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Analysis of oil flow in fractured oil reservoir using carbondioxide (CO_2) foam injection

Minhee Choi, Junwoo Seo, Hyemin Park and Wonmo Sung*

Department of Natural Resources and Environmental Engineering, Hanyang University, 222 Wangsimni-ro, Seongdong-gu, Seoul 133-791, Korea.

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Most carbonate reservoirs are heterogeneous in terms of pore distribution and the matrix is extremely low permeable, hindering the flow of oil, while highly permeable fractures are the primary flow conduit. This study presents the hybrid discrete fracture network (DFN) approach to represent fracture network, more realistically, which is a continuum approach equipped with local grid refinement (LGR). The LGR is adapted at the cells that fractures are passing through, in order to describe the fracture width less than 0.1 ft. In this approach, control volume of the well lying on the fracture is extremely small and thus, in this study, four-leg horizontal well concept substitutes the vertical well with the use of equivalent well radius for overcoming the numerical convergence problem. The hybrid DFN approach was applied for CO_2-foam injection in fractured carbonate reservoirs to investigate the effect of conformance control. This foam injecting method yields more imbibition of CO_2-foam into low permeable matrix, which contains most of the oil. From the numerical results, it shows that the foam controls CO_2 velocity and this increases the contact time between CO_2 and the rock matrix since CO_2 mobility is controlled by foam, that decreases relative permeability of CO_2 and increases its viscosity.

Key words: Carbonate, fracture, local grid refinement, CO_2-foam, conformance control, discrete fracture network (DFN).

INTRODUCTION

Carbonate reservoirs account for over 40% of total worldwide oil reservoirs, and heavy oil contained in these is estimated to be 1.6 trillion bbl in place (Briggs, 1992; Das, 2007). Most carbonate reservoirs are heterogeneous, comprising fractures, vugs, and cavities. Also, the matrix has very low permeability, hindering the flow of heavy oil, while highly permeable fractures are the primary flow conduit. This renders the recovery process highly ineffective, and a large amount of oil is retained by the tight matrix after the application of primary and secondary recovery methods. Of current enhanced-oil-recovery (EOR) methods, CO_2 flooding has great potential for recovering additional oil after water flooding. The advantage of CO_2 as an injection gas is its relatively low minimum miscibility pressure (MMP), making CO_2 applicable in a broad range of reservoirs (Stalkup, 1983). However, gravity override and viscous fingering caused by geological heterogeneity and unfavorable CO_2 mobility lead to poor macroscopic sweep efficiency and early CO_2 breakthrough.

The application of foam can reduce gas mobility, mitigate the effects of heterogeneity, and increase sweep efficiency (Liu et al., 2011). For the creation of foam, surfactant must be present. Foam can be injected into the

*Corresponding author. E-mail: wmsung@hanyang.ac.kr.

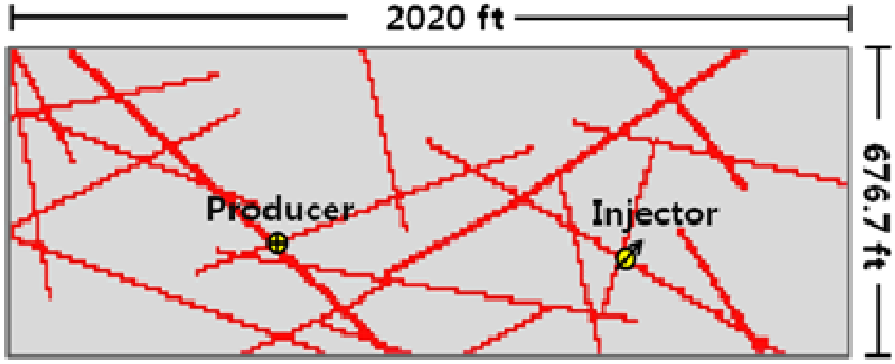

Figure 1. System description.

reservoir by co-injection of surfactant solution and gas, or by surfactant-alternating gas (SAG) injection. Foam moves through the porous media via the film network of bubbles, and gas moves through the system by breaking and by re-forming bubbles throughout the length of the flow path (Hirasaki, 1989). The stability of foam is a function of the surfactant type, surfactant concentration, foam quality, reservoir temperature, salinity, oil saturation, and other variables.

CO_2 foam reduces the mobility of CO_2 within the fracture network and decreases the velocity of CO_2 through the fractures, increasing the contact time between CO_2 and the carbonate rock matrix. This increases the imbibition of CO_2 into the low permeable matrix. Furthermore, with mobility control, foam diverts CO_2 and the surfactant solution to the tight matrix, where it can alter the wettability characteristics of the carbonate matrix from oil-wet to water-wet, causing more CO_2 foam to be imbibed into the matrix. Also, it reduces the interfacial tension (IFT) between the oil and water for release and mobilization of matrix oil, increasing the recovery factor.

Although several field studies and numerous laboratory tests with foam have shown some success (Heller et al., 1985; Hoefner et al., 1995; Holm et al., 1988), foams are a highly complex technology, both chemically and operationally, making them difficult to successfully apply in the oilfield (Sydansk and Romero-Zeron, 2011). Thus, prediction of CO_2 foam behavior in field-scale, especially for fractured carbonate reservoirs with a tight matrix still needs to be studied. In the present study, we conducted field-scale numerical simulations of CO_2 foam injection in fractured carbonate reservoirs with low permeable matrices containing heavy oil, using the hybrid discrete fracture network (DFN) approach. This approach represents fracture network more realistically, which is a continuum approach equipped with local grid refinement (LGR). The LGR is adapted at the cells that fractures are passing through, in order to describe the fracture width less than 0.1 ft. Also, control volume of the well lying on the fracture is extremely small and thus, in this study, four-leg horizontal well concept substitutes the vertical well with the use of equivalent well radius for overcoming the numerical convergence problem. The hybrid DFN approach, which is free of the limitations of the dual porosity/dual permeability (DP/DK) model, allows the investigation of fluid transfer between a fracture and a matrix as well as fluid flow only through the fractures. The foam model in the simulator was used to apply the mobility reduction. In this study, we focused on determining the effect of several operational parameters on CO_2 foam behavior to control fast CO_2 flow through fractures and to improve oil flow in a rock matrix by considering the imbibition of CO_2 foam into the matrix.

