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Linear Oil Displacement by
the Emulsion Entrapment Process

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Thesis
Master of Science

January, 1982

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David Paul Schmidt

Linear Oil Displacement by the Emulsion Entrapment Process

ABSTRACT

Lack of mobility control is one of the major impediments to successful enhanced oil recovery, especially for high viscosity oils. This work presents experimental and theoretical results for linear secondary oil displacements using dilute, stable suspensions of oil drops. The major hypothesis is that emulsions provide mobility control through entrapment or local permeability reduction, not through viscosity ratio improvement. In order to describe the displacement process, previous emulsion filtration theory is extended to longer cores and to two-phase flow.

Quantitative agreement between theory and experiment is satisfactory for continuous secondary oil displacement with various drop-size emulsions in unconsolidated sand packs of permeabilities ranging from $0.7 \mu\text{m}^2$ to $3.3 \mu\text{m}^2$. Linear emulsion floods are shown to be most effective when the mean drop-size to pore-size ratio is in the region between straining and interception at the emulsion shock. Floods are more effective when the emulsion concentration is high which minimizes retention lag. Additionally, a parallel flooding apparatus is utilized to determine qualitatively the macroscopic benefits of emulsion mobility control. Direct analogies are established between augmented oil recovery with dilute emulsions and with entrapping polymers.

TABLE OF CONTENTS

	<u>Page</u>
ACKNOWLEDGEMENTS.....	vii
LIST OF TABLES.....	viii
LIST OF FIGURES.....	ix
I INTRODUCTION.....	1
II EXPERIMENTAL.....	6
A. Apparatus.....	6
1. Pressure Drop.....	11
2. Effluent Monitoring.....	12
3. Core Preparation.....	13
4. Emulsion Preparation.....	17
B. Experimental Procedures.....	18
1. Emulsion Flow.....	18
2. Oil Flooding.....	18
3. Water Flooding.....	19
4. Linear Emulsion Flooding.....	21
5. Parallel Emulsion Displacement.....	21
APPENDIX II.....	22
A. Core Preparation.....	22
B. Emulsion Concentration and Drop Size Distribution Determination.....	26
III THEORY.....	33
A. Water Displacement.....	33
1. Graphical Solution.....	43
2. Experimental Relative Permeabilities.....	44
B. Emulsion Flow.....	46
1. Single Phase Flow.....	47
2. Scaling.....	55
3. Filtration Parameters in Two-Phase Flow.....	63

TABLE OF CONTENTS (continued)

	<u>Page</u>
C. Emulsion Displacement.....	72
1. Physical Description.....	72
2. Theory.....	80
3. Graphical Solution.....	83
4. Discussion.....	94
APPENDIX III.....	99
A. Dynamic Pressure Drop.....	99
1. Water Displacement.....	99
2. Emulsion Displacement with High Drop Penetration.....	101
3. Emulsion Displacement with Low Drop Penetration.....	103
IV DISCUSSION AND RESULTS.....	105
A. Linear Emulsion Displacement.....	106
1. Low Drop-Size to Pore-Size Ratio.....	106
2. High Drop-Size to Pore-Size Ratio.....	112
3. Intermediate Drop-Size to Pore-Size Ratio....	116
B. High-Concentration Emulsion Displacement.....	125
C. Parallel Cores.....	132
APPENDIX IV.....	140
A. Displacement Parameters.....	140
B. Immobilized Water.....	142
V CONCLUSIONS.....	148
VI NOMENCLATURE.....	150
VII LITERATURE CITED.....	154

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LIST OF TABLES

<u>Table</u>	<u>Page</u>
II A.1 Sandpack Grain-Size Distribution and Permeability.....	24
II B.1 Zeiss Counter Distribution and Drop Size Determination.....	31
4.1 Oleate Effect on Surface Tension.....	111
4.2 High-Concentration Emulsion Flood Effluent Drop Size Shift, $\langle D_d \rangle_i = 1.8 \mu\text{m}$	128
IV A.1 Relative Permeability and Linear Emulsion Displacement Parameters.....	141

LIST OF FIGURES

<u>Figure</u>	<u>Page</u>
2.1 Flooding apparatus.....	7
2.2 Emulsion reservoir stirring mechanism.....	10
2.3 Comparative secondary waterflooding.....	20
B.1 Effect of focal plane on drop image.....	29
3.1 Relative permeability curves for a viscous mineral oil, k_{rn} , and water, k_{rw} $n=3.2$, $p=2.0$, $k_{rn}^0=0.84$, $k_{rw}^0=0.2$	35
3.2 Fractional flow curve for a viscous mineral oil and water.....	38
3.3 Saturation profile for a water displacement of a viscous mineral oil after 0.25 pore volumes injected.....	41
3.4 Secondary waterflood production history plotted as a fraction of oil produced versus pore volumes injected.....	42
3.5 Secondary oil recovery (triangles) and pressure history (circles) for the waterflood of a viscous oil.....	45
3.6 The mechanism of emulsion flow in porous media....	48
3.7 Short core reduced filter coefficient as a function of mean drop-size to pore-size ratio....	51
3.8 Short core flow diversion parameter as a function of mean drop-size to pore-size ratio.....	52
3.9 Short core flow-restriction parameter as a function of mean drop-size to pore-size ratio....	53
3.10 Emulsion concentration history in a short, 3 cm, core and in a long, 33 cm, core.....	57
3.11 Emulsion concentration history in a long, 33 cm, core.....	58
3.12 Initial drop-size distributions for the experiments depicted in Figures 3.10 and 3.11.....	60
3.13 Effluent emulsion mean drop-size for long (circles) and short (squares) cores of Figure 3.11.....	61

LIST OF FIGURES (continued)

<u>Figure</u>	<u>Page</u>
3.14 Effluent emulsion mean drop-size for long, 33 cm, core of $0.42 \mu\text{m}^2$ depicted in Figure 3.11.....	62
3.15 Emulsion concentration history in a core containing immobile oil as a function of aqueous pore volumes.....	65
3.16 Effluent emulsion mean drop size for the immobile oil saturation experiment depicted in Figure 3.15.....	68
3.17 Emulsion concentration history in a core containing immobile oil as a function of aqueous pore volumes injected.....	69
3.18 Effluent emulsion mean drop size for the immobile oil saturation experiment depicted in Figure 3.17.....	71
3.19 Fractional flow of aqueous phase versus S_w for differing permeability reductions.....	74
3.20 Total emulsion retention per bed void volume versus aqueous phase saturation.....	76
3.21 Graphical solution for small $S_{wc}/\bar{\alpha}C_1$, high drop penetration.....	84
3.22 Saturation profile for both a waterflood (dashed line) and the emulsion flood of Figure 3.21 (solid line) after injection of 0.2 pore volumes.....	87
3.23 Fraction of oil in place produced versus pore volumes of aqueous phase injected, for waterflood (solid line) and emulsion flood (dashed line) described by Figures 3.21 and 3.22.....	88
3.24 Graphical solution for large $S_{wc}/\bar{\alpha}C_1$, low drop penetration.....	90
3.25 Saturation profile for both a standard waterflood (dashed line) and the emulsion flood of Figure 3.24 (solid line) after injection of 0.2 pore volumes.....	92
3.26 Fraction of oil in place produced versus pore volumes of aqueous phase injected for both waterflood (solid line) and the emulsion flood (dashed line) described by Figures 3.24 and 3.25 ..	93

LIST OF FIGURES (continued)

<u>Figure</u>	<u>Page</u>
3.27 Effect of injected drop size on oil production history.....	96
3.28 Effect of emulsion drop concentration on oil production history.....	98
4.1 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a 3.3 μm^2 core.....	107
4.2 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) of Figure 4.1.....	109
4.3 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a 0.7 μm^2 core.....	113
4.4 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the results shown in Figure 4.3.....	114
4.5 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a 1.15 μm^2 core.....	117
4.6 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the results shown in Figure 4.5.....	118
4.7 Emulsion effluent mean drop size and concentration corresponding to the emulsion displacement shown in Figures 4.5 and 4.6.....	120
4.8 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a 2.0 μm^2 core....	123
4.9 Pressure drop history for both the waterflood (circles)s and emulsion flood (triangles) for the experimental results shown in Figure 4.8.....	124
4.10 Secondary waterflood (circles) and high concentration emulsion flood (triangles) recovery history in a 1.9 μm^2 core.....	127
4.11 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the experimental results shown in Figure 4.10....	131

LIST OF FIGURES (continued)

<u>Figure</u>	<u>Page</u>
4.12 Parallel core test results shown as the fraction of oil in place produced per core, versus the total injected pore volumes.....	133
4.13 Fraction of total volumetric flow through the low, 0.65 μm^2 permeability core versus total pore volumes injected.....	135
4.14 Fraction of oil in place produced for both the 0.65 and 1.8 μm^2 cores as a function of injected pore volumes into each core, not total pore volumes injected.....	137
IV B.1 Graphical solution for high $S_{wc}/\bar{\alpha}C_1$ containing no immobile water (solid tangent) and 0.3 pore volumes immobilized water (long dashed tangent).....	144
IV B.2 Graphical solution for low $S_{wc}/\bar{\alpha}C_1$ containing no immobile water (solid tangent) and 0.3 pore volumes immobilized water (long dashed tangent).....	145
IV B.3 Fraction of oil in place produced versus pore volumes injected.....	147

I. INTRODUCTION

Recovering oil from underground reservoirs is an important problem that is challenging from both economic and technical standpoints. After primary recovery, the current practice is to inject water into the reservoir to displace oil. Unfortunately, water is highly mobile and does not displace viscous oil very effectively. Waterflooding, as well as all more advanced fluid displacement techniques, must establish mobility control in order to increase significantly oil recovery.

The term mobility control refers to the efficiency or success of controlling unfavorable flow disturbances which lead to poor oil production from underground reservoirs. On a macroscopic scale, injection fluids can channel through high permeability regions, or thief zones, while never coming into contact with vast quantities of trapped oil. On a smaller scale, displacement fluids may invade ahead of the oil, even in a homogeneous medium, leaving significant portions behind. This thesis deals with improving mobility control on a microscopic scale by the use of dilute, stable oil-in-water emulsions.

To determine how mobility control may be improved, Darcy's law for a fluid flowing in a one-dimensional porous medium is written:

$$v_j = - \left[\frac{k_{rj} K_o}{\mu_j} \right] \frac{\partial P_j}{\partial x} \quad j = n, w \quad (1.1)$$

The subscript "j" denotes either the wetting phase, w, usually water, or the nonwetting phase, n, oil. In Equation (1.1)

V indicates the superficial velocity, K_o is the absolute permeability, k_{rj} is the relative permeability, P denotes pressure, μ is the Newtonian viscosity, and x is the axial distance. The product $k_{rj}K_o$ also is defined as the effective permeability to phase j . Mobility of a phase is defined as the bracketed coefficient multiplying the pressure gradient in Equation (1.1). It is a measure of the flow resistance that phase j experiences in the porous medium. Higher mobilities indicate less resistance to flow. If the local pressure drop in each phase flowing is the same, then the ratio of the water-to-oil velocities is given by

$$M \equiv \frac{V_w}{V_n} = \left[\frac{k_{rw} K_o}{\mu_w} \right] / \left[\frac{k_{rn} K_o}{\mu_n} \right] \quad (1.2)$$

which also defines the mobility ratio, M . Since the viscosity of water is usually less than that of oil, water travels faster, and thus leaves oil behind. To achieve improved mobility control one attempts to lower the mobility ratio.

Equation (1.2) indicates two ways of reducing M : either the mobility of water can be decreased or the mobility of oil increased. In changing the water mobility two possibilities exist: the water viscosity could be increased or the effective permeability to water might be reduced compared to that of the oil. Water viscosity can be increased by the addition of water soluble polymers and leads to the process of polymer flooding. This thesis investigates the use of dilute emulsion flooding as a means of lowering the effective water permeability and, hence, improving recovery of viscous oils.

Emulsion flooding may be attractive especially in California where crude oils are quite viscous, which thwarts standard water-flooding techniques. These crudes also contain significant acid components which form surfactants upon contact with alkali. Alkaline saponification can yield emulsions with little, if any, mixing energy and at a small cost. Hence, use of dilute emulsions may be attractive economically, when compared to polymer flooding.

The possible economic benefits of alkaline generated emulsions have led to the suggestion of two processes for aiding oil recovery (1). In one process, emulsification with entrainment, oil drops are generated in-situ upon reaction of alkali with acidic crude oil. The resulting oil production occurs as an oil-in-water emulsion. According to the entrainment view, oil drops do not interact with the reservoir medium. In emulsification with entrapment, the other process, oil drops that are generated in-situ or which are externally injected, aid in oil recovery by providing mobility control. According to the entrapment view, oil drops interact strongly with the reservoir medium to impede the flow of the aqueous displacing phase.

Recent work by Soo and Radke (2) on the details of dilute emulsion flow in unconsolidated porous media shows that oil drops clog pore constrictions and capture on pore walls, thereby restricting flow. Once captured there is negligible particle re-entrainment. Even drops smaller than the pore throats have a significant capture probability. The study of Soo and Radke supports the entrapment picture as a more viable description of emulsion flow.

However, in spite of successful field applications of the entrapment technique (3, 4) no current methodology exists to predict

quantitatively the possible mobility control improvement. The purpose of this work is to predict quantitatively the displacement process for dilute emulsion flooding. The more macroscopic flow distributions that will be present in actual heterogeneous reservoirs are discussed only qualitatively for the case of two regions differing in permeability. Filtration theory is relied on heavily to describe transient emulsion flow in water-saturated cores. In modeling enhanced oil recovery with dilute emulsions, the previous filtration theory (2) must be extended to long cores and to two-phase flow. Combination with extensions of classical Buckley-Leverett waterflooding theory then permits the calculation of transient displacement.

The significance of the mathematical treatment pertains more broadly than to just the emulsion entrapment technique. It is well known that certain polymers, notably polyacrylamides, establish more mobility control than can be accounted for by bulk rheology (5-11). Large permeability reductions are observed upon polymer injection and are denoted in petroleum literature as residual resistance factors. Adsorption does not appear to be the main cause of this flow restriction, but rather mechanical entrapment, that is trapping of high-molecular-weight polymer molecules, or gels, in pore restrictions. The analogy to emulsion entrapment is obvious. Hence, any theory devised for one phenomenon should, in principle, be applicable to the other. Throughout this thesis the analogies between polymers and emulsions will be stressed.

Following directly in Chapter II, the experimental apparatus and operating procedures are outlined to familiarize the reader with

the techniques used. Chapter III contains the development of the theoretical framework of emulsion flow in water saturated cores and for emulsion displacement of oil. Discussion of the experimental results and engineering of a successful emulsion flood follow in Chapter IV.

II. EXPERIMENTAL

To investigate the influence of dilute emulsion on viscous oil recovery, three different types of flow experiments are performed in quartz sandpacks. First, emulsions are injected into long (33 cm) water-saturated cores to determine if the model proposed by Soo and Radke (2) properly scales to longer cores. Next, emulsions are injected into cores containing a constant oil and water saturation, which enables evaluation of the emulsion retention as a function of water saturation. This permits the application of Soo and Radke's emulsion retention theory to emulsion displacement. Finally, secondary emulsion floods are compared to standard water-flooding results. These emulsion displacements constitute the major effort of this thesis. Additionally, both a water and emulsion flood are performed on two cores of different permeabilities mounted in parallel in order to ascertain any redistribution of flow between the cores. All experiments are conducted at constant injection rate to permit comparison with the theory presented in Chapter III.

A. Apparatus

The experimental flooding apparatus is depicted in Figure 2.1. An Altex liquid-chromatograph pump delivers isopropyl alcohol to an intermediate reservoir containing mercury. This pump is used because of its low flow rate capability of $4.7(10^{-4})\text{cm}^3/\text{sec}$, its $4.7(10^{-4})\text{cm}^3/\text{sec}$ flow rate increments, and an operating pressure range of up to 69 MPa. Because it is a dual piston, positive displacement pump, the Altex exhibits negligible flow oscillations; therefore, air cushioned flow dampeners are not needed to reduce

Figure 2.1 Flooding apparatus

flow pulsation.

Originally, the pump was purchased to deliver mercury directly to the displacement reservoirs. However, the supplied ruby ball check valves, which are less dense than mercury, did not seal properly, resulting in a back flow of mercury into the pistons. Precision tungsten check balls, that are denser than mercury, were installed to solve this problem. The check valves again did not operate properly, due probably to the high surface tension of mercury and its small density difference against tungsten (i.e. 13.7 g/cm^3 for mercury versus 19.2 g/cm^3 for tungsten). A possible solution would have been to design spring loaded check valves. Instead, the ruby check valves were reinserted, and an intermediate isopropyl alcohol system was designed for driving the mercury.

Isopropyl alcohol is stored in a glass reservoir and is filtered through a $5 \text{ }\mu\text{m}$ stainless steel frit before delivery to the pump. This is done to remove any particles which could damage the pistons. However, with prolonged use, the isopropyl alcohol became contaminated, as evidenced by a yellow tint. The pump then varied in flow rate due to the check valves sealing improperly. Therefore, the isopropanol was discarded and the check valves cleaned. By using fresh, technical grade isopropyl alcohol, constant and consistent flow rates are assured. Hence, the isopropyl alcohol is routinely changed to a fresh supply.

From the pump, the isopropyl alcohol is delivered to the top of a reservoir containing mercury, which is then displaced from the bottom. Mercury is chosen to drive the oil, water or emulsion into the porous medium because it will not contaminate the displacing phase, and it is

immiscible in both oil and water. All reservoirs contacting mercury are constructed of 316 stainless steel, and are designed to withstand pressures up to 7MPa. 316 stainless steel provides high resistance to both mercury and caustic corrosion. Use of the 30 cm long, 8 cm diameter cylindrical reservoirs enables injection of up to 13 pore volumes of fluid into the 33 cm long, 4 cm diameter porous medium. These reservoirs are positioned to provide a gravity recharge of mercury to the intermediate alcohol-mercury reservoir. This has the advantage of both charging the isopropanol reservoir and the corresponding oil, water or emulsion reservoir at the same time.

Since the emulsion must be supplied to the core at a uniform concentration and drop size for a period of several days, stirring of the emulsion reservoir is required. As shown in Figure 2.2, stirring is achieved by a perforated teflon disk attached to a disk magnet, driven up and down by a second external magnet. This external magnet is oscillated by an eccentric cam attached to an electric motor. Because the poles of the two magnets are aligned similarly, north to north, the external magnet pushes the internal one upwards. The internal magnet with its attached teflon disk, then settles by gravity. Oscillation frequency is determined by the weight of the internal magnet stirrer and the speed of the motor. This type of low shear stirring prevents emulsion creaming or drop breakup and does not induce perikinetic coalescence of the stabilized oil drops. Periodic sampling of the emulsion just before injection into the core confirms that a uniform concentration and drop size is supplied.

Other more conventional methods of emulsion agitation will not

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Figure 2.2 Emulsion reservoir stirring mechanism.

work. Since the vessel walls are thick enough to withstand 7MPa, a conventional magnetic stirrer would not operate. Even so, a bar stirrer would not specifically reduce vertical drop segregation in a deep vessel. A stirring rod could be used but only with a high pressure shaft seal. The system designed here provides simple and convenient low-shear stirring.

Tubing from the outlet of the emulsion reservoir to the porous medium is short and is placed horizontally so that little drop creaming occurs. This is particularly important when buoyant emulsion drops are studied.

1. Pressure Drop

The pressure difference across the core is continuously monitored by a variable reluctance Validyne transducer (model DP15). Deformation in a metal diaphragm used in the transducer produces a change in the magnetic inductance of the plate, which is amplified and displayed by a carrier demodulator. The signal is also transmitted to a Linear chart recorder. The Validyne transducer provides a high degree of flexibility, since the metal diaphragm can be removed, and a narrower or wider pressure-range plate can be installed. Full scale accuracy is achieved by choosing the proper diaphragm. Each time the pressure transducer is disassembled and another plate installed, the transducer must be recalibrated. Calibration is accomplished with a mercury manometer.

