

Modeling Wettability Alteration by Surfactants in Naturally Fractured Reservoirs

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Summary

Laboratory surfactant and hot-water floods have shown a great potential in increasing oil recovery for reservoirs that are naturally fractured and have low-permeability, mixed-wet matrix rocks. Fractured, mixed-wet formations usually have poor waterflood performance because the injected water tends to flow in the fractures and imbibition into the matrix is not very significant. Surfactants have been used to change the wettability for increasing the oil recovery by increased imbibition of the water into the rock matrix. The mechanisms for oil recovery are combined effects of reduced interfacial tension (IFT), reduced mobility ratio, and wettability alteration. The goal of this research is to adapt an existing numerical reservoir simulator to model chemical processes leading to wettability alteration in naturally fractured reservoirs. Surfactants have been used to change the wettability, with the goal of increasing the oil recovery by increased imbibition of the water into the rock matrix. Reservoir simulation is required to scale up the process from laboratory to field conditions, as well as to understand and interpret reservoir data. A chemical-flooding simulator is adapted to model improved-oil-recovery processes involving wettability alteration using surfactants. Multiple relative permeability and capillary pressure curves corresponding to different wetting states are used to model the wettability alteration. Simulations are performed to better understand and predict enhanced oil recovery as a function of wettability alteration, and to investigate the impact of uncertainties in the fracture and matrix properties, reservoir heterogeneity, matrix diffusion, buoyancy-driven flow, initial water saturation, and formation wettability. The proposed wettability-alteration model and its implementation were successfully validated against laboratory experiments. Upscaled simulations indicated the importance of matrix properties on the rate of imbibition. The oil recovery increases with an increase in matrix permeability and a decrease in matrix initial water saturation.

Introduction

Approximately one-half of the world's oil reservoirs are carbonates, and many are naturally fractured and mixed-wet or oil-wet (Downs and Hoover 1989; Roehl and Choquette 1985). Typically, a large volume of the original oil in place in these reservoirs remains even after many decades of primary and secondary oil recovery. The fraction of oil recovered from naturally fractured carbonate reservoirs is typically even less than two-thirds—often much less. Waterflooding produces oil from these reservoirs through imbibition of water from the fractures into the rock matrix and the flow of the oil out of the matrix and through the fractures to the production wells. The capillary driving force is strong and effective when the rock is water-wet. Unfortunately, many naturally fractured reservoirs are mixed-wet or oil-wet with low rock-matrix permeability; therefore, the driving force is weak or nonexistent, and the oil recovery is very low. The oil recovery can be improved in such cases by using chemicals (Milter and Austad 1996; Austad et al. 1998; Spinler and Baldwin 2000; Chen et al.

2000; Yang and Wadleigh 2000; Hirasaki and Zhang 2004) or heat (Babadagli 1996; Snell et al. 2000; Al-Hadhrami and Blunt 2000; Tang and Kovscek 2002), as follows:

- Decrease the IFT between the oil and water.
- Change the matrix wettability from mixed- or oil-wet to water-wet.
- Increase the viscous forces.

Babadagli (2001) compared the rate of capillary imbibition for both light and heavy crude oils by chemicals (surfactant and polymer) and hot water in corefloods. The results showed that the rate of oil recovery by water imbibition was the highest for the hot-water injection. However, surfactant addition yielded greater oil recovery at a faster production rate than the brine case. Babadagli (2001) also conducted experiments to investigate the use of surfactants and hot water on heavy-oil production from fractured chalk. The results indicated a higher recovery when the combination of hot water and surfactant was used for heavy oils.

Austad et al. (1998) conducted imbibition experiments in nearly oil-wet, low-permeable (1- to 2-md) rocks with and without surfactant present. A 1 wt% cationic dodecyltrimethyl-ammonium bromide surfactant solution was used. The results indicated a sudden increase in oil recovery when surfactant was present. Laboratory experiments using the Yates-San Andreas reservoir core indicated that the injection of dilute nonionic surfactants resulted in an improved oil recovery compared to an injection of brine (Chen et al. 2000).

Hirasaki and Zhang (2004) used surfactant solutions to recover oil from dolomite cores. Their work was different from earlier work, because sodium carbonate and anionic surfactants were used to alter the wettability and reduce the IFT to very small values. Several surfactant and alkali formulations were studied. The wettability was altered because sodium carbonate changes the charge at the calcite/brine interface from positive to negative. Effects of aging, temperature, and chemical composition on wettability were investigated. They performed spontaneous-imbibition experiments in dolomite cores using several surfactant/alkali formulations. Additional oil was recovered when the imbibition was enhanced. The amount of oil recovered was a function of core-aging condition, permeability, surfactant formulation, surfactant adsorption, and initial oil saturation.

A significant research effort is being made to develop a chemical process to overcome the mechanisms of oil entrapment in oil-wet and mixed-wet fractured carbonate oil reservoirs (Hirasaki et al. 2004; Seethepalli et al. 2004; Delshad et al. 2007). The objective is to use small concentrations of an anionic surfactant with and without an alkali to reduce the IFT and alter the wettability. The laboratory results are scaled up to the field using numerical models based on the understanding of the key mechanisms.

Several scaling numbers are proposed to scale up the rate of imbibition from laboratory to field scale. Ma et al. (1995) proposed a dimensionless number for the rate of imbibition as follows:

$$t_D = t \sqrt{\frac{k}{\phi}} \frac{\sigma}{\sqrt{\mu_w \mu_o} L_c^2}, \dots \dots \dots (1)$$

where t_D is dimensionless time; t is time; k is permeability; ϕ is porosity; σ is interfacial tension; μ_w and μ_o are water and oil viscosities; and L_c is a characteristic length. However, the dimensionless number proposed by Ma et al. (1995) and others does not

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apply to the processes discussed in this paper in which the wettability and IFT are changing.

Limited huff'n'puff surfactant field treatments have been performed but with mixed results. Encouraging results were reported for the surfactant tests in the Yates field (Yang and Wadleigh 2000). The average oil production increased from 35 to 67 B/D per well. Wettability alteration and gravity segregation were reported as the oil-recovery mechanisms. A field project was performed with single-well surfactant treatment to alter the wettability in a naturally fractured carbonate rock of the Spraberry formation of the Cottonwood Creek Unit in Wyoming (Weiss et al. 2004). More than 70% of the 23 well treatments were failures, but several wells showed a marked increase in oil rate as a result of treatments. Another huff'n'puff test was done in the Maudud reservoir in Bahrain (Zubari and Babu Sivakumar 2003). The initial studies on this field showed alkaline/surfactant flooding may potentially recover at least 15 to 20% of the residual-oil saturation.

Adibhatla et al. (2005) developed a 3D simulator to model the wettability alteration—taking into account the effect of contact angle and IFT on relative permeability, capillary pressure, and residual saturations. No phase-behavior calculation was shown as a function of surfactant and salt concentrations. However, IFT was correlated with concentrations based on a fit to the laboratory IFT data. The simulator matched the imbibitions-cell data, and then it was used for scaleup studies.

