Relative Permeability Measurements in Carbonate Rock

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ABSTRACT

This paper presents an investigation of relative permeability test procedures for carbonate cores. The work was part of an extensive reservoir characterization study for a carbonate reservoir, the Southwest Andrews Field, in Andrews County, Texas. The paper initially describes the geological setting and the coring program. Difficulties experienced during the relative permeability test program redirected the laboratory efforts to focus on eliminating a persistent core-damage problem. The relative permeability procedures investigated here include: unsteady state and steady state (x-ray CT) testing, crude and refined oils, synthetic formation brine versus a non-scaling brine, and a mild flushing of a core before testing. Relative permeabilities for cores that sustained damage were found to be characterized by water relative permeabilities that displayed a strongly decreasing slope with increasing water saturation. Numerical simulations verified the influence of core damage on the fluid flow characteristics of the rock. Based on the test results, recommendations are made to minimize damage during testing, namely, mild miscible flushing and the use of non-scaling brine.

INTRODUCTION

This work was part of a cooperative project to fully characterize the Southwest Andrews Field, a carbonate reservoir located on the eastern side of the Central Basin Platform in Andrews County, Texas.[1, 2] The field was put on production in the early 1950's and is in the late stage of primary recovery. Three new wells were drilled in separate areas of the field to provide fresh core material for geologic and engineering studies (Wells V-7, X-1 and AD-3). The specific objective of the work reported here was to characterize relative permeabilities for numerical simulations.

The initial scope of this worked was based on unsteady state relative permeability testing with crude oil, with some additional steady state testing to ensure reliability. Once the program was underway, however, it became clear that testing would become challenged by the poor hydraulic conductivity of the cores. At the end of the laboratory program, only 1 of 4 plugs, from 18 of 46 initially selected locations, yielded samples that were successfully tested (approximately 10%). The test program evolved to include unsteady state testing using different oils (lab and crude), steady state testing, different brine formulations, and core preflushing. This paper presents and compares the relative permeabilities from the different test procedures. Based on the results, recommendations are made for procedures to be used for future relative permeability test programs.

GEOLOGICAL SETTING

The zones of interest for this study (Wolfcamp Reef and Canyon formations) occur at depths between 8600 ft to 9400 ft. The formations are Pennsylvanian and Lower Permian shelf limestones.[2, 3] The uppermost zone of interest, the Wolfcamp Reef (approximately 8600 ft to 8770 ft) is a major oil zone composed of up to 14 depositional units. The most productive units are made up of thicker packstones and fossiliferous wackestones (10-ft to 30-ft thick, 10% porosity, and 1 mD to 10 mD permeability) associated with generally deepening and transgression during the Lower Permian. The lowermost section of interest, the Canyon Zone (approximately 9100 ft to 9400 ft) is subdivided into three major intervals (Upper, Middle and Lower Canyon) with numerous depositional cycles occurring within each. Like the Wolfcamp, the Lower Canyon is dominated by thicker cycles and composed mainly of mudstones and wackestones. Lower permeabilities are found here because of moldic porosity. This zone is a primary target for secondary recovery by waterflooding. The Middle and Upper Canyon are made up of thinner depositional cycles (3-ft to 15-ft thickness) containing more abundant shales. In general, reservoir quality is a complex combination of depositional facies, diagenetic changes associated with subaerial exposure, and burial history.

WELL-SITE CORING PROGRAM

The main objective of the coring program was to obtain core material that represented the intervals of interest with as little handling alteration as possible. As core was brought to the surface, selected segments were quickly transferred from the core barrel into a capped PVC tube. Air was displaced from the tube by crude oil in preparation for transport to the testing lab. An on-site geologist confirmed sample selections and ensured that reservoir-quality rock was not overlooked.

PLUG SELECTION AND REMOVAL FROM WHOLE CORES

A total of 46 locations (from all 3 wells) were chosen for plug sites. These included 32 in the Wolfcamp Reef, 2 from the Canyon, and 12 from the Lower Canyon. This selection was made based on well logs, core gamma logs, and visual inspection of the fresh core at the well site. Although this was a moderate "high grading" of the samples, it was deemed necessary in order to ensure suitable plugs for flow testing.