The taps for measuring the pressure drop across the porous media are located 7 mm from each end of the packed core. This enables the measurement of pressure to be free of end effects. The tap holes, which are 0.8 mm in diameter, sometimes plug while packing

the core and the pressure drop then has to be measured across the outside of the core. The difference in pressure is negligible between the two methods of measurement, since the core size is designed to have small end effects and the taps are close to the inlet and outlet. Therefore, this is not a surprising result.

2. Effluent Monitoring

Produced fluids from the core are continuously collected in test tubes by a model 2112 Redirick fraction collector. The collector is capable of sampling for time periods as low as 6 seconds and as long as 99 minutes. By automatic effluent collection at fixed time intervals the flow rate can also be constantly checked.

Disposable 15 x 85 mm glass test tubes collect the effluent. Prior to use, each tube is weighed using a Mettler automatic balance interfaced with a Hewlett-Packard 97S calculator programmed to print out the weight of the tube. The tubes are then loaded into the collector and the sampling time is set so that approximately 8 cm³ of effluent is charged into each tube. All tubes are stoppered once filled, to reduce evaporative loss. The volumes of all collected samples are established by weight in order to determine accurately small fractional volumes of oil.

In the case where both oil and water phases occupy a single sample tube, as during displacement tests, the method for determining the volume fraction of each is as follows. Tubes, containing all of the effluent collected, are weighed. A syringe is used to remove the bulk of the oil phase, if there is a significant fraction of oil present. Once the fraction of oil is small enough, less than 0.5 cm³, a different method is used to remove the

remaining oil. Oil phase removal is now accomplished by taking advantage of wetting properties and the high viscosity of the oil. A brass rod is dipped into the test tube and quickly pulled out and wiped off. The oil wets the rod, and because of its high viscosity, drainage is minimized. Rod collection is repeated until all of the oil is removed. By weighing before and after oil removal, the oil and water volumes are found. Densities of the various fluids have been previously measured with a pycnometer.

When emulsion appears in the effluent aqueous phase, it is analyzed for drop concentration and size distribution. This analysis procedure is described later in Appendix IIB.

3. Core Preparation

Fine Ottawa sand of mixed grain size is packed into a stainless steel core holder and serves as the experimental porous medium. The sand is obtained from the Ottawa Sand Co. and consists of a mixture of grain sizes, which are separated by use of Tyler brass mesh sifting screens. A 200 gram sample is dry sifted for 20 minutes in a Tyler portable shaker using in order, screens of U.S. sieve designation 30, 50, 70, 100. The various grain sizes are then stored in Nalgene bottles until being mixed to produce the desired permeability. X-ray diffraction of a sand sample revealed the composition to be 98 percent quartz and approximately 2 percent kalonite by weight.

The smallest grains of the commercially obtained sand are 0.106 mm and any combination of these grain sizes does not produce low enough permeability. In order to obtain a mixture of sand which gives the desired permeability, smaller grain sizes are needed.

Sand is first ground in a vibratory mill utilizing alumina as the grinding medium. Grinding time, initial grain size, and charge size all influence the particle size produced. The ground sand is then dry sifted and stored. Later it was determined that this ground sand contained a significant amount of alumina. It was, therefore, discarded. New sand was then reduced in size using a vibratory mill having quartz as the grinding medium. This removed the possibility of introducing impurities into the quartz sand. The ground sand is sifted by screens in order of 100, 140, 200 mesh and stored. Once sand has been separated into known size fractions, it may then be combined into known quantities to give a mixture of desired permeability. The two major variables affecting the permeability of the sand pack are the packing pressure and the sand mixture. For a discussion of the effect of sand mixtures and compression techniques see Appendix IIA.

During packing, sand is charged into the stainless steel core holder and compressed by a hydraulic press in 1.2 cm increments so that a homogeneous pack is prepared. Stainless steel screens of 200 and 400 mesh are then placed between the sand and the end caps of the core holder to prevent the loss of sand particles during flooding. If the core holder is slightly overfilled such that the end caps do not sit flush on the holder, a slight over burden pressure can be exerted by tightening the end caps. This helps prevent movement of fines in the porous medium and keeps the core homogeneous, even after injection of numerous pore volumes of fluid.

The size of the core holder is 33 cm long and 4 cm in diameter. Its dimensions are calculated to ensure that scaled, stabilized

flow occurs at the injection velocities used (12). Core dimensions are also chosen to permit viscous fingering and to minimize end effects (13, 14). To facilitate an even distribution of fluid at the inlet and outlet, the endcaps were milled in a pattern to promote distribution as outlined by Kelly (15). The average pore volume of the pack is 125 cm^3 with a porosity of 30 percent. Permeabilities range from 0.4 to $3.2 \text{ } \mu\text{m}^2$. A 125 cm^3 pore volume enables accurate measurement of the breakthrough and elution times. Each experimental flood requires injection of approximately 7 pore volumes of fluid. At the frontal advance rate of $18 \text{ } \mu\text{m}/\text{sec}$ ($5 \text{ ft}/\text{day}$) used in most tests and with the core length of 33 cm, the experimental flooding time per flood is, therefore, 1 to 2 days.

After packing the core, the nitrogen permeability is measured. In a gas permeater, nitrogen at constant temperature is passed through the sand at various flow rates while monitoring the pressure drop across the core and the exit volumetric flow, Q . Using this data the nitrogen permeability is determined according to Darcy's law for an ideal gas in a linear flow system:

$$K_o = \frac{2\mu LPQ}{A(P_1^2 - P_2^2)} \quad (2.1)$$

Nitrogen permeability follows from the slope of the line of experimental flow rate (in cm^3/s at $P=1 \text{ atm}$ and the flowing temperature) versus the difference in the squares of the inlet pressure P_1 and outlet pressure P_2 (in atm). Likewise, L is the length of the core in cm, A is the cross-sectional area in cm^2 , and μ is the

viscosity of nitrogen at the flow temperature in centipoise. With the above units the obtained value of K_o is given in Darcy. Once a core has been water saturated, comparison of nitrogen and water permeabilities determines the degree of water saturation.

During water saturation, great care is taken to ensure that all air is removed from the sandpack, otherwise the permeability obtained for water will not agree with that of nitrogen and trapped air is present in the core. First, the water for saturation is degassed. Next, oxygen is passed through the core to displace nitrogen, since oxygen is twice as soluble as nitrogen in water. The porous medium is then evacuated of oxygen to a vacuum of 50 μ m of mercury for approximately an hour. Degassed water is allowed to enter the core, and between four and eight pore volumes of fluid are pulled through by vacuum. The weight of the sandpack is measured before and after saturation enabling the determination of porosity and pore volume. The water permeability is evaluated by injecting water at various flow rates through the saturated core while measuring the pressure drop. The permeability follows from Darcy's law and the incompressibility of water:

$$K_o = \frac{\mu L Q}{A(P_1 - P_2)} \quad (2.2)$$

Again, the slope of the line of flow rate plotted against the difference between inlet and outlet pressures determines the absolute permeability to water. If all of the oxygen is removed, the water and nitrogen permeabilities should be identical. Commonly, the water permeability averages 10 percent below that of nitrogen, which

is within the error of measurement. If the water permeability is higher or much lower than the nitrogen value, the core is dried and the process repeated. During the water desaturation, heating tape is used, while a vacuum is drawn on the core. This is continued until no difference in core weight with time is found. If the second nitrogen and water permeabilities do not correspond, the core is discarded, and another one is packed.

4. Emulsion Preparation

The oil used in preparing the neutrally buoyant oil-in-water emulsion is a mixture of Chevron 410H, a 1 mPa.s viscosity mineral oil, and carbon tetrachloride. Emulsion is made by adding oleic acid to the oil, at a concentration of $4.0(10^{-2})$ g/g oil, and then blending with aqueous sodium hydroxide at a pH of 10 in a 1 to 50 volume ratio. A pH of 10 is used to have both negatively charged drops and quartz at low ionic strength where the drops are stable and will not coalesce. A Waring blender emulsifies the mixture with a blender speed and time of agitation controlling the drop-size distribution. Such oil-in-water emulsions are extremely stable and will last many days before a drop-size shift can be detected (2). Before use, the emulsion is diluted with pH 10 water to the desired drop concentration.

Oil drop concentration, drop size, and drop-size distribution are all measured from photomicrographs with a Zeiss particle counter. The method used is presented in Appendix IIB. Some of the variables which affect the measured drop size are: the microscope magnification and focus, the time before photographing and the degree of photographic enlargement. Typical emulsion concentrations range from 0.3 to 1.5 volume percent, and drop sizes range from below

1 to 5 μm .

B. Experimental Procedures

1. Emulsion Flow

Continuous emulsion injection into a water-saturated core is the simplest flow experiment. The oil-in-water emulsions are injected at constant flow rate, while the pressure drop and effluent drop size and drop concentrations are monitored. The results of the emulsion flow experiment are interpreted according to the filtration theory of Soo and Radke, as previously outlined (2). After the emulsion flow test is completed, the mercury-alcohol reservoir is recharged, and the core removed from the apparatus.

2. Oil Flooding

Prior to water or emulsion displacement tests, the water saturated core must be oil saturated. A viscous 140 mPa.s Chevron mineral oil is colored by Sudan III red dye. Dyeing gives better oil phase definition, permits distinction between emulsified and continuous flowing oil, and allows precise judgement of complete oil removal from the receiving test tubes by the rod collection technique. Oil flooding is continued at the proposed emulsion injection rate until the pressure drop stabilizes and water is no longer eluted for one pore volume. Typically three to five pore volumes of oil are injected, depending on the core permeability. Connate water saturation, or the saturation of water that remains after oil flooding, is determined from the volume of water displaced from the core. Values typically range from 10 to 20%. The displaced fluid is collected in 250 cm³ graduated cylinders with the volume of water being measured directly. The oil, mercury-alcohol, and

alcohol reservoirs are all then recharged prior to waterflooding or emulsion displacement.

3. Water Flooding

After oil flooding, water is continuously injected at the proposed emulsion flow rate. Effluent is collected by the fraction collector, while the pressure drop is monitored. Water is injected until oil no longer appears in the effluent, typically for 5 to 8 pore volumes. From the pressure and oil recovery data, water and oil relative permeabilities are calculated. The calculational method is outlined in the theory section of this thesis.

Before conducting an emulsion flood, the water flooded core must again be oil saturated. Hence, the core is loaded with oil until the pressure stabilizes and no more water is produced, as described above. Connate water saturation is then measured. It should be the same or slightly higher than the value obtained before initial waterflooding.

One experiment was performed to establish that the resaturation process does not affect the core packing or change the waterflooding behavior (i.e., that it does not alter the relative permeability curves). After resaturating with oil, a second waterflood was performed to check the difference between the two displacements. Figure 2.3 shows the results. Here the fraction of oil originally in the core and then produced, FOP, is shown as a function of injected fluid pore volumes, τ , for the two waterfloods. Agreement between the two floods is excellent, and well within experimental error.

Figure 2.3 Comparative secondary waterflooding: first flood (circles), second flood (squares). Solid line gives waterflood fit from relative permeability curves.

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4. Linear Emulsion Flooding

Emulsion is prepared and charged to its reservoir. The emulsions, even though very stable, are prepared as needed, and never stored for more than a day. They are sampled and photographed to determine their properties, and then injected continuously into an oil resaturated core at the same velocity as the waterflood. Pressure drop and effluent oil fraction, emulsion drop-size, and emulsion volume concentration are monitored.

5. Parallel Emulsion Displacement

The experimental procedure for this test is the same as for linear emulsion displacement except that two cores of differing permeability are flooded in parallel. The cores are individually oil saturated and waterflooded in parallel. Both cores are then individually oil resaturated according to the procedure outlined above. The emulsion flood of the parallel cores is then performed. In all tests, including the parallel core test, the total volumetric flow rate is held constant. Hence, for the two parallel cores neither core is flooded at constant velocity or at constant pressure.

These experiments permit the documentation of emulsion flow in long cores and emulsion displacement of oil. By performing both waterfloods and emulsion floods on the same core, the direct mobility improvement can be measured. Also, the parallel core test gives insight into emulsion behavior in heterogeneous systems. This is of importance since all reservoirs vary in permeability. A qualitative effect of emulsions can be drawn for macroscopic or field mobility. With the use of the theory following directly in Chapter III the linear emulsion displacements can be quantitatively predicted.

APPENDIX II A

Core Preparation

The differing permeability sandpacks obtained in this thesis are prepared by varying the grain-size distribution, packing pressure, and the degree of vibration while packing. All cores are dry packed on a Carver hydraulic press in 1.2 cm increments. The extent to which packing pressure controls the permeability is significant. A pressure of more than approximately 35 MPa crushes some of the sand grains, and results in a core of unknown grain distribution and lower permeability. When packing at a pressure of less than 7 MPa the core will have a high permeability, unless a large fraction of fine particles, less than 140 mesh size, is used in the sand mixture. The packing pressure is typically between 10 and 21 MPa. Packing of the core is accomplished by use of differing length 4 cm diameter steel rods. By packing the sand in 1.2 cm increments, the possibility of layering in the core is minimized.

Vibration of the core holder while packing also influences the permeability. When packing at high pressures a significant amount of friction occurs between sand grains and the core holder walls. A rubber mallet is used to strike the core holder while the sand is under pressure. This shifts the sand grains so that they pack tighter and more uniformly. The holder is typically tapped lightly 20 to 30 times per 1.2 cm incremental addition. By tapping, the packing pressure is lessened, due to the sand readjusting. Hence, the pressure of the press is increased back to its original value before the pressure is relieved and the procedure repeated. An effort is made not to vibrate the core too vigorously otherwise,

grain-size separation may occur. Separation of grain sizes leads to a non-homogeneous, layered sandpack.

The major controlling factor of permeability is the sand grain-size mixture. A slight shift in the distribution of the fine grains, those less than 140 mesh size, greatly reduces the permeability. Table IIA.1 lists the values of sand grain distribution and packing pressure and sand grain-size mixture on permeability are clearly seen. The first core listed in Table IIA.1 is for a $7.4 \mu\text{m}^2$ nitrogen permeability sandpack. All other permeabilities are given with respect to water. Even though the packing pressure is 21 MPa the permeability is still very high. This core contains only 5 weight percent of grains less than 140 mesh, and, therefore, exhibits a high permeability. The $7.4 \mu\text{m}^2$ sand mixture corresponds to the material purchased commercially. To obtain permeabilities in the desired range of 0.5 to $2.0 \mu\text{m}^2$ the original sand is ground in a quartz ball mill, as noted in the experimental section.

By comparing the 1.5 and $1.15 \mu\text{m}^2$ cores, the packing pressure effect is seen. Even with a decrease in the fraction of grains less than 140 mesh (i.e., 26 to 17 mass percent) an increase of the packing pressure from 14 to 21 MPa results in a reduced permeability. Likewise when increasing the fraction of fines present but maintaining the same packing pressure, the permeability is reduced. This effect can be seen when comparing the 2.2 and $0.9 \mu\text{m}^2$ cores. If one were to increase both packing pressure and the fraction of particles less than 140 mesh, the permeability would drop significantly.

Reproducibility of results is shown by using the same grain-

Table II A.1

Sandpack Grain Size Distribution and Permeability

Ko μm^2	ϕ_0	MPa	weight percent between Tyler mesh screens						
			14-28	28-48	48-65	65-100	100-140	140-200	<200
7.4	--	21	15.4	23.0	22.0	17.6	16.5	5.0	0.0
2.2	0.311	21	8.9	19.2	19.2	19.2	19.2	8.0	6.4
1.9	0.310	21	8.9	19.2	19.2	19.2	19.2	8.0	6.4
1.5	0.303	14	4.2	25.9	10.7	11.8	21.4	10.8	14.8
1.15	0.294	21	7.8	18.7	18.7	18.7	18.7	8.7	8.7
0.9	0.290	21	7.8	18.4	18.4	18.4	24.0	4.9	8.0
0.7	0.288	10	14.8	20.2	9.9	15.4	17.8	18.0	3.8
0.23	0.284	16	0.0	29.4	11.1	18.7	8.9	14.9	17.0

size distributions and packing pressures. The 2.2 and 1.9 μm^2 cores are packed using the same sand composition with a packing pressure of 21 MPa. A similar comparison is shown for the 1.1 and 0.9 μm^2 permeability cases where the total weight of grains below 100 mesh are the same.

In conclusion, an increase in the packing pressure results in a lowering of permeability. Also, an increase of the fraction of small sand grains, less than 140 mesh, gives a core of lower permeability. By using the outlined experimental procedure, a consistent, homogeneous, quartz sandpack is obtained. As shown in Table IIA.1 the porosity of the core, ϕ_0 , is smaller the lower the permeability, as expected.

APPENDIX IIB

Emulsion Concentration and Drop-Size Distribution Determination

Evaluation of liquid drop sizes between 1 and 10 μm is difficult. Many methods of determination have been employed, including, Coulter counters, photomicrographs, and image analysers. Each technique has its advantages and disadvantages. With a Coulter counter low drop concentrations must be used, which requires dilution of the emulsions used in this study. An image analyser requires sharp contrast and even lighting of the microscope image. This is difficult for the magnifications needed to view 1 μm drops. Image analysers have the advantage of automatically measuring drop size and number of drops, but due to poor contrast and uneven lighting, the obtained values may be in error. In this study drop sizes and concentrations are determined from photomicrographs and a manual Zeiss particle counter.

Drop sizes and concentrations are determined by placing a cover glass on a hemacytometer cell and then charging a drop of emulsion in the V-notch of the cell where capillary forces draw the emulsion in. A phase contrast equipped Nikon microscope having 10X and 40X lenses is used with a 10X eyepiece to view the emulsion. A Nikon camera with microscope adapter records the image. The photograph is then developed and enlarged. The print is evaluated using a Zeiss counter to obtain the drop concentration and drop-size distribution. Factors which influence the measured values of drop size are microscope magnification, focus and contrast, enlargement size of the photograph, as well as the time the emulsion spends in the cell before it is photographed. Each of these variables is

discussed below.

The rise time, or the time before the picture is taken of the emulsion in the cell, is important because of the small depth of field of the microscope. The depth of the hemacytometer cell is 0.1 mm, while the depth of focus of the microscope is about 0.001 mm. If a photograph is taken before all the drops rise to the cover plate, then the measured concentration and drop size will be in error. Drops outside of the field of focus will either not be seen or will be difficult to measure because of poor focus and contrast. Thus, the value obtained for the drop size will be high due to the smaller drops not rising as fast as the larger ones. As well, the concentration obtained will be low because of the drops not all being counted. With the close to neutrally buoyant drops used in this study, the rise time is long, typically 20 minutes. All emulsions remain in the cell between 20 and 40 minutes before photographing. The smaller the drops the longer the rise time. A rough estimate of the expected drop size is known from the speed and agitation time of the blender.

For drops below 2 μm in diameter Brownian motion is noticeable. Brownian motion slows the drop rise time, and some of the smaller drops never reach the cover plate. When photographing at high magnification low shutter speeds are needed due to the low light level transmitted to the camera. Brownian motion causes the small drops image on the photograph to be blurred. This makes determination of drop sizes below 2 μm difficult. The larger drops which rise quickly present a stable photographic image.

