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Pilot Testing Issues of Chemical EOR in Large Fractured Carbonate Reservoirs

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Abstract

Many world class large carbonate reservoirs leave behind at least half of the initial oil in place. Typically water injection is used to improve oil recovery while gas injection is used to maintain pressure or to promote oil gravity drainage. Immiscible gas injection, including injection of CO_2 , has been considered but not implemented on a large scale for economic reasons. Furthermore, interest in using surfactants in large carbonate reservoirs has recently flourished. As a result, we began to investigate the viability of designing and conducting a manageable pilot test program in a large fractured carbonate reservoir using a single-well, dual-completion system to evaluate the efficacy of the surfactant oil mobilization and oil capture. However, pilot testing in large reservoirs is very expensive and requires a long time to complete. These issues are less problematic in pilot testing of small and thin reservoirs in onshore field.

In this paper we will present the results of a conceptual model to simulate the performance of surfactant flooding in the above-mentioned pilot test configuration. Three different model formulations, having different approaches to gridding and grid-refinement, were used. These include conventional dual-porosity, dual-permeability, and single-porosity models with variable porosity and permeability to simulate fracture-matrix interactions. Simulation of pilot tests using dual-porosity models shows that gravity is most effective during waterflood but not as effective during the surfactant injection while in the dual-permeability models, the surfactant oil recovery is greater because both gravity and viscous displacement contribute. We will explain the reasons and will indicate which model is more reliable. In general the results of this study give an insight into the viability of using surfactant injection in thick carbonate reservoirs both in the pilot and production stage.

Introduction

In the U.S, typically about a third of the original oil in place (OOIP) is recovered by primary and secondary recovery processes, leaving two-thirds of the oil behind as remaining oil (NPC, 1984). About 60% of world's discovered oil reserves are in carbonate reservoirs, and many of these reservoirs are naturally fractured (Rohel and Choquette, 1985). According to a recent review of 100 fractured reservoirs (Allan and Sun, 2003), fractured carbonate reservoirs with high matrix porosity and low matrix permeability could be good candidates for enhanced oil recovery (EOR) processes. The oil recovery from these reservoirs is typically very low because about 80% of fractured carbonate reservoirs are either oil-wet or mixed-wet. Injected water will not penetrate easily into the oil-wet porous matrix to displace oil. Wettability of carbonate reservoirs probably is the most important oil recovery controlling parameter (Morrow and Mason, 2001; Tong et al., 2002; Hirasaki and Zhang, 2006).

Typically water injection is used to improve oil recovery, while gas injection is used to maintain pressure or to promote oil gravity drainage as an IOR process. If gas injection is miscible or near-miscible, oil recovery is enhanced because a fraction of the conventional residual oil is mobilized by miscibility or near-miscibility conditions. Water and gas injection have been used to produce oil from the matrix in naturally fractured reservoirs (NFR) mainly by gravity drainage. Viscous displacement in fracture-dominated NFR generally plays a minor role except for chemical flooding, where surfactants might enter the matrix from fractures with assistance from viscous displacement to mobilize oil. Even this effect appears to be small because of the lack of deep surfactant penetration.

In water-wet NFR, water imbibes strongly into the matrix and produces a lot of oil. However, in oil-wet reservoirs, water-flooding is relatively inefficient. This is characterized by the early water breakthrough and rapidly increasing water-oil ratio. The reason is that, for an oil-wet reservoir, the injected water tends to travel only through the fractures and not enter the

pores of the rock matrix. The same processes take place during primary production in a fractured reservoir with a strong aquifer.

In crestal gas injection projects, gas will contribute to the oil production from the matrix via gravity drainage mechanism. This mechanism dominates if gas is allowed to build a large negative gravity head to promote oil drainage from the matrix pores as gas enters the matrix; otherwise, gas breaks through in the wells diminishing oil recovery efficiency. In a dual-porosity model, fracture pore space is composed of a series of interconnected cracks that can transmit fluids easily due to their high permeability, but this pore space is only a small fraction of the total pore space of the reservoir.

History of Chemical Flooding in Fractured Carbonate Reservoirs

Chemical EOR methods had their best times in the 1980s when the total of active projects peaked in 1986 with polymer flooding as the dominant chemical flooding method (Alvarado and Manrique, 2010). Polymer flooding has been used both in sandstone and carbonate reservoirs. Chemical EOR is highly sensitive to oil, and chemical prices. The development of the alkali-surfactant-polymer (ASP) technology since mid 1980s and new advances in surfactant chemistry have brought a renewed interest in chemical flooding in recent years, especially to boost oil production in mature water flooded fields. Based on 1,507 international EOR projects the most EOR applications have been in sandstone reservoirs (Alvarado and Manrique, 2010). Polymer and micellar-polymer flooding have been the most popular chemical EOR methods in sandstone reservoirs (Manning et al., 1983), and carbonate reservoirs have made a relatively small contribution to polymer flooding in terms of total oil recovered in the U.S. (Manrique et al., 2007). Also in offshore, there is few documented field application of chemical EOR methods in the literature. For example, only single-well alkali-surfactant-polymer (ASP) in Lagomar Field, Venezuela (Manrique et al., 2000) and in Angsi Field, Malaysia (Othman et al., 2007) is documented.

Use of pure urfactants (such as etoxhylated alcohols) in injected water can improve oil recovery in oil-wet carbonate reservoirs presumeably by enhancing imbibition through wettability alteration. On the other hand, surfactant also reduces interfacial tension (IFT) while altering wettability. The use of such simple surfactant systems is presumed viable because of low amount of surfactant concentration and associated adsorption (Yang and Wadleigh, 2000, Xie et al., 2004, Seethepalli et al., 2004).