A sampling protocol was established to extract 4 closely spaced plugs from each depth of interest. A total of 184 plugs were extracted from the 46 sample locations. Typically, the plugs were 5- to 6.4-cm (2- to 2-1/2 in.) long, and 3.81 cm (1-1/2 in.) in diameter. Plugs were removed from the whole core using crude oil as a drill-bit lubricant, and stored in jars completely immersed in crude oil. Prior to testing, individual plugs were frozen and shaped using liquid nitrogen. After trimming, the plugs were placed in sealed containers completely submerged in evacuated crude. CT inspection ranked individual plugs within each set by considering the distribution of heterogeneities (i.e., fluid flow barriers, fractures) and x-ray attenuation (density).

Mercury injection tests were conducted on trimmed end sections from the plugs. Results indicated that most pore throats ranged from about 0.1 to 10 microns, although some as high as 100 microns and as small as 0.001 microns were also present. Compared to the Canyon samples, most Wolfcamp samples showed a greater population of pores with diameters between 1 and 10 microns, and a greater intrusion volume. Some Wolfcamp samples, with a greater proportion of larger pore-throat sizes and possibly fractures, were not successfully tested because of high permeabilities and low pressure drops.

Several plugs from the Wolfcamp and Lower Canyon were subjected to wettability testing. The results ranged from lack of a confirmation of a strong wetting preference to either water or oil, to one sample with Amott indices to water and oil of 0.0 and 0.73, respectively. The wettability test results indicate that the rocks lack an affinity for water, and have a more dominant preference for oil.

UNSTEADY STATE TEST APPARATUS AND PROCEDURE

The main items of the unsteady state test apparatus were a core holder, two quartz pressure transducers, two computerized positive-displacement pumps (1000 ml capacity), a continuous flow oil-water separator, and 2 digital balances (for oil and water). The apparatus was monitored by computer to record pressures, temperatures, and balance readings. A test typically ran for 3 to 4 hours, with data acquired at 1-minute intervals.

Synthetic brine was prepared in accordance with an analysis of the formation water (**Table 1**). For a test using crude oil (4 cp), a fresh sample was taken from the field and stored in a sealed container under a nitrogen blanket. A working volume of oil was heated to 130° F and filtered through a 0.45-micron filter. Alternatively, if refined oil was used, the oil was selected or blended from research-grade supplies (purified and filtered) to provide a viscosity (4 cp to 20 cp) for an appropriate pressure differential.

In preparation for testing, a core plug was placed in a vertical core holder under a confining pressure of 2500 psi in an environment maintained at 130° F. The core was stabilized by pumping several pore volumes of crude oil until a constant pressure drop was obtained. After pressure stabilization, a baseline oil permeability was recorded and injection switched to brine. The water injection rate was determined by preliminary tests on a similar core and typically was in the range of 12 to 30 ml/hr. Relative permeabilities were calculated using the JBN method.[4]

After testing, a sample was removed from the coreholder and placed in a Dean-Stark apparatus to extract fluids and measure the brine volume. The extracted sample was then dried in a vacuum oven at 180° F for at least 48 hrs. After allowing the samples to cool under vacuum, air permeability was measured. Porosity was determined gravimetrically after vacuum resaturation of a core with brine. Mercury injection tests were conducted on core trimmings to determine capillary pressures and pore-throat size distribution.

CRUDE OIL VERSUS REFINED OIL TESTING

Table 2 summarizes the results from all the tests and is divided into three main sections. The upper part of the table lists the results from Well V-7, which were conducted mainly to determine if using crude or refined oil resulted in a significant difference. Plugs from both the main pay (Wolfcamp) and Lower Canyon zones were included.

Discussion of Unsteady State Crude Oil and Refined Oil Tests

Figures 1 and 2 show a comparison of the crude oil and refined oil test results for the Wolfcamp and Lower Canyon zones, respectively. The relative permeabilities are plotted using analytical models of the test data based on a Corey approach.[5] The large volume of data points from each test would otherwise make comparisons extremely cluttered. Curves are labeled using the Plug number and (CO) for crude oil; where required for clarity in later figures, (SS) designates Steady State and (USS) indicates Unsteady State.

The curves for refined oil and crude oil tests (**Figure 1)** have similar shapes, but a large spread in relative permeabilities. The decrease in slope of the water relative permeability with increasing water saturation was inconsistent with performance reports from the field. Wettability tests also indicated that these cores trended toward being oil wet, which should result in a more favorable water relative permeability than obtained here. Results from the Lower Canyon samples (**Figure 2**) are similar, but widely spaced due to differences in initial water saturations.

