1 of 2

Design and Construction of an Experiment for Two-Phase Flow
in Fractured Porous Media

SUPRI TR 95

By
Rafel E.G. Ayala
Khalid Aziz

August 1993

Work Performed Under Contract No. DE-FG22-93BC14899

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Thomas B. Reid, Project Manager
Bartlesville Project Office
P. O. Box 1398
Bartlesville, OK 74005

Prepared by
Stanford University
Petroleum Research Institute
Stanford, CA 94305-4042

MASTER

ep

Acknowledgements

The authors are grateful for the financial support from the Department of Petroleum Engineering of Stanford University, the SUPRI Industrial Associates and DOE through contract No. DE-FG22-93BC14899.

Abstract

In numerical reservoir simulation naturally fractured reservoirs are commonly divided into matrix and fracture systems. The high permeability fractures are usually entirely responsible for flow between blocks and flow to the wells. The flow in these fractures is modeled using Darcy's law and its extension to multiphase flow by means of relative permeabilities. The influence and measurement of fracture relative permeability for two-phase flow in fractured porous media have not been studied extensively, and the few works presented in the literature are contradictory.

Experimental and numerical work on two-phase flow in fractured porous media has been initiated. An apparatus for monitoring this type of flow was designed and constructed. It consists of an artificially fractured core inside an epoxy core holder, detailed pressure and effluent monitoring, saturation measurements by means of a CT-scanner and a computerized data acquisition system. The complete apparatus was assembled and tested at conditions similar to the conditions expected for the two-phase flow experiments.

Fine grid simulations of the experimental setup were performed in order to establish experimental conditions and to study the effects of several key variables. These variables include fracture relative permeability and fracture capillary pressure. The numerical computations show that the flow is dominated by capillary imbibition, and that fracture relative permeabilities have only a minor influence. High oil recoveries without water production are achieved due to effective water imbibition from the fracture to the matrix. When imbibition is absent, fracture relative permeabilities affect the flow behavior at early production times.

Contents

Acknowledgements	iii
Abstract	v
Table of Contents	vii
List of Tables	xi
List of Figures	xiii
1 Introduction	1
2 Literature Survey	3
3 Description of Apparatus	6
3.1 Fluid Injection	6
3.2 Pressure Measurement	9
3.2.1 System Description	9
3.2.2 Calibration	10
3.3 Effluent Handling	12
3.4 Data Acquisition System	15
3.4.1 Hardware	15
3.4.2 Software	16
3.5 Saturation Measurement	18
3.6 Cores and Core Holders	19

4	Experimental Accomplishments	23
4.1	Rock Characterization	23
4.1.1	Petrographic Description	23
4.1.2	Porosity	24
4.1.3	Absolute Permeability	24
4.1.4	Capillary Pressure	27
4.2	Properties of Fluids	29
4.3	Preliminary Results	31
4.3.1	Core Preparation	31
4.3.2	Hardware and Software Testing	32
4.3.3	CT-Scanner Measurements	35
5	Simulation Results	41
5.1	Base Case Simulation	41
5.1.1	Base Case Properties	41
5.1.2	Grid Size	43
5.1.3	Boundary Conditions	45
5.2	Design of Experiment	50
5.2.1	Injection Flow Rate	50
5.2.2	Simultaneous Oil and Water Injection	51
5.2.3	Oil to Water Viscosity Ratio	51
5.2.4	Fracture Aperture	51
5.2.5	Fracture Orientation	57
5.3	Sensitivity Analysis	57
5.3.1	Capillary Pressure	57
5.3.2	Wettability Effects	61
5.3.3	Fracture Relative Permeability	65
5.3.4	Homogeneous vs. Fractured Porous Media	72
6	Summary of Results and Recommendations	81
A	Nomenclature	83

B List of Equipment	85
C Transducer Calibration	87
D Data Logging Program	89
E CT-Scanner Measurements	102
Bibliography	105

List of Tables

4.1	Boise sandstone porosity calculation.	26
4.2	Boise sandstone permeability calculation.	26
4.3	Measured Boise sandstone drainage and imbibition capillary pressure.	28
4.4	Cyclohexane Properties.	30
4.5	CT-scanner conditions.	32
4.6	Absolute permeability test (core #1).	35
5.1	Base case simulation data.	42
5.2	Matrix relative permeability calculated from imbibition capillary pressure.	43
5.3	Capillarity to gravity number ratio for some numerical simulations.	60
5.4	Intrinsic contact angle for capillary pressure curves selected.	65
E.1	Dry scans of core #1, code C1AIR01.	103
E.2	Dry scans of core #2, code C2AIR02.	103
E.3	NaI solution saturated scans of core #1, codes C1NAI01 and C1NAI02.	104
E.4	NaI solution saturated scans of core #2, codes C2NAI01.	104

List of Figures

3.1	Experimental apparatus.	7
3.2	Fluid injection system.	8
3.3	Pressure measurement system.	10
3.4	Calibration system.	11
3.5	Effluent handling system. From Wang (1986).	13
3.6	Forces acting on the confining cup.	14
3.7	Data logging program flow chart.	17
4.1	Boise sandstone photomicrograph. From Sanyal (1972).	25
4.2	Boise sandstone drainage capillary pressure curve.	29
4.3	Calibration test of one psi range pressure transducers. Pressure readings of one and zero psi are correctly determined.	33
4.4	Absolute permeability test of core #1. Pressure drop data.	34
4.5	Core #1 CT-scans. Top figure is for incomplete saturation, and bottom figure is for complete saturation.	36
4.6	Fracture definition of Core #2 using CT-scanner. Top figure is for air saturated core, and bottom figure is for NaI solution saturated core.	37
4.7	Missing mass for a fracture filled with different fluids. a) air, b) NaI solution, c) oil and d) oil and NaI solution.	40
5.1	Boise sandstone imbibition capillary pressure. After Sanyal (1972).	44
5.2	Boise sandstone relative permeabilities calculated from capillary pressure data.	45
5.3	X-Z cross section of the grid used in the numerical simulations.	46

5.4	Selection of simulation dimensionality. 3-D vs. 2-D grid.	47
5.5	Selection of simulation grid size. Fine 48x1x19 vs. coarser 13x1x18 grid.	48
5.6	Comparison of boundary conditions. Case A: injection/production only in fracture blocks, Case B: injection/production in all boundary blocks (matrix and fracture).	49
5.7	Comparison of the effect of different injection flow rates on water cut.	52
5.8	Water saturation profiles. Note that the fracture in the middle has lower water saturation.	53
5.9	Time to reach steady state with simultaneous oil and water injection at experimental conditions (oil recovery).	54
5.10	Time to reach steady state with simultaneous oil and water injection at experimental conditions (water cut).	55
5.11	Effect of viscosity ratio on water cut at experimental conditions.	56
5.12	Effect of fracture aperture on water cut.	58
5.13	Effect of fracture orientation on water cut.	59
5.14	Effect of matrix/fracture capillary pressure on oil recovery.	62
5.15	Effect of matrix/fracture capillary pressure on water cut.	63
5.16	Normalized capillary pressure curves for different wettabilities.	64
5.17	Effect of wettability on water cut.	66
5.18	Capillary pressure curves used to show the effect of dP_c/dS_w	67
5.19	Effect of the slope of the capillary pressure curve on water cut.	68
5.20	Fracture relative permeabilities, cases I to IV.	69
5.21	Effect of fracture relative permeabilities on water cut, $q_w = 1 \text{ cm}^3/\text{min}$	70
5.22	Effect of fracture relative permeabilities on water cut, $q_w = 10 \text{ cm}^3/\text{min}$	71
5.23	Effect of fracture relative permeabilities on water cut, wettability case #1.	73
5.24	Effect of fracture relative permeabilities on water cut, wettability case #2.	74
5.25	Effect of fracture relative permeabilities on water cut, wettability case #3.	75

5.26	Effect of fracture relative permeabilities on water cut, wettability case #4.	76
5.27	Effect of fracture relative permeabilities on water cut, no imbibition present.	77
5.28	Water cut for a fractured and a homogeneous core, $q_w = 1 \text{ cm}^3/\text{min}$	78
5.29	Water cut for a fractured and a homogeneous core, $q_w = 10 \text{ cm}^3/\text{min}$	79
5.30	Water cut for a fractured and a homogeneous core, $q_w = 20 \text{ cm}^3/\text{min}$	80

Section 1

Introduction

Multiphase flow in naturally fractured reservoirs, and specifically in the fractures, is modeled using similar equations to those used in multiphase flow in porous media. That is using Darcy's law and relative permeabilities. Relative permeability is one of the most important factors in multiphase flow in porous media. The present study deals with multiphase flow in fractured porous media, emphasizing the role of fracture relative permeabilities on displacement.

Numerical simulation of naturally fractured reservoirs commonly assumes that flow between blocks is present only through the fractures (double porosity, single permeability simulators). The flow of a given phase is then directly proportional to its relative permeability in the fracture. The amount of research focused in fracture relative permeability is sparse and contradictory. As a consequence, little is known about the effect of this parameter on the overall flow and the way to estimate its value as a function of saturation.

The proposed method of research was to design and build an apparatus to monitor two-phase flow in a core with a fracture where pressure, saturation and flow rates are carefully measured. Fine grid simulation would be used to history match the experimental results. In order to have a fair estimate of fracture relative permeability, the rest of the rock and flow properties need to be well established. An unfractured core, similar to the fractured core, would also be used in the experiments. The same matrix rock would be used in both sets of experiments, and the effect of the fracture

SECTION 1. INTRODUCTION

would be isolated if the matrix influence is known. Single phase flow experiments were performed, but difficulties with the equipment precluded the two-phase flow experiments. These difficulties are described in Section 4.

Section 3 gives a detailed description of the apparatus and its operation. Section 4 describes the work done on matrix characterization, fluids selection and apparatus testing. Section 4 also presents the state of the experimental work, serving as a background and guide for the next steps in this continuing research. Section 5 describes several numerical experiments used to plan the experiments. Apparatus modifications and adjustments were done according to conditions predicted by results of the numerical simulations. The simulations of Section 5 also suggest what variables are of major significance and should be carefully studied during the experiments.

The report finishes with a summary of results. It also lists some of the recommendations for future work, but the entire report could be regarded as a first step in a series of research activities aimed at understanding and modeling multiphase flow in fractured reservoirs.

Section 2

Literature Survey

The following literature survey briefly discusses some of the most relevant papers related to this research. It does not follow a chronological order, but it is organized in groups of related topics.

Jones, Wooten and Kaluza (1988) performed experiments with single phase flow through rough-walled fractures with apertures between 50 to 650 μm . They found that for large fracture apertures, the cubic law equation (Whiterspoon et al. (1980)) can be used to calculate absolute permeability and to characterize single phase flow. Considerable deviation from the cubic law was found for smaller apertures and rough-walled fractures. The behavior observed for these fractures approached that of a porous media. It is expected that narrow and rough-walled fractures will also give fracture relative permeabilities similar to those for porous media.

Romm (1966) presented two-phase flow experiments in smooth vertical parallel plates. Fracture apertures ranged from 65 to 125 μm . Water and kerosene were used as the two phases, and the saturation was calculated from resistivity measurements. His results show that fracture relative permeability is equal to the phase saturation, i.e., straight line relationship between relative permeability and saturation. Romm (1966) explained that the reason for straight line relative permeabilities is the wide aperture of the fractures as opposed to narrow pore throats. He realized that the results could not be applied to flow in fractured media where a system of interconnected fractures is present. Also as shown by Jones, Wooten and Kaluza (1988), natural

SECTION 2. LITERATURE SURVEY

rough-walled fractures give different behavior from smooth parallel plates, even for single phase flow.

Merrill (1975) performed several two-phase flow experiments in horizontal fractures. Brine and either n-heptane, n-decane, n-tetradecane, kerosene or a silicon oil were used. Glass plates with separations from 30 to 100 μm , and artificially fractured rocks with fracture apertures from 10 to 75 μm were studied. After pressure and rate measurements, the oil saturation was determined by displacing it with water and measuring the volume. Relative permeability could not be directly correlated with saturation.

Kazemi and Merrill (1979) matched two-phase flow experiments using a single porosity simulator. The experiments are similar to those of Merrill (1975). Straight line relative permeabilities and a "small" capillary pressure were used for the fracture. The main matching parameter was matrix capillary pressure. The final matrix capillary pressure after history matching was very close to the one measured in the same matrix using a centrifuge. The effect of fracture relative permeability was not included. The assumed fracture capillary pressure could have had a strong effect on the matching procedure, but it was not discussed.

Kazemi and Merrill (1979) also observed that at low flow rates imbibition causes water to flow faster in the matrix than in the fracture. At high rates the water in the fracture flows faster. This observation was also made in our study and will be discussed later.

