Oil & Gas Science and Technology – Rev. IFP, Vol. 59 (2004), No. 3, pp. 267-273

Oil Recovery by Dynamic Imbibition in Low Tension Aqueous Systems

A.A. Al-Quraishi[1]

1 King Abdulaziz City for Science and Technology, PAPRI, PO Box 6086, Riyadh 11442 - Saudi Arabia
e-mail: aqurishi@kacst.edu.sa

Résumé — Récupération d'huile par imbibition dynamique aux systèmes aqueux de basse tension — L'imbibition est un mécanisme très important de récupération dans les réservoirs naturellement fracturés. Plusieurs études ont été effectuées en statique pour déterminer l'effet d'une réduction de la tension interfaciale (IFT) sur la récupération de l'huile due à l'imbibition spontanée. Le but de cette recherche est d'étudier l'effet de solutions aqueuses de faible IFT sur la récupération de l'huile dans des réservoirs naturellement fracturés par imbibition dynamique, que l'on estime plus représentatif de la performance du réservoir. L'imbibition dynamique est un phénomène dans lequel la phase imbibée s'écoule en continu à travers la fracture à une vitesse inférieure à celle de l'imbibition. Ceci a été réalisé au laboratoire par l'emploi de roches de grès de Berea fracturées et réassemblées. Afin d'exclure tout effet de variation des propriétés des roches, chaque échantillon a subi deux essais d'imbibition : premièrement avec de l'eau (IFT = 23,4 mN/m) en tant que référence, puis avec une solution d'agent tensioactif de concentration prédéterminée (en l'occurrence IFT = 5,15, 1,03 et 0,013 mN/m). La comparaison de l'imbibition par l'eau et par l'agent tensioactif dans chaque roche montre que, pour les solutions de tension interfaciale intermédiaire, il n'y a pas de diminution de la vitesse de récupération de l'huile. En revanche, la récupération finale est plus faible que celle obtenue avec l'eau en tant que fluide imbibé. Lorsque la valeur de l'IFT est davantage baissée, la récupération finale de l'huile commence à augmenter pour se rapprocher de celle de l'eau. Cependant, une réduction sévère de l'IFT à 0,013 mN/m est nécessaire pour observer une augmentation appréciable de la récupération finale, avec une légère diminution de la vitesse de récupération.

Abstract* — *Oil Recovery by Dynamic Imbibition in Low Tension Aqueous Systems — *Imbibition is an important recovery mechanism in naturally fractured reservoirs. Several studies have been conducted to investigate the effect of reduced interfacial tension (IFT) on oil recovery due to static spontaneous imbibition. This study is aimed at investigating the effect of low IFT aqueous solutions on oil recovery by dynamic imbibition in naturally fractured reservoirs, which is believed to be more representative of reservoir performance. Dynamic imbibition is the process in which an imbibing phase is continuously flowing through a fracture at a rate less than the imbibition rate. This was conducted in the laboratory using artificially fractured Berea sandstone cores. To exclude any effect of core sample properties variation, each core was subjected to two imbibition runs; water first (IFT = 23.4 mN/m) as a base case then to a predetermined surfactant concentration solution (*i.e. *IFT = 5.15, 1.03 and 0.013 mN/m). Comparing water and surfactant imbibition in each core, intermediate reduction of interfacial tension solutions show no delay on oil recovery rate. On the other hand, ultimate recovery was less than that obtained with water as imbibing fluid. As IFT is lowered more, ultimate oil recovery starts to increase to approach that of water. However it required a drastic IFT reduction to 0.013 mN/m to observe a slight late time delay on recovery rate and an appreciable increase on ultimate recovery.*

NOMENCLATURE

t_D	dimensionless time
t	time
k	permeability
σ	interfacial tension
Φ	porosity
μ_W	water viscosity
L	length of porous media
$\Delta\rho$	density difference
g	acceleration of gravity
H	height of porous media
C	constant
v	velocity
A_f	fracture area
θ	contact angle
A_m	matrix area
R	grain radius
OOIP	original oil in place.

