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Experimental and Theoretical Investigation of Multiphase Flow in Fractured Porous Media

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Abstract

The fluid transfer parameters between rock matrix and fracture are not well known. Consequently, simulation of fractured reservoirs uses, in general, very crude and unproven hypotheses such as zero capillary pressure in the fracture and/or relative permeability linear with saturation. In order to improve the understanding of flow in fractured media, an experimental study was conducted and numerical simulations of the experiments were made.

A laboratory flow apparatus was built to obtain data on water-air imbibition and oil-water drainage displacements in horizontal single-fractured block systems. For this purpose, two configurations have been used: a two-block system with a 1mm spacer between the blocks, and a two-block system with no spacer. During the experiments, porosity and saturation measurements along the cores have been made utilizing an X-ray Computerized Tomography (CT) scanner. Saturation images were reconstructed in 3-D to observe matrix-fracture interactions. Differences in fluid saturations and relative permeabilities caused by changes in fracture width have also been analyzed.

In the case of water-air imbibition, the thin fracture system showed a more stable front and faster breakthrough than the wide fracture system. However, the final water

saturation was higher in the blocks near the wide fracture, thus showing that capillary pressure in the narrow fracture has more effect. During oil-water drainage, oil saturations were higher in the blocks near the thin fracture, again showing the effect of fracture capillary pressure. Oil fingering was observed in the wide fracture.

Simulations of the experiments have been performed using a commercial reservoir simulator. Relative permeability and capillary pressure curves were obtained by history matching the experiments. Sensitivity analysis of parameters such as fracture relative permeability, capillary pressure in the fracture, and fracture width were also conducted.

The results showed that the assumption of fracture relative permeability equal to phase saturation is incorrect. Moreover, higher resistance in the fractures was observed by comparing the experiments with numerical simulation work. We found that the processes are dominated by both capillary and viscous forces.

Chapter 1

Introduction

Fractured porous media are usually divided into two systems: a matrix system that contains most of the fluid storage, and a fracture system where fluids can flow more easily. Under this assumption, flow equations are written such that recovery is dominated by the transfer of fluid from the matrix to the high conductivity fractures. Fractures are often entirely responsible for flow between blocks and flow to wells.

Flow through fractured media depends on imbibition, drainage, snap-off, and piston-like flow mechanisms that can be studied by means of both numerical analysis and experimental work. Although some people have already worked on the problem, no one knows exactly which mechanisms occur and how strongly they affect results. We know that a better understanding of the physical mechanisms and the parameters that influence flow through fractured porous media leads to more accurate results from simulator calculations.

Any representation of the material balance equation, that models the flow through fractured porous media will assume the knowledge of both rock and fluid properties, capillary pressure, and relative permeabilities. Any of these parameters can be obtained for the matrix by laboratory work, but the properties of the fractures are not easily measured. To obtain reliable data about parameters such as fracture capillary pressure, fracture relative permeabilities, and/or saturation distributions, further experimental work is necessary. Therefore, the purpose of this study is to investigate this problem both experimentally and by numerical simulation.

Several authors (Kazemi and Merrill (1979), Beckner (1990), Gilman et al. (1994)) have assumed that fracture capillary pressures are negligible. Others have shown experimentally that capillary continuity becomes important when gravity provides a driving force (Horie et al. (1988), Firoozabadi and Hauge (1990), Labastie (1990), Firoozabadi and Markeset (1992). Kazemi (1990) stated that capillary continuity is prevalent in the vertical direction and has suggested that, to reduce the number of equations to solve, fractured reservoir simulations should use the dual permeability formulation for the z direction and the dual porosity formulation for the x and y directions.

Previous experiments can be grouped into several broad categories: 1) imbibition dominated experiments, 2) gravity dominated experiments, and 3) flow in a single fracture experiments. The last case is mostly studied in geothermal and hazardous waste disposal

problems, where the main topic is the understanding of flow with no or little matrix interaction in an attempt to obtain better fracture relative permeability data in more realistic fractures.

Guzman and Aziz (1993) designed an experiment to measure saturation distribution in two square cores of identical material, with the final objective of measuring fracture relative permeabilities. Saturations would be measured by means of a CT scanner. The experiment was built, but problems at the very beginning did not allow them to obtain results.

Hughes(1995) redesigned Guzman and Aziz's experimental set-up, improving the previous experiment by building a new apparatus and obtaining some results on water imbibition into a dry system of two square fractured blocks. Three core configurations were constructed. Saturation measurements were intended to be made throughout the displacement experiments using a CT Scanner. However, only CT images without calculations of porosity or saturation were presented. His results suggest that it is incorrect to assume negligible capillary continuity between matrix blocks as is often done.

For this work, detailed measurements of pressure, rate and saturation distribution were performed, and phase distribution inside the fracture was also measured using a (CT) scanner. This research resulted in a much better understanding of the physical processes

that occur when two or three phases flow in a fractured system, compared to previous reported studies (Guzman and Aziz (1993), Hughes (1995)).

Our first step was constructing an apparatus capable of emulating the functions of that built by Hughes(1995). Thus, we ran similar experiments using one of the core holders used by him in order to verify that this new experiment gives proper results. Once the apparatus was tested, we ran multiphase flow experiments using an 8% NaBr brine solution as the wetting phase, and decane as the nonwetting phase. Three stages in each experiment were completed: study of water imbibing into a dry core, decane displacing water in a water saturated core, and water displacing oil. Differences in fluid saturations and relative permeabilities caused by changes in fracture width were also analyzed.

The experimental results were matched using a commercial reservoir simulator. Relative permeability and capillary pressure curves were obtained by history matching the experiments qualitatively. Sensitivity analysis of parameters such as fracture relative permeability, capillary pressure in the fracture, and fracture width was completed.

Chapter 2

Literature Review

The following literature review briefly discusses some of the most relevant papers related to this research.

Most of the early studies focused on the representation of reservoirs by means of single reservoir blocks. Most of the time these studies have relied on sparse experimental data in the literature (Mattax and Kyte, 1962; Kleppe and Morse, 1974; Kazemi and Merrill, 1979) to verify their models. However those experiments provided rough approximations of the recovery obtained in the actual reservoirs. Later, experimental work focused on understanding the mechanisms that control the flow of fluids in porous media (Horie et al. 1988; Firoozabadi and Hauge, 1990; Labastie, 1990; Firoozabadi and Markeset, 1992). Hughes (1995) presents a detailed discussion of the aforementioned experiments. From the most recent experiments, we can see that most of them lack an explicit saturation distribution, since its accurate measurement has been one of the biggest difficulties in these kind of studies. Some of the experimental studies focused on the mechanisms dominant in gravity drainage situations and in small block imbibition

displacements. Whereas others, have emphasized understanding flow through a single fracture with no transfer from the matrix.

Jones, Wooten, and Kaluza (1988) studied single phase flow through rough-walled fractures, and found that for wide fractures, Whitherspoon's et al.(1980) cubic law equation can be used to calculate absolute permeability and to characterize single-phase flow. Romm (1966) presented two-phase flow experiments in smooth vertical parallel plates. He found that fracture relative permeabilities are equal to the phase saturation. He stated that these results could not be applied to flow in fractured media where a system of interconnected fractures is present.

In general, several authors (Kazemi and Merrill (1979), Beckner (1990), Gilman et al. (1994)) have assumed that fracture capillary pressures are negligible. Others have shown experimentally that capillary continuity becomes important when gravity provides a driving force (Horie et al. (1988), Firoozabadi and Hauge (1990), Labastie (1990), Firoozabadi and Markeset (1992a, 1992b)). Kazemi (1990) states his belief that capillary continuity is prevalent in the vertical direction and has suggested that, to reduce the number of equations to solve, fractured reservoir simulations should use the dual permeability formulation for the z direction and the dual porosity formulation for the x and y directions. Kazemi and Merrill (1979) matched two-phase flow experiments using a single porosity simulator. They used straight-line relative permeabilities and quite small capillary pressure in the fracture. They also found that for low flow rates, imbibition

makes water flow faster in the matrix than in the fracture. At high rates the water in the fracture flows faster.