The refined oil tests resulted in lower initial water saturations than the crude oil tests. Closely spaced plugs (for example, Plugs 1-7 and 1-8) have initial water saturations greater than 20 saturation units apart and permeabilities differing by nearly a factor of two. Differences in initial water saturation are possibly associated with the process of exchanging crude oil in the core with refined oil. During such an exchange, the core would typically be less resistant to flow than when preflushing with crude oil. Thus greater throughput of refined oil may have resulted in the lower initial water saturations.

CT scans of the cores revealed that closely spaced samples had internal heterogeneities on a similar scale, but that the detailed distribution of features (vugs, density variation) was random. Such differences in core anatomy provide a possible reason for the range of permeabilities measured in the closely spaced plugs.

Figure 3 shows examples of differential-pressure behavior from two unsteady state tests. The curve for Plug 1-83 is typical of the higher pressure drops experienced while testing the Canyon and Lower Canyon samples, while that for Plug 1-7 is representative of the better-quality Wolfcamp rock. Differential pressure initially rises due to two-phase flow effects, and then decreases after water breakthrough.

This suite of tests indicates that relative permeabilities are generally similar in shape for unsteady state crude oil and refined oil tests. Curves may be widely shifted primarily due to individual sample characteristics. The decrease in slope of the water relative permeability with increasing water saturation, and high-pressure drops, suggest core damage. The low absolute permeabilities of these plugs, and use of synthetic formation brine, contributed to difficulty in distinguishing damaged from undamaged behavior. Preliminary simulations (by the field office) indicated that the unsteady state relative permeability data did not reasonably represent field performance. The test plan was thus revised to include steady state testing for verification.

STEADY STATE TEST APPARATUS AND PROCEDURE

The main items of equipment comprising the steady state test apparatus were an x-ray CT scanner (Delta-100), an aluminum core holder, two quartz pressure transducers, and two computerized positive-displacement pumps (1000-ml capacity). The flow apparatus was monitored by computer to record temperature and pressures (upstream and downstream).

A core sample was placed in an x-ray transparent (aluminum) core holder and subjected to a confining pressure of 2500 psi. The oil chosen was a mixture of iododecane and a refined mineral oil. The resulting mixture had a viscosity of 12 cp and a specific gravity of 0.973. The core was stabilized by first pumping through several pore volumes of the oil mixture until CT saturation analysis and pressure drop indicated that the crude oil was exchanged for test oil (at irreducible water). After pressure stabilization, oil permeability was recorded and co-injection of oil and brine was initiated. The flowing oil-to-brine ratios were typically 20:1, 7:1, 1:1, 1:7 and 1:20, followed by an extended waterflood. The injection rate was held constant and set by pressure drop, typically, in the range of 5 to 20 ml/hr.

After a test, a sample was cleaned in-place and resaturated to obtain x-ray CT calibration scans (100% oil and 100% brine). After these scans, the core was removed from the coreholder and placed in a Dean-Stark apparatus for extraction. Finally, permeability and porosity measurements were taken. The duration of a steady state test was typically 5 to 7 days, plus additional time for preparation, cleaning, and calibration scans.

STEADY STATE VERSUS UNSTEADY STATE TESTING

A suite of tests was conducted to determine if using an unsteady state (crude oil at reservoir temperature) or steady state (refined oil at 70F) procedure resulted in a significant difference on results. The core used was from the second well (Well X-1), and included plugs from both the Wolfcamp and Canyon zones (mid section of **Table 2**). Eleven unsteady-state tests were attempted, but only the 3 reported were successful tested. The most common reason for test abortion was high pressure drop.

Discussion of Steady State and Unsteady State Testing

Figures 4 and 5 present a comparison of the unsteady state and steady state test results for the Wolfcamp and Canyon zones, respectively. In **Figure 4**, the traditional procedure of using crude oil and unsteady state testing is compared against a refined oil, steady state x-ray procedure. In contrast to unsteady state testing, the steady state results (Plug 2-23) show a water relative permeability more representative of this rock. These data were further supported by reports from the field that simulations using the steady state data better represented field performance.

Figure 5, using plugs from the Canyon zone, gives further confirmation of the water relative permeability trend from the steady state procedure. The unsteady state relative permeability curves from Well X-1 are generally similar to those from Well V-7. The flattening of the water relative permeability curves with increasing water saturation remains consistent. This flattening suggests that the unsteady state test procedure causes a reduction in permeability during testing. The displacement mechanism associated with unsteady state testing is more piston-like compared to the gradual saturation changes with steady state testing. The permeability loss thus appears to result from the transport of compounds or particles causing a "check-valve" action in pore throats.