Yu et al. (2008) developed a 1D mathematical model to simulate spontaneous-imbibition tests in which seawater was injected in the oil-wet chalk core plugs. The authors stated that seawater has the potential to improve oil recovery from chalk cores because of the adsorption of sulfate and some divalent cations, such as calcium and magnesium, onto the chalk surfaces to make the surface less positively charged. This mechanism contributes to the wettability alteration from oil-wet to water-wet. The wettability-alteration model proposed was based on two sets of curves for capillary pressure and relative permeability corresponding to the oil-wet and water-wet conditions. The adsorption of the wettability-alteration agent, such as sulfate, was modeled using a Langmuir-type isotherm. The wettability transition was modeled using an interpolation based on the adsorption isotherm and two sets of relative permeability and capillary pressure curves.

The time dependence and upscaling of the laboratory imbibitions-test results were addressed by Stoll et al. (2008) using a 1D model to simulate numerous imbibition experiments. Their results indicated that in the absence of buoyancy forces, the imbibition is very slow and diffusion is limited after the wettability alteration. Consequently, the wettability alteration of oil-wet fractured carbonates is not economically feasible, unless there is a faster transport mechanism, such as forced imbibition with viscous or buoyancy forces.

Although laboratory experiments are essential, it is impossible to predict the performance of these complex processes with only laboratory experiments. Reservoir simulation is required to scale up the process from laboratory to field conditions, and to understand and interpret reservoir data. Without detailed, mechanistic simulations, it is very unlikely that a cost-effective process can be developed and applied economically. The predictive simulations of such complex processes reduce the risk of failure of the field projects. A compositional chemical reservoir simulator with wettability-alteration capability was needed to model these processes. The University of Texas at Austin chemical-flooding simulator was adapted to model the improved-oil-recovery processes for this study. This paper focuses on the wettability-alteration model developed and implemented in the simulator, validation using laboratory imbibition data, and 3D simulation results in a naturally fractured oil reservoir.

Model Description

The main mechanisms for the imbibition process using surfactants are gravity, diffusion, buoyancy, IFT reduction, and emulsification, in addition to wettability alteration. An in-house chemical-flooding simulator was used to model these mechanisms. The simulator is a

3D, multicomponent, multiphase, compositional chemical-flooding simulator (Datta-Gupta et al. 1986; Delshad et al. 1996; Delshad et al. 2002). The model accounts for surfactant/brine/oil phase behavior and IFT, two- and three-phase relative permeabilities as a function of trapping number, aqueous-electrolyte chemistry, precipitation/dissolution of minerals, and reaction of acidic components of crude oil with the alkali to generate surfactant in situ. The flow and mass-transport equations are solved for any number of user-specified chemical components. Chemical flooding of naturally fractured reservoirs is modeled using either discrete fractures or the multicomponent, multiphase dual-porosity model (Aldejain 1989). The mass-balance equation for each component includes a Fickian dispersive flux with a full-tensor dispersion term, including the molecular diffusion (Bear 1979; Delshad et al. 1996).

The simulator has been used to model surfactant/polymer (Saad and Sepehrnoori 1989; Anderson et al. 2006) and alkaline/surfactant/polymer processes (Delshad et al. 1999) for both laboratory experiments and field projects.

Wettability alteration is modeled with changes in relative permeability and capillary pressure. A brief description of the model is given herein. Relative permeabilities are calculated with an exponential function described in subsequent text. The relative permeabilities are assumed to be unique functions of their respective saturations only. The latter assumption is supported by experimental data measured for a mixture of surfactant/oil/brine in a Berea-sandstone core (Delshad et al. 1987; Delshad 1990):

$$k_{r\ell} = k_{r\ell}^o \bar{S}_{\ell}^{n_{\ell}} \quad \ell = 1, 2, 3, \dots \quad (2)$$

where ℓ is either water, oil, or microemulsion phases; $k_{r\ell}^o$ is the relative permeability endpoint for phase ℓ ; n_{ℓ} is the relative permeability exponent of phase ℓ ; and \bar{S}_{ℓ} is the normalized saturation of phase ℓ calculated as follows:

$$\bar{S}_{\ell} = \frac{S_{\ell} - S_{\ell r}}{1 - \sum_{\ell=1}^3 S_{\ell r}} \quad \ell = 1, 2, 3, \dots \quad (3)$$

where S_{ℓ} is the saturation of phase ℓ ; and $S_{\ell r}$ is the residual saturation of phase ℓ . As mentioned previously, in addition to the wettability-alteration effect, surfactants also reduce the IFT between oil and aqueous phases and help in the oil mobilization. This effect is modeled by means of a dimensionless number called a trapping number, which is a combination of a capillary number and bond number and can adequately model the combined effect of viscous, capillary, and buoyancy forces in 3D (Delshad 1990; Jin 1995; Delshad et al. 1996). As the surfactant enters a grid-block, it reduces the IFT and, as a result, the trapping number increases. The IFT reduction and oil-mobilization effect of surfactants affects the residual-phase saturations, endpoint relative permeabilities, and exponents. The mobilization effect on residual-phase saturations is modeled (Delshad et al. 1986) as follows:

$$S_{\ell r} = \min \left[S_{\ell} \left(S_{\ell}^{\text{high}} + \frac{S_{\ell r}^{\text{low}} - S_{\ell r}^{\text{high}}}{1 + T_{\ell} N_{T\ell}} \right) \right] \quad \ell = 1, 2, 3, \dots \quad (4)$$

where $S_{\ell r}^{\text{high}}$ and $S_{\ell r}^{\text{low}}$ are residual saturations of phase ℓ at high and low trapping numbers, respectively (given as input parameters); T_{ℓ} is a positive input parameter of phase ℓ ; and $N_{T\ell}$ is the trapping number of phase ℓ . $S_{\ell r}^{\text{high}}$ is typically zero. This correlation was derived on the basis of the experimental data for oil/brine/surfactant solutions (Delshad et al. 1986; Delshad 1990). The trapping number for phase ℓ displaced by phase ℓ' is obtained by a force balance on the displaced blob of phase ℓ and is defined as follows (Jin 1995):

$$N_{T\ell} = \frac{\left| -\vec{k} \cdot \nabla \Phi_{\ell'} - \vec{k} \cdot [g(\rho_{\ell'} - \rho_{\ell}) \cdot \nabla h] \right|}{\sigma_{\ell\ell'}}, \dots \quad (5)$$

where ℓ and ℓ' are the displaced and displacing fluids, respectively; Φ is the flow potential; g is the gravitational acceleration; k is the permeability tensor; h is the height to a reference datum; ρ_ℓ and $\rho_{\ell'}$ are densities of the displaced and displacing fluids, respectively; and σ is the IFT.

