SCALING OF VISCOSITY RATIO FOR OIL RECOVERY BY IMBIBITION FROM MIXED-WET ROCKS.

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ABSTRACT

Displacement of oil by spontaneous imbibition from the rock matrix of fractured reservoirs can be a dominant production mechanism. Laboratory tests on reservoir cores are often used to predict oil recovery from the reservoir by scaling results to reservoir conditions. Factors involved in scaling are the rock properties, liquid viscosities, interfacial tensions, core geometry and wettability. Some previous developments in scaling were based on oil recovery from very strongly water-wet rocks (VSWW); results for different viscosity ratios were closely correlated by the geometric mean of the oil and aqueous phase viscosities.

Most reservoirs have mixed wettability (MXW), and, as judged from rate and extent of imbibition, many are weakly water-wet. Results have been obtained for mixed-wet sandstone prepared by adsorption from an asphaltic crude oil. The crude oil used to induce wettability change was displaced by decalin followed by mineral oil. The MXW states attained by this technique depended on the aging temperature, the initial water saturation, and the number of pore volumes of decalin used to displace the crude oil. For MXW cores prepared by this technique, imbibition rates were much slower than for strongly water-wet cores and were highly sensitive to initial water saturation. A series of imbibition tests were performed with initial water saturation ranging from 11.0% to 28.0%. MXW imbibition results for recovery of mineral oil, with viscosities ranging from 3.8 to 180.0 cp and initial water saturation close to 21%, were correlated satisfactorily by the geometric mean of the viscosity ratio.

INTRODUCTION

Reservoir wettability and its effect on oil recovery involve a variety of complex issues. In fractured reservoirs, displacement of oil from the rock matrix by spontaneous imbibition may be essential to economic recovery. In heterogeneous reservoirs, spontaneous imbibition into bypassed zones of low permeability may make a significant contribution to oil recovery. The view that most reservoirs are strongly water wet has changed to acceptance that adsorption from crude oil in the presence of connate water results in some form of mixed wettability (MXW). Prediction of oil recovery from laboratory measurements at mixed-wet conditions requires that results be scaled to reservoir conditions.

A large body data for oil recovery by spontaneous imbibition at very strongly water-wet (VSWW) conditions has been correlated (Ma et al., 1997) as original oil in place (OOIP) versus dimensionless time, t_D, defined by,

back to contents

$$t_D = t\sqrt{\frac{k}{f}}\frac{s}{\sqrt{m_o m_w}}\frac{1}{L_c^{\,2}} \qquad (1)$$

where t is time, k is permeability, ϕ is porosity, σ is the interfacial tension, μ_o and μ_w are the oil and brine viscosities. L_c, is a characteristic length that compensates for sample size, shape and boundary conditions (Ma et al., 1997). The correlation was initially developed mainly for VSWW conditions with zero initial water saturation. Imbibition with finite initial water saturation has also been investigated (Viksund et al., 1998).

Spontaneous imbibition measurements have been reported for MXW conditions induced by adsorption from crude oil for variation in sample size, shape, boundary conditions, and initial water saturation. For the tested MXW conditions, rate of recovery of the crude oil by imbibition decreased by several orders of magnitude relative to VSWW results. The characteristic length L_c provided satisfactory correlation of the MXW data (Xie and Morrow, 2000).

Tests of scaling oil/water viscosity ratios at MXW conditions are also needed. However, variation of viscosity ratio at fixed MXW conditions generated by adsorption from crude oil is problematic. Crude oils of different viscosities will generally have different wetting properties. There are limitations to modification of the composition of a crude oil to give variation in viscosity because of likely variation in wetting properties. The chosen approach was to induce wettability change by adsorption from an asphaltic crude oil. After exposure to crude oil, a core was flushed with a solvent that was in turn displaced by a mineral oil. This approach (Morrow et al., 1986, Graue et al., 1999) allows imbibition tests to be performed at MXW conditions prepared by a set procedure up to the introduction of mineral oil according to the required viscosity.