Fracture flow visualization has been another area of research. Lowry and Kawaji (1988) used transparent smooth plates to observe air and water flow. Plates separation ranged between 0.5 to 2 mm . Four different flow patterns were observed: plug, churn, bubbly and annular flow. Persoff, Pruess and Myer (1991) presented flow visualization experiments made on epoxy replicas of natural rough-walled fractures. This experiment is closer to flow in a real but isolated fracture. No steady-state phase distribution inside the fracture was obtained. Preliminary results of fracture relative permeability suggested considerable deviation from straight line behavior.

Estimation of relative permeabilities for naturally fractured reservoirs from field

performance has also been suggested. Owusu and Ershaghi (1989) estimated relative permeabilities for a "composite homogeneous system" through history matching techniques. History matching techniques are more useful when there is a sound understanding of the process being modeled, and the value and influence of most of the variables is known. The accuracy and certainty of the predictions obtained from a simulator decrease, as we increase the number of unknown variables, and as the understanding of the process is decreased.

Tsang and Tsang (1987) proposed a different mathematical model for flow in fractures. They represented the fluid flow in fractures as a limited number of tortuous and intersecting channels. Calculated tracer breakthrough curves agree in shape to some curves observed experimentally. Transfer of fluids between matrix and fracture and the adaptability of new fracture equations to existing single porosity simulators is not an easy task. On the other hand, the use of Darcy's law to model fracture flow is easy to implement in existing simulators, but physical reasons behind its usage are not clear.

A recent study by Johns et al. (1991) presented a method to measure aperture of natural fractures using computer aided tomography (CAT-scanner). This method is suggested as a way to characterize fractures, and may be extended to measure saturations inside the fracture.

Kazemi (1990) states that fracture relative permeabilities are not well understood. This statement is verified by the preceding discussion. Kazemi (1990) also affirms that the future numerical simulation of naturally fractured reservoirs will include "finer-grid simulation and rigorous physics of flow". In order to achieve this rigorous numerical representation, experimental research on the physics of flow is one of the tasks to be done.

Section 3

Description of Apparatus

An apparatus was design to monitor pressure, flow rates and saturation of a rectangular core during steady state two-phase flow experiments. The experiments were performed at room temperature and low pressure. The steady state was achieved by injecting the fluids at a constant rate while maintaining constant outlet pressure by means of a back pressure regulator.

Figure 3.1 shows a schematic of the experiment equipment. Appendix B lists the specifications and distributors of the main parts used to build the apparatus. The equipment consists of the following main parts: two constant rate pumps, six pressure transducers and six signal carriers or demodulators used to measure pressure drop between different points in the core, a data acquisition system, two balances to measure flow rates and a CT-Scanner (Computer Aided Tomography) to measure fluid saturations. A more detailed description of each component is given in the following sections.

3.1 Fluid Injection

Figure 3.2 shows the injection system for one of the two liquids. The second liquid is injected using a similar system. All the connecting lines are made out of 1/8 inch plastic tubing, with a maximum working pressure of 250 psi.

The fluid is withdrawn from a container and then filtered to prevent equipment

Figure 3.1: Experimental apparatus.

SECTION 3. DESCRIPTION OF APPARATUS

Figure 3.2: Fluid injection system.

plugging and damage. The pumps used are Constametric 3200¹ with the following specifications:

Maximum pressure	6000 psi
Flow rate	0.01 to 9.99 mL/min
Flow accuracy	1.5% @ 5 mL/min, 3000 psi
Flow stability	0.1% of flow rate

The pumps deliver the fluids at specified constant rates. The three-way ball valve in Figure 3.2 directs the flow either to or away from the experiment. The ball valve can be used to isolate the core from the pump. The two fluids are mixed at the tee fitting, and passed through the relief valve that prevents overpressuring the system.

¹LDC analytical, Inc.

In case of high pressure the fluids are directed to a drain. After this relief valve the fluids enter the core being tested. The pressure measurement system will be discussed in the next section.

3.2 Pressure Measurement

Pressure drop is measured between five different positions along the core and the core outlet end. This section describes the equipment involved in these measurements and their calibration.

3.2.1 System Description

Six Celesco DP31 differential pressure transducers are installed as part of the equipment. The transducers employ variable reluctance technology. Interchangeable diaphragms allow differential pressure ranges from 0.1 to 500 psi of full scale.

The deflection of a stainless steel diaphragm causes an imbalance in the reluctance of two magnetic circuits. The deflection, and therefore the imbalance, is linearly related to the differential pressure applied. Each transducer is connected to a carrier-demodulator Celesco CD10D. The demodulator produces a DC signal output proportional to the pressure drop. The DC output signal ranges from -10 to +10 VDC. It is registered by a data logger and interpreted and stored in a computer.

Figure 3.3 shows a schematic of the pressure measuring system. The upstream or positive side of the transducer is connected to the core using brass Swagelok O-seal straight thread connectors. The downstream or negative side of the transducer is connected to the core outlet end. This arrangement permits pressure drop measurement between a point upstream and the production end.

The negative side of pressure transducer # 6 (DPT6 in Figure 3.3) is open to atmospheric pressure. It provides the absolute pressure at the production end, from which all the other absolute pressures can be calculated. The pressure taps shown in Figure 3.3 are spaced every two inches. This is believed to give proper pressure monitoring during an experiment.

SECTION 3. DESCRIPTION OF APPARATUS

Figure 3.3: Pressure measurement system.

3.2.2 Calibration

Before any experiment, it is necessary to calibrate the transducers, demodulators and data acquisition system all together. Figure 3.4 shows a schematic of the calibration setup. This design avoids the removal of any part from the equipment minimizing system failure.

The pressure transducers are calibrated with either a test gauge at higher pressures (between 1 and 30 psi) or a water manometer at lower pressures (between 0 and 1.5 psi). A nitrogen cylinder is the pressure source when the test gauge is used. For low pressures, the water column inside the manometer serves as the pressure source.

Figure 3.4: Calibration system.

SECTION 3. DESCRIPTION OF APPARATUS

There are two 3-way ball valves for each pressure transducer. Valve A (see Figure 3.4) is connected to either the calibration line or to the pressure tap for measurements during an experiment. Valve B is connected to valve A or to a loop that applies a zero pressure drop on the transducer.

The calibration procedure is listed in Appendix C.

3.3 Effluent Handling

Figure 3.5 shows the automatic cumulative production measuring system. To the best of the author's knowledge, it was first used by Wang (1986). Wang (1986) states that the design was suggested by a Conoco representative at the 1983 SUPRI advisory committee meeting. The next description of the production measurement system partially follows that of Wang (1986).

Production pipe (7) in Figure 3.5 carries oil and water. The oil is separated and held inside confining cup (4). Water overflows through siphon (2) and is collected and measured in balance (9). The change in the buoyancy force applied on the confining cup (4) is measured by means of balance (10). This change reflects the variation of total oil accumulated inside confining cup (4).

The change of cumulative production of oil and water with time ($\frac{dQ_o}{dt}$ and $\frac{dQ_w}{dt}$) are the oil and water production rates. At steady state conditions, they have to equal the injection rates.

Applying a force balance on the confining cup we have (forces are sketched in Figure 3.6):

$$T + p_2 A = W + p_1 A, \quad (3.1)$$

where T is the tension on the cord holding the cup (balance (10) reading), W is the weight of the cup, A is the area on which p_1 and p_2 are applied. The difference in pressures is given by:

$$p_1 - p_2 = (\gamma_w - \gamma_o)h. \quad (3.2)$$

Figure 3.5: Effluent handling system. From Wang (1986).

SECTION 3. DESCRIPTION OF APPARATUS

Figure 3.6: Forces acting on the confining cup.

Substituting Equation 3.2 into Equation 3.1 and knowing that $Q_o = hA$, we can measure oil cumulative production using:

$$Q_o = \frac{W - T}{\gamma_w - \gamma_o}. \quad (3.3)$$

Balance (9) measures total production from which cumulative water production can be calculated ($Q_w = Q_T - Q_o$). Flow rates can be calculated using numerical differentiation as follows:

$$q_j = \frac{Q_j^n - Q_j^{n-1}}{t^n - t^{n-1}}, \quad (3.4)$$

where j is either oil or water, n and $n-1$ are time steps. Water fractional flow can be calculated using:

$$f_w = \frac{q_w}{q_o + q_w}. \quad (3.5)$$

The data acquisition system performs all the calculations and stores the information as shown next.

3.4 Data Acquisition System

This discussion was divided in two parts. The first one deals with the equipment and different connections. The second part deals with a computer program used to gather the data and handle the information.

3.4.1 Hardware

The data acquisition system is made up of two main parts. A personal computer (PC) that serves as a controller and provides data storage, and a Hewlett-Packard HP 3497A data logger.

On a command from the controller, the data logger reads the voltage signal from the demodulators and transfers the information back to the computer. A total of six channels are used (0 to 5), one for each transducer. The data logger takes ten readings per trigger from each channel, that is from each transducer.

The connections between the demodulators, data logger and computer are as follows:

Transducer	Demodulator	Serial Cable	Data Logger
DPT	Number	Pin Numbers	Analog Channel
1	1	1,14	0
2	2	2,15	1
3	3	3,16	2
4	4	4,17	3
5	5	5,18	4
6	6	6,19	5

SECTION 3. DESCRIPTION OF APPARATUS

The two balances are connected directly to the computer using parallel ports com1 and com2.

3.4.2 Software

A BASIC program was written to control the gathering, processing, storing and display of data. Pressure drop from the six transducers and flow rates from the balances constitute the data handled by the computer program. The flow chart shown in Figure 3.7 presents the program organization.

The computer code is listed on Appendix D. A brief description of the functions of each subroutine is given next.

- Data logger initialization.
 1. Identify data logger type.
 2. Start time controller.
 3. Set initial conditions.
- Read initial data.
 1. Run identification.
 2. Name of output file.
 3. Experiment date.
 4. Oil and water flow rates.
 5. Time interval between readings.
 6. Assign values to voltage to pressure conversion constants.
- Time control. Call subroutines to read data accordingly with time intervals between readings.
- Balance reading.
 1. Read weight from each balance.

Figure 3.7: Data logging program flow chart.

SECTION 3. DESCRIPTION OF APPARATUS

2. Calculate flow rates and water fractional flow.

- Pressure reading.
 1. Take ten readings per trigger per channel.
 2. Take average of the ten readings.
 3. Calculate pressure drop in psi.
- Display and store information.

3.5 Saturation Measurement

The SUPRI CT-Scanner is used to measure saturation at different positions along the core. It consists of an EMI 5005 second generation scanner, two DATA general ECLIPSE 200 computers and several other computers for data handling and storage, (Castanier, 1989).

Computerized tomography measures linear attenuation coefficients α , with a cross sectional resolution smaller than 1 mm^2 , and differences in α as low as 0.1%. In order to calculate saturations during two-phase flow experiments, the linear attenuation coefficient of the porous media saturated with each fluid is needed (α_1 and α_2). Once α_1 and α_2 are known, the following equations are used to calculate fluid saturations S_1 and S_2 (Withjack, 1988):

$$\alpha = \alpha_1 S_1 + \alpha_2 S_2, \quad (3.6)$$

$$1 = S_1 + S_2, \quad (3.7)$$

where α is the linear attenuation coefficient of the porous medium containing both fluids. Saturation is calculated from the CT-number obtained for each pixel and from reference runs with the two saturating fluids.

A method for determining fracture saturation is discussed in Section 4.3.3.

3.6 Cores and Core Holders

Two Boise sandstone rectangular cores were prepared for the experiments. Core dimensions were approximately 3x3x12 inches in both cases. An artificial fracture was created in core #2, while core #1 was left intact. The fracture was created by cutting core #2 in half. Teflon tape was used as the spacer and to prevent epoxy from invading the fracture. More information on the sandstone used is found in Section 4.1.

Epoxy is an x-ray transparent material and core holders of this material are recommended by Castanier (1989), when making CT-scanner measurements. Considerable effort was made in selecting the kind of epoxy, and the mixing and casting procedure for the core holders. The following discussion summarizes the epoxies and techniques tried, and problems associated with each one.

Test for compatibility between epoxy, rock, plexiglass and different fluids were performed before using the epoxy. Bonding and imbibition of the epoxy with the rock were checked. While problems were not observed during the short time of the tests, they became apparent with time in real core holders.

Plexiglass plates glued to the cores were used to attached the pressure taps. Holes were drilled and threads were tapped on the plexiglass plates for this purpose. The plexiglass plates were immersed inside the epoxy. No undesirable reaction between epoxy and plexiglass was observed during the preliminary tests mentioned earlier.

The two fluids used during the experiments, NaI solution and cyclohexane, and solvents like isopropal alcohol, did not show any negative effects on either the plexiglass or the epoxy.

Different epoxies and casting techniques used are listed next:

1. Evercoat model 552 marine resin was the first epoxy tried. The epoxy is prepared by mixing 40 cm^3 of hardener per gallon of resin and then cured at room temperature. First an epoxy layer was applied with a brush and then the plexiglass plate was attached. The core was then cast one side at a time. Some curing problems were observed after casting a core with this epoxy, but the end product appeared to be of good quality. However the epoxy kept curing and three days after casting the core broke.