The endpoint relative permeability enhancements caused by residual-saturation reduction of the conjugate phase as a function of the trapping number are modeled with the following correlation validated against experimental data (Delshad et al. 1986):

$$k_{r\ell}^o = k_{r\ell}^{\text{low}} + \frac{S_{\ell r}^{\text{low}} - S_{\ell r}}{S_{\ell r}^{\text{low}} - S_{\ell r}^{\text{high}}} (k_{r\ell}^{\text{high}} - k_{r\ell}^{\text{low}}) \quad \ell = 1, 2, 3, \dots \quad (6)$$

where $S_{\ell r}$ is the residual saturation of the conjugate phase (e.g., oil), and $k_{r\ell}^{\text{low}}$ and $k_{r\ell}^{\text{high}}$ represent the endpoint relative permeability of phase ℓ (i.e., surfactant-rich microemulsion phase) at low- and high-trapping numbers, respectively. A similar correlation is developed for the relative-permeability exponents. Eq. 7 gives the relative-permeability exponents as a function of the trapping number (Delshad et al. 1986).

$$n_\ell = n_\ell^{\text{low}} + \frac{S_{\ell r}^{\text{low}} - S_{\ell r}}{S_{\ell r}^{\text{low}} - S_{\ell r}^{\text{high}}} (n_\ell^{\text{high}} - n_\ell^{\text{low}}) \quad \ell = 1, 2, 3, \dots \quad (7)$$

where n_ℓ^{low} and n_ℓ^{high} represent the relative permeability exponents for low- and high-trapping numbers, respectively, specified as input parameters.

Eqs. 2 through 7 are solved once for the initial reservoir-wettability condition ($k_{r\ell}^{\text{initial}}$) and once for the altered condition of strongly water-wet ($k_{r\ell}^{\text{final}}$). Two sets of relative permeabilities ($k_{r\ell}^o, S_{\ell r}, n_\ell$) and trapping parameters (T_ℓ) are required as model input corresponding to each wettability state. The relative permeability in each gridblock ($k_{r\ell}$) is then obtained by linear interpolation between the relative permeability corresponding to the two different wettability conditions, provided the concentration of surfactant in the gridblock is greater than the critical micelle concentration. Interpolation is based on a scaling factor ω .

$$k_{r\ell} = \omega k_{r\ell}^{\text{final}} + (1 - \omega) k_{r\ell}^{\text{initial}} \quad \ell = 1, 2, 3, \dots \quad (8)$$

represent the relative permeabilities corresponding to the two extreme wetting states (i.e., final and initial wettability states, respectively). The scaling factor is either a constant-user input or related to the adsorbed-surfactant concentration in each gridblock as follows:

$$\omega = \frac{\hat{C}_{\text{surf}}}{\hat{C}_{\text{surf}} + C_{\text{surf}}}, \dots \quad (9)$$

where \hat{C}_{surf} and C_{surf} represent the adsorbed and total concentration of surfactant, respectively. The historical maximum of ω in each gridblock is used for the interpolation.

The capillary pressure as a function of wettability is also modeled using linear interpolation between the initial and final wetting-state capillary pressures, as follows:

$$P_C = \omega P_C^{\text{final}} + (1 - \omega) P_C^{\text{initial}} \quad (10)$$

The capillary pressure P_c is scaled with the oil/microemulsion IFT (σ_{om}) as follows:

$$P_C = P_{\text{COW}} \frac{\sigma_{\text{om}}}{\sigma_{\text{ow}}}, \dots \quad (11)$$

where

$$P_{\text{COW}} = C_{\text{pc}} (1 - \bar{S}_\ell)^{E_{\text{pc}}}, \dots \quad (12)$$

where C_{pc} also takes into account the effect of permeability and porosity using the Leverett J-function.

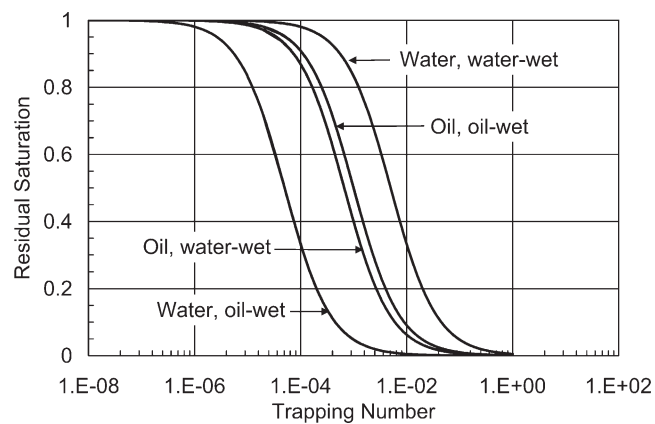


Fig. 1—CDCs used in simulations.

Examples of wettability effects on oil/water relative permeability and oil capillary-desaturation curve (CDC) in Berea sandstone are those measured by Mohanty (1983) and Morrow et al. (1973). The effect of wettability on the oil CDC in a carbonate rock has been reported by Kamath et al. (2001).

CDCs, relative permeability endpoints, and exponents as a function of trapping number for different wetting conditions of water-wet and mixed-wet are given in Figs. 1 through 3, respectively. Relative permeabilities are then calculated using Eqs. 2 through 7 with a constant wettability scaling factor of 0.5. The relative permeability parameters listed in Table 1 for water-wet and mixed-wet conditions are based on the relative permeability measurements of Morrow et al. (1973). Relative permeabilities are calculated for different trapping numbers of 10^{-7} , 10^{-5} , and 10^{-3} given in Figs. 4 through 6, respectively. The capillary pressure curves calculated for water-wet and oil-wet conditions using Eq. 11 and a mixed-wet curve using the scaling factor of 0.5 in Eq. 10 are shown in Fig. 7. Table 1 gives the capillary pressure parameters.

Model Validation

To validate the wettability model and its implementation in the enhanced simulator, the laboratory alkaline/surfactant imbibition experiments reported by Hirasaki and Zhang (2004) were used. The experiments were conducted with formation brine, crude oil, and core samples of the dolomite formation from the Yates field (Yang and Wadleigh 2000). The core and fluid properties are summarized in Table 2. The core sample was oil flooded to residual-water saturation and aged for 24 hours at 80°C. Oil recovery was measured by placing the oil-saturated core into an imbibitions-test cell filled with either formation brine or alkaline/surfactant solution. The surfactant solution was a mixture of 0.025 wt%

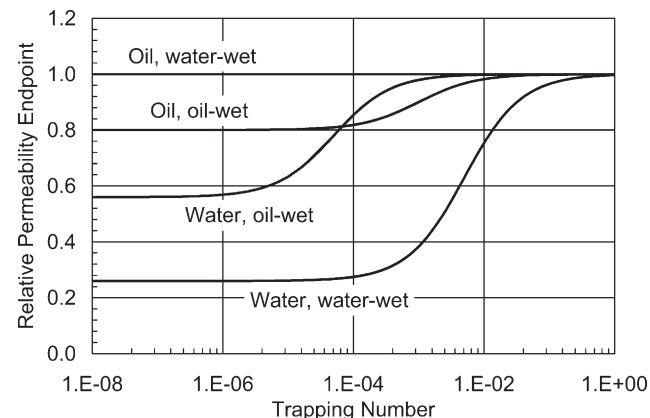


Fig. 2—Endpoint relative permeability.