Persoff et al. (1991) dealt with rough-walled fractures using epoxy replicas. They obtained the best possible matches for an isolated fracture. Their results suggest that fracture relative permeability should not be considered as a straight line. Pan et al. (1996) showed that straight-line fracture relative permeabilities can be used, but they also stated that the values are not necessarily equal to the phase saturation. Johns et al. (1991) presented a method to characterize fractures, and stated that this method could be extended to measure saturations. Finally, Kazemi (1990) stated that fracture relative permeabilities are not well understood.

Two of the previous studies are worth discussing in more detail. The first one was a study initiated by Guzman and Aziz (1993), in which an experiment was designed with the intent of measuring saturation distribution in two cores of identical material, with the final objective of measuring fracture relative permeabilities. Saturations would be measured by means of a CT Scanner. Fine-grid simulations were performed to help in the design of the experimental procedure. The experiment was built, but problems at the very beginning did not allow them to obtain results.

The second one was developed by Hughes (1995). He redesigned Guzman and Aziz's experimental set-up, improving most of their experiment by building a new

apparatus and obtaining some results on water imbibition into a dry system of two fractured blocks. Three core configurations were constructed. The configurations were a compact core, a two-block system with a 1mm spacer between the blocks, and a two-block system with no spacer. The blocks were sealed in epoxy so that saturation measurements could be made throughout the displacement experiments using a CT scanner. Hughes presented results from a water/air experiment. However, he only presented raw CT images. His results suggest that it is incorrect to assume negligible capillary continuity between matrix blocks as is often done. He evaluated how water imbibed into an unsaturated core. Migration of the water was monitored with the CT scanner. Despite the fact that water was being injected only into the bottom block, capillary imbibition pulled the water across the discontinuity and through the top block such that water from the top block actually broke through before the bottom block.

Three rectangular blocks of Boise sandstone were prepared for this work. The first was a compact (solid) core measuring $3\frac{1}{8} \times 3\frac{1}{16} \times 11$ inches. The second and third cores consist of two $2\frac{15}{16} \times 1\frac{1}{2} \times 11$ inch blocks. The second core system has a 1 mm thick spacer fastened in place with Epoxy 907 to provide a separation between the blocks that simulates a fracture. The third core system is constructed similarly but has no spacer between the blocks. The original design of Hughes had two pressure taps on the top and two on the bottom. In addition, a Plexiglas plate that was epoxied to the top surface of the core was removed in the new design. The plate was found to be unnecessary and a potential source for leaks.

Chapter 3

Equipment Description

A new design for an apparatus to monitor pressure, flow rates and fluid saturations in a rectangular core has been developed. The experiments presented in this work were made using an apparatus similar to the one designed, constructed and used by Hughes (1995). The decision to use this set-up was made because this equipment seemed to be easy to fix and improve since it was the last one constructed at Stanford and the results obtained using it were still considered significant.

The following sections give a detailed description of the materials and methods used to build the core holders and components for these experiments.

3.1 Cores

For this work, we used two of the three rectangular blocks of Boise sandstone cores constructed and used by Hughes (1995). Both core holders consist of two $2 \frac{15}{16}$ x

1 ½ x 11 inch blocks. The first core holder is a system of the two blocks together, i.e. with no spacer between the blocks. The second one is a similar configuration, but has a 1mm thick spacer fastened in place with Epoxy 907 to provide separation between the blocks to simulate a fracture.

3.2 Core Holders

Due to the rectangular shape and the desire to measure in-situ saturations through the use of the CT scanner, special core holders must be used (Hughes, 1995). Epoxy is an X-ray transparent material and core holders of this material are recommended by Castanier (1989), when CT scanner measurements are to be made. The original was suggested by Guzman (Guzman and Aziz, 1993). Making some improvements, Hughes (1995) designed a new core holder, which consisted of epoxy resin surrounding the core. He used Tap Plastic Marine Grade Resin #314 as the resin system, and Tap Plastic #143 as the hardener. A detailed explanation of the core holder construction procedure, curing time and materials is reported in Hughes, 1995. A table of the specifications for the epoxy system is given in Appendix A. Figure 3.1 shows the final design of the core holder utilized in the experiments reported in this work.

Coreholder Design

Figure 3.1: The core holder.

The experimental design also consisted of Plexiglas end plates which were used to close the remaining two open faces of the core. One end plate was attached to the other with Plexiglas rods as shown in Fig. 3.1. Holes were drilled and threads were tapped in the plates. A piece of 1/4 inch Viton acting as a gasket surrounding the core. That is held in place with automotive gasket material (Permatex Ultra Blue RTV Silicon Gasket) was also used. The Viton was cut at each end face of the core holder, so that the core face

would be exposed. This procedure was reported to cause problems in Hughes' (1995) experiments, such that the injected water first dribbled down in the space in between the Plexiglas end plate and the rock (the hole previously cut in the Viton.) To avoid this problem, four sheets of filter paper having a similar thickness as the Viton gasket, were used to fill the void space. Automotive gasket material was then used to glue the Viton to the epoxy and then to the Plexiglas end plates.

3.3 Positioning System

The positioning system consists of a moving table with a 0.01mm accuracy that is positioned electronically by means of a control panel. Basically, any flat surface can be attached to this table using screws.

A device that could be attached to this moving table and that could hold the core holder at the same time was designed and built. This tool consists of two 1/2 inch metallic pieces attached in an orthogonal position in such a way that once one of the pieces was screwed to the moving table, the other would be in a vertical position and would be able to hold the core holder from one of its ends as shown in Figure 3.1.

This positioning system was one of the major improvements to previous designs (Guzman, 1993; Hughes, 1995), because in this way, we can obtain cross sectional images of the core at the same locations at any desired time of the experiment. This could not be performed in other studies because the standard patient table of any CT Scanner of this type lacks comparable accuracy.

3.4 Pumps

Two positive displacement pumps were calibrated and used. The first one was an LDC III Pump whereas the other is an LDC Analytical Pump. Calibration curves for these pumps are given in Figure 3.2 and Figure 3.3 . Each pump delivers 0.01 to 9.99 cm³/min with 0.01 cm³/min increments. To use these pumps, the user sets the desired discharge rate, the minimum allowable pressure, and the maximum allowable pressure. Plumbing downstream of the pumps mixes of the fluids being discharged by each pump. This setup allows injection pressure to be monitored with a test gauge and recirculation to measure pump output rates.

Figure 3.2: LDC III pump calibration curve.

Figure 3.3 LDC analytical pump calibration curve.

3.5 Flow System

All tubing used for the experiment was Paraflex 1/8-inch diameter, with 500 psi working pressure nylon tubing connected with stainless steel Swagelok fittings. This system allows fluids to be directed to any port or combination of ports in the experiment such that: 1)it can be directed to test the calibration of the pressure transducers, 2)it can be used to inject from one end and produce from the opposite end, 3)it can be used to inject into one or more of the ports on the top and bottom of the core holder, or 4)it can be used to bypass the core holder completely. Figure 3.4 shows the flow system utilized for this work.

Figure 3.4: Flow system (after Hughes, 1995.)

In Figure 3.4 a square with a T-x label denotes a pressure transducer. A circle with a right angles inside denotes a three-way valve. Two-way valves are also labeled to allow easier description.

3.6 Production Measurement System

The production measurement system is an adaptation of a design built by Ameri and Wang (1985). Figure 3.5 shows this system.

Figure 3.5: Production system (after Hughes, 1995)

The tubing labeled with 'from Core outlet' in Figure 3.5 carries oil and water from the core. The oil is separated due to density differences and held inside a confining cap in an inner vessel that is suspended from an electronic balance. Water over flows through siphon and is collected in a container (e.g. a beaker) which is on other balance.

