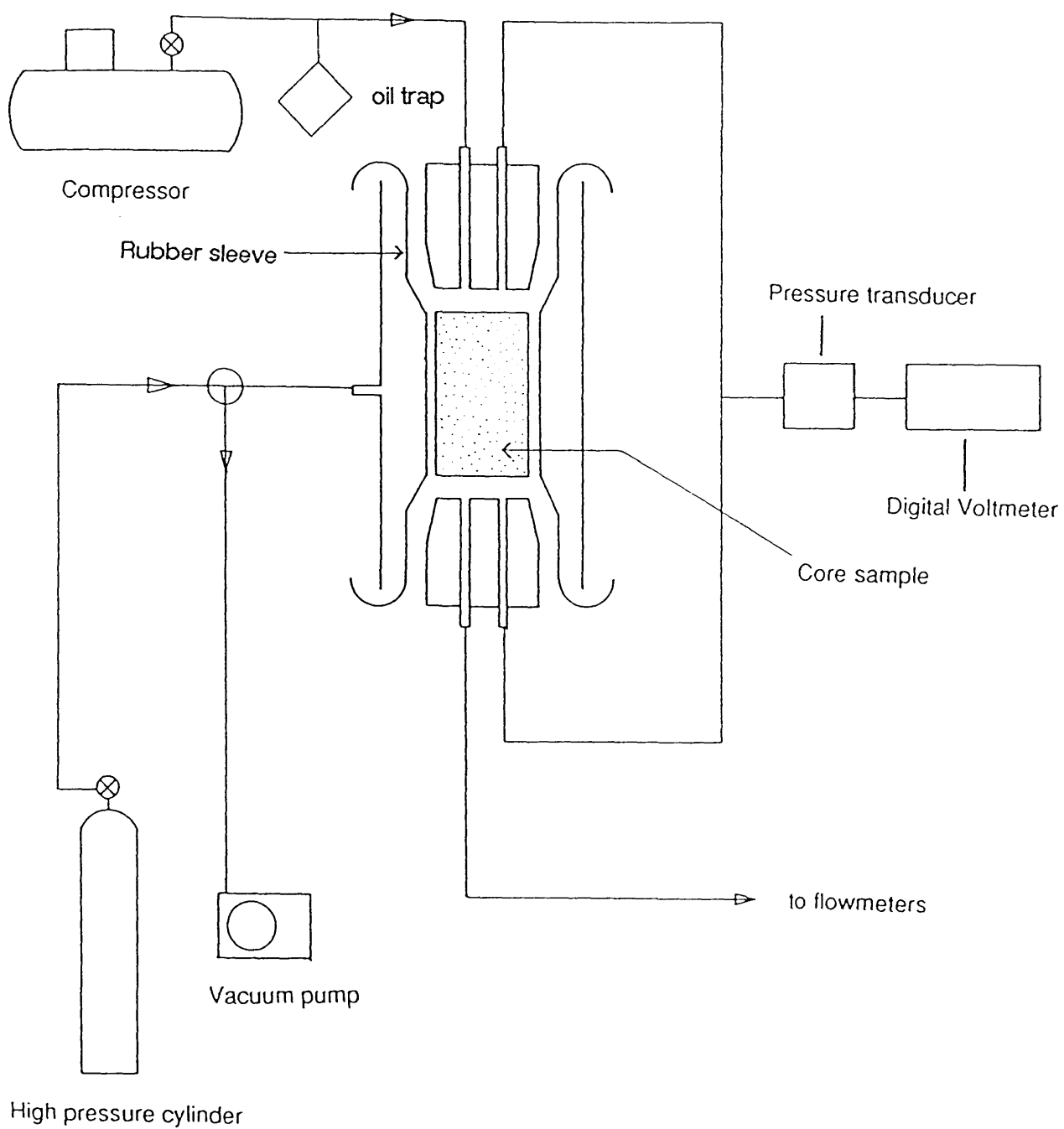


Figure A3.2 Schematic arrangement of Hassler cell assembly for flow measurement

To determine the permeability of a rock sample in the laboratory, the sample is placed in a permeameter, which comprises a Hassler core holder, and pressure regulators. The Hassler cell assembly, including ancillary equipment, is shown schematically in Figure A3.2. The rubber sleeve of the permeameter holding the sample is subjected to 250 psi confining pressure from the high pressure cylinder in order to prevent gas flow along the side walls of the core. Dry air is injected into the core plug using the compressor while the outlet end pressure is open to the atmosphere. Flow valves are used to establish linear flow and the flow rate and corresponding inlet end pressure is recorded. At low pressures, the permeability measured is usually higher than the real values, so Klinkenberg correction for gas slippage is necessary. This involves making several measurements of permeability at different inlet pressures and calculating mean pressure $p_m = (p_1 + p_2)/2$. The measured values of permeability k are then plotted against $\frac{1}{p_m}$ as illustrated in Figure A3.3. The true (liquid) permeability k_L is obtained by extrapolation of the measured data on a straight line to the point $\frac{1}{p_m} = 0$ (i.e. infinite mean pressure).

If liquids must be used for permeability determination (e.g., where correction may be erroneous as for permeabilities approaching 1 Darcy), Equation (A3.15) can be transformed to equation for flow of liquids. Using the relationship $Q_b p_b = Q_m p_m$, where Q_m is the volume rate of flow at the mean pressure, and factoring the denominator of Equation (A3.15) shows that

$$k = \frac{\mu Q_m L}{A(p_1 - p_2)} \quad (\text{A3.16})$$

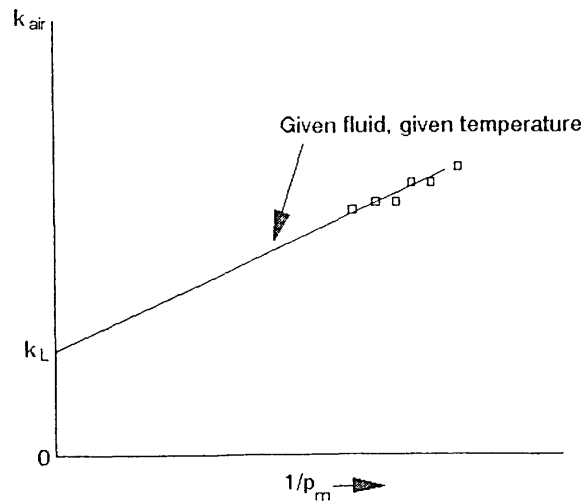


Figure A3.3 A typical Klinkenberg correction plot

A3.2 Two Phase Flow Description

Darcy's law (1856) is extended to multiphase flow by postulating that these phase pressures are involved in causing each fluid to flow. Hence, Darcy's law is rewritten for each phase as:

$$\vec{v}_{nw} = -\frac{kk_{rnw}}{\mu_{nw}}(\nabla p_{nw} - \rho_{nw}g\nabla D) \quad (3.1a)$$

$$\vec{v}_w = -\frac{kk_{rw}}{\mu_w}(\nabla p_w - \rho_w g\nabla D) \quad (3.1b)$$

where,

∇p comprises components $\frac{\partial p}{\partial x}, \frac{\partial p}{\partial y}, \frac{\partial p}{\partial z}$; and
 ∇D comprises components $\frac{\partial D}{\partial x}, \frac{\partial D}{\partial y}, \frac{\partial D}{\partial z}$.

$\vec{v}$ - flow velocity vector [m/s]

k - absolute permeability [m^2]

k_r - relative permeability

μ - viscosity [Pa.s]

g - acceleration due to gravity [m/s^2]

p - pressure [Pa]

D - depth [m]

x, y, z - distance [m]

ρ - the density of the fluid [g/cm^3]

the subscripts nw and w refer to nonwetting and wetting phase, respectively.

A continuity equation is also written for each of the two-phases as:

$$-\nabla \cdot (\alpha \rho_{nw} \vec{v}_{nw}) + \alpha q_{nw} = \alpha \frac{\partial(\phi \rho_{nw} S_{nw})}{\partial t} \quad (3.2a)$$

$$-\nabla \cdot (\alpha \rho_w \vec{v}_w) + \alpha q_w = \alpha \frac{\partial(\phi \rho_w S_w)}{\partial t} \quad (3.2b)$$

where,

$\alpha = \alpha(x, y, z)$ is a function arbitrarily defined as "geometric factor". For three dimensions α is equivalent to unity.

ϕ is the porosity of the medium, and

ρ is the density of the fluid.

By combining Equations (3.1) and (3.2) a set of simultaneous differential equations that describe two-phase flow is obtained:

$$\nabla \cdot \left[\frac{\alpha k k_{rnw}}{\mu_{nw}} (\nabla p_{nw} - \rho_{nw} g \nabla D) \right] + \alpha q_{nw} = \alpha \frac{\partial(\phi \rho_{nw} S_{nw})}{\partial t} \quad (3.3a)$$

$$\nabla \cdot \left[\frac{\alpha k k_{rw}}{\mu_w} (\nabla p_w - \rho_w g \nabla D) \right] + \alpha q_w = \alpha \frac{\partial(\phi \rho_w S_w)}{\partial t} \quad (3.3b)$$

This set of equations is extremely general in applicability, including, the effects of compressibility, capillary pressure, and relative permeability, as well as variations with position of the absolute permeability and the porosity (Peaceman 1977). Of particular interest is the saturation form of the equations derived by Buckley and Leverett (1942) for 1-D case of incompressible and immiscible displacement of oil by water which can be used to solve directly for saturation as a function of position and time.

$$v_{s_w} = \frac{dx}{dt} \Big|_{s_w} = \frac{q_t}{\phi A} \frac{df_w}{dS_w} \Big|_{s_w} \quad (3.4)$$

where,

v_{s_w} - velocity of a plane of constant water saturation travelling through a linear system.

x - distance along part of flow,

$q_w = q_t - q_o$ - constant rate of water injection,

A - cross sectional area,

f_w - fraction of flowing stream which is water.

The Buckley - Leverett equation (Equation 3.4) has become the basic equation for describing immiscible and incompressible multiphase flow in one dimension. The equation implies that, for a constant rate of water injection ($q_t = q_i$), the velocity of a plane of constant water saturation is proportional to the derivative of fractional flow equation evaluated for that diffuse saturation. In this equation fractional flow is assumed to be strictly a function of the water saturation, hence the use of the total differential of f_w .

A3.2.1 The fractional flow equation

A simple model of the displacement process obtains when oil displacement is assumed to take place under the so-called diffuse flow condition. Diffuse flow condition means that fluid saturations at any point in the linear displacement path are constant with time and single valued. This assumption permits the displacement to be described, mathematically, in 1-D. The 1-D description follows from the fact that since the wetting phase saturation is uniformly distributed then so are the relative permeabilities to both phases, which are themselves functions of the

wetting phase saturation at any point. It is worth noting that diffuse flow is the condition mostly assumed in the laboratory determination of relative permeability *rock* curves for 'homogeneous' samples. Such *rock* relative permeabilities must be regarded as point relative permeabilities which are functions of the point water saturation in the rock. It is, therefore, only when describing displacement in a homogeneous porous medium, under the diffuse flow condition, that *rock* relative permeabilities can be used (with appropriate scaling-up) in field calculations.

The fractional flow equation is derived for this simplest model of the displacement process at a constant reservoir condition pressure $\bar{p}$ and temperature $\bar{T}$ by applying Darcy's law, for linear flow, to oil displacement by water in a tilted reservoir block which has a uniform cross sectional area A . The 1-D equations for the simultaneous flow of oil and water are

$$q_o = -\frac{kk_{ro}A\rho_o}{\mu_o} \frac{\partial\Phi_o}{\partial x} = -\frac{kk_{ro}A}{\mu_o} \left(\frac{\partial p_o}{\partial x} + \rho_o g \sin \theta \right) \quad (3.5a)$$

and

$$q_w = -\frac{kk_{rw}A\rho_w}{\mu_w} \frac{\partial\Phi_w}{\partial x} = -\frac{kk_{rw}A}{\mu_w} \left(\frac{\partial p_w}{\partial x} + \rho_w g \sin \theta \right) \quad (3.5b)$$

where,

q - flow rate, expressed in reservoir volume/time.

