Numerical Investigation of the Most Affecting Parameters on Foam Flooding Performance in Carbonate Naturally Fractured Reservoirs

Seyyed Ali Ghoreishi, University of Calgary, Calgary, Canada; **Behnam Sedaee***, University of Tehran, Tehran, Iran

Abstract

As one of the methods for reducing gas mobility and delaying gas breakthrough time, foam flooding has potentials to play a crucial role in the oil industry. Thus, being used in highly heterogeneous reservoirs, e.g., naturally fractured reservoirs, it can increase sweep efficiency. In this paper, a conceptual 3D model has been used for demonstration of influential factors on foam flooding in naturally fractured reservoirs. A series of numerical analysis on fracture and matrix permeability, fracture spacing, wettability, and foam parameters have been conducted. Furthermore, an investigation of certain phenomena, including diffusion and the block-to-block effect, has been conducted. Based on the simulations, increasing fracture permeability increased GOR in foam flooding, while increasing matrix permeability decreased it. Moreover, regardless of the intensity of the fracture in the models, the foam decreased the gas rate and increased the oil recovery. However, cases with higher fracture spacing ended up having higher GORs. Foam injection performed very well in both water-wet and oil-wet scenarios; however, it performed better in the oil-wet case. While consideration of diffusion increased GOR in model with very low matrix permeability, taking the block-to-block effect decreased GOR and increased oil recovery in all scenarios. Furthermore, the foam injection rate was one of the most critical variables that needed to be optimized. In conclusion, the foam flooding not only tended to decrease GOR drastically but also increased oil recovery significantly in naturally fractured reservoirs. However, different rock, fluid, and injection properties can significantly change the results.

Introduction

Oil is known to be one of the most important elements of modern industry. Taking into account the growing demand for energy in the following decades, it is vital to meet the needs. In this sense, carbonate reservoirs, as one of the most significant sources of oil, have the potential to play a significant role in filling the gap. However, the heterogeneous nature of carbonate oil reservoirs has made not only oil production but also enhancing oil recovery very challenging. The contrast between fracture and matrix media has rendered CO_2 flooding less effective (Trivedi and Babadagli 2010; Shedid 2009), which is mainly the result of CO_2 mobility and viscose fingering. In this regard, gas injection and even water injection have poor results because of the early breakthrough. To face the challenge, varied solutions have been proposed, including foam injection. The purpose of this approach is to reduce gas mobility and divert the gas to the matrix to increase sweep efficiency. This aim is to be claimed by having foam lamella to provide resistance to gas flow and increase oil recovery.

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*Corresponding author: sedaee@ut.ac.ir

In addition, the Jamin effect tends to create higher resistance in high-permeable parts compared to low-permeable areas, allowing foam to block fractures and causing gas to divert into the matrix. Many experimental studies have investigated the application of CO_2 foam as a means of reducing gas mobility and increasing sweep efficiency (Khalil and Asghari 2006; Farzaneh and Sohrabi 2013; Zhang et al. 2014). Experimental and simulation results indicate that CO_2 foam can be used to improve macroscopic sweep efficiency and recover more oil from fractured reservoirs (John et al. 2010; Farajzadeh et al. 2010). Furthermore, although the improvement in the sweep in the more heterogeneous reservoirs was smaller than that in the less heterogeneous reservoirs when the foam was present, there was an improvement in the breakthrough time and incremental oil recovery in more heterogeneous reservoirs as well (Tham 2015). Moreover, many other investigations have shown that foam injection can yield a higher oil recovery compared to other EOR methods such as water alternating gas (WAG) or CO_2 injection. When comparing WAG injection and surfactant alternating gas (SAG) injection at the same condition, the pressure buildup in the wellbore could be very different, inferring blockage and reduction of permeability due to the presence of foam (Foo et al. 2014). The simulation study indicates that the performance of CO_2 foam flooding on oil recovery and displacement efficiency is better than that obtained by water flooding, CO_2 flooding, and WAG (Farajzadeh et al. 2009; Tham 2015). Furthermore, fractured reservoirs can have a different distribution of heterogeneities, all of which can contribute to many problems in the implementation of EOR schemes. However, based on research conducted by Tham (2015), as the heterogeneity of the reservoir increases, the degree of improvement using SAG increases. In more recent research carried out at the University of Harriot-Watt, it was pointed out that the ratio of surfactant to the gas used in SAG is also very important, and higher ratios of surfactant to gas yield higher recovery as the fracture intensity increases.

Modelling foam is very complicated as foam is not only very unstable, but also it is a combination of gas and liquid. As a result, it cannot be studied and considered as a different phase (Almaqbali et al. 2017; Hematpur et al. 2018). There are various models used to simulate foam flow, including the population balance model, the limiting capillary pressure model, fractional flow theory, and the stone model for continuous foam injection (Falls et al. 1988; Friedmann et al. 1991; Kovscek et al. 1995; Farajzadeh et al. 2012; Ma et al. 2015).

Based on our best knowledge, the role of the most affecting parameters were not comprehensively studies at NFRs. In this study, the effects of rock and fluid properties on foam flooding in naturally fractured reservoirs were numerically simulated and the most affecting parameters were discussed, compared, and addressed.