The electronic balance attached to the inner vessel measures the buoyant weight of the vessel. The change on the weight corresponds to the variation of total oil accumulated inside the inner vessel. These changes on the cumulative production of oil and water are the oil and water production rates. These rates should be equal to the injection rates when steady state conditions are reached.

The electronic balances are connected to the serial communication ports of a personal computer (PC).

3.7 Pressure Measurement System

Pressure drop along the core can be measured between any of the six different positions on the core labeled as T-x. In Figure 3.4, one can easily see that two of the transducers are connected to the inlet and outlet of the core holder. The transducers utilized in this work are Celesco DP31 differential pressure transducers. Interchangeable stainless steel diaphragms allow differential pressure ranges from 0.1 to 500 psi of full

scale. All the diaphragms for the transducers for the experiments of this work were of the 5-psi type.

Each transducer was connected to a carrier demodulator Celesco CD10D. The demodulators produce a DC signal output in the range from -10 to +10 that is proportional to the pressure drop. The output signals of the carrier demodulators were connected to a 1243 Chart Recorder (Soltec Transducer Products, Inc.). The data were also captured in digital form. It is very important to calibrate the pressure measurement system as a whole, i.e. transducers, demodulators and chart recorder all together.

The first step in calibration is to isolate the transducer by setting the corresponding values correctly. An equal uniform pressure is applied to both sides of the transducer. Since, the difference in pressure is zero, the output should be zero, if not the demodulator is adjusted so that it reads zero.

Once the zero has been obtained, the three-way valve is opened so that the negative side of the transducer is open to the atmosphere. This applies the 5 psi pressure only to the positive side; at that point, the demodulator must be calibrated to +10 volts and the chart recorder must be calibrated in such a position in the paper that fractions of ten (i.e. tenths) can be easily read.

This procedure is now repeated for different pressures. For instance every 1 psi up to 5, and then going backward every 1 psi up to zero to verify that there is no hysteresis in the process. Finally, a plot of each calibrated transducer should be drawn, so one can get the corresponding relation. If no hysteresis is present, the relation is a straight line in all cases for any pressure increment.

Fig 3.6: Transducer calibration curve.

3.8 CT Scanner

A CT scanner can be used to calculate porosity, saturation and in some cases, concentration distribution and to track advancing fronts. It can also be used to measure fracture aperture. Both static and dynamic experiments can be conducted using a CT

scanner. Dynamic experiments, such as corefloods, follow the change in CT numbers with position and time. The timing of these experiments is more crucial. If there is a moving front and it is only several slices thick, one can get a good approximation of its real position.

The CT Scanner utilized in this work is a Picker 1200SX Dual Energy CT scanner. It is a fourth generation medical scanner that is now used for laboratory purposes. Any CT Scanner measures linear attenuation coefficient, α , with a cross sectional resolution less than 1 mm. The most important aspect in CT use is good image quality, since it affects the results of the saturation calculations. If the noise level is high or the variation in CT number is not a function of the object density, then the resulting calculations will have high error. Two aspects affect image quality, the experiment design and the machine parameters.

In terms of the experiment design, one can assume that these experiments were performed under ideal conditions, since pressure measurement, flow measurement, etc. can be perfectly controlled through any time. In terms of machine parameters, the best quality resolution as well as the optimum parameters were selected in order to obtain the most reliable images from the CT scanner, and the calculations to obtain the saturation images were also the best possible ones. Table 3.1 shows the scanner settings used in this work.

Table 3.1: CT Scanner settings

Parameter	Setting
Field of View	24 cm
Image Matrix	1024 x 1024
Sampling	1024
Scan Speed	3 sec
Slice Thickness	10 mm
Resolution	High
kV	140
mA	65
x-ray filter	3
MAS	341 per slice
Exposure	5.09 sec/slice
Pilot	0.00 sec

3.9 Fluids

CT numbers of fluids are proportional to their densities. Castanier (1989) found that adding dopants to the water helps to obtain saturations. Demiral (1991) found that an increase of CT numbers can be obtained with increase of dopant.

A selection of fluids and dopant were completed in order to obtain the best contrast in CT numbers, so the images could be more representative in terms of oil and water phases.

Decane was used to represent the oil phase, and 8% NaBr by weight solution for the water phase was also used. It is very important to know the fluid properties as accurately as possible because the saturation calculations as well as the simulation work need to be fed with proper values. Otherwise, good representations of the experiment will not be achieved. Pure fluids were scanned because their values are needed for the saturation calculations. The CT numbers as well as some fluid properties are shown in Table 3.2.

Table 3.2: Fluids properties used in the experiments and simulation work.

Property	8% NaBr Solution	Decane	Air
Specific Gravity	1.001	0.73421	0.0012
Viscosity	1.075 cp		~0.0 cp
CT Number	~ 350	~ -280	~ -1000

Chapter 4

Experimental Procedure and Results

This section summarizes the experimental procedure and the experimental results achieved. It is important to keep in mind that the objective of this work is to estimate fracture relative permeability curves, which requires numerical simulation and history matching of the two-phase flow experiments. This section provides data on multiphase flow, including petrographic description as well as of the porosity, and fluid saturation values.

4.1 Experimental Procedure

The first core used had a fracture with no space in between the blocks. Due to the length of this core (11 inches), and despite the stainless steel fittings that were used for the ports on the top and the bottom of the core holder, it was decided to choose a regular sequence of scan locations. This was because even when the fitting ports could be avoided

it was found that both the previous and the next slices had some artifacts because of the stainless steel fittings, so it was better to find a distribution in which we could scan exactly at those locations and reduce the effects on the previous and next slices as well.

Thus, it was decided to fix the scan location every 2 cm starting from the first two centimeters from the inlet face. Any initial location at less than 2 cm could have either effects from the injection stainless steel fitting port or scans the Viton gasket and filter paper.

The total travel distance of the positioning system (accuracy 0.01 mm) was then 25.5 cm, resulting in 13 slices including those two located at the fitting ports (fourth and eleventh, for the first experiment; and fourth and tenth, for the second one.) Figure 4.1 shows the CT scan locations.

Figure 4.1. CT Scan locations

To assure the same locations for the following stages of the experiment, the patient table of the CT scanner was fixed at a proper location, so the positioning system (accuracy $\pm 0.01\text{mm}$) would do the rest of the locating process. This provided more accurate results for the porosity and saturation calculations. This was a major improvement compared to Hughes (1995) experiments, since he was using the patient table whose accuracy is $\pm 1\text{ mm}$. The field of view used for this experiment was 24 cm, the image matrix, resolution, voltage, amperage, filter used, and more scanner settings are shown in Table 3.1.

The first step of this experiment was to scan the dry core. This step was very important to verify that the apparatus and all the set-up was working properly. For instance, there were some problems with the core holder in a first trial for the dry scan. We could not keep its position horizontal, because it was quite heavy and held only by one of the sides. Moreover, the gasket makes it harder to hold since it was not rigid. In order to solve this problem, two C clamps were used to strengthen the attachment to the positioning system and, thus, to keep the core holder in the same positions (horizontal) during the experiment. After these improvements, the dry scans were done successfully.

The second step was to evaluate how water imbibed into an unsaturated core. This part of the experiment gave us results that can be compared with the ones obtained by Hughes (1995), and eventually used to evaluate how well the new experiment worked. Starting with a flow rate of $2\text{ cm}^3/\text{min}$, CT images of the core were taken every 5 minutes until the first 20 minutes of water injection (0.15 PV); after this, images were taken at 30

min (0.22 PV), 45 min (0.33 PV), 1 hr. (0.45 PV), 1hr 30 min (0.67 PV), 2 hr (0.89 PV), 3 hr (1.34 PV), and 4 hours (1.78 PV) after water injection started. Following that the top and bottom ports were opened since we wanted to fill up the core to the maximum water saturation ($S_w=1.$) Common to all time steps, we tried to take images up to one location ahead of the possible water front.