EXPERIMENTAL

Cores: The rock samples were cut from a batch of Berea sandstone blocks as supplied. All the core plugs were nominally 3.8 cm in diameter and 7.6 cm in length. The air permeabilities of the cores ranged from about 80 to 100 md, and the porosities were all close to 18.5% (see Tables 1 and 2).

Crude oil*:* An asphaltic crude oil of 0.9086 g/ml density, Alaska 95 (A95) from Prudhoe Bay, was used to change the wettability of the cores. The oil was degassed by vacuum treatment. The oil had 6.55 wt% of n-heptane asphaltenes and no dissolved wax (Xie, 1996). The viscosity of the evacuated oil was 70.9 cp at room temperature (22°C). The acid and base numbers were 0.24 and 2.2 respectively. This oil was selected because it was known to induce significant change in wettability and problems associated with wax deposition would not be encountered, even at ambient temperature.

Decalin: The full name is decahydronaphthalene ($C_{10}H_{18}$), with density of 0.8816 g/ml and viscosity of 2.5 cp at ambient. When decalin is used to displace the crude oil from the

aged core samples, only the bulk crude oil is removed, the polar components adsorbed on the rock surfaces which alter the wettability stay in place.

Mineral Oil: Mineral oils with different viscosities were prepared by mixing Soltrol 220 mineral oil (3.8 cp) and white mineral oil (180.0 cp) in ratios selected to give intermediate viscosities as required. The mineral oils were equilibrated with silica and alumina gel. Densities and viscosities of the two oils and their mixtures are presented in Table 1 and 2.

Brine: Synthetic reservoir brine was prepared of composition: NaCl 21.3g/L, KCl 0.10g/L, $CaCl_2$ 0.61g/L, $MgCl_2$ 0.20g/L. NaN_3 (0.10g/L) was added as a biocide. This brine density is 1.025g/l at ambient.

Establishing initial water saturation: The core samples were first saturated with reservoir brine by vacuum and allowed to soak for at least 10 days to attain ionic equilibrium. Initial water saturation, S_{wi}, higher than 19% was established by displacing reservoir brine with up to 25 PV of A95 crude oil at room temperature. S_{wi} lower than 19% was established by means of a porous plate apparatus (soil moisture ceramic plate extractor). Pressures from 15 up to 130 psi, were applied in increments of 5 psi for the lower range (less than 80 psi) and 10 psi for the higher range. The desaturation process took 1 month to reach the lowest tested water saturation of 12%. The cores were next saturated with A95 crude oil under vacuum. Full saturation of each core was checked by mass balance.

Aging*:* The cores containing initial water and crude oil were submerged in crude oil in sealed aging cells. Cores were aged at either 75°C or 95°C for 10 days.

Replacement of crude oil with mineral oil: After aging, the core was mounted in a core holder. The temperature was then raised to 60°C and the crude oil was displaced by 5 to 20 PV of decalin. The objective of the solvent flush was to remove the bulk crude oil from the core but leave the polar components adsorbed on the rock surfaces. This procedure avoids precipitation of asphaltenes and other possible effects on adsorbed components that might result from direct displacement with mineral oil. The decalin was then displaced by 5 to 20 PV of the selected mineral oil at 60°C.

Spontaneous imbibition: After displacement with mineral oil, the cores were set in glass imbibition cells filled initially with brine. All of the imbibition tests were performed at room temperature. Oil volume produced by imbibition of brine (expressed as percentage of original oil in place - %OOIP) versus time was recorded.

RESULTS AND DISCUSSION

1. *VSWW Reproducibility and representative results*

For high permeability (nominally 500 md) Berea sandstone and zero initial water saturation, close correlation of results for variation in viscosity ratio and boundary conditions was obtained by Zhang et al. (1996). This rock, which will be referred to as Berea 500, was not available for the present work. The highest permeability of available

Berea from the same quarry for the past two years was described as 200 md by the supplier but was found to be in the range of 79 to 106 md with porosities of about 18.5% (Tables 1 and 2). This rock will be referred to as Berea 90.