In field-scale no major surfactant flooding project in fractured carbonate reservoirs is reported in the U.S. (Alvarado and Manrique, 2010). In the U.S., surfactant injection has been tested in carbonate reservoirs as chemical stimulation method only in the Yates Fields, Texas (Yang and Wadleigh, 2000; Chen et al., 2000 and 2001). Marathon Oil Co. conducted a dilute surfactant well stimulation pilot tests in the early 1990's. Surfactant slugs were injected into the oil water transition zone using single and multi-well injection patterns. During surfactant injection the well was shut-in for a short time. The well was returned to production increasing the recovery of oil mainly due to the reduction of IFT, gravity segregation of oil and water between the fractures and the matrix, and although to a possibly lesser extent wettability alteration.

Issues with Surfactant Injection in Oil-wet Fractured Carbonate Reservoirs

Wettability and matrix block size are two major factors in fluid transfer between fractures and matrix. For an oil-wet fractured carbonate reservoir, containing only water and oil, water from an injection well or from an aquifer can flow in fractures easily and much faster than in the matrix. Gravity drainage can produce oil if the matrix block is thick enough to overcome the negative water-oil capillary pressure. This is true particularly for oil-wet fractured carbonate reservoirs. On the other hand, if the matrix is water-wet, oil can be produced by imbibing water into the matrix. Wettability and gravity effects similarly affect oil drainage when a matrix block is surrounded by gas.

Surfactant injection EOR method in an oil-wet, DP model might not be effective because of the following reasons:

- 1- Pressure gradient may be too small to displace oil from the matrix in fractured formations in contrast with homogenous un-fractured reservoirs.
- 2- High permeable fractures could act like thief zones and bypass small fractures. In this case using mobility control agents like foam might be considered.
- 3- Gravity difference between fracture and matrix could be ineffective to mobilize oil by chemical flooding depending on the matrix block height. The smaller the block height, the less the effectiveness of gravity drainage.

Pilot Testing

For decades, there has been a lot of effort to use surfactant injection as a post water-flood process to recover oil from conventional reservoirs. Nearly all of these efforts were conducted in non-fractured sandstone reservoirs. Except for two or three surfactant pilot tests, one does not find any other documented literature on the use of surfactant EOR in fractured carbonate reservoirs in a commercial setting. This indicates lack of adequate practical knowledge about surfactant use in dual-porosity, fractured carbonate reservoirs. Because such EOR method require large investment of time and resource, pilot testing is highly desirable. However, pilot testing in large reservoirs is also very expensive and requires a long time to complete. Furthermore, two technical issues affect the viability of pilot testing: (1) establishing a credible production base line and (2) capturing the mobilized oil.

Pilot Test Design using Commercial Software

We designed a 2-D vertical conceptual model of a single-well dual-completion pilot test. Three different models for simulation of fractured reservoir were studied: a classical dual-porosity, a classical dual-permeability, and a variable permeability/porosity fine-grid model. The size of conceptual model in dual-porosity and dual-permeability cases is 13x1x11. Matrix porosity is 0.05 and total fracture porosity is 0.02. Matrix block sizes are 20 ft in all sides. Permeability of matrix is 10 md and fracture is 10000 md. In variable permeability/porosity fine-grid model the size of fracture is 0.1 ft and fracture porosity is 0.98 percent. Figure 1, shows the schematic view of the variable permeability/porosity fine-grid model for a two-well system of injection and production. To reach the same oil recovery during water flood a much fined-grid model is necessary. Doing this, from original model size with 143 grids, we ended up with more than 10530 grids. This conceptual model has been built using CMG¹. Simulation run time for this model is more than 10 hours on a PC with 2.16 GHz CPU and 4 GHz RAM. Running dual-porosity and dual-permeability takes less than 5 minutes on the same PC. Rock fluid data during waterflood and surfactant flood has been shown in Figure 3. Two sets of relative permeability for water flooding and surfactant injection are provided. Capillary pressure curve at high concentration increases to values close to zero or in wettability alteration conditions turns to positive.

Recovery factor for 600 days of water flooding followed by 80 days of surfactant injection has been shown in Figure 2. From Figure 2 it is seen that during surfactant injection dual-porosity and dual-permeability models cannot produce the same as variable-permeability/porosity fine-grid model. Surfactant incremental oil recovery in dual-porosity and dual-permeability is at most 1 percent but in the other model is more than 3 percent. The probable reason for this difference is that gravity and viscous forces in dual-porosity model is not effective as variable porosity/permeability model.

Enough concentration of surfactant in matrix will reduce the interfacial tension between water and oil phases to such lower values that facilitates the phase mobilization. Figure 3 shows the IFT reduction around the injection well in less than one month of surfactant injection in variable permeability/porosity fine-grid model. As it is seen in Figure 3, the IFT can be reduced to values close to zero. Production and injection distance has been chosen short, 40 ft, to not let surfactant go far from the pilot area. Production and injection intervals are completed in fracture nodes.



Figure 1. Variable permeability/porosity fine-grid model for a 5x5 matrix refinement

¹ Computer Modeling Group



Pilot Test Design using In-house Developed Numerical Simulator

Generally, dual-porosity model is based on the discrete fracture network (DFN) models. In this model fractures are connected but matrices are not. Fracture and matrix can be connected by means of transfer function. Since in this model there is no matrix connection capillary discontinuity exists. Because of overburden pressures most of the horizontal fractures are closed and therefore vertical fractures dominate the fluid flow inside the fractured reservoirs. In these cases one can use dual-permeability models too. In dual-permeability models matrices are connected and because of this connectivity there is capillary continuity. This model will result in more oil recovery comparing to the dual-porosity model.

