1 of 1

Reservoir Condition Special Core Analyses and Relative Permeability
Measurements on Almond Formation and Fontainebleu Sandstone Rocks

Topical Report

By
Dan Maloney

November 1993

Work Performed Under Cooperative Agreement No. DE-FC22-83FE60149

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

Rhonda Lindsey, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
IIT Research Institute
National Institute for Petroleum and Energy Research
P.O. Box 2128
Bartlesville, OK 74005

MASTER

sp
DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

TABLE OF CONTENTS

	<u>Page</u>
ABSTRACT.....	1
INTRODUCTION	1
PROJECT OBJECTIVES	2
SUMMARY OF PROGRESS.....	2
Environmental, Safety, and Health Review.....	2
Reservoir Condition Relative Permeability Tests on Almond Formation Rock.....	2
Selection and Characterization of Fontainebleu Sandstone.....	2
Fontainebleu Sandstone Relative Permeability Results	4
Discussion of Relative Permeability Results.....	5
Condensate Fluid Design.....	6
Coreflood Simulator.....	8
CONCLUSIONS.....	8
ACKNOWLEDGMENTS	9
APPENDIX A - CAPILLARY PRESSURE AND RELATIVE PERMEABILITY DATA.....	10
APPENDIX B - INNOVATIONS IN FLUID SEPARATOR DESIGNS.....	13
APPENDIX C - RELATIVE PERMEABILITY ESTIMATION USING COREFLOOD SIMULATION.....	18

ILLUSTRATIONS

1 Oil/brine relative permeability results from 74° F (sample 4959) and 120° F (sample 4953) tests	2
2 Pore entry radius versus mercury saturation, Fontainebleu sandstone.....	3
3 Capillary pressure versus mercury saturation, Fontainebleu sandstone.....	3
4 Oil/brine (Soltrol 100/2% KCl brine) capillary pressure versus average saturation from centrifuge tests on Fontainebleu samples FB1 and FB2.....	4
5 Imbibition oil/brine steady-state relative permeability results, Fontainebleu sandstone.	5
6 Gas/brine steady-state relative permeability results, Fontainebleu sandstone.	5
7 Gas/oil steady-state relative permeability results, Fontainebleu sandstone.	5
8 Surfactant-brine/oil relative permeability results	5
9 Capillary number versus saturation.	6
10 Bubble point data for 1-bromopropane	7
11 Bubble point data for 1-bromopropane (1-BrC3) propane, and a 1:1 molar mixture of the two.....	7
12 PVT data for the 1:1 molar mixture of propane and 1-bromopropane at 68° F.....	7
13 PVT results for a 1:1 molar mixture of propane and 1-bromopropane.....	7

RESERVOIR-CONDITION SPECIAL CORE ANALYSES AND RELATIVE PERMEABILITY MEASUREMENTS ON ALMOND FORMATION AND FONTAINEBLEU SANDSTONE ROCKS

By Dan Maloney

ABSTRACT

This report describes the results from special core analyses and relative permeability measurements conducted on Almond formation and Fontainebleu sandstone plugs. Almond formation plug tests were performed to evaluate multiphase, steady-state, reservoir-condition relative permeability measurement techniques and to examine the effect of temperature on relative permeability characteristics. The Fontainebleu sandstone was selected for tests because of its uniformity and 100-mD permeability range.

In addition to rock tests, a fluid system consisting of propane and 1-bromopropane was designed and evaluated for tests simulating condensate deposition. In condensate systems, liquid and gas phase volumes within the rock are pressure and temperature sensitive. Insufficient time was available to use the fluid in flow tests.

An increase in temperature from 23° to 49° C appeared to increase the brine relative permeability of the Almond formation core plug for brine saturations below 45%. Oil/brine, gas/brine, and gas/oil steady-state relative permeability results are reported for the Fontainebleu sandstone. Most of the relative permeability versus saturation results could be represented by one of two trends — either k_{rx} versus S_x or k_{rx} versus S_y trend where x and y are fluid phases (gas, oil, or brine). For example, k_{ro} versus S_o and k_{rw} versus S_w results fell along the same trend. Capillary number versus saturation results from the k_{rx} versus S_x data appeared to follow a similar trend as well.

In lieu of using the pentane/bromopropane fluid system, tests to examine interfacial tension (IFT) effects were performed using an oil/brine fluid system in which surfactant was added to the brine phase. The IFT between the brine and oil phases was 0.20 mN/m compared to the typical oil/brine IFT of 30 mN/m. It appeared that, while low interfacial tension increased the aqueous phase relative permeability, it had no effect on the oil relative permeability.

Progress was made toward using the PC version of the (BOAST) simulator, DOE's black oil reservoir simulator, for coreflood history matching. The simulator may be very useful in determining rock relative permeability functions from reservoir-rate displacement tests while accounting for capillary effects. An attractive feature of the BOAST simulator is that it was developed as a result of Department of Energy funded research and is publicly available at low cost.

Also described are fluid separator designs. Innovations were targeted toward improved automated methods for detecting fluid interface levels within fluid

separators. Two techniques were developed which offer significant improvements over existing designs. One technique uses X-ray attenuation methods to locate interfaces as the separator is vertically scanned with a linear X-ray scanner. The other technique uses RF admittance probes to locate both gas/oil and oil/brine interface levels electronically. Both methods have merit.

INTRODUCTION

The multiphase relative permeability measurement laboratory at NIPER provides a well-utilized avenue for direct transfer of DOE supported Base Program technology to the oil production industry. The technology developed under this Base Program project is available to the petroleum industry for immediate application to increase oil production. Multiphase relative permeability information is an indispensable component of accurate reservoir simulation, a technique used in the oil industry and other Base Program projects to plan reservoir management and advanced recovery strategies. A variety of projects conducted by NIPER for major oil companies have impacted development and production strategies for major reservoirs in the United States, Asia, South America, and Europe. NIPER has provided contract training and software support to industrial clients to help them increase their relative permeability measurement and data interpretation skills.

The concept of relative permeability for two-phase flow is not new. Engineers and analysts require accurate data describing the permeability or fluid-flow capacity of reservoir rock in order to design production facilities and to optimize resource recovery strategies. Under conditions of multiphase flow, fluids such as oil, brine, and gas compete for the same flow paths through reservoir rock. The additional resistance to flow that occurs when more than one fluid is present in the rock is described by normalizing permeabilities with respect to a base permeability for each of the flowing phases at each fluid saturation condition. This measurement and normalization process yields relative permeability data. Relative permeability characteristics are functions of the rock and fluid system. Laboratory tests are required for these measurements.

Tasks for FY93 were planned to increase the relative permeability data base established in the previous years while addressing temperature effects and effects of interfacial tension reduction on relative permeabilities. Many significant rock/fluid interactions that affect multiphase fluid flow behavior at petroleum reservoir conditions cannot be duplicated in the laboratory at ambient temperature and pressure conditions. For this reason, the

test program was conducted on reservoir rock samples at simulated reservoir stress and temperature conditions.

PROJECT OBJECTIVES

The objectives of this project are to improve the reliability of laboratory measurements of two- and three-phase relative permeabilities for steady- and unsteady-state conditions in core samples; to investigate the influence of rock, fluid, and rock-fluid properties on two- and three-phase relative permeabilities; and to expand the capabilities of measuring relative permeabilities under broader temperature and pressure conditions.

SUMMARY OF TECHNICAL PROGRESS

Environmental, Safety, and Health Review

The first task of the project year was to evaluate environmental, safety, and health aspects of the planned research. A status report entitled "Project BE9 Environmental, Safety, and Health Evaluation," was written. The status report, described environmental, safety, and health aspects relative to the project and explained how the project staff intended to meet ES&H objectives. No adverse environmental, safety, or health conditions were encountered during the project year.