SIMULATION SYSTEM

Simulational strategy and scenarios

To analyze CO_2 foam behavior in a fractured carbonate reservoir, a two-dimensional model was constructed, as shown in Figure 1. Generally, a dual-porosity/dual-permeability (DP/DK) model is used to conduct the simulation in fractured reservoirs, including carbonates, but the directional property of each fracture cannot be described using this model (Muhammad, 2011). For this reason, we used the hybrid DFN approach in which it is possible to input permeability into each of the cells in the single-porosity (SP) model. Using this approach, we generated a fracture network, consisting of 19 fractures connected together, with matrix permeability of 1.0 md and fracture permeability of 2000 md.

CO_2 gas and surfactant solution were set up to co-inject and generate CO_2 foam under the reservoir condition. The wells were located on the connected fracture network, and the producer was specified by constant bottom-hole pressure while the injector was specified by constant rate to investigate the effect of injection rate. The total period of injection and production was 3 years, and the other input data in the model are listed in Table 1.

In fluid and rock properties, the oil-wet characteristic of carbonate rock is considered by the oil-water relative permeability curve (Figure 2). Also, because we assumed a dead-oil system without free gas and solution gas, the gas existing in the reservoir repre-

Table 1. Input data for the simulation study.

Parameter		Value
No. of Global Cell (X-Y)		13400 (200 × 67 × 1)
No. of LGR Cell (X-Y)		1569 (3 × 3 × 1)
Permeability [md]	Fracture	2000
	Matrix	1.0
Porosity		0.20
Initial Pressure [psia]		4000
Initial Oil Saturation		0.80
Initial Water Saturation		0.20
Depth [ft]		9000
Production Well BHP [psia]		3000
Injection Rate	Water (STBD)	40.0
	CO_2 (MSCFD)	4.7754
Oil Density [lb/ft^3]		62.5
CO_2 Density [lb/ft^3]		0.117
Surfactant Concentration [wt%]		0.001

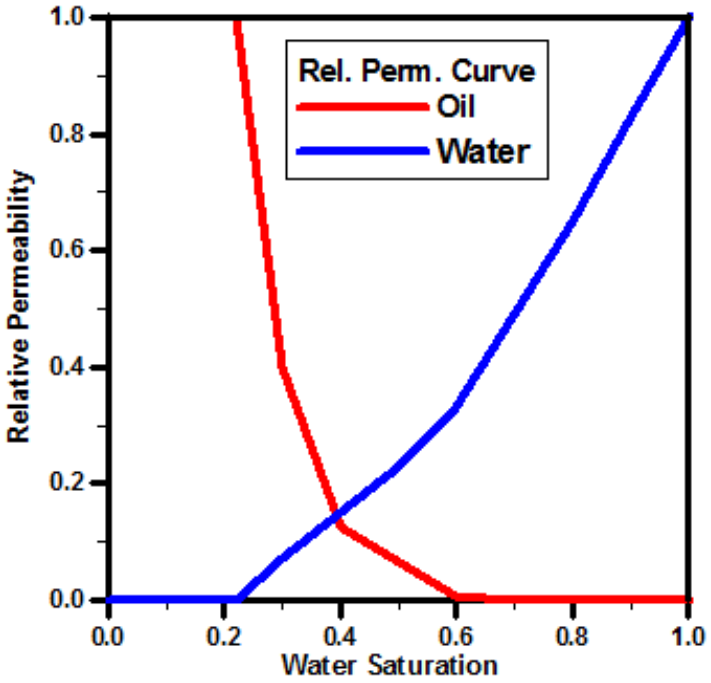

Figure 2. The relative permeability curve for oil-wet carbonate reservoir.

sents only CO_2 gas, which has a surface density of CO_2. Once CO_2 gas is injected into the reservoir, CO_2 becomes miscible or immiscible with oil as it flows (Karaoguz et al., 1989; Shoaib et al., 2009). We assumed an immiscible process because oil has a high molecular weight in the case of heavy oil, making it difficult to develop miscibility with CO_2.

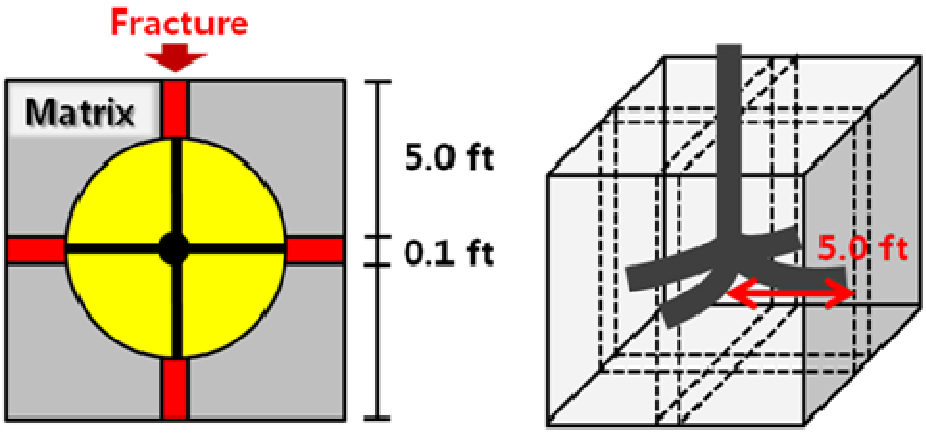

Figure 3. Multi-segment well in LGR fracture cell.