Case 1: Dual-porosity model

For a two phase system including water and oil following finite-difference forms of flow equations is provided: Fracture water material balance,

$$\nabla \cdot \left(k_{f,eff} \cdot \lambda_{wf}\right) \left[\nabla P_{of} - \gamma_{w} \nabla D - \nabla P_{cwof}\right] - \tau_{w} + \hat{q}_{wf} = \phi_{f} \left[S_{wf}\left(c_{\phi} + c_{w}\right) \frac{\partial P_{of}}{\partial t} + \frac{\partial S_{wf}}{\partial t}\right]$$
(1)

Matrix water material balance,

$$\tau_{w} = \phi_{m} S_{wm} \left(c_{\phi m} + c_{w} \right) \frac{\partial P_{om}}{\partial t} + \phi_{m} \frac{\partial S_{wm}}{\partial t}$$

$$\tag{2}$$

Fracture oil material balance,

$$\nabla \cdot \left(k_{f,eff} \cdot \lambda_{of}\right) \left[\nabla P_{of} - \gamma_{o} \nabla D\right] - \tau_{o} + \hat{q}_{of} = \phi_{f} \left[S_{of} \left(c_{\phi} + c_{o}\right) \frac{\partial P_{of}}{\partial t} + \frac{\partial S_{of}}{\partial t}\right]$$
(3)

Matrix oil material balance,

$$\tau_o = \phi_m S_{om} \left(c_{\phi m} + c_o \right) \frac{\partial P_{om}}{\partial t} + \phi_m \frac{\partial S_{om}}{\partial t} \tag{4}$$

In dual-porosity formulation transfer function is the rate of fluid exchange between fracture and matrix in a grid block. Transfer functions for water and oil system are given by

$$\tau_{w} = 0.006328\sigma k_{m}\lambda_{wf/m} \left[\left(P_{o_{f}} - P_{o_{m}} \right) + \frac{\sigma_{z}}{\sigma} \gamma_{w} \left(h_{wf} - h_{wm} \right) - \left(P_{cwof} - P_{cwom} \right) \right]$$

$$(5)$$

$$\tau_o = 0.006328\sigma k_m \lambda_{om/f} \left[\left(P_{o_f} - P_{o_m} \right) + \frac{\sigma_z}{\sigma} \gamma_o \left[\left(h_{wf} - h_{wm} \right) \right] \right]$$
(6)

This formulations account for pressure gradient (viscous force), gravity, and capillarity in each local matrix and fracture system. A form of transfer function which accounts for fluid expansion and molecular diffusion is provided by Ramirez et al., 2009. In contrast with single-porosity formulations, fluid exchange in a dual-porosity system is based on replacement process rather than displacement. To account for a better fluid displacement in dual-porosity models viscous force in above formulations needs to be adjusted. We have applied this adjustment and we will present the results at the end of this paper. Depending on the flowing phase present, capillary and gravity forces are generally dominant in fractured reservoirs, therefore an approximation form of Eq. 5 and Eq. 6 is:

$$\tau_{w} = 0.006328\sigma k_{m} \frac{\lambda_{wf/m} \lambda_{of/m}}{\lambda_{t}} \left[\left(P_{cwof} - P_{cwom} \right) + \frac{\sigma_{z}}{\sigma} (\gamma_{w} - \gamma_{o}) \left(h_{wf} - h_{wm} \right) \right]$$
(7)

Eq. 7 is called pseudo transfer function. Using this form we will have:

$$\tau_o = -\tau_w$$

In Eqs. 5, 6, and 7 the terms inside the bracket represent the driving forces. We have used both forms of transfer function in dual-porosity formulation. They provide very close results because as pointed before in current dual-porosity formulation pressure gradient is negligible. The effects of capillary and gravity forces are different from case to case. They can work together or can be against each other. For example in gas injection always gravity difference will play the major role but in water flooding both mechanisms might be effective. Adding water and oil material balance equations give global pressure equation, and from that equation implicitly we can obtain fracture and matrix pressures. Overall pressure equation is provided by Eq.9:

$$\nabla \cdot \left(k_{f,eff}\right) \left[\lambda_{tf} \nabla P_{of} - \left(\gamma_{w} \lambda_{wf} + \gamma_{o} \lambda_{of}\right) \nabla D - \lambda_{wf} \nabla P_{cwof}\right] - \tau_{t} + \dot{q}_{tf} = \phi_{f} c_{tf} \frac{\partial P_{of}}{\partial t}$$

$$\tag{9}$$

Solving water or oil material balance gives saturation explicitly per time step. To obtain saturations in matrix either Eq.2 or Eq.4 is used. Auxillary equations for this part are given in Appendix A.