SECTION 3. DESCRIPTION OF APPARATUS

The same epoxy was tried again, but this time the whole core was cast at the same time. It was believed that uneven epoxy application had caused the fracturing of the core. The same problems were experienced this second time and the epoxy was discarded. It is believed that thermal contraction of the epoxy causes strong stresses on the rock and finally breaks it.

2. Two new epoxies, with similar properties to the first epoxy, were tried. Evercoat model 561 laminating resin and hardener, and Tap Plastics general purpose epoxy resin and hardener. The hardener mixed with the epoxy resin is a catalyst that creates an exothermic reaction. The heat thus generated reduces the curing time to only a few hours. Common pigments used in conjunction with the epoxy reduce the action of the catalyst. That is, they dissipate the heat generated by the exothermic reaction. A red color pigment (Tap Plastics) was used to help in dissipating the heat and preventing the cracks described in the previous item. Sand was also added to the mixture to increase epoxy strength. As a result of these tests, the Tap Plastics epoxy was selected and used to cast the two cores used in the experiments described in Section 4. The core was cast using the procedure mentioned in item 1.

Pressure taps were connected and end plates were attached. The inlet and outlet plates were made out of plexiglass and had small grooves in a spider-wed pattern. Plexiglass rods going from the inlet to the outlet of the core hold the two end plates in place. Metal rods, with higher strength than the plexiglass rods, were not used because of interference between the X-rays and the metal. The two cores were pressure tested up to 25 psi and no leaks were detected.

After approximately four months of use, the two core holders failed. Separation between the epoxy and the plexiglass plates, and separation between the first thin epoxy layer and the second thick epoxy layer was present. No further experiments were possible.

3. A series of casting procedures were tried in order to establish an appropriate procedure and find the right material to manufacture the core holders. Rectangular 1x1x6 inches Berea sandstone cores were used for these tests. The

following list presents a summary of the different techniques used.

- (a) Evercoat laminating epoxy without sand or dye was used. The epoxy was mixed and the core was immediately immersed in it. Considerable amount of escaping air bubbles were trapped inside the epoxy, leaving a path for fluids leak. The epoxy imbibed nearly 1 mm into the core, providing a good bond. Pressure taps were threaded into the epoxy.
- (b) The same procedure as in item (a) was followed but sand was added to the epoxy mixture. A harder epoxy was obtained, less imbibition and therefore fewer problems with air bubbles were present. Pressure taps were threaded and a pressure of 120 psi applied. The core was cut and separation between the rock and the epoxy was found. Sand addition may have caused the bonding problems observed with cores #1 and #2.
- (c) In order to reduce the air bubbles a third core was cast, this time applying a thin epoxy layer before immersing the core in epoxy. Tap Plastics epoxy was used and the same problems with air bubbles were present. It is believed that not enough time was allowed for the first epoxy layer to dry.
- (d) Tab Plastics epoxy was used with a core that was saturated with water. Good results in terms of bonding and casting were obtained. Also less escaping bubbles (droplets in this case) were present.
- (e) Theramic high temperature epoxy type 450 was also tried. Special curing procedure is involved with this epoxy. It includes mixing the epoxy and hardener at 50 °C, curing for 2 hours at 100 °C and 4 hours at 180 °C. The result is a very hard but brittle epoxy, with good bond to the rock. The core holder obtained is also useful for high temperature experiments. Color change was present in the interior of the rock. It may have been due to temperature changes, or chemical changes caused by fumes from the epoxy. The effects of this color change are not known and should be considered before using the epoxy as the core holder material.

It is not necessary to use a plexiglass plate to attach the pressure taps. Threads

SECTION 3. DESCRIPTION OF APPARATUS

directly in the epoxy can be used, thus avoiding the bonding problems between the epoxy and plexiglass. Leaving the inlet and outlet ends open while casting the core also reduces the air bubble problem. Inlet/outlet plates can be attached after the rest of the core holder is ready. Evercoat Laminating epoxy or Tap Plastics epoxy appear to have good potential if no sand or dye are added.

Section 4

Experimental Accomplishments

This Section summarizes the experimental activities to date. They include rock and fluids characterization, core preparation, testing of flow model and data acquisition system, and CT-scanner measurements. This section will provide the state of the experimental work, difficulties encountered and basis for continuing work this.

4.1 Rock Characterization

The method proposed to estimate fracture relative permeability, requires numerical simulation and history matching of the two-phase flow experiments. In order to limit the number of unknowns and increase accuracy of history matching, a proper characterization of the rock matrix is needed. This section includes a petrographic description of Boise sandstone and measurements of absolute permeability, porosity, and capillary pressure.

Matrix relative permeabilities will be measured using the apparatus described in Section 3.

4.1.1 Petrographic Description

The following petrographic description of Boise sandstone and the photo-micrograph shown in Figure 4.1 are taken from Sanyal (1972).

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

“Coarse-grained, feldspathic sandstone with angular grains; very poor sorting; large, angular feldspar grains in a matrix of small quartz, feldspar and Fe-Ti minerals; loosely cemented; small clay content; approximately 50% quartz, 45% feldspar, 5% clay and opaque minerals; feldspar only slightly kaolinized or leached; small secondary porosity; pore spaces well interconnected.”

Section 4.2 describes observed interactions between the rock and the water phase. Chemical composition of the matrix rock is needed if chemical reactions between rock and fluids are to be explained.

4.1.2 Porosity

A total of eight Boise sandstone core plugs were drilled. Diameter and length were measured using a caliper and then the samples were dried at 110°C for four to five hours. An analytical balance was used to determine the weight of the dry plugs. Vacuum was applied for 24 hours, with a vacuum pressure of 100 μ Torrs. Distilled water was allowed to saturate the samples for 24 hours and the plugs were weighted again. Table 4.1 lists a summary of all these measurements along with porosity calculations using the following formula:

$$\phi = \frac{\text{pore volume}}{\text{bulk volume}} = \frac{\frac{\Delta W}{\rho_w}}{\pi r^2 h} \quad (4.1)$$

An average value of 0.254 was selected as the representative porosity. Chatzis and Morrow (1984) reported a porosity of 0.253 for Boise sandstone, which is in close agreement with the porosity measured in the present work.

4.1.3 Absolute Permeability

Absolute permeability was measured on samples H2 and V1 using a RUSKA liquid permeameter and distilled water as the fluid. Table 4.2 shows the calculations. Permeability was calculated using Darcy's law:

Figure 4.1: Boise sandstone photomicrograph. From Sanyal (1972).

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Table 4.1: Boise sandstone porosity calculation.

Sample	d in cm	l in cm	V bulk in cm^3	ΔW gr	ϕ
V1	2.004	3.703	11.682	2.954	0.253
V2	2.003	3.590	11.317	2.938	0.260
V3	2.005	5.369	16.955	4.272	0.253
V4	2.004	5.321	16.786	4.360	0.260
H1	2.021	3.456	11.081	—	—
H2	2.003	3.423	10.787	—	—
H3	2.008	4.953	15.684	3.931	0.251
H4	1.993	4.941	15.408	3.768	0.254

Table 4.2: Boise sandstone permeability calculation.

Sample	T in $^{\circ}C$	μ in cp^*	Δp atm	t in sec	V cm^3	k Darcy
V1	23	0.9325	1.246	6.35	10.0	1.348
				6.00		1.464
				6.20		1.464
H1	22.5	0.9437	0.5	25.5	10.0	0.804
			0.5	26.0		0.798
			1.0	11.5		**

* from CRC handbook of chemistry and physics (1988).

** leak was detected.

$$k = q \frac{\mu L}{A \Delta p} \quad (4.2)$$

Absolute permeability of core plug V1 represents vertical permeability, since the plug was drilled perpendicular to the horizontal flow direction of the cores. The average value for the vertical permeability is 1422 mD. Core plug H2 was drilled parallel to the flow direction, and its permeability represents horizontal permeability with an average value of 797 mD. These horizontal and vertical orientations are taken with respect to the flow direction and not with respect to rock sedimentation.

Chatzis and Morrow (1984) reported absolute permeability of Boise sandstone in the range of 785 to 745 mD. These values are in close agreement with the horizontal

permeability reported in Table 4.2.

4.1.4 Capillary Pressure

Capillary imbibition is one of the most important recovery mechanisms in naturally fractured reservoirs. Its significance has been long recognized and the literature dealing with it is broad. Birks (1955), Mattax and Kyte (1962), Iffly, Rousselet and Vermeulen (1972), Mannon and Chilingar (1972), Kleppe and Morse (1974), Kazemi and Merrill (1979), Van Golf-Racht (1982), Cuiec, Bourbiaux and Kalaydjian (1990), Schechter, Zhou and Orr (1991), Beckner (1990), Dutra and Aziz (1991) are some of the authors that stress the importance of capillary forces in naturally fractured reservoirs. Fine grid simulations discussed in Section 5 also point out the dominant factor of capillarity in such systems.

Porous plate drainage and imbibition capillary pressure curves were measured for Boise sandstone core plugs. The method is time consuming but regarded as accurate by Amyx, Bass and Whiting (1960). Two core plugs H1 and H2 were selected for this measurements (see Table 4.1).

Core plugs were dried and weighted and then evacuated together with the porous diaphragm. Vacuum pressure of $100 \mu\text{Torr}$ s was maintained for 24 hours before a 2% NaI solution was allowed to saturate the core plugs and the diaphragm. After the saturation was completed, capillary pressure measurements were started.

Figure 4.2 shows drainage and imbibition capillary pressure curves measured on core plugs H1 and H2. Figure 4.2 also shows capillary pressure measured by Sanyal (1971) for Boise sandstone. Table 4.3 lists the data used to plot Figure 4.2. The difference between the drainage capillary pressure curves of the two measurements was expected and can be explained by the difference in the temperature and the fluids used in each case. Figure 4.2 also shows a large difference between the two imbibition capillary pressure measurements. The main reason for this discrepancy is the high saturation at which the imbibition was started in our measurements. Lower water saturations were not possible due to equipment limitations. This limitations include the maximum pressure available to displace the water, and the maximum capacity of the pipet used to measure water volume.

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Table 4.3: Measured Boise sandstone drainage and imbibition capillary pressure.

Measured Capillary Pressure $T = 67^{\circ}F$				Capillary Pressure, Sanyal (1971) $T = 175^{\circ}F$			
Drainage		Imbibition		Drainage		Imbibition	
Sw	Pc Psi	Sw	Pc Psi	Sw	Pc Psi	Sw	Pc Psi
0.643	0.135	0.507	0.774	0.432	1.00	0.189	12.4
0.541	0.348	0.507	0.735	0.276	6.25	0.194	9.0
0.520	1.006	0.511	0.677	0.232	9.00	0.199	5.0
0.450	2.320	0.512	0.658	0.198	14.50	0.206	4.5
0.422	2.340	0.515	0.522	0.189	17.00	0.219	2.5
0.438	2.470	0.517	0.425			0.310	1.0
0.438	2.630	0.520	0.367			0.460	0.2
0.434	2.800	0.522	0.309				
0.414	2.960	0.527	0.232				
0.401	3.380	0.536	0.155				
0.397	4.120	0.539	0.116				
		0.545	0.038				
		0.557	0.000

Figure 4.2: Boise sandstone drainage capillary pressure curve.

Despite the few points measured, the high permeability and the low viscosity fluids, it took more than three months to obtain the data shown in Figure 4.2.

The small change in saturation during the imbibition process indicates weak or even intermediate NaI solution wetness. This is a key factor as shown in Section 5.

4.2 Properties of Fluids

Accurate interpretation of the flow experiments requires knowledge of the properties of the fluids involved. A light hydrocarbon representing the oil phase and NaI solution representing the water phase were selected for the experiment.

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Table 4.4: Cyclohexane Properties.

Property	Temperature	Value	Units
Interfacial tension with water	—	51.1	$\frac{mN}{m}$
Viscosity	17 °C	1.02	cp
Specific Gravity	20 °C	0.7785	—

Addition of dopants (such as NaI) to the water helps CT-scanner determination of saturations (Castanier, 1989). Heavy elements show an increase in the linear attenuation coefficient, amplifying the difference in CT numbers between phases with and without dopant.

Demiral (1991) showed that a linear increase in CT number is obtained with increase in NaI concentration. At low values of NaI concentration, CT numbers are high enough to show significant contrast between water and a light hydrocarbon. A value of 2% by weight was selected for the experiments.

Properties of the 2% NaI solution are expected to be close to the water properties (density of 1 cm^3 and viscosity of 1 cp), but it is necessary to measure these properties for better accuracy.

Table 4.4 list Cyclohexane properties taken from CRC Handbook of Chemistry and physics (1988). A light hydrocarbon like Cyclohexane was chosen as the oil phase since its properties are well defined, and it is easy to handle in the laboratory.