Microscope focus and drop concentration both greatly affect the

measured drop size. If the concentration of the oil-in-water emulsion is high, for example, above 0.5 volume percent oil, then the drops that have risen may overlap and obstruct a distinct image. This again will give an improper drop size and concentration. If a concentration below 0.5 volume percent is made by dilution, then a larger area of a photograph must be counted in order to maintain a statistical average for the drop size. Errors of dilution are minimized by the determination of dilution volumes by weight. If drops touch on another, determination of the proper radius is difficult since the drops deform. Inter-drop contact can also lead to the drops being at different depths from the cover plate. If this occurs, then one drop will be out of focus with respect to the other. When photographed some drops will appear to have larger apparent diameters, since they are out of focus. An example of this is shown in Photograph B.1. If the plane of focus is slightly above a drop, the image recorded will be a dark spot or a thick ring, depending on the drop size (drops 1, 2 Photograph B.1). The smaller the drop the more it appears like a spot. As the focus plane descends to the drop maximum diameter, the black ring decreases in width but remains approximately at the same external diameter. Once this point of focus is passed, the image becomes lighter and the outer radius of the drop image increases (drop 3 of Photograph B.1). Therefore, when determining the drop diameter to be used with the Zeiss counter, a judgement must be made as to the true drop diameter depending on the type of image. In all cases except for when the focus plane is below the drop (i.e., drop image is lighter and wider) the outer radius of the drop is measured. When the focus

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Photograph B.1. Effect of focal plane on drop image. Drops 1, 2 indicate focus plane above maximum drop diameter. Drop 3 indicates focal plane below maximum drop diameter.

plane is below the drop, an approximate diameter less than that of the image is chosen depending on the image of the drop.

Microscope magnification, contrast, resolution and print enlargement are all interrelated and also influence the determination of drop size. The operation of a Zeiss counter is an important consideration when choosing the magnification and print enlargement to be used. The Zeiss counter produces a circular light image through an aperture of variable diameter. The light beam is positioned over each drop on the photographic enlargement and adjusted to match the external diameter of each drop, except as noted above. Once the beam and drops match, a foot pedal is depressed and the counter indexes the drop into a particular range. There are 48 separate size increments for the Zeiss counter used. Each size division or column is denoted with an average diameter and an upper and lower bound. The light beam diameters range from 1.21 to 27.71 mm in diameter. In this way, if the microscope magnification and print enlargement are chosen such that all the drops fall into only a few columns, then the results obtained are usually in error. In some cases errors of up to 200 percent in concentration are measured.

One example is shown in Table IIB.1. Here the microscope magnification is 400X with two print enlargements of 10 cm = 100 μ m and 10 cm = 50 μ m given for two different negatives (A and B). The same negative is used for both pictures A with only enlargement size being varied. The same is true for photographs B. Print enlargement is determined from the measurement of the projected image of the hemacytometer grid lines, which are etched into the cell 50 μ m apart. Each time a roll of film is used, a photograph of the grid

Table II B.1
Zeiss Counter Distribution and Drop Size Determination
Column mean diameter, mm

Picture	1.49	2.04	2.59	3.14	3.70	4.25	4.80	5.35	5.90	6.46	7.01	7.56	8.11	8.66	9.22	$\langle D_p \rangle$ μm	Conc. %
+ A 10cm-100	195	67	15	1	3	1	-	-	-	-	-	-	-	-	-	1.72	1.9
A 10cm-50	85	21	21	24	12	11	3	1	1	-	2	-	-	-	1	1.21	1.42
B 10cm-100	46	3	-	-	-	-	-	-	-	-	-	-	-	-	-	1.52	0.018
B 10cm-50	21	3	3	-	1	-	-	-	-	-	-	-	-	-	-	0.73	0.005

+ Actual drop concentration in photograph a is 1.5 volume percent.

lines is taken to permit quantitative enlargement. The mean drop-sizes for the two different enlargements of the same negative for photograph A are 1.72 and 1.21 μm with concentrations of 1.9 and 1.42 percent respectively. The 1.21 mean drop-size was determined from the 10 cm = 50 μm enlargement, with the 1.72 μm mean drop size obtained from the 10 cm = 100 μm enlargement. The actual concentration is approximately 1.5 volume percent as measured from addition of volumes. By comparing the concentrations obtained it is obvious that the greater enlargement gives a more accurate result. The drops for the 10 cm = 100 μm enlargement are counted only in the first six columns of the Zeiss counter. The smallest drops are all placed in the first column even though a large volume of these drops are much smaller than the mean drop-size assigned. This results in the high value for concentration obtained, and also shifts the mean drop-size to a larger value. It is obvious then that the number of columns of the Zeiss counter should be maximized. Unfortunately, contrast and resolution limit the amount of enlargement possible. The optimal size has been found to be an end magnification of 10 cm = 50 μm from a negative taken using a 40X lens and a 10X eyepiece.

It is obvious that many factors influence the measured drop size and concentration of an emulsion. The most important consideration in determining the true size is the photograph from which the drops are measured. Great care must be taken to ensure that the image is of good quality and of proper enlargement size. If this is not the case, then the results obtained could be significantly in error.

III THEORY

A. Water Displacement

The theory for emulsion displacement involves a combination of the model for emulsion flow in porous media and classical water displacement theory. In order to familiarize the reader, it is necessary to outline the principles of oil displacement by water. The original treatment was accomplished by Buckley and Leverett (16), and the concepts are now well understood. Several basic petroleum texts give the needed background (17, 18). We provide here only a brief review before proceeding to the theories of emulsion flow and emulsion displacement.

Buckley and Leverett consider the case of isothermal and incompressible two-phase flow in a homogeneous, linear porous medium. Total volumetric flow is constant, and capillary forces are negligible compared to viscous forces. All experiments performed in this study are conducted under these same conditions. For a porous medium of constant porosity, ϕ_0 , an unsteady local material balance performed on the wetting phase (i.e., water) demands that:

$$\frac{\partial S_w}{\partial \tau} + \frac{\partial f_w}{\partial \tilde{x}} = 0 \quad (3.1)$$

where $\tau = Vt/\phi_0 L$ is a dimensionless time, or injected fluid pore volumes, $\tilde{x} = x/L$ is a reduced column length, V is the total superficial velocity, t is time, S_w is the volume fraction of wetting phase in the void space or, equivalently the local water saturation, and f_w is the local fractional flow of water, or V_w/V . Clearly, information as to the form of f_w is required for the solution of

Equation (3.1).

Darcy's law for multiphase flow in porous media, Equation (1.1) of the Introduction, specifies the flow rate of each flowing phase. Therefore, for a wetting phase (water) and a nonwetting phase (oil), flowing simultaneously, the following expression can be written:

$$f_w \equiv \frac{V_w}{V_w + V_n} = \frac{1}{1 + \frac{k_{rn}\mu_w}{k_{rw}\mu_n}} \quad (3.2)$$

where the pressure gradient in each phase is assumed identical for the case of negligible capillary forces.

Figure 3.1 shows the relative permeability curves for a high viscosity mineral oil and water flowing in a quartz sandpack, as experimentally determined in this thesis. The method of obtaining the relative permeabilities will be presented shortly. The most important aspect of Figure 3.1 is the strong variation of relative permeability with changing saturation. Extension of Darcy's law to multiphase flow is based on the assumption that relative permeabilities depend primarily on the relative amounts of the fluid phases present in the porous medium. One can argue that relative permeabilities might depend on other variables, such as interfacial tension, contact angle, total flow rate or pressure drop, and fluid viscosities. However, the dependence of relative permeability on these flow properties is apparently weak, except at their extreme limits. Therefore, they will not be of concern in this work.

Oil and water phases interact in a complicated manner with the sandpack medium as depicted in Figure 3.1. Relative permeabilities

XBL 815-3023

Figure 3.1 Relative permeability curves for a viscous mineral oil, k_{rn} , and for water, k_{rw} . ($n=3.2$, $p=2.0$, $k_{rn}^0=0.84$, $k_{rw}^0=0.2$.)

do not sum to be unity. There are also, at finite saturations, points of zero flow, known as end point relative permeabilities. At some high oil saturation water will no longer flow. The water saturation at which this occurs is labelled, S_{wc} , in Figure 3.1, and is denoted as connate water saturation. Most natural reservoirs contain connate water, and are usually in this state when flooding is initiated. Likewise, at high water saturations, oil flow no longer occurs. The corresponding immobile oil is defined as, S_{or} , the residual oil saturation. Even after an infinite amount of waterflooding, oil unfortunately remains in the reservoir porous medium at the residual oil saturation.

No adequate theory presently exists to predict relative permeabilities. They must be obtained experimentally for each type of porous medium, and for each combination of wetting and nonwetting fluids. Some of the qualitative reasons for the shapes of the curves in Figure 3.1 are understood, and may be found in standard petroleum engineering tests (17, 18). Kelly (15) in his thesis also discusses relative permeabilities.

To correlate the experimental relative permeability data, the algebraic expression suggested by Sigmund and McCaffery (19) is applied in this work:

$$k_{rw} = k_{rw}^o \frac{S(\epsilon + S^{n-1})}{(1+\epsilon)} \quad (3.3)$$

$$k_{rn} = k_{rn}^o \frac{(1-S) [\delta + (1-S)^{p-1}]}{(1+\delta)}$$

where S is an effective water saturation defined as:

$$S = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{nr}} \quad (3.4)$$

and ϵ and δ are constants given values of 0.01 here. End point relative permeabilities, k_{rw}^0 and k_{rn}^0 are found from flow experiments at connate water and residual oil saturations. The power indices n and p control the shape of the relative permeability curves, and are determined to provide a best fit for the experimental data. Equations (3.3) and (3.4) have no fundamental significance, and are used only because of their flexibility in fitting the data.

From the relative permeability results of Figure 3.1, the water fractional flow curve can be constructed according to Equation (3.1). This is shown in Figure 3.2. Note that the fractional flow curve has an S-shape with fractional flow of water going to zero and unity at connate water and residual oil saturation, respectively. It is also important to note that the fractional flow curve not only depends on the relative permeabilities but also on the fluid viscosity ratio, as shown in Equation (3.2). When the water-to-oil viscosity ratio is increased, the S-shaped water fractional flow curve shifts to higher water saturations, while keeping the end points fixed. This, as will be shown later, increases the efficiency by which oil is displaced from the porous medium.

Once the saturation dependence of the oil and water fractional flow curve is specified, Equation (3.1) can be rewritten as:

$$\frac{\partial S_w}{\partial \tau} + \left(\frac{df_w}{dS_w} \right) \frac{\partial S_w}{\partial x} = 0 \quad (3.5)$$

XBL 815-3024

Figure 3.2 Fractional flow curve for a viscous mineral oil and water. S_{wb} is the saturation at water breakthrough.

Equation (3.5) is a highly nonlinear partial differential equation. However, it is of first order and can be solved by the method of characteristics (20). With the boundary conditions for continuous water injection into a core containing a uniform saturation profile of oil and connate water:

$$\begin{aligned} S_w(0, \bar{x}) &= S_{wc} \\ S_w(\tau, 0) &= 1 - S_{nr} \end{aligned} \quad (3.6)$$

the resulting mathematical solution is then:

$$\frac{\bar{x}}{\tau} = \frac{df_w}{dS_w} \quad \text{for } S_w > S_{wb} \quad , \quad (3.7)$$

which yields $S_w(\tau, \bar{x})$ implicitly in terms of a characteristic saturation velocity. By differentiating the fractional flow curve of Figure 3.2, it is discovered that water saturations less than that of the inflection point travel more slowly. Hence, smaller water saturations are overtaken by higher saturations, which travel more quickly. A shock front must, therefore, develop. This saturation shock is the result of neglecting second order terms in Equation (3.5), and corresponds physically to ignoring capillary forces.

An overall material balance yields the velocity and water saturation of the shock, S_{wb} . This shock velocity must match the saturation velocity at the saturation S_{wb} . Therefore, the shock location is found by the relation;

$$\frac{\bar{x}}{\tau} = \left. \frac{df_w}{dS_w} \right|_{S_{wb}} = \frac{f_w|_{S_{wb}}}{S_{wb} - S_{wc}} \quad (3.8)$$

The water shock saturation, S_{wb} , is also defined as the breakthrough saturation, because it is the first saturation of water that appears at the core outlet. According to Equation (3.8) the breakthrough saturation is a constant property of the system and is uniquely determined from the fractional flow curve. Ahead of the water saturation shock, only oil flows while water remains stationary at connate saturation.

A schematic of a transient saturation profile is shown in Figure 3.3. In front of the water shock only oil flows. A region in which the saturation of oil and water remains constant is called an oil bank. Behind the shock the position of each saturation follows according to Equation (3.7). Oil is therefore swept out in the subordinate mode by the water phase.

Along with the transient saturation profile, waterflooding theory also predicts the production history of oil, which can be readily measured. Usually the outlet oil production is presented as the fraction of oil originally in place that is produced, FOP, as a function of pore volumes of water injected. By definition, FOP is the difference between the average water saturation in the column and the initial connate water saturation, divided by the amount of oil originally in place, (i.e., one minus the connate water saturation). Construction of the saturation profile from Equations (3.7) and (3.8) permits the calculation of FOP. A typical waterflood oil production history is shown in Figure 3.4. The oil bank in front of the water shock is first produced and results in the straight line portion of the FOP curve up to the time of water breakthrough

XBL 815-3025

Figure 3.3 Saturation profile for a water displacement of a viscous mineral oil after 0.25 pore volumes of water injected.

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Figure 3.4 Secondary waterflood production history plotted as a function of oil in place produced versus pore volumes injected. Breakthrough of water occurs at τ_b .

at τ_b . Oil and water are then produced simultaneously with the fractional flow of oil steadily decreasing as time increases until residual oil saturation is reached. FOP will not approach unity as time goes to infinity because residual oil is left in the porous medium.

1. Graphical Solution

A simple graphical technique can also be used for the determination of the saturation profile and production history of a linear waterflood. This technique is outlined by Welge (21) and also by Johnson, Bossler and Naumann (22). For example, as shown in Figure 3.2, a dashed straight line, tangent to the fractional flow curve and intersecting the origin at the connate water saturation determines the breakthrough saturation according to Equation (3.8). The positions of the water phase saturations follow from the slope of the fractional flow curve according to Equation (3.7). The fraction of oil in place, produced, can also be calculated from this graphical technique. From the Buckley-Leverett equations the line tangent to the fractional flow curve at the endpoint saturation of the core, when extended to unity f_w , gives the average saturation of water for that point in the production history. FOP can then be determined as before, since it is defined as the average saturation of water minus the connate water saturation divided by $1-S_{wc}$.

If an analytic form is available for the relative permeabilities as in Equations (3.3) and (3.4), then a numerical solution procedure is more convenient. The graphical solution, however, gives considerable insight into the behavior of water displacement

and the oil production history.

2. Experimental Relative Permeabilities

The use of Buckley-Leverett waterflooding theory is so well accepted that it may be used with experimental data to obtain values for the oil and water relative permeabilities. In this dynamic technique, oil production history along with transient pressure drop is measured. Waterflooding theory yields explicit expressions for pressure drop in terms of the relative permeabilities of both oil and water. These equations are developed in Appendix IIIA at the end of this chapter. By fitting the data for both oil production and pressure drop from a waterflood displacement of oil, it is possible to determine the parameters appearing in the relative permeability expressions of Equations (3.3) and (3.4).

Flow data at connate water and residual oil saturation fix the end point relative permeabilities, while values of the power indices, n and p , are numerically chosen until satisfactory agreement is achieved between the experimental and theoretical curves for oil production and pressure drop. Figure 3.5 depicts typical waterflood results for the displacement of the viscous, 140mPa·s, mineral oil, used in this study. Both reduced pressure drop, $\Delta P/\Delta P_i$, and FOP data are shown as discrete points even though they are measured continuously. The solid lines correspond to values obtained from the best-fit parameters of Equations (3.3) and (3.4). Agreement is excellent between experiment and fit showing the adequacy of waterflooding theory, and the flexibility of the empirical relative permeability expressions used. Additional information on

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Figure 3.5 Secondary oil recovery (triangles) and pressure history (circles) for the waterflood of a viscous oil. Solid lines indicate the fit from the relative permeability curves.

waterflooding is brought forward in Figure 3.5. Water breakthrough is quite early, at about 0.3 pore volumes of injected fluid. A significant fraction of the oil recovered is produced after water breakthrough has occurred. More efficient waterfloods have a longer period of only oil being produced, while less oil is recovered after breakthrough. The origin of the inefficient oil recovery behavior shown in Figure 3.5 is the high oil viscosity. The viscous oil shifts the fractional flow curve, (i.e., see Figure 3.2) to the left according to Equation (3.2). Essentially the flow resistance of the less viscous water is small compared to that of the viscous oil. Water, therefore, tends to move ahead of the oil, and does not effectively displace the oil. This ineffective displacement is quantitatively reflected in waterflooding theory through the fractional flow curve. In order to achieve more effective oil recovery, the flow resistance of the water phase must be increased with respect to the oil phase. In other words, better mobility control needs to be achieved.

B. Emulsion Flow

Before extending Buckley-Leverett waterflooding theory to describe emulsion displacement, it is necessary to understand quantitatively how dilute emulsions flow in porous media. The original work in this area was done by Soo (2) who studied emulsion flow in short 3 cm long water-saturated sandpacks. In order to utilize Soo's results in emulsion displacement theory, they must be scaled to longer cores and extended to two-phase flow. Initially, Soo's model of dilute emulsion flow will be reviewed and then its

extensions developed.

1. Single Phase Flow

The picture developed by Soo and Radke during 1977-79, of emulsion flow in a water-saturated porous medium is shown in Figure 3.6. Oil drops larger than pore constrictions clog those constrictions by wedging between sand grains. This mode of capture is denoted in filtration literature as straining. Additionally, smaller drops and some fraction of the larger drops capture on pore walls and on larger pore throats due to macroscopic van der Waals' and hydrodynamic forces. Interception is then designated capture mode. Droplet interception near pore throats may then permit straining of other drops. As retention builds, flow is diverted to the larger pores where capture probability is lessened because of the increased pore size. Also the now greater fluid velocity in these larger pores also reduces droplet capture. When the drops and the porous medium grains have surface charges of the same sign, capture by interception is not large. Thus, if the larger pores in the porous medium form a contiguous path, a steady state is approached where all flow is in the larger channels and where particle capture tends to zero.

Figure 3.6 also applies to polymer flow. Interception corresponds to polymer adsorption, while straining corresponds to mechanical entrapment. Clearly, clogged liquid or solid particles, or polymer can have a severe influence on flow behavior. In polymer flow, however, the bulk phase non-Newtonian rheology must be accounted for, whereas, in dilute emulsion flow the bulk phase viscosity

Figure 3.6 The mechanism of emulsion flow in porous media. XBL 815-3028

is essentially that of the external fluid, and bulk rheology need not be considered.

To quantify the schematic picture of Figure 3.6 requires a statement about the kinetics of particle capture. If $q_w(t,x)$ is the volume of oil drops retained per clean void volume available for water flow at an axial position x and time t , then Soo writes (2):

$$\frac{\partial \phi \sigma_w}{\partial t} = \lambda V C (1 - \alpha \sigma_w), \quad (3.9)$$

where ϕ is the bed void fraction, V is the superficial velocity, C is the local emulsion volume concentration, and λ is the filter coefficient. The factor $1/\lambda$, which has dimensions of length, is the average distance a drop travels before it captures. The bracketed term in Equation (3.9) accounts for flow diversion: α is the flow-diversion parameter or the inverse steady-state retention. Combination of Equation (3.9) with a differential suspension material balance leads to the bed retention and concentration profiles for a step increase of emulsion injected into a clean bed, of initial porosity, ϕ_o , and for small porosity changes (i.e., $\phi/\phi_o \sim 1$):

$$\sigma_w(T, \tilde{x}) = \frac{1 - \exp(\alpha \lambda C_i T)}{\alpha [1 - \exp(\lambda \tilde{x} - \exp(\alpha \lambda C_i T))]}, \quad (3.10)$$

and

$$\frac{C(T, \tilde{x})}{C_i} = \frac{\sigma_w(T, \tilde{x})}{\sigma_{wi}(T)}, \quad (3.11)$$

where $\tilde{x} = x/L$ is the reduced axial distance, $T = \tau - \tilde{x}$ is a shifted time variable, $\tau = Vt/\phi_0 L$ is the pore volumes of injected fluid, and $\Lambda = \lambda L$ is the reduced filter coefficient. Equations (3.10) and (3.11) predict transient exponential decaying concentration and retention profiles. Such retention profiles have been measured by Szabo for C^{14} -tagged polyacrylamide flowing in sandpacks (10). As steady state is approached, the retention is uniform throughout the bed at the value, $1/\alpha$.

