Iranian Journal of Oil & Gas Science and Technology, Vol. 5, No. 1, pp. 13-26
http://ijogst.put.ac.ir

Simulation and Assessment of Surfactant Injection in Fractured Reservoirs: A Sensitivity Analysis of some Uncertain Parameters

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Received: April 25, 2015; *revised:* November 01, 2015; *accepted:* December 20, 2015

Abstract

Fracture reservoirs contain most of the oil reserves of the Middle East. Such reservoirs are poorly understood and recovery from fractured reservoirs is typically lower than those from conventional reservoirs. Many efforts have been made to enhance the recovery and production potential of these reservoirs. Fractured reservoirs with high matrix porosity and low matrix permeability need a secondary or EOR technique to achieve the maximum production. One of the effective EOR approaches is surfactant flooding, which reduces interfacial tension and alters wettability. Due to the complexity and uncertainty associated with such reservoirs, implementing a simulation and numerical analysis is primarily necessary to evaluate the effect of key engineering parameters on ultimate reservoir performance. This study assesses and provides a good insight into surfactant injection into fractured reservoirs using ECLIPSE software as a numerical simulator. The influences of fracture-matrix permeability ratio, initial water saturation, and the number of grids on reservoir performance were assessed and a sensitivity analysis was carried out. This study takes surfactant-related phenomena such as adsorption, surface tension reduction, and wettability alteration into account. The simulation results demonstrate that fracture-matrix permeability ratio is an important screening quantity for the selection of surfactant flooding as an EOR agent and that uncertainty in the initial water saturation of matrix has a great influence on the simulation outputs.

Keywords: Surfactant, Fracture Reservoir, Simulation, Dual-porosity

1. Introduction

Typically over 20% of the world's oil reserves are naturally fractured (Saidi, 1983), while over 60% of the world's remaining oil lies trapped in fractured reservoirs (Kathel and Mohanty, 2013). Unfortunately, after primary and secondary oil recovery processes, two third of the original oil in place (OOIP) will be remained in reservoirs due to trapping in pore structures and/or injected fluids bypassing (Uleberg and Kleppe, 1996).

Among the petrophysical properties applied in reservoir engineering studies, wettability takes the overall impact on the other rock-fluid properties, which quantitatively represent rock and fluid interactions such as relative permeability, capillary pressure, and the distribution of fluid phases in

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porous media. Wettability, therefore, is of significant importance in affecting the rate of production and ultimate oil recovery (Rao and Girard, 1996) and could result in a failure of some EOR processes. In this regard, the study conducted by Allan and Sun (Allan and Sun, 2003) on 100 fractured reservoirs showed that conventional water flooding operations mostly lead to lower oil recovery than expected because of mixed- or oil-wet initial wettability in almost all of the investigated reservoirs.

In fractured reservoirs, if the matrix wettability is altered toward water-wet, a large amount of oil would be recovered through spontaneous imbibition while pushing oil by an external fluid. To date, several enhanced oil recovery methods such as thermal (Babadagli, 2003) including steam and hot water injection and chemical flooding using surfactants and low salinity brine (Nasr-El-Din, 2013) have been employed to alter the wettability of fracture reservoirs. In the case of common methods, surfactant injection is an effective and well-known operation, which reduces surface tension between original oil and the injected fluids, and this is the main reason for using surfactants. Figure 1 schematically shows surfactant injection operation.

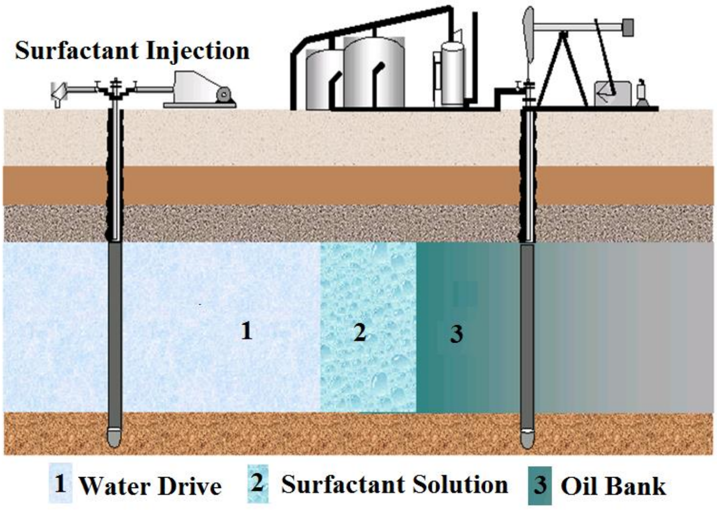

Figure 1
A schematic of surfactant flooding operation (Shah, 2012).