Corrosion problems are present with certain fittings exposed to the NaI solution. It does not, however, represent a major problem at this moment, but it should be considered for long term experiments.

Preparation of the NaI solution gives a transparent liquid that becomes yellow after a few hours. This may be caused by oxidation of iodide into iodine. Recirculation of the yellow solution into the Boise sandstone core turns the solution transparent again. It is not known what is causing the color change of the solution inside the rock. It may be due to adsorption of iodide or iodine to the rock surface. The effect of this reaction on subsequent CT-scanner measurements needs to be investigated.

Two simple experiments are proposed. First determine the solution compositions

before and after injection into the core. Perform CT-scanner measurements of the core while it is being flushed with NaI solution. Replace the transparent recirculated solution with fresh yellow solution and continue flushing and scanning. Check for any CT-number increase. The two experiments proposed should provide a clue to the cause of this color change. NaI is a dopant commonly used by petroleum research groups and effects like the one discussed here could be important.

4.3 Preliminary Results

Following is a description of the experiments completed at the time of this report. They include testing of the flow model and CT-scanner measurements.

4.3.1 Core Preparation

In the following discussion, the core without the fracture is referred to as core #1 and the core with the fracture is referred to as core #2.

A first CT-scan with the two cores completely dried was desired as a base case and for porosity calculations. Cycles of CO_2 injection and vacuum were applied to each core to ensure complete water removal. CO_2 was injected at a pressure of 5 psig for 2 to 3 hours, and then vacuum was applied for the same amount of time. The sequence was repeated for several days.

Core #1 was scanned several times to determine the optimum CT-scanner settings. Some of the variables included in this sensitivity study were the number of detectors, energy level, mode (number of pixels in x and y direction), speed and photo multiplier status. Table 4.5 lists the CT-scanner conditions selected for subsequent experiments. The criteria used to determine the best conditions were picture quality, resolution and minimum artifacts present.

After scanning both cores saturated with CO_2 , a 2% NaI solution was injected and the cores were scanned again. Results of these scans will be discussed later. In order to achieve 100% water saturation, vacuum was applied and then water was allowed into the core while maintaining a vacuum. The vacuum pump was turned off only

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Table 4.5: CT-scanner conditions.

Variable	Setting
Wedge	32 cm
Photomultiplier status	7
Mode	7 (320x320 pixels)
Speed	slow
Reference dial	7
Number of detectors	7
Kv (voltage)	140
mA (current)	28
Window width	100
Window level	530
Position	Head on back

when water was seen coming out of the core towards the vacuum system. Vacuum pressure for core #1 was 120 μTorr s and 100 μTorr s for core #2.

Single phase flow experiments were performed during CT-scanner measurements. Two phase flow experiments were to follow these scans, but the core holder failed and showed leaks that prevented the planned experiments.

4.3.2 Hardware and Software Testing

The goals of this work were to design and construct an apparatus capable of monitoring two-phase flow in fractured porous media. This section presents two test of the apparatus built: the first one consists of a calibration run and the second is an absolute permeability measurement.

Calibration Test

Experiments with core #1 require pressure drop measurements between 1 and 10 psi and below 1 psi for core #2. Calibration is then necessary for both high pressure (10 psi in our case) and low pressure ranges (below 1psi). Small pressure drops require very sensitive transducers, which translates into difficult calibration procedures.

Figure 4.3: Calibration test of one psi range pressure transducers. Pressure readings of one and zero psi are correctly determined.

A water manometer was constructed to calibrate the transducers in the 1 psi range. Figure 4.3 shows calibration data obtained with the data acquisition system, while performing a calibration run. Data for only three transducers is included to avoid confusion of several curves. Calibration accuracy is close to 2% of full scale, and is satisfactory for the proposed experiments.

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Figure 4.4: Absolute permeability test of core #1. Pressure drop data.

Absolute Permeability Test

Absolute permeability of core #1 was initially measured while it was being flushed with NaI solution. Core #1 was then mounted on the CT-scanner for 100% water saturation scans. All the connections were done and data acquisition started. Figure 4.4 shows pressure drops during this experiment (only three data from three transducers are included).

Table 4.6 shows permeability calculations of core #1 with the data from the apparatus built and from the water flushing. A value of 830 mD is consistent between the two methods, and it agrees fairly well with 797 mD obtained from core plugs.

Table 4.6: Absolute permeability test (core #1).

Method	q in cm^3/min	Dimensions in inches	μ cp	Δp psi	k mD
Core flushing	17.7	3x3x10	1.0	1.4	830
New apparatus	9.0	3x3x10	1.0	2.3	827

4.3.3 CT-Scanner Measurements

CT-scanner measurements were taken to cores #1 and #2 saturated with CO_2 and with NaI solution. Appendix E lists the file names of the CT images and includes a summary of average CT numbers at different positions of the cores.

Withjack (1988) showed how to calculate porosity from CT scans using:

$$\phi = \frac{CTN_{NaI sat. core} - CTN_{air sat. core}}{CTN_{NaI} - CTN_{air}}, \quad (4.3)$$

where CTN is the CT number. Figure 4.5 and Figure 4.6 show a comparison of images taken before and after saturating the cores with the NaI solution. The top image of Figure 4.5 shows that the saturation procedure was not successful and some air was trapped inside the core (air being a lighter material is shown as darker regions). The bottom image of Figure 4.5 shows near 100% NaI solution saturation of core #1. This figure illustrates the advantage of using a CT-scanner as a research tool in petroleum engineering. Erroneous saturation was evident and corrections were possible.

A space filled with a light material tends to be amplified such as the fracture in the dry core of Figure 4.6. Better definition of the same fracture is obtained when a denser material is filling the gap (NaI solution in Figure 4.6). As a result, fracture apertures seem to be much wider than they actually are. The reason for this behavior is the insufficient CT-scanner resolution to clearly define the fracture aperture. A more detailed description of this behavior is given by Johns et al. (1991).

Figure 4.7 sketches the density determined with a CT-scanner along a line that crosses a fracture filled with different fluids. This behavior was observed during the CT-scans performed on core #2 and can be inferred from Figure 4.6. The flat line with maximum density represents the rock density. Johns et al. (1991) found that the

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Figure 4.5: Core #1 CT-scans. Top figure is for incomplete saturation, and bottom figure is for complete saturation.

Figure 4.6: Fracture definition of Core #2 using CT-scanner. Top figure is for air saturated core, and bottom figure is for NaI solution saturated core.

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

shaded areas in Figure 4.7a (which was called missing mass by Johns et al. (1991)), is proportional to the fracture aperture:

$$m_g = Aw + B, \quad (4.4)$$

where m_g is the missing mass in $\frac{mm-gr}{L}$, and w is the fracture aperture in mm. A and B are two constants determined by calibration. The constant A represents the difference in density in $\frac{gr}{L}$ between the rock and the fluid filling the fracture, and B is approximately equal to zero for an air filled fracture. The calibration is performed on a fracture of known aperture using two slabs of polished rock. Boise sandstone should be used in our case. Spacers of known thickness are placed between the two slabs, and CT-scans are carried out. A plot of missing mass m_g vs fracture aperture w will produce a straight line from which the constants A and B can be determined. The aperture of the fractured core used for the experiments can then be estimated in as many locations as necessary, using Equation 4.4.

The value of the missing mass is smaller for a fracture with a heavier fluid. Figure 4.7b sketches a fracture filled with a NaI solution and Figure 4.7c is for a fracture filled with oil. When both oil and NaI solution fill the fracture, the missing mass is somewhere in between the missing mass for a fracture with oil and a fracture with a NaI solution (see Figure 4.7d). It may then be possible to extend Johns et al. method to measure fracture saturation.

It is necessary to measure the missing mass for a fracture entirely filled with NaI solution ($m_g(b)$), and then measure the missing mass for the fracture filled with oil ($m_g(c)$), at the same location. The missing mass measured on the fracture with both NaI solution and oil may then be used to calculate saturation using the following system of equations:

$$\begin{aligned} m_g(d) &= S_w m_g(b) + S_o m_g(c) \\ 1 &= S_w + S_o. \end{aligned} \quad (4.5)$$

The possibility of accurately measuring fracture saturation using the proposed method is not known. There is one complication and that is the effect of the saturation

of the nearby rock. The missing mass is obtained mainly from the fracture volume and the fluids in it, but there is also an effect of the nearby rock and the saturating fluids. The influence of this needs to be investigated.

SECTION 4. EXPERIMENTAL ACCOMPLISHMENTS

Figure 4.7: Missing mass for a fracture filled with different fluids. a) air, b) NaI solution, c) oil and d) oil and NaI solution.

Section 5

Simulation Results

The reasons to do numerical simulations before an experiment are several. It helps in the experimental design and gives information about conditions expected during the experiment. A sensitivity analysis of the effect of key variables provides information on the influence of such variables. A commercial simulator ECLIPSE was used in this study (Eclipse Reference Manual, 1988).

The numerical experiments start by defining the base case for simulation. The analysis is then divided in two parts. The first part deals with the design of the experiment, where rock and fluid properties represent those values expected in the laboratory. The variables studied in this part are those that can be easily modified in the laboratory. The second part is a sensitivity analysis of variables like fracture relative permeability, matrix wettability and capillary pressure.

5.1 Base Case Simulation

This section discusses the selection of rock and fluids properties, grid size and boundary conditions used in most of the cases simulated.

5.1.1 Base Case Properties

Table 5.1 lists rock and fluids properties used in the base case simulation.

SECTION 5. SIMULATION RESULTS

Table 5.1: Base case simulation data.

Oil and water incompressible flow	
Core length	12 inches
Core width	3 inches
Core height	2.75 inches
Porosity	0.254
Horizontal permeability	797 mD
Vertical permeability	1422 mD
Fracture permeability	$8.4417 \times 10^9 \text{ w}^2 \text{ mD}$
Fracture aperture (w)	0.04 inches (1 mm)
Water injection rate	$1.0 \text{ cm}^3/\text{min}$
Oil density	$0.7 \text{ gr}/\text{cm}^3$
Water density	$1.0 \text{ gr}/\text{cm}^3$
Oil viscosity	10.0 cp
Water viscosity	1.0 cp
Straight line fracture relative permeability	
Zero fracture capillary pressure	
Initial pressure	1.0 atm

A fracture aperture of 1 mm is rather large and smaller apertures were also considered, as discussed in a later section. For apertures smaller than 1 mm, the grid blocks representing the fracture are very small. This strongly limits the timestep size and creates convergence problems in the simulator.

An injection rate of $1 \text{ cm}^3/\text{min}$ was used because of timestep size limitations at higher rates. Nonetheless, higher flow rates were studied and results are shown in this section.

The initial pressure inside the core is expected to be the atmospheric pressure. This is the initial condition used in the simulations. Minimum water saturation obtained from capillary pressure measurements is used as the initial saturation, except in the fracture where it is assumed to be zero.

The imbibition capillary pressure curve shown in Figure 5.1 was measured by Sanyal (1972) and was used in the simulations. The capillary pressure measurements reported in Section 4 were not available at the time of the numerical simulations.

Table 5.2: Matrix relative permeability calculated from imbibition capillary pressure.

Sw %	Pc psi	k_{rw}	k_{ro}
18.9	12.4	0.0	1.0
19.4	9.0	0.0	1.0
19.9	5.0	0.0	1.0
20.6	4.5	0.0	1.0
21.9	2.5	0.0	1.0
31.0	1.0	0.002	0.998
40.3	0.45	0.009	0.991
46.0	0.2	0.034	0.966
100.0	0.1	1.0	0.0

Figure 5.2 shows matrix relative permeabilities calculated from the capillary pressure data, using Purcell's formulas (Purcell, 1949):

$$k_{ro} = \frac{\int_0^{S_w} \frac{dS}{P_c^2}}{\int_0^1 \frac{dS}{P_c^2}}, \quad (5.1)$$

$$k_{rw} = \frac{\int_{S_w}^1 \frac{dS}{P_c^2}}{\int_0^1 \frac{dS}{P_c^2}}, \quad (5.2)$$

Table 5.2 lists the values for matrix relative permeability shown in Figure 5.1. The accuracy of imbibition relative permeability calculated from capillary pressure data is uncertain (Honapour, Koederitz and Harvey, 1986). Direct measurement of relative permeability for the Boise sandstone should be done.

5.1.2 Grid Size

It was desired to represent the fracture by a series of blocks of high permeability and unit porosity. This results in very small grid blocks representing the fracture. The matrix block size was selected in a way that avoids large size contrast between neighboring blocks, but at the same time reduces the number of blocks needed.

Figure 5.3 shows the grid selected for the simulations. The fracture is represented by the dark blocks in the middle of the bigger matrix blocks. The matrix block size

SECTION 5. SIMULATION RESULTS

Figure 5.1: Boise sandstone imbibition capillary pressure. After Sanyal (1972).

increases logarithmically from the fracture towards the outer blocks.

