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Final Report

Modeling Wettability Alteration using Chemical EOR Processes in Naturally Fractured Reservoirs

Submitted by:
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Modeling Wettability Alteration using Chemical EOR Processes in Naturally Fractured Reservoirs

Final Report
Project period 10/01/04 - 09/30/07

By

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DISCLAIMER

ABSTRACT

The objective of our search is to develop a mechanistic simulation tool by adapting UTCHEM to model the wettability alteration in both conventional and naturally fractured reservoirs. This will be a unique simulator that can model surfactant floods in naturally fractured reservoir with coupling of wettability effects on relative permeabilities, capillary pressure, and capillary desaturation curves.

The capability of wettability alteration will help us and others to better understand and predict the oil recovery mechanisms as a function of wettability in naturally fractured reservoirs. The lack of a reliable simulator for wettability alteration means that either the concept that has already been proven to be effective in the laboratory scale may never be applied commercially to increase oil production or the process must be tested in the field by trial and error and at large expense in time and money.

The objective of Task 1 is to perform a literature survey to compile published data on relative permeability, capillary pressure, dispersion, interfacial tension, and capillary desaturation curve as a function of wettability to aid in the development of petrophysical property models as a function of wettability. The new models and correlations will be tested against published data. The models will then be implemented in the compositional chemical flooding reservoir simulator, UTCHEM. The objective of Task 2 is to understand the mechanisms and develop a correlation for the degree of wettability alteration based on published data. The objective of Task 3 is to validate the models and implementation against published data and to perform 3-D field-scale simulations to evaluate the impact of uncertainties in the fracture and matrix properties on surfactant alkaline and hot water floods.

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INTRODUCTION

We have developed UTCHEM simulator over many years with the support of the Department of Energy and it is clearly the most versatile reservoir simulator for chemical EOR processes. Here we are adapting UTCHEM to model the wettability alteration in both conventional and naturally fractured reservoirs. This will help us and others to better understand and predict the oil recovery mechanisms as a function of wettability in naturally fractured reservoirs. The predictive simulations of such complex processes will aid to reduce the risk of failure of the field projects.

The primary focus of this research proposal is on surfactant processes, which recovers additional oil through ultra-low interfacial tension and also through wettability alteration. The secondary objective is to model the wettability alteration during hot water injection, which enhances oil recovery by mobility reduction and also wettability alteration. The combination of surfactant and hot water injection will also be investigated to assess the potential for improved oil recovery of moderately heavy oils in naturally fractured rocks. The enhanced simulator to be developed as part of this research will make it possible to select and optimize the best candidates for field application and tailor process design to the particular characteristics of each reservoir.

The objective of this research is to develop a simulation tool to improve our understanding of multiphase flow of surfactant at elevated temperature in naturally fractured oil reservoirs. The emphasis is on enhanced oil recovery processes that reduce the interfacial tension, reduce the mobility ratio, and any possible enhancement due to wettability alteration. The project comprise of three tasks where Task 1 is the development of petrophysical properties as a function of wettability, Task 2 is the development of wettability correlation, and Task 3 is the field-scale simulations. In this final report, we give our progress for the second half of the second year of the project.

EXECUTIVE SUMMARY

Increased domestic oil production using advanced technologies of enhanced oil recovery processes involve numerical modeling of such processes to minimize the risk involved in development decisions. The oil industry is requiring much more detailed analyses with a greater demand for reservoir simulations with geological, physical, and chemical models of much more detail than in the past.

Fractured, mixed-wet formations usually have poor waterflood performance because the injected water tends to flow in the fractures and spontaneous imbibition into the matrix is not very significant. Surfactants have been used to change the wettability with the goal of increasing the oil recovery by increased imbibition of the water into the matrix rock. Very little is known about the detailed mechanisms of this process and the interactions with the geochemical and geological properties of the oil reservoir, what conditions are most favorable for enhancing the rate of imbibition, and how this process compares with alternative oil production methods from such reservoirs.