Although many operations suffer from surfactant adsorption on rock surface, which causes economical and technical issues, the induced wettability alteration could be beneficial in most cases and has received attention in recent years. Schmid and Sophie (Schmid, 2012) conducted an experimental study to evaluate the effect of additive surfactants in aqueous solutions on the degree of wettability alteration and their numerical simulation showed that by altering wettability towards water-wet, more oil will be recovered.

In spite of numerous core-scale laboratory researches on wettability alteration (Adibhatla et al., 2006; Delshad et al., 2009; Mojdeh Delshad and Najafabadi, 2009; Delshad et al., 2006), it seems that more numerical and simulation works are required for comprehending mechanisms involved in larger-scale operations. In this work, we investigate the advantages of surfactant injection in fractured reservoirs using commercial simulation software (ECLIPSE 100). We focus on the influence of some engineering parameters on the operation performance of surfactant flooding, while the effect of surface tension and wettability alteration in oil recovery improvement are taken into account.

The presence of fracture, which is defined by Barenblatt (Barenblatt, 1962) as discontinuity in the reservoir rock, imposes more complexity than conventional cases in the simulation process. To make a convenient representation of fluid flow through fractured reservoirs, researchers have made attempts to suggest simple models to overcome this complication (Warren and Root, 1963; Kazemi and Merrill, 1979). Dual porosity is a well-known notion in petroleum industry, which was introduced for the first time by Warren and Root (Warren and Root, 1963). In this model, reservoir structure is divided into two media, namely a matrix representing continuous mass of rock and media of the main storage capacity and the fracture as a media with much higher permeability than matrix, which provides less resistive paths for fluid movement in rock. Figure 2 depicts the idealized model of an actual fractured reservoir.

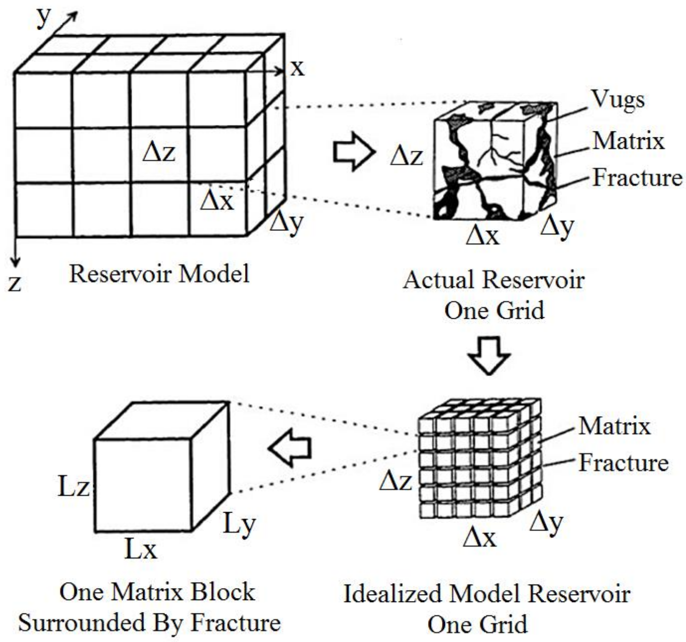

Figure 2
An idealized representation of a fractured reservoir by sugar cubic model (Fathi Najafabadi, 2009).

Further studies propose a similar approach named dual permeability, in which matrixes are connected together like fractures and contribute to fluid conduction toward production wells. Figure 3 shows the difference between these models. Kazemi et al. (Kazemi and Merrill, 1979) advanced fracture reservoir modeling by extending Warren and Root's suggested concept for multi-phase fluid flows. They derived two sets of flow equations, one for matrix and the other for fracture media. These equations are included in the Appendix. Figure 3 schematically depicts the concept of dual porosity and permeability. The important point regarding these equations is transfer function, representing fluid exchange capacity between matrix and fracture in terms of pressure difference between two media and a proportionality factor known as the shape factor. In first view, this function seems to be simple, but the presence of the shape factor as an unknown parameter makes the simulation an experience-based work, which requires pronounced knowledge of all the physical and mathematical influencing parameters.

Many parameters, for instance, initial water saturation even with empirically measureable techniques are in reality uncertain. The data monitored from logging and well-test operations inherently possess some uncertainty regarding petrophysical properties such as initial water saturation, permeability and so on. Fracture and matrix permeability simultaneously control the overall performance of the reservoir and also their ratio is a criterion for fractured-reservoir classification. Any simulations need the discretization of continuum media into finite connected cells called grids. Converting real complex reservoir into a simple numerical model is affected by the number of grids selected to represent the real reservoir. Thus any reservoir engineer needs pre-knowledge of the influence of grid selection on the result of reservoir simulation.