Simulations

Rock and Fluid Properties. The STARS module of the CMG™ package software was used to build a simple 3D model with 20×20×1 grid blocks. All grids had the height, width, and depth of 100 m. **Table 1** summarises the properties of the dual-porosity model (DP). The transmissibility in the fracture-matrix fluid flow term used in this dual-porosity model has been calculated using the Gilman and Kazemi (1988) formulation. The base DP model was water-wet, and its capillary pressure and relative permeability for the water-wet and oil-wet model curves are presented in **Figures 1** and **2**. The reservoir fluid is saturated under flood conditions with a gas cap. Furthermore, gas and foam were injected from this cap. The fluid properties of the models, including density and viscosity, are presented in **Table 2**. The initial conditions of the model are summarized in **Table 3**. A vertical production well with a constant maximum rate of 800 m_3/d and a minimum pressure of 1,500 kPa was considered; furthermore, a vertical injection well with a constant pressure of 20,000 kPa was considered perforated through the first layer.

Table 1—Reservoir properties of the model used in this study.

Parameters	value
Matrix Porosity	0.1
Fracture Porosity	0.01
Matrix Permeability, mD	10
Fracture Permeability, mD	1000

Table 2—Fluid properties of the model used in this study.

	Water	Dead oil	Solution gas	Surfactant
Densities, kg/m^3	978	843	15	379.1
Viscosity @80°C , cp	0.38	0.38	2.28	0.16
Live oil viscosity @ 26013 kPa, cp			0.42	
Critical pressure of live oil, kPa	137895			
Critical temperature of live oil, °C	760			

Table 3—Initial conditions of the reservoir.

Parameters	Value
Initial pressure, kPa	17500
Initial temperature, °C	80
Initial water saturation, fr	0.27
Initial oil saturation, fr	0.73
Initial oil saturation in gas cap, fr	0.20
Initial gas saturation in gas cap, fr	0.53

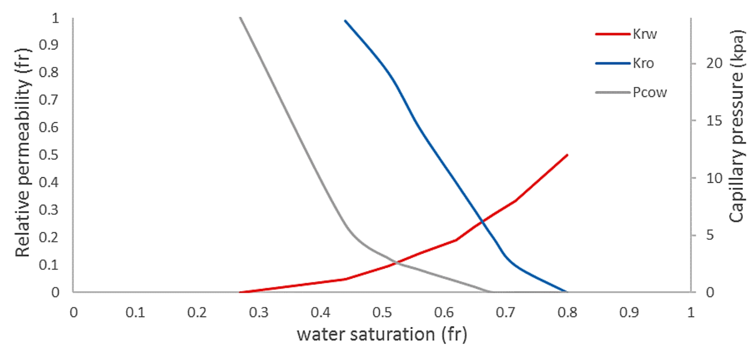

Figure 1—Capillary pressure and relative permeability curve (water-wet).

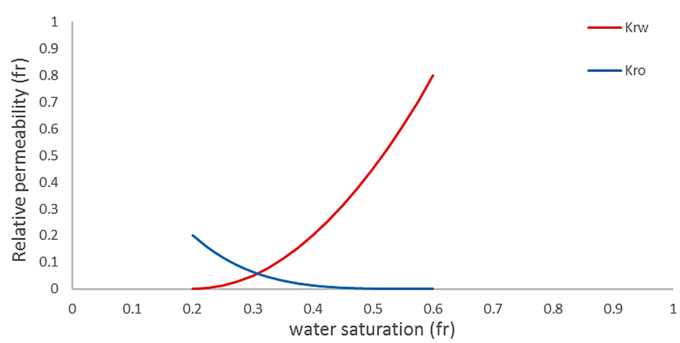

Figure 2—Relative permeability curve (oil-wet).

Foam Model and Foam Properties. The foam is generated in-situ by injecting gas and alpha-olefin sulfonate (AOS) solution. The success of foam as a displacing fluid in porous media depends on the longevity and strength of foams in the presence of nonaqueous phase liquids such as hydrocarbons, which are controlled by several factors, including critical water and surfactant concentration, brine salinity, oil saturation, and so on. Many different models have been developed to describe foam through porous media; generally, there are two main modelling approaches used to simulate foam in commercial simulators: empirical and mechanistic (Abbaszadeh et al. 2018), Which use different parameters for simulating foam's stability and performance. The approach used in this study is the empirical method, which tends to modify the relative permeability in the presence of foam; however, the texture of the foam is not considered directly in the calculations.

$$\begin{cases} \mathrm{k_{rg}^{f}} = \mathrm{k_{rg}} \times \mathrm{FM} \\ \mathrm{FM} = \left[1 + f_{mmob} \cdot f_1 \cdot f_2 \cdot f_3 \cdot f_4 \cdot f_5 \cdot f_6 \cdot f_{dry}\right]^{-1} \\ f_1 = \left(\frac{mole\ fraction(ICPREL)}{f_{msurf}}\right)^{ep_{surf}} \\ f_2 = \left(\frac{f_{moil} - s_o}{f_{moil} - f_{loil}}\right)^{ep_{oil}} \\ f_3 = \left(\frac{f_{mcap}}{capillary\ number}\right)^{ep_{cap}} \\ f_4 = \left(\frac{capillary\ number - fmgcp}{f_{mgcp}}\right)^{ep_{gcp}} \\ f_5 = \left(\frac{f_{mof} - x_{numx}}{f_{mof}}\right)^{ep_{omf}} \\ f_6 = \left(\frac{mole\ fraction - f_{lsalt}}{f_{msalt} - f_{lsalt}}\right)^{ep_{salt}} \\ f_{dry} = 0.5 + \frac{\arctan(sfbet(s_w - SF))}{\pi} \end{cases} \quad ,\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