INTRODUCTION

The problem of water channeling through high permeability fractured systems promoted the idea of employing water imbibition displacement for oil recovery. Water imbibition is known by many researchers to be the most effective mechanism of oil production in water flooding of tight highly fractured formations. Water imbibition is the process by which water is imbibed due to capillary forces into the oil saturated matrix blocks from the fracture displacing the matrix resident oil into the fracture (countercurrent flow), which is then displaced by the oncoming water (viscous flow). The importance of such mechanism in oil displacement was recognized in early studies and described by Leverett and Lewis [1] in 1942.

Mattax and Kyte [2] were the first to describe the imbibition process with fixed interfacial tension (IFT). They reported that dimensionless imbibition time is a function of matrix geometry and fluid physical properties such as viscosity and IFT and it is expressed as follows:

$$t_D = t\sqrt{\frac{k}{\phi}}\,\frac{\sigma}{\mu_w L^2} \tag{1}$$

Defour [3] investigated the effect of oil density, viscosity and IFT on vertical counterflow. He indicated that classical multi-phases technique will not describe fluid distribution since the counterflow is unsteady and unstable process and accordingly he proposed a new dimensionless time function expressed as follows:

$$t_D = \frac{tk}{\mu L}\left(\Delta\rho g - 4.5\sqrt{\frac{k}{\phi}}\,\frac{\sigma}{L}\right) \tag{2}$$

In order to recover additional oil, low-tension displacement process is considered. Since the force that drives imbibition is the capillary pressure, which is directly proportional to fluids interfacial tension, imbibition presumably should not occur. However Snow [4] extended the work of Defour and concluded that countercurrent recovery rate increases with increasing IFT and decreasing viscosity while ultimate recovery increases with increasing viscosities and decreasing IFT. A similar conclusion was reached by Cuiec *et al.* [5] using different IFT values in low permeability chalks. In contrary, Keijzer and Varies [6] conducted their work on Berea sandstone and they observed no increase on ultimate recovery when lowering IFT however a delay was noticed on recovery rate. Al-Lawati and Saleh [7] conducted static imbibition tests on sandstone and limestone cores using reduced IFT solutions. They concluded that imbibition rate might increase or decrease depending on the relative contribution of capillary and gravity forces given by the inverse Bond number (N_B^{-1}) defined as follows:

$$N_B^{-1} = C\,\frac{\sigma\sqrt{\frac{\phi}{k}}}{\Delta\rho g H} \tag{3}$$

Babadagli [8] proposed and tested a modified scaling group for capillary imbibition under cocurrent and countercurrent flow conditions for surfactant and polymer solutions. He observed that gravity forces dominate in case of low IFT cocurrent imbibition, and hence modification to the gravity-scaling group for boundary conditions is required. In low IFT countercurrent imbibition, capillary and gravity scaling groups were not applicable even with the modification proposed.

All the above mentioned studies were static imbibition tests. In naturally fractured reservoirs, injected fluid flow in the fracture due to its high conductivity and at the same time exchange of fluids occurs between the fracture and the matrix in contact with the displacing phase. The two driving mechanisms controlling this process are the viscous and capillary forces. The first (viscous force) controls the flow of displacing fluid in the fracture, while the second (capillary force) controls the flow of displaced phase from the matrix into the fracture. These two forces are grouped in a dimensionless form called fracture capillary number (N_C) defined as the ratio of viscous force to capillary force and expressed as follows [9]:

$$N_C = \frac{v\mu_W A_f}{\sigma\cos\theta A_m} \tag{4}$$

Viscous force is believed to either retreat or supplement capillary force by lowering the volume of water imbibed or forcing the water to flow through the matrix respectively.

Rangel-German and Kovscek [10] investigated air expulsion by water capillary imbibition in 3-D geometry, at different injection rates and fracture aperture, using computer tomography (CT) scanner. They observed the significance of gravity force in dynamic imbibition in addition to the capillary and viscous forces. Through a balance with capillary force, gravity force sets the equilibrium distribution of displaced and displacing phases.