$\frac{\partial\Phi}{\partial x}$ - datum corrected pressure gradient

subscripts o and w refer to oil and water, respectively

θ - angle measured from the horizontal to the line indicating the direction of flow [degree].

By expressing the oil rate in relation to the total flow rate q_t (r.vol/time) as

$$q_o = q_t - q_w$$

the subtraction of equations (3.5) gives

$$q_w \left(\frac{\mu_w}{kk_{rw}} + \frac{\mu_o}{kk_{ro}} \right) = \frac{q_t \mu_o}{kk_{ro}} + A \left(\frac{\partial p_c}{\partial x} - \Delta \rho g \sin \theta \right) \quad (3.6)$$

in which the capillary pressure gradient in the direction of flow is

$$\frac{\partial p_c}{\partial x} = \frac{\partial p_o}{\partial x} - \frac{\partial p_w}{\partial x}$$

and

$$\Delta \rho = \rho_w - \rho_o$$

The fractional flow of water, at any point in the sand body, is defined as

$$f_w = \frac{q_w}{q_o + q_w} = \frac{q_w}{q_t}$$

substitution into equation (3.6) of which gives the fractional flow equation:

$$f_w = \frac{1 + \frac{k k_{ra} A}{q_t \mu_o} \left(\frac{\partial p_c}{\partial x} - \Delta \rho g \sin \theta \right)}{1 + \frac{\mu_w}{k_{rw}} \cdot \frac{k_{ra}}{\mu_o}} \quad (3.7)$$

The effect of the three forces which control two-phase flow of oil and water in reservoir rock can be understood by considering the influence of the various component parts of the fractional flow equation (Equation (3.7)). The forces are viscous, capillary and gravity. One or two of these forces may predominate over the others under given conditions of the flow process.

The gravity term is $\Delta \rho g \sin \theta$, where θ is the angle measured from the horizontal to the line indicating the direction of flow. Provided all the other terms in the equation are the same, f_w for displacement updip ($0 < \theta < \pi$) is lower than for displacement downdip ($\pi < \theta < 2\pi$). Gravity tends to suppress the flow of water updip, and vice versa.

The effect of the capillary pressure gradient term can be more easily understood from Figure 3.1 by expressing it as

$$\frac{\partial p_c}{\partial x} = \frac{dp_c}{dS_w} \cdot \frac{\partial S_w}{\partial x} \quad (3.8)$$

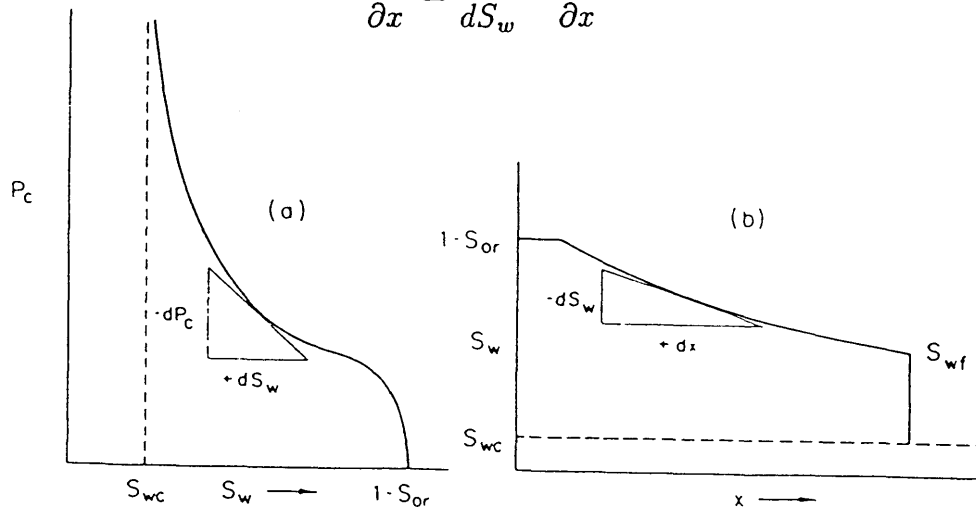


Fig.3.1 (a) Capillary pressure curve and (b) water saturation profile

(after Dake, 1978)

$\frac{dp_c}{dS_w}$ is the slope of the imbibition capillary pressure curve as illustrated in Figure 3.1(a), and is always negative; $\frac{\partial S_w}{\partial x}$ is the slope of the water saturation profile in the direction of flow as illustrated in Figure 3.1(b), also negative. Therefore, $\frac{\partial p_c}{\partial x}$ is always positive, hence the capillary pressure gradient term tends to increase the f_w .

If only the gravity term is neglected, then the fractional flow equation can be expressed as

$$f_w = \frac{1 + \frac{k k_{ro} A}{q_i \mu_o} \left(\frac{\partial p_c}{\partial x} \right)}{1 + \frac{\mu_w}{k_{rw}} \cdot \frac{k_{ro}}{\mu_o}} \quad (3.9)$$

In the absence of gravity and capillary pressure gradient terms, the effect of the viscous flow forces can be better understood. For example, for displacement in a horizontal homogeneous sand body ($\sin \theta = 0$), and neglecting, the capillary pressure gradient, the fractional flow equation is reduced to

$$f_w = \frac{1}{1 + \frac{\mu_w}{k_{rw}} \cdot \frac{k_{ro}}{\mu_o}} \quad (3.9a)$$

From this equation it can be seen that flow is regulated primarily by the relative permeabilities and viscosities. The more viscous the oil, the less readily it flows under a given pressure gradient, hence increased oil viscosity results in a more gradual approach to residual oil saturation (ROS). Provided the oil and water viscosities remain unchanged during displacement, f_w is strictly a function of water saturation S_w , as related through the relative permeabilities. For a typical set of relative permeabilities, the fractional Equation (3.9a) usually has the shape indicated in Figure 3.2. The viscosity ratio of oil to water influences the shape of the fractional flow curve and the water saturation profiles.