Where, f_{mmob} is the pressure gradient function that represents the reduction in foam mobility when all conditions are favorable, which can be a good indication of foam strength; f_1 is the surfactant concentration function; f_2 is the oil saturation function; f_3 and $f4$ are the capillary number functions; f_5 is the critical oil mole fraction; f_6 is the salinity function. This model takes various parameters that affect foam mobility into account, including sharpness of transition zone (ep_{surf}), critical oil saturation (f_{moil}), lower oil saturation (f_{loil}), exponent of oil saturation (ep_{oil}), reference capillary number (f_{mcap}), exponent of capillary number (epgcp), exponent of critical oil mole fraction (ep_{omf}), lower salt mole fraction (f_{lsalt}), critical salt mole fraction (f_{msalt}), dry out function (f_{dry}) and a parameter to control the sharpness of transition zone between two foam regimes (s_{fbet}). Defining foam parameters can be very challenging and has inherited uncertainty due to non-uniqueness of the calibration of the foam model parameters with experimental data. As a result, the foam parameters presented in this study have been matched by in-situ generation of foam in fractured carbonate rocks. The foam parameters used in this study are listed in **Table 4**.

Table 4—Experimental foam parameters for foam.

Foam experiments	f_{mmob}	s_{dfdry}	s_{fbet}	f_{macap}	e_{pcap}
Foam	7,720	0.13	5,224	0.02	0.03

Results and Discussions

The base model with a gas injection had a breakthrough time of two years. Furthermore, the ultimate GOR after 10 years of gas injection was 1.0×10^5 (m^3/m^3) and oil production rate of 253 m^3/day which was half of its initial production rate of 500 m^3/day. This gas injection performance was improved by using foam injection.

In this study, various properties, including fracture permeability, matrix permeability, spacing, and wettability, were investigated to find out their effects on breakthrough time, GOR, and oil recovery.

Fracture Permeability. Effect of fracture permeability was investigated from 100 mD to 4000 mD to study its influence on breakthrough time and GOR. It is shown in **Figure 3**, as the heterogeneity of the reservoir increases, the gas-oil ratio also increases. Furthermore, foam injection tends to decrease the GOR ratio more significantly in higher fracture permeabilities as a result of the Jamin effect. Besides, although the difference of gas-oil ratio between the most and the least homogeneous model was about an order of magnitude, it was very subtle in case of foam injection. However, the permeability variations did not have a very significant impact on the gas breakthrough time after foam injection, while they caused a difference of approximately two years in gas injection (Figure 3). Generally, as can be observed in **Table 5**, foam tended to increase oil recovery for all models. However, it improved oil production much more in the more homogeneous ones (Table 5).

Table 5—Effect of fracture permeability on oil recovery after 10 years.

	K_f=100 mD	K_f=1000 mD	K_f=4000mD
Gas injection	0.11	0.15	0.18
Foam injection	0.15	0.17	0.20

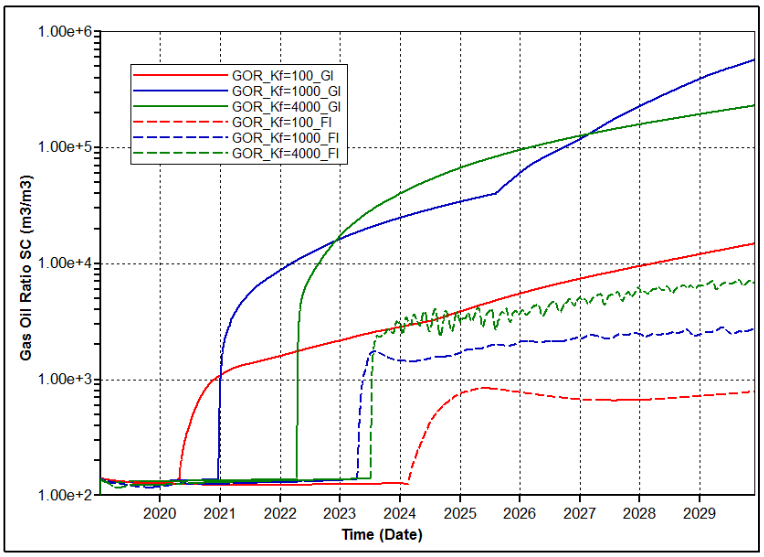

Figure 3—Effect of fracture permeability on GOR for gas injection and foam injection.