In a second paper Rangel-German and Kovscek [11] stated that two different fracture flow regimes exist in 3-D geometry. The first regime is *filling fracture* where relatively slow water flows through the fracture showing variable length plane source. The second regime is *instantly filled fracture* where the time to fill the fracture is much less than the imbibition time indicating a constant plane source imbibition. The first regime behaves linearly with time while the second regime, is similar to the one dimensional co-current and countercurrent imbibition reported in the literature, behaving linearly with square root of time.

This investigation is conducted to explore the effect of low IFT aqueous solutions on oil recovery by a dynamic imbibition mechanism using fractured Berea sandstone samples.

1 EXPERIMENTAL APPARATUS AND PROCEDURE

Figure 1 is a schematic of the experimental set-up designed to investigate the rate and amount of oil recovery from oil saturated cores being exposed to imbibing fluids. It is composed of a positive displacement pump to generate the required flow rates. It pumps red dyed mineral oil at a certain flow rate through a three-way valve and 3.175 mm Teflon tubing network to any of the fluid vessels. The pumped oil, in turn, displaces the required injection fluid at the same rate from the vessel to the core sample mounted into a Hassler type core holder. Backpressure was regulated at the outlet end of the core holder to control the system. The effluents are collected in a fraction collector with graduated glass tubes.

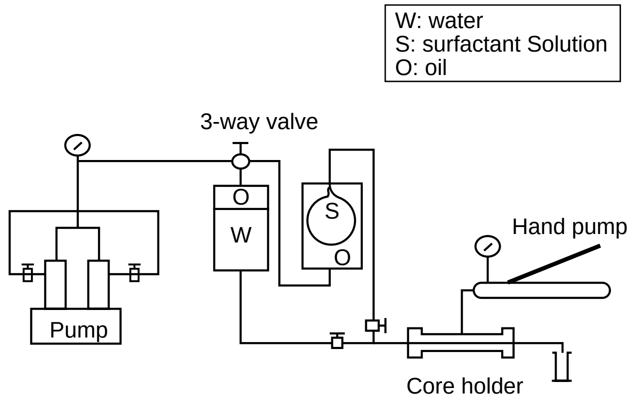

Figure 1

A scheme of the dynamic imbibition unit.

Porous medium was cylindrical Berea sandstone cores with diameter and length of 5.1 cm and 13.97 cm respectively. Oil phase was a mixture of 75% mineral oil and 25% decane while water phase was deionized water. Low tension aqueous solutions were obtained by mixing *Bio-terge* PAS-8S commercial surfactant agent with water at different predetermined concentrations. Table 1 and Table 2 list the physical rock and fluids properties.

A spinning drop tensiometer was used to measure the interfacial tension (IFT) of the oil-surfactant solutions. Figure 2 is a plot of IFT versus surfactant concentration used to determine the critical micelle concentration (CMC), which was found to be 0.75%, and hence the surfactant concentration of solutions to be used in this study.

Cores were fired gradually to 454ºC to stabilize any clay minerals and to achieve strong water wet condition. Each core was then saturated and placed in the core holder and

TABLE 1

Rocks physical properties

Core	Φ (%)	K (mD)	S_{wi}		S_{or}		N_C	N_B^{-1}
			Water flood	Surfac. flood	Water flood	Surfac. flood	$\frac{v\mu_W A_f}{\sigma \cos\theta A_m}$	$\frac{\sigma}{\Delta\rho g R^2}$ **
1	20.7	265	0.390	0.378*	0.306	0.309*	5.26E-9	14222.8
2	20.9	397	0.397	0.381	0.332	0.359	2.38E-8	2168.79
3	20.5	445	0.350	0.360	0.352	0.352	8.55E-8	502.7
4	20.7	264	0.390	0.385	0.306	0.206	9.41E-6	7.95

* Second water flood.
** Grain radius (R) is obtained using Kozeny-Carman equation.