Reservoir-Condition Relative Permeability Tests on Almond Formation Rock

After 1 year of exposure to 7 MPa confining pressure and 4 months at 49° C, the epoxy-resin jacket around sample 4959 developed a leak. Sample 4953 was prepared for reservoir-condition tests. An oil/brine steady-state relative permeability test was conducted on sample 4953. The 4953 sample characteristics are similar to those of sample 4959. Both rocks are from the Almond formation. The Almond formation is composed of thin beds of sandstones and shales from the Arch Unit well 120 of Patrick Draw field.

Relative permeability characteristics of sample 4953 were anticipated to be similar to those of 4959. The sample was subjected to the same test conditions as the 4959 sample except that the test temperature was 49° C instead of 23° C.

Fig 1. - Oil/brine relative permeability results from 74° F (sample 4959) and 120° F (sample 4953) tests.

Figure 1 shows relative permeability results from tests at the two test temperatures. The results suggest an increase in wetting-phase relative permeability and decrease in non-wetting phase relative permeability with increase in temperature. The test was repeated, yielding similar results.

Selection and Characterization of Fontainebleu Sandstone

A consortium meeting was held during the first week of December. Fontainebleu sandstone was discussed as a possible rock for use in FY93 activities. The rock is a clean sandstone, and relationships between porosity and permeability of Fontainebleu sandstone samples are reported to be well correlated.

Fontainebleu sandstone was selected as the test rock for FY93 activities. Samples were cut and plugged from a block of the rock. Air permeability and porosity, X-ray diffraction (XRD) mineralogical analysis, thin section and scanning electron minipermeameter (SEM) analyses, and mercury injection tests were performed to measure properties of the sandstone.

Air permeabilities measured on unconfined samples of the sandstone ranged from 60 to 130 mD, depending upon the plugging direction. Porosities ranged from 8 to 11.3%. XRD results indicated that the sample is predominantly quartz (99%) with traces of feldspars, calcite, kaolinite, and illite. SEM photomicrographs of the rock illustrated the moderately porous character of the medium-grained, very-well sorted, quartz-cemented, quartzarenitic sandstone. Detrital grains were interlocked throughout the sample. Detailed inspection of the intergranular contacts showed the presence of traces of authigenic illite matting the grain surfaces. The thin section description of the sample performed by Mineralogy Inc. of Tulsa is as follows:

"This sample is comprised of medium-grained, very-well sorted, well-rounded, quartz-cemented, quartzarenitic sandstone. The mean grain diameter is approximately 0.26 mm, with a maximum grain diameter of 0.60 mm. The detrital framework is mildly to moderately compacted, and displays a predominance of point-to-point and elongated intergranular contacts. The interlocking nature of the authigenic quartz overgrowths is suggestive of a densely-compacted framework, however, careful inspection of the intergranular relationships indicates that quartz overgrowth cement precipitated early on in the burial history of this sandstone prior to significant compaction. Petrographic modal analysis indicates that the detrital composition is dominated by monocrystalline quartz (59.0%), together with minor amounts of polycrystalline quartz (7.0%), and feldspar (1.0%). In addition to these three components, traces of chert, as well as metaquartzite fragments, are also present. Quartz overgrowth cement is the dominant authigenic constituent within this sandstone, accounting for approximately 19.0% of the bulk volume. The quartz cement occurs as ubiquitous syntaxial rims flanking the detrital quartz grains. As previously mentioned, the overgrowths are commonly interlocked between the adjoining quartz grains. Traces of pore-lining and grain-coating clay matrix are present within the sandstone, occurring as dust rims which separate the detrital and authigenic quartz constituents, as well as late-stage pore-lining clays commonly situated within the intergranular pore throats. Authigenic clay matrix is estimated to account for approximately 0.5% of the bulk volume within this sandstone. Illite is the dominant pore-lining and grain-coating clay constituent. In addition to illite, traces of authigenic kaolinite are present as a scattered replacement for altered feldspar grains and chert grains. X-ray diffraction analysis indicated the presence of traces of calcite within the sample, however, none was detected in the thin section sample. The macro pore volume is comprised of moderately well-preserved intergranular porosity, together with trace amounts of intragranular dissolution void space and rare grain-moldic pores. The secondary voids have developed chiefly at the expense of altered and leached feldspar grains and chert fragments. Intergranular macro porosity accounts for approximately 13.5% of the bulk volume within this sandstone. The intergranular voids are moderately well-interconnected, and are likely to contribute to moderate to good fluid permeability for this sandstone. Percentage values for mineral constituents and pore types listed above are based on a 200 point modal analysis of the thin section."

Fig 2. - Pore entry radius versus mercury saturation, Fontainebleu sandstone.

Fig 3. - Capillary pressure versus mercury saturation, Fontainebleu sandstone.

Mercury intrusion porosimetry tests were conducted on several Fontainebleu sandstone plugs. Results were very consistent, so only one data set is described in this section. An inspection of the mercury injection porosimetry results indicates that most of the pore throats are in the 10 to 20 μm range. Figure 2 shows pore entry radius versus pore volume % saturated by mercury. The mean pore radius is 14.4 μm . Capillary pressure versus mercury saturation results are shown in Fig. 3. Most of the pores are similar in size to the mean pore diameter, as shown by the two figures. Data are provided in Table A1.

Centrifuge oil/brine capillary pressure tests were conducted on two 2.54-cm-diameter by 2.54-cm-long plugs of Fontainebleu sandstone. The plugs were designated FB1 and FB2. Plug FB1 had an air permeability of 92.1 mD and a porosity of 8.63%. The permeability and porosity of FB2 were 63.4 mD and 7.95%, respectively. After saturating the plugs with brine, the plugs were loaded in centrifuge tubes and were spun to a residual brine saturation condition at 3,000 rpm for 12 hours. Imbibition (brine

displacing oil) measurements were recorded after 4-hr stabilization at speeds of 400, 900, 1,500, 2,100, 2,600, and 3,000 rpm. Drainage measurements were then recorded at similar rotational speeds. Again, 4-hr stabilization time was allowed before recording data and increasing the centrifuge speed. Average saturation values were used in calculating USBM wettability indices. Capillary pressure versus saturation curves were truncated at the maximum capillary pressure achieved during the drainage cycle in calculating areas for wettability index calculations.

Figure 4 shows capillary pressure versus average saturation results for the two plugs. Wettability indices for the plugs were both greater than 0.3, indicating a slight to moderate preference for water wetting. Numerical results are shown in Table A2.

Fontainebleu Sandstone Relative Permeability Results

Steady-state relative permeability tests were conducted on a Fontainebleu sandstone plug. The plug was 3.816 cm in diameter by 7.702 cm long. The plug was subjected to 7 MPa confining pressure throughout each test. Test temperatures were 23°C.

The plug was saturated with brine. The brine contained 2% KCl by weight and 5% KI by weight in deionized water. The brine viscosity was 1.05 cP. The permeability to brine under conditions of 100% brine saturation was 106.4 mD. The plug was oil flooded to a residual brine saturation condition. Soltrol 100, an isoparaffinic oil sold by Phillips Petroleum Co., was used as the oil phase. The viscosity of the oil was 1.59 cP. The oil/brine interfacial tension was 29.5 mN/m.

Steady-state oil and brine permeabilities were recorded at various brine fractional flows as the oil saturation was reduced to a residual condition. Relative permeabilities were normalized with respect to the brine permeability under conditions of complete brine saturation. Results are shown in Fig. 5 and Table A3.