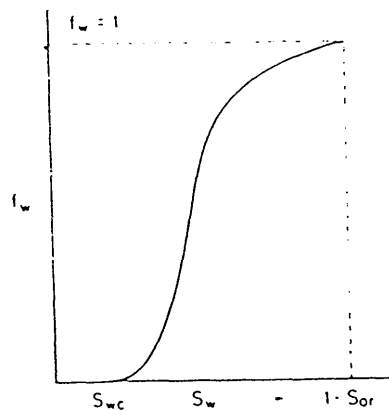


Figure 3.2 Typical Fraction flow curve (after Dake, 1978)

A3.2.2 Fractional Flow Analysis and Oil Recovery

Analysis of the fractional flow equation allows the recovery performance of the reservoir rock system to be determined. For homogeneous core floods under diffuse flow condition the relationship is usually analysed by the method of Buckley and Leverett and Welge; example calculations of which can be found in many standard texts, including Craig (1971) and Dake (1978). If the capillary pressure gradient term is included in the fractional flow equation, then a partial differential of f_w is used in the Buckley-Leverett equation.

Before water breakthrough at the producing end of a reservoir rock with a constant initial saturation, the oil recovered is simply equal to the volume of water injected for incompressible displacement. By integrating the Buckley-Leverett equation for the total time since start of injection the positions of planes of constant water saturation S_w as the flood moves through the rock can be obtained, and hence the water profile.

At the time of breakthrough (subscript bt) the flood front saturation, $S_{wf}=S_{wbt}$, reaches the producing end, and the oil recovery is simply

$$N_{pd_{bt}} = \frac{1}{\left. \frac{df_w}{dS_w} \right|_{S_{wbt}}} \quad (3.10)$$

where,

$N_{pd_{bt}}$ is the cumulative volume of oil recovered expressed in dimensionless pore volumes.

$\left. \frac{df_w}{dS_w} \right|_{S_{wbt}}$ is the gradient of the fractional flow curve at the front with respect to the breakthrough saturation (from the point $S_w = S_{wc}$, $f_w = 0$ to the point $S_w = S_{wf} = S_{wbt}$, $f_w = f_w|_{S_{wf}} = f_{wbt}$).

At the time of breakthrough and subsequently, the integral of the Buckley-Leverett equation is used in a different manner, to evaluate the effect of increasing the water saturation at the producing end. In this case $x=L$, the length of the core or reservoir structure, which is constant, the following expression is used

$$\frac{W_i}{LA\phi} = \frac{1}{\left. \frac{df_w}{dS_w} \right|_{S_{wc}}} = W_{id} \quad (3.11)$$

where,

W_i is the cumulative water injected $\frac{\sum q_i t_i}{\Delta t}$ and is assumed, as an initial condition to be zero when $t = 0$,

S_{we} is the current value of the water saturation in the producing well, and

W_{id} is dimensionless number of pore volumes (PV) of water injected ($1PV = LA\phi$).

After breakthrough calculation of the oil recovered is somewhat more complex and requires the application of Welge equation in the form

$$\bar{S}_w = S_{we} + (1 - f_{we}) \frac{1}{\left. \frac{df_w}{dS_w} \right|_{S_{we}}} \quad (3.12)$$

or

$$\bar{S}_w = S_{we} + (1 - f_{we}) W_{id} \quad (3.13)$$

where,

$\bar{S}_w$ is the average water saturation behind the front, and

f_{we} is the current value of the fractional flow at the producing end.

Subtracting S_{wc} (the connate water saturation) from both sides of Equation (3.12) gives the oil recovery equation

$$N_{pd} = \bar{S}_w - S_{wc} = (S_{we} - S_{wc}) + (1 - f_{we}) W_{id} \quad (3.14)$$

where the oil recovered, N_{pd} , is in pore volumes.

In practice this equation can be used either directly by determining f_{we} and W_{id} from the fractional flow curve for each chosen value of S_{we} , or in a graphical manner as described by Dake (1978).