After 5 hours of water injection (2.25 PV), the flow rate was changed to 0.5 cm^3/min in order to inject water for 14 more hours to reach steady state. After 19 hours (8.55 PV), reference 100% water saturated images were taken. Then, at 19 hours and 45 min (8.9 PV) the water rate was changed back to 2 cm^3/min , and the top and bottom ports were closed. At 21 hours (9.45 PV) a final set of slices was taken to find a possible change in CT numbers. Negligible changes in CT numbers were observed. At 23 hours of water injection, the third step of the experiment started. Table 4.1 summarizes the flow rates used.

The third step of the experiment involved injecting decane at 2 cm^3/min . The scanning frequency was intended to be the same as the water injection process. Thus, images of the core were taken every five minutes until the first 20 minutes of oil injection (0.15 PV). After that, more images were taken at 30 min (0.22 PV), 45 min (0.33 PV), 1 hr. (0.45 PV), 1hr 30 min (0.67 PV), 2 hr 30 min (1.13 PV), and 3 hr 45 min. (1.69 PV) after oil injection started. Then, the top and bottom ports were opened at 4 hours (1.79 PV) of starting oil injection since we wanted to fill the core up to the maximum possible

Table 4.1. Rates and timing for the core with narrow fracture.

Fluid Injected	Time [hrs]	Flow Rate [cm ³ /min]	Ports
Water	0.0 - 4.0	2.0	Top and bottom closed, lateral open.
Water	4.0 - 5.0	2.0	Top and bottom open, lateral closed.
Water	5.0 - 19.8	0.5	Top and bottom open, lateral closed.
Water	19.8 - 23.0	2.0	Top and bottom closed, lateral open..
Decane	23.0 - 27.0	2.0	Top and bottom closed, lateral open.
Decane	27.0 - 28.0	2.0	Top and bottom open, lateral closed.
Decane	28.0 - 44.7	1.0	Top and bottom open, lateral closed.
Water	44.7 - 46.0	9.99	Top and bottom closed, lateral open.
	46		Shut down everything

point. At 4 hr 30 min of oil injection, one more set of images was taken. After 5 hours (2.25 PV) of oil injection, the flow rate was changed to 1 cm³/min for 16 hours (7.2 PV) to reach higher possible oil saturations ($1-S_{wc}$). After 21 hours of oil injection (9.45 PV), a new set of slices was taken, and the ports were closed. Then, at 21 hours and 39 min the oil injection was stopped, and water injection at the maximum pump rate (9.99 cm³/min) was started.

The fourth step of the experiment was the water displacing oil stage. Injecting 9.99 cm³/min of water, images were taken at 5 min (0.04 PV), 15 min (0.13 PV), and 30 min (0.23 PV). At 1hr 10 min (0.53 PV), water injection was stopped, the inlet and outlet lateral ports were also closed, leaving all of the core holder's ports closed. One more set of images was taken after two days of closing the core holder to observe if capillary equilibrium had been reached. Table 4.1 summarizes the flow rates used and the timing of each of them.

The second experiment was performed using the core holder that contained a system with two Boise sandstone blocks with a 1 mm thick fracture in between. The same experimental procedure was followed. Essentially, we wanted to obtain CT images, and then saturation values for equivalent times, so we could eventually compare the differences between the two systems. The rates and timing for the case of two blocks with a wider fracture are shown in Table 4.2.

Table 4.2. Rates and timing for the core with wide fracture.

Fluid Injected	Time [hrs]	Flow Rate [cm ³ /min]	Ports
Water	0.0 - 5.0	2.0	Top and bottom closed, lateral open.
	5.0 - 21.0	0.0	Top and bottom closed, lateral closed.
Water	21.0 - 22.5	2.0	Top and bottom open, lateral closed.
Water	22.5 - 25.6	2.0	Top open, bottom closed, and lateral closed.
	25.6 - 45.0	0.0	Top and bottom closed, lateral closed.
Decane	45.0 - 48.0	2.0	Top and bottom closed, lateral open.
Decane	48.0 - 49.2	4.0	Top and bottom closed, lateral open.
Decane	49.2 - 51.0	4.0	Top and bottom open, lateral closed.
	51.0 - 52.0	0.0	Top and bottom closed, lateral closed.
Water	52.0 - 54.3	4.0	Top and bottom closed, lateral open.
Water	54.3 - 68.8	0.5	Top and bottom closed, lateral open.
Water	68.8 - 71.0	4.0	Top and bottom open, lateral closed.
	71		Shut down everything

4.2 Method of Solution

Using the CT number obtained from the experiments, porosity and saturation distributions along the core were determined. The most common way to calculate porosity from CT Scanner images is by using the following expression (Withjack, 1988):

$$\phi = \frac{CT_{cw} - CT_{cd}}{CT_w - CT_a} \quad (4.1)$$

where CT_{cw} is the CT number for a 100% water saturated core at a matrix location, CT_{cd} is the CT number for a dry core at a matrix location, CT_w is the CT number for water, and CT_a is the CT number for air. The CT number for water (8%NaBr solution, for this work) is around 360, while the CT number for air is -1000.

We found that the average value for porosity calculated from the scans was 14.5% which matches with the average value 14.35% reported by Hughes (1995); however, this value differs from the average porosity measurements of 25.4% obtained by Guzman and Aziz (1993) and 29.3% obtained by Sumnu (1995). All of these previous studies have also shown areas in the rocks, which have lower permeability.

The water and oil saturations were also calculated from the CT images. The following equations show how to evaluate water saturation for the water displacing air case, and for the oil displacing water or water displacing oil case.

$$S_w = \frac{CT_{aw} - CT_{cd}}{CT_{cw} - CT_{cd}} \quad (4.2)$$

where CT_{aw} is the CT number for water and air saturated core at a matrix location.

Similarly, for the case of oil-water systems

$$S_w = \frac{CT_{ow} - CT_{cw}}{\phi (CT_o - CT_w)} \quad (4.3)$$

where CT_{ow} is the CT number for a water and oil saturated core at a matrix location, and CT_o is the CT number for oil. The CT number for oil (decane, for this work) is around -272.

All the saturation values are shown in the following section, as well as the way to read them in the corresponding figures.

4.3 Experimental Results

Guzman and Aziz (1993) presented a CT image from which it can be seen that CT numbers can indicate differences in fluid saturation. Later on, Hughes (1995) presented images showing how water imbibes into an unsaturated core. As we stated previously, his core holder contained a gap between the core and the Plexiglas plate, so the CT images show the water flowing down, filling first the gap and then imbibing into the core. It can be easily concluded, that his results showed the water imbibing first the bottom block. After some time water filled the gap, but it was late because the water had imbibed a good distance along the bottom block, and finally much time had passed before water reach the fracture level. Hughes' (1995) results are good in the sense that he conducted a reasonably controlled experiment. He showed that CT images for different times could be obtained, and that his techniques could be improved. Improving previous designs, following carefully the procedure planned and trying to obtain the data as accurately as possible, we were able to complete a multiphase flow experiment in fractured porous media. We also obtained images of the porosity distribution, as well as the saturation images.

Figure 4.2. Porosity distribution for the experimental system

The following sections present a set of images, each square shows a scan location, with the distribution shown in Figure 4.1. First of all, we computed the values of porosity at each location. The different porosity images for both systems are shown in Figure 4.2, the values below each square correspond to the mean and the standard deviation respectively of the porosity obtained from CT numbers. This step was essential for both experiments because from these images and their corresponding values we could differentiate the regions with higher or lower porosity. Thus, in those images, the range of values is shown in the color bar in the right hand side in Figure 4.2. There, we can also see

that the system with the thin fracture has a little higher porosity than the system with the wide fracture, especially in the top block, where values up to 0.13 were observed.