The plug was cleaned within the coreholder by a flow-through process using isopropyl alcohol, pentane, and methanol. The plug was dried with nitrogen gas, and the permeability to gas was measured when the plug was completely gas saturated. The gas permeability was 171 mD. The sample was saturated with brine. The gas/brine interfacial tension was measured as 60.1 mN/m. Gas and brine steady-state permeabilities were measured as the brine saturation was incrementally lowered to a residual condition. Additional measurements were recorded as the gas saturation was reduced to a residual condition. Permeability data were normalized with respect to the 106.4-mD brine permeability. Results are shown in Fig. 6 and Table A4.

Fig 4. - Oil/brine (Soltrol 100 / 2% KCl brine) capillary pressure versus average saturation from centrifuge tests on Fontainebleu samples FB1 and FB2.

The plug was again cleaned and dried. The permeability of the sample to gas was measured as 114 mD. The sample was saturated with Soltrol 100. The oil permeability was measured as 151.1 mD. The gas/oil interfacial tension was measured as 22.3 mN/m. Several two-phase, steady-state permeability measurements were recorded as the gas saturation in the sample was increased. After finding a gas leak, the plug was oil flooded to a residual gas condition. Steady-state permeability measurements were recorded subsequently for a decreasing oil saturation cycle (d2) and an increasing gas saturation cycle. Results were normalized with respect to the 114 mD gas permeability value. Figure 7 and Table A5 show test data.

The plug was again cleaned. Surfactant was mixed with the brine to lower the oil/brine interfacial tension. The surfactant was a mixture of 80% LXS 810 and 20% RS-16. LXS 810 is an Enordet made by Shell Development Co. RS-16 is a Sandopon made by Sandoz Chemicals. The brine originally contained 2% KCl and 5% KI by weight. The surfactant-solution contained 0.5% surfactant and 99.5% brine. The interfacial tension of the oil/surfactant-solution was measured as 0.2 mN/m using the spinning drop technique. The plug was saturated with

the surfactant-solution. The permeability of the plug to the surfactant-solution was 184 mD. Nearly all of the brine was displaced from the pore space when the plug was flooded with oil to a residual brine saturation condition. Steady-state oil and brine permeabilities were measured for increasing and decreasing brine saturation cycles. Results were normalized with respect to a brine permeability of 106.4 mD to be comparable with previous oil/brine data. Results are shown in Fig. 8 and Table A6.

Several fluid separators were designed and assembled for steady- and unsteady-state laboratory measurements. These are described in appendix B. The three types of separators described in the appendix offer advantages over some of the existing measurement techniques.

Fig 5. - Imbibition oil/brine steady-state relative permeability results, Fontainebleu sandstone. Normalized with respect to $k_w = 106.4$ mD when $S_w = 1$.

Fig 6. - Gas/brine steady-state relative permeability results, Fontainebleu sandstone. Normalized with respect to $k_w = 106.4$ mD when $S_w = 1$.

Fig 7. - Gas/oil steady-state relative permeability results, Fontainebleu sandstone. Normalized with respect to $k_g = 114$ mD when $S_g = 1$.

Fig 8. - Oil/surfactant-solution relative permeability results. Results are normalized with respect to $k_w = 106.4$ mD at $S_w = 1$ although the permeability of the sample to the surfactant-solution was 184 mD.

Discussion of Relative Permeability Results

Oil relative permeability versus brine saturation curves were similar from oil/brine and oil/surfactant-brine tests, whereas significantly higher brine relative permeabilities were achieved with the surfactant-brine at each brine saturation condition. The primary differences in oil/brine and oil/surfactant solution results were the higher surfactant-solution relative permeability values compared to those from the oil/brine test. Relative permeability versus saturation comparisons were made using results from the various tests. Two primary groups of results were found in which relative permeability versus saturation curve trends were very similar. The groups were as follows:

k_{rx} versus S_x similarities

k_{ro} versus S_o from gas/oil tests

k_{ro} versus S_o from oil/surfactant-brine tests

k_{rg} versus S_g from gas/oil tests

k_{rw} versus S_w from oil/brine tests

k_{rw} versus S_w from gas/brine tests

k_{rx} versus S_y similarities

k_{rw} versus S_o from oil/brine tests

k_{ro} versus S_w from oil/surfactant-brine tests

k_{ro} versus S_g from gas/oil tests

k_{rw} versus S_g from gas/brine tests

While plots within each group were similar, saturation ranges and residual saturations varied. To examine whether trends would remain consistent when capillary effects are considered, capillary numbers were calculated by:

$$N_c = k (\Delta P/L) / (IFT) \quad (1)$$

where N_c = capillary number
 k = phase permeability measured during two-phase, steady-state flow conditions
 $\Delta P/L$ = pressure gradient

For units, we used

$$N_c = 6.804e-7(k, \text{mD}) \quad (2)$$
$$(\Delta P, \text{psi/L, cm}) / (IFT, \text{mN/m})$$

Figure 9 is a plot of N_c versus saturation for three sets of measurements recorded during two-phase steady-state tests. Brine, gas, and oil results all follow a similar trend on the plot. It appears that, for this sandstone sample, two-phase steady-state relative permeabilities, capillary numbers, and saturations are correlated fairly well.

Condensate Fluid Design

Fluid design criteria were discussed during the consortium meeting. One conclusion from the discussion was that a binary condensate fluid system using 1-bromopropane as one of the hydrocarbon fluids might provide good test characteristics. The 1-bromopropane should provide good X-ray absorption contrast between the brine and hydrocarbon phases as bromine has a fairly high X-ray mass attenuation coefficient.

A laboratory was refurbished for combined IFT/PVT analyses with elevated temperature and pressure conditions. Equipment was moved into the laboratory, and the apparatus was assembled. Condensate fluid components were ordered and received. A fluid system was designed

Fig 9. - Capillary number versus saturation. The legend refers to the phase, test, and saturation designations (phase, test, plotted saturation).

for tests simulating condensate systems. The interfacial tension between the hydrocarbon liquid and gas phases was anticipated to be less than the IFT for a typical brine/oil or oil/gas system. Preliminary phase behavior predictions were made using a simulator. One of the fluid components is 1-bromopropane. Since little information is available describing characteristics of bromopropane, bubble point and other characteristics were experimentally determined. The bubble point characteristics of bromopropane were measured and were found to be different from predicted values. After an initial comparison of PVT (pressure, volume, temperature) properties for methane, ethane, propane, and decane, propane was selected as the second component of this binary fluid system.

Figure 10 shows results from 1-bromopropane laboratory PVT measurements. Measurements were limited to temperatures below 180° C. The 180° C maximum temperature was selected for simplicity and safety considerations. Insufficient data were available from the laboratory measurements to predict the characteristics of the propane/1-bromopropane mixture. Therefore, actual laboratory measurements were required. We decided to test a 1:1 molar mixture of propane and 1-bromopropane.

Several attempts to produce liquid propane by changing the propane pressure at ambient temperature were unsuccessful. Liquid nitrogen was then employed to cool a receiving cylinder, reducing the cylinder temperature enough to liquefy propane. The cylinder was used to transfer liquefied propane into a 500 cm³ accumulator and into the PVT cell at a pressure of 1140 kPa. The volume of 1-bromopropane required for a 1:1 molar mixture was then pumped into the PVT cell. 1-bromopropane is liquid at ambient temperature and pressure conditions.