TABLE 2

Fluids physical properties

Phase	Fluid type	Density (gm/cc)	Viscosity (cp)	IFT (mN/m) (with oil)
Water	0% surfactant	1	1	23.3
	0.03% surfactant	1	1	5.15
	0.09% surfactant	1	1	1.43
	0.60% surfactant	1	1	0.013
Oil	75% mineral oil + 25% decan	0.8	6.5	

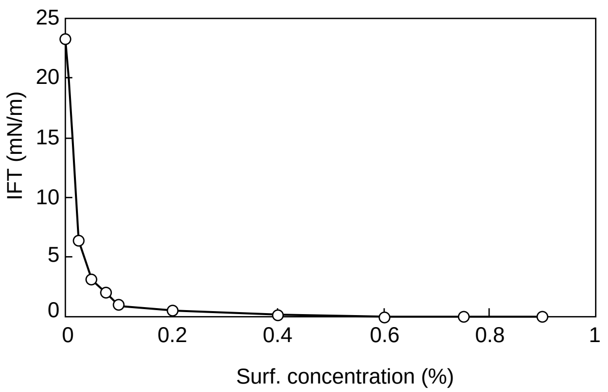

Figure 2

Interfacial tension *versus* surfactant concentration.

flooded with water to measure absolute permeability using the Darcy equation. The core was then cut along its long axis into two parts to simulate a fractured reservoir and the two parts were dried, and then weighed. The core parts were saturated again with water and the water saturated core parts were weighed again and the pore volume of the two parts was calculated. Total pore volume of the fractured core was attained by estimating the fracture volume and adding it to the pore volume of the core parts. The two parts of the core were combined together with layers of soft tissue placed in between to maintain capillary continuity and placed in the core holder and flooded with oil until water production ceases. Oil and water saturations were determined using material balance calculation. The core parts were then taken out of the core holder and the tissue layers were removed. The two parts were put together again with no spacer and placed in the core holder with the faces of the matrix blocks sealed off at both ends, orienting the fracture horizontally. Flooding started by injecting water at a constant rate of 6.25 cm^3/h, and oil recovery due to water imbibition *versus* injection time was recorded. At the end of the water flooding experiment, core parts were cleaned using toluene and dried in an oven. The core was then saturated with the oil at initial water saturation through the steps mentioned above and a predetermined concentration of surfactant solution was used to carry out the flooding process into the fracture the same way as the water flood.

2 RESULTS AND DISCUSSION

To insure the experimental repeatability and to exclude any wettability alteration due to cleaning procedure conducted between imbibition runs made in the same core sample, two consecutive water imbibition runs were conducted on core sample number 1. The two recovery curves for that sample shown on Figure 3 were identical which indicates that any variation in recovery curves in the subsequent cores is a result of the variation of the fluids IFT. Three sets of

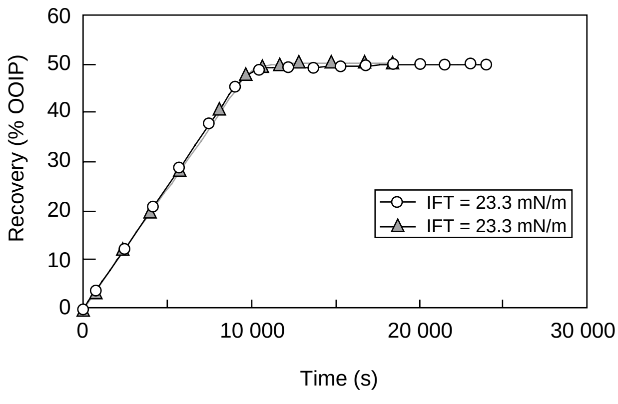

Figure 3

Repeatability of dynamic water imbibition.