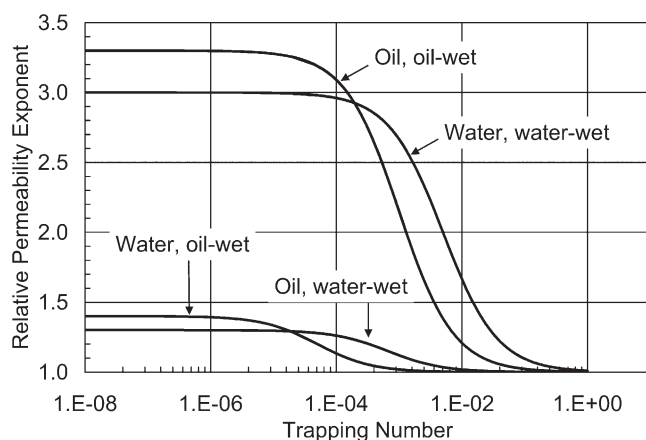


Fig. 3—Relative permeability exponent.

CS-330 (C_{12} -3EO-sulfate) and 0.025 wt% TDA-4PO-sulfate (C_{13} -4PO-sulfate) with 0.3 molar sodium carbonate added to reduce the surfactant adsorption. The alkalinity of the sodium carbonate also generated surfactants (soap) in situ by reacting with the naphthenic acids in the Yates crude oil.

The driving forces included capillary pressure and buoyancy. Spontaneous imbibition did not occur when partially oil-saturated dolomite core samples were placed into a test cell filled with brine for 1 to 2 weeks, which is another confirmation of the oil-wet nature of the core used. The formation brine was then replaced with the alkaline/surfactant solution. There was significant spontaneous imbibition when the brine was replaced by the alkaline/surfactant solution. The buoyancy-driven gravity drainage was reported to be the dominant recovery mechanism rather than countercurrent capillary imbibition. This result was supported by the appearance of oil on the top of the core rather than on the sides of the core. The initial oil saturation was 0.68. The experimental cumulative oil recovery was approximately 44% of the original oil in place (OOIP), as shown in Fig. 8. The oil was recovered in approximately 138 days.

A 3D numerical model was set up to simulate the experiment and validate the wettability model. A homogeneous Cartesian grid with $7 \times 7 \times 7$ gridblocks was set up to simulate both the rock and fluids in the cell surrounding the core. A $5 \times 5 \times 5$ portion of the middle grids was given petrophysical properties representing the rock (Table 3), and the remaining gridblocks were given properties representing the imbibition cell (i.e., porosity of 1.0, permeability of 1,000 darcies, and zero capillary pressure). A vertical cross section through the center of the model is shown in Fig. 9. The initial surfactant concentration for the imbibition simulation in which the light region (zero initial surfactant concentration) is the "rock gridblocks" and the dark gray region (0.05% initial surfactant concentration) is the "nonrock gridblocks" is also shown in Fig. 9. The porosity, permeability, and initial oil saturation are shown in Table 2, and the relative-permeability and capillary-pressure parameters of the rock gridblocks are given in Table 3. The difficulty of this simulation model results from the

fact that it does not have any wells to induce flow, convective fluxes are extremely small, and there are extreme property changes between rock and nonrock gridblocks.

An initial simulation was run to determine the oil recovery based on an assumption that the wettability is not altered from the original oil-wet conditions. This simulation models only the effect of surfactant and soap on IFT reduction and oil mobilization. Surfactant concentration in gridblocks representing the oil-wet core initially increases, primarily because of an effective molecular diffusion, and has an impact on the onset of oil being produced from the core but with very little impact on final oil recovery. An effective molecular diffusion/dispersion of 6.5×10^{-5} ft²/D was used in the simulation. On the basis of the published data of Lam and Schechter (1987), the expected surfactant molecular diffusion is several orders of magnitude smaller than was simulated. Therefore, the value presented herein can be described as a pseudodiffusion/dispersion coefficient.

Once the surfactant concentration within a gridblock exceeds the critical micelle concentration, microemulsion is formed, IFT is reduced, and capillary pressure is reduced. This process allows for slow imbibition of the surfactant solution and oil displacement. The results are given in Fig. 8, in which the maximum oil recovery is approximately 24% OOIP with at least an order of magnitude slower response time compared to the experimental results. On the basis of this result, it is clear that additional mechanisms are taking place to enhance the oil recovery.

Next, the enhanced simulator was used to model combined IFT reduction and wettability-alteration effects of surfactant/alkali solution on oil recovery. It was assumed that the altered-wettability condition was water-wet, with relative permeability and capillary pressure parameters as shown in Table 3. The interpolation-scaling factor for this simulation was assumed to be a constant value of 0.5. A fairly good comparison of the simulated and experimental oil recoveries is obtained as shown in Fig. 8. The distribution of surfactant concentration and oil saturation are given in Figs. 10 and 11, respectively after 10 days of imbibition. The result gives a much better agreement with the laboratory data than the case without wettability alteration. The simulation with wettability alteration has a faster response to oil production and a higher cumulative oil recovery. This result is because of the increase in oil relative permeability and initial change in capillary pressure from negative to positive during the wettability-alteration process. Therefore, there is more surfactant solution imbibing into the rock gridblocks and displacing more oil before the IFT reduction decreases the capillary pressure to zero.

Upscale Simulations and Results

To understand the effects of wettability on surfactant flooding of mixed-wet fractured reservoirs, several simulations were conducted with the same hypothetical reservoir model and well conditions, but differing relative permeability curves, CDCs, and capillary pressure curves to mimic different wettability conditions.

CDCs, relative permeability endpoints, and relative permeability exponents, as a function of a trapping number for different wettability conditions of water-wet and mixed-wet, are given in

TABLE 1—RELATIVE PERMEABILITY AND CAPILLARY PRESSURE PARAMETERS (LOW TRAPPING NUMBER IN MATRIX)

	Oil-Wet		Water-Wet	
	Oil	Water	Oil	Water
Residual saturation	0.28	0.12	0.25	0.12
Endpoint relative permeability	0.80	0.56	1	0.26
Relative permeability exponent	3.3	1.4	1.3	3
Trapping parameters (T_d)	1,000	20,000	1,500	200
Capillary pressure endpoint (C_{PC})	-15		7	
Capillary pressure exponent (E_{PC})	6		2	

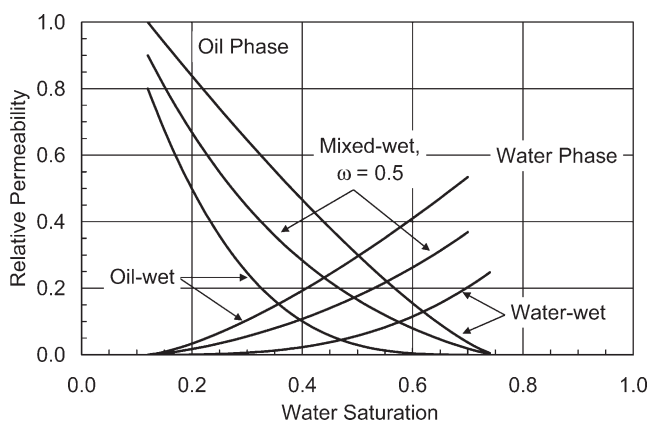


Fig. 4—Calculated relative permeability curves for different wettability conditions at low trapping number of 10^{-7} .