Fracture surfactant material balance

Surfactant concentration per time step can be solved explicitly or implicitly using Eq. 9. In this equation pressures and saturations are known at n+1 level. This equation includes diffusivity term, surfactant participation in oil phase, and surfactant adsorption on the solid phase surface.

$$\nabla \cdot \left[\frac{k_{f,eff} \lambda_{wf}}{B_{wf}} C_{wsf} \left(\nabla P_{wf} - \gamma_w \nabla D \right) + \frac{k_{f,eff} \lambda_{of}}{B_{of}} C_{wsf} \left(\nabla P_{of} - \gamma_o \nabla D \right) \right] - \left(\tau_w C_{wsf/m} - \tau_o C_{osf/m} \right) \\ -\nabla \cdot \left[\left(\frac{D}{\tilde{\tau}} \phi S_w \right)_m \nabla C_{wsm} \right] - \nabla \cdot \left[\left(\frac{D}{\tilde{\tau}} \phi S_o \right)_m \nabla C_{osm} \right] + \left(C_{wsf} q_{wf} + C_{osf} q_{of} \right) = \frac{\partial}{\partial t} \left[\phi_f \left(C_{wsf} \frac{S_{wf}}{B_{wf}} + C_{osf} \frac{S_{of}}{B_{of}} \right) + \left(1 - \phi_f \right) \cdot \rho_r \cdot a_{sf} \right]$$

$$(10)$$

Eq. 11 accounts for surfactant participitation into oil phase. To account for adsorption we used Longmuir isotherm adsorption formula. This formulation is provided in Appendix B.

$$C_{os} = \beta_s C_{ws_f} \tag{11}$$

Matrix surfactant material balance

Surfactant can penetrate into matrix through transfer function terms; Eq. 12 accounts for this process. Upstream weighting determine whether surfactant goes into or out of matrix. In ideal condition surfactant from fracture goes with water transfer function term. Adsorption is included in the second part of the left right hand side of Eq.12.

$$\tau_{w}C_{wsf/m} - \tau_{o}C_{osf/m} = \frac{\partial}{\partial t} \left[\phi_{m} \left(C_{wsm} \frac{S_{wm}}{B_{wm}} + C_{osm} \frac{S_{om}}{B_{om}} \right) + \left(1 - \phi_{m} \right) \cdot \rho_{r} \cdot a_{sm} \right]$$
(12)

A conceptual model with the size of 10x1x10 grid blocks, with almost the same size of the conceptual model in CMG, has been built using three different methods; dual-porosity, dual-permeability, and variable permeability/porosity fine-grid model. Implicit-pressure/explicit-saturation (IMPES) formulation is implemented. Single-well dual-completion method is used in this conceptual model with injection rate of 30 bbls/day. Surfactant incremental oil recovery was investigated by using IFT reduction and wettability alteration methods. During surfactant injection simulator calculates IFT, Capillary number or Bond number, residual oil saturation, relative permeability, capillary pressure, fluid heights in fracture and matrix nodes. IFT will be calculated based on surfactant concentration. We used two forms of Bond number and Capillary number:

$$N_{B} = \frac{k_{m} (\gamma_{w} - \gamma_{o})}{\phi_{m}.IFT.\cos\theta}$$
⁽¹³⁾

Where, k_m is the absolute permeability of the matrix [md], $(\gamma_w - \gamma_o)$ gravity gradient in [psi/ft], ϕ_m , porosity of the matrix, IFT, water-oil interfacial tension in [dynes/cm], and $\cos \theta$ is contact angle. In addition to use the above formulation, we have used a combination form of Capillary number and Bond number in the matrix, which gives close results as Bond number. Using the driving force in pseudo transfer function, we have:

$$N_{c} = 2.262 \times 10^{-8} \frac{k_{m} \left[\left(P_{cwof} - P_{cwom} \right) + \left(\gamma_{w} - \gamma_{o} \right) \left(h_{wf} - h_{wm} \right) \right]}{\phi_{m} \ell_{z} . IFT. \cos \theta}$$
(14)

Where, ℓ_z is matrix block height (ft) in z direction. To achieve a Bond number or Capillary number greater than 10⁻⁵, we need to have a very low IFT, which requires large amount of surfactant concentration inside the matrix. Our simulation shows that we need to inject a high concentration into the reservoir. Residual oil saturation will be interpolated based on

(8)

Capillary or Bond number. For IFT interpolation versus concentration we used work done by Gupta and Mohanty, 2008, and for residual oil saturation versus Capillary number we used work presented by Kamath et al., 2001. Surfactant concentration is calculated in matrix and fracture in both implicit and explicit formulations.

Figure 4 shows the recovery factor and incremental oil recovery for 1000 days of water flood followed by 300 days of surfactant flood. Surfactant injection in a water invaded zone using dual-porosity model results in a very low incremental oil recovery, here is less than one percent. Because of oil-wet nature of carbonate reservoir negative capillary pressure is overcoming the other two mechanisms; gravity and viscous displacement forces. Gravity force is negligible at the end of waterflood because fractures around matrix blocks are mostly full of water. Pressure difference between matrix and adjacent fractures are very small, so viscous forces also are not effective. Therefore fluid exchange will not take place in an effective way to carry enough surfactant into the matrix block. Eq. 15 was used to calculate the capillary pressure in presence of surfactant. At high concentrations IFT can reduce capillary pressure to zero.

$$Pc(surf) = \frac{IFT(surf)}{IFT_{initial}} Pc(S_{or_{if}})$$
(15)

Where, Pc (surf) is the capillary pressure in presence of surfactant, and Sor_{sf} is the new residual oil saturation calculated at that grid. In wettability-induced incremental oil recovery, it is believed that at high concentrations surfactant can change the capillary pressure values into positive values. This results in complete or partially altering the wettability of the rock. In this paper we used assumptions based on the surfactant concentration to change the capillary pressure (Eq. 16).

$$P_{c}(surf) = P_{c}\left(S_{or_{sf}}\right) + \frac{Maximum \ shift(=0.5 \ psi)}{C_{s_{injection}}} \times C_{s_{grid}}$$
(16)

Where $C_{s_{injection}}$ is the concentration in injection well, $C_{s_{grid}}$ is the concentration in each grid. Based on the concentration in each grid a vlue between 0 to 0.5 psi will be added to the capillary pressure at that node. This method is just an approximation. Another work to model the wettability alteration by changing the capillary pressure based on concentration was done by Farhadinia and Delshad, 2010. The maximum negative capillary at the end of water flood in our system is around -0.15 psi. For example for concentration of 4000 ppm, capillary at wettability alteration condition will be +0.05 psi in that grid.



