Numerical approach for enhanced oil recovery with surfactant flooding

Sadegh Keshtkara, Morteza Sabetib, Amir H. Mohammadi, * a-Department of Petroleum Engineering, Faculty of Petroleum Engineering, Petroleum University of Technology, Ahwaz, Iran b-Department of Chemical Engineering, Isfahan University of Technology, Isfahan, Iran c-Institut de Recherche en Génie Chimique et Pétrolier (IRGCP), Paris Cedex, France d-Thermodynamics Research Unit, School of Engineering, University of KwaZulu-Natal, Howard College Campus, King George V Avenue, Durban 4041, South Africa e-Département de Génie des Mines, de la Métallurgie et des Matériaux, Faculté des Sciences et de Génie, Université Laval, Québec (QC) G1V 0A6, Canada

ARTICLE INFO

Article history:
Received 5 September 2015
Received in revised form
3 November 2015
Accepted 5 November 2015

Keywords:
Surfactant flooding
Numerical simulation
Finite difference
Two phases-three component system
Partition coefficient

ABSTRACT

The remained oil in the reservoir after conventional water-flooding processes, forms a dispersed phase in the form of oil drops which is trapped by capillary forces and is almost about 70% of the original oil in the place (OOR). To reduce oil residual saturation in laboratory experiments and field projects, surfactant flooding is effective via decreasing the interfacial tension mobility ratio between oil and water phases. Estimation of the role of design variables, like chemical concentrations, partition coefficient and injection rate in different performance quantities, considering a heterogeneous and multiphase oil reservoir is a critical stage for optimal design. Increasing demand for oil production from water-flooded reservoirs has caused an increasing interest in surfactant-polymer (SP) and alkali-surfactant-polymer (ASP). Modeling minimizes the risk of high cost of chemicals by improving our insight of process. In the present paper, a surfactant compositional flood model for a three-component (water, petroleum and surfactant),two phase (aqueous and oleic) system is studied. A homogeneous, two-dimensional, isothermal reservoir with no free gas or alkali is assumed. The governing equations are in three categories: the continuity equations for the transport of each component, Darcy’s equation for the transport of each phase and other auxiliary equations. The equations are solved by finite-differences using a procedure implicit in pressure and explicit in saturation. The validation of the model is achieved through comparing the modeling results with CMG simulators and Buckley–Leverett theory. The results of modeling showed good agreement with CMG results, and the comparison with Buckley–Leverett theory is explained according to different assumptions. After validation of the model, in order to investigate sensitivity analysis, the effects of system variables (partition coefficient, surface tension, oil viscosity and surface injection concentration) and performance variable (cumulative oil recovery) are studied. Finally, the comparison of oil recovery between water-flooding and surfactant-flooding was done. The results showed higher oil recovery with changes in capillary number when the partition coefficient is greater than unity. Increasing oil viscosity resulted in decreasing the oil recovery by changing in fractional flow. Moreover, it was concluded that the oil recovery was enhanced by increasing surfactant injection concentration. The oil recovery was increased when surfactant was

* Corresponding author. Institut de Recherche en Génie Chimique et Pétrolier (IRGCP), Paris Cedex, France.
E-mail addresses: a.h.m@irgcp.fr, amir_h_mohammadi@yahoo.com (A.H. Mohammadi).

Peer review under responsibility of Southwest Petroleum University.
1. Introduction

The purpose of surfactant-flooding is decreasing the interfacial tension between oil phase and water phase, then oil can easily displace in porous media. Surfactant-flooding is a multicomponent-multiphase system, and can improve oil recovery by injecting a solution of surfactant. This method of EOR, recovers the residual oil saturation by reducing interfacial tension between oil and water phases. Surfactants in low concentration make better the desired oil recovery by decreasing the interfacial tension, alteration of wettability from oil-wet to water-wet, and increasing Capillary number \cite{1,2}. The mechanism of surfactant flooding relates to structures of surfactants molecules which they typically composed of a strong hydrophilic (water loving) group, and a strong hydrophobic (water fearing) group. After injections, it goes to the interface of oil phase and water phase and by accumulating in the form of micelles reduces the interfacial tension between the phases. After the formation of microemulsion of oil and water, the trapped oil is mobilized and the oil recovery increases. Also, surfactant is adsorbed on the surface of the reservoir, and alters the wettability of the reservoir from oil wet to water wet \cite{3,4}. Surfactant flooding can also recover a very high fraction of trapped oil at tertiary oil recovery, so the process should be designed in a cost effective way.