Figs. 1 through 3. The base relative permeability parameters given in Table 1 for water-wet and mixed-wet conditions are based on the relative permeability measurements of Morrow et al. (1973). The capillary pressure curves calculated for water-wet and oil-wet conditions are shown in Fig. 7. The capillary pressure parameters are listed in Table 1.

Several 3D simulations were performed. The simulation model is 250 ft long, 250 ft wide, and 55 ft thick (Fig. 12). Gridblocks with a permeability of 1,000 md and a porosity of 2% were used to represent the fractures between matrix blocks. Matrix blocks are 68 ft in both x and y directions with a permeability of 50 md and a porosity of 30%. Each matrix block was subgridded to 22.7-ft blocks. Initial water saturation in the matrix block was 0.4. The reservoir properties are listed in Table 4. Injection and production wells were located in fractures.

Waterflood simulations were first performed for different wettability conditions of water-wet and oil-wet. The oil recovery for these cases is compared in Fig. 13. As expected, the case with relative permeability and capillary pressure representing water-wet rock matrix gives higher recovery of 26% OOIP because of the higher rate of capillary imbibition. Surfactant-flood simulations were then performed injecting a dilute surfactant concentration of 0.1 vol%. The purpose in this paper was to model the wettability-alteration aspect of the flood rather than a conventional low-IFT-surfactant flood. Wettability-alteration simulations were run for both a constant input value of $\omega = 0.5$ and a value of ω computed from Eq. 8. The initial matrix wettability was oil-wet.

Oil-saturation distributions at 1,200 and 3,600 days are shown in Figs. 14 and 15, respectively, for wettability-alteration simulation with a constant ω of 0.5. Surfactant concentration at the end of 3,600 days is given in Fig. 16. The oil saturation is reduced in the middle matrix block in which the surfactant concentration is

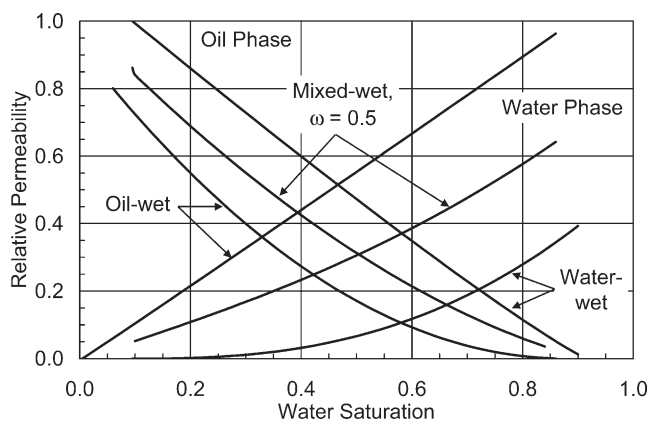


Fig. 6—Calculated relative permeabilities for different wettability conditions at a trapping number of 10^{-3} .

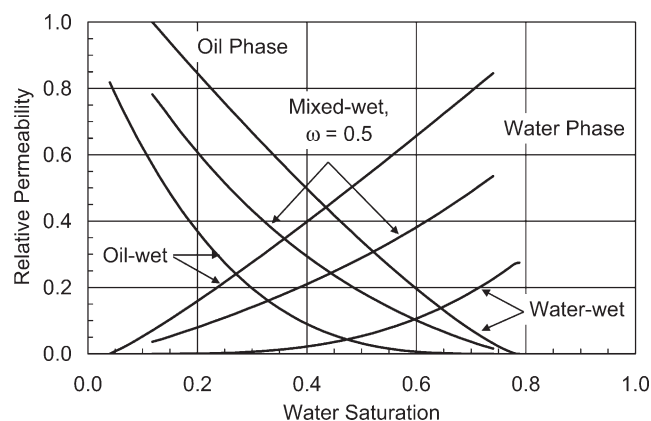


Fig. 5—Calculated relative permeability curves for different wettability conditions at a trapping number of 10^{-5} .

increased. Cumulative oil recoveries are compared for different wettability conditions in Fig. 17. The highest recovery is the case of a strongly water-wet condition with recovery of approximately 42% OOIP, which is almost twice the waterflood oil recovery. The surfactant flood of the reservoir with an oil-wet matrix was not effective because there was no surfactant imbibed into the matrix. The oil recoveries increased by a factor of two when wettability was changed to more water-wet.

The effects of matrix properties, such as initial water saturation and permeability, on oil recovery in the case with constant ω of 0.5 are shown in Figs. 18 and 19, respectively. The recovery is higher when there is less water initially in the matrix. A higher-matrix permeability gives higher-oil recovery.

Conclusions

- The effect of surfactant on the wettability alteration was modeled and implemented in a reservoir simulator by changing relative permeability, capillary pressure curves, and CDCs. The model was validated by comparison with published surfactant experiments.
- More laboratory and model validations are needed to better understand the mechanisms responsible for oil recovery under different conditions to be able to design the field trials effectively.
- The 3D simulations of dilute surfactant flooding in a naturally fractured reservoir demonstrated the significance of wettability alteration from mixed-wet to water-wet on increasing oil-production rate.
- The simulation tool developed aids in a mechanistic understanding of low-concentration surfactant flooding in fractured-carbonate reservoirs.

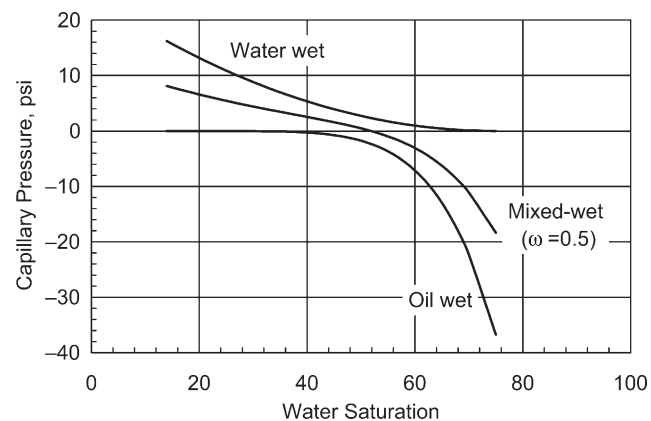


Fig. 7—Calculated capillary pressure curves for different wettability conditions.