Figure 4. Recovery factor during water-flood and incremental oil recovery for IFT induced and wettability altered surfactant injection in dual-porosity

Case 2: Dual-porosity matrix refinement formulation

Dual-porosity model does not produce incremental oil recovery during surfactant injection. After water flooding all fractures are nearly full of water, therefore gravity force will not be effective to help surfactant penetrate into the matrix. On the other hand viscous force (pressure gradient) is negligible. Therefore, the only mechanism remains is capillary pressure but oil-wet nature of the fractured reservoir makes it hard for surfactant to penetrate into matrix block. We believe that in a real situation surfactant might only can touches the surface or a very shallow deep of the matrix. To be more realistic we chose matrix refinement approach to investigate the effect of refinement on both water flooding and surfactant injection. In this method we kept the same matrix block size (20ft in all directions) and refined it into sub-internal-blocks. A schematic view of one nested matrix block is shown in Figure 5. In this figure original matrix block is divided into three nested blocks.



Figure 5. Matrix refinement using three nested blocks (Bulogun, 2005)

For simplicity we assumed that all three blocks have the same volume. The volume of each block is one third of the outer matrix block (original block).

$$V_{m1} = V_{m2} = V_{m3} = \frac{L_{x1}L_{y1}L_z}{3}$$
(17)

In this case total pressure equation will be solved for the interaction between fracture and first matrix ring and all of the rest of nested blocks are connected through their transfer function. So Eq. 9 will have the new form:

$$\nabla \cdot \left(k_{f,eff}\right) \left[\lambda_{tf} \nabla P_{of} - \left(\gamma_{w} \lambda_{wf} + \gamma_{o} \lambda_{of}\right) \nabla D - \lambda_{wf} \nabla P_{cwof}\right] - \frac{V_{m1}}{V_{block}} \tau_{t} + \dot{q}_{t} = \phi_{f} c_{tf} \frac{\partial P_{of}}{\partial t}$$

$$\tag{18}$$

Where, V_{ml} is the volume of the first ring and V_{block} is the volume of the whole matrix block. Each nested matrix block has its own shape factor, pressure, phase saturation, capillary pressure, fluid heights, and compressibilities. Therefore we need to calculate the separate transfer functions. In fact these nested blocks are connected through transfer function terms. Following are the developed shape factor and transfer functions for each nested matrix block.

Shape factor for a refined matrix

In below formulations "f" stands for fracture and "1", "2", and "3" stand for first, second, and third nested matrix blocks respectively.

$$\sigma_{f/1} = \frac{24}{L_{x1}L_{y1}} \left[\frac{L_{x1}}{L_{y1} - L_{y2}} + \frac{L_{y1}}{L_{x1} - L_{x2}} \right]$$
(19)

$$\sigma_{1/2} = \frac{24}{L_{x1}L_{y1}} \left[\frac{L_{x2}}{L_{y1} - L_{y3}} + \frac{L_{y2}}{L_{x1} - L_{x3}} \right]$$
(20)

$$\sigma_{1/2} = \frac{24}{L_{x1}L_{y1}} \left[\frac{L_{x2}}{L_{y1} - L_{y3}} + \frac{L_{y2}}{L_{x1} - L_{x3}} \right]$$
(21)

Vertical transfer function for each ring is as following:

$$\sigma_{\mathcal{J}^{/1}} = \frac{12}{L_{x1}L_{y1}L_z} \left(\frac{L_{x1}L_{y1} - L_{x2}L_{y2}}{L_z} \right)$$
(22)

$$\sigma_{z1/2} = \frac{12}{L_{x1}L_{y1}L_z} \left(\frac{L_{x2}L_{y2} - L_{x3}L_{y3}}{L_z} \right)$$
(23)

$$\sigma_{z^{2/3}} = \frac{12}{L_{x1}L_{y1}L_z} \left(\frac{L_{x3}L_{y3}}{L_z}\right)$$
(24)

Above equations have been derived from the general form of shape factor introduced by Kazemi et al., 1992:

$$\sigma = \frac{1}{V} \sum_{i=1}^{J} \frac{A_i}{D_i}$$
⁽²⁵⁾

Where V is the volume of the matrix block, A is the open face normal to the flow, and D is the half length from the center of the matrix block. Assuming $L_{x1} = L_{y1} = L_z = 20$ ft calculation of the lengths and shape factor for each of the rings gives:

$$L_{x2} = L_{y2} = 16.33 \text{ ft}, L_{x3} = L_{y3} = 11.33 \text{ ft}, \text{ and } \sigma_{f/1} = 0.6, \sigma_{1/2} = 0.24, \sigma_{2/3} = 0.08 \text{ ft}^{-2}$$