Recovery of 3.8 and 40.7 cp mineral oil from VSWW Berea 90 is shown in Fig.1a for seven core samples. Plots of normalized recovery versus dimensionless time are presented in Fig. 1b together with the correlation for Berea 500. The normalized recovery can be gotten through dividing oil recovery by final oil recovery. This correlation is representative of previously tested porous media with permeabilities ranging from a few millidarcies to several darcies (Viksund et al, 1998). The range of t_D covered by these rocks is indicated in Fig. 1b.

Two features of the results for Berea 90 relative to Berea 500 stand out. First, 47% recovery was typical of Berea 90 compared to about 55% for Berea 500 (Fig.3). This is consistent with previous observations; increased trapping with decrease in permeability and porosity was ascribed to increase in pore-to-throat aspect ratio with decrease in permeability and porosity (Wardlaw and Cassan, 1978, Chatzis et al., 1983). Thin-section examination showed that Berea 90 had poor connectivity. Second, dimensionless times for imbibition are longer than for previously tested rocks. (Departure from VSWW wettability is a possibility but from general experience with Berea sandstones, seems unlikely.) This may be due in part to the high residual oil and the correspondingly low relative permeability to brine, a factor that is not included in the correlation.

The plots of normalized recovery versus dimensionless time for Berea 90 are shown in Fig. 1b. A representative curve for VSWW Berea 90, Swi = 0%, was obtained by curve fitting the group with shorter overall t_D to a model of the form $R/R_\infty = 1 - e^{-at_D}$ (Aronofsky et al, 1958). R is the oil recovery at time t_D, R_∞ is the final recovery, and a = 0.014. This curve is indicated in subsequent plots as VSWW 90.

2. Wettability Alteration and Reproducibilty of MXW spontaneous imbibition:

In the course of investigating the wettability alteration procedure, the amount of decalin used to displace the crude oil was tested at 5, 10, and 20 PV for a range of initial water saturation. Examples of imbibition curves for MXW are shown in Fig. 3 for the indicated conditions of initial water saturation S_{wi}, aging temperature, T_a, PV decalin displacement, and mineral oil viscosity. The induced MXW state causes imbibition to be several orders of magnitude slower than for VSWW 90. Compared to the increase in t_D for MXW wetting, the ambiguity in definition of VSWW 90 is minor.

The increased effect on imbibition of PV decalin flush with decrease in initial water saturation is consistent with the concept of mixed wettability. As connate water saturation is decreased, the area of rock surface exposed to adsorption increases and the relative effect on wettability that results from increasing the decalin flush PV also increases (Fig. 3).

3. *Initial water saturation*

Initial water saturation has been shown to be a dominant variable in the generation of mixed wettability as shown by its effect on rate and extent of recovery of crude oil by spontaneous imbibition (Xie and Morrow, 2000). Two sets of data obtained for variation in initial water saturation with other factors held constant are shown in Fig. 4. For the set presented in Fig. 4a(i) the aging temperature was 75°C; the cores were flushed with 10 PV of decalin. Initial water saturation was varied from 19.4 to 27.3%. Scaled imbibition rate decreased systematically with decrease in initial water saturation (Fig. 4a(ii)). For the second data set, the aging temperature was 95°C; the cores were flushed with 5 PV of decalin. Seven values of initial water saturation, ranging from 11.0 to 28.0%, were tested (see Fig. 4b(i)). Again the results showed strong and systematic dependence on initial water saturation (4b(ii)). Tests of scaling of other variables such as viscosity ratio at mixed-wet conditions therefore requires that the initial water saturation, at the time the core is exposed to crude oil, be held essentially constant.

4. *Viscosity scaling*

Imbibition recovery curves are shown in Fig. 5a(i) for recovery of 3.8, 8.2, 16.0, 18.2, and 36.7 cp mineral oil with initial water saturations all close to 21.5%. The cores were flushed with 20 PV of decalin. Results for the 8.2, 16.0, and 36.7 cp oils were closely correlated. For the 3.8 cp oil, the dimensionless times were somewhat less than for the more viscous oils.

Results are shown in Fig. 5b(i) for an aging temperature of 95°C and 5 PV decalin flush. Five oil viscosities, ranging from 3.8 to 66.0 cp, were tested. The results were closely correlated by dimensionless time; there was continued slow recovery of oil with time except for the 66.0 cp oil which approached a plateau in recovery of about 13%.