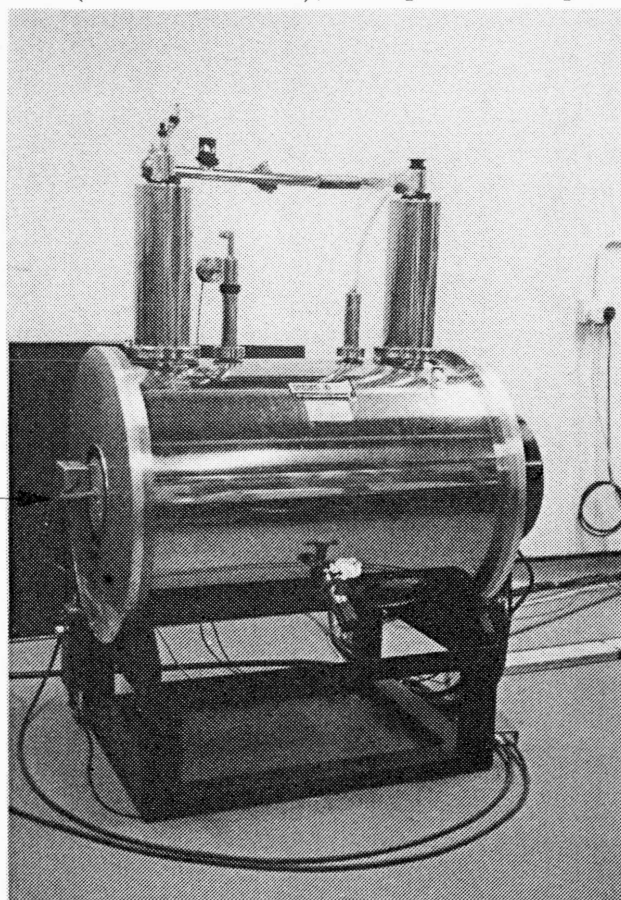
Appendix 4

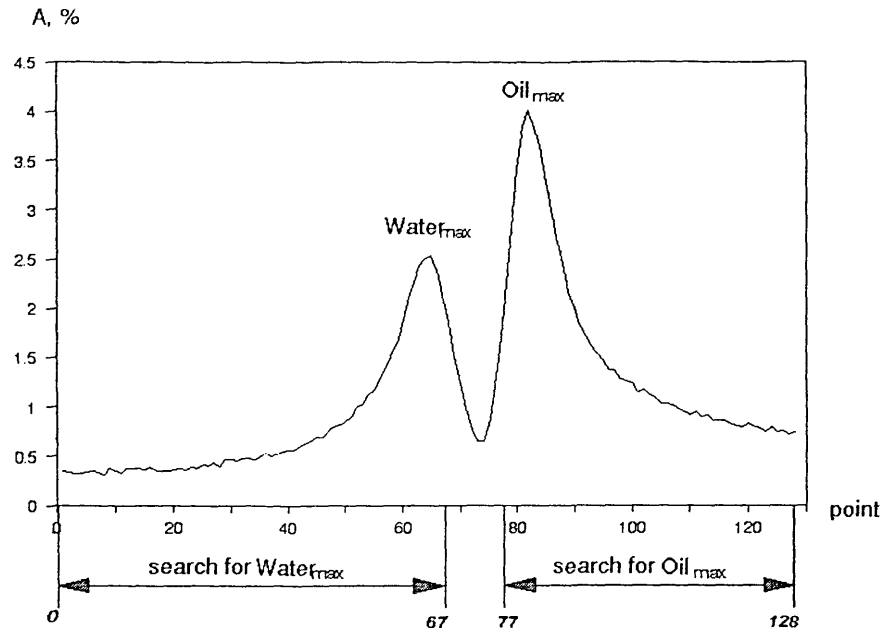
MRI and rock system

A4.1 System Specification

- Magnet :* Oxford Instrument^R Superconducting Magnet at 0.4 T.
The photograph is shown below.
- Shim Set :* Oxford Instruments combined shim and gradient set,
120 mm internal bore diameter, water cooled with
internal Faraday shield.
- Gradient Supply :* Oxford Instrument 2.5 G/cm with 1 ms.
- rf Amplifier :* 1 Kilowatt ENI amplifier.
- Imaging Console :* SMIS MR2000 system with imaging software,
plotter, hard disk and tape streaming facilities.
- rf System :* SMIS MR 2010 system with broad band receiver
noise - 3dB filter, 8 pole Besel pre-selectable 4 ranges
(500Hz - 20KHz); and quadrature phase accuracy of 0.1°.

The rf coil
assembly





Maximum amplitude height for water NMR spectral line is at point 64

Maximum amplitude height for oil NMR spectral line is at point 80

Figure A4.1 Positions of the oil and water spectral lines

A4.2 Optimised Imaging Parameters

<u>Imaging parameter</u>	<u>2-D CSI</u>	<u>1-D CSI</u>
Image dimension	64 x 64	64
Sample rate	$500\mu s \text{ points}^{-1}$	$500\mu s \text{ points}^{-1}$
ADC delay	30 points	30 points
Frequency offset (capture)	250 Hz	250 Hz
Averages	2	4
Filter range (-3db pt)	1000 Hz	1000 Hz
Frequency synthesizer		
phase increment	180°	180°
power	13 dBm	13 dBm
frequency increment	500 Hz (x2)	500 Hz (x2)

A4.3 Mineralogical Analysis of Cores

Rock Sample : 17-4

Type : Carboniferous Sandstone

Grain Size : $\leq 0.2mm$

Clay Minerals : 8%

Quartz : 85%

Alkali Feldspar : 5%

Mica : 2%

Shape : Sub-rounded

Sphericity : Moderate

Maturity : Mineralogically and texturally immature

Rock Sample : 16-5

Type : Upper Carboniferous Sandstone, Millstone Grit Series

Grain Size : 0.1 - 0.3 mm

Matrix : Feldspar (50%)

Quartz : 85%

Microcline Feldspar : 10%

Mica : 5%

Shape : Very irregular

Sphericity : 0.7

Maturity : Mineralogically Submature, texturally immature

Rock Sample : 15-8

Type : Lower Carboniferous Sandstone

Grain Size : 0.2 mm

Quartz : 95%

Feldspar, Clay inclusions, biotite : 5%

Cement : Calcite (35%), with some chert

Shape : Angular to sub-angular

Sphericity : Poor

Maturity : Mineralogically mature, texturally submature to mature

Rock sample : 1-0
Type : Oelian sandstone
Grain size : 0.2 mm
Quartz : 91%
Feldspar: 5%
Clay minerals : trace
Shape : sub-rounded - rounded
Sphericity : Poor
Maturity : Mineralogically and texturally mature

Rock sample : 19'-4
Type : Upper Triassic Sandstone
Grain size : 0.5 mm
Clay Minerals : 0
Quartz : 95%
Alkali Feldspar, Calcite : 5%
Shape : Sub-angular - sub-rounded
Sphericity : Poor
Maturity : Mineralogically mature, texturally submature

Rock sample : 18-1
Type : Lower Permian, Magnesium Limestone series, Dolomite Sandstone
Grain size : 0.5 mm
Quartz : 93%
Clay minerals : 5%
Alkali Feldspar : 2%
Shape : Sub-rounded
Sphericity : Poor
Maturity : Mineralogically and texturally submature

Rock sample : 21"-5
Type : Portland limestone
CaCO₃ : 97%
Kaolinite : 2%
Calcite : trace

Rock sample : 18-2

Type :

Grain size : Lower Permian "Penrith"

Quartz : 95%

Clay minerals : 0

Shape : Sub-rounded - rounded

Sphericity : Poor

Maturity : Mineralogically and texturally submature

Rock sample : 1-1

Grain size : 0.2 mm

Quartz : 95%

Clay minerals : 0

Shape : Sub-rounded - rounded

Sphericity : Poor

A4.4 Core Holders

1. Core holders made with heat shrink tubing

This type of flow assembly had 1" diameter end platens with alternatives of either $\frac{1}{16}$ " or $\frac{1}{8}$ " outer diameter (od) flexible pipe fittings machined from PEEK^R (ITR Limited). PEEK is a highly inert, chemical and heat resistant polymer. The sleeve was a dual-wall heat shrink tubing, the outer material providing rigidity to the platens and core assembly when heat shrunk, assisted by the inner adhesive melt liner. The melt liner was compatible with aliphatic hydrocarbons and did not penetrate the core. Imaging indicated that prolonged contact of the melt liner with oil caused the liner to lose its adhesiveness. Flow therefore, would bypass and flow between the sample and sleeve. However, this flow rig was easy to make locally (about 5 min.) and cheaply too, and the sample was easy to recover from the sleeve to be reused. This is the type of flow assembly used with the bead packs.