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 both scale up of the process from laboratory to field conditions and 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 objective of our search is to develop a mechanistic simulation tool by adapting UTCHEM to model the wettability alteration in both conventional and naturally fractured reservoirs. This will be a unique simulator that can model surfactant floods in naturally fractured reservoir with coupling of wettability effects on relative permeabilities, capillary pressure, capillary desaturation curves, and dispersivities.

The capability of wettability alteration will help us and others to better understand and predict the oil recovery mechanisms as a function of wettability in naturally fractured reservoirs. The lack of a reliable simulator for wettability alteration means that either the concept that has already been proven to be effective in the laboratory scale may never be

applied commercially to increase oil production or the process must be tested in the field by trial and error and at large expense in time and money.

The objective of Task 1 is to perform a literature survey to compile published data on relative permeability, capillary pressure, dispersion, interfacial tension, and capillary desaturation curve as a function of wettability to aid in the development of petrophysical property models as a function of wettability. The new models and correlations will be tested against published data. The models will then be implemented in the compositional chemical flooding reservoir simulator, UTCHEM. The objective of Task 2 is to understand the mechanisms and develop a correlation for the degree of wettability alteration based on published data. The objective of Task 3 is to validate the models and implementation against published data and to perform 3-D field-scale simulations to evaluate the impact of uncertainties in the fracture and matrix properties on surfactant alkaline and hot water floods.

In this final report, we emphasis on our results obtained in the last six months of the project period. We reported on the development, implementation, and validation of a wettability alteration model in the previous progress report. We have made field-scale simulations in a fractured media. Waterflood recoveries are compared for a case where the reservoir is initially water wet against a case where reservoir is mixed wet. Surfactant flood simulations were then performed and the effect of wettability on oil recovery is investigated. We made scale up simulations to investigate the effect of matrix permeability and matrix initial saturations on the surfactant flood performance.

EXPERIMENTAL

This project does not include an experimental component.

RESULTS AND DISCUSSION

A summary of the progress on different tasks is reported as discussed below.

Task 1: Development of Petrophysical Properties as a Function of Wettability

Subtask 1.2: Implementation

Wettability is a very important parameter controlling the relative permeability and capillary pressure. However, the wettability is not an explicit parameter in the flow equations but its effects should be reflected by the changes in capillary pressure and relative permeability curves. In our previous progress report, we developed a wettability alteration model to take into account the effect of wettability on relative permeability. Here we report on the extension of the model to take into account the effect of wettability on capillary pressure. Two extreme wetting conditions are assumed, original and final wetting conditions, and relative permeability and capillary pressure in each gridblock are calculated for each extreme case. Both relative permeability and capillary pressure calculated for each gridblock, which is referred to as *actual* relative permeability, at each timestep is then obtained by interpolation between these two extreme conditions. The relative permeabilities are calculated using Corey-type exponential functions. Capillary pressures are computed using a modified Brooks-Corey function. The interpolation is based on either by a constant input parameter provided by the user or it is calculated based on the adsorbed surfactant concentration in each gridblock.

Task 2: Development of Wettability Correlation

For the purpose of completeness of this progress report, we review the model that is formulated and implemented in UTCHEM (Delshad, Pope, and Sepehrnoori, 2006). Wettability alteration is modeled with changes in relative permeability and capillary pressure. A brief description of the model is given here. Corey-type relative permeabilities are calculated for each gridblock as follows:

$$k_{r\ell} = k_{r\ell}^{o} S_{n\ell}^{e_\ell} \quad \ell = 1, 2, 3 \tag{1}$$

where ℓ is either water, oil or microemulsion phases, $k_{r\ell}^{o}$ is the relative permeability endpoint for phase ℓ, e_{ℓ} is the Corey exponent of phase ℓ and $S_{n\ell}$ is the normalized saturation of phase ℓ calculated as follows:

$$S_{n\ell} = \frac{S_{\ell} - S_{\ell r}}{1 - \sum_{\ell=1}^{3} S_{\ell r}} \quad \ell = 1,2,3 \tag{2}$$