A third data set was obtained for cores aged at 75°C. In these tests, the crude oil was displaced by 5 PV decalin followed by 5 PV of the mineral oil of selected viscosity. Results for mineral oil viscosities of 3.8, 18.0, 106.8, and 180.0 cp are shown in Fig. 5c(i). The scaled results gave the close correlation shown in Fig. 5c(ii).

For each data set of the present study, core preparation conditions are held the same until the introduction of mineral oil. Differences in wetting properties could arise from differences in the chemical properties of the refined oils. However ability to scale results for the tested mixed-wet conditions by the geometric mean of the viscosities, a function originally identified from VSWW studies, suggests that this is minor. The observed difference between correlated results for strongly water-wet and mixed-wet conditions can therefore be ascribed to the effect of wettability on imbibition rate.

CONCLUSIONS

1. Dimensionless times for imbibition into Berea 90 sandstone, nominally of 90 md permeability, were longer than previously observed for a wide range of porous media.

2. Aging of sandstone in crude oil followed by displacement of crude oil with decalin gave closely reproducible spontaneous imbibition, and hence wetting states, for duplicate core plugs.

3. Water wetness decreased with decrease in initial water saturation during aging and increased with the volume of decalin used to displace crude oil after aging.

4. Spontaneous imbibition at mixed wettability for recovery of mineral oil of different viscosities was correlated satisfactorily by the square root of the geometric mean of the water and oil viscosities.

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NOMENCLATURE

a - constant for Aronofsky model
A_i -open area of ith face of the sample, cm^2,
k - gas permeability, md,
L_c - characteriistic length, cm,
R - oil recovery, %OOIP
R_∞ - final oil recovery, %OOIP
S_{wi} - initial water saturation, %,
t - imbibition time, min.
t_D - dimensionless imbibition time,
ϕ- porosity, %
σ-oil-water interfacial tension, dynes/cm.
μ_w - water viscosity, cp,
μ_o - oil viscosity, cp.
T_a – aging temperature
T_m – imbibition test temperature
T_f – decalin flush temperature

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Table 1. VSWW imbibition (S_{wi} = 0%, saturated by vacuum)

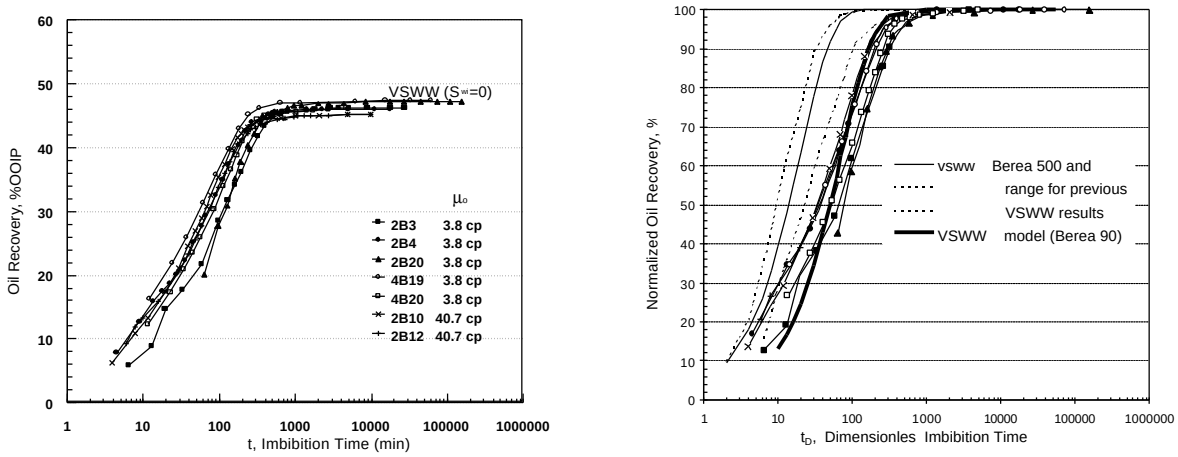
Core #	k_g, md	ϕ, %	L_c, cm	μ_o, cp*	Density* g/ml	Fig. No.
2B3	86.6	18.49	1.2707	3.8	0.7819	1a, 1b
2B4	85.2	18.44	1.2682	3.8	0.7819	1a, 1b
2B10	81.5	18.36	1.2698	40.7	0.8462	1a, 1b
2B12	81.8	18.37	1.2667	40.7		1a, 1b
2B20	84.6	18.40	1.2633	3.8	0.7819	1a, 1b
4B19	106.6	18.76	1.2606	3.8	0.7819	1a, 1b
4B20	93.0	18.67	1.2608	3.8	0.7819	1a, 1b