Transfer functions

For fracture and first ring:

$$\tau_{wf/1} = \sigma_{f/1} k_m \lambda_{wf/m1}^n \cdot \left[\left(P_{of}^{n+1} - P_{om}^{n+1} \right) + \gamma_w \left(h_{wf}^n - h_{wm1}^n \right) - \left(P_{cwof}^n - P_{cwom1}^n \right) \right]$$
For matrix ring 1 and matrix ring 2:
$$(26)$$

$$\tau_{w1/2} = \sigma_{1/2} k_m \lambda_{wm1/m2}^n \cdot \left[\left(P_{om1}^{n+1} - P_{om2}^{n+1} \right) + \gamma_w \left(h_{wm1}^n - h_{wm2}^n \right) - \left(P_{cwom1}^n - P_{cwom2}^n \right) \right]$$
(27)

For matrix ring 2 and matrix ring 3:

$$\tau_{w2/3} = \sigma_{2/3} k_m \lambda_{wm2/m3}^n \cdot \left[\left(P_{om2}^{n+1} - P_{om3}^{n+1} \right) + \gamma_w \left(h_{wm2}^n - h_{wm3}^n \right) - \left(P_{cwom2}^n - P_{cwom3}^n \right) \right]$$
(28)

Upstream weighting are used in the above equations. Also an internal matrix of coefficients has been solved to obtain matrix pressure at n+1 level in each nested matrix block. Therefore transfer function is calculated in a semi-implicit method. Solving new matrix of coefficients does not affect the simulation run time. Dual-porosity without refinement takes 123 seconds to run while dual-porosity with refinement takes 133 seconds.

As it is seen in Figure 6, comparing to the dual-porosity without matrix refinement surfactant does better using IFT reduction and wettability alteration assumptions; two percent and 4 percent respectively. Still in this formulation viscous force is not effective. In the next part of this paper we have built a dual-permeability model for purpose of checking the refinement approach and compare the results.

Case 3: Dual-permeability Fine-grid Formulation

It is not exactly dual-permeability formulation but the approach is the same. The size of the model is 10x1x10 grid blocks. Each matrix has been refined into 5 sub grids in 'x' direction to create the same refinement as dual-porosity model with matrix refinement. All matrix blocks are connected vertically and disconnected by a fracture in 'x' direction. There are two horizontal fractures at the top and bottom of the bed to connect vertical fractures. After refinement the size of the model is 55x1x15. Simulation of this model takes almost more than 2 hrs. All properties for matrix and fracture are the same as dualporosity model. Result of simulation is shown in Figure 7.



surfactant oil recovery

alteration in Dual-permeability (DK) approach

Water-flooding results in 36 percent recovery and surfactant injection in water invaded zone results in 6 percent incremental oil recovery by IFT reduction and more than 8 percent by wettability alteration assumptions. Figure 8 shows comparison between dual-permeability and dual-porosity reined matrix. In dual-permeability formulation during water flood and surfactant injection viscous and gravity forces overcome the negative capillary pressure. In the other words these two forces are still effective during surfactant injection. Because gravity always will be calculated from the top of the reservoir bed no matter of what kind of porosity or permeability exist in the system. We have shown this effect by comparing the above model with another dual-permeability model that has thin impermeable layers in z direction (Figure 9). The vertical thicknesses of these layers are 0.4 ft. Both models produce almost the same, which means existing of some zero permeability layers would not affect the oil production from dual-permeability model.



Figure 8. DP refined matrix vs. DK refined matrix Leftist induced incremental oil recovery, Right: Wettability altered incremental oil recovery



Figure 9. The effect of thin impermeable layers on DK refined matrix

Case 4: Dual-porosity with Adjustment for Viscous Displacement

In this formulation we have added extra terms accounting for pressure gradient in two sides of the matrix block. Eq.9 in a finite difference form turns into:

$$\nabla \cdot \left(k_{f,eff}\right) \left[\lambda_{tf} \nabla P_{of}^{n+1} - \left(\gamma_{w} \lambda_{wf} + \gamma_{o} \lambda_{of}\right) \nabla D - \lambda_{wf} \nabla P_{cwof}\right] - \tau_{t} - \tau_{vd} + \dot{q}_{tf} = \phi_{f} c_{tf} \frac{\partial P_{of}}{\partial t}$$
(29)

Where, τ_{vd} is the adjusted viscous displacement term in transfer function:

$$\tau_{vd} = -\nabla k_m \left[\left(\lambda_{wf/m}^* + \lambda_{of/m}^* \right) \nabla P_{of}^n - \left(\gamma_w + \gamma_o \right) \nabla D \right]$$
(30)

Upstream weighting determines which direction fluids flow and which phase mobility should be used. If fluid goes from fracture to the matrix, we use end point relative permeability at the face of matrix block. The same modification applied in fracture and matrix saturation equations; Eq.1 through Eq.4. Also during surfactant injection this modification applies in Eq. 10 and Eq. 12. In this paper we have applied gradient term in 'x' direction. All the properties in matrix and fractures are the same as coarse grid dual-porosity model. Result is shown in Figure 10. As it is seen in Figure 10, new dual-porosity model gives more incremental oil recovery than coarse grid model. This formulation even gives more recovery than dual-porosity with refinement approach. But we believe if we apply this modification into the dual-porosity refined matrix, it will result in more incremental oil recovery. Figure 11 shows the comparison of oil recovery between adjusted dual-porosity and a dual-permeability model without matrix refinement. In dual-permeability model a series of matrix column and fracture are provided.