TABLE 2—CORE PROPERTIES USED FOR IMBIBITION EXPERIMENT*

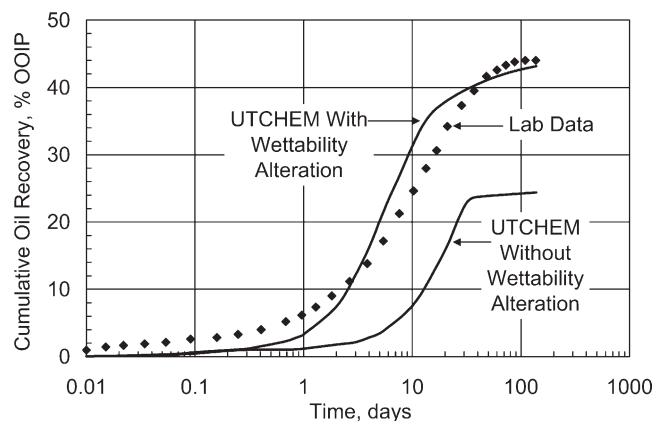
Diameter (in.)	1.5
Length (in.)	3
Porosity (%)	24
Permeability (md)	122
Brine	5.815 g/L NaCl
Crude oil viscosity (cp)	19
Initial oil saturation	0.68
Aging	80°C 24 hours
Time in brine (days)	8
Recovery in brine (% OOIP)	0
Surfactant	CS-330+TDA-4PO
Surfactant concentration (wt %)	0.025+0.025
Na ₂ CO ₃ (M)	0.3
Time in surfactant (days)	138
Recovery in surfactant (% OOIP)	44
Remaining oil saturation	0.38

* Delshad et al. (2007).

- With the wettability-alteration capability in a simulator, several enhanced-oil-recovery processes that use chemicals such as surfactants, polymer, and alkali or, in some cases, mixtures of these chemicals that recover additional oil through low IFT and wettability alteration can be simulated.
- Scaleup studies, assuming the same mechanisms as those in the imbibitions-cell experiment, indicate that the process is not economically feasible because of slow oil-recovery rates and project times on the order of several hundred years to produce the oil.
- Dynamic laboratory experiments and modeling are required to evaluate chemical floods for naturally fractured reservoirs. Imbibition-cell experiments are not representative of the field operations and lack the viscous forces that may play a critical role in the design of field applications and scaleup studies from laboratory to field scale.

Nomenclature

- D = depth, L
 C_{pc} = capillary pressure endpoint, mt^{-2}
 E_{pc} = capillary pressure exponent
 g = gravitational constant, Lt^{-2}
 \vec{k} = permeability tensor, L^2
 $k_{r\ell}$ = relative permeability of phase ℓ
 $k_{r\ell}^o$ = endpoint relative permeability of phase ℓ

**Fig. 8—Comparison of simulated and laboratory-imbibition oil recovery.**

- $k_{r\ell}^{\text{high}}$ = phase ℓ endpoint relative permeability at high trapping number
 $k_{r\ell}^{\text{low}}$ = phase ℓ endpoint relative permeability at low trapping number
 n_{ℓ}^{high} = phase ℓ relative permeability exponents at high trapping number
 n_{ℓ}^{low} = phase ℓ relative permeability exponents at low trapping number
 $N_{T\ell}$ = trapping number of phase ℓ
 P_C = capillary pressure, $\text{mL}^{-1}\text{t}^{-2}$
 P_{COW} = oil/water capillary pressure, $\text{mL}^{-1}\text{t}^{-2}$
 S_{ℓ} = saturation of phase ℓ , L^3/L^3 , pore volume
 $S_{\ell r}$ = residual saturation of phase ℓ , L^3/L^3 , pore volume
 $S_{\ell r}^{\text{high}}$ = residual saturation of phase ℓ at high trapping number, L^3/L^3 , pore volume
 $S_{\ell r}^{\text{low}}$ = residual saturation of phase ℓ at low trapping number, L^3/L^3 , pore volume
 \bar{S}_{ℓ} = Normalized saturation of phase ℓ
 T_{ℓ} = trapping parameter for phase ℓ
 $\vec{\nabla}\Phi_{\ell}$ = flow potential gradient given by $\vec{\nabla}P_{\ell} - g\rho_{\ell}\vec{\nabla}D$
 ρ_{ℓ} = density of phase ℓ , mL^{-3}
 $\sigma_{\ell\ell'}$ = IFT between phases ℓ and ℓ' , mt^2
 Φ_{ℓ} = potential of phase ℓ , $\text{mL}^{-1}\text{t}^{-2}$

Superscript

- ℓ = phase number (1: water, 2: oil, 3: microemulsion)
 r = residual

Subscript

- high = high trapping number
 low = low trapping number

TABLE 3—RELATIVE PERMEABILITY AND CAPILLARY PRESSURE PARAMETERS (IMBIBITION-CELL TEST SIMULATION)

	Oil-Wet		Water-Wet	
	Oil	Water	Oil	Water
Residual saturation	0.38	0.32	0.38	0.32
Endpoint relative permeability	0.59	0.23	1	0.15
Relative permeability exponent	3.3	2.9	2	2
T_{ℓ}	1,865	59,074	59,074	1,865
C_{PC}	−5		5	
E_{PC}	2		2	
Wettability scaling factor (ω)	0.5			

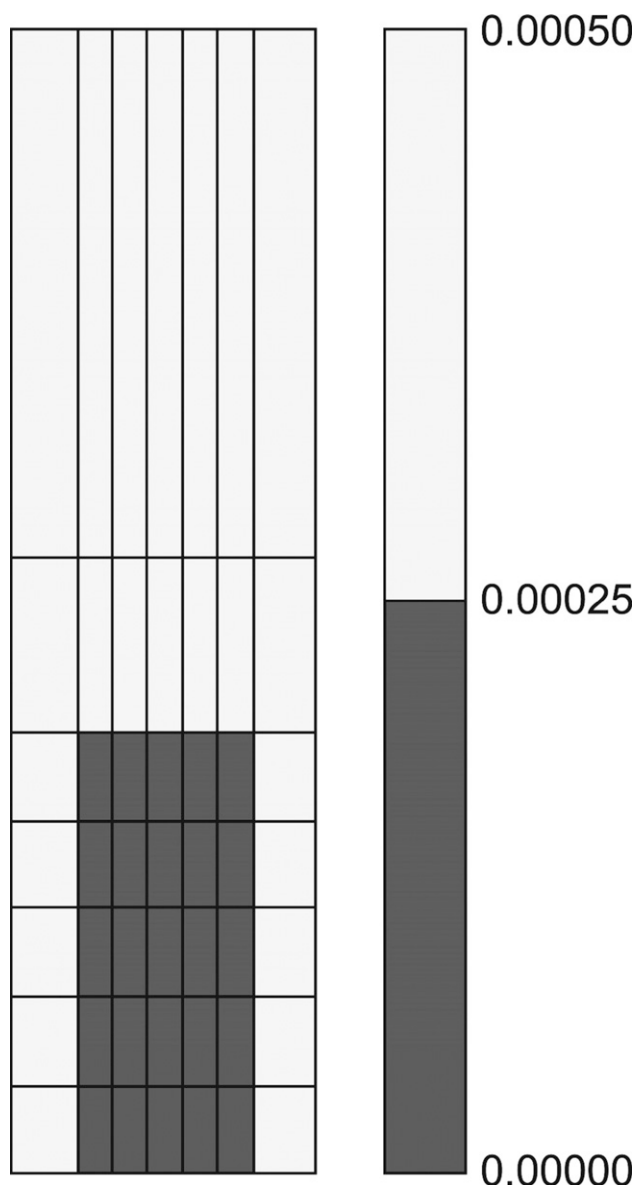


Fig. 9—Initial surfactant concentration (volume fraction) for the imbibition-test model.