2. Core holders made by Coating

Another type of flow rig used was made by first coating the sample on all but the inlet and outlet faces with Araldite^R in order to create no flow surfaces. The end platens were installed on both faces and then sleeved. This was the standard technique used in the Department of Energy in Winfrith. These flow assemblies were designed for work at ambient conditions, and to withstand differential pressures of a few psia. This type of assembly could only be used for one sequence of experimentation (not re-useable).

3. The multipurpose core holder

This flow cell, custom-built by ITR, was predominantly used in the flow imaging experiments. As shown schematically in Figure A4.4.1, a confining pressure up to 100 psi could be provided with heavy water or gas in the annulus between the rubber sleeved core sample and the wall of the solid casing. All materials used in its construction were non-magnetic, and heavy water or gas were used because they produce no measurable ¹H NMR signal.

4. Core holders made with perspex material

Figure A4.4.2 illustrates this type of core holders. The core with distributors at the end faces was cast with molten perspex material. The inlet and outflow ends were threaded to permit flexible pipe fittings.

In all four types of flow assembly flexible plastic flow tubing and fittings were used to connect the inlet end of the assembly to a PERFUSOR^R pump and the outlet end to a pipette outside the magnet. A pressure transducer was also connected across the assembly using flexible tubing at a three-way fitting and valve unit on each side of the core. Both pump and transducer were kept outside the zone of influence of the superconducting magnet.