The flow is essentially a two dimensional problem, and the grid shown in Figure 5.3 represents an X-Z cross section. Three dimensional simulations were performed to test the validity of a two dimensional representation. Figure 5.4 compares the results from a 3-D and a 2-D simulation of the base case. The close agreement of the two results justifies the use of 2-D simulations.

Finer grid than the one shown in Figure 5.3 was used to determine the effect of numerical dispersion. Figure 5.5 compares water cut vs. oil recovery for two grid sizes. The difference between the finer 48x1x19 grid and the coarser 13x1x19 grid, is not large enough to justify finer grid. Thus the 13x1x19 grid was used in all subsequent

Figure 5.2: Boise sandstone relative permeabilities calculated from capillary pressure data.

simulations.

5.1.3 Boundary Conditions

The boundary conditions specified tried to match the conditions present during experiments. That is, constant total injection rate and constant production pressure. No capillary end effects were included and their influence is not known for our particular case. At the low pressures used in the experiments, the system behaves as incompressible and the injection rate equals the production rate.

Two different injection and production conditions were used. In the first one only

SECTION 5. SIMULATION RESULTS

Figure 5.3: X-Z cross section of the grid used in the numerical simulations.

Figure 5.4: Selection of simulation dimensionality. 3-D vs. 2-D grid.

the fracture blocks at the injection and production ends were receiving or producing fluids. The rest of the boundary blocks had a specified no-flow boundary condition. It was assumed that the high permeability fracture would be the preferred flow path. This is the usual assumption made when simulating double porosity reservoirs, where the wells are only connected to the high permeability fractures.

The second injection/production condition allowed for flow to or from the matrix blocks at the inlet and outlet ends. A single fictitious well representing either injection or production, was opened to flow in each boundary block. Total injection and production well rates were specified and then distributed among the blocks by the simulator, according to their transmissibilities (Aziz and Settari, 1979).

SECTION 5. SIMULATION RESULTS

Figure 5.5: Selection of simulation grid size. Fine 48x1x19 vs. coarser 13x1x18 grid.

Figure 5.6 compares the results for the base case simulation, using the two boundary conditions described above. An earlier and smoother breakthrough is observed when all inlet and outlet blocks are open to flow. The smoothness of the breakthrough is then an indication of the type of boundary condition used in a particular simulation. The difference between the two curves is not significant. The assumption of injection and production through only the fracture blocks at inlet and outlets seems to be appropriate.

In order to accurately simulate the boundary conditions, a representative or equivalent well index is needed. Steady state linear flow between the inlet block and the center of the first boundary block is given by:

SECTION 5. SIMULATION RESULTS

Figure 5.6: Comparison of boundary conditions. Case A: injection/production only in fracture blocks, Case B: injection/production in all boundary blocks (matrix and fracture).

SECTION 5. SIMULATION RESULTS

$$q = \frac{kA}{\mu} \left(\frac{p - p_{well}}{L/2} \right), \quad (5.3)$$

where L is the length of the first block.

The well index or geometric factor is defined as:

$$WI = \frac{kA}{L/2}. \quad (5.4)$$

Differences in permeability between the matrix and the fracture blocks, and differences in cross-sectional area A between each block, requires a different well index for each well completion. Care must be taken when changing grid size or block permeabilities since this will change the well index value.

5.2 Design of Experiment

The following simulations are intended to give basic knowledge of the conditions expected during the experiments.

5.2.1 Injection Flow Rate

Relatively low flow rates were chosen (from 1 to 10 cm^3/min) because low flow velocities are required when using a CT-scanner to determine saturations along a core. If high flow velocities are used, the conditions at which the first CT-scanner image is taken (e.g. inlet of the core) will be different from the conditions at which the last CT-scanner image is taken (e.g. outlet of the core). It is then not possible to evaluate the saturation at a given time. Furthermore, the low rates are more representative of the conditions expected in the reservoir.

Figure 5.7 shows water cut vs. oil recovery for 1, 2 and 10 cm^3/min water injection rates. In all the cases, there is a high recovery before water breakthrough. This indicates that imbibition is an effective recovery mechanism for the conditions simulated. The saturation profiles shown in Figure 5.8 indicate that water is flowing preferentially through the matrix, even though it is being injected in the fracture. Capillary forces are dominant and the water is imbibing at a fast rate, efficiently

displacing oil from the matrix. The saturation profiles of Figure 5.8 also show higher water saturation in the lower matrix block due to gravity.

Earlier breakthrough is obtained as the injection rate is increased, but the three cases show similar oil recovery after 10 hours of injection. Observation of a sequence of saturation maps show a stable front sweeping initially the oil from the matrix and then from the fracture.

Pressure drops for the total core length vary from 0.1 to 0.3 psi. This is an important consideration that helps in selecting the pressure transducers and their range of calibration.

5.2.2 Simultaneous Oil and Water Injection

Steady state relative permeability measurements require simultaneous oil and water injection. Figures 5.9 and 5.10 show oil production and water cut vs. time for injection water cuts ranging from zero to 0.97.

Approximate times to achieve steady state (equal injection and production water cuts) range from one to ten hours. This time gives an idea of the time needed for each experiment. Average fracture water saturations at steady state conditions vary from 0.04 to 0.97, if they are measurable with the CT-scanner, this saturation range is wide enough and appropriate for relative permeability measurements.

5.2.3 Oil to Water Viscosity Ratio

Oil to water viscosity ratio was varied from 5 to 20. Figure 5.11 shows water cut vs. time in hours for viscosity ratios of 5, 10 and 20. The effect of viscosity is not very strong. Earlier breakthrough and lower oil recovery is obtained for the highest viscosity ratio, as expected.

5.2.4 Fracture Aperture

Fracture apertures of 0.1, 0.01 and 0.001 cm were simulated, and some of the results are shown in Figure 5.12 in terms of water cut vs. time in hours. Fracture permeability

SECTION 5. SIMULATION RESULTS

Figure 5.7: Comparison of the effect of different injection flow rates on water cut.

Figure 5.8: Water saturation profiles. Note that the fracture in the middle has lower water saturation.

SECTION 5. SIMULATION RESULTS

Figure 5.9: Time to reach steady state with simultaneous oil and water injection at experimental conditions (oil recovery).

Figure 5.10: Time to reach steady state with simultaneous oil and water injection at experimental conditions (water cut).

SECTION 5. SIMULATION RESULTS

Figure 5.11: Effect of viscosity ratio on water cut at experimental conditions.

was calculated using the fracture width as follows: (see for example: Johns, Wooten and Kaluza, 1990)

$$k_f = 8.4417 \times 10^6 w^2, \quad (5.5)$$

where k_f is the fracture permeability in Darcies and w is the fracture width in cm.

Water breaks through faster when a smaller fracture is present. Water is injected at the same rate in all cases and similar imbibition is present in all the cases. The difference in breakthrough time is caused by different water velocities in the fracture. The smaller fractures have smaller area open to flow, which gives higher velocities and shorter break through times.

Pressure drop for the fracture of 100 μm aperture is close to 0.5 psi which is the optimum value for a 1 psi pressure transducer.

5.2.5 Fracture Orientation

The effect of the fracture orientation is not significant as can be seen in Figure 5.13. Water cut vs. pore volume injected for both horizontal and vertical fracture is essentially the same at conditions expected in the laboratory.

5.3 Sensitivity Analysis

For an imbibition dominated flow displacement, rock/fluid properties like capillary pressure and wettability are very important. The influence of these properties were studied and some of the results are presented in this section. The effect of fracture relative permeabilities is also included. Finally, differences between the fractured core and the homogeneous core are evaluated using numerical simulations.

5.3.1 Capillary Pressure

The base case simulation assumes zero capillary pressure in the fracture. Several authors claim that this is not a valid assumption, and that the effect of a nonzero fracture capillary pressure is important. Firoozabadi and Hauge (1990), Firoozabadi

SECTION 5. SIMULATION RESULTS

Figure 5.12: Effect of fracture aperture on water cut.

Figure 5.13: Effect of fracture orientation on water cut.

SECTION 5. SIMULATION RESULTS

Table 5.3: Capillarity to gravity number ratio for some numerical simulations.

Simulation case	N_{cap}/N_{grav}
Base	164.7
$q = 5cm^3/min$	164.7
$P_{c_{rock}} = 1/2$ base case	82.3
$P_{c_{rock}} = 0.1$ base case	16.5
Kleppe and Morse experiments* (1974)	
Low flow rate	24.4
Kleppe and Morse experiments* (1974)	
High flow rate	24.7

* After Beckner (1990).

and Thomas (1990), Horie et al. (1988) and Labastie (1990), are some references concerning this subject.

The numerical calculations of the preceding sections have shown that imbibition is the dominant force. Table 5.3 lists the values of the ratio of the dimensionless capillary and gravity numbers for some of the simulations experiments. The dimensionless numbers were calculated using the expression presented by Orr (1987):

$$N_{cap} = \frac{k_{ref} w \Delta P c}{q \mu_{ref}}. \quad (5.6)$$

$$N_{grav} = \frac{\bar{g} L w k_{ref} \Delta \rho_{max}}{q \mu_{ref}}. \quad (5.7)$$

where N_{cap} is the capillary number, N_{grav} is the gravity number, L is the core length, w is the core width and μ_{ref} and k_{ref} are reference viscosity and permeability.

Beckner (1990) used the same expressions to characterize the fine grid simulations of a matrix and fracture system. For comparison, the values calculated by Beckner (1990) for the Kleppe and Morse (1974) experiments are also listed in Table 5.3.

The values presented in Table 5.3 agree with the observation of a capillary imbibition dominated process. Simulations with lower capillary pressure were also considered, and the results are given in Section 5.3.2.

Capillary imbibition is caused by a difference between the capillary pressure in the

matrix and the capillary pressure in the fracture. Figure 5.14 shows oil recovery for different matrix/fracture capillary pressure conditions. If the capillary pressure of the matrix and fracture are zero, the recovery is due almost exclusively to gravity, and is lower than the recovery when imbibition is present. Figure 5.14 also shows that if very high fracture capillary pressures are present, water will flow from the matrix to the fracture decreasing the oil recovery. That is, the water will imbibe into the fracture. This can happen when high fracture capillary pressure is present and the matrix water saturation is higher than the fracture saturation. These two conditions were present in the simulation results shown in Figure 5.14. High fracture capillary pressures are not expected to be realistic. They were only used to emphasize the effect of capillary pressure. For more realistic values of fracture capillary pressure, the oil recovery from the experiments will decrease but not in the proportion shown in Figure 5.14.

In the absence of imbibition, the water injected in the fracture is produced very fast. This can be seen in Figure 5.15 where water cut is plotted against oil recovery. The shape of the curve for zero fracture capillary pressure in Figure 5.15 can be interpreted as follows: An early water breakthrough from the fracture is followed by a stabilized water cut. Some water is produced from the fracture and while oil is being displaced by water from the lower matrix block. A second jump in water cut is seen due to water breakthrough from the matrix.

5.3.2 Wettability Effects

In order to investigate the effect of wettability, four imbibition capillary pressure curves were selected from the experiments presented by Morrow (1976). The selected curves are reproduced in Figure 5.16. Morrow (1976) presented the curves in terms of curvature J . Capillary pressure is calculated using the Young-Laplace equation:

$$P_c = J\sigma, \quad (5.8)$$

where σ is the interfacial tension. In the present work a value of 51.1 mN/m was used for σ , which is the approximate value of σ between water and cyclohexane. The curves

SECTION 5. SIMULATION RESULTS

Figure 5.14: Effect of matrix/fracture capillary pressure on oil recovery.

Figure 5.15: Effect of matrix/fracture capillary pressure on water cut.

SECTION 5. SIMULATION RESULTS

Figure 5.16: Normalized capillary pressure curves for different wettabilities.

in Figure 5.16 were normalized to obtained equal end point water saturations. Water saturation of 32.7% and 89.0% were selected as endpoint saturations from curve #1. The normalized water saturation was calculated using the following formula:

$$Sw_N = \left(\frac{Sw - Sw_{min}}{Sw_{max} - Sw_{min}} \right) (Sw_{max} - Sw_{min})_{base} + Sw_{min,base}. \quad (5.9)$$

The imbibition capillary pressure curves taken from Morrow (1976) are listed in Table 5.4, showing the intrinsic contact angle they represent. Wettability conditions vary from strongly to weakly water wet. For intermediate wettability there is no spontaneous imbibition and the effect is the same as having zero capillary pressure.

Table 5.4: Intrinsic contact angle for capillary pressure curves selected.

Curve	Core Number	Intrinsic Contact Angle
1	1	$0 < \theta_e < 22$
2	1	49
3	1	60
4	5	$0 < \theta_e < 22$

Figure 5.17 compares the results of simulations using the capillary pressure curves shown in Figure 5.16. The effect of wettability observed in this figure is not significant. Figure 5.18 reproduces the capillary pressure curve shown as a solid line in Figure 5.16, and contains three straight line capillary pressure curves. These capillary pressure curves were used to investigate the effect of their slope during water injection. Figure 5.19 shows the results of the simulations in terms of water cut. Water breaks through earlier when the slope of the capillary pressure curves is higher. This is because the transport due to capillary force is proportional to dP_c/dS_w .