PVT characteristics of the 1:1 molar mixture of propane and 1-bromopropane were measured at temperatures from 22° to 68° C. To simplify experiments, maximum temperature and pressure limits of 7 MPa and 66° C were

selected for PVT measurements. Bubble points were measured visually for each temperature. Results are shown in Fig. 11. Bubble points were normally obtained from graphs by plotting pressure versus volume. The bubble point for 68° C was measured by both visual and pressure/volume graphical methods for comparison. Visual bubble point observations yielded higher bubble point pressures than those determined with graphical techniques as shown in Fig. 12. This result should be kept in mind when experiments are performed using live fluids. It may be prudent to keep the pressure at least 20% higher than the bubble point pressure when a gas phase cannot be tolerated.

After measuring the bubble point at a test temperature, the pressure was reduced, and the resulting gas volume percentage was measured. Gas and liquid volumes were measured at four pressures for each temperature condition. Results are shown in Fig. 13. Gas volumes greater than 60% of the total fluid volume could not be achieved during these tests because of volume and pressure constraints. For future work, higher gas saturations should be measured. To achieve 100 % gas, pressures approaching vacuum will probably be required.

The 1-bromopropane stays mostly liquid throughout the range of pressures and temperatures selected for this project. This facilitates X-ray saturation measurements.

A small change in pressure causes a high change in gas saturation, as shown in Fig. 13. Depending on experimental constraints, this may be viewed as an advantage or disadvantage. During flow tests with this fluid, pressure drops across the length of the rock sample must be kept low in order to maintain uniform gas saturations.

Fig 10.- Bubble point data for 1-bromopropane.

Fig 11.- Bubble point data for 1-bromopropane (1-BrC3), propane, and a 1:1 molar mixture of the two.

Fig 12.- PVT data for the 1:1 molar mixture of propane and 1-bromopropane at 68° C.

Figure 13.- PVT results for a 1:1 molar mixture of propane and 1-bromopropane.

Laboratory flow tests using the propane/1-bromopropane fluid system were designed. Time limitations prevented relative permeability tests from being performed using the propane/1-bromopropane fluid system.

Coreflood Simulator

Work was directed toward development of a simulator to evaluate relative permeability functions by history matching results from coreflood experiments. Although we consider steady-state relative permeability results to be generally more reliable than unsteady-state results, unsteady-state tests offer the advantage of taking less time to perform than steady-state tests. Some state-of-the-art petroleum industry laboratories are using simulation and history matching to calculate relative permeability results from slow-rate corefloods. Additionally, the coreflood simulator should be useful in verifying that laboratory measurements of relative permeability and capillary pressure functions, when entered into the simulator, yield simulation results which are similar to the actual coreflood.

A modified version of BOAST was used for this work. The BOAST simulator was developed by Department of Energy funded research and is available in the public domain. The compiled BOAST simulator, when run on our PC, was tried on several 1D and 2D simulations. On 2D simulation involving approximately 3,000 grid blocks, the simulator requires about 30 minutes to perform 600 trials before reaching terminating conditions. For a 1D simulation involving 40 grid blocks, the simulator required 33 seconds for approximately 1,000 trials before reaching an endpoint. During this 33-second run, the simulator output 36 data files showing 1D oil, water, and gas saturations and how the flood front traversed the length of the model during the simulation. The simulator was used to examine effects of variations in relative permeability and capillary pressure functions on saturation distributions and fluid production predictions. Procedures and results are described in appendix C.

The following conclusions were made describing simulation efforts:

1. The BOAST simulator was successfully modified to run simulations at plug scale, using capillary pressure as one of the input parameters.
2. The simulator output was shown to be sensitive to variations in the relative permeability and capillary pressure input data. Simulation results provide demonstrations of the effects of these parameters on oil production.

3. A set of curves relating oil saturation distributions and cumulative oil production to variations in relative permeability and capillary pressure have been obtained which can be used to estimate these parameters from oil saturation distributions obtained for real corefloods.

4. Further work would be useful in simplifying the coreflood simulation process using the BOAST simulator.

CONCLUSIONS

Some conclusions from this project are as follows:

1. An increase in temperature appeared to cause an increase in brine relative permeability results for an Almond formation plug compared to room temperature results. The plug was tested using steady-state oil/brine methods. The oil was a low-viscosity, isoparaffinic refined oil.
2. Fontainebleu sandstone rock and fluid flow characteristics were measured and are reported. Most of the relative permeability versus saturation results could be represented by one of two trends — either a k_{rx} versus S_x or k_{ry} versus S_y trend where x and y are fluid phases (gas, oil, or brine). For example, k_{ro} versus S_o and k_{rw} versus S_w results fell along the same trend. Capillary number versus saturation results from the k_{rx} versus S_x data appeared to follow a similar trend as well and may be useful in describing reasons for variations in mobile fluid saturations when comparing results for different fluids.
3. An oil/surfactant-brine steady-state relative permeability test was performed to examine changes in oil/brine relative permeability characteristics from changes in fluid IFTs. It appeared that, while low interfacial tension increased the aqueous phase relative permeability, it had no effect on the oil relative permeability.
4. The BOAST simulator was modified for coreflood simulation. The simulator was useful for examining effects of variations in relative permeability and capillary pressure functions. The simulator will be used in the future to try to history match coreflood results.
5. Coreflood production monitoring and separator interface level measurement techniques were developed using X-ray absorption, weight methods, and RF admittance technologies. The three types of separators should be useful for routine and specialized core analysis applications.

ACKNOWLEDGMENTS

This work was performed for the U. S. Department of Energy (DOE) under Cooperative Agreement DE-FC22-83FE60149. The work was also supported by Mobil Research and Development Corporation, Unocal Corporation, and Phillips Petroleum Company. The author thanks Willis Waldorf, Alan Brinkmeyer, Kevin Doggett, Ron Masias, Sam Swan, Liviu Tomutsa, Daryl Doughty, and Mike Madden of NIPER for their assistance in performing this work. We thank the NIPER personnel who reviewed this manuscript, and Rhonda P. Lindsey, the DOE Project Manager, for her support.

APPENDIX A

CAPILLARY PRESSURE AND RELATIVE PERMEABILITY DATA

Capillary Pressure Data

TABLE A1
Mercury injection porosimetry data

Pore throat radius, μm	Hg Saturation, %	P _c , Bar	Pore throat radius, μm	Hg Saturation, %	P _c , Bar
5.47e+01	6.11e-02	2.28e-01	9.54e+00	7.19e+01	1.31e+00
5.03e+01	1.83e-01	2.48e-01	8.88e+00	7.64e+01	1.40e+00
4.66e+01	4.27e-01	2.68e-01	7.98e+00	8.17e+01	1.56e+00
4.34e+01	6.72e-01	2.87e-01	6.27e+00	8.71e+01	1.99e+00
4.06e+01	1.10e+00	3.07e-01	3.66e+00	9.05e+01	3.41e+00
3.81e+01	1.59e+00	3.27e-01	2.67e+00	9.25e+01	4.67e+00
3.58e+01	1.95e+00	3.48e-01	2.09e+00	9.39e+01	5.97e+00
2.96e+01	3.85e+00	4.21e-01	1.22e+00	9.65e+01	1.02e+01
2.50e+01	6.29e+00	4.99e-01	8.05e-01	9.80e+01	1.55e+01
2.16e+01	8.55e+00	5.77e-01	5.54e-01	9.87e+01	2.25e+01
1.90e+01	1.20e+01	6.56e-01	3.22e-01	9.95e+01	3.87e+01
1.70e+01	1.65e+01	7.33e-01	2.27e-01	9.96e+01	5.49e+01
1.53e+01	2.25e+01	8.15e-01	1.75e-01	9.98e+01	7.12e+01
1.40e+01	3.11e+01	8.91e-01	1.42e-01	9.99e+01	8.78e+01
1.26e+01	4.36e+01	9.89e-01	1.19e-01	9.99e+01	1.05e+02
1.16e+01	5.23e+01	1.07e+00	1.03e-01	9.99e+01	1.21e+02
1.09e+01	6.04e+01	1.14e+00	9.06e-02	9.99e+01	1.38e+02
1.02e+01	6.67e+01	1.22e+00			

TABLE A2
Centrifuge oil/brine (Soltrol 100 / 2% KCl brine) capillary pressure versus average and face saturation results for plugs FB1 and FB2.