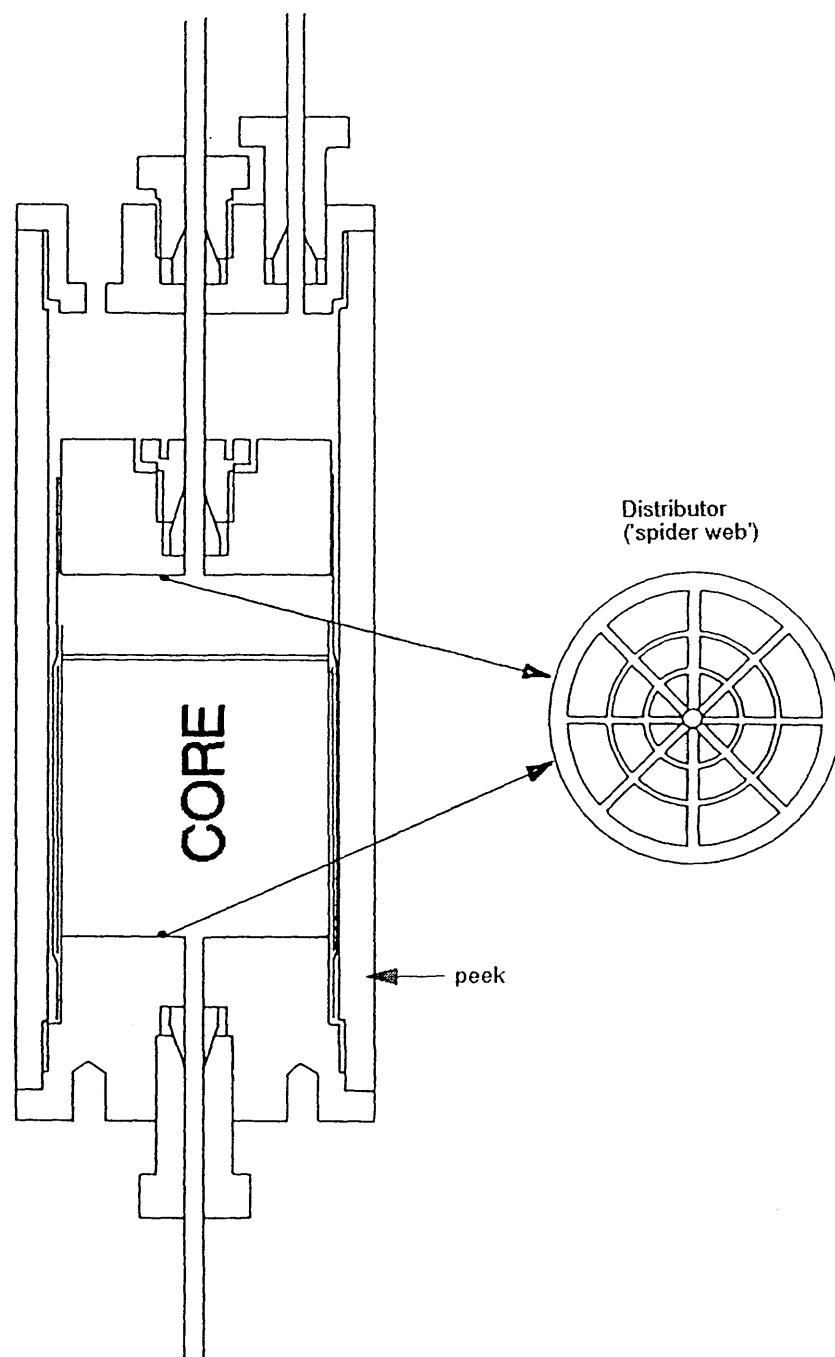


Figure A 4.4.1 The multipurpose core holder

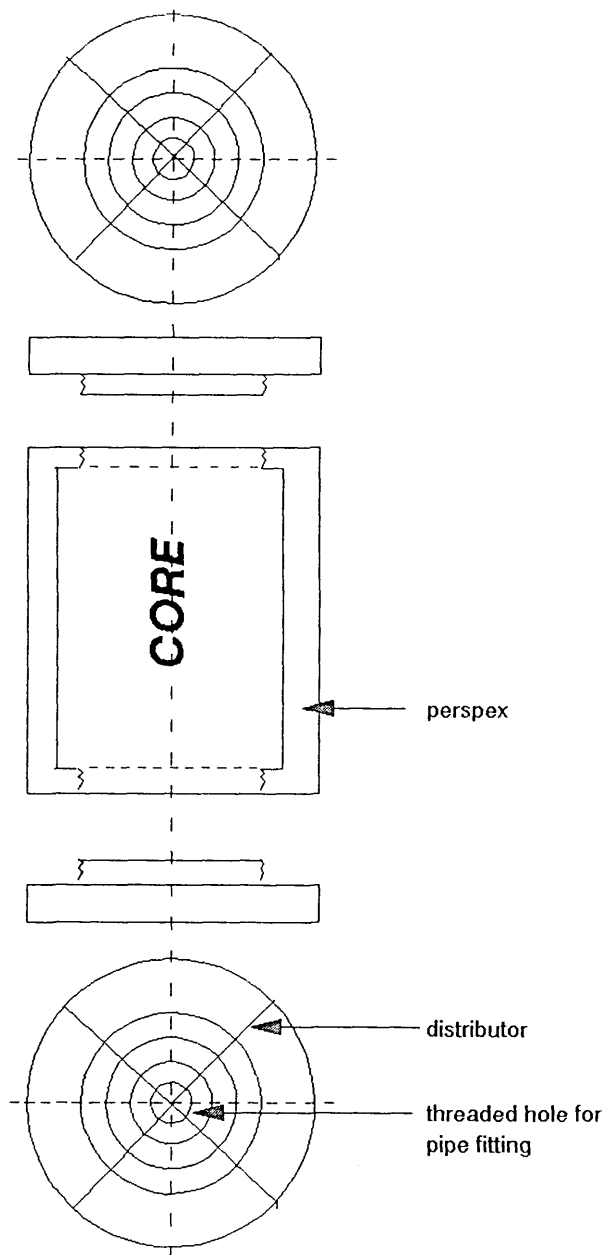


Figure A4.4.2 Core holder made with perspex

Appendix 5.1

Extrapolating Signal ($t_e = 40$ ms to $t_e = 0$)

The oil and water NMR lines were fitted with Gaussian weighted Lorentzian lineshapes with optimal $T_2^* = 18$ ms and then integrated to obtain the oil and water distributions. The peak heights of the oil and the water lines were measured for each spectrum. The bulk T_2 decay properties of the fluids in the core were determined using a non-selective $90^\circ - 180^\circ$ sequence and recording the Fourier transform of the signals at various echo times. The T_2 values were 50 ms for the decane and as well as for the water in the sample. Therefore, the ratio of the oil signal to the water signal at the imaging echo time $t_e = 40$ ms would be the same as the signal ratio at $t_e = 0$ (Figure A5.1). The ratio of the proton densities (i.e. mass of protons per cm^3 of fluid) for water H_2O and n-decane $C_{10}H_{22}$ is about unity. T_1 for each fluid was measured at 100% single-phase saturation of the fluid in a plug taken from an adjacent end of the core plug. These were $T_1 = 177$ ms for the water and $T_1 = 883$ ms for the n-decane.

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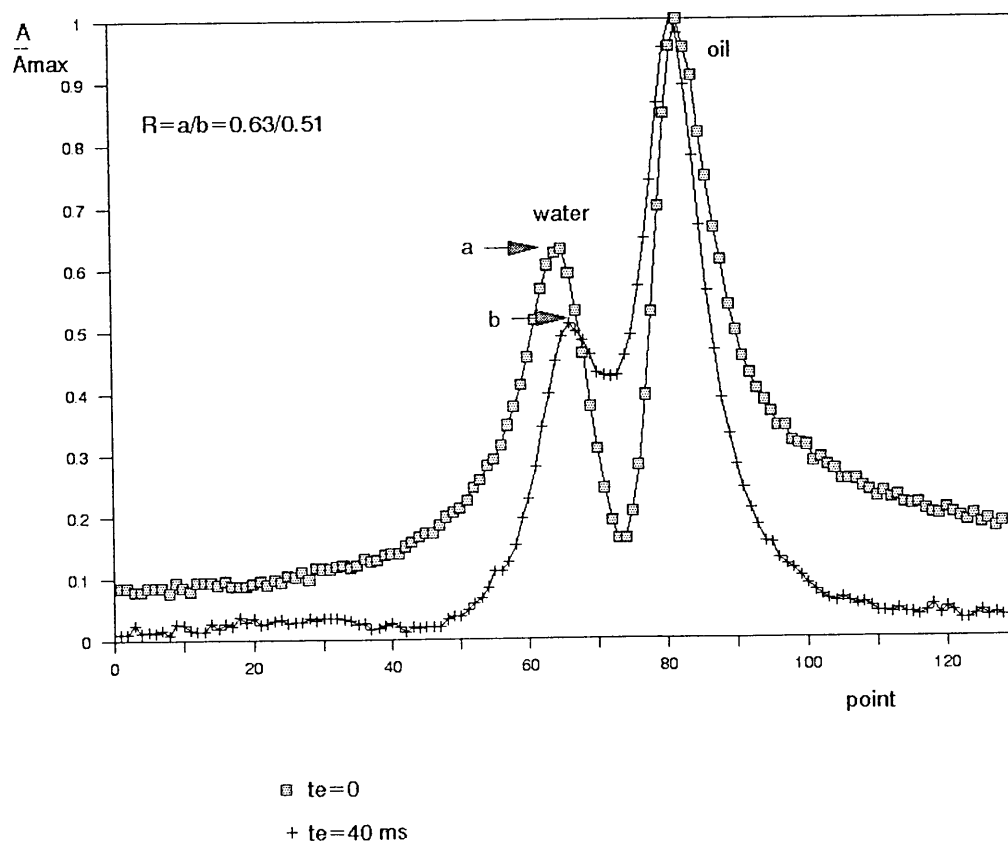
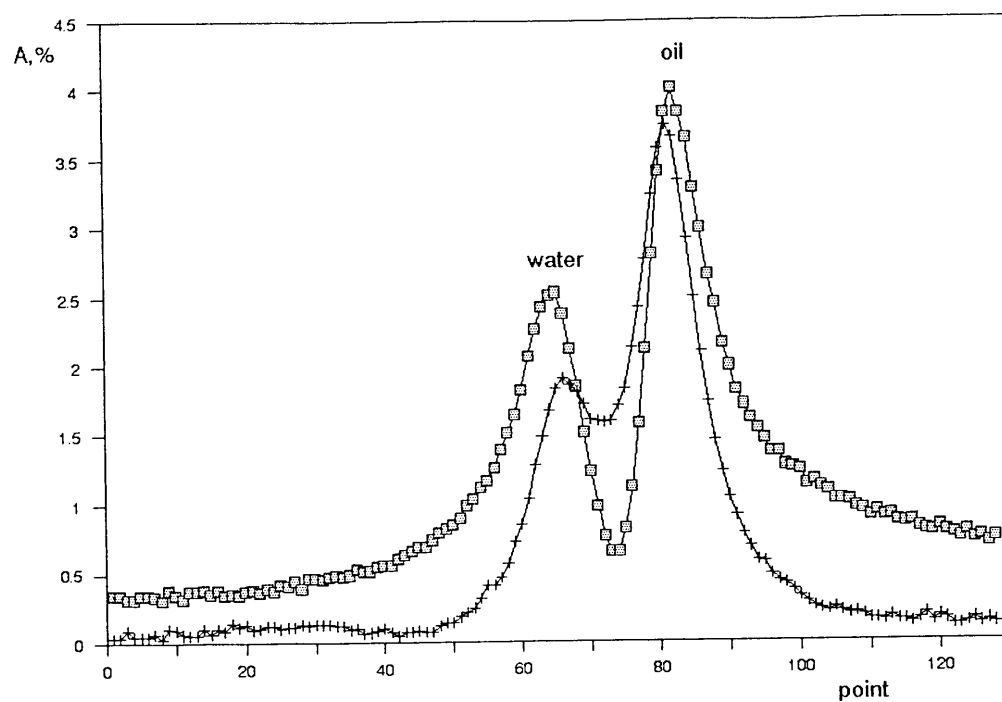