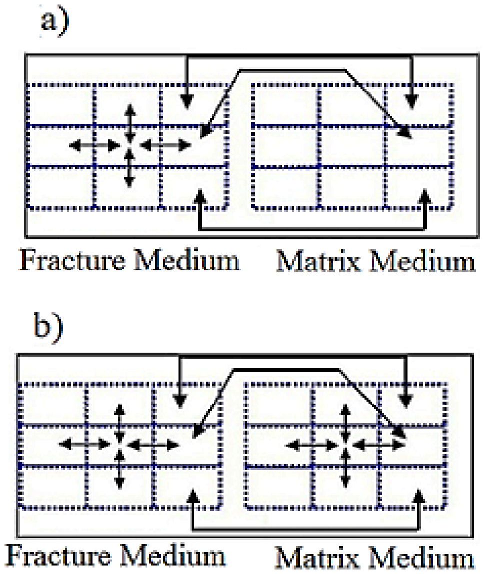

Figure 3
Fluid exchange in (a) dual porosity and (b) dual permeability models (Fathi Najafabadi, 2009).

A few simulation studies have been carried out by Delshad et al. (Farhadinia and Delshad, 2010), Fathi (Fathi Najafabadi, 2009), and Goudarzi (Goudarzi, 2011) for investigating the impact of surfactant adsorption on the performance of a simple cubic geometrical reservoir and a number of substantial results were attained on the role of adsorption in recovery improvement solely by employing simulation software and experimentally obtained data. However, all of these works have utilized UTCHEM as their simulating tool. Although UTCHEM has proved its acceptable performance on an academic level, it is not worldwide and convenient to use in comparison with other commercial software like ECLIPSE and CMG. Amongst, Eclipse is well-known simulator software in petroleum industry and is able to precisely simulate fluid flow in reservoir with the aid of geological and engineering data; moreover, it has been implemented by most companies all over the world.

2. Simulation process

In this work, we intent to investigate the effect of some less considered parameters, including initial water saturation, fracture to matrix permeability ratio, and the number of grids on the performance of oil recovery through surfactant injection. In this context, for simplicity and focusing narrowly on the considered parameters, a reservoir was modeled as a cubic geometry with no flow boundary having equal length, width, and thickness of 100 ft. The model consists of two wells, one in a corner and the other in the opposite point. The scheme of the grid structure is shown in Figure 4. A distinct zone of the grid blocks with a permeability of 2000 mD in all directions and a porosity of 0.01 was used to represent the fractures between matrix blocks. The matrix blocks are 10 ft. in all directions with a permeability of 34 mD and a porosity of 0.298. The summery of rocks, fluids, and input simulation parameters are listed in Table 1. As a typical industrial operation, like Figure 1, firstly a small slug of surfactant as an interfacial tension reducing agent was injected and then water continually flooded for a longer time. It should be noted that the reservoir modeled in this study is initially oil-wet and the injected surfactant is able to change wettability to water-wet.

Table 1
Input simulation parameters.

Simulation parameter	Matrix	Fracture
Grid	10×10×10	10×10×10
Grid size (ft.)	10	10
Porosity	0.298	0.01
Permeability (mD)	34	2000
Initial water saturation	0.1	0.05
Flow rate (ft^3/day)	50	
Surfactant concentration of injected micro-emulsion (lb./STB)	218	
Water and oil viscosity (cP)	1.038 and 1.30	

In ECLIPSE, the upper half grids are considered as matrix and the lower ones as fracture grids. In black oil mode, the continuum equations were implicitly solved for each grid and a transfer function represented corresponding fluid exchange between each matrix and fracture. As explained before, the shape factor is the main controlling factor in this function and regarded as a history matching parameter by reservoir engineers, but not as a realistic physical parameter. The equations proposed by Kazemi et al. (Kazemi and Merrill, 1979) are considered as the default formula, given in the Appendix, for calculating the shape factor value in the ECLIPSE simulator. However, a sensitivity analysis is beneficial for understanding the significant role of the shape factor in instantaneous and ultimate reservoir recovery.

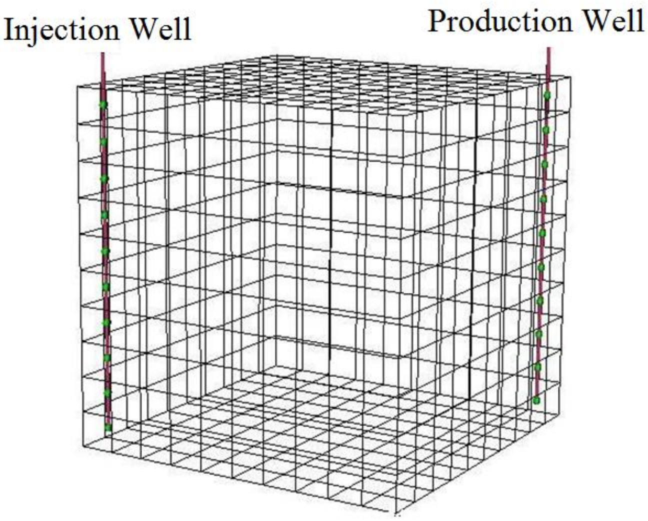

Figure 4
Grid structure and well locations in the model used for the simulation of the reservoir.