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

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

where $S_{\ell r}^{high}$ and $S_{\ell r}^{low}$ are residual saturations of phase ℓ at high and low trapping numbers respectively (given as input parameters), T_{ℓ} is the input trapping parameter of phase ℓ and $N_{T\ell}$ is trapping number of phase ℓ. $S_{\ell r}^{high}$ are typically zero. The trapping number for phase ℓ displaced by phase ℓ' is defined as follows (Delshad *et al*., 1986):

$$N_{T\ell} = \frac{\left| \vec{\vec{k}} \cdot \left(\vec{\nabla}\Phi_{\ell'} + g\Delta\rho\vec{\nabla}D \right) \right|}{\sigma_{\ell\ell'}} \quad \ell = 1,2,3 \tag{4}$$

Mobilization effects on endpoint relative permeabilities are modeled using the following correlation (Delshad *et al*., 1986):

$$k^{o}_{r\ell} = k^{o\,low}_{r\ell} + \frac{S^{low}_{\ell' r} - S_{\ell' r}}{S^{low}_{\ell' r} - S^{high}_{\ell' r}} \left(k^{o\,high}_{r\ell} - k^{o\,low}_{r\ell} \right) \quad \ell = 1,2,3 \tag{5}$$

where $S_{\ell' r}$ is the residual saturation of the conjugate phase e.g. oil is the conjugate phase for microemulsion phase and $k^{o\,low}_{r\ell}$ and $k^{o\,high}_{r\ell}$ represent the endpoint relative permeability of phase ℓ at low and high trapping numbers respectively. Equation 6 gives the relative permeability exponents as a function of trapping number (Delshad *et al*., 1986).

$$e_{\ell} = e^{low}_{\ell} + \frac{S^{low}_{\ell' r} - S_{\ell' r}}{S^{low}_{\ell' r} - S^{high}_{\ell' r}} \left(e^{high}_{\ell} - e^{low}_{\ell} \right) \quad \ell = 1,2,3 \tag{6}$$

where e^{low}_{ℓ} and e^{high}_{ℓ} represent the relative permeability exponents for low and high trapping numbers respectively specified as input parameters.

Equations 1 through 6 are solved once for the initial reservoir wettability condition $(k^{initial}_{r\ell})$ and once for the altered condition of strongly water-wet $(k^{final}_{r\ell})$. Two sets of relative permeability ($k^{o}_{r\ell}$, $S_{\ell r}$, e_{ℓ}) and trapping parameters (T_{ℓ}) are required as input parameters 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 that the concentration of surfactant in the gridblock is greater than the critical micelle concentration. Interpolation is made based on the scaling factor ω.

$$k_{r\ell} = \omega\, k^{final}_{r\ell} + (1-\omega)\, k^{initial}_{r\ell} \quad \ell = 1,2,3 \tag{7}$$

where ω is the interpolation scaling factor and $k_{r\ell}^{final}$ and $k_{r\ell}^{initial}$ 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 parameter or is related to the concentration of surfactant adsorbed in each gridblock as follows:

$$\omega = \frac{\hat{C}_{surf}}{\hat{C}_{surf} + C_{surf}} \tag{8}$$

where $\hat{C}_{surf}$ and C_{surf} represent the adsorbed and total concentration of surfactant, respectively.