Figure A5.1 Determination of absolute NMR signal ratio

Appendix 6

Calculation of $\frac{\partial p_c}{\partial x}$

The capillary pressure gradient was calculated as follows:

At a given saturation on the saturation profile, the saturation gradient is measured or calculated from the equation of the curve

$$\frac{\partial S_w}{\partial x} = -0.1845 + 0.094x$$

where x is the position along the length of the core where the S_w exists. For example, $S_w = 0.57$ on profile '1' in Figure 7.4 exists at $x = 1.13$ cm from the inlet end of the core plug, hence

$$\frac{\partial S_w}{\partial x} = -0.08 \text{ cm}^{-1}$$

At the same saturation on the capillary pressure curve, the gradient $\frac{dp_c}{dS_w}$ is measured or calculated from the equation of the curve

$$\frac{dp_c}{dS_w} = 35.16S_w - 37.37 = -17.3 \text{ psi } (-1.18 \text{ atm})$$

Then the capillary pressure gradient was calculated as

$$\left. \frac{\partial p_c}{\partial x} \right|_{S_w=0.57} = \frac{dp_c}{dS_w} \cdot \frac{\partial S_w}{\partial x} = (-0.08) * (-1.18) = 0.09 \text{ atm/cm}$$

Appendix 7

Defining f_w curve from measured saturation profile

The saturation profile numbered '1' in Figure 7.4 of Chapter 7 represents a plot from the following equation (from Buckley and Leverett, 1942)

$$x_{S_w} = \frac{W_i}{A\phi} \frac{\partial f_w}{\partial S_w} \Big|_{S_w}$$

The saturation profile is used to define the fractional flow curve as follows:

- (1) For a given saturation $S_{wf} < S_w < 1 - S_{or}$ calculate

$$\frac{\partial f_w}{\partial S_w} \Big|_{S_w} = \frac{A\phi x_{S_w}}{W_i}$$

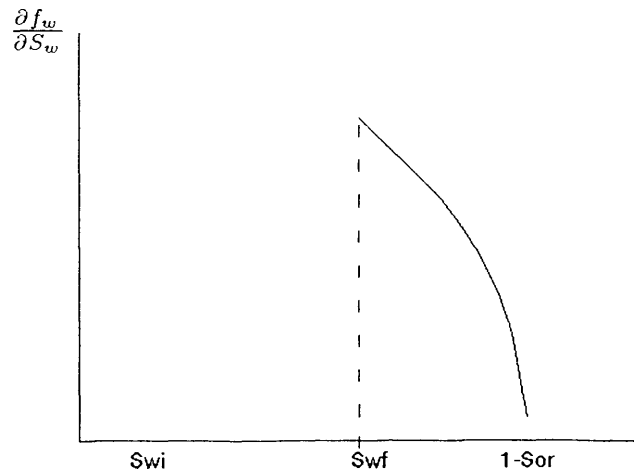
For example, for $S_w = 0.57$ at $x_{S_w} = 1.13$ cm, $W_i = 0.44 \text{ cm}^3$, $A = 4.67$ cm and $\phi = 0.15$,

$$\frac{\partial f_w}{\partial S_w} \Big|_{S_w} = 1.8$$

For the frontal saturation $S_{wf} = 0.54$ at $x_{S_{wf}} = 1.79$ cm

$$\frac{\partial f_w}{\partial S_w} \Big|_{S_{wf}} = 2.85$$

This calculation provides the plot of $\frac{\partial f_w}{\partial S_w}$ versus S_w for saturations greater than the frontal saturation as illustrated below



(2) Use Welge's equation (Welge, 1952) obtained by direct integration of the saturation profile to define the f_w for $S_{wf} \leq S_w \leq 1 - S_{or}$ corresponding to $f_w|_{S_{wf}} \leq f_w \leq 1$.

$$f_w|_{S_{wf}} = 1 - (\bar{S}_w - S_{wf}) \left. \frac{\partial f_w}{\partial S_w} \right|_{S_{wf}}$$

For $S_w = S_{wf} = 0.54$, $\bar{S}_w = 0.58$

$$f_w|_{S_{wf}} = 1 - (0.58 - 0.54) \times 2.85 = 0.89$$

The values calculated in this way were used to plot the fractional flow curve shown in Figure 7.5 in Chapter 7.

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