Once the retention profiles are calculated, the pressure drop-flow rate relation follows directly by recognizing that the captured particles alter the local permeability, K_x . Soo gives the following expression (2):

$$\frac{K_x}{K_0} = 1 - \beta \sigma_w \quad (3.12)$$

where β is a flow-restriction parameter, whose genesis lies in the bundle-of-constricted-tube model of a porous medium (2). Equations (3.10) and (3.12) along with Darcy's law permit an analytic solution of the overall transient permeability when the flow rate is held constant. Thus, by fitting experimental pressure drop and emulsion effluent concentration data it is possible to obtain the filtration parameters: λ , α , and β .

Figures 3.7 through 3.9 give Soo's experimental results for those three parameters obtained in a short sandpack, 2 cm in diameter and 3 cm long, for several combinations of mean drop size and mean pore size (i.e., different initial core permeabilities).

XBL 815-3029

Figure 3.7 Short core reduced filter coefficient as function of mean drop-size to mean pore-size ratio. The solid circle denotes an upper bound value calculated only from transient pressure drop data.

XBL 815-3030

Figure 3.8 Short core flow diversion parameter as a function of mean drop-size to pore-size ratio. The solid circle denotes a calculated value obtained from initial transient pressure drop data.

XBL 815-3031

Figure 3.9 Short core flow-restriction parameter as a function of mean drop-size to mean pore-size ratio. The solid circles denote calculated values based on initial transient pressure drop data.

The results of these experiments collapse reasonably well onto single curves when plotted against the ratio of mean drop-size, $\langle D_d \rangle$, to mean pore throat diameter, $\langle D_p \rangle$. Figures 3.7 through 3.9 demonstrate that at lower drop-size to pore-size ratios the dominant capture mechanism is interception, whereas at higher drop-size to pore-size ratios the dominant capture mode is straining. For the particular emulsions and sandpacks that Soo studied, the transition point arises at a drop-size to pore-size ratio of about one seventh. Both the filter coefficient λ and flow diversion parameter are very sensitive to drop to pore-size ratio. They are seen to vary over two orders of magnitude, and hence, are plotted on semilogarithmic scales. For convenience, the filter coefficient is reduced by the mean grain diameter, $\langle D_g \rangle$, obtained from sieve analysis. In Figure 3.7, $\langle D_g \rangle$, is around $100 \mu\text{m}$ so that the larger drops travel several hundred microns before they are captured. Conversely, the smaller drops travel several hundred grain diameters, or a few centimeters before they capture. The inverse of the flow diversion parameter is plotted in Figure 3.8, because $1/\alpha$ gives the steady-state emulsion retention. Figures 3.8 and 3.9 are important because they are utilized in the displacement calculations to follow.

Since the steady-state droplet retention, σ_∞ , approaches $1/\alpha$, Equation (3.12) gives the overall steady-state permeability, K_∞ , as:

$$\frac{K_\infty}{K_0} = 1 - \frac{\beta}{\alpha} \quad (3.13)$$

The ratio K_{∞}/K_0 is sometimes called the residual resistance factor. From Figures 3.8 and 3.9 Soo's data for emulsion flow show that for a given drop size, the lower the initial core permeability (i.e., a smaller $\langle D_p \rangle$) the larger the permeability reduction. Gogarty (6); Jennings, Rogers and West (9); and Smith (7) all present data demonstrating this same conclusion for polyacrylamide polymers in various porous media. Further, Equation (3.13) predicts that the residual resistance factor should be independent of injected emulsion concentration. Soo validates this prediction in his emulsion flow studies. Jennings, Rogers and West (9) also verify this behavior for high-molecular-weight polyacrylamide polymers.

One feature of Soo's emulsion filtration flow model needs to be emphasized. Except with extreme precautions emulsions exhibit a drop-size distribution, which is wider for larger mean drop sizes. Equation (3.9) presumes that the emulsion is pseudo-monodisperse, and the filtration parameters are reported for the volume mean drop diameter. What is actually observed is that the smaller drops elute earlier followed by the larger drops. In Soo's short cores the droplet segregation is not a major factor, as indicated by the filtration parameters collapsing onto single curves in Figures 3.7 through 3.9. For longer cores, however, droplet segregation is more distinct, and will play a more important role.

2. Scaling

The results obtained in Figure 3.7 through 3.9 apply strictly to short sandpacks, 3 cm in length. Displacement tests and field applications, however, are performed on cores and reservoirs of

much greater lengths. Due to the increased residence time in the long cores, Equations (3.10) and (3.11) predict that the emulsion front sharpens as the core length or $\Lambda = \lambda L$ increases. Figure 3.10 presents experimental confirmation of this predicted sharpening effect. Here the effluent concentration is plotted as a function of injected pore volumes for a 0.3 percent emulsion in a 3 cm, short, and a 33 cm, long, sand pack. The mean drop size is $1.6 \mu\text{m}$ and both cores have initial permeabilities around $2.0 \mu\text{m}^2$ yielding mean drop-size to mean pore-size ratios of approximately 0.05. In the short core, which is of slightly lower initial permeability, the drop retention is greater and, consequently, the mean emulsion breakthrough time is about 3 pore volumes. The emulsion front is spread over a 5 pore-volume interval. The solid line in Figure 3.10 shows a best fit of Equations (3.10) and (3.11). In the longer core, injecting the same emulsion, the mean emulsion breakthrough time is slightly earlier at 2 pore volumes. The dashed line is calculated "a priori" from the data of Soo given in Figures 3.7 and 3.8 with Equations (3.10) and (3.11). Agreement between the predicted effluent history and the experimental history is excellent in this case. Thus, in long cores, the emulsion front scales to a shock behind which droplet retention is at a steady-state value.

A similar emulsion concentration history for $1.65 \mu\text{m}$ mean drops eluting from the long 33 cm core is shown in Figure 3.11. For this experiment the core is of a lower initial permeability, $0.42 \mu\text{m}^2$. The mean drop to mean pore-size ratio is accordingly greater at 0.09. Although the increased drop retention, and, hence the later

XBL 815-3032

Figure 3.10 Emulsion concentration history in a short, 3 cm, core and in a long, 33 cm, core. The solid line is a best fit according to Equation (3.10) and the dashed line is predicted from Equation (3.10) and the short core data. Parameters for the short core: $\beta = 10.2$, $\alpha = 200$, $\Lambda = 2.4$. Parameters for the long core: $\beta = 11.7$, $\alpha = 315$, $\Lambda = 25$.

XBL815-3033

Figure 3.11 Emulsion concentration history in a long, 33 cm. core. Solid line denotes predicted breakthrough from Equation (3.10).

mean break-through time is correctly predicted, short core data and corresponding theory do not adequately predict the effluent concentration spread. To ascertain the reason for the disagreement in Figure 3.11, initial drop-size distributions are shown in Figure 3.12 for the experiments depicted in Figures 3.10 and 3.11.

Figure 3.12 demonstrates that the largest drops in the two distributions are around 3.0 to 3.5 μm in diameter. These larger drops yield drop to mean pore-size ratios of 0.10 for the 2.0 μm^2 core, and of 0.19 for the 0.42 μm^2 core. From the filtration flow diversion parameters in Figure 3.8, it is discovered that for the 2.0 μm^2 core of Figure 3.10 interception is the only capture mode, whereas a significant fraction of the emulsion droplets in the 0.42 μm^2 core enter into the straining capture mode. It should be noted that Figure 3.8 holds for drop-size distributions in short cores and does not strictly give α for a specific drop size. A drop-size distribution tends to blur the distinction of α between straining and interception. Still the two capture regimes can be clearly seen in Figure 3.8. In the low permeability core of Figure 3.11 the larger drops will strain more than in the higher permeability core of Figure 3.10. Hence, the smaller drops in the 0.42 μm^2 core should elute significantly ahead of the larger drops, whereas, for the 2.0 μm^2 core all drop sizes should elute close together.

Figures 3.13 and 3.14, which show the mean drop-size histories, support this contention. In Figure 3.13, corresponding to the 2.0 μm^2 core, there is little drop-size segregation. At all concentrations the effluent drop-size distributions are approximately the same, in both

XBL 815-3034

Figure 3.12 Initial drop-size distributions for the experiments depicted in Figures 3.10 and 3.11.

XBL 815-3035

Figure 3.13 Effluent emulsion mean drop-size for long (circles) and short (squares) cores of Figure 3.10.

Figure 3.14 Effluent emulsion mean drop-size for a long, 33 cm. core of $0.42 \mu m^2$ depicted in Figure 3.11.

the short and long core. However, in the $0.42 \mu\text{m}^2$ core of Figure 3.14 there is a noticeable shift in the drop-size distribution toward early elution of the smaller drops. The largest drops, which constitute a significant volume fraction, still have not eluted in Figure 3.14, or in Figure 3.11 after 4 pore volumes. Such drop-size shifts are also seen in the short core studies of Soo (2), but the sharpening effect of the increased residence time in the long cores magnifies the effect.

In conclusion, the effluent spread seen in Figure 3.11 is due to drop segregation, and not to a failure of resident time scaling. In long cores or reservoirs, emulsions travel in shock waves, as do favorably adsorbing chemicals. Since the amount of emulsion retained as steady-state is approached is independent of inlet concentration, the shock velocities vary directly with emulsion concentration. By injecting a higher inlet concentration of emulsion; faster shock velocities are obtained. This shock-front behavior is utilized in emulsion displacement theory to follow.

A significant amount of effluent emulsion concentration spreading will occur in long cores or reservoirs whenever the emulsion drop distribution relative to the mean pore size indicates that both straining and interception regimes are operative. When this occurs, drops of various drop size travel at differing shock velocities. In this case the assumption of a strictly monodisperse system is invalid. Nevertheless, the monodisperse emulsion displacement theory provides adequate prediction of emulsion retention and oil recovery.

3. Filtration Parameters in Two-Phase Flow

In the previous section the results of dilute emulsion flow in short, water-saturated cores were extended to longer cores. This established the existence of emulsion shock fronts when core length was sufficiently long. During emulsion displacement of oil, however, both oil and water flow simultaneously in the porous medium. It is important then to determine how oil saturation influences emulsion retention.

When water and nonwetting oil flow in a porous medium, the oil generally occupies the larger pore channels. Stable non-coalescing emulsion drops, flow only in the water phase, and, therefore, transport only in those channels available for water flow. Thus, an emulsion sees mostly the small void spaces of the porous medium, and its capture probability increases over that in the same porous medium with no oil present. Szabo (10) observes this enhanced retention with oil saturation for entrapping polymers.

This increased emulsion retention in the presence of immobile oil is reported in Figure 3.15 for an unconsolidated sandpack. Plotted is the emulsion effluent concentration as a function of the pore volumes of wetting phase injected, τ/S_w , when the average immobile oil phase saturation is 0.4. If the core maintains a pore-size distribution to the water phase corresponding to complete water saturation, the mean break through time, $\tau/S_w = (1 + 1/\alpha C_1)$, predicted from Figure 3.8 is close to unity. This is shown by the calculated solid line in Figure 3.15 depicted for an average pore-size of $34\mu\text{m}$. However, emulsion mean breakthrough is not observed until after 1.5 pore volumes. This additional droplet hold up, or retention, is not due to coalescence of drops into the immobile oil phase because the emulsions

XBL 815-3037

Figure 3.15 Emulsion concentration history in a core containing immobile oil as a function of aqueous pore volumes. The solid line is calculated according to a water relative permeability of unity, whereas the long dashed line is calculated according to a water relative permeability at immobile oil of 0.15.

are highly stable, and the transient effluent drop-size distributions are similar to those measured from completely water-saturated sandpacks.

To calculate the influence of local oil saturation on emulsion retention and flow, the experimental relative permeabilities are utilized. At a specified water saturation the effective permeability to water is obtained from the relative permeability curves and the absolute initial core permeability. Reported in Appendix IV are the calculated relative permeability parameters for the experiments shown in Figures 3.15 and 3.17. This permeability to water is in turn converted to an average pore diameter using measured capillary drainage pore-size distributions of differing permeability sandpacks. Specifically a power law expression, suggested by Marsden (23), is used to relate the core permeability to an equivalent mean pore size:

$$\langle D_p \rangle = 2.33(K_w)^{0.34} \quad (3.14)$$

In Equation (3.14), when the effective permeabilities to water are expressed in millidarcys the resulting mean pore diameter is obtained in microns. Figures 3.8 and 3.9 are then available to calculate the emulsion retention and flow restriction. In this manner the dependence of the filtration parameters α and β on water saturation are fixed "a priori".

The long dashed line in Figure 3.15 shows the resulting predicted emulsion breakthrough history. According to the suggested calculation procedure, the mean pore size is reduced to $16 \mu\text{m}$ by the presence of the immobile oil. The trend toward higher emulsion

retention is correctly reflected. The value of α for the effluent emulsion has been shifted from approximately 500 to a value of 75. The resulting experimental value obtained is 100. β also shows good agreement with the proposed correction on saturation. The predicted value for the $16\text{ }\mu\text{m}$ mean pore size is 10, whereas the experimental result yields 9.3. Due to the drop-size to pore-size ratio of 0.09 at the 0.6 water saturation in this experiment, α is in a very sensitive region (see Figure 3.8). Slight errors in drop size determination yield large errors in predicted retention. The experimental results shown in Figure 3.15 do not exactly agree with those predicted but are within experimental error and correctly demonstrate the trend of increased retention with oil saturation.

Spreading of the emulsion front is again seen in the experiment shown in Figure 3.15. The mean drop to pore-size ratio is 0.09, and the drop-size distribution is such that a significant volume fraction of drops range from 0.06 to 0.12 in drop to mean pore diameter ratio. This range of drop to mean pore size slightly invades the straining capture regime. Figure 3.16 depicts the drop size shift for the immobile oil experiment in Figure 3.15. Again, the shorter elution time of the smaller drops is responsible for the concentration spread of Figure 3.15. This pseudomonodisperse calculation, however, gives the correct mean drop holdup.

Figure 3.17 reports a similar result for increased emulsion retention in the presence of immobile oil. Again the concentration history is shown, but for a lower absolute permeability core of $1.9\text{ }\mu\text{m}^2$ and a slightly larger emulsion drop size of $1.65\text{ }\mu\text{m}$ mean diameter. The solid line denoted with a mean pore size of $30\text{ }\mu\text{m}$

XBL815-3038

Figure 3.16 Effluent emulsion mean drop size for the immobile oil saturation experiment depicted in Figure 3.15.

XBL815-3039

Figure 3.17 Emulsion concentration history in a core containing immobile oil as a function of aqueous pore volumes injected. Solid line is calculated according to a relative permeability of unity. Dashed line is calculated according to a relative permeability at immobile oil of 0.126.

predicts emulsion breakthrough assuming the oil has no effect on the mean pore size to water. Using the relative permeability calculational procedure, the mean pore size in the presence of a 0.36 oil saturation falls to $15\mu\text{m}$. A dashed line gives the predicted mean emulsion breakthrough, and is in much better accord with the experimental findings.

The most interesting aspect of Figure 3.17 is that the effluent drop concentration does not rise to the inlet value even after injection of 8 pore volumes of wetting fluid. The 36 percent pore volume of immobile oil has increased the mean drop to mean pore-size ratio from 0.06 to 0.12. Now more than 50 volume percent of the emulsion drops capture in the straining regime. These larger drops are significantly retarded and elute very slowly. They have not yet appeared in the effluent even after injection of 8 pore volumes of emulsion. Figure 3.18, which shows the mean drop-size effluent history corresponding to Figure 3.17, confirms this explanation of drop-size separation.

Obviously, the presence of a nonwetting oil in a porous medium increases the retention of dilute oil-in-water emulsions. The explanation for this resides in the confinement of the wetting aqueous phase to the smaller channels of the core material. The proposed calculational procedure, based on the relative permeabilities, accounts for the increased droplet capture and closely predicts the mean emulsion break-through time. Due to drop segregation, and the possibility of a non-uniform immobile oil distribution, the experimental results are not exactly predicted. Nevertheless, the influence of local oil saturation on the parameters α and β is

XBL 815-3040

Figure 3.18 Effluent emulsion mean drop-size for the immobile oil saturation experiment depicted in Figure 3.17.

critical to the displacement process. This calculational procedure provides a first-order estimate of the magnitude of the saturation effect on the filtration parameters.

C. Emulsion Displacement

1. Physical Description

Given the concepts of water displacement theory and the extensions of single-phase dilute emulsion transport to two-phase flow in porous media, a theory for emulsion displacement is now developed. In the zone where an aqueous emulsion and oil are flowing simultaneously the classical Buckley-Leverett unsteady water balance of Equation (3.1) continues to apply. However, in the case of emulsion flow the aqueous phase fractional flow expression is modified by the presence of the droplets. Retained emulsion drops lower the local effective permeability in the water flow channels, and, therefore, divert water into the relatively larger pores, which are occupied by oil. This leads to a greater fractional flow of oil and to a more efficient oil displacement. Since relative permeabilities are not strong functions of absolute permeability, we presume that the relative permeabilities of both oil and water are unaffected by the emulsion. Hence, the fractional flow of water in the region of emulsion flow is described by:

$$f_{w/e} = \frac{1}{1 + \frac{k_{rn}}{k_{rw}} \frac{K_o}{K_\infty} \frac{\mu_w}{\mu_n}}, \quad (3.15)$$

where the effective permeability to water is reduced to $k_{rw}K_\infty$ by the emulsion drops. The reduced absolute permeability, K_∞ is

utilized because of the long-core assumption of an instantaneous steady state, as noted previously.

Equation (3.13) relates the filtration parameters α and β to the residual resistance factor, or the water-phase absolute permeability reduction, K_{∞}/K_0 . When no droplets are present in the aqueous phase, there is no permeability reduction, and β/α in Equation (3.13) is zero. Therefore, K_{∞}/K_0 is unity, and Equation (3.15) reduces to its normal form for the fractional flow of water as given by Equation (3.2). Since K_{∞}/K_0 is less than unity where emulsion flows, Equation (3.15) demands a smaller fractional flow of water at a given saturation than if no emulsion droplets were present. The water fractional flow curve, f_w versus S_w , shifts to the right. Figure 3.19 demonstrates such altered fractional flow curves for three different emulsion permeability reductions. The fractional flow curve on the extreme left, labeled by a β/α ratio of zero, corresponds to no permeability reduction, or to a standard waterflood. The greater the permeability reduction the more the fractional flow curve shifts to the right. This is seen in Figure 3.19 for permeability reductions of 50, 75, and 90 percent, or β/α ratios of 0.5, 0.75 and 0.9, respectively. Equation (3.15) states that there is no distinction between lowering K_{∞} , as emulsions do, or increasing μ_w , as polymers mainly do. Both procedures lower the water-oil mobility ratio, and result in an increase of oil recovery efficiency.

In order to utilize Buckley-Leverett theory for emulsion displacement, the total emulsion retention in the core, or the velocity of the emulsion shock front must be determined. Since in the region

XBL815-3041

Figure 3.19 Fractional flow of aqueous phase versus S_w for differing permeability reductions. Ratios of β/α are 0, 0.5, 0.75, 0.9. β/α equal to zero is typical waterflood of a viscous oil. Relative permeability curve parameters are: $n=3.0$, $p=1.4$, $k_{rn}^0=0.87$, $k_{rw}^0=0.2$.

of emulsion flow the water saturation is constantly changing, the parameters α and β which are functions of saturation, also vary. With the relative permeability calculation procedure outlined in the preceding section, it is possible to determine the specific dependence of α and β water saturation.

Figure 3.20 reports calculated results for the retention parameter α as a function of water saturation. The quantity S_w/α is plotted versus S_w rather than $1/\alpha$, because S_w/α gives the total emulsion retention per bed void volume. Only water saturations above 0.5 are shown, since during oil displacement emulsion flow is only in the regions of higher water saturation. The solid line in Figure 3.20 is calculated by the relative permeabilities correction procedure, and refers to an initial absolute permeability of $1.9 \mu\text{m}^2$ and a $1.65 \mu\text{m}$ mean drop-size emulsion. Also shown in Figure 3.20 are the experimental steady-state drop retention at an immobile oil saturation of 0.36, and the calculated retention for a completely water-saturated core as obtained from Figure 3.8. The dotted line denotes the region of saturation where experiments are not readily possible because continuous oil cannot flow.