The capillary pressure as a function of wettability is also modeled using linear interpolation between the capillary pressure of the initial wetting state and the final condition.

$$P_c = \omega P_c^{final} + (1-\omega)\, P_c^{initial} \tag{9}$$

where the capillary pressure P_c is a scaled with the interfacial tension as follows:

$$P_c = P_{cow} \frac{\sigma_{om}}{\sigma_{ow}} \tag{10}$$

where

$$P_{cow} = C_{pc} \left(1 - S_{n\ell}\right)^{E_{pc}} \tag{11}$$

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

Capillary desaturation curves, relative permeability endpoints, and relative permeability exponents as a function of trapping number for different wettability conditions of water wet and mixed wet are given in Figs. 1 through 3. Relative permeabilities are then calculated using Equations 1 through 7 with a constant wettability scaling factor of 0.5. The base 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). Figure 4 shows 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. 9. Table 1 lists the capillary pressure parameters.

To validate the wettability model and its implementation in the simulator, the laboratory alkaline/surfactant imbibition experiments conducted at Rice University (Hirasaki and Zhang, 2004) were successfully modeled and reported in the previous progress report (Delshad, Pope, and Sepehrnoori, 2006).

Task 3: Field-Scale Simulations

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. Capillary desaturation curves, relative permeability endpoints, and relative permeability exponents as a function of trapping number for different wettability conditions of water wet and mixed wet are given in 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). Figure 4 shows the capillary pressure curves calculated for water wet and oil wet conditions. Table 1 lists the capillary pressure parameters.

Several 3D simulations were performed. The simulation model is 250 ft long, 250 ft wide, and 55 ft thick (Fig. 5). Gridblocks with a permeability of 1000 md and a porosity of 2% were used to represent the fractures between matrix blocks. Matrix blocks are 68 ft 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. Table 2 lists the reservoir properties. Injection and production wells were located in fractures. Waterflood simulations were first performed for different wettability conditions of water wet and oil wet. Figure 6 compares the oil recovery for these cases.

As expected, the case with relative permeability and capillary pressure representing water-wet matrix rock 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 here was to model the wettability alteration aspect of the flood rather than a conventional low interfacial tension surfactant flood. Wettability alteration simulations were run for both a constant input value of ω = 0.5 and a value of ω computed from Eq. 8. The initial matrix wettability was oil wet.

Oil saturation distributions at 1200 and 3600 days are shown in Figs. 7 and 8 respectively for wettability alteration simulation with a constant ω of 0.5. Surfactant concentration at the end of 3600 days is given in Fig. 9. The oil saturation is reduced in the middle matrix block where surfactant concentration is increased. Cumulative oil recoveries are compared for different wettability conditions in Fig. 10. The highest recovery is for the case of a strongly water wet condition with recovery of about 42% OOIP. This is almost twice the waterflood oil recovery. The surfactant flood of the reservoir with an oil-wet matrix was not effective since 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 of the case with constant ω of 0.5 are shown in Figs. 11 and 12. The recovery is higher when there is less water initially in the matrix. Higher matrix permeability gives higher oil recovery.

CONCLUSIONS

The performance of waterflooding in naturally fractured reservoirs is normally low. This is due to the fact that most of the fractured reservoirs are oil-wet or mixed-wet and as a result of that have a low tendency for imbibition of injected water into the matrix. It is desirable to change the wetting state of the matrix rocks to more water-wet conditions in order to increase the rate of imbibition of the injected water. This can be achieved by injection of a surface active agents or surfactants.

Surfactant solutions have two important effects on the rock/fluid system. The first effect is reduction of interfacial tension between the trapped oil and injected aqueous phase and therefore solubilization and mobilization of trapped oil. The second effect is the alteration of the wettability of the matrix rock towards more water-wet conditions, which would increase the brine imbibition rates. Both effects are modeled here in order to have a better prediction of oil recovery from surfactant floods, especially in naturally fractured reservoirs. The interfacial tension reduction and oil mobilization effects of the surfactant are modeled using a dimensionless number called *trapping number* that takes into account the effect of viscous, gravity, and capillary forces. The effect of surfactant on wettability alteration is modeled and implemented in UTCHEM simulator by its effect on the relative permeability and capillary desaturation curve for each phase. Two wetting conditions are defined in the input as two sets of relative permeability, capillary pressure, and capillary desaturation curves. The wetting state of the rock at each time step in UTCHEM is then obtained by interpolation between these two sets. Two interpolation methods are used for this propose. The first method uses a constant weight factor that is user defined. The second method uses a time dependant weight factor calculated based on the concentration of adsorbed surfactant at each time step in each gridblock.