5.3.3 Fracture Relative Permeability

The numerical work presented so far used straight line fracture relative permeabilities. A set of four different fracture relative permeabilities were utilized to investigate its effect on the flow experiments. Figure 5.20 shows the four mentioned sets.

Simulations using the four sets of fracture relative permeabilities showed small influence of this variable. Figure 5.21 and Figure 5.22 show the results for 1 and 10 cm^3/min injection rates. Fracture apertures smaller than 0.1 cm reduced the difference between water cut curves. This lack of influence could explain some of the difficulties experienced by some researchers (Merrill (1980)), when trying to measure fracture relative permeabilities.

Figures 5.23 to 5.26 show the effect of straight line (case III and case IV) fracture relative permeabilities on systems with different wettability (Table 5.4). The effect of fracture relative permeability is almost negligible.

It has been shown in Section 5.1.3 that the majority of the fluids are produced

SECTION 5. SIMULATION RESULTS

Figure 5.17: Effect of wettability on water cut.

Figure 5.18: Capillary pressure curves used to show the effect of dP_c/dS_w

SECTION 5. SIMULATION RESULTS

Figure 5.19: Effect of the slope of the capillary pressure curve on water cut.

Figure 5.20: Fracture relative permeabilities, cases I to IV.

SECTION 5. SIMULATION RESULTS

Figure 5.21: Effect of fracture relative permeabilities on water cut, $q_w = 1 \text{ cm}^3/\text{min}$.

through the fracture. The results presented here suggest that regardless of the fracture relative permeability of a fluid, it is produced once it reaches the fracture without any significant resistance due to multiphase flow effects in the fracture. Capillary imbibition seems to govern the flow process even in systems with weak water wettability (Figure 5.25). Experimental work is needed to test the validity of the numerical results shown here.

Fractured systems that present intermediate wettability (no spontaneous imbibition), show a more pronounced effect of fracture relative permeability. Figure 5.27 is an example this. The difference in behavior between systems with and without imbibition could be explained as follows: With imbibition acting, the fluids present

Figure 5.22: Effect of fracture relative permeabilities on water cut, $q_w = 10 \text{ cm}^3/\text{min}$.

in the fracture and therefore produced, are a strong function of matrix to fracture transfer mechanisms. In the second case, the production of fluids is almost a unique function of the fluids saturating the fracture.

It is a common practice to model the flow in the fractures using the same formulation as for flow in porous media, that is in terms of Darcy's law and relative permeabilities. The physical reason for using this formulation is not clear. Some authors have proposed a different types of formulations for two-phase fracture flow (Tsang and Tsang, 1987), but more research is needed to test if Darcy's law formulation can provide good representation of the flow, or a new fracture flow model is needed.

SECTION 5. SIMULATION RESULTS

5.3.4 Homogeneous vs. Fractured Porous Media

Injection rates of 1, 10 and 20 cm^3/min were used to compare the behavior of a core with a single fracture and a homogeneous core. The word homogeneous refers to the core without the fracture. Figures 5.28 to 5.30 show some of the results of these simulations.

At low injection rates water breaks through earlier in the homogeneous case. There is a flow rate at which water breakthrough times for both cases are essentially the same. If the flow rate is further increased, water breaks through in the fractured core first.

Strong viscous forces together with adverse mobility ratio result in poor water-oil displacements. Capillary cross flow tends to recover oil that is left behind the displacement front, improving displacement efficiency. At low injection rates the high permeability fracture reduce the viscous forces and enhance the effectiveness of capillary imbibition. An example of this situation is shown in Figure 5.28. At high flow rates capillary imbibition is not as effective due to higher viscous forces and shorter times for imbibition. This results in earlier breakthroughs compared to low injection rate displacements. Figure 5.30 shows an earlier breakthrough for the fractured core than for the homogeneous core.

There is a threshold injection rate at which water breakthrough time is the same for the homogeneous and the fractured cores. Figure 5.29 shows that a value of 10 cm^3/min is the approximate threshold injection rate for the conditions simulated.

Mattax and KYTE (1962) presented the concept of "critical flow rate". They defined the critical rate as "... rate of water advance at which the water level in the fracture is the same as the water level in the matrix". Dutra and Aziz (1991) defined the critical rate as the rate at which there is a complete imbibition in the matrix zone in contact with the water in the fracture. This definition has a clearer physical meaning and is easier to estimate. This concept is different from the threshold flow rate. Mattax and KYTE (1962) compared the water level between the matrix and the fracture of one core, and not between two different cores as in Figures 5.28 to 5.30.

Figure 5.23: Effect of fracture relative permeabilities on water cut, wettability case #1.

SECTION 5. SIMULATION RESULTS

Figure 5.24: Effect of fracture relative permeabilities on water cut, wettability case #2.

Figure 5.25: Effect of fracture relative permeabilities on water cut, wettability case #3.

SECTION 5. SIMULATION RESULTS

Figure 5.26: Effect of fracture relative permeabilities on water cut, wettability case #4.

Figure 5.27: Effect of fracture relative permeabilities on water cut, no imbibition present.

SECTION 5. SIMULATION RESULTS

Figure 5.28: Water cut for a fractured and a homogeneous core, $q_w = 1 \text{ cm}^3/\text{min}$.

Figure 5.29: Water cut for a fractured and a homogeneous core, $q_w = 10 \text{ cm}^3/\text{min}$.

SECTION 5. SIMULATION RESULTS

Figure 5.30: Water cut for a fractured and a homogeneous core, $q_w = 20 \text{ cm}^3/\text{min}$.

Section 6

Summary of Results and Recommendations

An apparatus that can be used to monitor two-phase flow experiments in fractured porous media was designed, built and tested. It consists of a fractured core cast in an epoxy core holder, with pressure measurements at six different locations. A computerized data acquisition system takes automatic readings of pressure and water fractional flow. Saturations inside the core are determined by means of a CT-scanner. Single phase flow runs were performed to test the apparatus.

Different techniques and materials were tried to cast cores inside epoxy. A recommended procedure was developed and outlined in Section 4. Epoxy core holders are specially useful when a CT-scanner is being used to determine saturations.

Boise sandstone was used as the matrix for the fractured core. Measurements of porosity, absolute permeability and drainage and imbibition capillary pressure were performed. CT-scanner calibrations with the cores (fractured and homogeneous) saturated with CO_2 and NaI solution were also obtained.

It was observed that the color of the NaI solution changed as it was injected into the cores. This color change may be an indication of Sodium Iodine being adsorbed by the sandstone. The effect of this observation in the CT-scanner measurements is not known; a procedure to investigate this phenomenon is proposed in Section 4.

Fracture aperture can be determined following the CT-scanner the method used

SECTION 6. SUMMARY OF RESULTS AND RECOMMENDATIONS

by Johns et al. (1991). An extension of this method is proposed to measure fracture saturations.

Fine grid simulations were used to predict the conditions of the experiments. Adjustments to the apparatus were implemented according to some results of the simulations. Pressure drops, time to achieve steady state and effect of fracture aperture are some of the parameters that helped in the design of the apparatus.

Fine grid simulations were also used to estimate the influence of variables like fracture relative permeability, matrix/fracture capillary pressure and matrix wettability. Capillary pressure is the dominant parameter in the type of water displacements considered. The results are considerably different in cases where no imbibition is present, as in rocks with intermediate wettability. Knowledge of the capillary pressure function is then critical. Fracture capillary pressure decreases the efficiency of the water displacements for the water wet systems considered.

Oil and water production from the fractured core appears to be independent of the fracture relative permeabilities when capillary imbibition is present. Several simulations using different injection rates, fracture apertures, matrix wettability support this conclusion.

Appendix A

Nomenclature

A	Core cross sectional area
d	Core diameter
f_w	Water fractional flow
J	Curvature
K	Absolute permeability
k_f	Fracture absolute permeability
k_r	Relative permeability
L	Core length
m_g	Missing mass
N_{cap}	Dimensionless capillary number
N_{grav}	Dimensionless gravity number
p	Pressure
P_c	Capillary pressure
q	Flow rate
Q	Cumulative production
r	Core radius
S	Saturation
t	Time
T	Temperature
V	Volume

APPENDIX A. NOMENCLATURE

w	Fracture aperture
WI	Well index

Greek

α	Linear attenuation coefficient
γ	Specific gravity
δp	Pressure drop
θ_e	Intrinsic contact angle
μ	Viscosity
π	3.14159....
ρ	Density
σ	Interfacial tension
ϕ	Porosity

Subscripts

f	Fracture
min	Minimum
max	Maximum
nwt	Nonwetting phase
o	Oil
w	Water
wt	Wetting phase

Appendix B

List of Equipment

<u>Equipment</u>	<u>Specification</u>	<u>Manufacturer or Distributor</u>
Back pressure regulator	SD-91LW 400-25 psi	Grove Valve & Regulator Co. 6529 Hollis St. Oakland, CA 94608
Balance	PE1600	Mettler instrument corp. Hightstown New Jersey
Ball valve	Whitey B-43F2	Sunnyvale Valve & Fitting Co. 929 Weddell Court Sunnyvale, CA 94089
Connectors	Swagelock	Sunnyvale Valve & Fitting Co. 929 Weddell Court Sunnyvale, CA 94089
CT-Scanner	EMI 5000	EMI Medical 3605 Woodhead Drive Northbrook, Illinois 60062

2 of 2

APPENDIX B. LIST OF EQUIPMENT

Data logger	hp3497A	Hewlett-Packard Co. P.O. Box 301 Loveland, Colorado 80537
Differential pressure transducer	DP31	Celesco Transducer Products inc. Canoga Park,CA
High performance liquid chromatography pump	Constametric 3200	LCD Analytical inc. P.O. Box 10235 Riviera Beach, FL 33419
Personal computer	IBM compatible	
Relief valve	Nupro SS-RL3M4-F4	Sunnyvale Valve & Fitting Co. 929 Weddell Court Sunnyvale, CA 94089
Signal carrier or demodulator	CD10D	Celesco Transducer Products inc. Canoga Park,CA
Test gauge	Marshall Town 0-30 psi	Valin Corporation 209 Fair Oaks Ave. Sunnyvale, CA 94086
Three way ball valve	Whitey B-42XF2	Sunnyvale Valve & Fitting Co. 929 Weddell Court Sunnyvale, CA 94089

Appendix C

Transducer Calibration

In order to calibrate the transducers, the following procedure is used (refer to Figure 3.4):

1. Select pressure source and calibration indicator (low or high range).
2. Set all 3-way valves B to loop.
3. Set all 3-way valves A to calibration.
4. Apply full scale pressure.
5. Set the zero and spans nobs of the demodulators to midscale.
6. Turn demodulators on.
7. Start data logging system. The logging procedure was discussed in Section 3.4.
8. Connect a voltmeter to the demodulator selected for calibration.
9. Set 3-way valve B of selected transducer to calibration. The full scale pressure is then applied to the transducer. The voltmeter reading should be 10 volts and the pressure reading on the logging system should be the full scale pressure range on the transducer. Adjust the span nob on the demodulator until the readings are correct.

APPENDIX C. TRANSDUCER CALIBRATION

10. Repeat zero and span cycle at least three times or until the readings are correct.
11. Set 3-way valve B to loop and proceed with next transducer.