The important feature of Figure 3.20 is the predicted decrease of total emulsion retention with increasing water saturation, especially for the initial water-saturated core pore size. This calculation predicts that, even though oil occupies the larger pores, and, therefore, blocks some droplet capture sites, the total emulsion retention is still larger than that for the completely water-saturated sandpack. In the context of an oil displacement this means that droplet retention will decrease behind the emulsion shock front

XBL 815-3042

Figure 3.20 Total emulsion retention per bed void volume versus aqueous phase saturation. Experimental values obtained at $S_w = 1.0, 0.64$. Solid line calculated from relative permeability procedure. Dashed line denotes region of saturation not available for experiment.

even though oil is being displaced and more capture sites are then available for droplet capture. This situation is possible only if captured drops re-entrain. However, the work by Soo (2) clearly demonstrates that drop re-entrainment is absent or negligible. Therefore, the total retention must increase, and cannot decrease as more sites open due to oil displacement from the porous medium.

The explanation for the decreasing retention trend with increasing water saturation in Figure 3.20 is not clear. It is possible that when the emulsion is forced to flow only in the smaller channels additional capture sites are created. Szabo (10) accepts this hypothesis for his increased entrapping-polymer retention at residual oil saturation as compared to that at complete water saturation.

We offer a second proposal. The change of total emulsion retention with saturation is most dramatic in the region from a water saturation at residual oil, 0.74 in Figure 3.20, to the completely water-saturated core. With the $1.65 \mu\text{m}$ mean drops used, the calculated mean drop to mean pore-size ratio shifts from .094 to .054 over this range of saturation. The values of α in the low drop-size to pore-size ratio range, where capture is slight, change very rapidly. (see Figure 3.8) Small differences in experimental determination of steady-state capture in Figure 3.8 can have a dramatic influence. For a large permeability core with small drops in which drop capture is small, there is little redistribution of flow among the pores due to drop retention. Almost all of the flow is in the large channels, and the smaller channels see only a minor portion of the emulsion drops. Attainment of steady-state retention in

these smaller pores might be reached only after many pore volumes of throughput. Hence, the values of $1/\alpha$ in Figure 3.8 may be underestimated when the drop-size to pore-size ratio is small.

During oil displacement, and also for the case of larger drop to initial pore-size ratios, redistribution of flow among the pores is much greater, and the attainment of steady-state retention in the smaller pores is more closely approached. Because of increased drop retention in the larger pores, flow is directed into the smaller pores. The capture sites in these smaller pores then more quickly fill. Steady-state is then approached. Hence, when there is significant flow redirection there should be little variation of total emulsion retention with saturation. This is evidenced by the slight shift in total retention with saturation from 0.5 to 0.74 where the calculated drop-to pore-size ratio varies from 0.15 to 0.094. The value of $1/\alpha$ in this region indicates significant straining and redirection of flow.

The lowest saturation at which droplets capture is at the emulsion shock front; this front will be the point of highest drop to pore-size ratio, and will be the point of greatest redirection of flow. Also drop retention at this shock is closest to steady-state, since any additional capture behind the shock occurs at higher drop to pore-size ratios, where redirection is less. It is known that re-entrainment does not occur. Therefore, behind the emulsion front additional capture must occur in sites opening because of oil displacement, and total retention, S_w/α , must increase. The emulsion droplets are assumed to immediately fill these capture sites. However, because the newly available capture sites are in the larger pores, additional

capture is small compared to that at the front. We assume that this filling-in effect can be neglected. Then S_w/α is constant at the emulsion shock front.

The emulsion shock causes a discontinuity in water saturation denoted by S_{wbk} . In the theory section to follow the calculation of these two saturations is presented. Since the emulsion sees all water saturations between S_{we} and S_{wbk} , it is not clear which mean pore size characterizes droplet capture at the front. This question does not arise in surfactant or polymer flooding because surfactant or polymer adsorption is not a function of water saturation. For emulsion drops, however, the lower the water saturation, the higher is the mean drop to mean pore-size ratio, with a correspondingly higher retention and higher permeability reduction.

Evaluation of the mean pore size at the lower water saturation, S_{wbk} , over-estimates the emulsion retention during oil displacement, since not all drops capture at this mean pore size. Conversely, evaluation of the mean pore size at the higher shock water saturation, S_{we} , under-estimates drop retention during an emulsion flood. For convenience, we establish the mean pore size at the emulsion front from the arithmetic average of the two limits on water saturation at the emulsion front, $\overline{S_{we}} = (S_{we} + S_{wbk})/2$. The filtration parameters estimated at $\overline{S_{we}}$ are denoted by $\overline{\alpha}$ and $\overline{\beta}$. Total water void volume at the emulsion shock front available for droplet capture is the highest water saturation, S_{we} . Therefore, with neglect of the filling-in effect, emulsion retention behind the shock front is taken as a constant at the value $S_{we}/\overline{\alpha}$, evaluated at the mean emulsion front water saturation.

By assuming that the total emulsion capture is uniform the values of $\bar{\alpha}$ and $\bar{\beta}$ in the fractional flow expression of Equation (3.15) are then constant at the mean emulsion shock front saturation. A constant $\bar{\beta}/\bar{\alpha}$ ratio is used to determine the permeability reduction, since $\bar{\alpha}$ and $\bar{\beta}$ are no longer considered to be functions of saturation. Details of the mathematical displacement theory can now be outlined.

2. Theory

In the zone of emulsion flow, a local unsteady material balance on the water phase again yields Equation (3.5), with the exception that the water fractional flow dependence is given by Equations (3.13) and (3.15). Again, $\bar{\alpha}$ and $\bar{\beta}$ are constants evaluated at the mean emulsion shock-front saturation. The boundary conditions, given by Equation (3.6), still apply, and, hence, the saturation profiles in the emulsion flow region are given by:

$$\frac{\bar{x}}{\tau} = \frac{df_{w/e}}{dS_w} (S_w; \bar{\beta}/\bar{\alpha}) \quad \text{for } S_w > S_{wc} \quad (3.16)$$

Since the fractional flow curve for the emulsion is S-shaped as shown in Figure 3.19, a shock front develops, as previously noted. We denote the saturation of water at the emulsion shock front by S_{we} . The position of this shock front is found from an overall material balance on the emulsified drops:

$$\tau = \int_0^{\bar{x}_e} \left[\frac{S_w}{\alpha C_i} + S_w \right] d\bar{x} \quad , \quad (3.17)$$

where $\tilde{x}_e$ denotes the reduced axial position of the emulsion shock.

With the approximation that $\frac{S_w}{\alpha}$ is a constant, Equation (3.16), along with integration by parts, transforms Equation (3.17) to give the emulsion shock velocity:

$$\frac{\tilde{x}_e}{\tau} = \frac{df_{w/e}}{dS_w} \bigg|_{S_{we}} = \frac{f_{w/e}}{S_w + \frac{S_w}{\alpha C_i}} \bigg|_{S_{we}} \quad (3.18)$$

The similarity to the Buckley-Leverett waterflood result of Equation (3.8) is quite obvious. However, now the emulsion shock velocity is lowered by the drop retention term, $\frac{S_{we}}{\alpha C_i}$. Equation (3.18) is also directly analogous to that for surfactant or polymer flooding (8)

where the second term in the denominator of the right side then corresponds to reversible or irreversible adsorption loss. Here the factor $\frac{S_{we}}{\alpha C_i}$ is the ratio of droplet retention per void volume of bed, $\frac{S_{we}}{\alpha}$, to the local droplet volume concentration, C_i . The retention term also indicates the fraction of pore volume of injected emulsion that is stripped of drops due to retention in the core.

Ahead of the emulsion front an oil bank forms. The water saturation in this bank S_{wbk} , is given from an overall material balance on water:

$$\frac{\tilde{x}_e}{\tau} = \frac{f_{w/e} \big|_{S_{we}} - f_w \big|_{S_{wbk}}}{S_{we} - S_{wc}} \quad (3.19)$$

Water in the oil bank is composed of both connate water and injected emulsion water which is stripped of droplets. Due to the S-shape

of the water fractional flow curve (i.e., now corresponding to $\frac{\beta}{\alpha} = 0$ in Figure 3.19), this oil-water bank front has a constant saturation and forms a shock at its front. The velocity of the oil bank shock front is found, as usual, from a second overall water material balance:

$$\frac{\tilde{x}_{bk}}{\tau} = \frac{f_w \Big|_{S_{wbk}} - f_w \Big|_{S_{wc}}}{S_{wbk} - S_{wc}} \quad (3.20)$$

Equation (3.20) only applies if the velocity of the oil-water bank shock is slower than that of the normal waterflood shock (i.e., if $(\tilde{x}_{bk}/\tau) < (\tilde{x}_b/\tau)$). Otherwise, the oil bank collides with a normal waterflood when $S_w = S_{wbk}$. In this case Equations (3.7) and (3.8) then dictate the water saturation profile ahead of the oil-water bank. The constant saturation bank runs into the waterflood at the position given by:

$$\frac{\tilde{x}_{bk}}{\tau} = \frac{df_w}{dS_w} \Big|_{S_{wbk}} \quad (3.21)$$

Whether Equation (3.20) will apply depends primarily on the value of $S_{we}/\alpha C_1$ or on how much emulsion water is stripped of emulsion. If $S_{we}/\alpha C_1$ is large, a fast oil-water bank forms ahead of the emulsion, and a partial waterflood displacement is observed. Equation (3.21) holds in this case. For a low $\frac{S_{we}}{\alpha C_1}$, little denuded water is produced and the water bank ahead of the emulsion is slower. No portion of a waterflood occurs in this situation and Equation (3.20) is valid. Once the saturation profile is calculated the oil production history follows identically as in Buckley-Leverett water

displacement theory. The interested reader may find further discussion in the article by Patton and Coats (8).

3. Graphical Solution

Construction of the saturation profiles and oil production histories from the emulsion displacement theory may be accomplished either graphically or numerically. When an analytic expression for the relative permeability curves is available (e.g., see Equation (3.3)), a numerical computation process is more exact and less time consuming. A graphical solution, however, reveals more insight into flow behavior and bank production. Hence, it is developed here. This technique is quite analogous to that presented by Patton and Coats (8) for an adsorbing polymer flood. Two additional restrictions which underlie this theory for displacement are: water stripped of emulsion must behave as connate water, and no connate water is immobilized by the injected emulsion.

Figure 3.21 gives the mathematical solution for the case of small emulsion retention where Equation (3.20) applies. Both the water fractional flow curve, labeled by $\frac{\bar{\beta}}{\bar{\alpha}} = 0$, and the emulsion fractional flow curve, labeled by $\frac{\bar{\beta}}{\bar{\alpha}} = 0.5$, are shown as curved solid lines in Figure 3.21. Equation (3.18) states that the straight line drawn tangent to the emulsion fractional flow curve originating from the abscissa at S_w equal to $(-\frac{S_{we}}{\bar{\alpha}C_i})$ fixes the velocity and saturation of the emulsion shock. The calculational procedure for emulsion displacement differs from that of polymers here because $\bar{\alpha}$ and $\bar{\beta}$ are functions of saturation and, therefore, are functions of S_{we} and S_{wbk} . For polymer retention by adsorption, retention is independent of saturation. The parameters S_{we} , S_{wbk} , $\bar{\alpha}$, and $\bar{\beta}$

XBL 815-3043

Figure 3.21 Graphical solution for small $S_{we}/\bar{\alpha} C_i$, high drop penetration. $\bar{S}_{we} = 0.39$. Relative permeability curves are the same as given in Figure 3.19. Equivalent to $0.9 \mu\text{m}$ mean drop-size emulsion in a $1.9 \mu\text{m}^2$ core.

are all unknowns in Equations (3.15) , (3.18), and (3.20) (or Equation (3.21)). Therefore, a trial-and-error calculation is required. A value is chosen for the mean emulsion water shock front saturation, $\overline{S_{we}}$. The corresponding values for $\overline{\alpha}$ and $\overline{\beta}$ follow from the relative permeability calculational procedure of the previous section. Next the fractional flow curve is constructed according to Equations (3.13) and (3.15). Finally, an iterative process is performed by varying $\overline{S_{we}}$ to obtain the tangent line drawn to the fractional flow curve as given by Equation (3.18). This tangent then yields values for S_{we} and S_{wbk} which follow from Equations (3.18) and (3.19). The intersection of the line tangent to the emulsion fractional flow curve with the water fractional flow curve gives S_{wbk} . The mean emulsion front water saturation is then computed and compared to the initial guess. This iterative process is repeated until the guessed and calculated values of $\overline{S_{we}}$ agree.

Once S_{we} and S_{wbk} have been established, the velocity of the oil-water bank shock is given by the slope of the dotted line in Figure 3.21, as demanded from the mass balance of Equation (3.20). Connate water and injected emulsion water stripped of drops form this bank. Because the emulsion shock front is slowed by emulsion retention, the oil-water bank shock travels faster than the emulsion, which is seen graphically in Figure 3.21 by the tangent line having a lower slope than the dotted line.

Also shown as a dashed line in Figure 3.21 is the standard waterflooding calculation, as previously depicted in Figure 3.2. Note that the line tangent to the emulsion flow curve intersects

the water fractional flow curve below the intersection point of the dashed tangent, which fixes the waterflood shock velocity. In this case, the oil-water bank shock formed by the emulsion travels slower than the standard waterflood shock, and, consequently, the waterflood shock is not involved in the production history.

The emulsion displacement saturation profile corresponding to Figure 3.21 is shown as a solid line in Figure 3.22 after 0.2 pore volumes of emulsion injection. A water displacement saturation profile is depicted in this figure as a long dashed line. The three solution regions are evident. Near the core exit only oil flows. This region is followed by the oil-water bank which has a constant oil and water saturation. Behind the oil-water bank is the emulsion flow zone. It is clear that the emulsion banks up oil ahead of it, and, therefore, leads to more efficient oil recovery than for simple waterflooding.

Emulsion flood oil production history, FOP, corresponding to this saturation profile and Figure 3.21 is given as a dashed line in Figure 3.23. Waterflooding of the same core is shown by the solid line in this figure. Regions of different flow are clearly evident in the emulsion flood. Pure oil is first produced from the outlet of the core, and yields the steep initial straight line in Figure 3.23. Once the oil-water bank breaks through, a constant ratio of oil-to-water is produced, corresponding to the saturation S_{wbk} , until the arrival of emulsion. This corresponds to the second straight dashed line of lower slope or of lower oil-to-water ratio. When emulsion appears in the effluent, oil production follows the emulsion fractional flow curve to residual oil saturation.

XBL815-3044

Figure 3.22 Saturation profile for both a waterflood (dashed line) and the emulsion flood of Figure 3.21 (solid line) after injection of 0.2 pore volumes.

XBL 815-3045

Figure 3.23 Fraction of oil in place produced versus pore volumes of fluid injected. For waterflood (solid line) and emulsion flood (dashed line) described by Figures 3.21 and 3.22. Water breakthrough occurs at τ_{bk} and emulsion breakthrough at τ_e .

The region of the curved production history reflects the time period after emulsion breakthrough. Eventually both the waterflood and the emulsion flood production history curves will asymptote to the same value of FOP when residual oil saturation is reached. However, the emulsion displacement produces more oil earlier than the waterflood.

For the case where there is high retention of the emulsion (i.e., low drop penetration, or a large value of $\frac{S_{we}}{\alpha C_i}$) more of the injected emulsion is stripped of droplets, and significant denuded water is present in the oil-water bank ahead of the emulsion. This is reflected by the tangent line to the enhanced or emulsion water fractional flow curve intersecting the water fractional flow curve at a high water saturation. The intersection is at a saturation larger than that for the waterflood breakthrough saturation, S_{wb} . Figure 3.24 portrays the graphical solution for this case. The iterative solid tangent line from $(-\frac{S_{we}}{\alpha C_i})$ again determines S_{we} according to Equation (3.18). Now, however, the emulsion retention relative to the injected emulsion concentration is large, so that this line intersects the water fractional flow curve at a saturation, S_{wbk} , which is above S_{wb} , rather than below as in Figure 3.21. The oil-water bank velocity is large causing the bank to invade the normal waterflood. In this high drop retention case, oil is produced until the normal waterflood saturation shock at S_{wb} arrives at the core outlet. The velocity of this shock front is given by Equation (3.8) and corresponds graphically to the slope of the dashed line in Figure 3.21. Equation 3.21 holds and the water fractional flow curve is followed by the waterflood, up to the intersection of the tangent to the emulsion flow curve and the water

XBL815-3046

Figure 3.24 Graphical solution for large $S_{we}/\bar{\alpha}C_i$, low drop penetration. $\bar{S}_{we} = 0.57$, $\bar{\alpha} = 12.0$, $\bar{\beta} = 9.0$. Relative permeability curves are those used for Figure 3.19. Equivalent to the injection of $2.0 \mu\text{m}$ mean droplets into a $1.9 \mu\text{m}^2$ core.

fractional flow curve. At this point the oil-water bank runs into the water displacement. Again Equations (3.18) and (3.19) fix the saturation of the oil bank formed by the emulsion. This oil-water bank is then followed at constant water saturation to the emulsion shock. From this point on the graphical treatment proceeds identically to the low retention emulsion case.

A displacement saturation profile for Figure 3.24 is depicted in Figure 3.25 as a solid line. The waterflood saturation profile is again shown as a long dashed line. Both floods are depicted at 0.2 pore volumes of fluid injection. The zone near the column outlet is, as before, pure oil flow. This zone is followed by the waterflood regime. Waterflooding is interrupted by the oil-water bank formed by the emulsion at $\bar{x}_{bk}$. Emulsion then follows this oil-water bank at $\bar{x}_e$. Because of the oil-water bank formation, the emulsion flood is still more efficient than the waterflood, but the difference in efficiency is not as great as in Figure 3.22, where the emulsion retention to injected concentration ratio is less.

The oil production history, or FOP, curve for Figure 3.25 is shown in Figure 3.26. A dashed line reveals the emulsion flood result while a solid line depicts the waterflood displacement. The various oil production modes are evident. Initially only oil is produced corresponding to the linear region. Subordinate phase waterflooding commences at water breakthrough and continues until the oil-water bank arrives at the outlet. A second linear rate of oil production occurs due to a constant oil-water ratio being produced until emulsion breakthrough. Further oil production then

XBL 815-3047

Figure 3.25 Saturation profile for both a standard waterflood (dashed line) and the emulsion flood of Figure 3.24 (solid line) after injection of 0.2 pore volumes.

Figure 3.26 Fraction of oil in place produced versus pore volumes of fluid injected for both waterflood (solid line) and the emulsion flood (dashed line) described by Figures 3.24 and 3.25. Water breakthrough at τ_b , emulsion breakthrough at τ_e .

XBL 815-3048

occurs in the emulsion subordinate mode. Oil production histories from both water and emulsion floods coincide at long injection times due to residual oil saturation being identical in each case. Again, even for the case of large emulsion retention, the emulsion displacement recovers oil more effectively than the standard waterflood.

Given the theoretical saturation profiles for an emulsion displacement, the transient pressure drop may also be predicted. The calculation is outlined in Appendix IIIA. This enables experimental pressure drop data along with FOP data to be compared to the displacement theory.

4. Discussion

In designing an emulsion flood for a specific reservoir the inlet emulsion concentration and mean drop-size must be chosen carefully to give the best displacement. The role of these two variables on oil production is outlined below.