The model was successfully validated by comparison with published surfactant experiments. 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. The following observations were made:

- 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 the oil production.
- The simulation tool developed aids in a mechanistic understanding of low concentration surfactant flooding in fractured carbonate reservoirs.
- With the wettability alteration capability in UTCHEM, several EOR processes that use chemicals such as surfactants, polymer and alkali, or in some cases

mixtures of them that recover additional oil through low interfacial tension and wettability alteration, can now be simulated.

Nomenclature

D	=	Depth, L
g	=	Gravitational constant, Lt^{-2}
$\vec{\vec{k}}$	=	Permeability tensor, L^2
$k_{r\ell}$	=	Relative permeability of phase ℓ
$k^o_{r\ell}$	=	Endpoint relative permeability of phase ℓ
$k^{o\,high}_{r\ell}$	=	Phase ℓ endpoint relative permeability at high trapping number
$k^{o\,low}_{r\ell}$	=	Phase ℓ endpoint relative permeability at low trapping number
e^{high}_ℓ	=	Phase ℓ relative permeability exponents at high trapping number
e^{low}_ℓ	=	Phase ℓ relative permeability exponents at low trapping number
N_{T_ℓ}	=	Trapping number of phase ℓ
P_c	=	Capillary Pressure, $mL^{-1}t^{-2}$
P_{cow}	=	oil-water capillary pressure, $mL^{-1}t^{-2}$
S_ℓ	=	Saturation of phase ℓ, L^3/L^3 PV
$S_{\ell r}$	=	Residual saturation of phase ℓ, L^3/L^3 PV
$S^{high}_{\ell r}$	=	Residual saturation of phase ℓ at high N_T, L^3/L^3 PV
$s^{low}_{\ell r}$	=	Residual saturation of phase ℓ at low N_T, L^3/L^3 PV
T_ℓ	=	Trapping parameter for phase ℓ

Greek Symbols

$\vec{\nabla}\Phi_{\ell'}$	=	Flow potential gradient given by $\vec{\nabla}P_{\ell'} - g\,\rho_{\ell'}\vec{\nabla}D$
ρ_ℓ	=	Density of phase ℓ, mL^{-3}
$\sigma_{\ell\ell'}$	=	Interfacial tension between phases ℓ and ℓ', mt^2
Φ_ℓ	=	Potential of phase ℓ, $mL^{-1}t^{-2}$

Subscripts

ℓ	=	Phase number (1: water, 2: oil, 3: microemulsion)
r	=	Residual

Superscripts

high	=	high trapping number
low	=	low trapping number

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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_ℓ)	1,000	20,000	200	1,500
Capillary pressure endpoint (CPC)	-15		7	
Capillary pressure exponent (EPC)	6		2	

Table 2—Base Case Simulation Model Properties

Number of gridblocks	11x11x11
Porosity	Matrix: 0.30 Fracture: 0.02
Permeability, md	Matrix: 50 Fracture: 1000
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

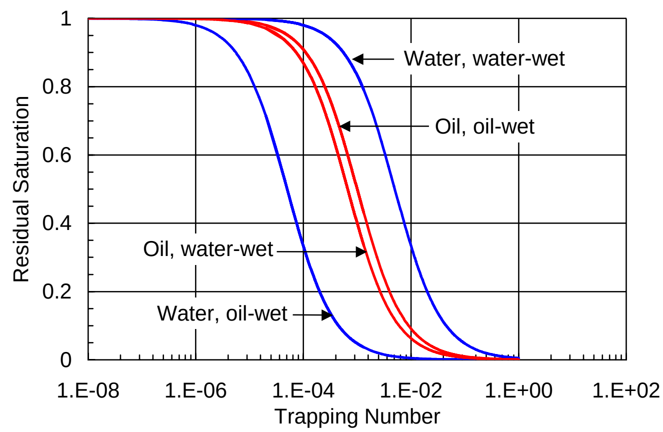

Fig. 1—Capillary desaturation curves used in simulations.