Brine-displacing-oil			Oil-displacing-brine		
P _c , Bar	S _w , ave	S _w , face	P _c , Bar	S _w , ave	S _w , face
Sample FB1, k _a = 92.1 mD, Ø = 8.63%					
0.000	0.120	0.120	0.000	0.750	0.750
-0.030	0.398	0.617	0.025	0.750	0.750
-0.124	0.676	0.758	0.061	0.620	0.620
-0.326	0.704	0.760	0.207	0.268	0.076
-0.642	0.741	0.761	0.411	0.166	0.071
-1.041	0.750	0.762	0.658	0.129	0.071
-1.357	0.750	0.763	0.851	0.120	0.071
FB1: wettability index = 0.32					
Sample FB2, k _a = 63.4 mD, Ø = 7.95%					
0.000	0.042	0.042	0.000	0.739	0.739
-0.031	0.429	0.597	0.026	0.739	0.739
-0.128	0.651	0.737	0.064	0.681	0.150
-0.337	0.700	0.742	0.214	0.235	0.025
-0.665	0.719	0.748	0.425	0.100	0.025
-1.078	0.739	0.755	0.681	0.071	0.025
-1.406	0.739	0.761	0.881	0.061	0.025
FB2: wettability index = 0.40					

Relative Permeability Test Data

TABLE A3		
Oil/brine relative permeability results. Normalized with respect to $k_w = 106.4$ mD at $S_w = 1.000$. Values are expressed as fractions.		
k_{rw}	k_{ro}	S_w
1.00e+00		1.000
	1.42e+00	0.000
	8.07e-01	0.093
1.63e-01		0.564
7.76e-03	4.59e-01	0.220
1.27e-02	3.66e-01	0.245
1.87e-02	2.55e-01	0.297
6.16e-02	8.61e-02	0.432
1.08e-01	8.54e-03	0.500
1.24e-01		0.512

wi2

TABLE A4		
Gas/brine relative permeability results. Normalized with respect to $k_w = 106.4$ mD at $S_w = 1.000$. Values are expressed as fractions.		
k_{rw}	k_{rg}	S_g
	1.61e+00	1.000
1.00e+00		0.000
6.65e-02	1.93e-03	0.675
4.93e-02	5.83e-03	0.700
4.44e-02	6.89e-03	0.704
3.92e-02	1.24e-02	0.727
3.81e-02	1.72e-02	0.750
3.42e-02	2.69e-02	0.727
3.32e-02	3.44e-02	0.719
2.84e-02	4.63e-02	0.764
2.77e-02	5.16e-02	0.788
	5.79e-01	1.000
3.42e-02	4.73e-02	0.824
3.51e-02	4.38e-02	0.770
3.20e-02	2.19e-02	0.743
3.65e-02	1.69e-02	0.726
3.39e-02	1.18e-02	0.725
4.05e-02	8.93e-03	0.717
3.81e-02	2.97e-03	0.723
5.20e-02	2.29e-03	0.657
6.79e-02	3.53e-04	0.534
9.13e-01		0.010

gil

gd1

TABLE A5		
Gas/oil relative permeability results. Normalized with respect to $k_g = 114$ mD at $S_g = 1.000$. Values are expressed as fractions.		
k_{rg}	k_{ro}	S_g
1.08e+00		1.000
	1.42e+00	0.000
2.33e-03	8.49e-01	0.076
3.04e-02	4.43e-01	0.216
4.08e-02	3.00e-01	0.247
5.85e-02	1.82e-01	0.383
1.22e-01	6.15e-02	0.599
5.93e-01		0.928
1.47e-02	7.80e-02	0.607
2.58e-02	6.89e-02	0.624
3.52e-02	7.05e-02	0.585
4.60e-02	6.95e-02	0.593
8.85e-02	5.82e-02	0.655
1.11e-01	5.39e-02	0.691
1.08e-01	5.50e-02	0.659
7.94e-02	5.92e-02	0.626
5.28e-02	6.02e-02	0.635
2.45e-02	6.80e-02	0.609
1.09e-02	7.35e-02	0.621
7.72e-03	8.60e-02	0.623
	6.38e-01	0.217

TABLE A6		
Surfactant-brine/oil relative permeability results. Normalized with respect to $k_w = 106$ mD at $S_w = 1.000$. The permeability of the sample to the surfactant-brine mixture was 184 mD when the sample was completely saturated with the surfactant-brine. Values are expressed as fractions.		
k_{rw}	k_{ro}	S_w
1.73e+00		1.000
	6.57e-01	0.010
2.64e-02	4.70e-01	0.103
8.95e-02	3.68e-01	0.177
2.06e-01	2.83e-01	0.245
3.50e-01	1.60e-01	0.390
5.84e-01	6.69e-02	0.605
1.30e-00		0.722
	5.38e-01	0.000
2.68e-02	4.79e-01	0.100
5.16e-02	4.48e-01	0.139
9.65e-02	3.98e-01	0.160
1.97e-01	2.70e-01	0.231
3.17e-01	1.45e-01	0.352
4.84e-01	5.55e-02	0.391
6.02e-01	1.45e-02	0.543
5.83e-01	8.25e-03	0.543
6.35e-01		0.726

APPENDIX B

INNOVATIONS IN FLUID SEPARATOR DESIGNS

INTRODUCTION

Fluid production versus time measurements are important in conducting many types of coreflood experiments. Instantaneous flow rates, hydrocarbon recovery, and average plug saturations are calculated from fluid volume and time data. For lack of a better method, produced fluid volumes are often determined by visually locating interfaces between fluid phases within a calibrated vessel. For example, when oil and brine are captured in a graduated cylinder during a waterflood test as shown in Fig. B1, oil and brine volumes are calculated by noting the interface between the water and oil and the interface between the oil and air. These results are then used to calculate oil and water volumes.

These visual measurements are tedious, especially when production rates are high. When times and pressures are recorded along with the fluid volumes, time lags between measurements can cause errors in results.

Accuracy and efficiency can be improved by using automated measurement techniques. We've reported about a technique for determining produced fluid volumes from weight measurements.^{1,2} We have found that X-ray attenuation measurements and RF level transmitters can be used to locate oil/gas and oil/water interfaces in containers when the fluids separate quickly. Descriptions of how to use these separator designs are described in the following sections.

Fig B1. - Visual determination of fluid volumes produced during a coreflood test.

MONITORING FLUID PRODUCTION USING A WEIGHT METHOD

An automated oil/water production data monitoring system was built using a separator in which the weights of produced fluids are measured. Fluid volumes are calculated from the weights and fluid densities. Two 1,800-gram-capacity balances are used for weight measurements. The balances feature RS232 communication capabilities and measure weights with 0.01 gram precision. Measurement techniques were described in other reports.^{1,2} Figure B2 is a schematic of the system. Figure B3 shows oil production results measured during an oil/brine unsteady-state test. Similar resolution was obtained for the brine phase. Modifications can be made to use the technique with back pressure and elevated temperatures.

Fig B2. - Fixture for measuring oil and brine fluid volumes during unsteady-state corefloods.

Fig B3. - Typical oil production results using the weight method separator.