Generally, the end points of the unsteady state displacement tests span a greater water-saturation range than the steady state test results. A review of test data was conducted to further understand this result. Higher pressure drops were associated with tests of poorer quality plugs (lower porosity, permeability), regardless of test procedure. For example, the steady state test of poorer-quality Plug 2-23 had a maximum pressure differential of 318 psi, while the unsteady state test of the better-quality Plug 2-27 had a maximum pressure differential of 70 psi. Differences in unsteady-state and steady-state oil viscosities and flow rates were nearly compensatory, and thus considered not to be a major influence on the water-saturation range. Other factors possibly include differences in oil displacement mechanisms (as mentioned above) which may play a more significant role in these heterogeneous cores. Further investigation of this finding was not possible within the time frame of this work.

ADDITIONAL RELATIVE PERMABILITY TESTING

Core material from Well AD-3 (Wolfcamp zone) was used for further investigation into the test procedures. The main objective of this phase of the test program was to confirm the core damage problem and recommend a test procedure to eliminate it in future tests. The results from this suite are grouped into the lower section of **Table 2**. Baseline unsteady state tests were performed using crude oil at reservoir temperature (Plugs 3-4, 3-10 and 3-35). For comparison, Plug 3-31 was tested using the steady-state procedure, doped oil and with a non-scaling brine (**Table 1**) that was formulated without sulfate and bicarbonate compounds. Finally, several confirmation tests were conducted on a plug that became available late in the test program (Plug 3-7).

Discussion of Additional Tests

The unsteady state tests using crude oil (**Figure 6**) again resulted in water relative permeability curves that decreased in slope with increasing water saturation (Plugs 3-4, 3-10 and 3-35). The steady state relative permeability test (Plug 3-31) resulted in a water relative permeability curve again in contrast to the unsteady state test results. The overall low relative permeabilities for this sample are attributed to poor rock quality (this plug was selected from a group of alternates after exhausting the primary choices).

A final test sequence was conducted on Plug 3-7, which became available late in the test program after being subjected to capillary-pressure tests (centrifuge). Test preparations included mild miscible flushing (toluene and methanol) and reconditioning by aging. The sample was first tested using an unsteady-state procedure (crude oil), followed by a steady-state test using doped brine and crude oil. In preparation for the steady state test the core fluids were exchanged for tagged brine by centrifuging. The core was then brought back to an initial condition by flowing crude oil until reaching steady state. The results (**Figure 7**) for both tests appear undamaged and generally have similar-shaped curves. This indicates that both unsteady-state and steady-test procedures can be conducted without core damage when using flushed cores and non-scaling brine.

Flushing, and the use of non-scaling brine, reduces potential damage by compounds and particles possibly retained in an unflushed core. Although flushing may introduce some uncertainty regarding the test condition of the core, this concern may be considered secondary (with this type of rock) when compared to the influence of core damage.

OIL RECOVERY

Figure 8 shows oil recovery (%PV) as a function of initial water saturation. Oil recovery is based on oil displaced from a core during a relative permeability test (1-Sor-Swi). The plot includes data from **Table 2**, plus several additional points from tests not included in the table. Although the data are scattered (correlation coefficient of about 0.5), the plot indicates an inverse relationship between oil recovery and initial water saturation. The average oil recovery from all the tests is about 43%.

COREFLOOD SIMULATIONS

Figures 9 and **10** show history matches for the unsteady state tests of Plug 3-35 (damaged) and Plug 3-7 (flushed), respectively. To achieve these matches, the data required adjustments to the absolute permeabilities (about 30% reduction), and in the case of Plug 3-7, a marginal shift in the mid range of the oil relative permeability curve. The decrease in the absolute permeabilities may reflect some degree of damage in both cores, or possibly an inaccuracy in baseline permeability measurements. Plots of the JBN and simulated relative permeability ratio curves (krw/kro) are shown in **Figure 11** (note that for Plug 3-35 the simulation and JBN curves are coincident).

Further refinements could have achieve an improved match for Plug 3-7, but the main point of verifying the impact of procedures has been demonstrated and such additional effort was deemed unwarranted. The simulation results indicate that the measured relative permeability curves are consistent with fluid flow through the rock. The calculations were made with a commercial reservoir simulator (EXODUS).[6]

CONCLUSIONS and RECOMMENDATIONS

1. Rock from heterogeneous carbonate formations can be difficult to test. Overall, the samples successfully tested represented 10% of the initial population (184 plugs).

2. A recommendation for plug sampling is the taking of multiple, closely spaced plugs. Ranking and classification (visual and x-ray) is also recommended.