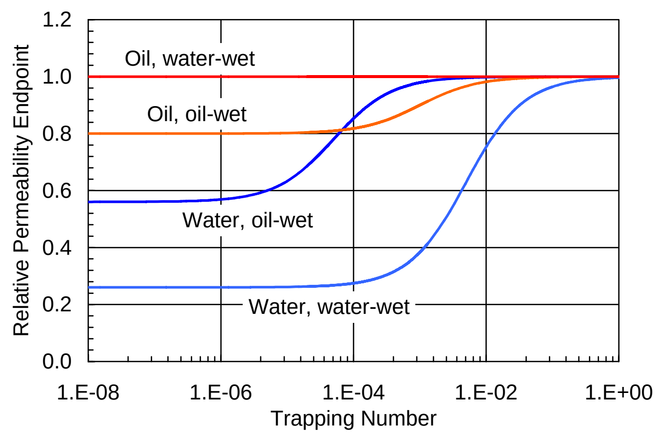

Fig. 2—Endpoint relative permeability.

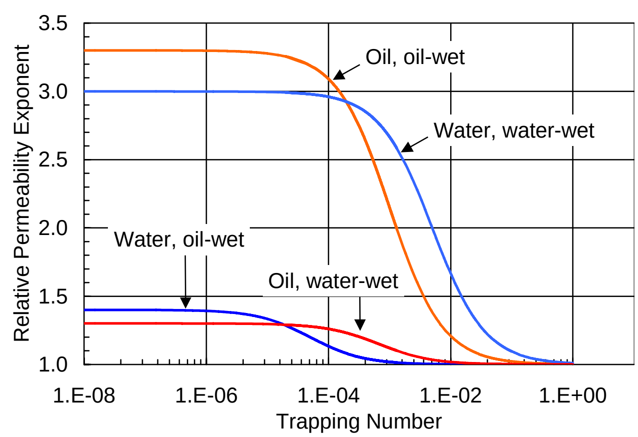

Fig. 3—Relative permeability exponent.

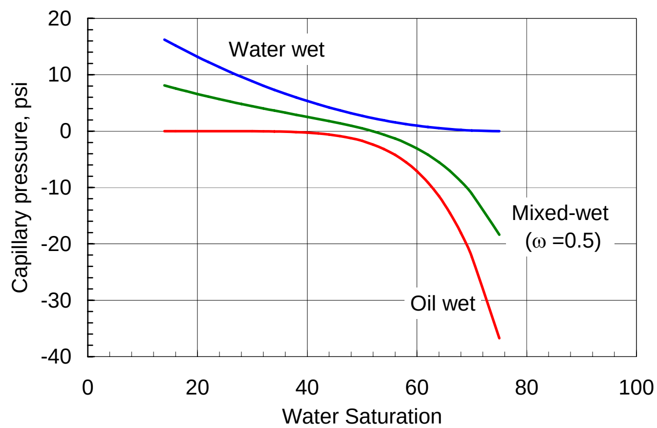

Fig. 4—Calculated capillary pressure curves for different wettability conditions.