Experimental researches revealed loads of parameters which affect the recovery process. One of the difficulties in chemical-flooding modeling is the complexity of the parameters. Physical properties presented in the process are: interfacial tension between phases, relative permeability, phase saturations, partition coefficients, salinity, surfactant concentration, adsorption, phase viscosities and retention of surfactants \cite{5,6}. Many researchers have been trying to apply different assumptions in order to simplify the complexity and relations among existing variables. Many authors studied the mechanism of chemical-flooding with different methods.

Paul et al. predicted a simplified model for estimating economical aspects of surfactant flooding. They considered the variations of capillary number, surfactant adsorption, wettability and permeability in their designation. Moreover, the effect of salinity which has an important role in oil recovery was ignored in Paul's model \cite{7}. Wang et al. investigated a sensitivity analysis on surfactant flooding, and studied the effect of different parameters. They used the modified model of Pope and Nelson. In one study they considered the process at constant salinity and in another case, extended the work to variable salinity. They detected the effect of salinity, changes of surfactant concentration due to adsorption and initial value of injected surfactant on oil recovery \cite{8}. Camilleri et al. designed the surfactant-polymer flooding process under isothermal, multicomponent and multiphase conditions in a porous media. They studied the effects of polymer viscosity, surfactant and polymer adsorption, and the dependency of saturations to capillary number and permeability. Finally, they validated their results against experimental data \cite{9–11}. Han et al. studied the designation of chemical flooding with GPAS simulator. In Han's modeling the third equation of state was used for hydrocarbon phase behavior, and Hand’s rule was used for surfactant/oil/water phase behavior. GPAS solves the modeling equations with fully implicit method. Han studied the phase behavior of surfactant/oil/water solution, interfacial tension, viscosities, adsorption and relative permeability \cite{12}. One of the most famous simulators developed at The University of Texas at Austin is UTCHEM. UTCHEM has the capability of simulating 19 components and 4 phases and considering most physical properties. UTCHEM simulates chemical-flooding in implicit pressure and explicit concentration (IMPES) code. Delshad et al. presented a complete survey of this simulator in several papers \cite{13}. Najafabadi et al. simulated the process of surfactant-polymer flooding with UTCHEM for three types of Winsor phase behavior. In their modeling not only the surfactant was partitioned into three phases, but also the polymer and salt were partitioned between the phases. They used the Hand’s rule for phase behavior, and neglected the effect of pressure on surfactant solution phase behavior. Finally, they compared the achieved results of UTCHEM with GPAS \cite{14}.

This study intends to present the governing equations for surfactant flooding using the implicit-pressure, explicit composition and explicit-saturation method. The brief review of formulations will be given, then the validation against Buckley–Leverett theory and CMG Simulation will be displayed. Finally, the sensitivity analysis of some parameters will be presented in details.

2. Model assumptions

1. Two phases—an oil phase and a water phase, three component-oil, water and surfactant—are considered.
2. Only the surfactant component is partitioned in two phases and the equilibrium component relation is given by:

\[ K_c = \frac{\gamma_{water}}{\gamma_{oil}} \]

3. Dispersion is neglected.
4. Isothermal condition in reservoir.
5. Adsorption of surfactant is not considered.
6. No free gas and Alkali is present in the system.
7. The system is two dimensional with uniform properties.
8. The effect of salinity on phase behavior is neglected.
9. There are no chemical reactions.
10. Darcy's law applies to the flow of each phase.

2.1. Governing equations

The theory presented here, provides an understanding for the case of two phase and three components flow in a porous medium. Using the above assumptions, the compositional mathematical modeling based on Sabeti's \cite{15–17} method is as follows:
2.2. Material balance

\[
\frac{\partial (\phi (x_m \tilde{\xi}_O + y_m \tilde{\xi}_W))}{\partial t} + \nabla \cdot (x_m \phi \tilde{u}_O + y_m \phi \tilde{u}_W) = q_m
\]  
(1)

Where subscripts O and W refer to oil and water phases and subscript m refers to each component.