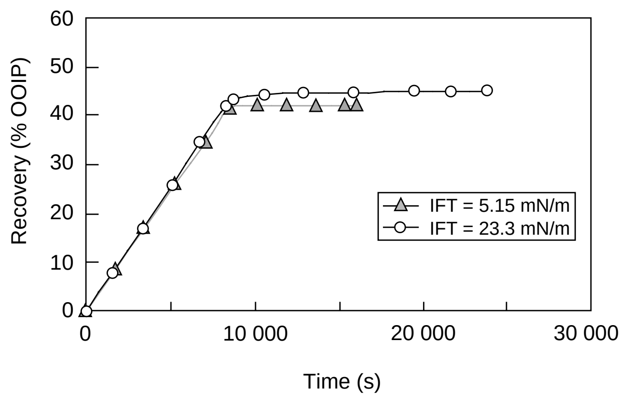

Figure 4

Recovery *versus* imbibition time for water and 0.03% surfactant solution.

experiments were conducted on three different Berea cores with four IFT values. Figure 4 is a plot of oil recovery *versus* time for core sample number 2 using water (base case) first as imbibing fluid then surfactant solution of 5.15 mN/m interfacial tension. Identical recovery rate between the two displacement experiments were noticed. However, minor decrease in ultimate recovery was observed when using surfactant solution. A new core (core sample number 3) was used to study the imbibition behavior with lower IFT solution. Figure 5 is a plot of water (base case) and surfactant solution of 1.43 mN/m interfacial tension recovery curves. Similarly no difference was noticed in recovery rate. However, less difference was noted in the two imbibing fluids ultimate recovery compared to that seen in the previous experiment with the oil recovery using the surfactant solution almost approaching that obtained when using water. Surfactant concentration was increased to prepare a much lower IFT solution (0.013 mN/m) and water and the prepared surfactant solution were flooded consequently in core sample number 4. Figure 6 is a plot of the two recovery curves. It indicates a late time delay in recovery rate and an appreciable continuing increase in the ultimate recovery when using very low IFT surfactant solution as imbibing fluid.

Water and intermediate IFT solutions used in experiments conducted on cores numbers 2 and 3 indicate a sharp breakthrough with minimum oil production afterward. This presents enough evidence that imbibition rate is either equal to or greater than the injection rate. The flow regime in these experiments is mainly filling fracture flow regime according to Rangel-German and Kovscek [11] as indicated by the trend of oil recovery scaled linearly with time. Viscous and capillary forces are the main controlling driving mechanism in the two flooding runs (water and surfactant solution) for both experiments with non effective gravity force on residual oil saturation as indicated by the high inverse Bond number *(Table 1)*. Morrow and Songkran [12] investigated the trapping of residual oil saturation in packing of equal spheres with a wide range of capillary and inverse Bond numbers. They estimated that gravity force diminish at $N_B^{-1} > 200$ and residual oil saturation is only capillary number dependant. In highly fractured reservoirs, there exist zones that are capillary dominated such as those away from injection end and others that produce oil due to viscous force nearby the injection end. In the two consequent runs conducted using water and surfactant solutions in cores numbers 2 and 3, viscous forces seem to dominate the recovery mechanism with capillary force acting at late time as indicated by the no delay in recovery rate for most of the recovery time and the little oil recovery after breakthrough. Less ultimate recovery was noticed when surfactant solution of 5.15 mN/m interfacial tension was used in the experiment conducted in core number 2. This is believed to be due to the wettability alteration from water wet to neutral wet with the usage of surfactant solution. Alveskog *et al.* [13] observed a dramatic change in wettability in a narrow range of low surfactant concentration. However, they noted an increase in recovery with increasing surfactant concentration which implies that lowering IFT more and more surpluses the negative effect of wettability alteration. This was observed as we drop the IFT to 1.43 mN/m in the experiment conducted in core number 3 with ultimate recovery increased almost approaching that of water. The increase in ultimate oil recovery compared to the second experiment is believed to be due to the rising role of gravity force and fluids relative permeability which improves the sweep efficiency of the matrix blocks.