Hybrid discrete fracture network (DFN) approach

In the case of fractured system, local grid refinement (LGR) of the cells passing along the fractures was set up to describe a fracture aperture representing a realistic fracture size. From among the total 13,400 cells, which have dimensions of 200 × 67 × 1, 1596 cells were used in LGR of 3 × 3 cells, and the fracture aperture was set to 0.1 ft (Figure 3). This resulted in increase of the grid cells number to be 26,168 cells, which is increasing by up to twice the original number of cells. Also, It is impossible to locate a vertical well on the fracture cell that can afford a practical flow rate because this cell has an extremely small size. Thus, as shown in Figure 3, a multi-segment well with four legs using the concept of equivalent well radius was adopted instead of vertical well to overcome the numerical convergence problem and to control the flow rate within the small cell volume.

Application of LGR technique is efficient for increasing the degree of accuracy with lower computational time and computer storage to obtain the solution. However, since the long and narrow cells lead to huge computing and numerical errors, extremely small size of time step, in which the initial time step size Δt_i is 0.00001 day (8 s), the maximum time step size $\Delta t_{\max}$ is 0.1 day (2.4 h), and the minimum time step size $\Delta t_{\min}$ is 0.01 day (14.4 min) was applied to control the convergence errors.

Foam model in simulator

In the foam module of the simulator, because flow of foam in a porous medium is highly complex, investigating and modeling the nature of foam generation and coalescence as well as its rheological and physical properties remains a challenge that requires further research. For this reason, the foam model used in this simulation study assumes a simple conservation equation (Eclipse® 100, 2012). Accordingly, the foam generation and breakage mechanism are not considered in detail, and the foam is modeled as a tracer that can be transported with the gas or the water phase, taking into account adsorption onto the rock surface (Emadi et al., 2011).

In this simplified simulation model, the effect of foam on gas mobility is modeled by reducing the gas relative permeability or increasing the gas viscosity. A mobility reduction factor, M_{rf}, is applied to alter both end point of gas relative permeability and trapped gas saturation, and this factor is calculated as follows;

$$M_{rf} = \frac{1}{1+\left(M_r \cdot F_1 \cdot F_2 \cdot F_3 \cdot F_4\right)} \quad (1)$$

where, F_i accounts for various effects, such as F_1 for surfactant concentration, F_2 for water saturation, F_3 for oil saturation, and F_4 for gas velocity (Spirove et al., 2012). These dimensionless groups are suitably scaled by exponents e_s, e_o and e_c and weighting factor f_w under varying physical conditions. Each of F_i implies that

$$F_1 = \left(\frac{C_S}{C_S^r}\right)^{e_S}$$

$$F_2 = 0.5 + \frac{a\tan\left[f_w \cdot \left(S_w - S_w^l\right)\right]}{\pi}$$

$$F_3 = \left(\frac{S_o^m - S_o}{S_o^m}\right)^{e_o}$$

$$F_4 = \left(\frac{N_C^r}{N_C}\right)^{e_C}$$

In the above equations, C_s, S_w, S_o and N_c represent surfactant concentration, saturation of water, saturation of oil, and capillary number, respectively. Their corresponding critical values are denoted by C_s^r, S_w^l, S_o^m and N_c^r.

In addition, M_r is the reference mobility reduction factor obtained at maximum surfactant concentration and zero oil saturation. Usually, M_{rf} has the range of 5 to 100. The gas relative permeability is then rescaled from k_{ro} to (k_{ro}·M_{rf}) by the foam effect.

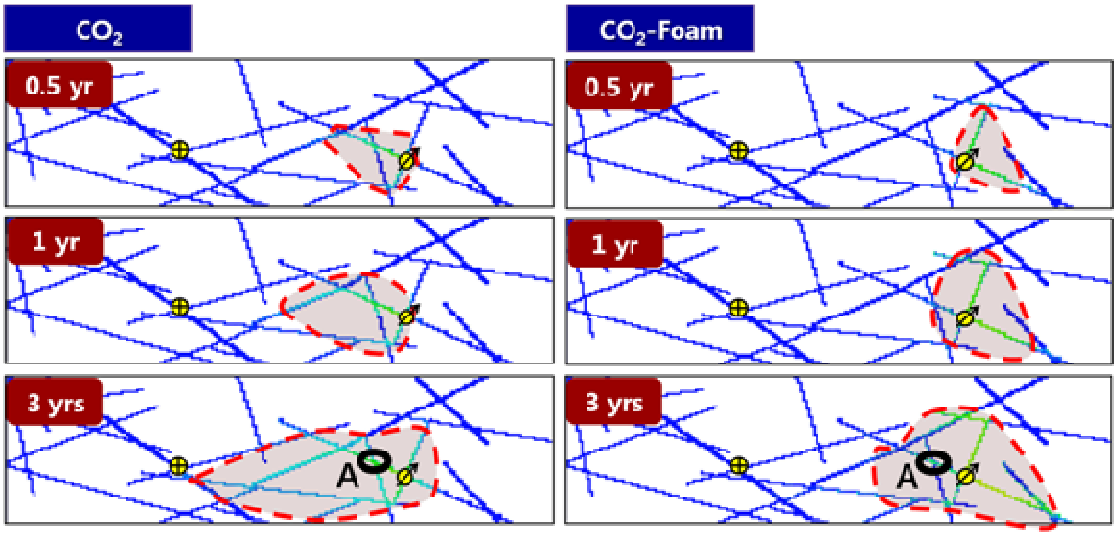

Figure 4. The CO_2 saturation distribution in fractured carbonate system.