4.3.1 Results for the Narrow Fracture system.

Following the procedure explained above, and the flow rates, times and injection/production conditions shown in Table 4.1, we ran the first experiment. Figures 4.3, 4.4, 4.5, and 4.6 show the sets of images corresponding to 20 min, 30 min, 45 min, 1 hour, 1.5 hours, and 2 hours of water injection. Similar to the porosity images, each square corresponds to one location, but now the water saturation distributions are shown. The pairs of values presented below each square correspond to the mean and standard deviation (separated by commas) of the top, bottom and both blocks, respectively. Colors for each saturation value were also assigned. The color bar on the right hand side shows the range of values and their corresponding lightness or darkness. In all the images shown in Figures 4.3, 4.4, 4.5, and 4.6, darker shades indicate lower water saturation. For instance, black means zero water saturation, and white means water saturation equal to 1. Different profiles, corresponding to different pore volumes of water injected are shown in Figure 4.7. There we can see that the profiles are stable and they appear to follow Buckley-Leveret theory.

after 20 min.

after 30 min.

press. port

after 45 min.

press. port

Figure 4.3. CT Saturation images for the narrow fracture system after 20, 30 and 45 min of water injection (0.15, 0.22 and 0.33 PV)

after 1 hour

press. port

-0.01, 0.04
-0.01, 0.04
-0.01, 0.09

-0.01, 0.03
-0.01, 0.04
-0.01, 0.36

Figure 4.4. CT Saturation images for the narrow fracture system after 1 hour of water injection

(0.45 PV)

Figure 4.5. CT Saturation images for the narrow fracture system after 1 hr 30 min of water injection

(0.67 PV)

Figure 4.6. CT Saturation images for the narrow fracture system after 2 hours of water injection

(0.89 PV)

Figure 4.7. Water saturation profiles for narrow fracture system for different PV of water injection

Similar images were obtained for the second stage of the first experiment (oil injection). Figures 4.8, 4.9, 4.10, 4.11, and 4.12 show sets of images corresponding to 20 min (0.15 PV), 30 min (0.22 PV), 45 min (0.33 PV), 1.5 hours (0.67 PV), 2.5 hours (1.13 PV), 3.75 hours (1.69 PV), and 4.5 hours (2.03 PV) of oil injection. Here, the pairs of values below each square indicate the mean and the standard deviation of oil saturation, respectively. Colors were also assigned to the oil saturation values. Thus, the color bar on the right hand side shows the range of values and their corresponding lightness or darkness. In all the images shown in Figures 4.8, 4.9, 4.10, 4.11, and 4.12 darker shades

indicate lower oil saturation. For instance, black means zero oil saturation. Figure 4.13 shows oil saturation profiles for different times. There, one can see some special behavior up to 3.75 hours (1.69 PV). However, we could not follow it because we opened the lateral ports of the core holder at 4 hours in order to fill up the core further, to an S_w of 1.

Images for the third stage of the experiment (water displacing oil) were also obtained. Due to problems with one of the pumps, we could not analyze properly the rest of the data.

Figure 4.8. CT Saturation images for the narrow fracture system after 20, 30 and 45 min of oil injection (0.15, 0.22 and 0.33 PV)

Figure 4.9. CT Saturation images for the narrow fracture system after 1 hr 30 min of oil injection
(0.67 PV)

Figure 4.10. CT Saturation images for the narrow fracture system after 2 hr 30 min of oil injection
(1.13 PV)

Figure 4.11. CT Saturation images for the narrow fracture system after 3 hr 45 min of oil injection
(1.69 PV)

Figure 4.12. CT Saturation images for the narrow fracture system after 4 hr 30 min of oil injection
(2.03 PV)

Figure 4.13. Oil saturation profiles for narrow fracture system for different PV of oil injection

4.3.2 Results for the Wide Fracture system.

Following the procedure explained above, and the flow rates, times and injection/production conditions shown in Table 4.2, we ran the second experiment. Figures 4.14, 4.15, 4.15, 4.16, and 4.17 show the sets of images corresponding to 20 min (0.15 PV), 30 min (0.22 PV), 45 min (0.33 PV), 1 hour (0.45 PV), 1.5 hour (0.67 PV), and 2 hours (0.89 PV) of water injection for the wider fracture system. Similar to the images obtained for the narrow fracture system, each square corresponds to one location, and also the water saturation distributions are shown. The pairs of values presented below each square also correspond to the mean and standard deviation (separated by commas) of the top, bottom and both blocks, respectively. In all the images shown in Figures 4.14, 4.15, 4.15, 4.16, and 4.17 darker shades indicate lower water saturation. For instance, black means zero water saturation, and white means water saturation equal to 1. Different profiles, corresponding to different pore volumes injected are shown in Figure 4.18. There we can see that the profiles are less stable than those for the thin fracture system.

after 20 min.

0.34, 0.31	-0.01, 0.03	-0.01, 0.03
0.09, 0.17	-0.01, 0.03	-0.01, 0.03
0.23, 1.30	-0.01, 0.47	-0.01, 0.08

after 30 min.

press. port

0.88, 0.28	0.58, 0.48	0.16, 0.03	-0.01, 0.10
0.85, 0.22	0.58, 0.33	-0.01, 0.04	-0.02, 0.07
0.88, 0.85	0.56, 0.52	0.07, 0.25	-0.02, 0.11

after 45 min.

press. port

1.01, 0.05	0.97, 0.12	0.74, 0.40	0.34, 0.48	0.24, 0.37	-0.01, 0.04	-0.01, 0.04
1.01, 0.04	1.02, 0.06	1.04, 0.05	0.98, 0.06	0.63, 0.16	-0.01, 0.04	-0.01, 0.04
0.98, 0.98	0.97, 0.97	0.87, 0.38	0.65, 0.48	0.39, 0.37	-0.02, 0.09	-0.02, 0.09

Figure 4.14. CT Saturation images for the wide fracture system after 20, 30 and 45 min of water injection (0.15, 0.22 and 0.33 PV)

after 1 hour

press. port

0.99, 0.05	0.98, 0.04	0.98, 0.06	0.96, 0.15	0.57, 0.50	0.46, 0.53	0.11, 0.31
1.00, 0.04	0.99, 0.04	1.00, 0.04	0.99, 0.06	1.00, 0.07	0.99, 0.08	0.90, 0.09
0.96, 2.18	0.99, 2.08	1.00, 0.10	0.98, 0.44	0.78, 0.44	0.71, 0.48	0.48, 0.53

press. port

-0.01, 0.04	-0.01, 0.03	0.02, 0.07	-0.01, 0.03	-0.01, 0.04	-0.01, 0.03
0.48, 0.31	0.00, 0.05	0.02, 0.05	-0.01, 0.03	-0.01, 0.03	-0.01, 0.03
0.20, 1.41	0.00, 0.83	0.03, 0.55	0.00, 0.91	0.00, 0.48	0.01, 0.06

Figure 4.15. CT Saturation images for the wide fracture system after 1 hour of water injection (0.45 PV)

Figure 4.16. CT Saturation images for the wide fracture system after 1 hr 30 min of water injection

(0.67 PV)

Figure 4.17. CT saturation images for the wide fracture system after 2 hours of water injection

(0.89 PV)

Figure 4.18. Water saturation profiles for wide fracture system for different PV of water injection .

Figures 4.19, 4.20, 4.21, 4.22, 4.23, and 4.24 show sets of images corresponding to 20 min (0.15 PV), 30 min (0.22 PV), 45 min (0.33 PV), 1.5 hours (0.67 PV), 2.5 hours (1.13 PV), 3.75 hours (1.68 PV), 4.5 hours (2.03 PV), and 6 hours (2.7 PV) of the second stage of the second experiment (oil injection.) Similar to the sets of images of oil injection of the first experiment, the pair of values below each square indicates the mean and the standard deviation of oil saturations, respectively. Colors were also assigned to the oil saturation values. In all the images shown in Figures 4.19, 4.20, 4.21, 4.22, 4.23, and 4.24, darker shades indicate lower oil saturation. For instance, black means zero oil

saturation. Figure 4.25 shows the profiles for different times. Nothing special can be seen due to some leaks during this stage. Although, we observe very low saturation values in zones far from the leaking point.