* measure at ambient.

Table 2. MXW imbibition

Core #	k_g, md	ϕ, %	L_c,cm	T_a, ^oC	μ, cp*	Density g/ml *	S_{wi}, %	Decalin (pv)	Fig. No.
1B13	100.4	18.51	1.2669	75	3.8	0.7819	21.8	20	2, 3, 5a
1B14	87.1	18.04	1.2665	75	3.8	0.7819	21.6	20	2, 5a
1B17	86.7	18.16	1.2652	75	36.7	0.8385	21.0	20	5a
1B18	105.2	18.57	1.2708	75	3.8	0.7819	19.4	10	4a
1B20	98.6	18.37	1.2731	75	16.0	0.8234	21.3	20	5a
1B21	106.2	18.43	1.2657	75	8.2	0.8072	21.2	20	5a
1B22	97.6	18.35	1.2741	75	3.8	0.7819	21.7	10	4a
1B24	89	18.24	1.2691	75	3.8	0.7819	24.2	10	4a
1B25	98.2	18.47	1.2662	75	3.8	0.7819	27.3	10	3, 4a
1B26	85.6	17.74	1.271	95	3.8	0.7819	11.0	5	4b
1B28	100.3	18.21	1.2663	95	3.8	0.7819	15.8	5	4b
1B29	93.1	18.46	1.2692	95	3.8	0.7819	12.5	5	4b
1B32	100.1	18.94	1.2646	95	8.4	0.8088	21.1	5	5b
1B33	91.7	18.7	1.2670	95	18.0	0.8255	21.3	5	2, 5b
1B34	98.1	18.97	1.2698	95	3.8	0.7819	24.8	5	4b
2B2	79.4	18.53	1.2619	95	39.5	0.8425	20.8	5	5b
2B9	88.1	18.55	1.2684	95	18.0	0.8255	21.3	5	2, 5b
2B14	82.2	18.48	1.2687	95	3.8	0.7819	28.0	5	4b
2B18	80.1	18.49	1.2660	95	66.0	0.8544	21.4	5	5b
2B19	80.8	18.26	1.2716	75	3.8	0.7819	21.5	5	3
2B25	89.3	18.74	1.2637	95	3.8	0.7819	19.0	5	4b
2B27	106.4	18.56	1.2646	95	3.8	0.7819	21.7	5	4b, 5b
2B28	83.9	17.85	1.2745	75	3.8	0.7819	27.0	5	3
4B5	86.6	18.11	1.2646	75	18.0	0.8255	21.7	5	5c
4B6	85.6	18.10	1.2663	75	3.8	0.7819	21.2	5	3, 5c
4B7	83.8	18.13	1.2665	75	106.8	0.8620	21.4	5	5c
4B9	101.2	18.18	1.2631	75	106.8	0.8620	21.7	5	5c
4B13	100.0	18.47	1.2609	75	180.0	0.8727	21.4	5	5c
4B16	107.4	19.17	1.2592	75	3.8	0.7819	21.3	5	5c

* measure at ambient.