Case 5: Sensitivity to matrix block dimensions

It can be shown, using fracture width distribution versus spacing, that the fractures with the larger apertures dominate flow, which, in turn, determines that the effective fracture spacing are typically large. To show that we conducted the following sensitivity analysis for the matrix block size. The results (Figure 12) show that taller matrix blocks causes more recovery than shorter ones because of the effective oil gravity drainage ($L_z=100$ ft, and $L_x=L_y=10$ ft). Larger plannar fracture spacing results in less effective viscous displacement force, which leads to lower oil production($L_x=L_y=50$ ft).



Discussion

Oil Recovery Mechanism

The simulation mechanism of oil gravity is quite different in dual-porosity compared to dual-permeability modeling. In dualporosity, gravity is constraint by the matrix block height. In dual-permeability the gravity is controlled by bed thickness height. Dual-permeability model transfers surfactant into matrix more effectively than the dual-porosity model. This leads to more oil recovery using dual-permeability models. The question remains is which model is the more reasonable one to use. During waterflood dual-permeability and dual-porosity models produce the same oil recovery because the gravity terms dominate oil displacement by water, but at the end of waterflood the dual-porosity gravity terms become very small while the gravity terms in dual-permeability remains high. This is why during surfactant flood the dual-permeability model gravity terms transfers surfactant more effectively than dual-porosity model.

Pilot Testing

Injection-production multiple-well pattern pilot is very time-consuming and expensive in large offshore reservoirs. Singlewell multiple might-completion design be a good way to reduce the time and cost. This includes dual- and triple-completions methods. In dual-completion mobilized oil capturing is more difficult. In triple-completion, the mobilized oil capturing is more focused.

Conclusions

The numerical modeling of pilot testing for surfactant injection in large carbonate reservoirs led to the following conclusions:

- 1 Surfactant can mobilize remaining oil in water-invaded naturally fractured carbonate reservoirs to enhance oil recovery, but the selection of the EOR chemical and the method of its delivery will determine the economic viability.
- 2 For large carbonate reservoirs, especially in an offshore environment, well-to-well pilot testing is prohibitive because of oil capture and base line issues. However, pilot testing in a dual- and/or triple-completion single-well is plausible.
- 3 The main issue with surfactant injection in carbonate NFR is the low penetration of surfactant into the matrix.
- 4 Assuming enough surfactant concentration penetrates matrix, IFT reduction and capillary pressure change to waterwet conditions become the main factors for mobilizing oil.
- 5 In oil-wet rocks, spontaneous capillary imbibition is absent. And, in fact, negative capillary pressures are present, which are hindrance to oil drainage; however, gravity can overcome capillary forces to promote drainage
- 6 With high pressure gradients between fracture and matrix viscous displacement could also promote oil drainage
- 7 Chemical injection in dual-porosity formulation of fractured carbonate reservoirs results in lower incremental oil recovery compared to a dual-permeability formulation. Because gravity and viscous displacement force in dual-permeability case are dominating the negative capillary pressure, which this is in contrast with dual-porosity case.
- 8 Refined matrix dual-porosity improves incremental oil recovery from surfactant.
- 9 Surfactant injection in a dual-porosity formulation will become more effective when viscous force term is included.
- 10 Existing of low permeability thin layers in dual-permeability formulation does not affect the incremental oil recovery from a specific target perforation. This is because gravity is a major mechanism that still is effective in such a case.
- 11 Using low-adsorption surfactants are necessary for oil mobilization
- 12 Small fracture spacing results in more oil recovery in the dual-permeability models.
- 13 Tall matrix blocks (tall fracture heights) result in more oil recovery in dual-porosity models.
- 14 During the pilot test, boundary conditions must be maintained as in the pre-test operating conditions.
- 15 Field application of surfactant EOR technology is very complex and requires expertise and experience.

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Nomenclature

| P_{φ} | pressure of phase φ , psi |
|-----------------------|--|
| P _{cwo} | water-oil capillary pressure, psi |
| $	au_{arphi}$ | matrix / fracture transfer function for phase ϕ , 1/day |
| k _{f,eff} | effective fracture permeability, $k_{f,eff} = k_f \phi_f$ |
| c_t | total system compressibility, Lt2/m, psi-1 |
| c_{arphi} | compressibility of phase φ , Lt2/m, psi-1 |
| $c_{oldsymbol{\phi}}$ | pore compressibility, Lt2/m, psi-1 |
| $C_{\varphi s}$ | Surfactant concentration in phase φ , ppm |
| $h_{oldsymbol{\phi}}$ | gravity head for phase φ , ft |
| h_f | fracture height, L, ft |
| h_{wf} | height of water inside the fracture, ft |
| h_{wm} | height of water inside the matrix, ft |
| k | 0.006328* absolute permeability, L2, md |
| k_f | 0.006328* fracture absolute permeability, L2, md |
| k_s | Langmuir coefficient |
| | |

| $k_{r\varphi}$ | relative permeability to phase φ , dimensionless |
|-------------------|---|
| q_{arphi} | source/sink term for phase φ , L3/t, ft3/d |
| \hat{q} | sink/source term per volume of grid block, 1/t, 1/day |
| S_{φ} | saturation of phase φ , fraction |
| $S_{\varphi r}$ | residual saturation of phase φ , fraction |
| B_{arphi} | formation volume factor of phase φ , rb/STB |
| D | Depth, ft |
| L | matrix block dimension, ft |
| 0.006328 | conversion factor to the field units of psi, psi/ft, cp, ft, md, |
| Greek Letters | |
| λ_{arphi} | mobility of phase φ , dimensionless |
| λ_t | total system mobility, dimensionless |
| ϕ_m | matrix porosity, fraction |
| ϕ_f | fracture porosity, fraction |
| γ_{arphi} | fluid gravity gradient for phase φ , psi/ft |
| σ | matrix block shape factor, L-2, 1/ ft2 |
| σ_z | matrix shape factor in z direction, L-2, 1/ft22 |
| β_s | partition coefficient |
| $ ho_r$ | rock density, lbm/ft^3 |
| Operators | |
| ∇ | gradient operator |
| ∇ · | divergence operator |
| Superscript | |
| n | current time level |
| n + 1 | next time level to be solved |
| Subscript | |
| т | matrix |
| f | fracture |
| 0 | oil |
| W | water |
| t | total, system |
| φ | fluid phase ($\varphi = g$, w for gas, and water, respectively) |