Matrix Permeability. Effect of Matrix permeability was investigated using 1mD to 50mD models for clarifying its impact on the gas rate and breakthrough time. As presented in **Figure 4**, foam decreased GOR in all the models dramatically, while there was not a consistent relation between matrix permeability and breakthrough time. Furthermore, the GOR of foam injection decreased as the matrix permeability increased, due to the fact that the increased matrix permeability tended to conduct gas to infiltrate the matrix more and result in a better sweep of oil at higher matrix permeabilities (**Figure 5**).

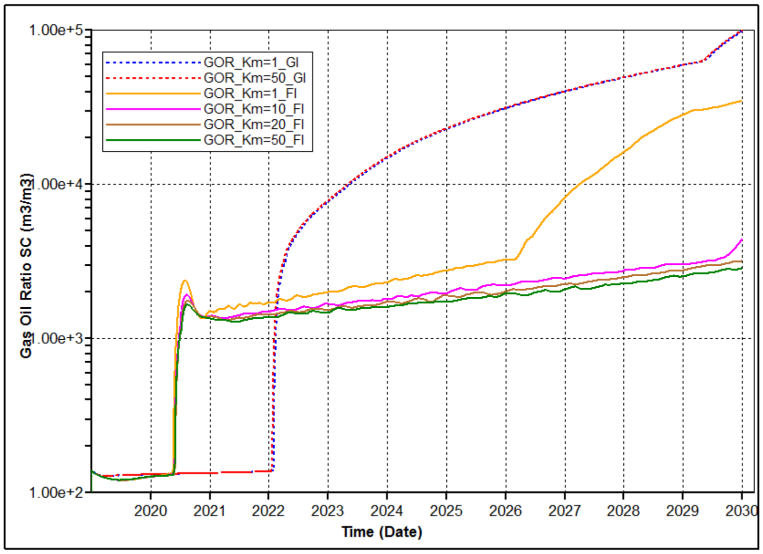

Figure 4—Effect of matrix permeability on the gas oil ratio for foam injection.

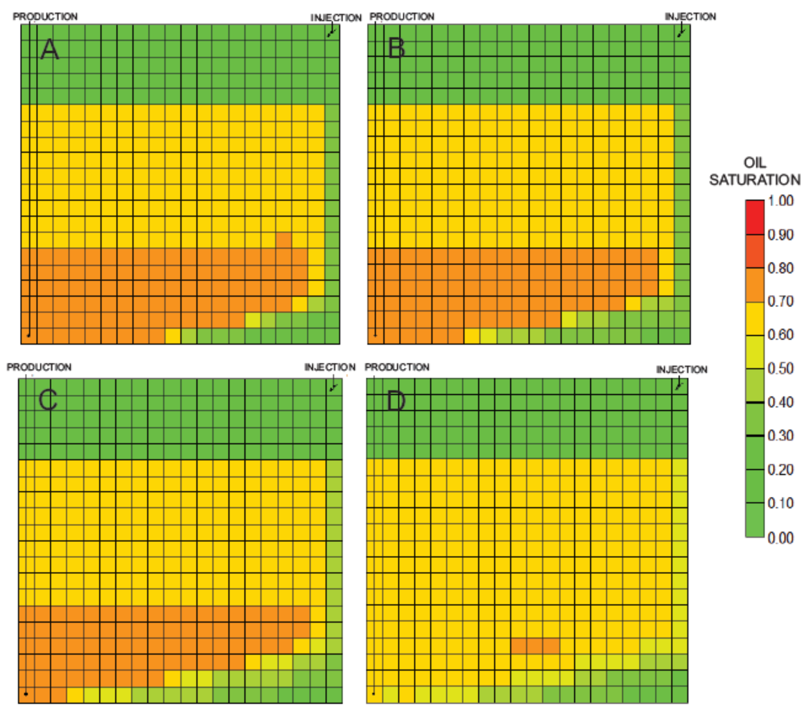

Figure 5—Oil saturation in the matrix after foam injection in A) matrix permeability=1 mD, B) matrix permeability=10 mD, C) matrix permeability=20 mD, and D) matrix permeability=50 mD.

Fracture Spacing. Effect of fracture spacing on gas breakthrough time, GOR, and oil recovery was investigated by changing it from 0.01 m to 70 m. As can be seen in **Figure 6,** the foam performed well in all cases. Breakthrough time decreased as the fracture intensity increased, which can be due to the fact that the lower fracture spacing helped the foam to spread better in the reservoir and decreased the chance of fingering. Furthermore, models with higher fracture intensity ended up with higher cumulative GOR (Figure 6). To end it, the foam drastically decreased the GOR and increased oil production in all cases.