3. Unsteady state tests using either refined or crude oil resulted in generally similar-shaped relative permeability curves for unflushed samples; the water relative-permeability curves indicated core damage.

4. For samples that were not preflushed, steady state tests using refined oil resulted in reasonable relative permeabilities compared to unsteady state tests at reservoir conditions (which showed damage).

5. Relative permeabilities from flushed cores and non-scaling brine indicate that either unsteady state or steady state tests can be conducted without damage. However, lack of precise agreement between water saturation ranges remains open to further study.

6. Numerical simulations validated the relative permeability data for both damaged and undamaged cores.

7. For heterogeneous carbonate rock, mild miscible flushing and the use of non-scaling brine are recommended for unsteady state testing; non-scaling brine is also recommended as a precaution for steady state testing.

ACKNOWLEDGEMENTS

The authors thank Baker Atlas, Spirit Energy, and the Japan National Oil Corporation (JNOC) for permission to present this work. We are especially thankful to Greg Fitzgerald for overall project coordination, Dr. Art Saller for geological interpretation, and Mr. Yuji Tsumuraya (JNOC). Thomas Tan is thanked for modifications to EXODUS for coreflood simulation.

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TABLE 1 - BRINE FORMULATIONS

Synthetic Field Brine (SG =1.12, μ = 0.71 cp @ 130 °F):

COMPONENT	CONCENTRATION, g/l
NaCl	129.40
CaCl2	23.34
MgCl2.6H2O	13.21
CaSO4.2H2O	1.54
NaHCO3	0.26

Modified (Non-Scaling) Brine (SG =1.09, μ = 0.78 cp @ 130 °F):

COMPONENT	CONCENTRATION, g/l
NaCl	127.63
CaCl2.2H20	32.21
MgCl2.6H2O	13.21

Doped (X-ray Scan) Brine (SG =1.47, μ = 1.45 cp @ 70 °F):

COMPONENT	CONCENTRATION, g/l
NaCl	69
CaCl2.2H20	32.21
MgCl2.6H2O	13.21
NaI	150

TABLE 2 - SUMMARY OF RELATIVE PERMEABILITY TESTS.

						Initial Conditions		Final Conditions				
Well No.	Plug No.	Formation Name	Depth, ft	Perm. md	Por. %	Water Sat. %	Oil Perm.,md*	Oil Sat. %	krw Fract.	Water Perm., md	Oil Rec. %PV	Oil Rec. %IOIP
UNSTEADY-STATE CRUDE OIL DISPLACEMENTS (130° F):												
V-7	1- 8	Wolfcamp	8576.1	7.091	13.40	26.2	4.109	18.8	0.955	3.923	55.0	74.5
V-7	1- 29	Wolfcamp	8616.5	7.782	13.58	34.9	1.318	25.5	0.333	0.439	39.6	60.8
V-7	1- 82	L. Canyon	9338.1	0.108	8.34	73.8	0.017	6.9	0.412	0.007	19.3	73.7
UNSTEADY-STATE REFINED OIL DISPLACEMENTS (70° F):												
V-7	1-7	Wolfcamp	8576.8	4.91	13.46	4.4	3.435	41.6	0.113	0.387	54.0	56.5
V-7	1-31	Wolfcamp	8616.9	1.73	12.96	5.0	0.779	33.7	0.104	0.081	61.3	64.5
V-7	1-83	L. Canyon	9339.0	0.28	9.30	40.9	0.099	30.4	0.242	0.024	28.7	48.6
UNSTEADY-STATE CRUDE OIL DISPLACEMENTS (130° F):												
X-1	2-17	Wolfcamp	8651.4	12.38	17.19	17.0	8.416	25.3	0.270	2.274	57.7	69.5
X-1	2-22	Wolfcamp	8654.4	5.79	14.84	21.8	4.82	21.2	0.172	0.827	57.0	72.9
X-1	2-30	Canyon	9349.6	3.27	10.16	19.0	1.122	34.4	0.435	0.488	46.6	57.5
STEADY-STATE REFINED OIL (TAGGED) DISPLACEMENTS (70° F):												
X-1	2-23	Wolfcamp	8654.6	4.54	11.28	5.0	2.239	56.0	0.056	0.126	39.0	41.1
X-1	2-40	L. Canyon	9381.8	16.22	12.10	24.0	9.475	43.0	0.037	0.351	33.0	43.4
X-1	2-45	L. Canyon	9392.9	4.1	13.04	13.0	2.01	42.0	0.084	0.169	45.0	51.7
UNSTEADY-STATE CRUDE OIL DISPLACEMENTS (130° F):												
AD-3	3-4	Wolfcamp	8655'11"	33.41	16.68	23.5	22.65	38.1	0.114	2.593	38.4	50.2
AD-3	3-10	Wolfcamp	8690'10"	1.84	7.34	22.4	1.29	29.2	0.233	0.301	48.4	62.4
AD-3	3-35	Wolfcamp	8659'5"	3.91	12.94	23.9	3.71	38.7	0.105	0.391	37.4	49.2
UNSTEADY-STATE CRUDE OIL DISPLACEMENT (Aged Core, 130° F):												
AD-3	3-7	Wolfcamp	8687'6"	33.41	13.08	23.7	23.00	24.8	0.504	11.600	51.6	67.5
STEADY-STATE CRUDE OIL DISPLACEMENT (Resaturated Core - X-ray Brine, 130° F):												
AD-3	3-7	Wolfcamp	8687'6"	22.29	13.08	33.4	0.25	32.7	0.217	0.054	33.9	50.9
STEADY-STATE REFINED OIL (TAGGED) DISPLACEMENT (70° F):												
AD-3	3-31	Wolfcamp	8657'3"	0.99	15.78	17.3	0.61	17.1	0.038	0.023	65.6	79.3