Appendix D

Data Logging Program

```
5   ' Copyright Hewlett-Packard 1984, 1985
10  '
15  ' Set up program for MS-DOS HP-IB I/O Library
20  ' For use independent of the PC instrument bus system
25  '
30  DEF SEG
35  CLEAR ,&HFE00
40  I=&HFE00
45  '
50  ' PCIB.DIR$ represents the directory where the
    library files
55  ' are located
60  ' PCIB is an environment variable which should be
    set from MS-DOS
65  ' i.e. A:> SET PCIB=A:\LIB
70  '
75  ' If there is insufficient environment space a
    direct assignment
80  ' can be made here, i.e
85  ' PCIB.DIR$ = "A:\LIB"
```

APPENDIX D. DATA LOGGING PROGRAM

```
90  '      Using the environment variable is the
      preferred method
95  '
100 PCIB.DIR$ = ENVIRON$("PCIB")
105 I$ = PCIB.DIR$ + "\PCIBILC.BLD"
110 BLOAD I$,&HFEOO
115 CALL I(PCIB.DIR$, I%, J%)
120 PCIB.SEG = I%
125 IF J%=0 THEN GOTO 160
130 PRINT "Unable to load.";
135 PRINT "      (Error #";J%;"")"
140 STOP
145 '
150 '   Define entry points for setup routines
155 '
160 DEF SEG = PCIB.SEG
165 O.S      = 5
170 C.S      = 10
175 I.V      = 15
180 I.C      = 20
185 L.P      = 25
190 LD.FILE  = 30
195 GET.MEM  = 35
200 L.S      = 40
205 PANELS   = 45
210 '
215 '   Establish error variables and ON ERROR branching
220 '
225 DEF.ERR = 50
230 PCIB.ERR$ = STRING$(64,32)
235 PCIB.NAME$ = STRING$(16,32)
```



```
240 CALL DEF.ERR(PCIB.ERR,PCIB.ERR$,PCIB.NAME$,PCIB.GLBERR)
245 PCIB.BASERR = 255
250 ON ERROR GOTO 410
255 '
260 J=-1
265 I$=PCIB.DIR$+"\\HPIB.SYN"
270 CALL D.S(I$)
275 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
280 '
285 ' Determine entry points for HP-IB Library routines
290 '
295 I=0
300 CALL I.V(I,IOABORT,IOCLEAR,IOCONTROL,IOENTER)
305 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
310 CALL I.V(I,IOENTERA,IOENTERS,IOEOI,IOEOL)
315 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
320 CALL I.V(I,IOGETTERM,IOLLOCKOUT,IOLLOCAL,IOMATCH)
325 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
330 CALL I.V(I,IOOUTPUT,IOOUTPUTA,IOOUTPUTS,IOPPOLL)
335 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
340 CALL I.V(I,IOPPOLL,IOREMO,IORESET)
345 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
350 CALL I.V(I,IOSEND,IOPOLL,IOSTATUS,IOTIMEOUT)
355 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
360 CALL I.V(I,IOTRIGGER,IODMA,J,J)
365 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
370 CALL C.S
375 I$=PCIB.DIR$+"\\HPIB.PLD"
380 CALL L.P(I$)
385 IF PCIB.ERR<>0 THEN ERROR PCIB.BASERR
390 GOTO 475
```

APPENDIX D. DATA LOGGING PROGRAM

```
395  '
400  '   Error handling routine
405  '
410  IF ERR=PCIB.BASERR THEN GOTO 425
415  PRINT "BASIC error #";ERR;" occurred in line ";ERL
420  STOP
425  TMPERR = PCIB.ERR
430  IF TMPERR = 0 THEN TMPERR = PCIB.GLBERR
435  PRINT "PC Instrument error #";TMPERR;" detected
      at line ";ERL
440  PRINT "Error: ";PCIB.ERR$
445  STOP
450  '
455  '   COMMON declarations are needed if your program
      is going to chain
460  '       to other programs.  When chaining, be sure
      to call DEF.ERR as
465  '       well upon entering the chained-to program
470  '
475  COMMON PCIB.DIR$,PCIB.SEG
480  COMMON LD.FILE,GET.MEM,PANELS,DEF.ERR
485  COMMON PCIB.BASERR,PCIB.ERR,PCIB.ERR$,PCIB.NAME$,
      PCIB.GLBERR
490  COMMON IOABORT,IOCLEAR,IOCONTROL,IOENTER,IOENTERA,
      IOENTERS,IOEOI,
      IOEOL,IOGETTERM,IOLLOCKOUT,IOLLOCAL,IOMATCH,
      IOOUTPUT,IOOUTPUTA,
      IOOUTPUTS,IOPOLL,IOPOLLIC,IOPOLLU,IOREMOTE,
      IORESET,IOSEND,
      IOSPELL,IOSTATUS,IOTIMEOUT,IOTRIGGER,IODMA
495  '

```

```
500 FALSE      = 0
505 TRUE       = NOT FALSE
510 NOERR      = 0
515 EUNKNOWN   = 100001!
520 ESEL       = 100002!
525 ERANGE     = 100003!
530 ETIME      = 100004!
535 ECTRL      = 100005!
540 EPASS      = 100006!
545 ENUM       = 100007!
550 EADDR      = 100008!
555 COMMON FALSE, TRUE, NOERR, EUNKNOWN, ESEL, ERANGE, ETIME,
ECTRL, EPASS, ENUM, EADDR
560 '
565 ' End Program Set-up
570 ' User program can begin anywhere past this point
1000 'FRACTURE RELATIVE PERMEABILITY DATA LOGGING PROGRAM
1010 '                September 1990
1020 '                Rafael Ernesto Guzman
1030 '                SUPRI
1040 '                Stanford University
1050 '
1060 '
1070 '
1080 ' Data logger analog chanel's used from slot 0:
1090 '      00 Pressure transducer 1
1100 '      01 Pressure transducer 2
1110 '      02 Pressure transducer 3
1120 '      03 Pressure transducer 4
1130 '      04 Pressure transducer 5
1140 '      05 Pressure transducer 6
```

APPENDIX D. DATA LOGGING PROGRAM

```
1150 ' Ports used for balances
1160 '      com1 to file 1, balace #1, oil prod
1170 '      com2 to file 3, balace #2, total prod
1180 ' *****
1185 ' *** THIS IS THE MAIN PROGRAM *****
1190 ' *****
1200 GOSUB 2000      ' INITI/LIZE DATA LOGGER
1210 GOSUB 3000      ' READ INITIAL DATA AND SET CONSTANTS
1220 GOSUB 4000      ' START EXPERIMENTAL RUN
1230 END

2000 ' *****
2010 ' ***** Initial Setups *****
2020 ' *****
2030 OPTION BASE 1
2040 MAXI=10
2050 ACTUAL = 0
2060 DIM P(6), T(6), PR(60)
2070 ' Initialize string with enough space
2080 CODE$ = SPACE$(50)
2090 C1$ = SPACE$(50)
2100 CLS : KEY OFF
2110 ' Set interface select code to 7 and device address
      to 09
2120 DEV = 709
2130 ' Set interface to its default configuration
2131 ISC=7
2140 CALL IORESET (ISC)
2170 ' Set no time lag between readings
2180 TIMEOUT = 0!
2190 CALL IOTIMEOUT (ISC,TIMEOUT)
2210 CALL IOCLEAR (ISC)
```

```
2220 CALL IOREMOTE(ISC)
2230 ' ***** Set data logger *****
2240 CODE$ = "SISO1SDOVAOVF1VSOAF00AL05"
2250 LENGTH = LEN(CODE$)
2260 CALL IOOUTPUTS(DEV, CODE$, LENGTH)
2280 RETURN
2290 END
2300 '
3000 ' *****
3010 ' ***** Initial data input *****
3020 ' *****
3030 CLS
3040 COLOR 14,1,0
3050 'Read data from keyboard
3060 LOCATE 4,5
3070 INPUT "Run ID  :";EXPE$
3080 LOCATE 6,5
3090 INPUT "Name of the output data file :";FILE$
3100 LOCATE 8,5
3110 INPUT "Date of the experiment :";D$
3120 LOCATE 12,5
3130 INPUT "Oil flow rate (cc/min)  :";FLO
3140 LOCATE 14,5
3150 INPUT "Water flow rate (cc/min) :";FLW
3160 LOCATE 16,5
3170 INPUT "Time interval between readings (sec)  :";DT
3180 LOCATE 18,5
3190 INPUT "Comments  :";C1$
3200 'Assign values to constants
3210 T(1)=-.1: T(2)=-.1: T(3)=-.1: T(4)=-.1: T(5)=-.1:
      T(6)=-2.5
```

APPENDIX D. DATA LOGGING PROGRAM

```
3220 POROS = .19
3222 ROW =1!
3223 TMB1 = 0!
3224 ROO = .87
3226 CUM01 = 0!
3228 CUMW1 = 0!
3229 CUP = 300!
3230 'Print information to output file
3240 OPEN "O", #2, FILE$
3250 PRINT #2, "Experiment ID = ";EXPE$
3260 PRINT #2, "Date = ";D$
3280 PRINT #2, "Oil flow rate (cc/min) =";FLO
3290 PRINT #2, "Water flow rate (cc/min) =";FLW
3292 FW=FLW/(FLO+FLW)
3295 PRINT #2, "Water Fractional Flow =";FW
3310 PRINT #2, "Time interval between readings =";DT
3315 PRINT #2, "Comments =";C1$
3320 PRINT #2,""
3330 FLAG=0
3340 RETURN
3350 END
4000 '*****
4010 '**** SUBROUTINE TO CONTROL TIME *****
4020 '*****
4030 TIME$ = "00:00:00"
4040 KEY OFF
4050 KEY 1,""
4060 KEY 2,""
4070 ON KEY (1) GOSUB 9000      'Stop Program
4080 ON KEY (2) GOSUB 9200      'Change DT
4090 KEY (1) ON
```

```
4100 CLS
4110 LOCATE 25,1
4120 PRINT "Press F1 to stop"
4130 LOCATE 25,25
4140 PRINT "Current DT (sec) = ";DT;" , "
4150 LOCATE 25,50
4160 PRINT "Press F2 to change DT"
4170 ON TIMER (DT) GOSUB 4220
4180 TIMER ON
4190 LOCATE 1,1:PRINT TIME$
4200 KEY (2) ON
4210 GOTO 4190
4215 RETURN
4216 END
4220 KEY (2) STOP
4230 GOSUB 6000      'Read from balance
4240 GOSUB 6500      'Read from pressure transducers
4250 TM=TIMER
4260 GOSUB 7000      'Print data to the screen
4270 GOSUB 7500      'Print data to file
4280 LOCATE 1,1
4290 RETURN
4300 END
6000 ' *****
6010 'Subroutine to read data from balances
6020 ' *****
6030 ' Open communication ports
6035 ON ERROR GOTO 6400
6040 OPEN "COM1:300,E,7,1,CS,DS" AS 1
6050 OPEN "COM2:300,E,7,1,CS,DS" AS 3
6060 IF LOC(1) = 0 THEN 6080
```

APPENDIX D. DATA LOGGING PROGRAM

```
6070 EMPTYA$ = INPUT$(LOC(1),1)
6080 IF LOC(3) = 0 THEN 6100
6090 EMPTYB$ = INPUT$(LOC(3),3)
6100 'READ WEIGHT FROM BALANCES
6110 INPUT #1, L$
6120 INPUT #1, L$
6130 INPUT #3, M$
6140 INPUT #3, M$
6150 ' Check for correct data transmtion
6160 LENGTHA = LEN(L$)
6170 LENGTHB = LEN(M$)
6180 IF LENGTHA < 12 THEN 6110
6190 IF LENGTHB < 12 THEN 6110
6200 IF LENGTHA > 14 THEN 6110
6210 IF LENGTHB > 14 THEN 6110
6220 'INDA$ = LEFT$(L$) :INDB$ = LEFT$(M$)
6230 'IF INDA$ <> "S " THEN 6110
6240 'IF INDB$ <> "S " THEN 6110
6250 ' Obtain value in g
6260 A = ABS(VAL(RIGHT$(L$,9)))
6270 B = ABS(VAL(RIGHT$(M$,9)))
6272 TOTP = B/ROW
6274 CUM02 = (CUP-A)/(ROW-ROO)
6276 CUMW2 = TOTP-CUM02
6280 CLOSE #1, #3
6281 TMB2 = TIMER
6282 QO = (CUM02-CUM01)/(TMB2 - TMB1)
6284 QW = (CUMW2-CUMW1)/(TMB2 - TMB1)
6300 ' Calculate Fw
6310 FWM=QW/(QO+QW)
6312 CUM01 = CUM02
```



```
6314 CUMW1 = CUMW2
6320 RETURN
6330 END
6400 RESUME
6500 '*****
6510 '***** Subroutine to read pressure *****
6520 '*****
6530 'Read voltage from transducers
6540 ' Set first and last chanel
6551 'read channel 00
6552 CODE$="AC00VN10VR3"
6553 LENGTH=LEN(CODE$)
6554 CALL IOOUTPUTS (DEV, CODE$, LENGTH)
6555 CALL IOENTERA (DEV, PR(1), MAXI, ACTUAL)
6556 P(1)=0!
6557 FOR J=1 TO 10
6558   P(1)=P(1)+PR(J)
6559 NEXT J
6560 P(1)=P(1)/10!
6561 'read channel 01
6562 CODE$="ASVN10VR3"
6563 LENGTH=LEN(CODE$)
6564 FOR J=1 TO 5
6574   CALL IOOUTPUTS (DEV, CODE$, LENGTH)
6575   CALL IOENTERA (DEV, PR(10*J+1), MAXI, ACTUAL)
6581 NEXT J
6582 'calculate average reading
6583 FOR J=1 TO 5
6584   P(J+1)=0!
6585   FOR I=1 TO 10
6591     P(J+1)=P(J+1)+PR(10*J+I)
```