Equation (1) can be written for each component:

Oil component:

\[
\frac{\partial (\phi (x_m \tilde{\xi}_O))}{\partial t} + \nabla \cdot (x_m \phi \tilde{u}_O) = q_{oil}
\]  
(2)

Water component:

\[
\frac{\partial (\phi (y_m \tilde{\xi}_W))}{\partial t} + \nabla \cdot (y_m \phi \tilde{u}_W) = q_{water}
\]  
(3)

Surfactant component:

\[
\frac{\partial (\phi (x_{surf} \tilde{\xi}_O + y_{surf} \tilde{\xi}_W))}{\partial t} + \nabla \cdot (x_{surf} \phi \tilde{u}_O + y_{surf} \phi \tilde{u}_W) = q_{surf}
\]  
(4)

Darcy’s equation:

\[
u_a = -\frac{k_a}{\mu_a} \mathbf{K}(P_a - \rho_a g \mathbf{F} \mathbf{Z})
\]  
(5)

Constrained relations:

\[
\sum_{m=1}^{N_c} x_m = 1
\]  
(6)

\[
\sum_{m=1}^{N_c} y_m = 1
\]  
(7)

\[
x_{surf} + S_w = 1
\]  
(8)

After substituting Darcy’s equation, Eq. (1) is changed for each component as follows:

\[
\frac{\partial (\phi (x_m \tilde{\xi}_O + y_m \tilde{\xi}_W))}{\partial t} = \nabla \cdot (x_m \phi \nabla P_a - \gamma_a \nabla Z) + T_m \nabla \cdot (\nabla P_a - \gamma_w \nabla Z) + x_m q_a + y_m q_w
\]  
(9)

By summing up Eq. (1) over all components, the following form of relation is obtained for calculating the pressure:

\[
\frac{\partial (\phi (S_0 \tilde{\xi}_O + S_w \tilde{\xi}_W))}{\partial t} = \nabla \cdot (T_a (P_a - \gamma_a \mathbf{F} \mathbf{Z})) + T_w (P_w - \gamma_w \mathbf{F} \mathbf{Z}) + q_a + q_w
\]  
(10)

\[
T_a = \frac{\xi_a k_a}{\mu_a} \mathbf{K}
\]  
(11)

\[
T_{ma} = \frac{x_{ma} \xi_a k_a}{\mu_a} \mathbf{K}
\]  
(12)

Now by using the formulations in Appendix, Eq. (10) can be simplified as follows:

\[
\begin{align*}
\frac{V_p}{\partial t} & \left( \frac{\partial^2 \xi}{\partial \xi_a} \right) + \frac{V_w}{\partial t} \left( \frac{\partial^2 \xi}{\partial \xi_a} \right) + \frac{V_r}{\partial t} \left( \frac{\partial^2 \xi}{\partial \xi_a} \right) + \frac{V_t}{\partial t} \left( \frac{\partial^2 \xi}{\partial \xi_a} \right) \right)_{ij} = \frac{\partial (\phi \xi_a)}{\partial \xi_a} \\
& = \frac{\partial (\phi \xi_a)}{\partial \xi_a} + \frac{\partial (\phi \xi_a)}{\partial \xi_a} + \frac{\partial (\phi \xi_a)}{\partial \xi_a} + \frac{\partial (\phi \xi_a)}{\partial \xi_a} \right)_{ij} = \frac{\partial (\phi \xi_a)}{\partial \xi_a}
\end{align*}
\]  
(13)

By considering the equilibrium relation, the right hand side of Eq. (9) can be written as follows:

\[
x_m \tilde{\xi}_O + x_m \tilde{\xi}_W = q_a (\tilde{\xi}_O + \tilde{\xi}_W)
\]  
(14)

Then by inserting Eq. (14) into Eq. (9) and discretization the new equation, the following relation can be obtained:

\[
\begin{align*}
\frac{z_{m+1} - z_m}{\Delta t} & = \left( \frac{T_{ma+1}}{x_{ma+1}} \right) \left( \frac{p_{m+1} - p_{m+1}}{\partial \xi_a} \right) + \left( \frac{T_{ma-1}}{x_{ma-1}} \right) \left( \frac{p_{m+1} - p_{m+1}}{\partial \xi_a} \right) + \left( \frac{T_{ma+1}}{x_{ma+1}} \right) \left( \frac{\partial^2 \xi}{\partial \xi_a} \right) + \left( \frac{T_{ma-1}}{x_{ma-1}} \right) \left( \frac{\partial^2 \xi}{\partial \xi_a} \right) \right)_{ij} = \frac{\partial (\phi \xi_a)}{\partial \xi_a}
\end{align*}
\]  
(15)

2.3. Solution procedure

The governing equations are solved by applying implicit pressure, and explicit saturation method. The essential reservoir variables (pressure, saturations and components) in the grid blocks at each step time are calculated by the following sequence:

