Influence of relative permeabilities on chemical enhanced oil recovery

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Abstract. The main objective of chemical flooding is to mobilize the trapped oil remaining after a secondary recovery by waterflooding. This purpose is achieved by lowering the oil-water interfacial tension and producing partial miscibility between both phases. The chemical partition among phases (phase behavior) influences all other physical properties. In particular, it affects residual saturations determining relative permeability curves. Relative permeabilities rule the flow of each phase through the porous medium, so they play an essential role in oil recovery. Therefore, in this work we study the influence of relative permeabilities on the behavior of a surfactant-polymer flooding for the three different types of phase behavior. This analysis is performed applying the 3D compositional numerical simulator UTCHEM developed at the University of Texas at Austin. From the examples studied, we conclude that the influence of relative permeabilities depends on the type of phase behavior, i.e., as microemulsion relative permeability decreases, oil recovery increases for Types II(+) and III while slightly decreases for Type II(-). Moreover, a better displacement efficiency is observed for Types II(+) and III, because they behave similarly to a miscible displacement.

1. Introduction
Statistically, after a waterflooding, more than half of the oil originally in place still remains trapped in the reservoir. The recovery of this trapped oil is the target of the Enhanced Oil Recovery processes (EOR), which implies the injection of materials not naturally present in the reservoir [1]. Among these materials, surfactants are injected to decrease the interfacial tension between oil and water in order to mobilize the trapped oil, and polymers are injected to reduce water mobility and improve the sweep efficiency. In a chemical flood a multicomponent, multiphase system is involved. The theory of multicomponent, multiphase flow has been presented by several authors [2]-[3]. Those studies led to the building of complex simulators, like the one developed at the University of Texas at Austin, UTCHEM [4]-[6], which accounts for most of the physical phenomena involved. For a Surfactant Pilot Simulation [7] those physical phenomena were described in terms of more than 70 parameters.

From a physical-chemical point of view, there are three pseudo-components: brine, oil and chemical. They are distributed between two or three phases: oleic, aqueous and microemulsion (phase behavior). The chemical has an amphiphilic character, making the oil partially miscible with water [8]. Phase behavior influences all other physical properties, and each of them, in turn, influences oil recovery. Relative permeability curves rule the flow of each phase through the porous medium, so they are essential in the oil recovery efficiency. These curves are represented by potential models
depending on two parameters [9]. In this paper we apply UTCHEM to analyze the influence of relative permeability curves and phase behavior on cumulative oil production.

2. Mathematical model
UTCHEM is a 3D compositional simulator which considers up to 4 phases (a single component gaseous phase, “g”, and three liquid phases: aqueous, “w”, oleic, “o”, and microemulsion, “m”) and 19 components. It is based in the following partial differential equations:

- the mass conservation equation for component \( k \),
  
  \[
  \frac{\partial \left( \phi \mathbf{C}_k \rho_k \right)}{\partial t} + \nabla \sum_{l=1}^{n_p} \rho_k \left( C_{kl} \mathbf{u}_l - \phi S_l \mathbf{D}_{kl} \nabla C_{kl} \right) = \phi \sum_{l=1}^{n_p} \mathbf{r}_{kl} + (1 - \phi) \mathbf{r}_s + Q_k
  \]

  where \( \phi \) is porosity, \( \rho_k \) is the density of pure component \( k \), \( n_p \) is the number of phases, \( C_{kl} \) is the mass concentration of component \( k \) in phase \( l \), \( S_l \) is saturation of phase \( l \), \( \mathbf{D}_{kl} \) is the dispersion tensor of component \( k \) in phase \( l \) and in solid phase \( s \), and \( \mathbf{r}_k \) is the injection or production rate per unit volume. The overall volume of component \( k \) per unit pore volume, \( \mathbf{C}_k \), is computed as,

  \[
  \mathbf{C}_k = \left( 1 - \sum_{k=1}^{n_c} \mathbf{C}_k \right) \sum_{l=1}^{n_p} S_l C_{kl} + \mathbf{C}_k, \quad k = 1, \ldots, n_c
  \]

  where \( n_c \) is the total number of component, \( n_{cv} \) is the total number of volume-occupying components and \( \mathbf{C}_k \) is the adsorbed concentration of species \( k \).

- Darcy’s equation for the flow of phase \( l \), which defines Darcy velocity \( \mathbf{u}_l \),

  \[
  \mathbf{u}_l = -\frac{k_{rl}}{\mu_l} \left( \nabla P_l - \gamma_l \nabla h \right); \quad l = 1, \ldots, n_p
  \]

  where \( k \) is the absolute permeability tensor, \( h \) is depth, and \( k_{rl}, \mu_l, P_l \), are relative permeability, viscosity and pressure of phase \( l \), respectively.