APPENDIX D. DATA LOGGING PROGRAM

```
6592  NEXT I
6593  P(J+1)=P(J+1)/10!
6594  NEXT J
6598  'calculate pressure difference
6660  FOR I=1 TO 6
6670  P(I)=P(I)*T(I)
6680  NEXT I
6690  TMP = TIMER
6700  RETURN
6710  '
6720  '
7000  '*****
7010  '**** SUBROUTINE TO PRINT DATA TO THE SCREEN*
7020  '*****
7030  LOCATE 3,16
7040  PRINT "STANFORD UNIVERSITY PETROLEUM RESEARCH INSTITUTE"
7050  LOCATE 5,15
7060  PRINT "FRACTURE RELATIVE PERMEABILITY DATA
      LOGGING PROGRAM"
7070  LOCATE 8,34
7080  PRINT "Rafael Guzman"
7090  LOCATE 9,35
7100  PRINT "Khalid Aziz"
7110  LOCATE 10,34
7120  PRINT "Roland Horne"
7130  LOCATE 13,5
7140  PRINT "TIME(MIN)      DP1      DP2      DP3      DP4
      DP5      DP6"
7150  LOCATE 14,5
7160  PRINT USING"###.### " ;TM/60!,P(1),P(2),P(3),P(4),
P(5),P(6)
```

```
7170 DEVI=ABS(FW-FWM)/FW*100
7180 LOCATE 17,14
7190 PRINT"Fw injection      Fw measured      Deviation %"
7200 LOCATE 18,16
7210 PRINT USING"###.###      ";FW,FWM,DEVI
7220 RETURN
7230 END

7500 '*****
7510 '**** SUBROUTINE TO STORE DATA IN A FILE *****
7520 '*****
7530 IF FLAG <> 0 GOTO 7560
7540 FLAG=1
7550 PRINT#2,"TIME(MIN)      DP1      DP2      DP3
DP4      DP5      DP6      FWM"
7560 PRINT #2, USING"###.### ";TM/60!,P(1),P(2),P(3),P(4)
,P(5),P(6),FWM
7570 RETURN
7580 END

9000 '***** Terminate the program *****
9010 CLOSE #2
9020 CLS
9030 COLOR 7,0,0
9040 LOCATE 10,15
9050 PRINT "Program was terminated"
9060 END

9200 ' ***** Read new interval between readings *****
9210 CLS
9220 LOCATE 16,5
9230 INPUT "Time interval between readings = ";DT
9240 RETURN 4100
9250 END
```

Appendix E

CT-Scanner Measurements

The following tables summarize the CT-scanner measurements of cores #1 and #2 at dry and 100% NaI solution saturation. The listed position corresponds to the location of the core on the scanner table. For the scans shown in Tables E.3 and E.4 a new core locator was built and the position units were shifted by 2250.

Notice the difference in average CT number of 509 for a dry core and of 645 of a NaI solution saturated core. The CT number for both dry cores is very similar, even though one core has a fracture. The fracture is “seen” if we compare the standard deviation of CT numbers. It is larger for the fractured core #2 than for core #1. This indicates the nonhomogeneity caused by the fracture.

Table E.1: Dry scans of core #1, code C1AIR01.

Slice	Position	CT Number	Standard Deviation	File Name
01	300	505.79	15.03	clair01.a
02	550	509.60	13.78	clair01.b
03	1250	508.15	12.26	clair01.c
05	1600	512.89	12.64	clair01.d1
06	2250	506.49	18.83	clair01.e
07	2600	506.71	12.34	clair01.f
08	3205	508.44	12.88	clair01.g
09	3600	514.01	13.20	clair01.h

Table E.2: Dry scans of core #2, code C2AIR02.

Slice	Position	CT Number	Standard Deviation	File Name
01	300	496.95	22.34	c2air02.a
02	550	500.23	22.52	c2air02.b
03	1250	495.83	26.81	c2air02.c
04	1600	500.90	27.43	c2air02.d
05	2250	510.74	28.89	c2air02.e
06	2600	512.66	20.31	c2air02.f
07	3205	507.16	23.90	c2air02.g
08	3600	501.82	25.16	c2air02.h

APPENDIX E. CT-SCANNER MEASUREMENTS

Table E.3: NaI solution saturated scans of core #1, codes C1NAI01 and C1NAI02.

Slice	Position	CT Number	Standard Deviation	File Name
02	1400	642.47	11.19	c1nai01.a
03	1700	642.61	11.24	c1nai01.b
04	2250	652.75	11.26	c1nai01.c
05	2800	653.60	10.82	c1nai01.d
06	3500	644.82	17.22	c1nai01.e
07	3850	625.27	19.17	c1nai01.f
07	4500	638.18	14.79	c1nai02
08	4850	653.12	11.86	c1nai02
09	5500	656.52	10.73	c1nai02
10	5850	653.18	11.01	c1nai02
11	6550	644.09	13.22	c1nai02
12	7000	634.12	14.07	c1nai02

Table E.4: NaI solution saturated scans of core #2, codes C2NAI01.

Slice	Position	CT Number	Standard Deviation	File Name
01	1400	*	*	c2nai01.a
03	1700	*	*	c2nai01.c
04	2250	*	*	c2nai01.d
05	2800	*	*	c2nai01.e
06	3500	*	*	c2nai01.f
07	3850	651.91	16.77	c1nai01.g
08	4500	658.84	14.97	c1nai02.h
09	4850	657.28	14.00	c1nai02.i
10	5500	655.41	16.16	c1nai02.j
11	5850	652.59	16.00	c1nai02.k
12	6550	649.68	19.99	c1nai02.l
13	7000	641.97	30.61	c1nai02.m
14	1400	654.13	22.57	c1nai02.n

* file not processed.

Bibliography

- [1] Amyx, J. W., Bass, D. M. Jr., and Whiting, R. L.: *Petroleum Reservoir Engineering*, McGraw-Hill Book Company, New York (1960).
- [2] Aziz, K., Settari, A.: *Petroleum Reservoir Simulation*, Applied Science Publishers Ltda, London (1979).
- [3] Beckner, B. L.: *Improved Modelling of Imbibition Matrix/Fracture Fluid Transfer in Double Porosity Simulators*, PhD dissertation, Stanford University (May. 1990).
- [4] Birks, J.: "Theoretical Investigation Into the Recovery of Oil from Fissured Limestone Formations by Water-Drive and Gas Cap Drive," Proc., Fourth World Pet. Cong., Rome (1955).
- [5] Castanier, L.M.: "An Introduction to Computerized X-Ray Tomography for Petroleum Research," SUPRI TR-66, Stanford, California (Jun. 1989).
- [6] Chatzis, I., and Morrow, N. R.: "Correlations of Capillary Number Relationship for Sandstone," *Society of Petroleum Engineers Journal* (oct. 1984) 555-562.
- [7] Cuiec, L. E., Bourbiaux, B. and Kalaydjian, F.: "Imbibition in Low-Permeability Porous Media: Understanding and Improvement of Oil Recovery," paper SPE 20259 presented at the 1990 SPE/DOE Seventh Symposium on Enhanced Oil Recovery.
- [8] Demiral, B.: "Three Dimensional Laboratory Steam Injection Model," SUPRI Heavy Oil Research Program, Fourteenth Annual Report, Stanford, California

BIBLIOGRAPHY

(Jun. 1990).

- [9] Dutra, T. V., and Aziz, K.: "A New Double-Porosity Reservoir Model for Oil/Water Flow Problems," paper SPE 21248 presented at the 1991 SPE Symposium on Reservoir Simulation.
- [10] Exploration Consultants Limited: *Eclipse Reference Manual* (Sep. 1988) Version 88/09.
- [11] Firoozabadi, A., and Hauge J.: "Capillary Pressure in Fractured Porous Media," *Journal of Petroleum Technology* (Jun. 1990) 784-791.
- [12] Firoozabadi, A., and Thomas L.K.: "Sixth SPE Comparative Solution Project: Dual-Porosity Simulators," *Journal of Petroleum Technology* (Jun. 1990) 710-763.
- [13] Honarpour, M., Koederitz, L. and Harvey, A. H.: *Relative Permeability of Petroleum Reservoirs*, CRC Press Inc., Boca Raton, Florida (1986).
- [14] Horie, T., Firoozabadi, A., and Ishimoto, K.: "Laboratory Studies of Capillary Interaction in Fracture/Matrix Systems," paper SPE 18282 presented at the 1988 SPE Annual Technical Conference and Exhibition.
- [15] Hossein, K.: "Naturally Fractured Reservoirs," Third International Forum on Reservoir Simulation, Baden, Austria (1990).
- [16] Iffly, R., Rousselet, D. C., and Vermeulen, J. R.: "Fundamental Study of Imbibition in Fissured Oil Fields," paper SPE 4102 presented at the 1972 SPE-AIME 47th Annual Fall Meeting.
- [17] Johns, R. A., Steude, J., Castanier, L. M., and Roberts, P.V.: "Non-Destructive Measurement of Fracture Aperture in Crystalline Rock Cores Using X-Ray Computed Tomography," To Be Submitted for Publication (1991).
- [18] Jones, T. A., Wooten, S. O., and Kaluza, T. J.: "Capillary Continuity Between Blocks of a Fractured Reservoir," paper SPE 20515 presented at the 1990 SPE Annual Technical Conference and Exhibition.

- [19] Kazemi, H.: "Naturally Fractured Reservoirs," Marathon Oil Company (198?).
- [20] Kazemi, H., and Merrill, L. S.: "Numerical Simulation of Water Imbibition in Fractured Cores," *Society of Petroleum Engineers Journal* (Jun. 1979) 175-182.
- [21] Kleppe, J. and Morse, R. A.: "Oil Production from Fractured Reservoirs by Water Displacement," paper SPE 4102 presented at the 1974 SPE-AIME 49th Annual Fall Meeting.
- [22] Labastie, A.: "Capillary Continuity Between Blocks of a Fractured Reservoir," paper SPE 20515 presented at the 1990 SPE Annual Technical Conference and Exhibition.
- [23] Lowry, B., and Kawaji, M.: "Adiabatic Two-Phase Flow in Narrow Flow Channels," A.I.Ch.E. Nat. Heat Transfer Conf., Houston (1988).
- [24] Mannon, R. W., and Chilingar, G. V.: "Experiments in Effect of Water Injection Rate on Imbibition Rate in Fractured Reservoirs," paper SPE 4101 presented at the 1972 SPE-AIME 47th Annual Fall Meeting.
- [25] Mattax, C. C., and Kyte, J. R.: "Imbibition Oil Recovery from Fractured, Water-Drive Reservoir," *Society of Petroleum Engineers Journal* (Jun. 1962) 177-184.
- [26] Morrow, N. R.: "Capillary Pressure Correlations for Uniformly Wetted Porous Media," *The Journal of Canadian Petroleum Technology* (Oct-Dec 1976) 49-69.
- [27] Orr, F. M.: "Reservoir Characterization for CO_2 Flooding," Third Wyoming EOR Symposium, Casper, Wyoming (May 1987).
- [28] Owusu, L. A., and Ershaghi, I.: "Relative Permeability of Naturally Fractured Reservoirs from Field Performance Data," paper SPE 18748 presented at the 1989 SPE California Regional Meeting.
- [29] Persoff, P., Pruess, K., and Myer, L.: "Two-Phase Flow Visualization and Relative Permeability Measurement in Transparent Replicas of Rough-Walled Rock

BIBLIOGRAPHY

- Fractures," Sixteenth Workshop on Geothermal Reservoir, Stanford University (Jan. 1991).
- [30] Purcell, W. R.: "Capillary Pressures - Their Measurement Using Mercury and the Calculation of Permeability Therefrom," *Trans. AIME*, 186, 39 (1949).
- [31] Romm E. S.: *Fluid Flow in Fractured Rocks*, Nerda Publishing House, Moscow (1966).
- [32] Sanyal, S. K.: *The Effect of Temperature on Electrical Resistivity and Capillary Pressure Behavior of Porous Media*, PhD dissertation, Stanford University (Dec. 1971).
- [33] Schechter, D. S., Zhou, D., and Orr, F. M. Jr.: "Capillary Imbibition and Gravity Segregation in Low IFT Systems," paper SPE 22594 presented at the 1991 66th SPE Annual Technical Conference and Exhibition.
- [34] Tsang, Y.W., and Tsang, C.F.: "Channel Model of Flow Through Fractured Media," *Water Resour. Res.*, v. 23, no. 3 (1987) 467-479.
- [35] van Golf-Racht, T. D.: *Fundamentals of Fractured Reservoir Engineering*, Elsevier (1982).
- [36] Wang, J.: "Relative Permeability Study," SUPRI Heavy Oil Research Program, Ninth Annual Report, Stanford, California (Jun. 1986).
- [37] Weast, R. C., and Astle, M. J.: *CRC Handbook of Chemistry and Physics*, CRC Press, Boca Raton, Florida (1982).
- [38] Witherspoon, P. A., Wang, J. S. Y., Iwai, K., and Gale, J. E.: "Validity of the Cubic Law for Fluid Flow in a Deformable Rock Fracture," *Water Resources Research*, Vol. 16, No. 6 (1980) 1016-1024.
- [39] Withjack, E. M.: "Computed Tomography for Rock-Property Determination and Fluid-Flow Visualization," *SPE Formation Evaluation* (Jun. 1988) 784-791.

**DATE
FILMED**

10/27/93

END