* Oil permeability at irreducible water saturation; base for relative permeability calculations.

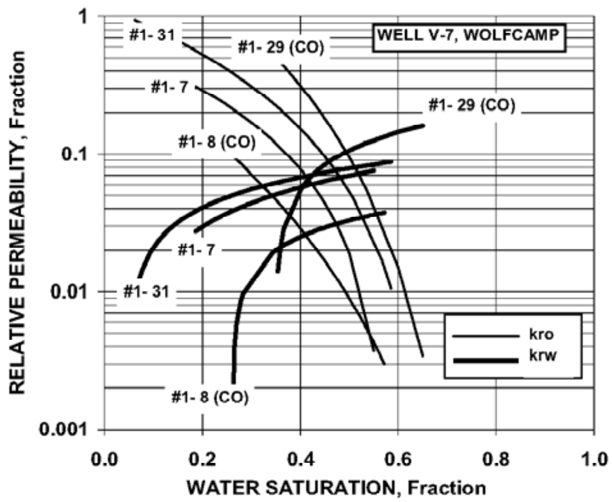

Fig. 1 - Refined and Crude Oil Tests (V-7, Wolfcamp).

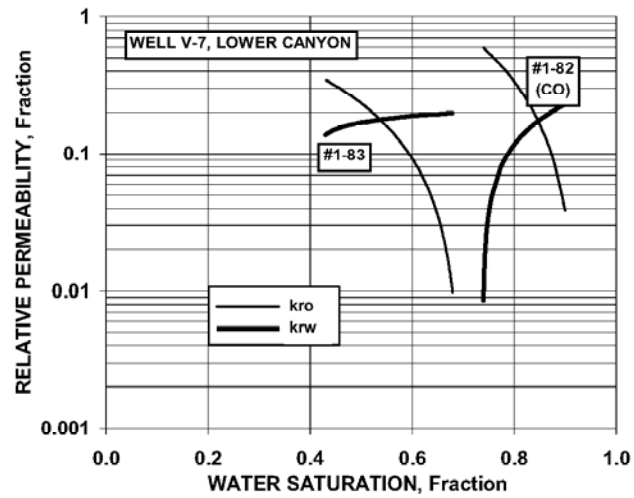

Fig. 2 - Refined and Crude Oil Tests (V-7, Lower Canyon).

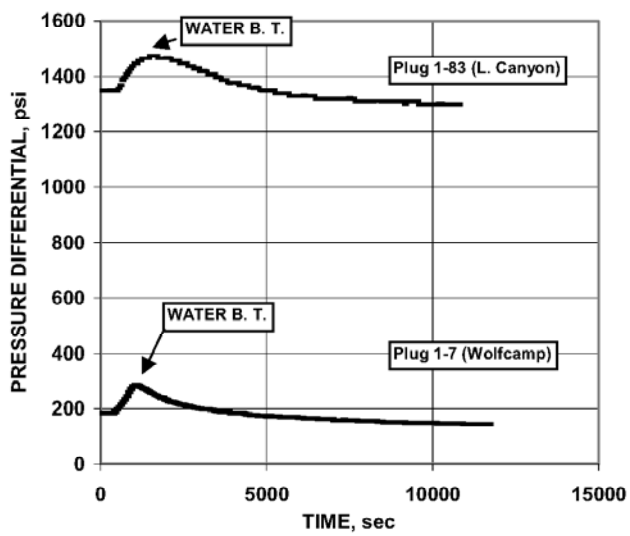

Fig. 3 - Typical Pressure Differentials.