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Appendix A – Auxillary equations used in in-house simulator

| Shape factor for dual-porosity formulation w/o refinement: | $\sigma = 4\left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2}\right)$ |
|---|---|
| Shape factor in z direction for dual-porosity w/o refinement: | $\sigma_z = \frac{4}{L_z^2}$ |
| Fluid Gravity: | $\gamma_{\varphi} = \frac{\rho_{\varphi}}{144}$ |
| Total compressibility: | $c_t = c_\phi + S_w c_w + S_o c_o + S_g c_g$ |
| Water compressibility: | $c_{wf} = -\frac{1}{B_{wf}} \frac{\partial B_{wf}}{\partial p}$ |
| Formation volume factor: | $B_{wf} = B_{wfb} \left(1 - c_{wb} P_w \right)$ |
| Oil compressibility: | $c_{of} = -rac{1}{B_{of}}rac{\partial B_{of}}{\partial P}$ |
| Mobility Ratio: | $\lambda_{arphi}=rac{k_{rarphi}}{\mu_{arphi}}$ |
| Total Mobility Ratio: | $\lambda_{t} = \lambda_{w} + \lambda_{g} + \lambda_{o}$ |
| Phase Fractional Flow: | $f_{arphi}=rac{\lambda_{arphi}}{\lambda_t}$ |
| Relative Permeability: | $k_{r\varphi} = k_{r\varphi} \left(S_{w} \right)$ |
| Capillary Pressure: | $P_{cow} = P_{cow}(S_w)$ |
| Saturation Constraints: | $S_w + S_o + S_g = 1$ |
| Water level in matrix or fracture | $h_{wm/f} = \left(\frac{S_{wm/f} - S_{wrm/f}}{1 - S_{wrm/f} - S_{orwm/f}}\right) L_{z}$ |

Oil level in matrix or fracture

$$h_{om/f} = \left(\frac{1 - S_{wm/f} - S_{orwm/f}}{1 - S_{wrm/f} - S_{orwm/f}}\right) L_z$$

APPENDIX B – relative permeability and capillary pressure equations for in-house simulator and inputs for commercial software

Water relative permeability in matrix/fracture:

~

$$\begin{split} k_{rwm/f} &= k_{rwm/f}^* \left(\frac{S_{wm/f} - S_{wrm/f}}{1 - S_{wrm/f} - S_{orwm/f}} \right)^{nvm/f} \\ k_{rom/f} &= k_{rom/f}^* \left(\frac{1 - S_{wm/f} - S_{orwm/f}}{1 - S_{wrm/f} - S_{orwm/f}} \right)^{nom/f} \end{split}$$

.

Oil relative permeability in matrix/fracture:

Capillary pressure in matrix:

$$S_{wm} < S_{wr} \longrightarrow P_{cwo} = 1pst$$

$$S_{wm} > S_{wrm} \text{ and } S_{wm} < S_{wx} \longrightarrow P_{cwo} = \alpha_2 \log\left(\frac{1 - S_{ox} - S_{wrm}}{S_{wm} - S_{wrm}}\right) psi$$

$$S_{wm} > S_{wx} \text{ and } S_{wm} < 1 - S_{orwm} \longrightarrow P_{cwo} = \alpha_1 \log\left(\frac{1 - S_{wx} - S_{orw}}{1 - S_{wm} - S_{orw}}\right) psi$$

$$S_{wm} > 1 - S_{orw} \longrightarrow P_{cwo} = -8psi$$

n

Where

$$\alpha_2 = -\left(\frac{S_{wx} - S_{wr}}{1 - S_{wx} - S_{orw}}\right) \cdot \alpha_1 \text{ , and } \alpha_1 = -0.1$$



Figure B.1. CMG input for rock fluid data for fracture (left) and matrix(right -Index "ff "stands for fracture and index "SF" stands for surfactant



Figure B.2. CMG input for capillary pressure; (left): Initial matrix capillary pressure; (right): matrix capillary pressure under the effect of optimum surfactant concentration



Figure B.4. A typical relative permeability in dual-permeability formulation in a grid cell close to injector; left: water flood, right: during surfactant injection



Figure B.5. A typical capillary pressure in a cell next to the injector in dual-permeability formulation; left: IFT-induced, right: wettability alteration



$$a_{sm}\left(C_{ws}\right) = \left\lfloor \frac{bC_{ws}}{1 + bC_{ws}} \right\rfloor a_{max}$$

$$a_{max} = \max \text{ adsorption} = 850 \left[ppm\right], b = \text{Longmuir coefficient}=0.0003 \left[ppm^{-1}\right], \text{ and } C_{ws} = \text{concentration} \left[ppm\right]$$
(B.1)



Figure B.6. A typical adsorption profile for a grid cell next to the injection cell left: dual-permeability refined-matrix right: dual-porosity refined matrix