Images for the third stage of the second experiment (water displacing oil) were also obtained. The most interesting sets are shown in Figures 4.26 and 4.27, where one can see that the displacement of oil is completed almost perfectly. Some oil is in the core at 16 hours (7.2 PV), and after 17 hours (7.65 PV) of water injection the oil is totally swept from the core. See the differences between Figures 4.26 and 4.27.

Figure 4.19. CT Saturation images for the wide fracture system after 20, 30 and 45 min of oil injection (0.15, 0.22 and 0.33 PV)

Figure 4.20. CT saturation images for the wide fracture system after 1 hr 30 min of oil injection
(0.67 PV)

Figure 4.21. CT saturation images for the wide fracture system after 2 hr 30 min of oil injection
(1.13 PV)

Figure 4.22. CT saturation images for the wide fracture system after 3 hr 45 min of oil injection
(1.68 PV)

Figure 4.23. CT saturation images for the wide fracture system after 4 hr 30 min of oil injection
(2.03 PV)

Figure 4.24 . CT saturation images for the wide fracture system after 6 hours of oil injection

(2.7 PV)

Figure 4.25. Oil saturation profiles for wide fracture system for different PV of oil injection

Figure 4.26. CT saturation images for the wide fracture system after 16 hours of water injection
(7.2 PV)

Figure 4.27. CT saturation images for the wide fracture system after 17 hours of water injection
(7.7 PV)

4.3.3 Comparison of the Results for Both Systems

Due to the fact that the experiments ended differently, we were able to compare the results up to the second stage of both experiments. This section shows the comparison graphically.

Three-dimensional (3-D) reconstructions of the sets of water saturation images were calculated. All these images were obtained using a color map for values above 50% of water or oil saturation, respectively. These 3-D images show more clearly how the fluids actually flow through fractured porous media. This work was intended to show the differences between the flow patterns for different fracture thicknesses. The reconstructed images are shown in Figure 4.28. Each image corresponds to a specific time. Thus, the first image on the left hand side of Figure 4.28 is compared to the first one of the right hand side of Figure 4.28. The second image on the left hand side was computed for the same time as the second image on the right hand side, and so on. There, we can see that the water front for the wider fracture system moves at almost at the same speed as the water front for the narrow fracture system does. For instance, one can see that after 1.5 hours of water injection, the water front of the narrow fracture-system seems to be ahead of the front for the wide fracture system; however, after two hours of water injection water has filled up both systems.

Similarly, the 3-D oil injection history was also reconstructed. Since the oil saturations were low for both cases, it is a bit harder to see the differences. It is possible to see that the thinner fracture system has higher oil saturation close to the fracture. This is shown in Figure 4.29. One can see that the narrow fracture system had lighter colors close to the injection surface. We can also see that for the case of the wide fracture system, the oil does not penetrate. Furthermore, oil flows almost completely through the fracture. This is shown in all the images on the right hand side of Figure 4.29 by the almost white horizontal line that corresponds to the fracture. Remember that for the case of oil injection stages, darker means lower oil saturation.

0.22 PV (30 min)

0.45 PV (1hr.)

0.67 PV (1hr. 30 min)

0.89 PV (2 hr.)

Figure 4.28. 3-D Reconstruction for both systems for water injection

1hr. 30 min

2 hr. 30 min

3 hr. 45 min

Figure 4.29. 3-D Reconstruction for both systems for oil injection

Chapter 5

Simulation Results

Fractured porous media are usually divided, conceptually, into two systems: a matrix system that contains most of the fluid storage, and a fracture system where fluids can flow more easily. Under this assumption, flow equations are written such that recovery is dominated by the transfer of fluid from the matrix to the high conductivity fractures. Fractures are often entirely responsible for flow between blocks and flow to wells. Simulations of the experiments ,described on Section 4, using a commercial reservoir simulator (Eclipse 100) were performed. This section describes a numerical study performed in order to match the experiment. Results and comparisons are presented graphically.

5.1 Difference Flow Equations.

A dual porosity formulation does not allow flow between matrix blocks; whereas, a dual permeability formulation allows the transfer of fluids from one matrix block to

another as well as transfer from matrix blocks to the fracture system. The dual permeability approach is applied here. Thus, the flow equations in finite difference form are given by Kazemi (1990):

For the fracture:

$$\Delta \left[T_{pf} (\Delta p_{pf} - \rho_{pf} D_f) \right] - \tau_{pmf} + q_{pf} = \frac{V}{\Delta t} \Delta_t \left(\frac{\phi S}{B} \right)_{pf} \quad (5.1)$$

where T_{pf} is the transmissibility of the phase p in the fracture system, Δp_{pf} is the change in the phase pressure between grid blocks in the fracture system for phase p, ρ_{pf} is the density of phase p in the fracture system, ΔD_f is the change in the depth between grid blocks in the fracture system, τ_{pmf} is the matrix-fracture transfer function for phase p, q_{pf} is the source term for phase p in the fracture system, V is the grid-block volume, Δt is the time step size for the simulation, and $\Delta_t(\phi S/B)_{pf}$ is the change over the time step of the porosity, phase saturation, and formation volume factor of phase p for the fracture system.

For the matrix:

$$\Delta \left[T_{pm} (\Delta p_{pm} - \rho_{pm} D_m) \right] + \tau_{pmf} + q_{pm} = \frac{V}{\Delta t} \Delta_t \left(\frac{\phi S}{B} \right)_{pm} \quad (5.2)$$

where T_{pm} is the transmissibility of phase p in the matrix system, Δp_{pm} is the change in the phase pressure between grid blocks in the matrix system for phase p, ρ_{pm} is the density of phase p in the matrix system, ΔD_m is the change in the depth between grid blocks in the

matrix system, τ_{pmf} is the matrix-fracture transfer function for phase p, q_{pm} is the source term for phase p in the matrix system, V is the grid block volume, Δt is the time step size for the simulation, and $\Delta_t(\phi S/B)_{pm}$ is the change over the time step of the porosity, phase saturation, and formation volume factor of phase p for the matrix system.

The transmissibility terms are:

$$T_{pf} = \frac{A\phi}{L} k_f \left(\frac{k_r}{\mu B} \right)_{pf} \quad (5.3)$$

$$T_{pm} = \frac{A\phi}{L} k_m \left(\frac{k_r}{\mu B} \right)_{pm} \quad (5.4)$$

where A is the grid block area in the direction of flow, L is the grid-block length in the direction of flow, k_f is the grid-block permeability of the fracture, k_m is the grid block permeability of the matrix system, k_r is the grid-block relative permeability of phase p, and μ is the viscosity of phase p.

The matrix-fracture interaction is modeled as a source function given by:

$$\tau_p = \sigma V k_m \left(\frac{k_r}{\mu B} \right)_{pmf} [p_{pf} - p_{pm} - \rho_p (D_f - D_m)] \quad (5.5)$$

where σ is the shape factor and has dimensions of $1/L^2$, V is the grid block volume and D_f and D_m are the fracture and matrix depths.

When using the dual porosity formulation of these equations, the T_{pm} term is set to 0 and, for grid blocks with no source terms, the matrix-fracture transfer function in the matrix equation simplifies to:

$$\tau_p = \frac{V}{\Delta t} \Delta_i \left(\frac{\phi S}{B} \right)_{pm} \quad (5.6)$$

Numerical simulation of the experiments were conducted to study fracture relative permeability and matrix/fracture interaction, to match previous experimental results, and to provide experimental-numerical based suggestions how to simulate multiphase flow in fractured porous media.