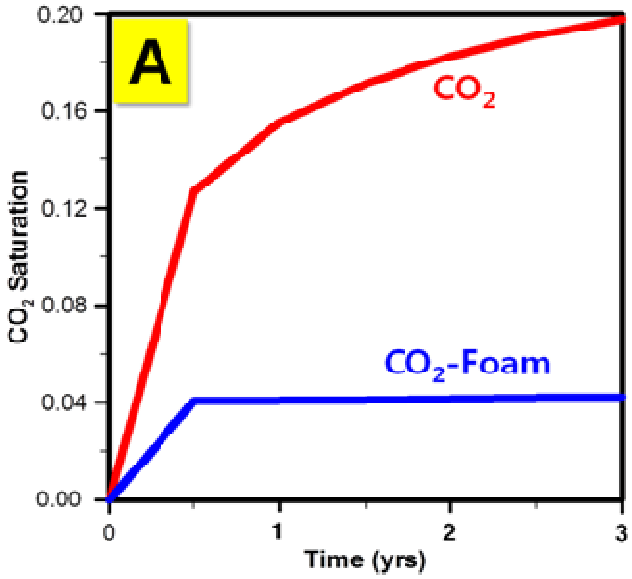

Figure 5. The CO_2 saturation change at location of "A".

RESULTS AND DISCUSSION

Oil flow in the matrix by CO_2 foam

To verify the effect of CO_2 foam injection with application of hybrid DFN approach using LGR on improving oil flow in the tight rock matrix, two simulation studies were conducted. First, we considered injection at 4.7754 MSCFD of CO_2 gas and 40 STBD of water with 0.001 wt% surfactant. A second process was used for comparative analysis of CO_2 flow velocity, which considered continuous injection of only CO_2 gas at 5 MSCFD (Figure 4). Figure 4 shows the CO_2 saturation distribution over 3 years; CO_2 quickly flows through the fractures toward the production well for continuous CO_2 injection compared with the case of CO_2 foam injection. We set point "A" between the two wells to examine the foam effect on flow control by observing the CO_2 saturation change. As shown in Figure 5, CO_2 saturation hardly increases after 0.5 year of CO_2 foam injection,

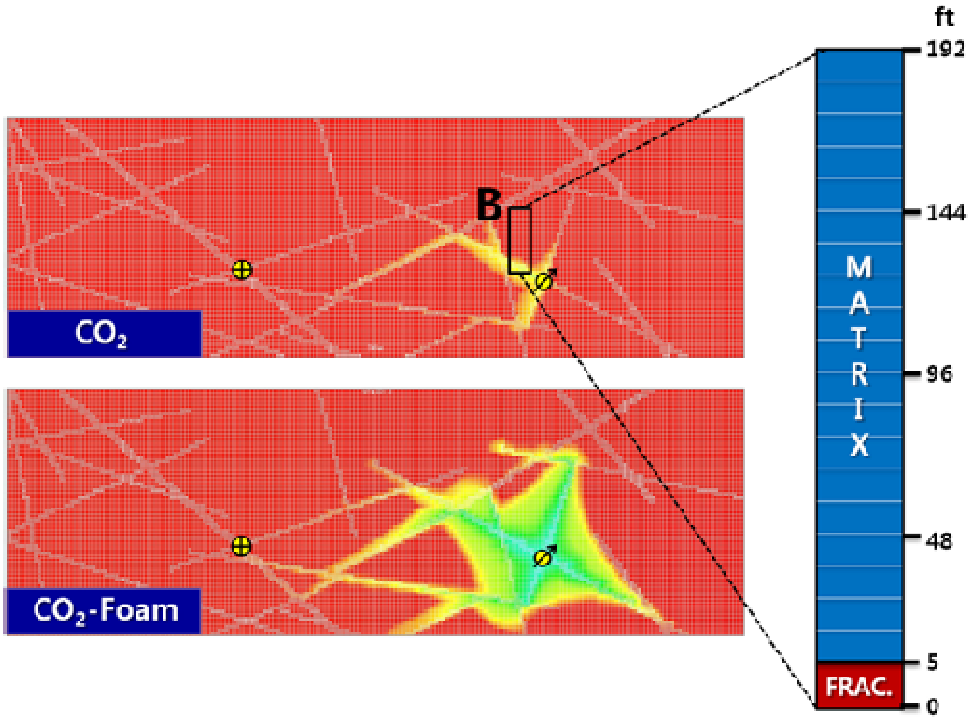

Figure 6. The oil saturation distribution at 1 year of production.

while CO_2 saturation consistently increases for the case of continuous CO_2 injection. This is because the mobility of gas-phase CO_2 is higher than that of liquid-phase foam, producing a greater flow velocity. It was shown that injection pressure for CO_2 foam injection with lower mobility has more than doubled compared to gas-phase CO_2 injection with higher mobility. This trend was also observed in the oil saturation distribution shown in Figure 6. For CO_2 foam injection, the sweep efficiency with oil improved because the liquid-phase foam enables capillary imbibition into the matrix as well as velocity control of fracture flow; for CO_2 injection, CO_2 gas preferentially moves through the fractures. With mobility control, foam diverts CO_2 and the surfactant solution to the tight matrix, where it can alter the wettability characteristics of the carbonate matrix from oil-wet to water-wet, causing more CO_2 foam to be imbibed into the matrix. Also, it reduces the interfacial tension (IFT) between the oil and water for release and mobilization of matrix oil, increasing the recovery factor (Fjelde et al., 2008; Shramm, 1994).

To analyze fluid imbibition into the rock matrix and improvement in oil flow in detail, the saturation change was measured at an arbitrary point “B”. Figure 6 shows that section “B” consists of 5 ft of fracture and the remaining matrix, totaling 192 ft long. As indicated in Figure 7, when only CO_2 was injected, oil and CO_2 saturation in the rock matrix started to change at 6 months, and, moreover, the changes reached just 20% of the total distance after 3 years. On the other hand, when CO_2 foam was injected (Figure 8), the change started at 1 month with a rapid increase in foam concentration and, accordingly, a decrease in oil saturation. Because the contact time and area between the injected CO_2 foam and the rock matrix increased, the oil in the rock matrix with a large area was displaced. Thus, the oil saturation change reached the total distance of 192 ft between 12 months and 18 months.