The drop-size to pore-size ratio controls the values of the filtration parameters α and β , which in turn control the permeability reduction. For a specific reservoir mean pore size, increasing the drop size of an injected emulsion increases $(1/\alpha)$ and decreases β (see Figures 3.8 and 3.9). Therefore, the permeability reduction is increased according to Equation (3.13) and the fractional flow curve of water is shifted to the right, as shown in Figure 3.19. Thus it appears desirable to use large drops, which yield high permeability reductions, as long as these drops are not so large that the reservoir becomes blocked.

Large drops, however, are significantly retained by the porous medium, which leads to large values of the factor $S_{we}/\alpha C_i$.

From Figures 3.23 and 3.26 it is discovered that when $S_{we}/\alpha C_i$ is large, the emulsion flood is not as effective. Emulsion breakthrough is late, penetration of the drops into the core is small, and the oil-water bank formed exhibits a higher saturation of water (i.e., it contains less oil). There is an important interplay between the effect of increasing drop size, thus increasing the permeability reduction, and retaining more oil in the porous medium. The first effect is beneficial in oil displacement, where the second is not.

Figure 3.27 illustrates these concepts. The oil production history is shown calculated for three emulsion floods, as dashed lines, and a standard waterflood, as a solid line. The emulsion concentration is 1.5 volume percent. Each emulsion flood corresponds to the injection of a specific mean drop size. This drop size as well as the values for $\bar{\alpha}$ and $\bar{\beta}$ from the calculational procedure are listed in the figure. Increasing values of the ratio $\bar{\beta}/\bar{\alpha}$ directly reflect an increasing mean drop-size. For the $\bar{\beta}/\bar{\alpha}$ case of 0.5, or small drops, the additional oil recovery is early. But, because the permeability reduction is slight, there is little added advantage over waterflooding. As the mean drops get progressively larger, for $\bar{\beta}/\bar{\alpha}$ ratios of 0.75 and 0.9, more oil is recovered compared to the waterflood. This recovered oil, however, is produced later in the flood due to larger droplet retention. In all three calculated floods the injected emulsion concentration is 1.5 volume percent. Remember that at long injection times, τ approaching infinity, all four floods of Figure 3.27 approach the same FOP. The behavior of emulsion production history on drop size

XBL815-3049

Figure 3.27 Effect of injected drop size on oil production history. Fraction of oil in place produced versus pore volumes injected for waterflood (solid lines) and three different emulsion mean drop sizes at 1.5 volume percent concentration (dashed lines). Calculated for drop sizes of: $\langle D_d \rangle = 1.1 \mu\text{m}$, $\bar{\beta} = 0.5$; $\langle D_d \rangle = 2.0 \mu\text{m}$, $\bar{\beta} = 0.75$; $\langle D_d \rangle = 2.6 \mu\text{m}$, $\bar{\beta} = 0.9$ in a $1.9 \mu\text{m}^2$ core $\bar{\alpha}$ described in $\bar{\alpha}$ Figure 3.19.

as outlined above and in Figure 3.27 will be important when the experimental results of this thesis are discussed.

The effect of emulsion concentration for a fixed drop size on oil production history is investigated in Figure 3.28. Here, two calculated emulsion displacement histories of differing droplet concentration (dashed lines) are compared to that for waterflooding (solid line). The values for $\bar{\alpha}$ and $\bar{\beta}$ are 30 and 15 so that the $\bar{\beta}/\bar{\alpha}$ ratio is 0.5. Since the same permeability reduction occurs in both emulsion floods, the two dashed lines coincide after the lower concentration emulsion breaks through. Clearly, the high-concentration emulsion recovers oil significantly earlier than the lower concentration emulsion. The reason lies with the lower value of $S_{we}^{\bar{\alpha}} C_i$ which reflects the greater penetration of the high concentration emulsion and the faster emulsion front shock velocity.

In summary, a theoretical description of emulsion flooding behavior is available by combining classical Buckley-Leverett water displacement theory with Soo's work on dilute emulsion flow in short water-saturated sandpacks. The resulting theory is not straightforward. Complications arise mainly in the detailed understanding of droplet transport in two-phase porous media flow. It is demonstrated that for improved oil recovery both large permeability reduction and high velocity of the emulsion front are desired. Otherwise, for low permeability reductions little additional oil is recovered, or if the permeability reduction is significant, oil that is recovered is eluted late in the flooding history. These facts will be confirmed in the experimental results of this paper, which now follow.

XBL815-3050

Figure 3.28 Effect of emulsion drop concentration on oil production history. Fraction of oil in place produced versus pore volumes injected for waterflood (solid line) and emulsion injection at various concentrations. Fraction flow described as in Figure 3.19 and is equivalent to injection of 1.0 μm mean droplets into a 1.9 μm^2 core.

APPENDIX III A

Dynamic Pressure Drop

This appendix outlines the equations used in the calculation of the pressure drop histories for water and emulsion floods. Positions and velocities of all fronts are determined by the methods outlined in the theory section of this thesis. Equations for the waterflood pressure history will be developed first and then extended to the emulsion displacement case.

1. Water Displacement

For a linear dynamic displacement of oil the transient pressure drop across the porous medium compared to the initial pressure drop of oil flowing across the core may be written by definition as

$$\frac{\Delta P}{\Delta P_i} = \frac{L}{\Delta P_i} \sum_{j=0}^m \int_{\tilde{x}_j}^{\tilde{x}_{j+1}} \frac{\partial P}{\partial x} d\tilde{x} \quad , \quad (\text{IIIA.1})$$

where capillary forces have been neglected, and the distance increments x_j to $x_j + 1$, correspond to the various saturation regions present in the core. During the initial stages of waterflooding there are two saturation regions present, as shown in Figure 3.3. Ahead of the shock only oil is flowing, while behind the shock both oil and water flow simultaneously in the subordinate mode. If the core initially contains connate water, then Equations (1.1), (3.2) and (3.3) permit Equation (IIIA.1) to be re-expressed as:

$$\frac{\Delta P}{\Delta P_i} = 1 - \tilde{x}_b + \frac{\mu_w}{\mu_n} \int_0^{\tilde{x}_b} \frac{k_{rn}^o}{k_{rw}} f_w d\tilde{x} \quad (\text{IIIA.2})$$

The term $\tilde{x}_b$ is the position of the shock in the core at a given time. This result is an intermediate one. A change of variables in the integral proves convenient. Equation (3.7) is differentiated at constant time and substituted into Equation (IIIA.2). Then with Equation (3.8) the resulting equation is,

$$\frac{\Delta P(\tau)}{\Delta P_i} = 1 - \left[\frac{df_w}{dS_w} \right]_{S_{wb}} - \frac{\mu_w}{\mu_n} \int_{1-S_{nr}}^{S_{wb}} \frac{k_{rn}^o f_w}{k_{rw}} \frac{d^2 f_w}{dS_w^2} dS_w \tau$$

for $\tau \leq \tau_b$

(IIIA.3)

The integral in Equation (IIIA.3) may be written by the use of parts (21,22). However, this is unnecessary here because of the form of the relative permeability equations chosen. Since the integral limits in Equation (III A.3) are constants, the transient pressure drop will be linear in time up to water breakthrough. The experimental data of Figure 3.5 verifies this behavior.

After water breakthrough, $\tilde{x}_b$ in Equation (III A.2) is replaced with unity since there no longer is a bank of only oil flowing in the core. In this case the resulting pressure drop is given by

$$\frac{\Delta P(\tau)}{\Delta P_i} = -\tau \frac{\mu_w}{\mu_n} \int_{1-S_{nr}}^{S_{wL}} \frac{k_{rn}^o f_w}{k_{rw}} \frac{d^2 f_w}{dS_w^2} dS_w$$

for $\tau \geq \tau_b$

(IIIA.4)

where S_{wL} is the transient value of the water saturation at the

end of the core after water breakthrough. S_{wL} follows from the Buckley-Leverett expression of Equation (3.7) with $\tilde{x}$ equalling unity.

A check of the validity of Equation (III A.4) is to take the limit as τ approaches infinity, where the water saturation in the core approaches $(1-S_{nr})$. The pressure drop must reduce to

$$\lim_{\tau \rightarrow \infty} \frac{\Delta P}{\Delta P_i} = \frac{\mu_w}{\mu_n} \frac{k_{rn}^o}{k_{rw}^o} \quad (\text{IIIA.5})$$

By careful application of l'Hospital's rule this result is verified.

Both the pressure profile and the oil production equations are now in terms of the physical properties and the relative permeabilities. It is then possible with experimental data to determine the power indices for the relative permeability equations of Equation (3.3). A computer program was developed to integrate numerically Equations (III A.3) and (III A.4) by a simple trapezoidal rule. A program was also written to determine the analytic differentiation of the fractional flow curve thereby obtaining the production history. After calculating the production history and corresponding saturation velocities, the pressure profile can be calculated, since the velocities of all saturations are then fixed. If the calculated and experimental values for FOP and pressure drop do not match, new values for n and p are chosen until good agreement is reached.

2. Emulsion Displacement with High-Drop Penetration

During the initial stages of an emulsion flood, in the case where drop penetration is high, three zones of flow are present before water breakthrough. These zones are shown in Figure 3.22. Ahead of the oil-water bank formed by the emulsion a bank comprised

of only flowing oil. In a core containing connated water, combination of Equations (1.1), (3.2), (3.3), (3.12), (3.15), and (3.20) permit Equation (III A.1) to be rewritten as:

$$\frac{\Delta P}{\Delta P_i} = (1 - \tilde{x}_{bk}) + \frac{\mu_w}{\mu_n} \frac{k_{rn}^o}{k_{rw}} \frac{f_w}{f_{w/e}} \bigg|_{S_{wbk}} (\tilde{x}_{bk} - \tilde{x}_e) + \frac{\mu_w}{\mu_n} \int_0^{\tilde{x}_e} \frac{k_{rn}^o}{k_{rw}} \frac{f_{w/e}}{f_w} d\tilde{x} \quad (IIIA.6)$$

The terms $\tilde{x}_{bk}$ and $\tilde{x}_e$ refer to the positions of the oil-water bank shock front and the emulsion shock front at a given time according to Equations (3.18) and (3.20). $f_{w/e}$ refers to the emulsion water fractional flow curve described by Equation (3.15), while f_w is the normal water fractional flow curve of Equation (3.2). A change of variables from position to saturation in the integral is performed and yields:

$$\frac{\Delta P(\tau)}{\Delta P_i} = (1 - \tilde{x}_{bk}) + \frac{\mu_w}{\mu_n} \frac{k_{rn}^o}{k_{rw}} \frac{f_w}{f_{w/e}} \bigg|_{S_{wbk}} (\tilde{x}_{bk} - \tilde{x}_e) - \frac{\tau \mu_w}{\mu_n} \int_{1-S_{nr}}^{S_{we}} \frac{k_{rn}^o}{k_{rw}} \frac{f_{w/e}}{f_w} \frac{d^2 f_{w/e}}{dS_w^2} dS_w \quad \text{for } \tau \leq \tau_{bk} \quad (IIIA.7)$$

This equation holds up to water breakthrough. At this time $\tilde{x}_{bk}$ becomes unity and the first term on the right side of Equation (III A.7) disappears, while the factor in the parenthesis of the second term becomes $(1 - \tilde{x}_e)$. The resulting equation holds until emulsion appears at the exit of the core, at which time the pressure drop reduces to:

$$\frac{\Delta P(\tau)}{\Delta P_i} = -\tau \frac{\mu_w}{\mu_n} \int_{1-S_{nr}}^{S_{wL}} \frac{k_{rn}^o}{k_{rw}} \frac{f_{w/e}}{f_w} \frac{d^2 f_{w/e}}{dS_w^2} dS_w \quad \text{for } \tau \geq \tau_e \quad (IIIA.8)$$

Again, S_{wL} is the transient water saturation at the end of the core, but its value follows from Equation (3.16) where $\tilde{x}$ equals unity. Equation (IIIA.8) will then hold for the remainder of the emulsion displacement.

3. Emulsion Displacement with Low-Drop Penetration

When drop penetration proceeds slowly into a core during emulsion displacement, $S_{we}/\bar{\alpha}C_1$ is large. A waterflood occurs in front of the emulsion. There are four regions of flow before water breakthrough, as pictured in Figure 3.25. First, a bank of only oil flowing is produced, followed by a waterflood displacement. This waterflood continues until, S_{wbk} , the oil-water bank shock saturation, is reached, which is in turn followed by the emulsion flow region. Combination of Equations (1.1), (3.2), (3.12), (3.15), and (3.31) permit the rewriting of Equation (III A.1) as:

$$\begin{aligned} \frac{\Delta P}{\Delta P_i} = (1 - \tilde{x}_b) + \frac{\mu_w}{\mu_n} \int_{\tilde{x}_{bk}}^{\tilde{x}_b} \frac{k_{rn}^o f_w}{k_{rw}} d\tilde{x} + \frac{\mu_w}{\mu_n} k_{rn}^o \frac{f_w}{k_{rw}} \bigg|_{S_{wbk}} (\tilde{x}_{bk} - \tilde{x}_e) \\ + \frac{\mu_w}{\mu_n} \int_0^{\tilde{x}_e} \frac{k_{rn}^o f_{w/e}}{k_{rw}} d\tilde{x} \quad \text{for } \tau < \tau_b \end{aligned} \quad (\text{IIIA.9})$$

As before, a change of variable yields the integral in terms of saturation:

$$\begin{aligned} \frac{\Delta P(\tau)}{\Delta P_i} = (1 - \tilde{x}_b) + \frac{\mu_w}{\mu_n} \int_{S_{wbk}}^{S_{wb}} \frac{k_{rn}^o f_w}{k_{rw}} \frac{d^2 f_w}{dS_w^2} dS_w + \frac{\mu_w}{\mu_n} \frac{k_{rn}^o f_w}{k_{rw}} \bigg|_{S_{wbk}} (\tilde{x}_{bk} - \tilde{x}_e) \\ - \tau \frac{\mu_w}{\mu_n} \int_{1-S_{nr}}^{S_{we}} \frac{k_{rn}^o f_{w/e}}{k_{rw}} \frac{d^2 f_{w/e}}{dS_w^2} dS_w \quad \text{for } \tau < \tau_b \end{aligned} \quad (\text{IIIA.10})$$

Equation (IIIA.10) only holds up to the point of water breakthrough. The value for $\tilde{x}_b$ is then replaced by unity and S_{wb} , the water breakthrough saturation, is replaced by S_{wL} . S_{wL} is described by Equation (3.7) with $\tilde{x}$ equal to unity. The first two terms on the left side of Equation (III A.10) reduce to a form similar to Equation (III A.4) with the remaining factors unchanged. The resulting equation is shown below, and holds until the breakthrough of the oil-water bank at a water saturation of S_{wbk} .

$$\begin{aligned} \frac{\Delta P(\tau)}{\Delta P_i} = & -\tau \frac{\mu_w}{\mu_n} \int_{S_{wbk}}^{S_{wL}} \frac{k_{rn}^o f_w}{k_{rw}} \frac{d^2 f_w}{dS_w^2} dS_w + \frac{\mu_w}{\mu_n} \frac{k_{rn}^o f_w}{k_{rw}} \bigg|_{S_{wbk}} (\tilde{x}_{bk} - \tilde{x}_e) \\ & -\tau \frac{\mu_w}{\mu_n} \int_{1-S_{nr}}^{S_{we}} \frac{k_{rn}^o f_{w/e}}{k_{rw}} \frac{d^2 f_{w/e}}{dS_w^2} dS_w \quad \text{for } \tau \leq \tau_{bk} \end{aligned} \quad (IIIA.11)$$

When the oil-water bank reaches the end of the core, $\tilde{x}_{bk}$ equals unity. The first term in Equation (III A.11), corresponding to the waterflood disappears, and the resulting expression for the pressure drop is analogous to that of the high-drop penetration case. The treatment for both emulsion flood cases becomes the same at this point with Equation (III A.8) holding after emulsion breakthrough.

The equations for the transient pressure history of an emulsion displacement are used with the calculated relative permeabilities and the 'a priori' values of $\bar{\alpha}$ and $\bar{\beta}$ to calculate pressure drop. As with the water displacement, the production history and corresponding saturation velocities must be calculated prior to the determination of the pressure history.

IV DISCUSSION AND RESULTS

In this chapter the major experimental work of this thesis is presented. Various displacement tests are performed in order to determine the validity of the theoretical model developed in the preceding chapter, as well as to confirm the result that emulsions do provide mobility control (3) and improve oil recovery. Discussion emphasis is placed on the quantitative comparison of the experimental production history and pressure drop to that predicted "a priori" by the theory for dilute, linear emulsion displacement. All the displacement parameters, including those for the relative permeabilities, are given for each core displacement test in Appendix IV A following this chapter. When discussing the results of a high concentration emulsion displacement and a parallel core test, where the developed theory does not strictly apply, qualitative comparison is stressed.

The four 1.5 volume percent linear emulsion displacements reported in this chapter are separated into three categories. These divisions are based on emulsion retention or drop to pore-size ratio. One is low drop-size to pore-size ratio, which corresponds to low permeability reduction with high-drop penetration. A second classification is large drop-size to pore-size ratio, and indicates a high degree of permeability reduction with little drop penetration. The third category discussed is that of intermediate drop-size to pore-size ratio. This experimentally yields the most interesting results, and, therefore, two displacement results are presented.

The desire not only to predict quantitatively dilute emulsion displacement in linear cores, but to better understand emulsion flow

in reservoirs dictated two additional types of experiments. A high concentration, 5.0 percent, emulsion displacement is presented along with a parallel displacement in two cores of differing permeability. The parallel test is helpful in understanding emulsion flow in regions of varying permeability. Since all oil reservoirs are heterogeneous with regard to permeability, this experiment indicates the possible effects of emulsion flooding on macroscopic flow diversion. The high-concentration flood is performed to determine if significant oil can be recovered early in the flooding history.

A. Linear Emulsion Displacement

1. Low-Drop Size to Pore-Size Ratio

Figure 4.1 illustrates a typical result of a secondary waterflood (circles) and a dilute, 1.5 volume percent, emulsion flood (triangles) expressed by the fraction of oil in place produced as a function of injected fluid pore volumes. Shown as squares in this figure is the effluent drop concentration, C_L/C_1 . This notation will be followed for each of the following linear emulsion displacement tests as well. Because the oil displaced in Figure 4.1 is viscous, 140 mPa · s, waterflood performance is poor with early water breakthrough and prolonged oil production at high water-to-oil ratios. The enhanced emulsion flood recovery in Figure 4.1 corresponds to the injection of 1.2 μm mean drop-size drops into the 3.3 μm^2 core, or a mean drop-size to mean pore-size ratio at the mean emulsion shock front water saturation of 0.10. The dilute emulsion is successful in achieving additional oil recovery at lower water-to-oil ratios. This behavior is quite similar to that observed with polymers (8,9) and reaffirms the original observations of

XBL 815-3051

Figure 4.1 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a $3.3 \mu m^2$ core. Mean drop to pore ratio at $\bar{S}_{we}$ is small, 0.10. Dashed line gives theoretical emulsion predicted behavior. Squares show effluent drop concentration.

McAuliffe on dilute O/W emulsion displacement (3).

The solid line in Figure 4.1 gives the best-fit behavior for the waterflood history, as determined from the relative permeability curves. The dashed line in this figure is the "a priori" calculated production history for the emulsion displacement. No adjustable parameters are used in the prediction of oil production since $\bar{\alpha}$ and $\bar{\beta}$ are fixed according to the calculational procedure of section C.3 in Chapter 3. The arrow in Figure 4.1 marks the calculated appearance of emulsion in the effluent and closely matches the experimental behavior. The displacement history for the emulsion has been clearly and accurately predicted beforehand by the emulsion flow theory developed in this thesis.

The experimental and calculated pressure profiles for the displacements of Figure 4.1 are depicted in Figure 4.2. Again, the circles represent the waterflood experimental data and the triangles emulsion flood data. Dimensionless pressure drop, or pressure drop divided by the initial pressure drop across the core, is plotted versus pore volumes of injected fluid. A solid line gives the best-fit waterflood pressure behavior. The dashed line is the "a priori" predicted pressure drop for the emulsion displacement. Agreement between calculated and experimental values is excellent. The increase of pressure drop for the emulsion displacement is due to the permeability reduction caused by emulsion capture, and not by any viscosity effect. The main mode of droplet retention is due to interception in this experiment. Emulsion drops reduce the permeability slightly by about 40 percent near the end of the flood.