1. The pressures in each grid block are calculated from Eq. (13).
2. The overall compositions of each component are calculated from Eq. (14).
3. The compositions of each component in each phase and the amount of each phase are computed from equilibrium relations.
4. The saturations of water phase and oleic phase are calculated from the following relations:
5 Evaluating the errors of each pressure grid block until the errors converge to minimum value.

\[ S_w^{n+1} = \left( \frac{\xi_o (1 - L)}{L \xi_w + (1 - L) \xi_o} \right)^{n+1} \]

\[ S_o^{n+1} = \left( \frac{\xi_w L}{L \xi_w + (1 - L) \xi_o} \right)^{n+1} \]

6 After evaluating the unknowns in present steps, the results are used to return to step 1 for new \((t + \Delta t)\).

3. Validation

A 1D numerical model with 20 and 100 gridblocks were considered to validate against Buckley-Leverett theory and CMG simulation. The relations between permeability and saturation were used from the data presented in Fig. 1. The initial water saturation was 0.22 (Table 1) and the capillary pressures of the phases are displayed at Table 2. The injection was done at a constant rate of 0.005 cm³/s and the production was obtained at a constant well-bore pressure. Fig. 2 shows the results of the modeling against CMG simulation and Buckley–Leverett theory at 7 h after beginning of the water-flooding.

As indicated in Fig. 2 there is a good agreement between the presented model and CMG simulation results for the 20 gridblocks. The results of Buckley-Leverret calculation are also depicted in Fig. 2. At normalized position 0.75, there is a difference between Buckley–Leverett theory and the models even with small gridblocks by 100 numbers. Buckley–Leverett is a quantitative relation for frontal-advanced theory which takes into account different simplification assumptions. But this theory approximately gives real results with accurate frontal saturation of water in a horizontal core sample. Always numerical modeling of water-flooding causes deviation from Buckley–Leverett theory results [16]. However, the average of water saturation is the same in both models and the theory.

---

Table 1

<table>
<thead>
<tr>
<th>Property</th>
<th>Permeability (mDarcy)</th>
<th>Porosity (%)</th>
<th>Reservoir pressure (kPa)</th>
<th>Oil density (g/cm³)</th>
<th>Initial oil viscosity (cp)</th>
<th>Residual oil saturation</th>
<th>Initial water saturation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>226</td>
<td>12.6</td>
<td>4000</td>
<td>0.725</td>
<td>2.24</td>
<td>0.35</td>
<td>0.22</td>
</tr>
</tbody>
</table>

Table 2

<table>
<thead>
<tr>
<th>Sw</th>
<th>Pcw0 (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.220</td>
<td>5</td>
</tr>
<tr>
<td>0.253</td>
<td>2.305</td>
</tr>
<tr>
<td>0.285</td>
<td>1.038</td>
</tr>
<tr>
<td>0.318</td>
<td>0.454</td>
</tr>
<tr>
<td>0.351</td>
<td>0.227</td>
</tr>
<tr>
<td>0.387</td>
<td>0.064</td>
</tr>
<tr>
<td>0.420</td>
<td>0</td>
</tr>
<tr>
<td>0.457</td>
<td>0</td>
</tr>
<tr>
<td>0.5</td>
<td>0</td>
</tr>
<tr>
<td>0.6</td>
<td>0</td>
</tr>
<tr>
<td>0.7</td>
<td>0</td>
</tr>
<tr>
<td>0.8</td>
<td>0</td>
</tr>
<tr>
<td>1</td>
<td>0</td>
</tr>
</tbody>
</table>

Fig. 1. The permeability of the reservoir.
Now by considering the accuracy of the presented simulator, some of the effective parameters in oil production on the reservoir bed will be studied. In this paper a mixture of water and surfactant was subjected to a reservoir at an average bed pressure of 4000 kPa and 65 °C during 1hr, then in continuation of process pure water under the same conditions was admitted. The characters of the reservoir were similar to Table 1 but the 50 × 25 × 5 cm³ (i × j × k) bed by 2D fluid flows was chosen for a considerable analysis, so the distance between the production and injection wells is 50 cm. The output results have been clarified at the following sections.

