OIL RECOVERY DURING CO$_2$-FOAM INJECTION IN FRACTURED CHALK ROCK AT RESERVOIR CONDITIONS

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ABSTRACT

Field studies and laboratory tests have shown that foam can reduce the mobility of CO$_2$ and mitigate the effects of gravity override, viscous fingering and channelling. Thus, macroscopic sweep efficiency is improved and oil production is increased. However, very limited information is available about CO$_2$-foam processes in fractured chalk rock.

The injection of CO$_2$-foam injection in fractured porous media, will result in foam been preferentially formed in the fractures. This will increase the local resistance to flow and divert more of the CO$_2$ and foaming agent solution into the low permeable matrix.

This paper presents both simulation and laboratory studies carried out on fractured water flooded chalk models to investigate the oil recovery efficiency during CO$_2$-foam flooding at reservoir conditions. The fractured model was created by drilling a hole through the centre of the core plug and homogeneously packing it with glass beads. The CO$_2$-foam process was conducted by injecting pre-formed foam into the fractured model at 340 bar and 55°C. CO$_2$-foam was also injected into a non-fractured model (core plug) to establish a base case behaviour at the same conditions. The transport of the foaming agent in the absence and presence of oil was also determined at the same effective permeability of the fractured chalk model. Simulations of the CO$_2$-foam floods in a fractured model similar to that used in the CO$_2$-foam experiments, were carried out using the compositional reservoir simulator STARS.

Results show that more oil is recovered in the CO$_2$-foam processes than in pure CO$_2$ processes at the same effective permeability. The simulation of CO$_2$-foam processes using the compositional simulator STARS gave a good match with experimental results. The transport of the foaming agent from the fractures into the matrices was also determined to be slower in the fractured models than in non-fractured models with viscous flooding. The results from this study can be used to estimate the loss of a foaming agent due to retention and aid in the design of a CO$_2$-foam process in fractured chalk reservoirs.

INTRODUCTION

CO$_2$-flooding is a well known and used enhanced oil recovery (EOR) technique (Felber, 2004). CO$_2$ can be used as an immiscible or a miscible displacing agent, depending on the reservoir conditions and the compositions of the crude oil. In fractured carbonates reservoirs, the oil recovery and sweep efficiency will depend on parameters such as matrix permeability, fracture-matrix geometry, wettability, reservoir temperature and pressure, oil and solvent viscosities as well as densities. CO$_2$ flooding is considered as an inefficient process for enhancing oil recovery in naturally fractured reservoirs (Asghari and Torabi, 2008). The presence of fractures leads to early CO$_2$ breakthrough resulting in poor sweep efficiency (Chakravarthy et al. 2006). The use of CO$_2$ as a

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displacing agent through these reservoirs aggravates the problems of low sweep efficiency due to its high mobility. Thus, the macroscopic displacement efficiency of CO_2 flooding in fractured reservoirs can be improved if the mobility of CO_2 can be decreased (Kovscek et al. 1995). Laboratory experiments have been carried out in an attempt to improve CO_2 sweep efficiency by controlling the CO_2 mobility in the fractures. For example, Chakravarthy et al. (2006) injected water viscosified with a polymer and a cross-linked gel directly into the fractures, to divert CO_2 flow into the matrix and delay its breakthrough. Karaoguz et al. (2007) also reported a successful field pilot application of polymer gels systems for reservoir conformance improvement in the on-going CO_2 injection project at the fractured carbonate Bati Raman field in south-eastern Turkey.

Another method is the use of foam to reduce CO_2 mobility or for blocking high-permeability zones (Khalil and Asghari, 2006). Because foam has a much higher effective viscosity than that CO_2, it has been investigated as a method for improving sweep efficiency and oil recovery (Yan et al. 2006). Stable foam can be formed by injecting CO_2 along with an aqueous CO_2-foaming agent solution (surfactant) into the reservoir. The inherent advantage of foam for mobility control is that CO_2 resides inside 'bubbles' that are separated by thin aqueous films called lamellae. For high pressure CO_2-foams, the dispersed phase is dense CO_2 with density as high as 0.9 g/cm^3 (Liu et al. 2005). The foam lamellae in porous media provide resistance to CO_2 flow, diverting most of the CO_2 into the matrix blocks (Renkema and Rossen, 2007).