One of the advantages of the measurement technique is that it can tolerate slow breaking emulsions without loss of accuracy.

Interface Level Detection Using RF Admittance Transmitters

During FY93, we've experimented with RF interface level instrumentation. Our objectives were to build measurement systems for two- and three-phase closed-loop fluid separators. We accomplished these objectives using two RF level transmitters; one for each interface location measurement.

RF admittance transmitters are typically used for determining interface levels in industrial applications, such as in large capacity tanks. The transmitters are admittance-to-current transducers. A change in the level of material in a container causes a change in the output current from the instrument. The transmitter is a two-wire, 4-20 mA device. Transmitters are available for interface

measurements with conducting liquids, liquid/liquid interfaces, insulating liquids, and granular solids.

Two-Phase, Closed-loop Separator

A separator was designed using a RF admittance probe to determine fluid interface levels during unsteady-state oil/brine flow tests. The probe was purchased from Drexelbrook Engineering. The separator was fabricated of clear plastic with a volume capacity of 25 mL. A piece of stainless steel shim stock was placed along the back wall of the separator tube. The shim stock was grounded. Figure B4a is a schematic of the continuous injection flow system.

The separator was tested using refined oil (Soltrol 100) and brine (2% KCl and 5% KI by weight in water). A change in the separator interface position indicates a change in fluid saturation within the core plug. Figure B4b shows the level transmitter calibration. The calibration shows good linearity.

Fig B4a - Schematic of measurement system and graphical output from the oil/brine separator.

Fig 4b. - Level transmitter calibration results.

Three-Phase Separator

Figure B5 shows a prototype 3-phase separator/monitor. We constructed the vessel of plastic to make it easier to compare transmitter output to the actual interface levels. Stainless steel shim stock was placed along the inside wall on one side of the vessel. The shim stock was grounded. The shim stock was used so that the plastic vessel simulated a grounded metallic cylinder. The separator was 63.5 cm tall with an ID of 3.8 cm. Flow ports were machined near the top and the bottom. RF transmitters were inserted into the top and bottom of the

vessel. The upper transmitter was calibrated to measure the position of the oil/air interface while the lower transmitter was calibrated to measure the position of the oil/water interface. The prototype was designed to simulate a closed loop system separator in which sufficient oil is maintained in the separator at all times to cover the lower portion of the oil/air transmitter and upper portion of the oil/water transmitter. Figures B6a and B6b show calibrations for the gas/oil and oil/brine transmitters. Output from each transmitter is very linear. Correlation coefficients are nearly equal to one.

Fig B5. - Prototype 3-phase fluid separator/monitor

Fig B6a. - Calibration results for an RF admittance probe used to measure gas/oil interface positions.

Fig B6b. - Calibration results for an RF admittance probe used to measure oil/brine interface positions.

Using the calibration results, the microprocessor receiver was calibrated to display volumes of oil and volumes of water with resolution to 0.1 mL. Accuracy to 0.01 mL should be possible with smaller total fluid volumes or by using a different display. This could be achieved easily by reducing the inside diameter of the separator.

Costs

We ordered transmitters with Teflon covered rigid rods of 1.4 cm diameter and insertion lengths of 28 cm. The probes are rated for 7 MPa at 38° C and 3.5 MPa at 150° C. Probes with higher pressure and temperature ratings may be available by special order. The transmitters purchased during FY93 cost \$1,600 each. Each transmitter includes a sensing element with cooling extension, cable, conduit and fitting, and an electronic unit. The microprocessor receiver cost \$1,600. The receiver provides 24 VDC power to the two transmitters. The receiver can be programmed to read the loop current and display results in user-defined units. The microprocessor can be used to program nonlinear calibration equations for irregularly shaped tanks and storage vessels. The unit also has RS/485 communications output, SPDT relay outputs, and a variety of other useful features. As an alternative, one could buy a 24 VDC power supply and a two-channel digital panel meter for about \$800 if the added features of the microprocessor receiver are not required.

Considering costs of other interface level measurement techniques, RF level transmitter costs are quite reasonable.

Applications

Applications include:

- Fluid production measurements during corefloods
- Production measurements during 2-phase relative permeability tests
- Liquid volume measurements with computerized data acquisition
- Injection-rate measurements during constant pressure tests
- 2- and 3-phase closed-loop fluid separators.

X-Ray Measurements of Fluid Interface Levels

A linear X-ray scanner is used to measure fluid saturations within rock plugs during flow experiments. The X-ray is a useful device for 'looking inside' closed containers. Using the X-ray, we can scan through core plugs within pressure vessels to measure changes in X-ray absorption resulting from changes in fluid saturation conditions. Usually, one of the test fluids is doped with an X-ray absorbent so that the fluids have very different X-ray absorption characteristics. The X-ray scanner can also be used to monitor fluid interface levels within a fluid separator. In addition to locating the interfaces between

gas/oil and oil/brine fluids, the X-ray measurements can be used to evaluate fluid X-ray attenuation coefficients or changes in attenuation coefficients during flow tests. The same approach is applicable using X-ray CT scanners.

Figure B7a is a schematic of the separator system. Fluids enter the vessel through a pipe or tube. The fluids separate. Fluids can be drawn out of the vessel for reuse during flow tests. Either the X-ray beam traverses the separator or the separator is moved through the X-ray beam. The fluid interface levels are determined by analyzing X-ray absorption results.

The system was tested by pushing a cylinder containing air, doped oil (Soltrol 100 doped with iododecane) and brine through a stationary X-ray beam. X-ray measurements (natural log of X-ray intensity) were recorded as the cylinder was advanced through the beam path in 2.5 mm increments. Results are shown in Fig. B7b. In this experiment, the X-ray beam had a circular cross section of about 13 mm diameter. When the leading edge of the X-ray beam touched the air/oil interface, the beam was attenuated to a small degree by the oil at the beam edge. X-ray attenuation increased as the beam area within the oil increased. Maximum attenuation occurred when the entire beam passed through only oil. The air/oil and oil/brine interface locations can be determined to within about half of a scan position increment (1.25 mm in this case) by inspection from Fig. B7b. The accuracy of the interface location measurement can be improved using smaller position increments and a narrower X-ray beam.

Fig B7a. - Schematic of the X-ray interface measurement system. In preliminary experiments, the separator was moved through the X-ray beam. The X-ray tube and detector can be moved when the separator position is fixed.

Fig B7b. - Separator elevation X versus X -ray (natural log of intensity) calibration results showing oil and brine interfaces.

Measuring X -ray absorption characteristics of fluids within a separator during flow tests offers some really impressive possibilities for simplifying test designs and for improving measurement accuracy. These techniques will be useful in determining X -ray calibrations to fluid saturations during both routine tests and tests in which the X -ray dose undergoes phase changes, such as during condensate experiments.

CONCLUSIONS

The fluid production measurement systems described in this section can be used to make fluid production measurements simpler and more accurate. Each technique has special merits. The weight method can be used with fluids that don't separate quickly. RF level transmitters can be used to locate oil/gas and oil/water interfaces in containers when the fluids separate quickly. The transmitters can be used in many laboratory applications for fluid volume measurements, simplifying experimental designs, improving accuracy, and reducing manpower requirements. X -ray scanning techniques can also be used to enhance saturation calibrations and data accuracy when an X -ray scanner is available in the laboratory.

REFERENCES

1. Maloney, D., and A. Brinkmeyer, *Three-Phase Relative Permeabilities and Other Characteristics of 260-mD Fired Berea*, NIPER-581 February, 1992, pp. 22-23.
2. Maloney, D. and A. Brinkmeyer. *Using a Weight Method for Laboratory Fluid Production Measurements*. Paper SCA 9306 pres. at the SCA Annual Technical Conference, Houston, TX, Aug. 9-11, 1993.