Surfactant and reservoir fluid properties are those reported for Norne E-segment (Emegwalu, 2010) and rock-fluid interaction properties, i.e., capillary pressure and relative permeability, proposed by

Farhadnia and Delshad (Farhadinia and Delshad, 2010) are included in Table 2 and were used for generating the related curves with Corey type model (Delshad and Pope, 1989) as given below:

$$k_{rl}=k_{rl}^{o}\left(\frac{S_l-S_{lr}}{1-\sum_{l=1}^{3}S_{lr}}\right)^{n_l} \tag{1}$$

$$P_{c_{lo}}=C_{pc}\frac{\sigma_{ol}}{\sigma_{ow}}\left(1-\frac{S_l-S_{lr}}{1-\sum_{l=1}^{3}S_{lr}}\right)^{E_{pc}} \tag{2}$$

where, subscripts o, w, and l denote oil, water, and either of them respectively. S, P_c, and k represent, respectively, saturation, capillary pressure, and permeability. Figures 5 and 6 show relative permeability curves obtained using Equation 1. It is noteworthy that these data have an experimental basis, so the model could be considered as a realistic reservoir sector.

Table 2

Relative permeability and capillary pressure parameters of the matrix and fracture.

Simulation Parameters	Matrix		Fracture	
	Oil-wet	**Water-wet**	**Oil-wet**	**Water-wet**
Residual water saturation(S_{wr})	0.1	0.2	0.05	0.1
Residual oil saturation(S_{or})	0.4	0.2	0.035	0.1
Water rel. perm endpoint(k_{rw}^{0})	0.3	0.2	0.4	0.3
Oil rel. perm endpoint(k_{ro}^{0})	0.4	0.7	0.6	1
Water rel. perm Exponent(n_w)	2	2.5	1.5	2
Oil rel. perm Exponent(n_w)	3	2	1.8	1.5
Positive capillary pressure endpoint (psia)	0.3	0.3	0	N/A
Negative capillary pressure endpoint (psia)	-0.43	-	0	-
Capillary pressure exponent (E_{pc})	3	3	0	N/A
Water saturation at zero capillary pressure	0.41	-	0	-

3. Results and discussion

A sensitivity analysis was performed on three parameters, namely (1) initial water saturation, (2) fracture to matrix permeability ratio, and (3) the number of grids. Almost all of the technical and economical results of an EOR process, such as those reported herein, are reflected in the amount of produced oil and chemicals.

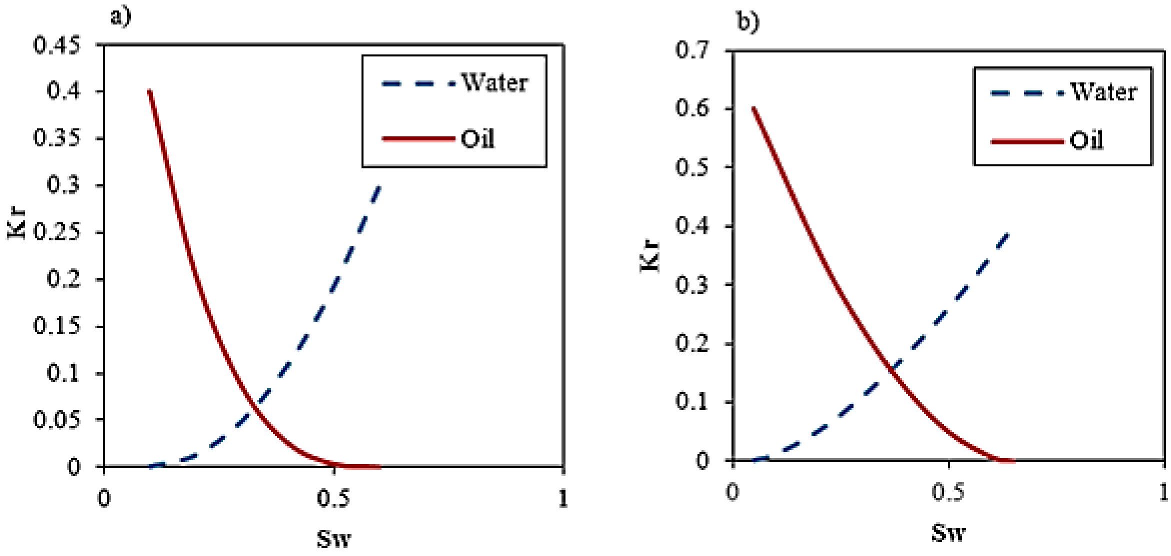

Figure 5
Relative permeability of oil-wet rock versus water saturation in oil-wet rock: (a) matrix and (b) fracture.