- Energy conservation equation. In this work we consider an isothermal reservoir, so this equation is not applied.

Summing up the mass balance equations over all volume-occupying components, substituting Darcy’s law for the phase flux terms and using the definition of capillary pressure, the following equation, formulated in terms of aqueous pressure (pressure equation), is obtained:

\[
\phi \mathbf{C}_i \frac{\partial P_i}{\partial t} + \nabla \cdot \mathbf{C}_i \mathbf{A}_{ric} \nabla P_i = -\nabla \cdot \sum_{l=1}^{n_p} \mathbf{C}_l \mathbf{A}_{rilc} \nabla h + \nabla \cdot \sum_{l=1}^{n_p} \mathbf{C}_l \mathbf{A}_{ric} \nabla P_{ic} + \sum_{k=1}^{n_c} Q_k
\]

Finally, the system of differential equations consists on Eq. (4) (pressure equation) and Eqs. (2) (concentration equations). The basic boundary condition assumed in UTCHEM is that there is no flow through any boundary. The system is completed with equations representing physical properties of rock and fluids [5].

The system is solved using a block-centered finite-difference scheme. The solution method is implicit in pressure and explicit in concentrations (IMPES type). To increase stability and robustness, a flux limiter that is total-variation-diminishing (TVD) has been added [5].

3. Physical properties
The main physical properties involved in a chemical flooding are: phase behavior, interfacial tensions between fluid phases, residual phase saturations, relative permeabilities, phase viscosities, capillary
pressures and adsorption. Phase behavior affects interfacial tensions, phase viscosities and adsorption. The main objective of surfactant injection is to lower oil water interfacial tension and thus mobilize the trapped oil. Therefore interfacial tension determines residual phase saturations. Besides, residual saturations affect capillary pressure and relative permeability curves. The relationship among physical properties is represented in Figure 1.

In this work we analyze the influence of phase behavior and relative permeabilities, so only these properties are described.

3.1. Phase behavior
The brine-oil-chemical system is considered as pseudoternary, defined by 3 pseudo-components:
- **brine**: polar species (water and salts) and polymers.
- **oil**: non-polar species (hydrocarbons)
- **chemical**: amphiphilic species (surfactants and alcohols)

Three types of phase behavior, shown in Figure 2, may be considered:
- **Type II(-)**: surfactant is more soluble in aqueous-phase. There are two phases: *excess oil* (essentially pure oil) and *water-external microemulsion* (brine, surfactant and solubilized oil).
- **Type II(+)**: surfactant is more soluble in oleic-phase. There are two phases: *excess water* and *oil-external microemulsion* (most of the surfactant, oil and solubilized water).
- **Type III**: a third surfactant-rich phase is formed, the *microemulsion*. There are three phases: excess oil, excess water and microemulsion.

3.2. Relative permeabilities
Relative permeabilities are functions of saturation. In UTCHEM, they are represented by a potential model with 2 parameters: the endpoint ($k_{rl}^*$) and the exponent ($n_l$), which determines the curvature [9].
They also depend on residual saturations ($S_r$); therefore, the curves change as residual saturations decrease. This fact is illustrated in Figure 3: with superscript high and low we denote the curves for high and low $S_r$, respectively. It should be noted that the low microemulsion relative permeability has an atypical shape, it is concave ($n_m < 1$). This behavior was experimentally found by Delshad et al. [9].

4. Numerical Results

We consider a 1D linear portion of a 933 ft (284 m) length reservoir located between an injection and a production well. Porosity, permeability and cross-sectional area, are assumed constant ($\phi = 13.6\%$, $k = 182\ mD = 1.82 \times 10^{13}\ m^2$, $A = 65337\ ft^2 = 6070\ m^2$). Two different cases are analyzed. The objective of Case 1 is to describe the general behavior of a surfactant flooding, comparing the UTCHEM results with a simplified analytical solution developed by Larson [10]. The objective of Case 2 is to perform a sensitivity analysis on the curvature of the microemulsion relative permeability curve on a polymer-surfactant flooding.

4.1. Case 1: Continuous surfactant injection

The injection fluid is a water solution with 1% surfactant and 0.54 mEq/mL salts. Initially the oil saturation is the residual saturation left behind after a waterflooding ($S_{or\ high}$). The objective of surfactant injection is to mobilize the trapped oil, reaching a lower residual oil saturation ($S_{or\ low}$). The injection flow rate is constant and equal to 1300 STB/d (STB=stock tank barrel=6.29 m$^3$).