APPENDIX C

RELATIVE PERMEABILITY ESTIMATION USING COREFLOOD SIMULATION

by Liviu Tomutsa, and Daryl A. Doughty, NIPER
Pin-Hu Wang, University of Oklahoma Student

INTRODUCTION

The measurement of relative permeability data, which is used to describe multiphase fluid flow in porous media, has traditionally been made using special core analysis in the laboratory.¹ The most direct method is the steady-state method which requires considerable time to reach equilibrium at the various fractional fluid flows used to determine the relative permeability data. Because of time constraints, the unsteady-state method is frequently used but requires a more complicated analysis to obtain meaningful results. Another approach is to use numerical simulation to model the observed fluid distributions during a coreflood. The simulators use relative permeability and capillary pressure data as inputs and calculate the production and pressure response for a given coreflood. By adjusting the input data to obtain a close match of the actual fluid saturation distributions obtained during corefloods, an estimate of the relative permeability can be obtained. The simulator used in this study is derived from the Black Oil Applied Stimulation Tool (BOAST) developed for the Department of Energy in 1982,² and recently adapted for use on a personal computer.³

EXPERIMENTAL

The BOAST simulator, which is readily available and in the public domain, was adapted for laboratory use in coreflood relative permeability simulation by modifying the dimensions to core plug scale. One-dimensional, two-phase simulations were performed using 100 x 1 x 1 grid blocks and the saturation outputs recorded at injected fluid volumes of 0.063, 0.126, 0.189, 0.252, and 0.315 pore volumes (PV). The actual input data to the simulator used during a typical simulation run are reproduced in the Table 1. The relative permeability data shown in Fig. C1, obtained from measurements on Tallant sandstone, were used as the reference data. Figure C2 shows the oil saturation profiles obtained using the simulator with the reference relative permeability data. To determine the sensitivity of the modified BOAST simulator to variations in k_{rw} , k_{ro} , and capillary pressure, a series of simulations were run using combinations of k_{rw} , k_{ro} , and capillary pressure data. Figures C3 - C6 show the various relative permeability data, plotted as a function of water saturation, used to determine the influence of changes in relative permeability data on simulator output in the absence of capillary pressure. Figure C3 shows the relative permeability data used to determine the influence of varying k_{rw} at fixed k_{ro} on the saturation distributions. Figure C4

shows the relative permeability data used to determine the influence of varying k_{ro} at fixed k_{rw} . Figure C5 shows the relative permeability data used to determine the influence of varying both k_{rw} and k_{ro} so that the cross point shifted vertically. Figure C6 shows the relative permeability data used to determine the influence of varying both k_{rw} and k_{ro} so that the cross point shifted horizontally. Figure C7 shows the capillary pressures plotted as a function of water saturation used to determine the influence of changes in capillary pressure on simulator output. The capillary pressure simulations were all run using the reference relative permeability data shown in Figure C1.

RESULTS

The results of the various simulations using the different input data sets are summarized in Figs. C8 - C17. These figures show the oil saturation distributions along the core at various volumes of injected water and the corresponding cumulative oil production (shown as percent of moveable oil) versus volume of injected water. Figure C8 shows the oil saturation profiles along the core at various volumes of injected water as a function of varying k_{rw} at fixed k_{ro} . Figure C9 shows the oil saturation profiles along the core at the corresponding volumes of injected water as a function of varying k_{ro} at fixed k_{rw} . The figures show that the oil saturation profiles generated from the simulator are sensitive to the relative permeability curves, with the sensitivity of the profiles to variations in k_{ro} being more pronounced. Also, as might be expected, the effects of varying k_{rw} and k_{ro} are complementary with the shapes of the oil saturation profiles at higher k_{rw} being similar to those obtained at lower k_{ro} and vice versa. The figures show that low k_{rw} or high k_{ro} retard the oil saturation front whereas high k_{rw} or low k_{ro} accelerate the front at given volumes of injected water. Also, the trailing edge of the front profile is more pronounced at high k_{rw} or low k_{ro} and the front is less steep, particularly for higher k_{rw} . Figures C10 and C11 show the corresponding cumulative oil production results for the preceding two cases. The shapes of the curves at higher k_{ro} or lower k_{rw} are similar with the results for variations in k_{ro} extending to larger volumes of injected water before topping out compared to the influence of k_{rw} .

Figure C12, which shows the oil saturation profiles along the core as a function of shifting the cross point in the k_{rw}/k_{ro} curves vertically, is complicated and

potentially confusing because of the wide variation in oil saturation front position as a result of varying both k_{rw} and k_{ro} in the same direction to shift the cross point in the relative permeability curves vertically. Thus, even at 0.126 PV of injected water some overlap of fronts from following sets has begun to occur. Also, a few of the profiles show some oscillatory behavior as they top out. This is probably caused by using a time step in the simulation which is too large. However, careful inspection of the figure will reveal the regular variations in oil saturation profiles and front positions as influenced by shifting both k_{rw} and k_{ro} . At a high value of the cross point (both k_{rw} and k_{ro} are high) the position of the front is strongly retarded and the profile rises steeply before tapering off to a region of gentle slope which is more pronounced as the flood progresses. At a low value of the cross point (both k_{rw} and k_{ro} are low) the position of the front is accelerated with the trailing edge of the profile rising at a gentle slope which is more pronounced as the flood progresses before rising steeply to the initial oil saturation. Figure C13 shows the corresponding cumulative oil production for the preceding case. The differentiation between the four simulations is not as pronounced and there is some ambiguity in the results though the oil production tends to peak at a higher rate as the cross point increases.

Figure C14 shows the oil saturation profiles as a function of shifting the cross point in the k_{rw}/k_{ro} curves horizontally to higher water saturation by increasing k_{ro} while decreasing k_{rw} . When the cross point occurs at lower water saturation (high k_{rw} and low k_{ro}) the oil saturation profile is less steep with a more gently sloping trailing edge and the front position is accelerated. When the cross point occurs at higher water saturation (low k_{rw} and high k_{ro}) the front profile is steeper and is retarded. These effects become more accentuated as the flood progresses. Figure C15 shows the cumulative oil production results for this series of simulations. As the cross point shifts to higher water saturation values the oil production tops out at lower volumes of injected water.

Figure C16 shows the oil saturation profiles as a function of capillary pressure at the reference k_{rw} and k_{ro} values. As capillary pressure increases the front profile becomes less steep with a more pronounced region of more gentle slope trailing the front. The position of the front is accelerated at higher capillary pressures. Figure C17 shows the cumulative oil production results as a function of capillary pressure. Increasing capillary pressure delays the topping out of the oil production curve.

DISCUSSION

These experiments have demonstrated that the BOAST simulator is sensitive to variations in relative permeability and capillary pressure. The Figures C8 - C17 provide a set of curves relating oil saturation profiles and

front positions together with cumulative oil production to variations in k_{rw} , k_{ro} , and capillary pressure which can be used as a starting point when simulations are done for a real plug. In applying this procedure to real corefloods, the core would be scanned with a suitable apparatus to determine saturation profiles and front positions as a function of injected fluid volumes. Suitable equipment might be X-ray attenuation, microwave adsorption, CT, or magnetic resonance imaging (MRI). The measured oil or water saturation profiles would be matched to the various simulation results such as those in Figs. C8 - C17 to obtain an estimate of the relative permeability values or capillary pressures. The validity of this approach could be checked against a core for which relative permeability data have been obtained using more traditional methods. This approach also provides a relatively simple procedure which could be used without requiring a highly sophisticated procedure to obtain results. These results also demonstrate in a clear manner the effects of relative permeability and capillary pressure on oil production.