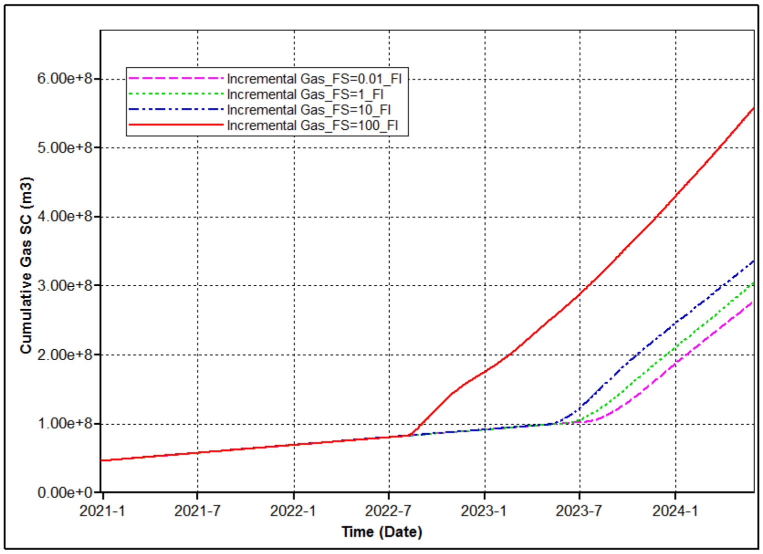

Figure 6—Effect of fracture spacing on gas breakthrough time for foam injection.

Gas Diffusion Effect. Gas diffusion has a major impact on models with very low matrix permeability. However, its influence decreased as the matrix permeability increased, to the point that it was almost non-existent at a matrix permeability of 1 mD (**Figure 7**). One of the main factors that controls foam stability is coarsening, the growth of the average bubble size, which is greatly affected by gas diffusion (Attia et al. 2013). To further elaborate, the diffusion of gas through the lamellae can lead to an increase in bubble size and end up making the foam less stable. As a result, the consideration of diffusion tended to increase the ultimate gas-oil ratio in all scenarios. This was especially important in ultra-low matrix permeabilities since the contribution of molecular diffusion in oil recovery is higher at lower flow rates in the matrix (**Table 6**). As a result, increasing matrix permeability reduced the importance of diffusion in GOR and oil recovery. In another scenario, the foam was injected for two years, followed by gas injection for eight years. The impact of diffusion was studied for lower matrix permeabilities. On the basis of simulations, foam tended to delay gas breakthrough and significantly decreased GOR significantly; however, foam flood performed better than foam injection for two years, since it decreased GOR more. Moreover, consideration of diffusion had much less impact in the second scenario. Although the GOR increased by more than an order of magnitude after considering diffusion during foam flood, it tended to increase less significantly in the latter (**Figures 7 and 8**). This results from continuous injection of foam in the first scenario. Continuous degradation of the foam until the end of the flood causes an acceleration of the rate of increase in GOR. In the latter case, the foam disappears after a while, resulting from instability of the foam; therefore, the rate of increasing the GOR becomes constant after some time. Consequently, although the GOR in the first scenario is lower than that in the second, the consideration of diffusion had a much greater impact on foam flood compared to foam injection for two years followed by eight years of gas injection.

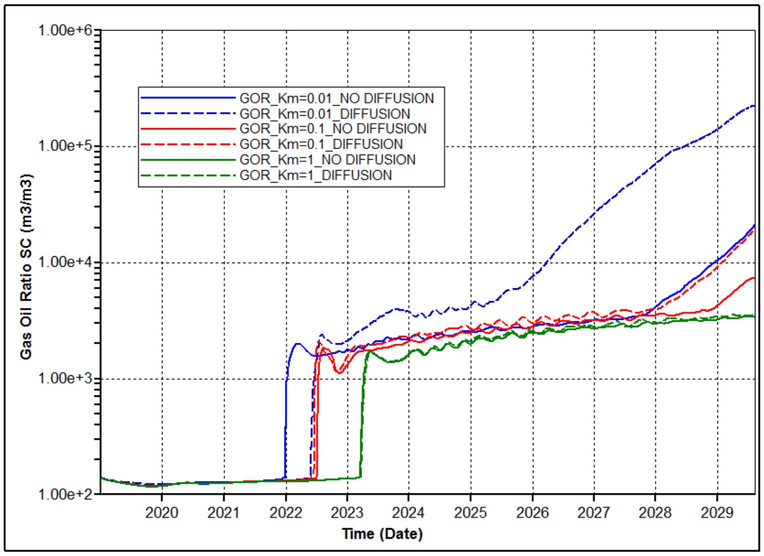

Figure 7—Effect of diffusion on GOR for foam flooding in different matrix permeabilities.

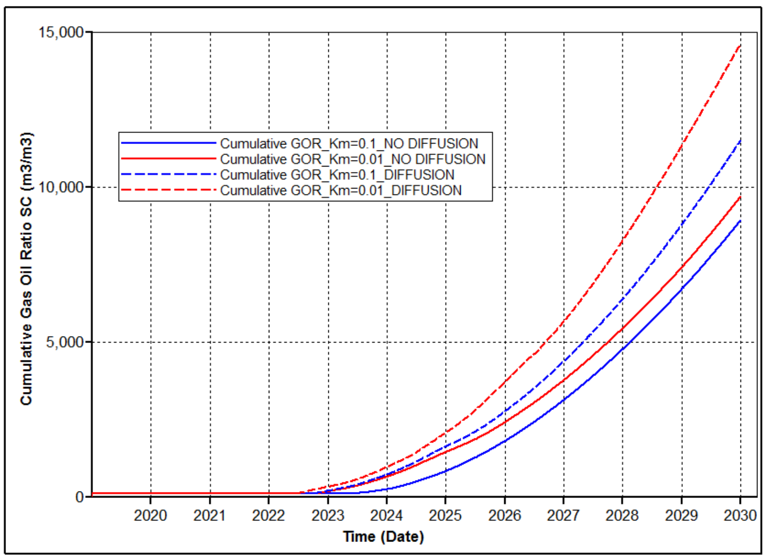

Figure 8—Impact of diffusion during foam injection in the second injection mode.