1a. Recovery vs time

1b. Comparison of Berea 90 with the results from other rocks

Figure 1. VSWW imbibition for Berea 90

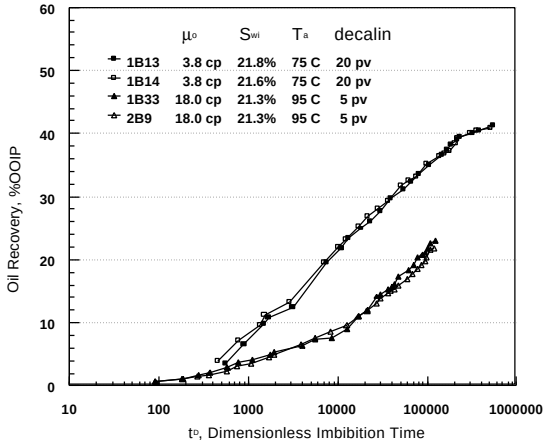


Figure 2. Reproducibility of recovery of mineral oil by spontaneous imbibition

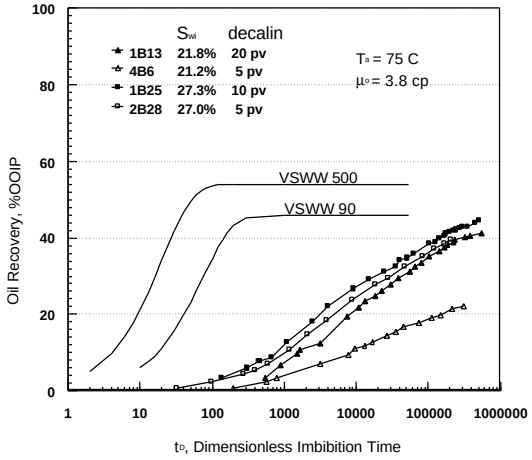
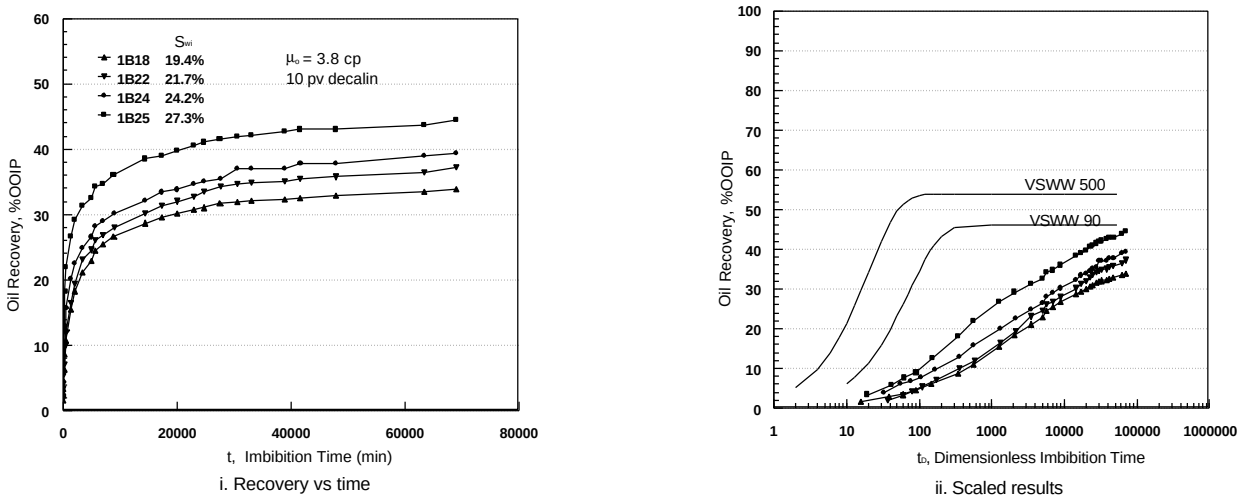
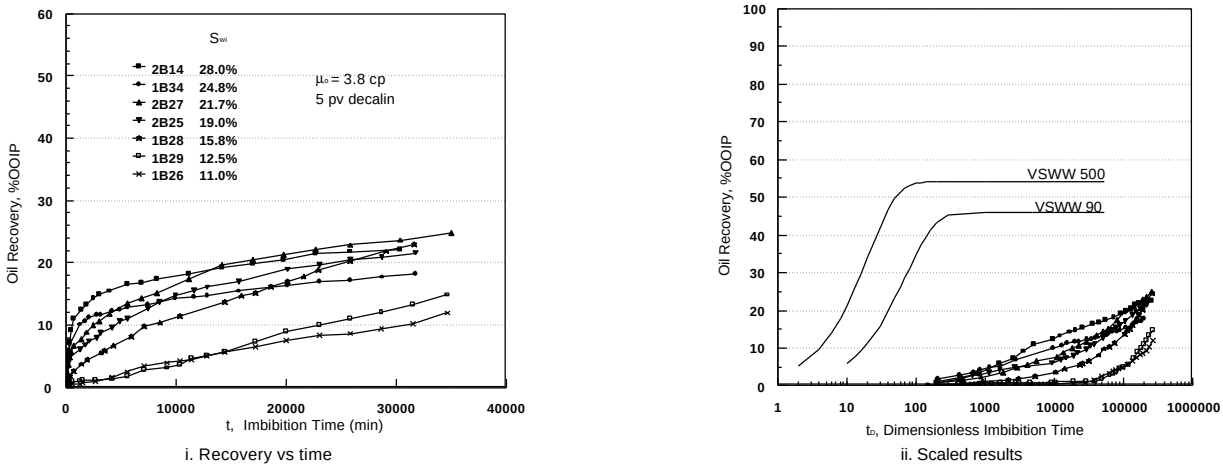