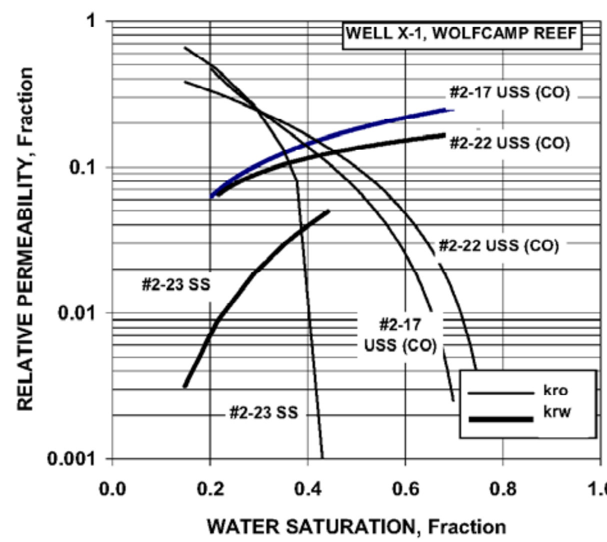

Fig. 4 - Unsteady and Steady State Tests (X-1, Wolfcamp).

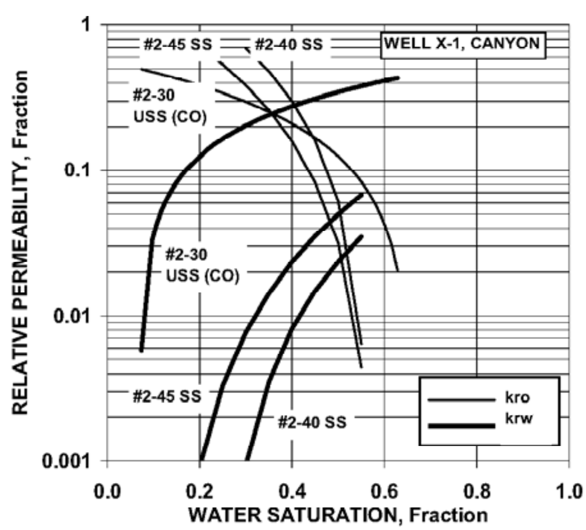

Fig. 5 - Unsteady and Steady State Tests (X-1, Canyon).

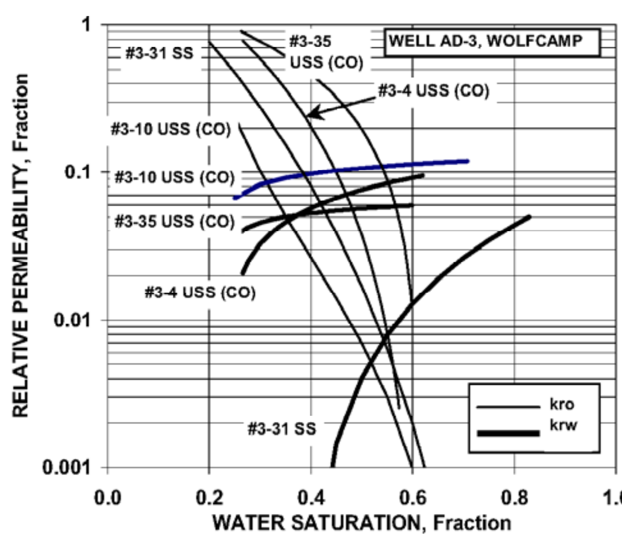

Fig. 6 - Unsteady and Steady State Tests (AD-3, Wolfcamp).

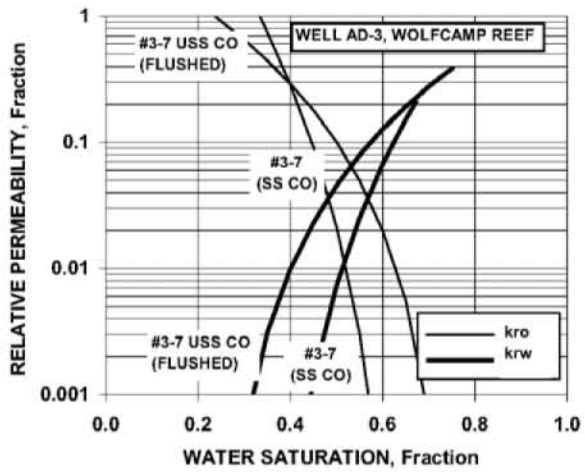

Fig. 7 - Comparison of Unsteady and Steady State Tests.