Laboratory experiments (Khalil and Asghari, 2006; Chang et al.1999), mechanistic studies (Kovseck et al. 1993; Alizadeh et al. 2007; Renkema and Rossen, 2007) as well as field tests (Stevens and Martin, 1998) have shown that injecting foam can enhance oil recovery. However, very little information has been reported about CO_2-foam in fractured chalk reservoirs. During CO_2-foam processes in fractured reservoirs, it is expected that the fluids will flow into the high permeability zones where foam will preferentially be formed. This will greatly increase the local resistance to flow, and divert the injected fluids into the low permeable matrix and improve the process efficiency (Yan et al. 2006). Kovscek et al. (1995) carried out experiments using a single fracture with an aperture of 30 μm to study the mechanisms of foam flow in fractured reservoirs. They observed larger flow resistance for foam with thin lamellae separating gas bubbles and vice versa for foam with thick liquid lenses separating the foam bubbles. Thus, the foam morphology inside the fracture depends on the gas fractional flow rates. Yan et al. (2006) developed a theory for foam flow in a uniform fracture and showed that foam can greatly affect the sweep efficiency in a heterogeneous fracture system. Alizadeh et al. (2007) carried out a full-field simulation study to investigate the effect of foam injection on CO_2 mobility and oil recovery improvement in a fractured carbonate reservoir. Kovseck et al. (1993) undertook a simultaneous experimental and simulation study of transient foam displacement in porous media.

In fractured carbonate reservoirs, CO_2-foam can block the fractures and enable the transport of the CO_2 and the foaming agent solution into the low permeable matrix blocks. However, the adsorption of the foaming agent onto the matrix blocks may retard the movement of the foaming agent molecules. Also, the presence of fractures may reduce the contact area between the matrix blocks and the foaming solution and the effective amount of the active product to be injected. Alkan et al. (1991) studied the effects of pH, flow rate and the fractured structure of reservoir cores on the adsorption of CO_2-foaming agents in limestone rock. For matrix blocks with high porosity, the transport of fluids from the fractures is expected to be governed by mechanisms such as

convective flow, viscous flow, dispersion, diffusion and retention (Chung, 1991). However, the efficiency of the CO_2-foam process will depend on transport of the fluids within the porous media, conditions at the matrix-fracture boundaries, fracture geometry as well flow conditions. When CO_2 is injected along with the foaming agent solution, the reduction of the mobility of CO_2 will be due to the total resistance to the transfer of CO_2 resulting from the sum of the liquid phase resistance, the CO_2 resistance and the interfacial resistance which arises from the adsorption of the foaming agent aggregates to the CO_2/foaming agent solution interface. Laboratory measurements have shown that soluble foaming agents have no significant effects on the passage of CO_2 molecules through the CO_2-fluid interface (Zuta et al. 2008a), however, soluble foaming agents can form high viscous phases which can offer resistance to CO_2 transport and reduce the ultimate oil recovery efficiency.

In this paper, laboratory experiments and simulation of dynamic CO_2-foam injection have been carried out to determine the oil recovery efficiency in water flooded fractured chalk models at typical reservoir conditions. The injections of CO_2-foam and CO_2 in non-fractured models (core plugs) were used to establish base case behaviours at the same reservoir conditions. The CO_2-foam process was carried out by injecting pre-formed foam into the models in a horizontal position. Dynamic retention experiments with the CO_2-foaming agent in both fractured and non-fractured chalk models with 100% water-saturation and at residual oil saturation after water flooding were also carried out.

EXPERIMENTAL PROCEDURES

Porous media
Core plugs from an outcrop of Liege chalk with a minor amount of clay and less than 2% silica (Strand et al. 2007) were used for all of the experiments. The plugs used were sampled from the same block. All the plugs had a diameter of 3.8 cm and a length of approximately 7.0 cm.