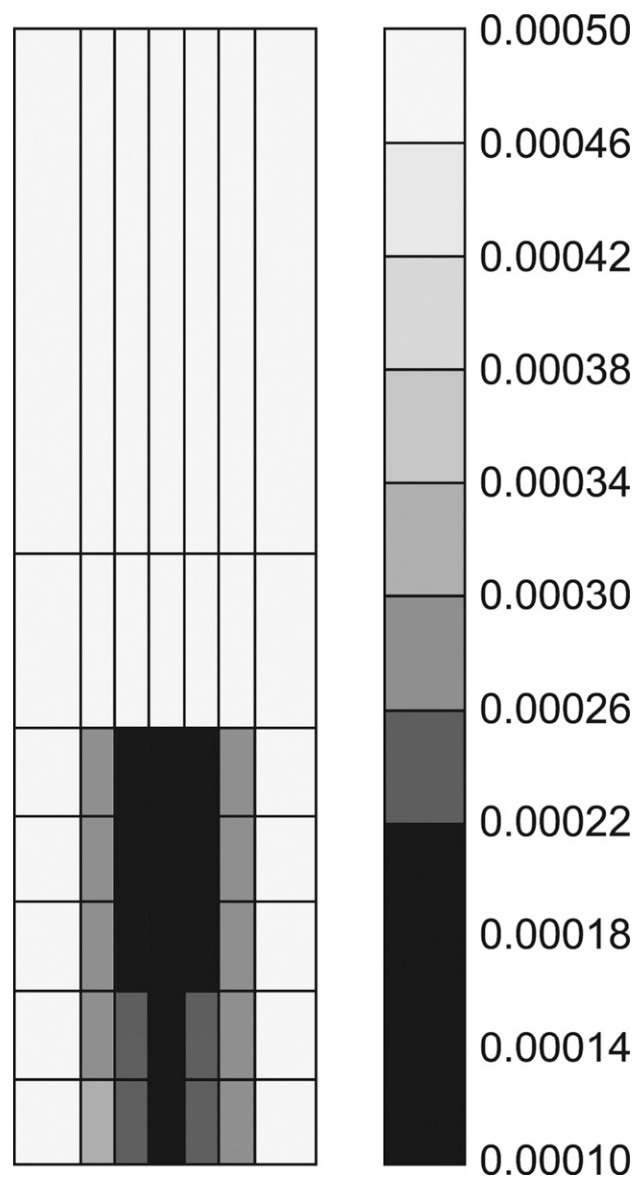


Fig. 10—Surfactant concentration (volume fraction) after 10 days of imbibitions.

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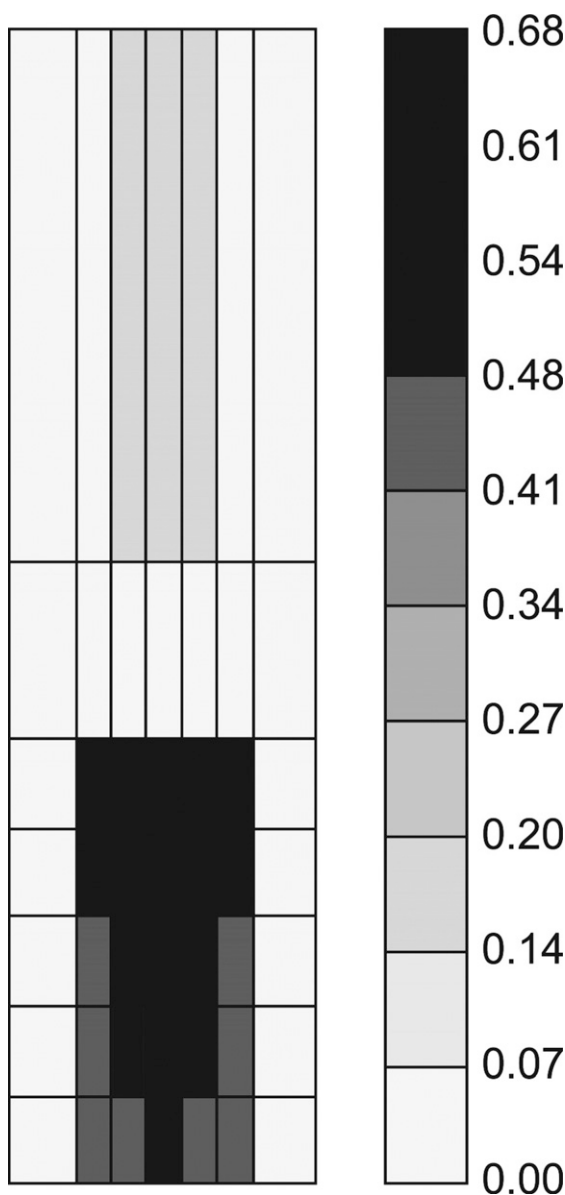


Fig. 11—Oil-saturation distribution after 10 days of imbibitions.

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TABLE 4—BASE-CASE SIMULATION-MODEL PROPERTIES	
Number of gridblocks (in.)	11x11x11
Porosity	Matrix: 0.30 Fracture: 0.02
Permeability (md)	Matrix: 50 Fracture: 1,000
k_v/k_h	0.1
Initial water saturation	Matrix: 0.40 Fracture: 0.02
Injection rate (ft ³ /D)	500
Surfactant concentration (%)	0.1

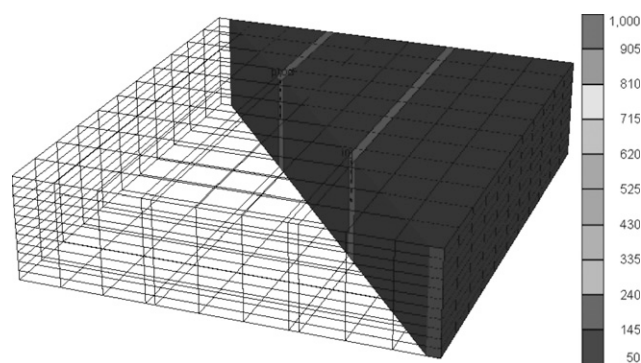


Fig. 12—Schematic of grid and permeability (md) for 3D simulations.