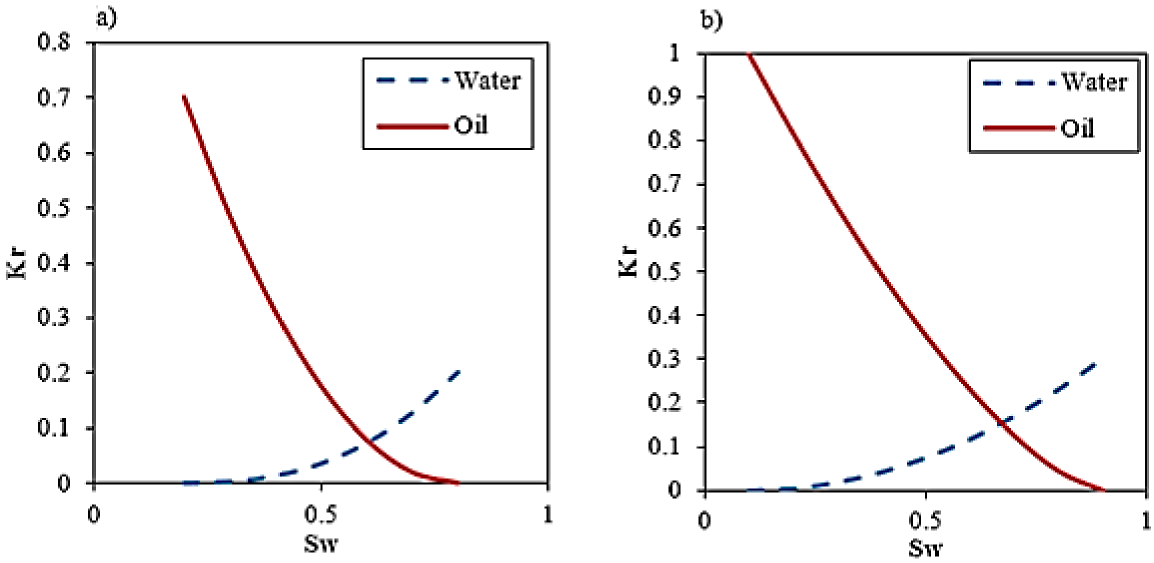

Figure 6
Relative permeability of water-wet rock versus water saturation in water-wet rock: (a) matrix and (b) fracture.

As Figures 7 and 8 show, initial water saturation strongly impacts reservoir performance. It should be noted that matrix water saturation interestingly has a significant effect on the simulation results; however, the influence of fracture on the results is negligible. As matrix contains most of the oil reserves, a slightly change in measuring or estimating its fluid saturation may lead to a significant deviation of the simulation prediction from the actual reservoir behavior. In contrast, the water saturation of the fractured media is of trivial impact.

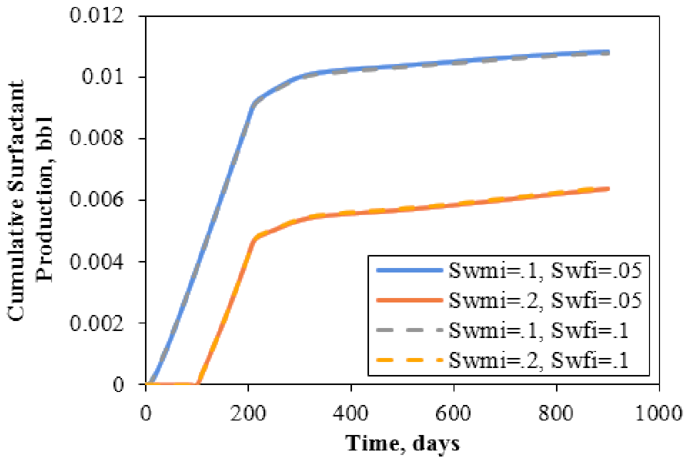

Figure 7
Effect of initial water saturation on cumulative surfactant withdrawal time.

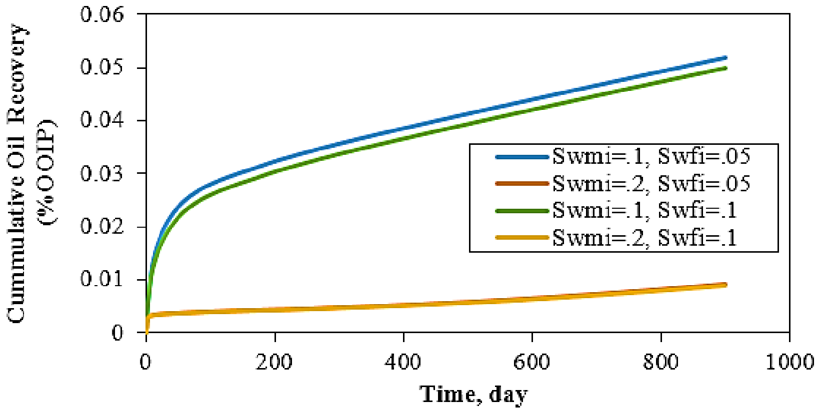

Figure 8
Effect of initial water saturation on cumulative oil recovery versus time.