Figure 4 shows the oil saturation as a function of dimensionless length corresponding to 300 days of injection. The pink curve represents the analytical solution and the grey one the results computed with UTCHEM. The analytical solution only considers two phases, so we choose a Type II(-) phase behavior. Besides, in UTCHEM, capillary pressure, dispersion, adsorption and chemical reactions have been neglected to satisfy other restrictions of the analytical solution. The remaining physical properties are taken from Han et al. [11]. Figure 4 illustrates the general behavior of a continuous surfactant injection. In the idealized analytical solution, an oil bank of approximate 55% saturation is formed. Behind it, there is a two-phase region that abruptly becomes a single phase with composition equal to that of the injected fluid. The UTCHEM solution approximates these results. The main difference is the time needed to reach $S_{or\ low} = 0$. The analytical solution considers only two residual oil saturations ($S_{or\ high}$ and $S_{or\ low}$) and only the microemulsion-oil relative permeability curves corresponding to the injected composition [10]. On the other hand UTCHEM is less restrictive, taking into account intermediate values of residual saturations and relative permeability curves. These intermediate values are computed using the reduced interfacial tensions [5]. As it can be seen in Figure 4, $S_{or\ low} = 0$ is obtained faster with the analytical solution than with UTCHEM. Besides, the use of intermediate relative permeabilities slightly delays the oil bank advance.
4.2. Case 2: Sensitivity analysis on the curvature of the microemulsion relative permeability curve

This example represents a pilot chemical flooding between an injector and a producer. From an economic point of view a continuous chemical injection is unreasonable. Therefore, chemical slugs are used, so a numerical solution is needed. Initially, there is 70% water and 30% oil. During the first 230 days, a surfactant slug (1% surfactant, 5% polymer and 0.54 mEq/mL salts) is injected, on the following 350 days a polymer slug (5% polymer and 0.54 mEq/mL salts) is injected, and on the following 2980 days water with the same salt concentration is injected. The injection flow rate is always 1300 STB/d (206.7 m$^3$/d). The three types of phase behavior are considered; they are determined controlling salinity parameters [11]. Capillary pressure and adsorption have been neglected. Other physical properties are taken from laboratory experiments (see references in Han et al. [11]).

The relative permeabilities are those shown in Figure 3. In this paper we only show the sensitivity analysis on the curvature of the microemulsion relative permeability curve (exponent $n_m$ parameter). Sensitivity studies on other parameters can be found in Destefanis and Savioli [12]. We consider different curvatures: $n_m = 0.48$ (concave), $n_m = 1$ (linear) and $n_m = 1.5$ (convex).

The results obtained for the three types of phase behavior are shown in Figure 5. For Types II(+) and III (Figure 5 (b) and (c)), as $n_m$ increases (or equivalently microemulsion relative permeability decreases) cumulative oil production ($N_p$) decreases. On the other hand, for Type II(-) (Figure 5 (a)), the behavior for different values of $n_m$ is almost the same; in fact, as $n_m$ increases, $N_p$ slightly increases. Let us note that we have a water-external microemulsion in Type II(-) systems, therefore, the increasing of “water” mobility reduces oil mobility, and consequently, oil recovery.

![Figure 5. Phase behaviors: (a) Type II(-) system, (b) Type II(+) system, (c) Type III system.](image)

In Figure 6, we compare the saturation profiles obtained with $n_m = 0.48$ at different times for the three types of phase behavior. Brine, oil and microemulsion saturation are represented in blue, brown and orange, respectively. Results for Type II(-) are shown in the second column of the plot, results for Type II(+) in the third column and results for Type III in the fourth one. Remember that Type II(-)
microemulsion is water external, Type II(+) microemulsion is oil external and Type III microemulsion constitutes a third phase. The typical characteristics of chemical displacement are seen in all figures, i.e., the formation of an oil bank (due to the reduction of interfacial tension and the partial oil-water miscibility) and the advance of the surfactant slug. In Type II(-) the displacement is practically immiscible, so no significant reduction of residual oil saturation is reached. On the other hand, Type II(+) and Type III displacements are miscible, oil is mostly removed and, consequently, recovery is higher.

Table: Saturation profiles at different times.

|         | Type II(-) | Type II(+) | Type III |
|---------|------------|------------|----------|
| t = 100 days | ![Saturation profile](image1) | ![Saturation profile](image2) | ![Saturation profile](image3) |
| t = 1000 days | ![Saturation profile](image4) | ![Saturation profile](image5) | ![Saturation profile](image6) |
| t = 3500 days | ![Saturation profile](image7) | ![Saturation profile](image8) | ![Saturation profile](image9) |

**Figure 6.** Saturation profiles at different times.

5. Conclusions

- The UTCHEM numerical results approach those of the idealized analytical solution, with a slower reduction of residual oil saturation.
- The influence of relative permeabilities depends on the type of phase behavior.
- For Types II(+) and III as microemulsion relative permeability exponent decreases, oil recovery increases.
- For Type II(-) the change in microemulsion relative permeability slightly affects oil recovery.
- Better displacements are obtained for Types II(+) and III because their characteristics are similar to that of a miscible displacement.

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