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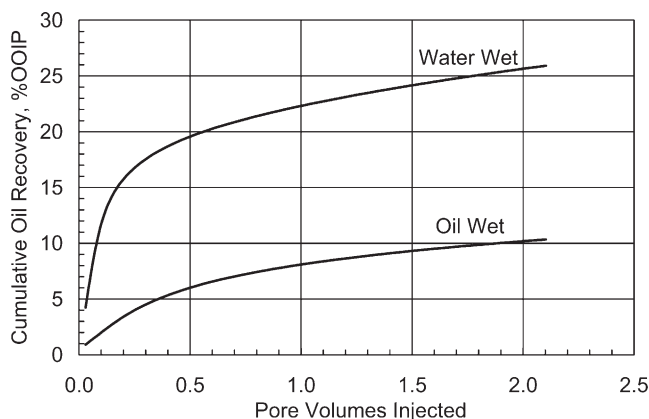


Fig. 13—Waterflood oil recovery in fractured reservoir at different wettability conditions.

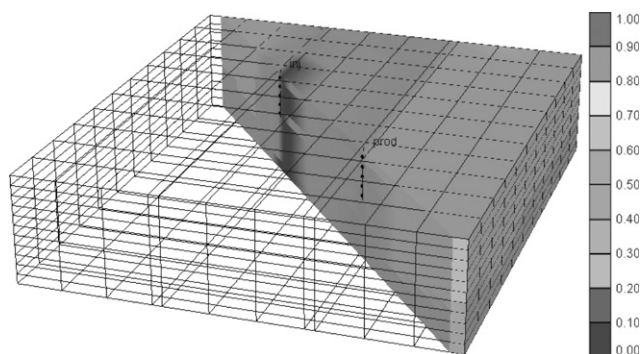


Fig. 14—Oil saturation at 1,200 days of surfactant injection (wettability-alteration case with $\omega = 0.5$).

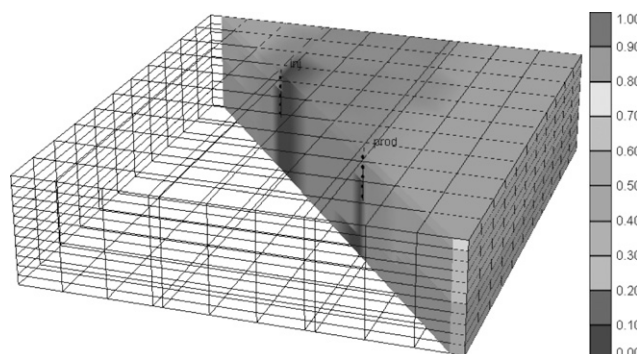


Fig. 15—Oil saturation at the end of 3,600 days of surfactant injection (wettability-alteration case with $\omega = 0.5$).

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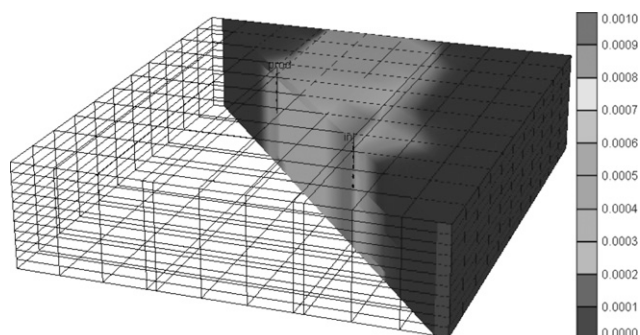


Fig. 16—Surfactant concentration in volume fraction at the end of 3,600 days of surfactant injection (wettability-alteration case with $\omega = 0.5$).

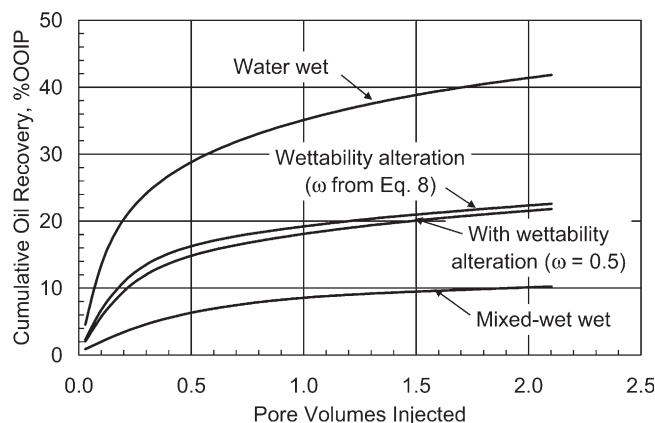


Fig. 17—Surfactant-flood oil recovery in fractured reservoir at different wettability conditions.

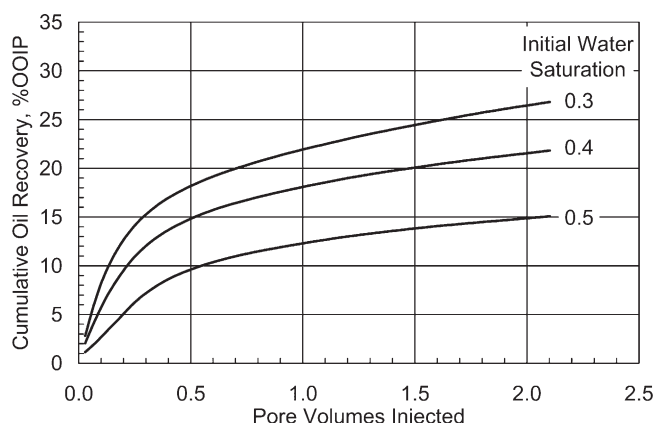


Fig. 18—Effect of initial water saturation in matrix during surfactant flood with wettability alteration.

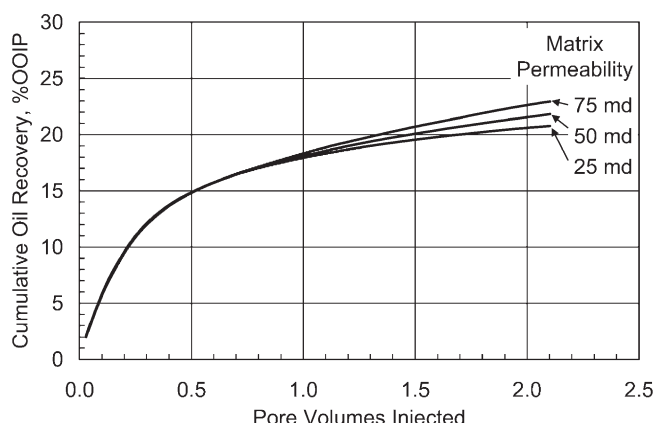


Fig. 19—Effect of matrix permeability during surfactant flood with wettability alteration.

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SI Metric Conversion Factors

bbl \times 1.589 873	E – 01 = m ³
cp \times 1.0*	E – 03 = Pa·s
ft ³ \times 2.831 685	E – 02 = m ³
°F (°F – 32)/1.8	= °C
in. \times 2.54*	E + 00 = cm

*Conversion factor is exact.

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