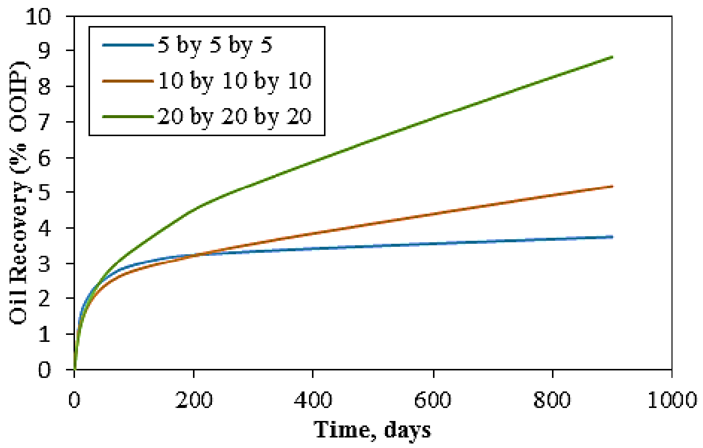

Figure 9
Effect of gridding on oil recovery versus time.

One can see a similarity in all Figures 7-15 in an early time interval of about 200 days, in which a sharp increase in the amount of the produced oil and surfactant is observed. Unsurprisingly, this is due to fracture dominant flow, which governs fluid movement behavior in the reservoir. In the early phase of injection, fractures provide a high conductive path for fluid movement. Thus, in this stage, regardless of the amount of k_f/k_m, all the injected surfactant along with the oil trapped in fractures will be produced. But, at the same time, some surfactant will penetrate through the matrix media, which will be effective in further production from matrix.

However, after this flow regime was elapsed, matrix showed its significant contribution. As Figure 13 shows, by increasing the fracture to matrix permeability ratio, the cumulative oil production decreases in longer times. As fracture to matrix permeability ratio becomes lower, the fluid phases could more deeply penetrate into the matrix media during the movement from the injection well toward the production well; hence there is a better opportunity for surfactant to be adsorbed onto the matrix media and subsequently change wettability from originally oil-wet into more water-wet.

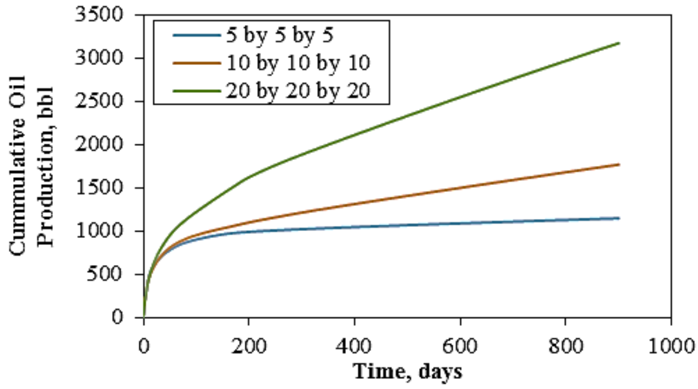

Figure 10
Effect of gridding on cumulative oil production versus time.

The number of grid block is an engineering selection of two opposite effects; having numerous, fine grids leads to the more accurate simulation of physical phenomena, especially fluid transport and exchange in a simulating process; however, it demands much computational effort. On the other hand, selecting a coarser mesh size could simulate reservoir as sufficient as the fine-grid model, while offering lower computational time.

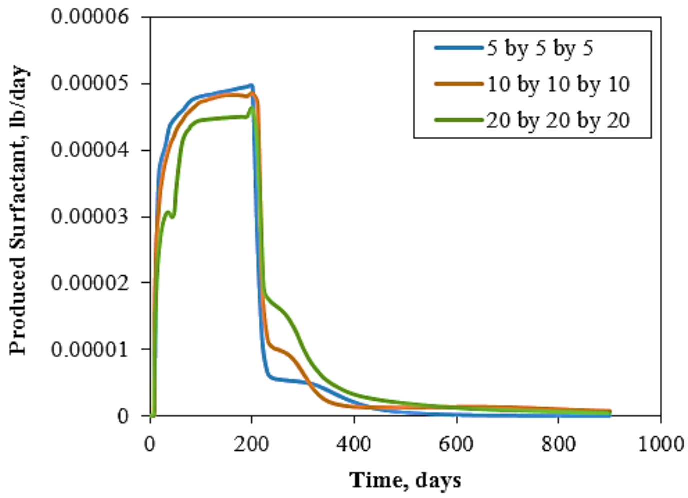

Figure 11
Effect of gridding on the rate of surfactant withdrawal versus time.