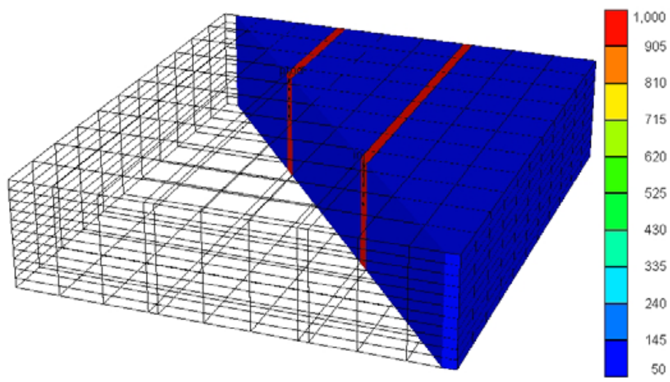

Fig. 5—Schematic of grid and permeability (md) for 3-D simulations.

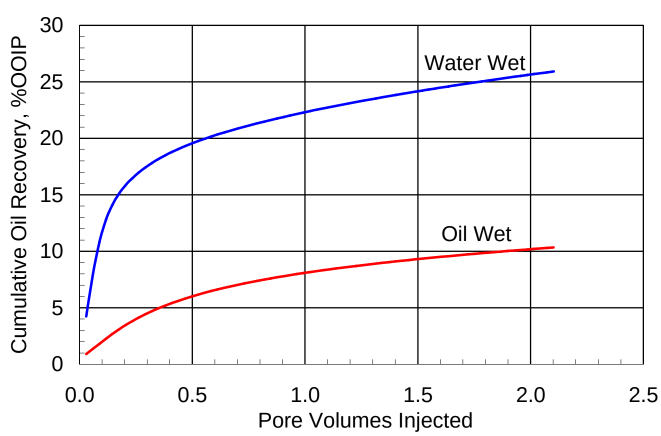

Fig. 6—Waterflood oil recovery in fractured reservoir at different wettability conditions.

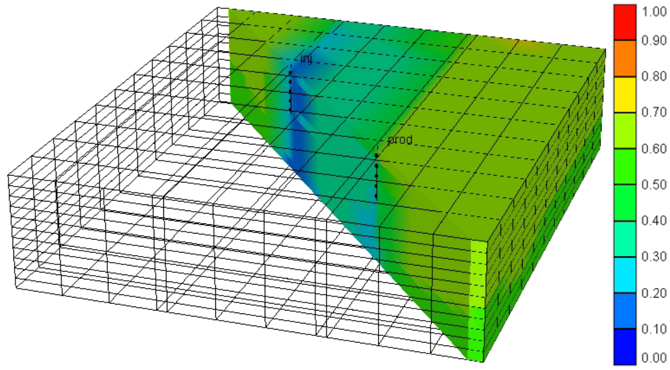

Fig. 7—Oil saturation at 1200 days of surfactant injection (wettability alteration case with ω =0.5).

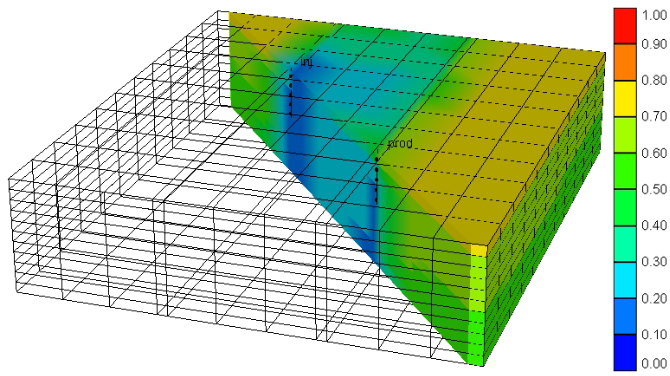

Fig. 8—Oil saturation at the end of 3600 days of surfactant injection (wettability alteration case with ω =0.5).