Because of the low value for $S_{we}/\bar{\alpha}C_1$ in this test, drop

Figure 4.2 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) of Figure 4.1. Dashed line gives theoretical predicted emulsion behavior.

XBL 815-3052

penetration into the core is good with emulsion breakthrough occurring close to 2.5 pore volumes. There is also negligible drop-size segregation since the value of $1/\bar{\alpha}$ for the mean drop-size to mean pore-size ratio at the emulsion shock water saturation is small. Due to the slight shift in the fractional flow curve, from the small permeability reduction, a small increase in oil production is seen. This point has been previously noted in Figure 3.27 of the emulsion displacement theory. As shown, enhanced oil recovery is obtained early in the flood. In the experiment depicted in Figure 4.1, additional oil is obtained before the injection of 3 pore volumes of emulsion.

The increase in oil production in Figure 4.1 could be attributed to the emulsion stabilizing surfactant in the system. The interfacial tension between the bulk oil and water phases could be affected and the relative permeability curves shifted, thus improving oil recovery. To test this possibility the surface tension of water stripped of emulsion is measured. Table 4.1 contains the results of this experiment. The surface tension of water is only slightly altered indicating a very small amount of surfactant. Such a small surfactant concentration cannot affect the relative permeability curves, since they are only functions of tension only at extremely low tensions (15). Therefore, the improved recovery that is observed is due to the mechanical entrapment of emulsion, and not the addition of the oleate surfactant to stabilize the emulsion drops.

From the results of this test the calculation procedure for the quantitative prediction of pressure profile and production history is verified. Both FOP and pressure drop are accurately predicted

TABLE 4.1

Oleate Effect on Surface Tension

	<u>*Surface Tension</u>
Distilled Water	73.4 $\pm$ 3%
Water at pH 10	74.1 $\pm$ 3%
Water Stripped of Emulsion	71.6 $\pm$ 3%

* units of surface tension are mN/m

"a priori" and with no adjustable parameters.

2. High Drop-Size to Pore-Size Ratio

The developed emulsion displacement theory predicts that higher permeability reductions increase the fractional flow of oil, and, therefore, recover more oil. Greater amounts of permeability reduction occur at higher drop to pore-size ratios.

A 1.5 volume percent emulsion of $1.7 \mu\text{m}$ mean droplet diameter is injected into a $0.7 \mu\text{m}^2$ permeability core. This results in a mean drop-size to pore-size ratio, at the emulsion shock front, of 0.173. Results of the emulsion displacement test and a reference water displacement are shown in Figures 4.3 and 4.4. Due to high drop-size to pore-size ratio of the emulsion injected, no emulsion droplets are found in the effluent even after 7 pore volumes of fluid injection. The proposed emulsion displacement theory predicts emulsion breakthrough at 9 pore volumes of injected fluid. At this injection time, the value of FOP is 0.7. The dashed line in Figure 4.3 indicates the "a priori" calculated oil production history. Agreement between experiment and calculation is excellent. The emulsion flood begins to enhance oil recovery after about 3 pore volumes, where the oil bank formed by the emulsion exits the porous medium. After this point, the constant oil-water bank is produced, resulting in the straight line production history. At emulsion breakthrough a greater oil production amount is predicted than for emulsion floods of the same concentration but smaller drop size, which yield lower permeability reductions. Unfortunately, this increased oil production does not occur until very late in the displacement, as shown in Figure 4.3 and in Figure 3.27 of Chapter 3. Because the large

XBL 815-3053

Figure 4.3 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a $0.7 \mu m^2$ core. Mean drop to pore-size ratio at $\bar{S}_{we}$ is large, 0.173. No emulsion in the effluent is observed.

XBL 815-3054

Figure 4.4 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the results shown in Figure 4.3. Dashed line gives theoretical emulsion behavior predicted. Solid line is best-fit from the relative permeability curves.

drops are efficiently captured by the porous medium, the velocity of the emulsion front is slow and the early oil production is the result of waterflooding. Even though large oil drops are predicted to produce large increases in oil recovery, they do so late in the production history. In this case, the large effective permeability reduction is overpowered by the significant hold up, or retention, of the drops. In Figure 4.3 the main mode of droplet retention is straining, since the mean drop to pore-size ratio at the emulsion shock front saturation is 0.173.

The pressure drop history corresponding to the emulsion injection of Figure 4.3 is shown in Figure 4.4. Calculated pressure drop history for the 1.7 μm drops is depicted as a dashed line with the solid line indicating the best-fit waterflood pressure drop from the relative permeability curves. The pressure response for the emulsion flood is under predicted. However, the proper trend of increasing pressure drop is correct. An explanation for the error in predicting the pressure drop history is unsteady straining by the larger emulsion drops at the inlet of the core, which gives rise to large pressure drops. The pressure drop across the core front can increase significantly without affecting the oil production.

Whenever there is significant drop straining, an emulsion flood will not be very effective. It is better to use smaller drops which penetrate further into the porous media with a faster shock velocity. The retention effect appears to outweigh the lesser permeability reduction obtained with the smaller drops. Of course, extremely small drops which do not reduce the permeability at all cannot be expected

to enhance oil recovery.

3. Intermediate Drop-Size to Pore-Size Ratio

In these displacement tests the mean drop-size to pore-size ratio at the emulsion shock water saturation falls into the region where both straining and interception are significant. Because of the distribution of drop sizes in the emulsion, drop segregation is likely to occur in this sensitive region of α . The two emulsion displacements that are performed in this classification are for injection of a $1.4 \mu\text{m}$ mean drop diameter emulsion of 1.5 percent volume concentration into a $1.15 \mu\text{m}^2$ core, and for the injection of $2.0 \mu\text{m}$ mean drops of the same concentration into a $2.0 \mu\text{m}^2$ permeability core. These experiments correspond to mean drop to mean pore-size ratios at the emulsion shock front saturation of 0.15 and 0.155, respectively. The results of both of these tests differ significantly from those presented previously in Figures 4.1 and 4.3. Oil is produced much earlier than anticipated by the theoretical calculation utilizing the pseudo-monovariant emulsion assumption.

Figures 4.5 and 4.6 give the results of oil production history and pressure history for the $1.15 \mu\text{m}^2$, $1.4 \mu\text{m}$ drop case. Although the "a priori" prediction quantifies oil recovery at longer times near emulsion breakthrough, the theory underestimates oil recovery early in the flood. An emulsion breakthrough near 5 pore volumes is predicted. As shown by the squares in Figure 4.5, indicating effluent emulsion concentration, the measured trend agrees with the calculated mean breakthrough time. The flood, however, was not conducted long enough to observe complete emulsion breakthrough.

One explanation for the increased oil recovery early in the

XBL 815-3055

Figure 4.5 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a $1.15 \mu\text{m}^2$ core. Mean drop to pore-size ratio at $\bar{S}_{we}$ is intermediate, 0.5. Dashed line gives theoretical emulsion behavior predicted. Squares show effluent drop concentration. Solid line fit from relative permeability curves.

XBL 815-3056

Figure 4.6 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the results shown in Figure 4.5. Dashed line gives theoretical emulsion behavior predicted. Solid line is best-fit from the relative permeability curves.

emulsion flood, is immobilized core water, or equivalently, inaccessible pore volume (25). Since the oil droplets can completely block some of the pores by straining, there is the possibility of isolating water which does not participate in the displacement process. Such immobilized water, which is apparently also present with entrapping polymers (24), but not in simple waterflooding, will increase oil recovery in the beginning stages of the flooding sequence. A quantitative calculation of this effect is given in Appendix IV B. Even with the assumption that all connate water is immobilized, the early recovery of Figure 4.5 cannot be accounted for. This is not an indication that immobilized water is unimportant in polymer flooding, but rather, when retention of drops or polymer is large (i.e., when $S_{we}/\bar{\alpha}C_i > 1$) the effect is minimal.

A second explanation for the early increase in emulsion flood performance is droplet size segregation. The theory presented assumes that the emulsion can be treated as pseudo-monovariant with a mean drop size characterized by $\bar{\alpha}$ and $\bar{\beta}$. As discussed earlier, when a significant amount of both straining and interception occur, drop-size segregation occurs in the porous medium. For this experiment, the mean drop-size to pore-size ratio at the emulsion shock front is approximately 0.15, indicating both straining and interception to be present. Smaller drops should progress ahead of the predicted mean front. As shown in Figure 4.7 the first drops to appear in the effluent have a mean diameter less than half of those injected. The smaller drops elute around 3 pore volumes, with the mean drop-size predicted to elute at 5 pore volumes. Since small drops capture less efficiently than the mean size drops, they move ahead of the

XBL 815-3057

Figure 4.7 Emulsion effluent mean drop size and concentration corresponding to the emulsion displacement shown in Figures 4.5 and 4.6.

expected position of the pseudo-monovariant shock, and reduce permeability slightly in this region. This slight permeability reduction produces oil ahead of the predicted monovariant shock front.

Figure 3.27 demonstrates the qualitative role of drop segregation on oil displacement. Small drops elute faster and recover oil earlier. Larger drops move more slowly but recover more oil at their respective drop breakthroughs. For emulsions which exhibit significant straining and interception, the droplets do not appear to migrate as a single shock with a mean retention. Rather, a series of smaller shocks occurs. These shocks are characterized by the various drop size separations occurring in the core. The result is an oil production response which is sooner than that predicted by the pseudo-monovariant theory. Oil production then follows a series of curves of increasing drop-size to pore-size ratio as shown in Figure 3.27.

Although the size separation trend agrees with the observed displacement tests, a quantitative theory of two-phase flow including varying local droplet size to pore-size distributions is difficult. Nevertheless, the results of Figure 4.5 demonstrate that in spite of drop segregation the calculated monovariant emulsion production history at mean emulsion breakthrough is quantitative.

Since the production history is not correctly predicted, errors are also expected in the pressure history. Figure 4.6 shows that the emulsion flood pressure history is first over, then under predicted. The important point, however, is that the pressure response trend is in the proper direction. Unsteady straining of large drops near the core inlet probably accounts for the greater experimental pressure drop at high emulsion throughputs. Over prediction of

pressure drop near one pore volume is due to an over estimate of the amount of oil in the porous media. Because the oil is quite viscous compared to water, the higher the fraction of oil present, the larger the pressure drop. Since the monodisperse calculation procedure over estimates the amount of oil present at early injection times in the core, the predicted pressure drop will, therefore, be high.

Figures 4.8 and 4.9 demonstrate oil production and pressure history results for a $2.0 \mu\text{m}^2$ permeability core upon emulsion flooding with $2.0 \mu\text{m}$ mean drops at 1.5 volume percent. The mean drop-size to pore-size ratio at the shock front saturation is 0.155, indicating that again straining and interception are significant capture mechanisms. Flooding results similar to the $1.15 \mu\text{m}^2$ core, presented in Figures 4.5 through 4.7, are expected.

Early oil production is under estimated in Figure 4.8 by the theoretical calculation. Quantitative agreement is found only near the predicted mean breakthrough point of the emulsion, which is shown by the arrow at 7 pore volumes in Figure 4.8. The mean drop breakthrough point is closely predicted by the theory. However, there is significant size segregation of the emulsion drops. All drops eluted have drop sizes below $1.5 \mu\text{m}$ in diameter compared to the mean diameter of $2.0 \mu\text{m}$ injected. The smaller drops travel ahead of the theoretical monovariant shock front. The explanation of the early under estimate of oil production is identical to that for Figure 4.5.

The pressure history corresponding to the emulsion flood of Figure 4.8 is shown in Figure 4.9. Dashed lines indicate the calculated pressure response upon emulsion injection. Theory under predicts the pressure drop. As before, straining or plugging near

XBL 815-3058

Figure 4.8 Secondary waterflood (circles) and emulsion flood (triangles) recovery history in a $2.0 \mu m^2$ core. Mean drop to pore-size ratio at $\bar{S}$ is intermediate, 0.155. The dashed line gives theoretical emulsion behavior. Squares show we effluent drop concentration. An arrow indicates predicted mean breakthrough point.

XBL 815-3059

Figure 4.9 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the experimental results shown in Figure 4.8. The dashed line gives theoretical emulsion behavior and the solid line is best-fit from the relative permeability curves.

the inlet of the core is the likely explanation. Only the trend of the increasing pressure drop is correctly reflected at the longer injection times. It is reemphasized, however, that no adjustable constants are available for the prediction in Figures 4.5, 4.6, 4.8 and 4.9.

When the drop-size to pore-size ratio indicates that both straining and interception contribute significantly to the emulsion retention, the assumption of a pseudo-monovariant system for the drop-size distribution is not accurate. The calculational procedure based on this assumption quantitatively predicts production history after the mean breakthrough of emulsion but underpredicts the displacement of oil at early times. Later in the flood, because of unsteady state straining of the dilute and very large drop-size fraction in the emulsion, pressure drops are underpredicted.

As shown by the experiments given in this section, drop-size segregation is a desired flooding effect. It allows one to obtain both significant permeability reduction with good penetration of the smaller drops. These drops have been shown to migrate ahead of the larger drops and reduce permeability slightly, thus recovering additional oil early in the flooding history. Therefore, when designing an emulsion flood it is desirable to have a drop-size distribution which spans the region of both straining and interception capture mechanisms.

B. High-Concentration Emulsion Displacement

In order to produce oil earlier in an emulsion displacement and still maintain the same permeability reduction, the emulsion drop concentration must be increased. This reduces the value of

$S_{we}/\alpha C_1$ and increases the velocity of the emulsion front. The dilute concentration emulsion flooding theory holds quantitatively up to drop concentrations around one volume percent (2). At high drop concentrations, the likelihood of simultaneous multiple-drop straining increases. Therefore, additional capture may occur for higher drop concentrations, and retention values predicted by dilute emulsions theory may be underestimated.

Figure 4.10 illustrates a secondary waterflood (circles) and a 5 volume percent emulsion flood (triangles) expressed as the fraction of oil in place produced versus the injected fluid pore volumes. The core permeability is $1.9 \mu m^2$ and the mean drop size is $1.8 \mu m$ giving a mean drop-size to pore-size ratio of 0.168 at the emulsion shock front. Note the significant amount of oil produced by the emulsion flood early in the flooding history. High concentration, stable emulsions can be quite successful in enhancing oil recovery. The dashed line is the "a priori" predicted emulsion displacement history based on the dilute emulsion concentration theory. Again, no adjustable parameters are employed in the calculation. Apparently the 5 percent emulsion does not deviate strongly from dilute theory as shown by the close prediction of the oil displacement history in Figure 4.10. With the drop to pore-size ratio, at the front having the value of 0.168, a concentration spread in the emulsion effluent is expected due to drop segregation. The squares in Figure 4.10 show this effect. Also Table 4.2 gives the measured drop size shift for this experiment. The first drops eluted have a mean diameter almost half of the injected mean. Clearly, drop segregation occurs.

Figure 4.10 Secondary waterflood (circles) and high concentration emulsion flood (triangles) recovery history in a $1.9 \mu\text{m}^2$ core. Mean drop to pore-size ratio at $\bar{S}$ is intermediate, 0.168. Dashed line gives theoretical emulsion behavior predicted. Squares show effluent drop concentration. Arrow indicates the predicted mean breakthrough point.

XBL 815-3060

TABLE 4.2

High Concentration Effluent Drop Size Shift, $\langle D_d \rangle_i = 1.8 \mu\text{m}$

τ, PV	$\langle D_d \rangle, \mu\text{m}$	C_L / C_i
0.86	1.04	0.005
1.26	1.65	0.31
2.35	1.73	0.87

The drop-size to pore-size at the mean emulsion shock front water saturation falls in the intermediate regime. Hence we may explain the behavior of this flood. Drops elute earlier than predicted by the monodisperse theory, as in the low concentration emulsion case. However, in the low-concentration flood the mean breakthrough time is accurately predicted, while for the high-concentration experiment the breakthrough time of the $1.8 \mu\text{m}$ drops is earlier. One possible explanation of this early mean breakthrough is found in the immobilized water effect. At higher concentrations the value of $S_{we}\sqrt{\alpha C_1}$ decreases for the same size drop in a specific porous medium. The effect of immobilized water on the production history therefore is greater (see Appendix IV B). In the calculation of production history in Figure 4.10 immobilized water has been neglected. However, immobilized water can slightly influence the emulsion breakthrough and production history. Likewise, the drop segregation accounts for some of the early production of oil as in the low-concentration emulsion flood.

Even though drop size segregation occurs in the high-concentration experiment, the spread of the effluent concentration shock is now not as large. When compared to the case given in Figure 4.8, for a 1.5 volume percent emulsion with an intermediate drop-size ratio, the spread is much less. In the high-concentration emulsion flood drops close to the initial mean diameter elute 1.5 pore volumes after effluent drops are first observed. In the 1.5 pore volume percent emulsion injection case, even 3.5 pore volumes after drops are first observed in the effluent, the initial mean drop-size is not reached (see the displacement of Figure 4.8). As

emulsion concentration increases, the effect of drop segregation on oil production history is reduced. At higher emulsion concentrations the assumption of a monovariant shock is more valid, and prediction of oil production at short injection times is more accurate. This is seen by comparison of the intermediate drop-size cases for both the high, 5 volume-percent, and the low, 1.5 volume-percent, emulsion injection. In Figure 4.10 the early oil production for the high-concentration emulsion is more closely predicted than for the 1.5 volume percent injection of Figure 4.8. This supports the conclusion that higher drop concentrations minimize the effect of drop segregation on oil displacement.

The experimental and calculated pressure histories for the displacements of Figure 4.10 are illustrated in Figure 4.11. Again the waterflood is represented by circles and the solid line is a best-fit from the relative permeability curves. Triangles denote the emulsion flood data, while the dashed line is predicted "a priori" according to the dilute emulsion theory. As in the 1.5 volume percent emulsion injection of an intermediate drop size, the initial pressure drop across the core is overestimated. The same reasoning applies to this high-concentration test as well as to the low-concentration tests. Due to the highly viscous oil being produced from the core earlier, a lower pressure drop is measured than expected from theory. However, the trend of pressure drop history does correspond at longer times, near 4 pore volumes of fluid injected for the higher concentration experiment.

From these experiments at both a high and low concentration and for large and small drop-size to pore-size ratios, certain

Figure 4.11 Pressure drop history for both the waterflood (circles) and emulsion flood (triangles) for the experimental results shown in Figure 4.10. Dashed line gives theoretical emulsion behavior predicted. Solid line is best-fit from the relative permeability curves.

XBL 815-3061

conclusions are drawn for increased recovery of oil. It is evident that at higher concentrations the velocity of the emulsion shock is faster, and, therefore, increased oil production occurs early in the flood. Also it is found that drop segregation is beneficial to oil displacement since drop penetration is improved. As long as there is significant permeability reduction oil recovery will be improved. A drop-size to pore-size ratio which indicates both straining and interception is desired for best flooding results.

C. Parallel Cores

During constant flow rate displacement of oil from two parallel cores of differing permeability, the flow into each core is not constant throughout the flood. Therefore, the theoretical framework developed previously is not applicable. The results of this experiment cannot be interpreted quantitatively. However, they reveal the effect of emulsion flow on displacement of oil from regions differing in permeability. This effect is important in understanding the macroscopic flow behavior of an emulsion in a heterogeneous porous medium.