In the experiment conducted in core sample number 4, an earlier breakthrough occurred when using 0.013 mN/m surfactant solution indicating the presence of two different

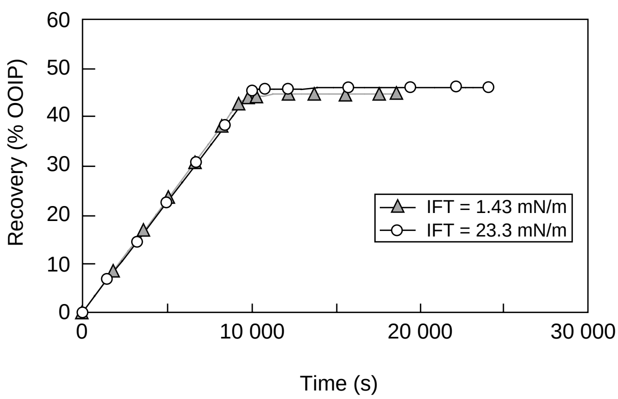

Figure 5

Recovery *versus* imbibition time for water and 0.09% surfactant solution.

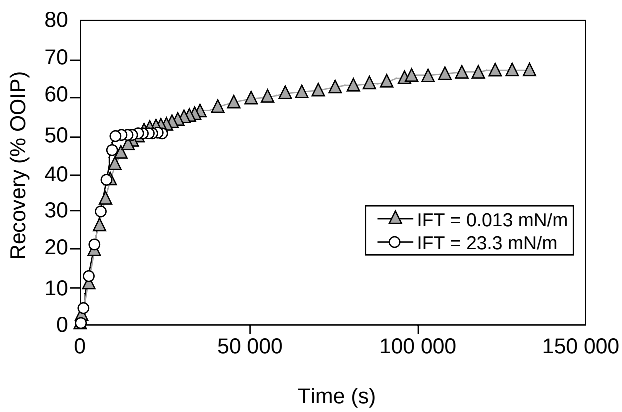

Figure 6

Recovery *versus* imbibition time for water and 0.6% surfactant solution.

fracture flow regimes. The early time *filling fracture* where relatively slow aqueous solution flows through the fracture and the late time *instantly filled fracture* where the solution is occupying the whole fracture and one dimensional co and countercurrent flow of displacing fluid is in progress with no boundary effect. The late time delay in recovery rate, when using low IFT solution, is attributed to the drastic drop in capillary forces as indicated by the increase in fracture capillary number and the need of the aqueous solution to travel longer in the fracture than water to imbibe into the matrix blocks. On the other hand, late in the process, an increase in ultimate recovery above that of water flood was seen. This is believed to be due to the substantial increase in gravity forces as indicated by low N_B^{-1} ($N_B^{-1} = 7.95$). Gravity force in this experiment supplement the drop in capillary force however the slow nature of gravity force compared to capillary force caused the delay in recovery rate. The behavior noticed is in agreement with the findings of Morrow and Songkran [12] when they indicated that even in horizontal displacement, the role of gravity forces can favourably affect recovery, and the influence of gravity in low tension displacement may well be significant. Taber [14] stated that a critical value of viscous to capillary forces is required to reduce the residual oil and it was estimated that low interfacial tension of the order of 1/100 mN/m is needed to mobilize significant quantities of residual oil. This again seems to be in agreement with the noticed substantial increase in the ultimate recovery with the drastic drop in IFT.

The dynamic nature of this work is more representative of fractured reservoir performance. Hence, it is very useful in studying the process efficiency compared to the static imbibition. The choice of low tension aqueous solutions flooding over water flooding in naturally fractured reservoirs depends mainly on whether recovery rate or ultimate recovery is the target. In high recovery factor reservoirs such as large fields, the target is to minimize the residual oil saturation in order to extend reservoir life, hence very low-tension aqueous solution seems to be a good choice as seen in the case of flooding with 0.013 mN/m IFT solution. However surfactant flooding according to this work is not feasible in low recovery factor reservoirs where increasing production rate is the target since recovery rate was either not affected when using high and intermediate IFT surfactant solutions or delayed when IFT is drastically reduced.

CONCLUSION

Based on the experiments conducted, the following conclusions are reached:

- No delay in recovery rate is noted when high to intermediate IFT solutions are used. However, a late time delay is observed with a drastic decrease of IFT.
- A major IFT drop is required in order to obtain an appreciable increase in ultimate oil recovery that exceeds that of water. However when using high to intermediate IFT solutions, recovery was less than that obtained with water due to wettability alteration.
- High concentration of surfactant solution injection seems to be a good choice in high recovery factor reservoirs in order to extend the reservoir life.