As a consequence of the above results, the curves in Figure 9 for average matrix oil saturation (except for fractures), indicate that both primary oil recovery by natural production and the case of simple CO_2 injection changed slightly, whereas CO_2 foam injection changed 10% from 0.8 to 0.72, confirming that CO_2 foam injection greatly improves oil flow in rock matrix.

Conclusively, as shown in production data at the well (Figure 10), the oil production rate for CO_2 foam injection is enhanced about five times compared to only CO_2 injection. Also, when CO_2 was injected, the CO_2 breakthrough time (BT) was 300 days. However, when CO_2 foam injection was applied, CO_2 breakthrough did not occur during the total production years, indicating that

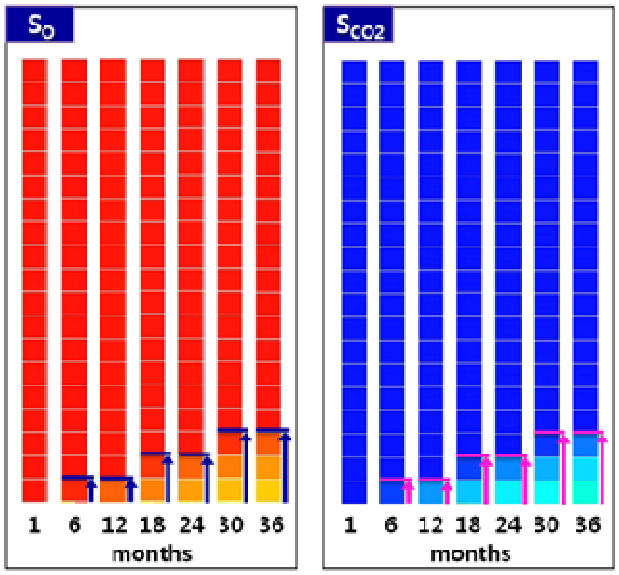

Figure 7. The changes of oil and CO_2 saturations at location of "B" in the case of CO_2 injection.

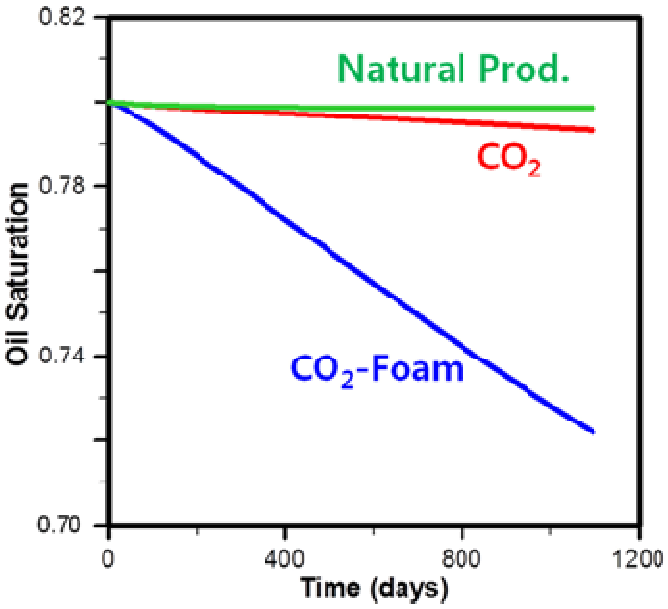

Figure 9. The average matrix oil saturation.

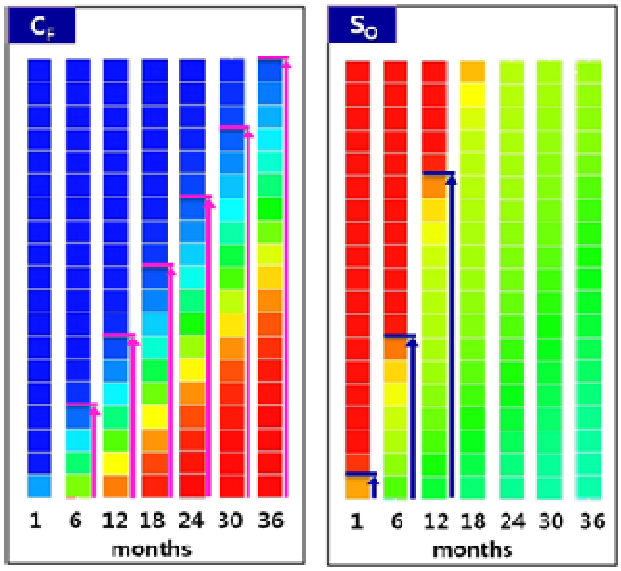

Figure 8. The changes of foam concentration and oil saturation at location of "B" in the case of CO_2 foam injection.