In this experiment, cores of 0.65 and $1.8 \mu\text{m}^2$, each having a connate water saturation of 0.13 , are flooded in parallel. In the emulsion flood $2.2 \mu\text{m}$ mean diameter drops at 1.5 volume percent are injected at the same total volumetric flow rate as in the comparison water displacement. Figure 4.12 demonstrates the improved oil recovery for the injection of emulsion for each core. This figure plots FOP for each individual core, versus the total pore volumes of fluid injected, based on the combined void volumes of both cores. The oil produced from the low permeability core is shown as open symbols with the triangles representing the emulsion displacement

XBL815-3062

Figure 4.12 Parallel core test results shown as the fraction of oil in place produced, per core, versus the total injected pore volumes.

and the circles representing the water displacement. Similarly, the closed symbols denote the displacement of oil from the high permeability core. Triangles again represent the emulsion flood and circles represent the waterflood. This figure clearly demonstrates an increase in oil production for emulsion injection but does not indicate the mechanism responsible for this increased recovery. Oil is produced earlier by the emulsion in the low permeability core, and a slightly greater fraction of oil is eluted late in the flood from the high permeability core. This additional recovery of oil could be due to plugging of emulsion drops which yields better mobility control, as in the linear waterflooding case, or by diverting flow from one core to the other.

Figure 4.13 demonstrates the lower difference in the degree of flow between the two cores during the emulsion flood. Here, the fraction of total flow through the low permeability core is shown versus the total injected pore volumes of the two cores for both water and emulsion flooding. The emulsion flood is again depicted by triangles and circles represent the waterflood. Water breakthrough in both the high and low permeability cores is shown for each flood. Here the long and short solid arrows indicate water breakthrough for the high and low permeability cores for the waterflood. Likewise, long and short dashed arrows correspond to water breakthrough in the high and low permeability core for the emulsion flood. The redistribution of flow obtained by the emulsion greatly decreases the time of water breakthrough in the $0.65 \mu\text{m}^2$ core, while only slightly increasing the time of water breakthrough for the $1.8 \mu\text{m}^2$ core. The flow rate in the low permeability core

XBL 815-3063

Figure 4.13 Fraction of total volumetric flow through the low, $0.65 \mu\text{m}^2$, permeability core versus total pore volumes injected. Solid arrows indicate breakthrough of water in waterflood for the high and low permeability cores. Dashed arrows give water breakthrough in the emulsion flood for the high and low permeability cores.

is doubled by emulsion retention in the high permeability core re-directing flow. Therefore, more oil is produced earlier in the flooding history of the low permeability core. This is clearly seen in Figure 4.12 for the low permeability core prior to one total pore volume injected.

Increased oil production in the low permeability core is not due to the effect of emulsion on the fractional flow curve as given in Equation (3.15). Emulsion drop penetration into the $0.65 \mu\text{m}^2$ core by the $2.2 \mu\text{m}$ drops is low, and therefore, from the theory outlined for linear displacements, $S_{we}/\bar{\alpha}C_i$ is large and a water displacement will occur ahead of the oil-water bank generated by the emulsion. Figure 4.14 demonstrates this for the low permeability core. In this figure the fraction of oil in place, FOP, for each core is plotted versus the pore volumes of injected fluid into each core, not the total pore volumes injected. This plot is analogous to that of Figure 3.4 for linear flooding. Since there is less flow in the low permeability core, less pore volumes are injected for a given time. The same legend of symbols is again used as in Figure 4.12. Even though data are determined continuously only selected points are displayed graphically in Figure 4.14. The production histories for both the emulsion and the waterflood are almost identical. With the information obtained from Figure 4.13 on the redistribution of flow into the low permeability core and the identical production histories for both water and emulsion floods we conclude that redistribution of flow is wholly responsible for the increased oil production of the $0.65 \mu\text{m}^2$ core.

Additional information on flooding behavior is obtained from

Figure 4.14 Fraction of oil in place produced for the 0.65 and the 1.8 μm^2 cores as a function of injected pore volumes into each core (not total pore volumes injected).

Figure 4.14. If one views the waterflood displacement in the high and low permeability cores (i.e., the solid and open circles in Figure 4.14 respectively) the two production histories closely match. Similarity is seen even though velocities and total permeability greatly differ. These experimental results confirm and support an assumption made previously that flow rate and overall permeability have little effect on the waterflooding production history or equivalently on the relative permeability curves.

By comparison of the emulsion production history to the waterflood result for the $1.8 \mu\text{m}^2$ core in Figure 4.14, the increase in oil recovery for the high permeability core in the parallel test can be explained. Even though flow has been diverted to the low permeability core, increased oil recovery is still seen in Figure 4.12 for the high permeability core. It is expected from the linear emulsion displacement theory developed in this thesis, that the $2.2 \mu\text{m}$ mean drops injected into the $1.8 \mu\text{m}^2$ core will cause a permeability reduction, and correspondingly an increase of recovery within 4 pore volumes of injected fluid. The increase in the production history for the emulsion injection into the $1.8 \mu\text{m}^2$ core is experimentally confirmed by Figure 4.14. The emulsion flood (solid triangles) production history is greater than that for the waterflood (solid circles) in that core. This result leads to the conclusion then that recovery of oil in the $1.8 \mu\text{m}^2$ core is slightly reduced as compared to the water flood early in the displacement, due to flow redistribution, but may eventually produce more oil later in the flood because of the increased fractional flow as described by Equation (3.15).

Upon reviewing Figure 4.12 for the high permeability core these expectations are confirmed.

Qualitative prediction of oil displacement from parallel cores of differing permeability by the method outlined in the preceeding theory correctly reflects the observed trends. Emulsions do improve recovery of oil by macroscopic redistribution of flow and also by increasing the fractional flow of oil by microscopic flow redistribution as in the linear displacement tests. As with constant velocity tests, drop penetration is desired but more importantly permeability reduction in the high permeability regions is responsible for flow diversion which produces oil earlier in the low permeability regions. Due to the method of the parallel core test (i.e., two separate cores with end point injection) redirection of flow back to the high permeability core occurs because of the large permeability reduction at the inlet of the low permeability core. In actual reservoirs these two permeability regions will be in contact with one another and cross flow redirection will be present. Therefore, the effect of redirection of flow by the emulsion should be even greater in cores contacting one another or in real reservoirs.

APPENDIX IV A

Displacement Parameters

Contained in this appendix are the calculated parameters for the relative permeability equations as described from the experimental water flood results. Also, the various values of the drop-size to pore size ratio, and $\bar{\alpha}$, $\bar{\beta}$, at the mean emulsion shock front water saturation are given. Water saturation at the shock fronts of the different flow regimes in the linear displacements are presented as well. Table IV A.1 contains these results. The relative permeability parameters for the two immobile oil experiments given in the theory section of this thesis are also tabulated. In these two tests oil saturation is not at residual. However, the fractional flow of water described by the relative permeability equations is greater than 0.99 and, therefore, mobile oil can be neglected.

TABLE IV A.1
Relative Permeability and Linear Emulsion Displacement Parameters

	K_o	n	p	k_{rn}^o	k_{rw}^o	S_{wc}	S_{nr}	$\langle r_d \rangle_l$ μm	$\langle d_d \rangle / \langle d_p \rangle$	$\overline{S_{we}}$	$\bar{\alpha}$	$\bar{\beta}$	S_{we}	S_{wb}	S_{wbk}
Low $\langle d_d \rangle / \langle d_p \rangle$	μm^2 3.3	3.0	1.25	0.930	0.078	0.190	0.20	1.2	0.10	0.10	26	10.7	0.71	0.48	0.60
High $\langle d_d \rangle / \langle d_p \rangle$	0.7	3.5	1.50	1.000	0.180	0.126	0.025	1.7	0.173		6	5.0	0.73	0.40	0.57
Intermediate $\langle d_d \rangle / \langle d_p \rangle$	1.15	4.0	1.70	1.000	0.142	0.155	0.22	1.4	0.15		11	8.0	0.71	0.47	0.57
Intermediate $\langle d_d \rangle / \langle d_p \rangle$	2.0	3.0	1.60	0.772	0.220	0.095	0.20	2.0	0.155		8	6.2	0.7	0.31	0.48
High Conc.	1.9	2.5	1.50	0.670	0.200	0.066	0.26	1.8	0.168		6.5	5.7	0.61	0.22	0.30
Immobile Oil $S_w = 0.6$	2.7	3.2	2.00	0.843	0.200	0.102	0.24	1.4	0.09		75	10.0			
Immobile Oil $S_w = 0.64$	1.9	3.0	1.90	0.895	0.200	0.128	0.26	1.6	0.11		33	9.0			

APPENDIX IV B

Immobilized Water

Dawson and Lantz (24) show that certain polymers create inaccessible fractions of pore volume by entrapment and adsorption. Likewise, with emulsions, due to interception and more significantly due to straining, inaccessible pore volume may be present during oil displacement tests. Such inaccessible pore volume may trap or immobilize water which no longer participates in the displacement process. If immobilized water is present, but is neglected in the calculation procedure for oil displacement, then the calculated recovery will be in error. This appendix addresses the prediction of the role of immobilized water on oil displacement history. The amount of inaccessible pore volume present for an emulsion displacement is unknown, but for certain polymers it has been calculated to be about 0.3 (24). All the calculations in this appendix are based on an assumed maximum value of 0.3 for inaccessible pore volume. It is expected that the saturation of immobilized water may, and probably is, much less than this maximum value.

Any immobilization of water is due to emulsion or polymer entrapment. Therefore, all immobilization occurs in the region of emulsion or polymer flow. We let S_{wt} denote the trapped or immobilized water saturation for the specific emulsion injected. The total emulsion retention, $S_{we}/\alpha C_i$, is denoted for simplicity by the symbol b . As noted previously, this is the fraction of pore volumes of emulsion water stripped of droplets. An overall material balance on emulsion now shows the shock-front velocity to be

$$\frac{\tilde{x}_e}{\tau} = \frac{f_{w/e}}{(S_w - S_{wt} + b)} \bigg|_{S_{we}} \quad (\text{IVB.1})$$

This equation is similar to Equation (3.18) and reduces to that form when S_{wt} is zero, or when no inaccessible pore volume is present.

The graphical solution technique, outlined in the Emulsion Displacement section of this thesis, is applied to Equation (IVB.1) and yields the oil production history. When b , the total retention to inlet concentration ratio is large, the effect of immobilized water on oil production history is small, and can be neglected. This result is shown by the graphical solution in Figure IVB.1 for a specific case. The value of $S_{we}/\bar{\alpha}C_1$ is 6.5 with S_{wt} being equal to 0.3, and with a $\bar{\beta}/\bar{\alpha}$ ratio of 0.75. The solid tangent line indicates the absence of immobilized water, while the long dashed tangent line indicates the trapped water result. The slight difference in the slopes of the tangents drawn to the increased fractional flow curve indicates a small difference in production history. With trapped water, the velocity of the emulsion shock front is slightly faster. Hence, the oil bank ahead of the emulsion is produced earlier, but not significantly. For this case any immobilized water saturation may be neglected.

However, when $S_{we}/\bar{\alpha}C_1$ is small, the effect of inaccessible pore volume is more noticable. The graphical solution for this case is shown in Figure IVB.2 with the oil production history depicted in Figure IVB.3. These results are calculated for a $S_{we}/\bar{\alpha}C_1$ of 0.5 with $\bar{\beta}/\bar{\alpha}$ equalling 0.75, and with a trapped water saturation of 0.3. The relative permeability curves used for both Figure IVB.1 and IVB.2

XBL 815-3065

Figure IV B.1 Graphical solution for high $S_{we} / \bar{\alpha} C_i$ containing no immobile water (solid tangent) and 0.3 pore volumes immobilized water (long dashed tangent). Relative permeabilities are those for Figure 3.19.

XBL 815-3066

Figure IV B.2 Graphical solution for low $S_w / \bar{\alpha} C_1$ containing no immobile water (solid tangent) and 0.3 pore volumes immobilized water (long dashed tangent). Relative permeabilities are those for Figure 3.19.

XBL 815-3067

Figure IV B.3 Fraction of oil in place produced versus pore volumes injected. The short dashed line represents the 0.3 pore volume of immobilized water calculation. The long dashed line gives the no immobile water calculation. This figure corresponds to the graphical solution given in Figure IV B.2.

are for the displacement of a viscous oil. The increased velocity of the emulsion front with immobilized water is clearly seen. The slope of the dashed line is much steeper corresponding to a faster velocity. The oil bank generated ahead of the emulsion flow zone is larger, as evidenced by the lower point of interception with the waterflood curve, and it is produced earlier than the bank of emulsion displacement with no immobilized water.

The oil production history of Figure IVB.3 reveals the effect trapped water can have. The history of the core containing immobilized water is given as a dashed line with the case for no trapped water is depicted as a solid line. Emulsion breakthrough is sooner when trapped water is present, with oil production occurring earlier. Once both emulsions have broken through, their production histories match and will be the same for the duration of the displacement. Immobilized water only increases the rate of recovery of oil and not the amount of oil produced.

Values for trapped water saturation are difficult to determine and may depend on flooding history (24). In this thesis no effort was made to determine quantitatively the extent of inaccessible pore volume present for oil displacement, since the experimental values of $S_{we}/\alpha C_i$ are large and the effect of even a large immobilized water saturation is negligible in the 1.5 volume percent emulsion linear displacements. In the high-concentration experiment of 5.0 volume percent emulsion however, the value for $S_{we}/\alpha C_i$ is smaller and some effect of immobilized water on production history is observed.

V CONCLUSIONS

Dilute, stable, oil-in-water emulsions are shown to aid in the displacement of viscous oils by decreasing the mobility of the aqueous phase. Lessened water mobility is achieved by small oil droplets irreversibly capturing in the porous medium due to straining and interception, thereby lowering the local permeability to water. This phenomenon is directly analogous to the residual resistance factor for high-molecular-weight polyacrylamide polymers, and constitutes the entrapment process.

A theoretical treatment is presented for dilute emulsion displacement based on a filtration model of emulsion flow in water saturated porous media. Extension of the filtration theory to two-phase flow and long cores is outlined. During two-phase flow, when both oil and water transport in the porous medium, emulsion retention is found to be larger than in a completely water-saturated medium. Apparently, emulsion drops are forced by the nonwetting oil to flow in the smaller channels where the capture probability is increased and steady-state retention is more closely approached. A quantitative estimate of the effect of oil saturation on drop retention utilizes relative permeability data to obtain an equivalent mean pore size. With the relative permeability correction, the emulsion retention, oil displacement history, and pressure drop history are predicted with no adjustable parameters. Comparison of the theoretical and experimental displacements show excellent agreement when little drop-size segregation occurs. In the intermediate drop-size to pore-size regime, where segregation does occur, the pseudomonovariant drop-size assumption underpredicts oil production at

early times. However, good agreement is shown for oil displacement, even in this case, after droplet breakthrough.

Emulsions also exhibit macroscopic flow redistribution for regions of differing permeability. Parallel core experiments demonstrate the positive effects of dilute emulsions not only in linear mobility control, but also for flow redistribution into lower permeability regions.

Two criteria are necessary for designing a successful emulsion displacement. Drop penetration or a high emulsion shock front velocity is desired, while maintaining significant permeability reduction. Unfortunately, these two criteria are inversely related. In a given porous medium large drop sizes, which effectively lower permeability to water, are greatly retained in the medium, leading to slow shock velocities and poor oil recovery. Conversely, small drops in a given porous medium penetrate quickly into the medium because of lower retention, but they do not effectively lower the permeability to water, and, hence, they also lead to poor oil recovery. Intermediate drop sizes provide the most efficient oil recovery. Drop segregation occurs which provides both drop penetration and significant permeability reduction to the water phase. High drop concentrations also improve oil recovery in that they overpower the drop retention and give rise to faster emulsion penetration. Hence, best oil recovery is expected for intermediate drop sizes and for higher drop concentrations.

VI NOMENCLATURE

A	cross-sectional area of unconsolidated porous media (cm^2)
C	concentration of emulsion drops, oil-in-water (volume percent)
C_i	inlet concentration of emulsion (volume percent)
C_L	outlet concentration of emulsion (volume percent)
D_d	diameter of emulsion drop (μm)
$\langle D_g \rangle$	mean diameter of emulsion drop distribution (μm)
$\langle D_d \rangle$	mean sand grain diameter (μm)
$\langle D_p \rangle$	mean pore diameter (μm)
EF	emulsion flood
FOP	fraction of oil in place produced
f_w	fractional flow of wetting phase, usually water
$f_{w/e}$	fractional flow of emulsion phase
K_o	initial overall permeability (μm^2)
K_x	local permeability (μm^2)
K_{∞}	reduced steady state permeability to water (μm^2)
k_r	relative permeability
k_{rj}	relative permeability of phase j
k_{rn}	relative permeability of nonwetting phase, usually oil
k_{rn}^o	end point relative permeability of nonwetting phase, usually oil
k_{rw}	relative permeability of wetting phase, usually water
k_{rw}^o	endpoint relative permeability of wetting phase, usually water
L	length of porous medium (cm)
M	mobility ratio, defined in Equation (1.2)
n	power index in wetting phase relative permeability equation
p	power index in nonwetting phase relative permeability equation

p	power index in nonwetting phase relative permeability equation
P_j	pressure in phase j (atm)
P_1	pressure at porous medium inlet (atm)
P_2	pressure at porous medium outlet (atm)
ΔP	pressure drop across the porous medium (atm)
ΔP_i	initial pressure drop across the porous medium prior to water or emulsion flooding
PV	pore volumes, $V_t/\phi_o L$, dimensionless
Q	volumetric flow rate (cm^3/s)
S	reduced saturation, $(S_w - S_{wc})/(1 - S_{wc} - S_{nr})$
S_{nr}	residual oil saturation
S_w	saturation of wetting phase, usually water
S_{wb}	saturation of water at waterflood shock front
S_{wbk}	saturation of water at the emulsion formed oil-water bank shock front
S_{wc}	connate water saturation
S_{we}	saturation of water at emulsion shock front
$\overline{S_{we}}$	mean saturation of water at the emulsion shock front, $(S_{we} + S_{wbk})/2$
S_{wt}	saturation of trapped water or inaccessible pore volume to emulsion or polymer
t	time (sec)
T	shifted time variable, $\tau - \tilde{x}$, dimensionless
V	total velocity of combined phases (cm/sec)
V_j	velocity of component j (cm/sec)
V_n	velocity of nonwetting phase (cm/sec)
V_w	velocity of wetting phase (cm/sec)
WF	waterflood
x	axial position in porous medium, (cm)

$\tilde{x}$	reduced axial distance = x/L
$\tilde{x}_b$	reduced axial position of water shock front saturation, S_{wb}
$\tilde{x}_{bk}$	reduced axial position of oil-water bank shock front saturation, S_{wbk}
$\tilde{x}_e$	reduced axial position of emulsion shock front saturation, S_{we}
α	flow diversion parameter, (cm^3/cm^3)
$\bar{\alpha}$	mean flow diversion parameter at the mean emulsion shock front water saturation, $\bar{S}_{we}$
β	flow restriction parameter
$\bar{\beta}$	mean flow restriction parameter at mean emulsion shock front water saturation, $\bar{S}_{we}$
ϵ	constant of 0.01
δ	constant of 0.01
λ	filter coefficient (m^{-1})
Λ	reduced filter coefficient, λL
μ	Newtonian viscosity (mPa.s)
μ_j	viscosity of phase j (mPa.s)
μ_n	nonwetting phase viscosity (mPa.s)
μ_w	wetting phase viscosity (mPa.s)
σ_w	volume of drops retained per clean void volume
σ_{wi}	initial volume of drops retained per void volume
σ_∞	steady state droplet retention, volume of drops per clean void volume
τ	pore volumes, $V_t/\phi_o L$, dimensionless
τ_b	pore volumes injected at waterflood water breakthrough
τ_{bk}	pore volumes injected at oil-water bank breakthrough
τ_e	pore volumes injected at emulsion breakthrough
ϕ	porosity
ϕ_o	initial porosity

Superscripts

o end point
 ~ reduced or dimensionless

Subscripts

i inlet
 l inlet
 L outlet
 2 outlet
 o initial
 ∞ steady state
 d drop
 p pore
 g grain
 r relative
 rw relative wetting
 j phase j
 w water or wetting phase
 w/e water with emulsion
 nr nonwetting residual
 wc connate water
 wt trapped water
 wb water breakthrough
 we emulsion breakthrough

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