CONCLUSIONS

1. BOAST simulator has been successfully modified to run simulations at plug scale, using capillary pressure as one of the input parameters.
2. The simulator output has been shown to be sensitive to variations in the relative permeability and capillary pressure input data and provide a demonstration of the effects of these parameters on oil production.
3. A set of curves relating oil saturation distributions and cumulative oil production to variations in relative permeability and capillary pressure have been obtained which can be used to estimate these parameters from oil saturation distributions obtained for real corefloods.

REFERENCES

1. Heaviside, J., in: *Interfacial Phenomena in Petroleum Recovery*, (N. R. Morrow, ed.), Marcel Dekker, Inc., New York, 1991, pp. 377 - 411.
2. Fanchi, J. R., K. J. Harpole, and S. W. Bujnowski, *BOAST: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool (Version 1.1)*. DOE Report DOE/BC 10033-3, September 1982.
3. Chang, M-M., P. Sarathi, R. J. Heemstra, A. M. Cheng, and J. E., *User's Guide and Documentation Manual for "BOAST-VHS for the PC"*. DOE Report NIPER-542, January 1992.

Fig C1 Oil and water relative permeability data as a function of water saturation used as reference data for simulations.

Fig C3 Water relative permeability data used to examine simulator oil production response as a function of varying k_{RW} at fixed reference k_{RO} .

Fig C2 Oil saturation profiles along the core obtained at listed volumes of injected water using BOAST simulator with reference relative permeability data.

Fig C4 Oil relative permeability data used to examine simulator oil production response as a function of varying k_{RO} at fixed reference k_{RW} .

Fig C5 Oil and water relative permeability data used to examine simulator oil production response as a function of shifting the cross point vertically.

Fig C7 Capillary pressure input data used to examine simulator oil production response as a function of varying capillary pressure at the reference relative permeabilities.

Fig C6 Oil and water relative permeability data used to examine simulator oil production response as a function of shifting the cross point horizontally.

Fig C8 Oil saturation profiles along the core obtained at listed volumes of injected water for the various k_{rw} input data.

Fig C9 Oil saturation profiles along the core obtained at listed volumes of injected water for the various k_{rO} input data.

Fig C11 Cumulative oil production as percent of moveable oil obtained from the simulator for the various k_{rO} input data.

Fig C10 Cumulative oil production as percent of moveable oil obtained from the simulator for the various k_{rW} input data.

Fig C12 Oil saturation profiles along the core obtained at listed volumes of injected water for the various $k_{rO} - k_{rW}$ input data with vertically shifted cross point.

Fig C13 Cumulative oil production as percent of moveable oil obtained from the simulator for the various $k_{RO} - k_{RW}$ input data.

Fig C15 Cumulative oil production as percent of moveable oil obtained from the simulator for the various $k_{RO} - k_{RW}$ input data.

Fig C14 Oil saturation profiles along the core obtained at listed volumes of injected water for the various $k_{RO} - k_{RW}$ input data with horizontally shifted cross point.

Fig C16 Oil saturation profiles along the core obtained at listed volumes of injected water for the various capillary pressure input data.

Fig C17 Cumulative oil production as percent of moveable oil obtained from the simulator for the various capillary pressure input data.

TABLE C1
Simulator input data

Input data for running the simulation using the reference k_{rw}/k_{ro} data and no capillary pressure.

W FLD/Uniform(KR3/23 CP/.1kx) 2.0inX.75inX.75in (100X1X1)

100 1 1

SO SHALE RESTART DT (SWITCH)

1 0 0 1

SAT INT(min) =0.2

W2

0.2

GGRID BLOCK LENGTH (INCH)

-1 -1 -1

0.02

0.75

0.75

GGRID BLOCK LENGTH MODIFICATION (NONE)

0 0 0 0

CCAPROCK BASE DEPTH TO TOP OF SAND

0

200

PPOROSITY AND PERMEABILITY DISTRIBUTIONS

-1 -1 -1 -1

0.26

210

200

21

PPOROSITY AND PERMEABILITY MODIFICATION (NONE)

0 0 0 0 0

TTRANSMISSIBILITY MODIFICATIONS (NONE)

0 0 0 0

170

SAT	KRO	KRW	KRG	PCOW	PCGO
0	0	0	0		
0.29	0	0	0		
0.34	0	0.0002	0		
0.4	0.12	0.001	0		
0.45	0.23	0.003	0		
0.5	0.5	0.008	0		
0.55	0.68	0.028	0		
0.6	0.82	0.048	0		
0.66	0.93	0.076	0		
0.71	1	0.076	0		
1	1.01	0.08	0		
1.1	1.01	0.08	0		
SAT	KRO	KRW	KRG	PCOW	PCGO

TABLE C1 (continued)

0	0	0	0	0	0
0.29	0	0	0	0	0
0.34	0	0.0002	0	0	0
0.4	0.12	0.001	0	0	0
0.45	0.23	0.003	0	0	0
0.5	0.5	0.008	0	0	0
0.55	0.68	0.028	0	0	0
0.6	0.82	0.048	0	0	0
0.66	0.93	0.076	0	0	0
0.71	1	0.076	0	0	0
1	1.01	0.08	0	0	0
1.1	1.01	0.08	0	0	0
PBO	MUSLOPE	BSLOPE	RSLOPE	PMAX	IREPRS
0.1	0.	0.	6000	0	
P	MUO	BO	RSO (OIL)		
0	23	1	0		
5	23	1	0		
10	23	1	0		
6000	23	1	0		
P	MUW	BW	RSW (WATER)		
0	1	1	0		
5	1	1	0		
10	1	1	0		
6000	1	1	0		
P	MUG	BG	CR		
0	0.01	0.0001	0.000003		
5	0.01	0.0001	0.000003		
10	0.01	0.0001	0.000003		
6000	0.01	0.0001	0.000003		
RHOSCO RHOSCW RHOSCG					
52.17 62.55 0.001					
EEQUILIBRIUM PRESSURE INITIALIZATION/CONSTANT SATURATION					
0 0					
3 0 10 0					
0.7					
0.3					
0					
KSM1 KCO1 KTR KCOF KSN1					
0 0 0 0 0					
NNMAX FACT1 FACT2 TMAX WORMAX GORMAX PAMIN PAMAX					
22000 1.2 0.5 1000 100000 100000 0. 50					
KKSOL MITR OMEGA TOL TOL1 DSMAX DPMAX					
2 3000 1.7 .01 0. .05 0.5					
RRECURRENT DATA					
1 1 1 1 1 0 0 0 0					
.01 .001 0.1					
RRATES --					
0 2 0					
IINJ					
1 2 0. -0.0922 0. 0. 2					
1 1 1 0.3448 0					
.01 .001 0.1					

TABLE C1 (continued)

PPROD

```

1 1 0. 0. 0. 0.0922 2
 100 1 1 0.3448 0
0 100 0 0 0 0 0 0
.01 .001 0.1
0 1 0 1 0 0 0 0
.01 .001 0.1
0 100 0 0 0 0 0 0
.01 .001 0.1
0 1 0 1 0 0 0 0
.01 .001 0.1
0 100 0 0 0 0 0 0
.01 .001 0.1
0 1 0 1 0 0 0 0
.01 .001 0.1
0 100 0 0 0 0 0 0
.01 .001 0.1
0 1 0 1 0 0 0 0
0 100 0 0 0 0 0 0
.01 .001 0.1
0 1 0 1 0 0 0 0
.01 .001 0.1

```

**DATE
FILMED**

6 / 9 / 94

END