5.2 Base Case Simulation.

For this purpose, we designed a cartesian grid-block system that was proportional to the original cores. This model has four different regions. Two of the regions simulate the top and bottom blocks with matrix rock properties, i.e., matrix capillary pressure curve, matrix relative permeability curves, matrix absolute permeability, porosity. The other set of blocks, simulates the horizontal fracture by employing very large absolute permeability, fracture capillary pressure curve, and fracture relative permeability curves.

The last set of blocks include the properties of the filter paper. Figure 5.1 shows a section of the grid system used in the numerical simulation. Fracture relative permeability and capillary pressure curves were obtained by history matching the experiments.

Figure 5.1. Section of the grid used in the numerical simulation

5.3 Reproduction of the Experiment.

Since our objective was to match experimental results, we followed the same procedure in our numerical studies. So for both the narrow and wide fracture system we simulated the imbibition (water injection into a dry core), water injection until steady-state is reached, and the drainage (oil injection into a 100% water saturated core). These following simulations were performed for both systems.

5.3.1 Imbibition.

For the imbibition simulation we started with the assumption that fracture relative permeability of a phase is equal to its saturation for air-water systems as shown in Figure 5.2. Later in this section we will show that this is not a very good assumption.

Figure 5.2. Boise sandstone imbibition relative permeability curves (After Persoff, 1989)

The matrix relative permeability and capillary pressure curves were assumed to be correct and constant. For the imbibition capillary pressure curve we used the curve shown in Figure 5.3 which was measured by Sanyal (1972). We obtained very good results, so we decided to keep them as reliable information.

Figure 5.3. Boise sandstone imbibition capillary pressure curves (After Sanyal, 1972)

For the fracture, different capillary pressure curves were used. Three different cases were studied as shown in Figure 5.4. In general, sensitivity analysis of parameters such as fracture relative permeability, capillary pressure in the fracture, and fracture width were also studied. A zero capillary pressure case was also included since several authors (Kazemi and Merrill (1979), Beckner (1990), Gilman et al. (1994)) have assumed that fracture capillary pressures are negligible.

Figure 5.4. Different cases for fracture capillary pressure curves

5.3.2 Drainage.

Following the experimental procedure, once the core was saturated with water, we started injecting oil into the system. For both narrow and wide fracture configurations, the following data were used to perform the numerical simulations.

Similar to imbibition, matrix oil-water capillary pressure and relative permeability matrix were assumed to be correct and constant. Figure 5.5 shows the capillary pressure curve used for oil-water drainage and imbibition, as presented by Sanyal (1972).

Figure 5.5. Boise sandstone capillary pressure curves for oil-water systems (After Sanyal, 1972)

Unfortunately, we could not find any relative permeability curves for oil-water systems in Boise sandstone, so we followed a procedure presented by Purcell (1949). He stated that having the capillary pressure curves, one can calculate the corresponding relative permeability curves using the following formulae:

$$k_{ro} = \frac{\int_0^{S_w} \frac{dS}{P_c^2}}{\int_0^1 \frac{dS}{P_c^2}} \quad (5.7)$$

$$k_{rw} = \frac{\int_{S_w}^1 \frac{dS}{P_c^2}}{\int_0^1 \frac{dS}{P_c^2}} \quad (5.8)$$

Using these formulae, we obtained the relative permeability curves shown in Figure 5.6. In this figure, linear relative permeability curves for the fracture are also plotted which is not, generally, true.

Figure 5.6. Boise sandstone relative permeability curves for oil-water systems

The accuracy of relative permeability curves calculated from capillary pressure data is uncertain (Honapour, Koederitz and Harvey, 1986). The most recommended procedure is to obtain direct measurements.

5.3.3 Other Considerations.

So far, we have discussed how to obtain the data necessary to simulate the actual experiments. Since the fluid transfer parameters between rock matrix and fracture are not well known, simulation of fractured reservoirs uses, in general, very crude and unproven hypotheses such as zero capillary pressure in the fracture and/or relative permeability linear with saturation. Nevertheless we know there is no theoretical basics to prove these assumptions. We studied different cases in order to improve the understanding of flow in fractured media and for the sake of completeness.

Moreover, Pan et al. (1996) found that a unit-slope straight line for fracture relative permeability should not be used. They state that a 0.6 to 0.8 slope straight line should be used, instead. It is important to note that for fracture relative permeability curves, the lower the slope of the straight line, the higher the resistance to flow through the fracture.

Thus, different cases for relative permeability curves in the fracture were studied. Figure 5.7 show these different cases; they go from the general assumption of unit-slope

straight line (relative permeability equal to the phase saturation), 0.75 slope straight line, and 0.6 slope straight line.

Figure 5.7. Fracture relative permeability curves for wetting and non-wetting phase.

The following subsections present the results obtained from the simulation studies and their comparisons with the experimental results. The results will be presented in a fashion similar to the experiments (Section 4). First we will discuss the water injection and then oil injection. The reader will find it easier to compare the simulations results to the 3-D reconstructions, since both of them were obtained for water or oil saturations

above 50%. The simulation images presented in this work show an axial vertical section of the core; i.e., along the direction of flow which goes from left to right.

5.4 Numerical Results

First, we studied capillary pressure in the fracture under the assumption that it is a linear function of water saturation. We considered each parameter independently. Different cases for capillary pressure curves and relative permeability curves for the fracture are shown in Figure 5.4 and 5.7. It is important to note that for fracture relative permeability curves, the smaller the slope of the straight line, the higher the resistance to flow through the fracture. Starting with a high capillary pressure in the fracture, we observed that the matrix front matched well, but the breakthrough time was too soon compared to our experimental results (Figure 5.8). We decreased the slope of the straight line capillary pressure in the fracture up to a point for which the breakthrough time as well as the matrix front matched the experiments (Figure 5.10). For the sake of completeness, we also studied extreme cases that are often used in real practice such as very low and no capillary pressure in the fracture. In the no capillary pressure case (Figure 5.11), the blocks worked independently. Thus, the capillary continuity that we had seen in the experiments did not occur anymore in the numerical studies.

After obtaining the proper description of capillary pressure in the fracture, we continued by studying the fracture relative permeability curves. The assumption of fracture

relative permeability equal to phase saturation is often used in numerical simulation. This assumption suggests, frictionless, ideal flow of fluids in the fractures, such that inside the fracture the phases can move past each other without hindrance. However, if relative permeabilities with a slope less than 1.0 is used, the effective total mobility is reduced (Figure 5.10). Pan et. al. (1996) discussed that larger from resistance in the fractures must be used, such as the 0.75 and 0.6 sloped straight lines instead whose results are shown in Figures 5.12 and 5.13. Our results show that the best matches are achieved when an slope of 0.6 is used.

In order to obtain the best match, we also investigated the heterogeneities present in the systems as shown in Figure 4.2, especially in the wide fracture system. We simulated different heterogeneous cases until we obtained better matches. We achieved this goal by assigning higher porosity (14%) to the bottom block and lower porosity (13%) to the top block. The results for this case are shown in Figure 5.14 which proves that, capillary pressure in the fracture can not be neglected and the heterogeneity must also be considered. Figure 5.15 shows the comparison of the experimental results with the numerical simulation results for the system with the wide fracture.

Similarly, we followed the same analysis for the system with no spacer in between the blocks. An interesting observation was that neither the capillary pressure nor the relative permeability curves in the fracture affected the results. That leads us to the conclusion that the fracture is so thin and each half mates so well that there is almost

perfect capillary continuity, and it acts like a solid block. Figure 5.16 shows the numerical results for the narrow fracture. Figure 5.17 also shows the comparison of the experimental results with the numerical simulation results for the system with no spacer. The fracture system without a spacer showed a more stable front and faster breakthrough than the wide fracture system, as we had seen in the experiments.

Similarly, we followed the same procedure for the oil injection part. The matches for the thin fracture system were not very good, but the results for the wide fracture system, where we had seen in the experiments that most of the oil flowed through the fracture, are better. In this case, the assumption of zero capillary pressure in the fracture worked properly. These results are shown in Figures 5.18.