4. Interfacial tension

It was shown previously [14] that at a surfactant flooding the contents of surfactant reduce the IFT between water and oil phases. Followed by reduction of IFT, the Capillary number is increased then the trapped oil is mobilized and finally it results in improvement of oil production. In a more tangible way, according to the equation of the Capillary number, \( N_{ca} = \frac{\mu_m}{\sigma_{ow}} \) [18], which is the ratio of viscous forces to capillary forces, by decreasing IFT capillary number will be increased. In another way, the reduction of IFT has an influence on relative permeability. The effect of mole fraction of surfactant on interfacial tension of the fluid sample and the range of capillary number values sequentially are classified in Table 3 and Table 4. Adding surfactant to the system can result in reduction of residual saturations and alteration of relative wettability of the phases. Finally, high concentrations of surfactant and hence very low IFT values, lessen the residual saturations and make the relative permeability curves straight. This fact was experimentally shown by Van Quy and Labrid [19] and by Amaefule and Handy [20]. Their curves can be derived by interpolating the data of Table 4. In this table, \( N_{cap\_wet} \) and \( N_{cap\_non\_wet} \) (see Nomenclature) have been defined for two cases of high interfacial tension curves (no surfactant) and ultra-low interfacial tension curves (straight lines.)

The diagram of the relative permeability after the injection of the surfactant has been displayed in Fig. 3.

4.1. Mole fraction of injected surfactant

The case in which oil viscosity was 2.24 cp for three different concentrations of injected surfactant, oil recoveries were investigated. First, there was no surfactant in injected solution, so water flooding was done only. In other two cases the concentrations were increased to 0.01 and 0.004 mol fraction. As shown in Fig. 4 oil recovery at 0.01 mol fraction of the surfactant is more than other two concentrations. As mentioned before, the

<table>
<thead>
<tr>
<th>Table 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Effects of the surfactant mole fraction on IFT.</td>
</tr>
<tr>
<td><strong>Surfactant mole fraction</strong></td>
</tr>
<tr>
<td>0</td>
</tr>
<tr>
<td>0.0005</td>
</tr>
<tr>
<td>0.001</td>
</tr>
<tr>
<td>0.002</td>
</tr>
<tr>
<td>0.003</td>
</tr>
<tr>
<td>0.004</td>
</tr>
<tr>
<td>0.005</td>
</tr>
<tr>
<td>0.006</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>The boundaries of capillary numbers and their relative permeabilities.</td>
</tr>
<tr>
<td><strong>Sw</strong></td>
</tr>
<tr>
<td>0</td>
</tr>
<tr>
<td>0.1</td>
</tr>
<tr>
<td>0.2</td>
</tr>
<tr>
<td>0.3</td>
</tr>
<tr>
<td>0.4</td>
</tr>
<tr>
<td>0.5</td>
</tr>
<tr>
<td>0.6</td>
</tr>
<tr>
<td>0.7</td>
</tr>
<tr>
<td>0.8</td>
</tr>
<tr>
<td>0.9</td>
</tr>
<tr>
<td>1</td>
</tr>
</tbody>
</table>
The purpose of injecting surfactant in reservoirs is the reduction of IFT between two phases (oil-water), so at higher concentrations of the injected surfactant, the effect of more reduced IFT causes better oil recoveries. Furthermore, Fig. 5 compares the trends of the oil production rates. According to the figure, the surfactant reduces the gradual drop of the oil rates with the passage of time. Therefore, more mole fractions of surfactant prevent sharp downward trend of oil production.

Fig. 3. The permeability of the reservoir after surfactant injection.

Fig. 4. The cumulative oil production at the different surfactant mole fractions.
4.2. Oil viscosity and partition coefficient

According to the equation of fractional flow, $f_w = 1 + \frac{k_{ro}}{k_{rw}} \frac{\mu_o}{\mu_w}$, oil viscosity and water fractional flow have a reverse relation in a reservoir flow, so increasing the quantity of oil viscosity implies more water fractional flow and results low oil production. On the other hand, the more quantity of oil viscosity can increase the Capillary value which, at the superficial view, may result better oil recovery.
Fig. 7. Variation of water phase viscosity at 
\[ \mu_{\text{oil}} = 2.24 \, \text{cp}, \; K = 0.2 \]

Variation of water phase viscosity at 
\[ \mu_{\text{oil}} = 2.24 \, \text{cp}, \; K = 5 \]

Variation of water phase viscosity at 
\[ \mu_{\text{oil}} = 5 \times 2.24 \, \text{cp}, \; K = 0.2 \]

Variation of water phase viscosity at 
\[ \mu_{\text{oil}} = 5 \times 2.24 \, \text{cp}, \; K = 5 \]

Fig. 8. Variation of oil capillary No at 3 hrs.
In order to study the previous matter, the initial oil viscosity of the reservoir was changed from 2.24 to 5 cp. As can be seen from Fig. 6 there is a large discrepancy between the productions of lower and higher oil viscosities. It confirms the importance of oil fractional flow, which strongly relates to phases viscosities accordingly.