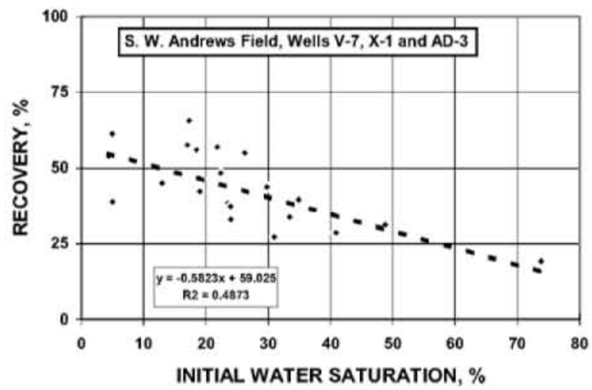

Fig. 8 - Recovery Versus Initial Water Saturation.

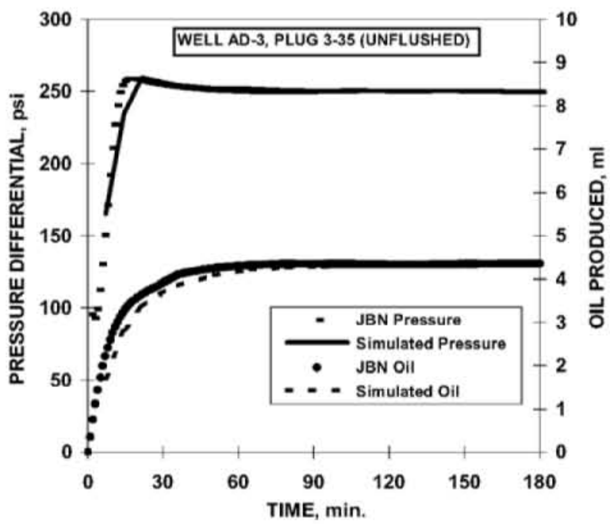

Fig. 9 - Unsteady State Test Simulation (Unflushed Plug).

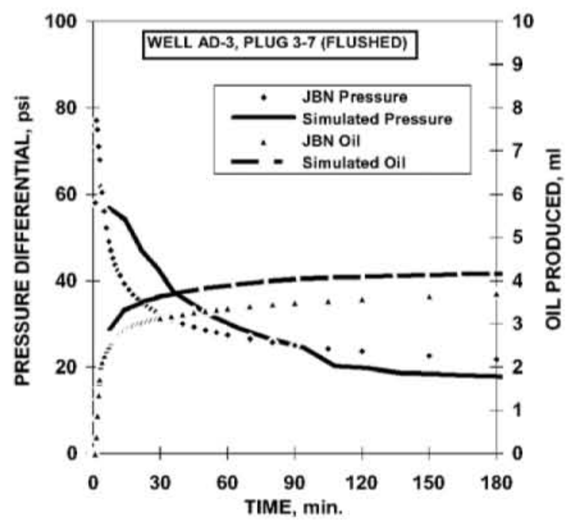

Fig. 10 - Unsteady State Test Simulation (Flushed Plug).

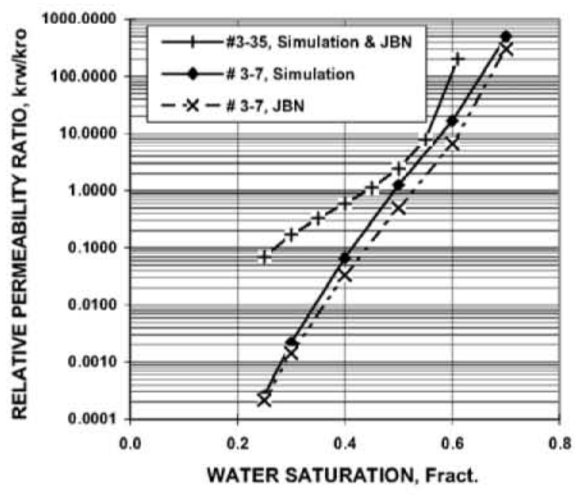

Fig. 11 - Simulated and JBN relative permeability ratios.