Table 6—Impact of diffusion on oil recovery in different matrix permeability.

Oil recovery (fr)	K_m=0.01 mD	K_m=0.1 mD	K_m=1 mD
With diffusion	0.08	0.10	0.12
Without diffusion	0.11	0.12	0.14

Wettability Effect. The main model in this study was water-wet. However, an investigation was conducted with an oil-wet model (Figure 2). The model shared all the properties of the water-wet model except wettability. In this model, gas injection and foam injection were performed. While GOR is higher during gas injections in the oil-wet systems (**Figure 9**), it does not change dramatically during foam injections in the same models. Furthermore, for higher fracture permeabilities, the difference between the ultimate GOR was greater in foam injection. The breakthrough time did not change significantly by altering the wettability (**Figure 10**).

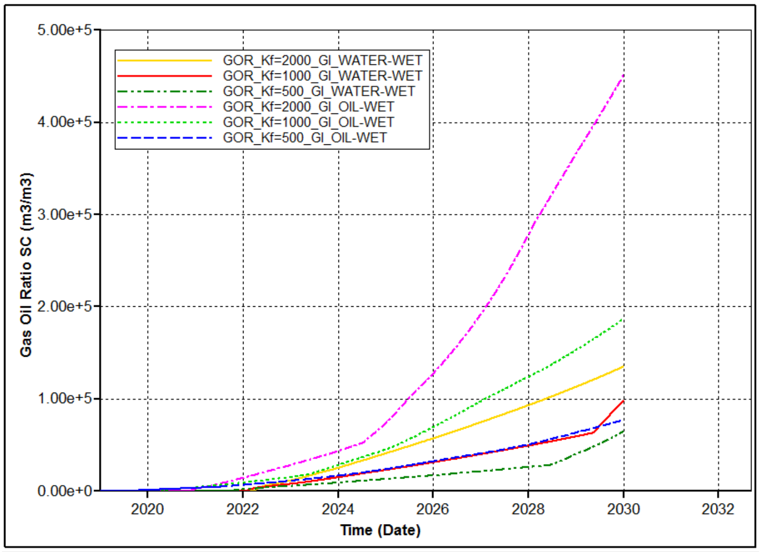

Figure 9—GOR in oil-wet and water-wet models with different fracture permeabilities (gas injection).

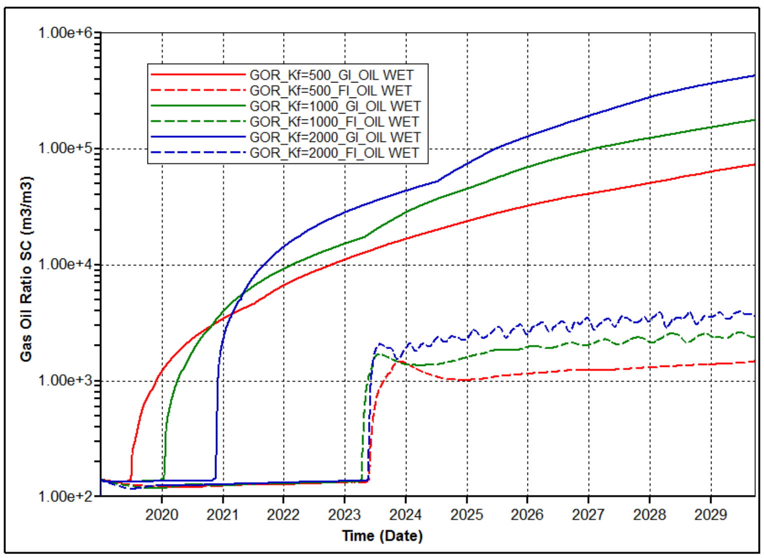

Figure 10—Breakthrough time in oil-wet models with different fracture permeabilities (foam and gas injection)

Re-infiltration Effect. All previous studies had used standard dual-porosity model; however, in order to study the effect of re-infiltration, a subdomain model has been used. The matrix element is divided into several nested volume domains that communicate with each other (**Figure 11**). Therefore, pressure, saturation, and temperature gradients are established inside the matrix, allowing transient interaction between fracture and matrix. Consequently, the fracture and matrix will start communicating earlier due to matrix sub-blocks. Matrix sub-blocks, as well as the fracture, have different depths and, hence, this model is suitable to simulate the gravity drainage process

This study investigates the block-to-block effect in the presence of gravity drainage. Reimbibition of oil to the lower block matrix can have significant impacts on gas breakthrough since considering this effect will increase sweep efficiency and conduct more gas to the matrix compared to the scenario that is not considered (**Figure 12**). As it can be observed in **Figure 13**, gas tends to breakthrough earlier when there is no block-to-block effect since it mainly sweeps the fracture. Although the block-to-block effect had postponed the breakthrough, the ultimate GOR was higher. Higher GOR in the second scenario can be explained by acknowledging that in the first scenario, no block-to-block effect, even after the breakthrough foam diverts some gas into the matrix while in the second scenario, foam has already conducted a considerable amount of gas into the matrix and not much of it is sweeping the matrix after breakthrough. Furthermore, cumulative oil production is also higher in the second model, which can approve higher sweep efficiency (**Table** 7).