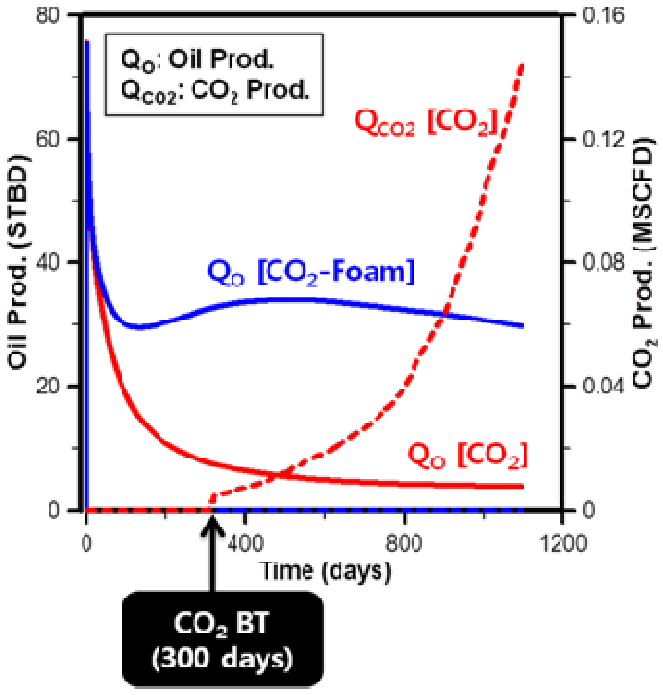

Figure 10. The oil production rate and CO_2 BT for the cases of CO_2 and CO_2 foam injection.

fracture flow was well-controlled by CO_2 foam injection, preventing early BT of CO_2.

Effect of injection fluid

It is important to determine which fluid plays a dominant role in promoting the foam effect when water, including surfactant, and CO_2 gas are co-injected to generate

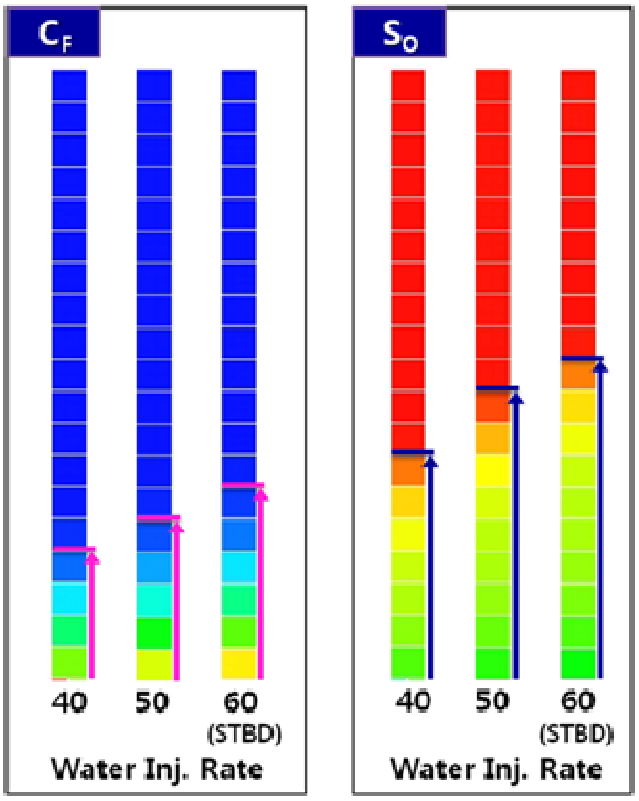

Figure 11. The changes of foam concentration and oil saturation at location of "B" for various cases of water injection rate at 6 months of production.

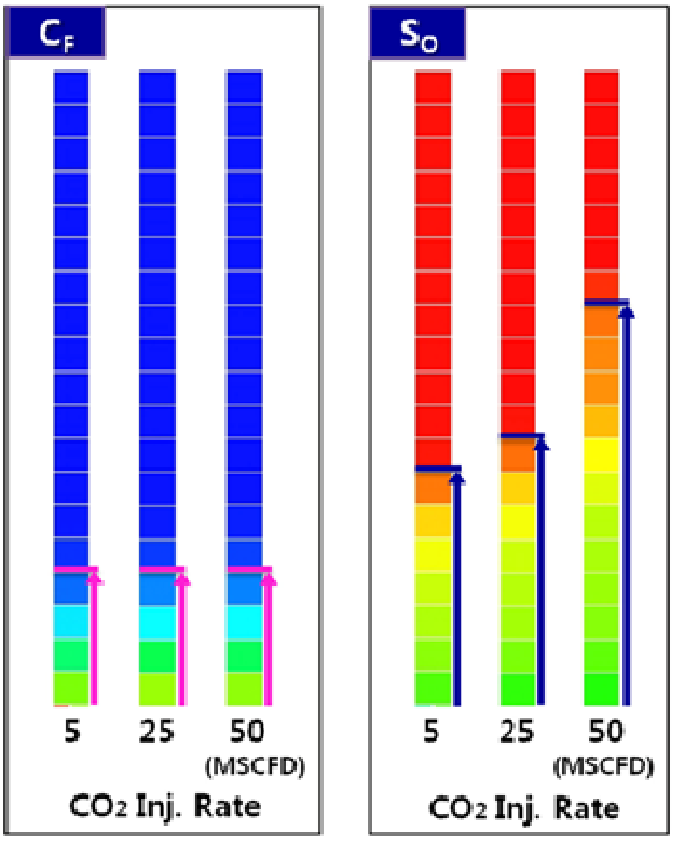

Figure 13. The changes of foam concentration and oil saturation at location of "B" for various cases of CO_2 injection rate at 6 months of production.

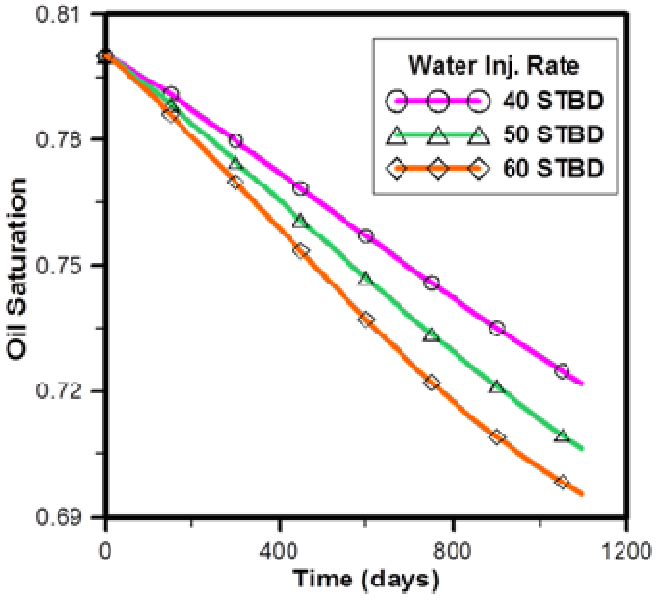

Figure 12. The average matrix oil saturations for various cases of water injection rate.