REFERENCES

1 Leverett, M.C. and Lewis, W.B. (1942) Dimensional Model Studies of Oil Field Behavior. *Trans. AIME*, 146, 175.

2 Mattax, C.C. and Kyte, J.R. (1962) Imbibition Oil Recovery from Fractured Water Drive Reservoirs. *Trans. AIME*, 225, 177.

3 Defour, M.A. (1981) The Influence of Viscosity, Gravity and Interfacial Tension on Isothermal and Non-Isothermal Vertical Oil-Water Exchange in a Porous Media. *PhD Thesis T-2428*, Colorado School of Mines.

4 Snow, S.E. (1984) A Study of the Vertical Counter-flow of Viscous Oil and Water in Porous Media. *Thesis T3003*, Colorado School of Mines.

5 Cuiec, L.E., Bourbiaux, B. and Kalaydlian, F. (1990) Imbibition in Low Permeability Porous Media: Understanding and Improvement of Oil Recovery. *SPE/DOE 2025*9, Tulsa, April.

6 Keijzer, P.M. and Varies, A.S. (1990) Imbibition of Surfactant Solutions. *Paper SPE 20222 presented at the SPE/DOE 7th symposium on Enhanced Oil Recovery*, Tulsa, Ok., 22-25 April.

7 Al-Lawati, S. and Saleh, S. (1996) Oil Recovery in Fractured Oil Reservoirs By Low Imbibition Process. *Paper SPE 36688 Presented at the SPE Annual Technical Conference and Exhibition*, Denver, Co., 6-9 October.

8 Babadagli, T. (2000) Scaling of Co-Current and Counter-Current Capillary Imbibition for Surfactant and Polymer Injection in Naturally Fractured Reservoirs. *Paper SPE 62848 Presented at the SPE/AAPG Western Regional Meeting*, Long Beach, Ca., 19-23 June.

9 Putra, E. and Fidra, Y. (1999) Study of Water Flooding Process in Naturally Fractured Reservoirs from Static and Dynamic Imbibition Experiments. *Paper SCA 9910 Presented at the International Symposium of the Society of Core Analysts*, Col., 1-4 August.

10 Rangel-German, E.R. and Kovscek, A.R. (2001) Water Infiltration in Fractured System: Experimental Analytical Model. *Paper SPE 71618 Presented at the SPE Annual Technical Conference and Exhibition*, New Orleans, 30th September-3rd October.

11 Rangel-German, E.R. and Kovscek, A.R. (2000) Matrix-Fracture Interaction in Single Matrix Blocks. *25th Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, Ca., 24-26 January.

12 Morrow, N.R. and Songkran, B. (1981) Effect of Viscous and Bouncy Forces on Non-Wetting Phase Trapping in Porous Media. *Surface Phenomena in Enhanced Oil Recovery*, Plentium Publishing Corp., 387-411.

13 Alveskog, P.L., Holt, T. and Torsaeter, O. (1998) The Effect of Surfactant Concentration on Amott Wettability Index and Residual Oil Saturation. *Journal of Petroleum Science and Engineering*, 20, 247-252.

14 Taber, J.J. (1969) Dynamic and Static Forces Required to Remove a Discontinuous Oil Phase from Porous Media Containing Both Oil and Water. *SPEJ*, **9**, 3, March.

15 Bourbiaux, B.J. and Kalaydjian, F.J. (1988) Experimental Study of Co-current and Countercurrent Flows in Natural Porous Media. *Paper SPE 18283 Presented at the SPE Annual Technical Conference and Exhibition*, Houston, Tx., 2-5 October.

16 Babadagli, T. (2001) Selection of Proper EOR Method for Efficient Matrix Recovery in Naturally Fractured Reservoirs. *Paper SPE 69564 presented at the SPE Latin American and Caribbean Petroleum Engineering Conference*, Buenos Aires, Argentina, 25-28 March.

Final manuscript received in May 2004