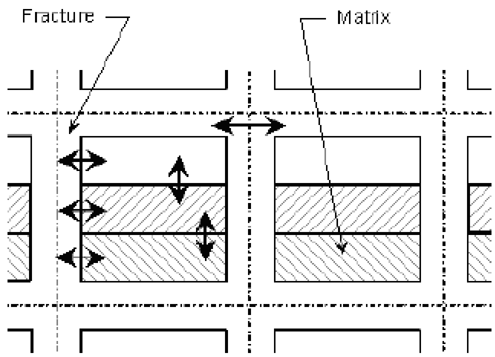

Figure 11—Subdomain model to investigate the re-infiltration effect.

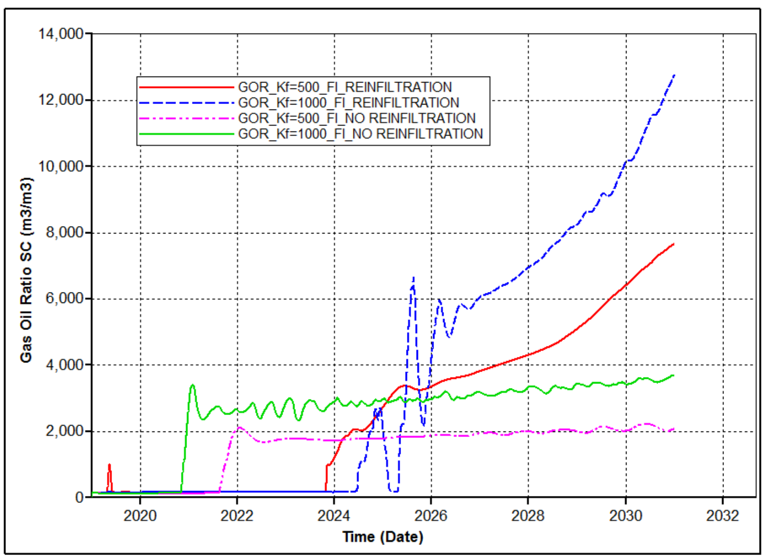

Figure 12—GOR in models with different fracture permeabilities with and without consideration of re-infiltration effect.

Table 7—Block-to-block effect on oil recovery with different fracture permeabilities.

Oil recovery	K_f=500 mD	K_f=1000 mD	K_f=2000 mD
With block-to-block effect	0.41	0.42	0.44
Without block-to-block effect	0.33	0.34	0.35

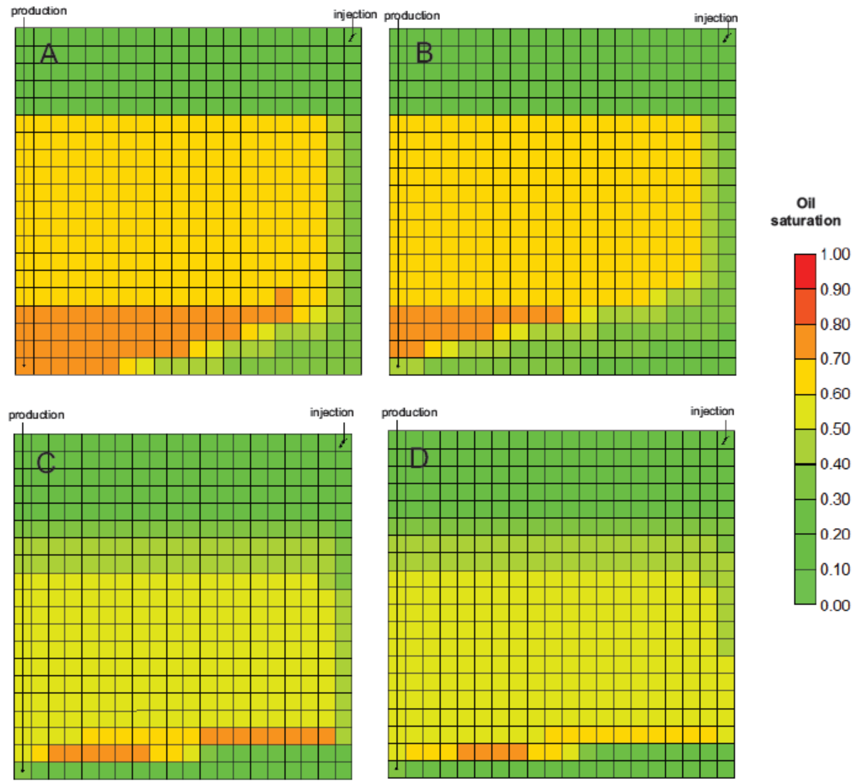

Figure 13—Effect of re-infiltration on oil saturation in the matrix: models without re-infiltration effect with fracture permeability of A) 500 mD and B) 1000 mD, models considering re-infiltration with fracture permeability of C) 500 mD and D) 1000 mD.