CO_2foam under the reservoir condition.

For this determination, three simulation runs were performed with water rates ranging from 40 to 50 and to 60 STBD with 0.001 wt% surfactant, while the co-injected CO_2 rate was fixed at 5 MSCFD. Figure 11 shows that higher water injection rates led to higher foam concentrations, decreasing the oil saturation deep in the rock matrix after 6 months. This means that, as the water (including surfactant) injection rate increases, more CO_2 foam is imbibed into the rock matrix, and rapid flow into fractures is controlled, displacing a large portion of oil remaining in the matrix. As a result, the average matrix oil saturation (Figure 12) further decreased when the water injection rate was high.

In sequence, three different CO_2 injection rates were considered: 5, 25, and 50 MSCFD with the same bottom-hole pressure at the injection well for the three simulations above according to water rate. The water injection rate was maintained at 40 STBD with 0.001 wt% surfactant. Figure 13 shows that greater CO_2 injection rates resulted in less oil saturation deep in the rock matrix

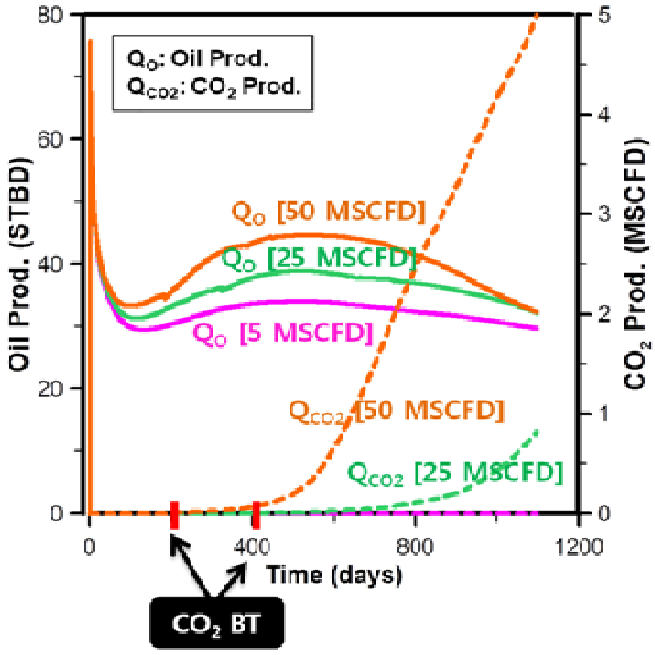

Figure 14. The oil production rate and CO_2 BT for various cases of CO_2 injection rate.

after 6 months, while the foam concentration did not change. Also, the CO_2 BT at the production well occurred early when the CO_2 rate was high (Figure 14). This indicates that an increase in amount of injected CO_2 did not affect fracture flow control via CO_2 foam; the result shown in Figure 13, in which matrix oil saturation was reduced, was likely due to the effect of increased total injection rate. That is, as the CO_2 injection rate increases, the amount of CO_2 imbibed into the rock matrix increases and displaces more oil from the matrix. However, it hardly influences foam flow and thus does not control rapid flow through the fractures on the contrary to the case of increasing water rates.

Effect of surfactant concentration

Since the surfactant is essential for generating foam, it is important to determine the proper surfactant concentration (Zuta et al., 2011). To investigate the effect of surfactant concentration with application of hybrid DFN approach using LGR, two comparative simulation runs were performed with a fixed CO_2 rate of 5 MSCFD and a water rate of 40 STBD with 0.01 and 1.0 wt% surfactant for 6 years.

Figure 15 shows the CO_2 saturation distribution in fractures, showing the effect on fracture flow control. In the case of high surfactant concentration of 1.0 wt%, CO_2 saturation was distributed densely within a narrow radius range compared to the case of low concentration of 0.01 wt%. Thus, CO_2 flow velocity in fractures is effectively slowed by high surfactant concentration, increasing the contact time between CO_2 and the rock matrix. In addition, Figure 16 shows that the CO_2 gas viscosity was held at a higher value for the case of higher surfactant concentration because this facilitated CO_2 foam formation. The viscosity change over time is caused with increases or decreases in pressure and temperature of the reservoir (Hirasaki et al., 1985). Consequently, Figure 17 shows that the CO_2 BT occurred at 1250 days with 11.2 pore volume of injection and 1600 days with 14 pore volume of injection for each case, indicating that BT was delayed with the high surfactant concentration.

Conclusion

A simulation for CO_2 foam injection in fractured carbonate reservoirs was performed to investigate the effect of foam on both rapid flow control in fractures and improved oil flow in a rock matrix. For the simulations, the fracture system was described using LGR and the hybrid DFN approach in which the fracture aperture is represented more realistically in comparison with exsiting works. The main results and conclusions are as follows:

1. Foam controls the CO_2 flow velocity and increases the contact time between CO_2 and the rock matrix. Hence,

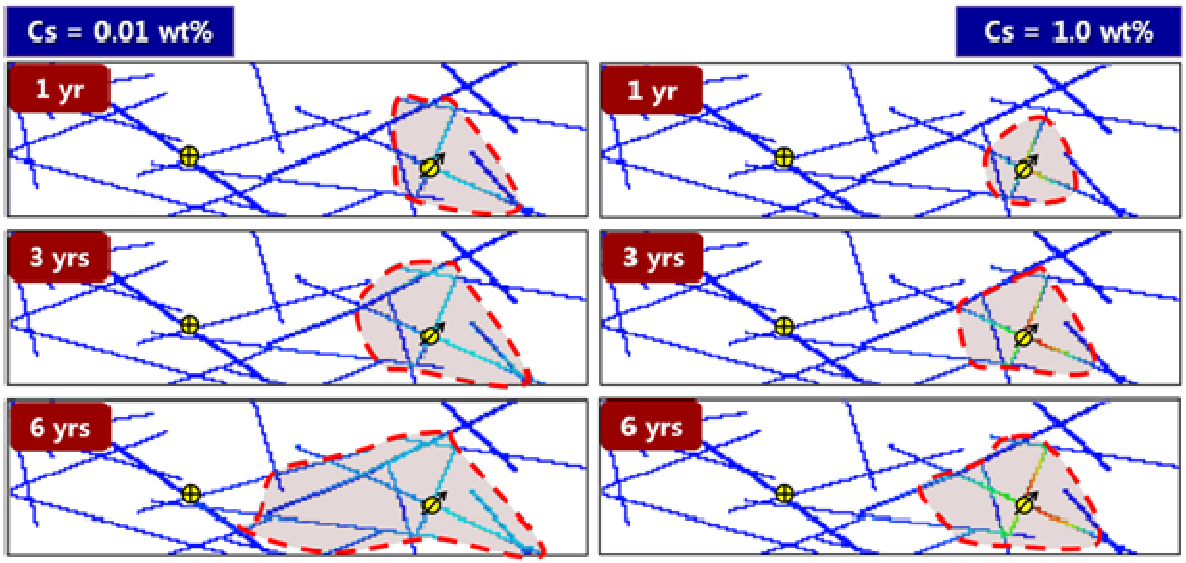

Figure 15. The CO_2 saturation distributions with surfactant concentrations.

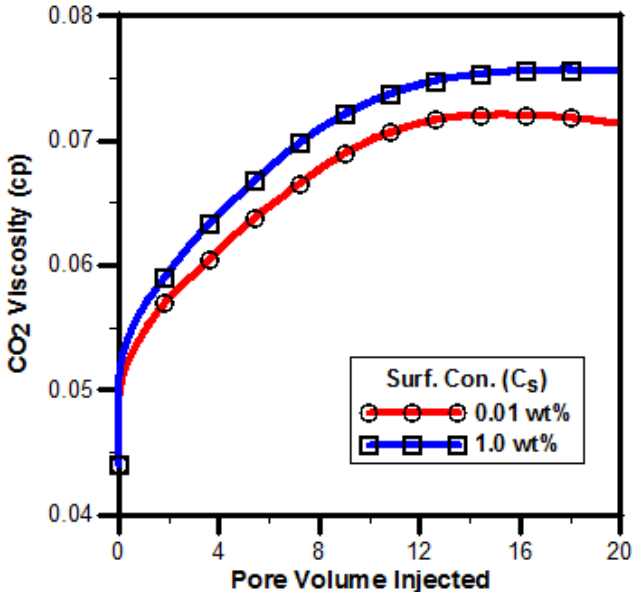

Figure 16. The CO_2 viscosity changes with surfactant concentrations.

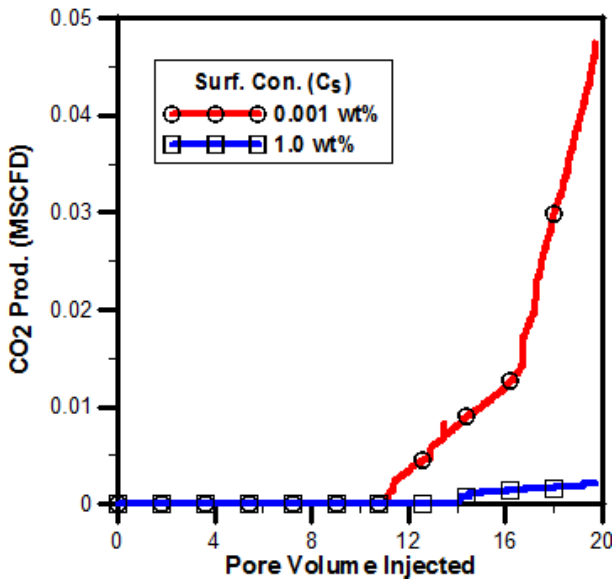

Figure 17. The CO_2 BT with surfactant concentrations.

injected CO_2 foam can be adsorbed and imbibed into the matrix, improving oil flow from the matrix. This is because CO_2 mobility is controlled by foam, which decreases CO_2 relative permeability and increases its viscosity.

2. During 3 years of production, the BT of the injected CO_2 was occurred at 300 days in the case of only CO_2 injection, meanwhile CO_2 breakthrough was not observed at producer when CO_2 foam was applied, indicating that foam prevents early CO_2 breakthrough.

3. The trend of decreasing oil saturation indicated that CO_2 foam injection is more effective for improving oil flow in the matrix; the decrease in oil saturation reached 16% of the total distance after 3 years for CO_2 injection, but it reached the total distance at 1.5 years for CO_2 foam injection.

4. In both cases of increasing water injection rate (with

the same surfactant concentration) and increasing CO_2 injection rate, the oil flow in the rock matrix was enhanced. However, CO_2 BT was occurred earlier, and oil production was lowered with increasing CO_2 injection rate. Therefore, the optimal design for injection rate is essential by considering injecting fluid in advance.

5. Higher surfactant concentration for CO_2 foam resulted in greater CO_2 viscosity. Thus, CO_2 flow velocity can be controlled effectively, resulting in increased oil production and retardation of CO_2 BT. Thus, formulation-related research should be continuously carried out in order to design cost-effective surfactant based EOR which requires an economic viability.

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