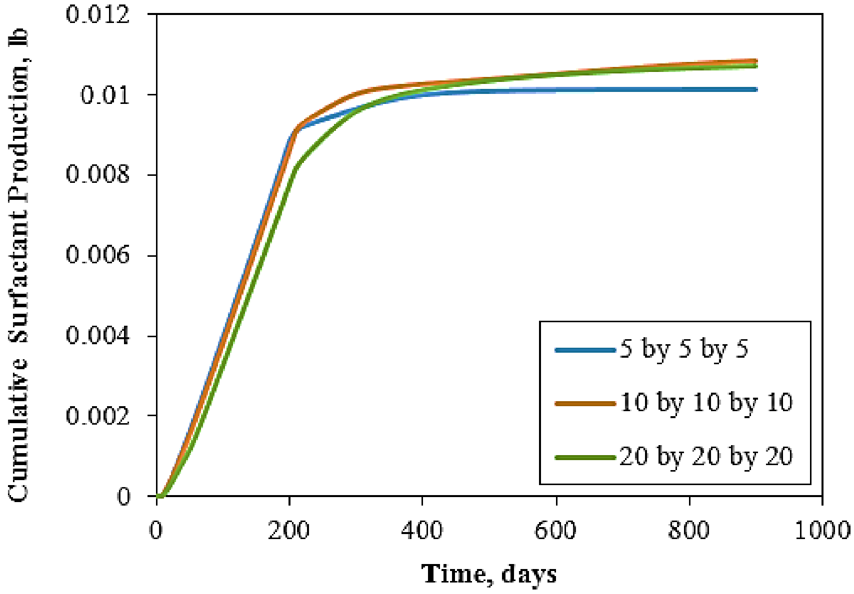

Figure 12
Effect of gridding on cumulative surfactant withdrawal versus time.

By taking this effect into account, Figures 9-12 show that increasing the number of grids leads to higher ultimate oil and surfactant production. This result demonstrates the strong dependency of simulation performance on the number of grids. The implementation of pore-scale phenomena demands a fine grid structure. As mesh structure changes toward coarser grids, the numerical simulation of rock-fluid interaction becomes a rougher estimate of the real state. On the other hand, using finer grids helps the accurate modeling of fracture-matrix and rock-fluid interaction. In summary, as expected, the cases with the higher number of grids (20×20×20) represents the real nature of the fluid flow exchange between the matrix and the fracture more accurately, and consequently takes surfactant-rock interaction into account better.

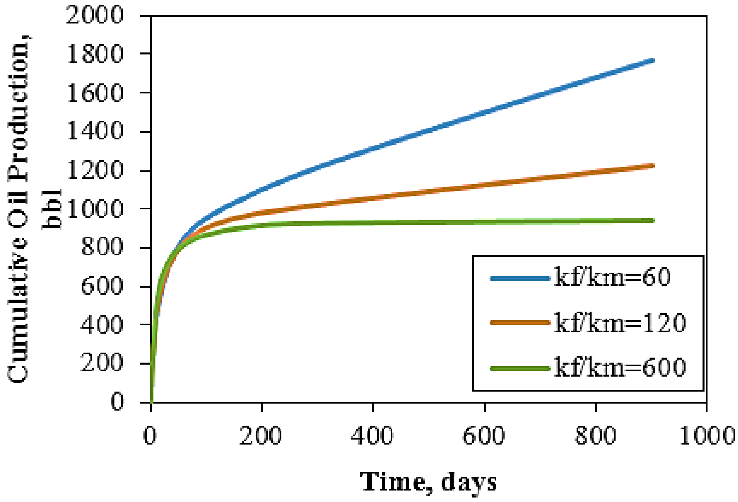

Figure 13
Effect of fracture to matrix permeability ratio on cumulative oil production versus time.

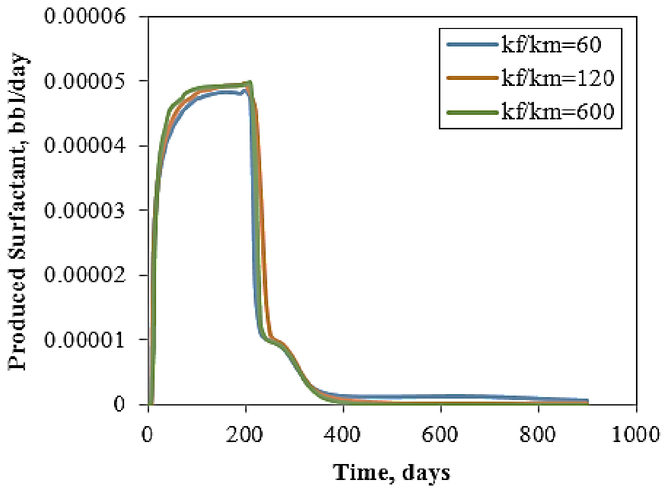

Figure 14
Effect of fracture to matrix permeability ratio on rate of surfactant withdrawal versus time.