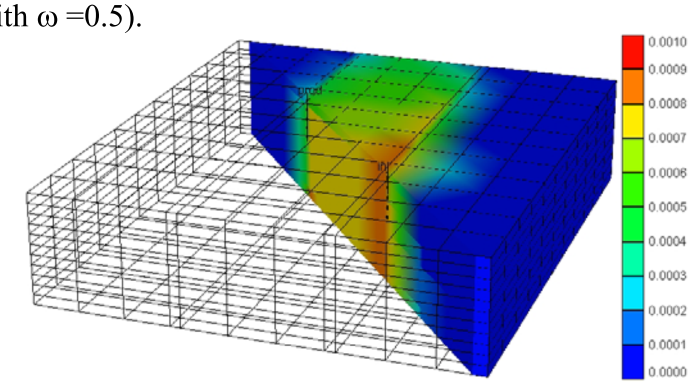

Fig. 9—Surfactant concentration in volume fraction at the end of 3600 days of surfactant injection (wettability alteration case with ω =0.5).

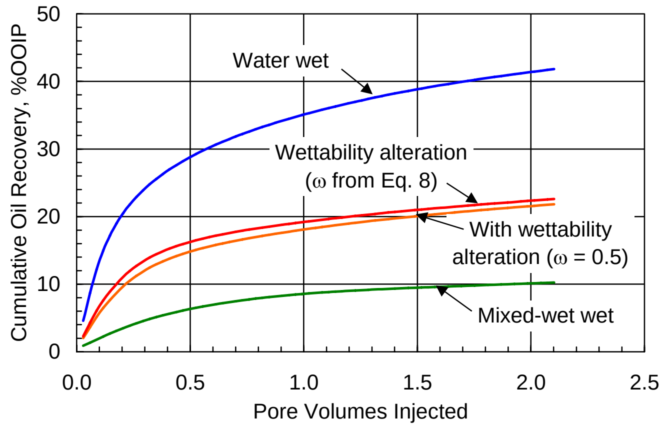

Fig. 10—Surfactant flood oil recovery in fractured reservoir at different wettability conditions.

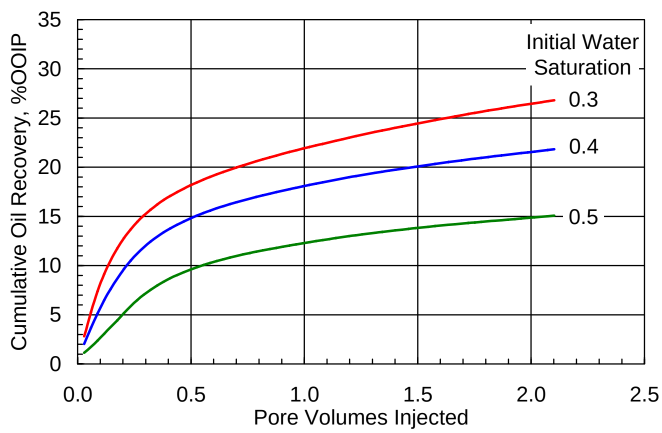

Fig. 11—Effect of initial water saturation in matrix during surfactant flood with wettability alteration.

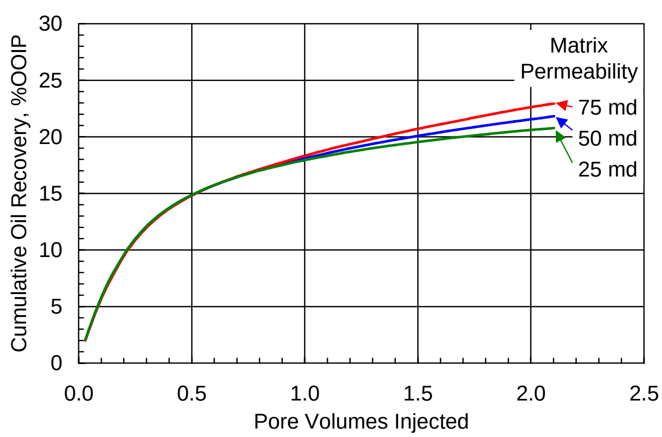

Fig. 12—Effect of matrix permeability during surfactant flood with wettability alteration.

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