Foam Injection Rate. Impact of the rate of foam injection on GOR and oil recovery has been investigated using the dual-porosity model for a wide range of rates. Increasing the injection rate did not have the same impact on the results. Increasing foam rate tended to increase oil recovery at a lower injection rate since it not only increased the sweep efficiency but also maintained the reservoir pressure. However, increasing the rates had adverse effects at higher injection rates. As a result, there is an optimum rate for maximizing the oil recovery in this period. This results from the fact that, while higher injection rates improve oil recovery before the breakthrough, they decrease it afterward, as they drastically increase gas production and GOR (**Figure 14**). In this study, the optimal rate was around 500 m^3/day, after which the increase in the rate had the opposite influence on oil recovery and significantly decreased GOR. It is important to point out that this is the technical optimum rate, however, this rate is always calculated based on economic variables and may be different in real reservoirs.

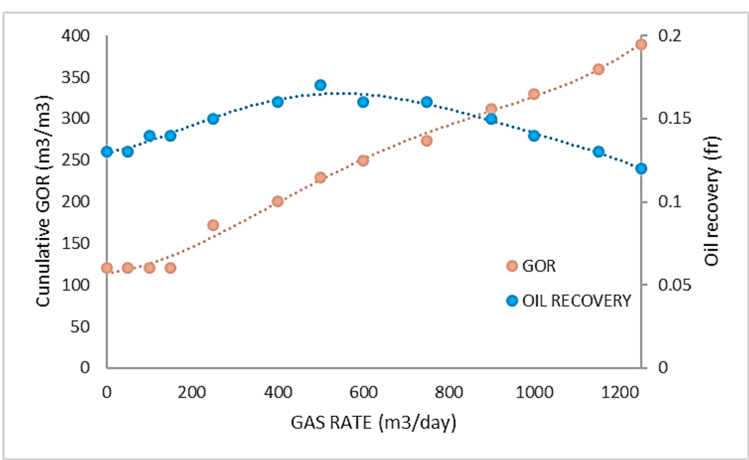

Figure 14—Impact of injection rate on cumulative GOR and oil recovery.

Conclusions

Gas injection and foam injection simulations were performed on a 3D reservoir model and the following conclusions can be drawn from this study:

1. Foam injection tends to decrease GOR, delay gas breakthrough, and increase oil production in all the cases of naturally fractured reservoirs studied; however, its impact was much notable in models with higher heterogeneities.
2. Although increasing matrix permeability and fracture intensity decreased GOR, the differences were not as striking as the changes caused by fracture permeability alterations.
3. Furthermore, although consideration of diffusion did not result in much change in higher matrix permeabilities, it increased GOR and decreased oil recovery in the cases with lower matrix permeability. This impact decreased as the matrix permeability increased.
4. The change in wettability from water-wet to oil-wet increased the GOR in gas injection; however, the foam model performed better and significantly decreased the GOR, even lower than that of the water-wet system.
5. The consideration of the block-to-block effect had significant impacts on the result. While for the scenarios with the reinfiltration option, it took longer for the gas to breakthrough, the ultimate GOR was higher for them.
6. An investigation of the injection rate clarified that increasing the injection rate does not necessarily increase oil recovery; in fact, it can decrease oil recovery after the breakthrough. However, increasing the rate before the breakthrough increases oil recovery. As a result, the optimal rate should be calculated.

Conflicts of Interest

The author(s) declare that they have no conflicting interests.

Nomenclature

f_{mmob} = pressure gradient function
f_1 = surfactant concentration function
f_2 = oil saturation function
f_3 = capillary number function
f_4 = capillary number function
f_5 = critical oil mole fraction
f_6 = salinity function
ep_{surf} = sharpness of the transition zone
f_{moil} = critical oil saturation
f_{loil} = lower oil saturation
ep_{oil} = exponent of oil saturation
f_{mcap} = reference capillary number
ep_{gcp} = exponent of capillary number
ep_{omf} = exponent of critical oil mole fraction
f_{lsalt} = lower salt mole fraction
f_{msalt} = critical salt mole fraction
f_{dry} = dry out function
s_{fbet} = parameter to control the sharpness of the transition zone between two foam regimes

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S. A. Ghoreishy received his Bachelor's degree in petroleum engineering from the University of Tehran. He is currently a master student and researcher at the University of Calgary. He mainly focuses on different phenomena that affect the fluid flow in porous media, including foam flow in porous media and flow alongside on the surface of porous media.

Behnam Sedaee is currently an Assistant Professor of Institute of Petroleum Engineering at University of Tehran. Behnam has authored several peer-reviewed journal publications and conference papers. He has been heavily involved in research on various aspects of reservoir engineering including natural fractured reservoir simulations (NFR), enhanced oil recovery (EOR), gas condensate, underground gas storage (UGS), and acidizing. His research has also included laboratory measurement and characterization of enhanced oil recovery (EOR). He developed several software for UGS, EOR and reservoir applications. Dr.Sedaee earned a BS in chemical Engineering and a MS, PhD in Petroleum Engineering from Polytechnics University.