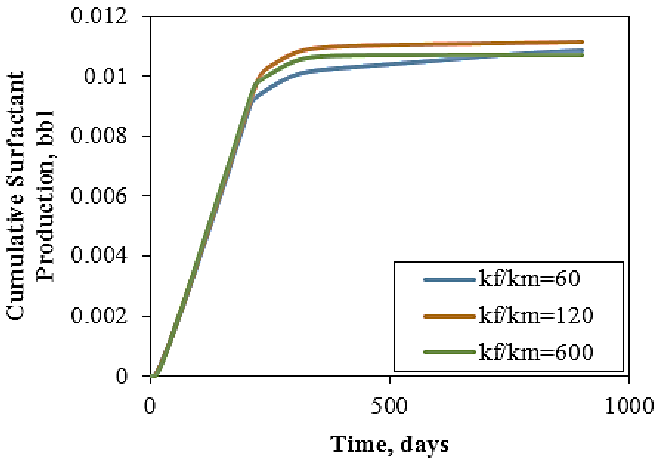

Figure 15
Effect of fracture to matrix permeability ratio on cumulative surfactant withdrawal versus time.

4. Conclusions

This study offers some points on the contribution of engineering parameters to the simulation of fractured reservoirs. In addition to considering matrix-fracture interaction, all the plausible effects during surfactant injection were taken into account to make the simulations more reliable and similar to what occurs in real reservoirs. Using real field and experimental data, the obtained results could be imagined for a real pilot project. The main results are as follows:

1. Surfactant flooding is not recommended for reservoirs with a high fracture to matrix permeability ratio.
2. Matrix initial water saturation interestingly shows a significant effect on the simulation results, whereas the influence of fracture initial water saturation is negligible.
3. To obtain a realistic model of surfactant injection into fractured reservoirs, the number of grids should be precisely considered and can affect the fluid exchange between fracture and matrix media.

Appendix

In dual permeability modeling, each fracture and matrix medium has its flow equation written as:

$$\nabla\lambda_{\alpha f/m}(\nabla P_{\alpha f/m}-\rho_{\alpha f/m}\frac{g}{g_c}\nabla Z)=\frac{\partial}{\partial t}(\frac{\phi S_\alpha}{B_\alpha})_{f/m}+q_{\alpha f/m}+\tau_{\alpha m-f} \quad (1)$$

where, $\tau_{\alpha m-f}$ denotes transfer function, which accounts for fluid exchange between the matrix and the fracture as follows:

$$\tau_{\alpha m-f}=\frac{\partial}{\partial t}(\frac{\phi S_\alpha}{B_\alpha})_m \quad (2)$$

where, $\lambda_{\alpha f/m}$ represents transmissibility and is defined by:

$$\lambda_{\alpha f}=\frac{k_{r\alpha f}}{\mu_\alpha B_\alpha}k_f \quad (3)$$

Transfer function ($\tau_{\alpha m-f}$) can be written in a general form as given below:

$$\tau_{\alpha m-f}=-T_{\alpha m-f}\left[\left(P_{\alpha f}-\rho_{of}\frac{g}{g_c}Z_f\right)-\left(P_{\alpha m}-\rho_{om}\frac{g}{g_c}Z_m\right)\right] \quad (4)$$

where, $T_{\alpha m-f}$ is the matrix/fracture transmissibly and is given by:

$$T_{\alpha m-f}=\sigma V_b k_m(\frac{k_r}{\mu B})_{\alpha m} \quad (5)$$

where, σ stands for the shape factor and is defined by:

$$\sigma=4\left(\frac{1}{L_x^2}+\frac{1}{L_y^2}+\frac{1}{L_z^2}\right) \quad (6)$$

As the above equation shows, σ depends on the matrix block dimensions.

Nomenclature

B	: Formation volume factor
f	: Fracture
g	: Gravity acceleration
g_c	: Gravity conversion factor
k	: Permeability (mD)
k_r	: Relative permeability (mD)
m	: Matrix

p	: Pressure (psi)
q_{α}	: Production or injection rate of phase (STB/day)
$\tau_{\alpha m-f}$	: Matrix/fraction transfer flow
S	: Saturation
t	: Time (day)
V_b	: Bulk volume
Z	: Depth measured positive downward
α	: Phase
ϕ	: Porosity
μ	: Viscosity (cP)
ρ	: Fluid density (lb./ft^3)

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