Figure 5.8. Numerical simulation results for the wide fracture system using unit slope X-type fracture relative permeability curves and large fracture capillary pressure

Figure 5.9. Numerical simulation results for the wide fracture system using unit slope X-type fracture relative permeability curves and regular fracture capillary pressure

Figure 5.10. Numerical simulation results for the wide fracture system using unit slope X-type fracture relative permeability curves and small fracture capillary pressure

Figure 5.11. Numerical simulation results for the wide fracture system using unit slope X-type fracture relative permeability curves and zero fracture capillary pressure

Figure 5.12. Numerical simulation results for the wide fracture system using 0.75 slope X-type fracture relative permeability curves and small fracture capillary pressure

Figure 5.13. Numerical simulation results for the wide fracture system using 0.6 slope X-type fracture relative permeability curves and small fracture capillary pressure

Figure 5.14. Numerical simulation results for the wide fracture system using 0.6 slope X-type fracture relative permeability curves and small fracture capillary pressure and adding heterogeneities

Figure 5.15. Numerical simulation results for the narrow fracture system using any slope X-type fracture relative permeability curves or any fracture capillary pressure

Figure 5.16. Comparison between experiment and simulation works for the narrow fracture system for different PV of water injection

30 min. (0.22 PV)

1 hr. (0.45 PV)

1 hr. 30 min (0.67 PV)

2 hours (0.89 PV)

Figure 5.17. Comparison between experiment and simulation works for the wide fracture system for different PV of water injection

0.67 PV (1 hr. 30 min)

1.13 PV (2 hr. 30 min)

1.68 PV (3 hr. 45 min)

Figure 5.18. Comparison between experiment and simulation works for the wide fracture system for different PV of oil injection

Chapter 6

Discussion of Results and Recommendations

An apparatus that can be used to obtain detailed measurements of pressure, rate and saturation distribution was built and tested. It consists of a fractured core in an epoxy core holder, with six different locations for pressure measuring. Phases distribution in the matrix and inside the fracture was also determined by means of a (CT) scanner.

Multiphase flow runs were performed , and data were obtained. The experimental results were well matched by numerical simulation. Numerical simulations were also used to estimate the influence of variables like fracture relative permeability, matrix/fracture capillary pressure, and fracture width. The results shown that capillary pressure is the dominant parameter in the type of water displacements. Knowledge of the capillary pressure function is then critical.

The combined experimental and simulation study resulted in a much better understanding of the physical processes that occur when two or three phases flow in a fractured system, compared to previous reported studies (Guzman and Aziz (1993), Hughes (1995)).

This work allowed us to find areas with lower permeability and porosity, and then use them in the numerical simulations to obtain the best matches as shown in Figure 5.14, for instance. All the CT images and the three-dimensional reconstructions obtained from them made much easier the understanding of multiphase flow and the comparing with the simulation results as shown in Figures 5.15 and Figures 5.17.

Several authors (Kazemi and Merrill (1979), Beckner (1990), Gilman et al. (1994)) have assumed that fracture capillary pressures are negligible. Others have shown experimentally that capillary continuity becomes important when gravity provides a driving force (Horie et al. (1988), Firoozabadi and Hauge (1990), Labastie (1990), Firoozabadi and Markeset (1992). Kazemi (1990) stated that capillary continuity is prevalent in the vertical direction and has suggested that, to reduce the number of equations to solve, fractured reservoir simulations should use the dual permeability formulation for the z direction and the dual porosity formulation for the x and y directions.

This work showed that capillary continuity can occur in any direction, depending on the relative strengths of the capillary and Darcy terms in the flow equations; the thin

fracture systems have a more stable front and slower breakthrough compared to wide fracture systems, and that capillary pressure has more effect when the fracture is narrow. We observed that neither the capillary pressure nor the relative permeability curves in the fracture affected the results for the narrow fracture system. That lead us to the conclusion that the fracture is so thin and/or each half mated so well that there is almost perfect capillary continuity, and it acts very similar to a solid block.

With this work we were able to verify that larger recoveries can be obtained when fractures are wider, and that the assumption of zero capillary pressure in the fracture is incorrect when dealing with air and water. This conclusion is shown on Figure 5.11.

The assumption of fracture relative permeabilities equal to the phase saturation was tested. This work shows that straight line fracture relative permeability can be used, but not necessarily equal to the phase saturation. X-type relative permeability curves can be used for fractured system using larger flow resistances in the fractures, such as 0.75 or 0.6 sloped straight lines instead. Our results show that the best matches are achieved when a slope of 0.6 is used.

This work has shown that the flow in fractures is dominated by both capillary and viscous forces. Moreover, a procedure for determining the parameters involved in transmissibility and transfer term that appear in the flow equations in finite difference form (Equations. 5.1 and 5.2) was established.

Finally, it is important to mention that there are still some areas of improvement. The first recommendation is that everything must be mounted in a single cart, so it is easy to fix any possible leaks, to calibrate the pressure transducers, or to replace any non-properly working item.

The reader should realize that experiments presented in this work were performed only once. We assumed that our results were correct because they were comparable to Hughes (1995) results and we could reproduce them very good by numerical simulations. However a repeatability test should be performed on these experiments to achieve a higher certainty of the conclusions presented here.

7. Nomenclature

A	Core cross sectional area
B	Formation Volume Factor
D	Depth
CT	CT number
K	Absolute permeability
k	Permeability
L	Length
p	Pressure
P_c	Capillary pressure
q	Flow rate
S	Saturation
t	Time
T	Transmissibility
V	Volume

Greek

μ	Viscosity
ρ	Density
σ	Interfacial tension or shape factor
ϕ	Porosity
τ	Matrix-Fracture transfer function

Subscripts

a	Air
aw	Air and water saturated core
c	Capillary
cd	Dry core
cw	Water saturated core
f	Fracture
m	Matrix
o	Oil
ow	Oil and water saturated core
p	Phase
r	Relative
w	Water

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Appendix A

Epoxy Specifications

<u>Property</u>	<u>Specification</u>
Resin System	Tap Plastic Marine Grade #314
Hardener	Tap Plastics Marine Grade#143
Resin/Hardener Ratio (by Volume)	2:1
Mixed Viscosity (cp)	780
Pot Life (minutes at 77 F, 25 C)	35-40
Recoat time (hours)	6.0-6.5
Recommended Minimum Use Temperature (F)	40
Heat Distortion Temperature (F)	110
Flexural Stength (psi)	10,500
Tensile Strength (psi)	7,000
Flexural Modulus (psi)	400,000
Tensile Modulus (psi)	360,000
Elongation %	6.0

Appendix B

List of Equipment

Equipment	Specification	Manufacturer or Distributor
Back pressure regulator	SD-91LW, 400-25 psi	Grove Valve & Regulator Co. 6529 Hollis St. Oakland, CA 94608
Balance	PE1600 & PE 3600	Mettler Instrument Corp. Princeton-Hightstown Road Highstown, NJ 08520
Ball valve	Whitey B-43F2	Sunnyvale Valve & Fittings Co. 929 Weddell Court Sunnyvale, CA 94089
Connectors	Swagelock	Sunnyvale Valve & Fittings Co. 929 Weddell Court Sunnyvale, CA 94089
CT Scanner	Picker 1200SX	Picker International, Inc. 595 Miner Road Highlands Heights, OH, 44143

Differential Pressure Transducer	DP31	Celesco Transducer Products, Inc. 7800 Deering Avenue Canoga Park, CA 91304
High Performance liquid chromatography pump	ConstaMetric 3200	LDC Analytical, Inc. P.O. Box 10235 Riviera Beach, FL 33419
Signal carrier or Demodulator	CD10A, CD10D CD25A	Celesco Transducer Products, Inc. 7800 Deering Avenue Canoga Park, Ca 91304
Chart Recorder	1243	Soltec Transducer Products, Inc. 11684 Pendleton Street Sun Valley, CA 91352