In detail, the partition coefficients also had a fairly influence on oil production. It has been shown by the contour plots of Fig. 7 and 8 how couple of the partition coefficients and phases viscosities can affect interconnected fractional flows and Capillary numbers in the reservoir flows. But briefly, partition coefficients present the distribution of surfactant between water and oil phases and the less partition coefficient value attaches more surfactant in oil phase and has a positive effect on oil Capillary number and oil relative permeability. On the other hand, the surfactant has a huge quantity value of viscosity. So, less partition coefficient value increases the oil phase viscosity and decreases oil fractional flow. In conclusion, according to Fig. 6 partition coefficients at different oil viscosity can have different effects on oil productions.

5. Conclusion

An implicit-pressure explicit composition and explicit-saturation method was developed to study sensitivity analysis of surfactant flooding parameters on oil production in a reservoir.

Water flooding decreases the oil production rate because of high IFT between oil and water, lower viscosity in comparison with oil, and inadequate amount of mobility. It was shown, surfactant reduces IFT between water and oil phases and eventually it implies to the mobility of trapped oil and higher oil production. The changes of interconnected fractional flows and Capillary numbers in the reservoir, determine how and how much oil could produce.

Surfactants prevent the fingering phenomenon, thus any amount of injected surfactant will result in partial increase in oil production. The study of concentrations of injected surfactant (and also flooding rates in a homogeneous medium) indicated that, increasing the concentration of injected surfactant significantly decreases IFT, therefore the production rate and recovery of oil increase to a higher extent. This is while the low amount of mole percentage of surfactant injection significantly affects cumulative oil production at the end of the process.

Appendix

The accumulation term of the modeling equation is changed as follows:

$$\frac{\partial (S_o \xi_o + S_w \xi_w)}{\partial t} = \left( S_o \frac{\partial (\phi \xi_o)}{\partial t} + \phi \frac{\partial S_o \xi_o}{\partial t} \right) + \left( S_w \frac{\partial (\phi \xi_w)}{\partial t} + \phi \frac{\partial S_w \xi_w}{\partial t} \right)$$

(A.1)

$$\frac{\partial (\phi \xi_o)}{\partial t} = \xi_o \frac{\partial \phi}{\partial t} + \phi \frac{\partial S_o \xi_o}{\partial t}$$

(A.2)

$$\frac{\partial (\phi \xi_w)}{\partial t} = \xi_w \frac{\partial \phi}{\partial t} + \phi \frac{\partial S_w \xi_w}{\partial t}$$

The capillary pressure’s relation applied in this modeling was introduced from Brown [21] and Sabeti et al. [15–17]:

$$P_w = P_o - P_{cow}. \quad P_{cow} = P_{cow}(S_w)$$

(A.4)

And, in general, the capillary pressure can be arisen from the establishing a connection between various parameters of porosity $\phi$, permeability $k$ and surface tension $\sigma$ by the name of $J$-function Brown [21].

$$J(S_w) = \frac{P_r k}{\sigma} \sqrt{\frac{1}{\phi}}$$

(A.5)

Nomenclature

- $\phi$: porosity of the reservoir bed, fraction
- $\xi_o$: density of oil phase, lbmol/ft3
- $\xi_w$: density of water phase, lbmol/ft3
- $g$: acceleration of gravity
- $K$: absolute permeability, md
- $k_{rel}$: relative permeability of phase $a$, fraction
- $P_r$: fluid pressure of phase $a$, psi
- $q_i$: sink or source terms of component $i$, lbmol/time
- $T_a$: transmissibility parameter of phase
- $t$: time, s
- $S_o$: saturation of oil phase, fraction
- $S_w$: saturation of water phase, fraction
- $u_a$: velocity of phase $a$
- $x_m$: composition of component in oil phase, fraction
- $y_m$: composition of component in water phase, fraction
- $Z_i$: total composition of component $i$

Variables of Table 4

- $Ncap_{non\_wet}$: residual oil saturation reaches zero (Critical capillary number for complete detrapping)
- $Ncap_{wet}$: residual water saturation reaches zero, and relative permeabilities are straight lines (Critical capillary number for complete detrapping)
- $Ncap_{non\_wet}$: both water and oil residual saturations start to decrease (Critical capillary number for detrapping to begin)
- $Ncap_{wet}$: intermediate curve reported by Van Quy and Labrid (Critical capillary number for detrapping to begin).

References