Figure 3. Sensitivity of MXW imbibition to decalin flush volume

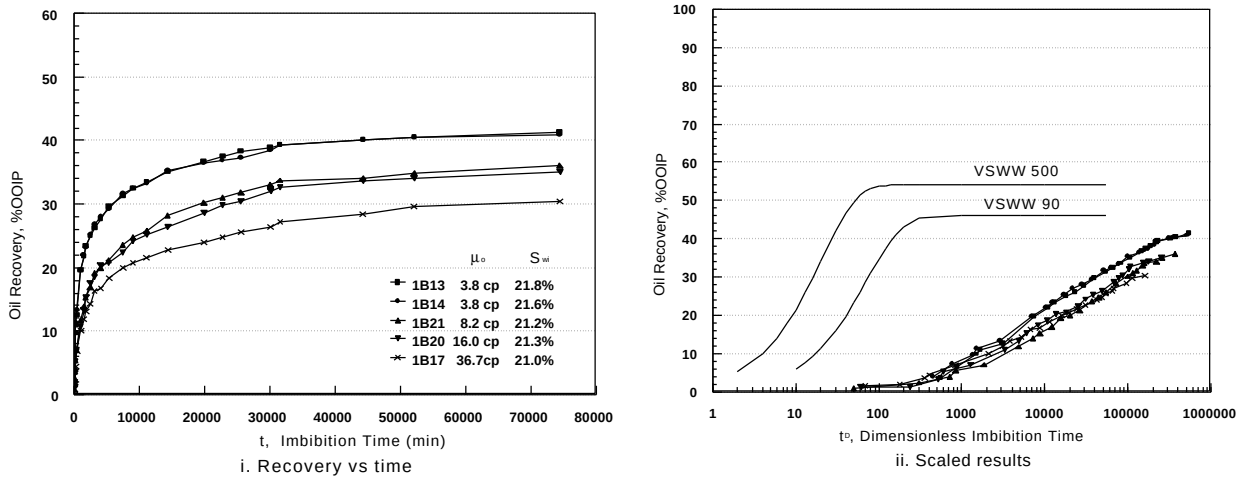


4a. Oil recovery of MXW for S_{wi} from 19.9 % to 27.3 % and $T_a = 75^oC$

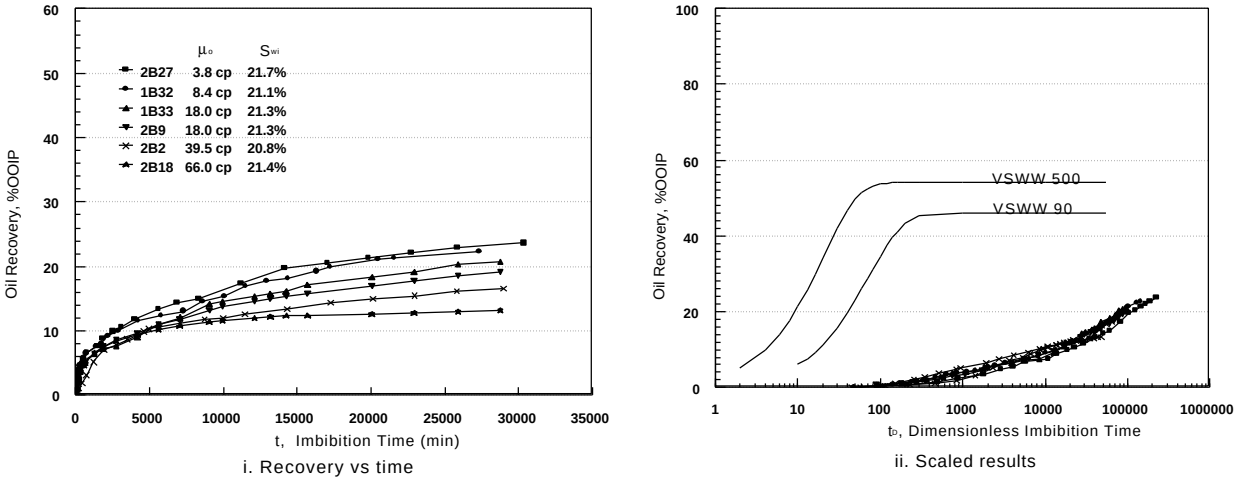


4b. Oil recovery of MXW for S_{wi} from 11.0 % to 28.0 % and $T_a = 95^oC$

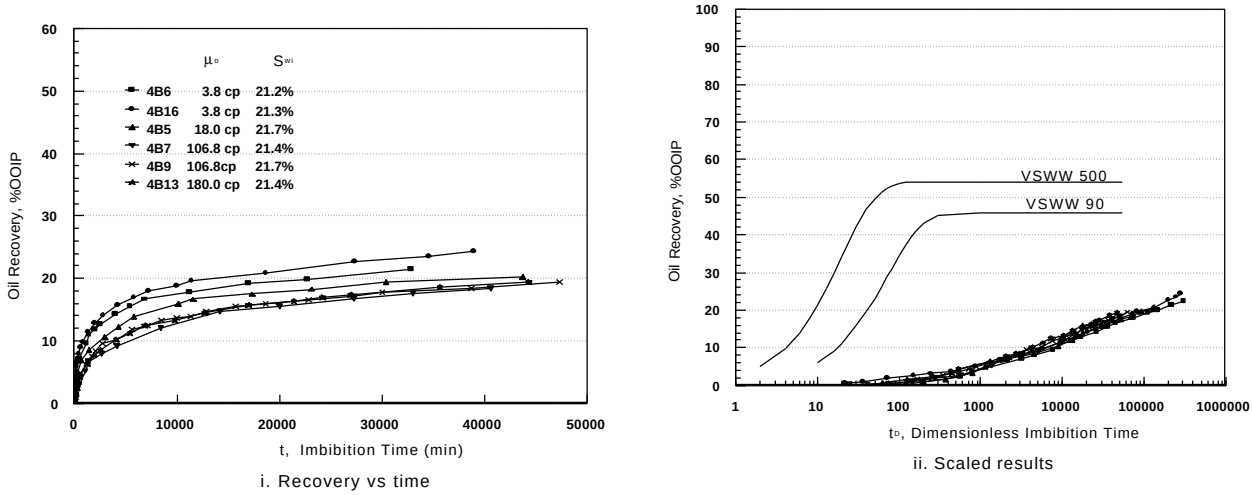
Figure 4. Effect of initial water saturation on oil recovery by spontaneous imbibition



5a. Viscosities from 3.8 cp to 36.7 cp, T_a = 75°C and 20 pv decalin



5b. Viscosities from 3.8 cp to 66 cp, T_a = 95°C and 5 pv decalin



5c. Viscosities from 3.8 cp to 180 cp, T_a = 75°C and 5 pv decalin

Figure 5. Recovery by imbibition from mixed-wet cores for different oil viscosities

back to contents