Salt	Artificial formation water (FW)	Seawater (SW)	Seawater with thiocyanate (SWT)
	g/l	g/l	g/l
NaCl	36.81	23.38	23.38
Na$_2$SO$_4$	-	3.41	3.41
NaHCO$_3$	-	0.17	0.17
KCl	0.31	0.75	0.75
MgCl$_2$·6H$_2$O	4.48	9.15	9.15
CaCl$_2$·2H$_2$O	33.25	1.91	1.91
KSCN	-	-	2.33

Table 1. Compositions of FW, SW and SWT with the tracer

Chemicals and fluids
The brines used were synthetic seawater (SW) and formation water (FW) with compositions as shown in **Table 1**. The CO_2-foaming agent (FA) used was a branched ethoxylated sulphonate with 9-11 carbon atoms in its chain length and 6 ethylene (EO) groups. Aqueous foaming agent solutions were prepared with SW including tracer (SWT), Table 1. The CO_2-foam injections and dynamic retention experiments were conducted with 1.0 wt. % active solutions. Stock tank oil from a North Sea reservoir was used for core preparation. All the fluids samples were filtered (0.45 µm) before use.

Preparation of plugs with formation water
The plugs were stored at 120°C overnight until constant weights, and later saturated with FW after been evacuated in a desiccator. Since sulphate ions have been found to exist in Liege outcrop rock (Fjelde et al. 2008a), the 100% FW saturated plugs were cleaned of sulphate by flooding them with FW until zero sulphate concentration in the effluent samples. The absolute permeability (k_{abs}) of the plugs to FW was also measured.

Preparation of plugs with stock tank oil
Plugs with initial water saturations (S_{wi}) were established by draining 100% FW saturated plugs with humified N_2 gas at room temperature with the unconfined porous disc method. The plugs were later aged with continuous injection of stock tank oil (STO) at 0.08 ml/min for 80 hours at 90^oC; 40 hours in opposite directions.

Preparation of fractured chalk models
The fractured model (**Figure 1**) was prepared by drilling a 0.3 cm concentric hole through the centre of plug with diameter of 3.8 cm and a length of approximately 7.0 cm, and homogeneously packing it with glass beads of 90-106 µm dimensions. Filter papers (0.45 µm) were placed on both ends of the fractured model to keep the glass beads in the model. In the experiments, plugs at 100% FW saturation or residual oil saturations after water flooding (S_{orw}) were used. Fractured models with S_{orw} were prepared by first water flooding the plugs and later creating the artificial fractures as described above. Core plugs without fractures (herein refered to as non-fractured models) were similarly prepared and used in the experiments.

Figure 1. Fractured chalk model

Procedure for dynamic retention experiments
The dynamic retention studies (done in the absence of CO_2) were carried out by injecting 1.0 wt% active foaming agent solutions into the models (**Figure 1**) at 0.1 ml/min (an interstitial velocity of approximately 0.009 cm/min) and 55^oC. Equal volumes (5 PVs) of the solutions were injected. Similar experiments were carried out with the non-fractured models and used as references.

After the retention experiments with the fractured models, the models were de-mounted and the glass beads in the fractures washed out. The fractures were then sealed with an epoxy and water flooded with SW to desorb the retained foaming agents. This was followed by flooding with methanol until zero foaming agent concentrations in the effluent samples. Effluent samples (5ml) were collected and analysed for foaming agent concentrations and tracer. Retention studies in the presence of oil were similarly conducted by injecting the foaming agent solution into the fractured model at S_{orw}. Water flooding was carried out by injecting SW at increasing rates of 0.1 to 0.5 ml/min until stable differential pressures.

Foam flooding experiments

The injection of CO_2-foam and CO_2 were carried out in both water flooded fractured (Figure 1) and non-fractured chalk models at supercritical CO_2 conditions (340 bar and 55^oC). In order to preserve the artificial fractures in the fractured models, two Quixiz pumps were simultaneously used to increase the over-burden pressure and pore pressure respectively. The first pump was used to increase the over-burden pressure from 25 to 365 bar, whiles the second pump was to used increase the pore pressure to 340 bar. The system back-pressure was 340 bar, thus maintaining a net confining pressure of 25 bar. The CO_2-foam processes were carried out by continuously injecting pre-formed foam from a foam generator (homogeneously packed with 45-53 µm glass beads) at fixed mass rates into the chalk models. CO_2 was injected at 0.1 ml/min (0.009 cm/min) whiles the 1.0 wt% foaming agent solution was injected at 0.011 ml/min (0.001 cm/min), i.e. a gas fractional flow of 90%. Pure CO_2 was injected at 0.1 ml/min and 340 bar into the chalk models. The pressure drops across the models were measured by a pressure transducer (0-5 bar). The experimental set-up is shown in **Figure 2**.
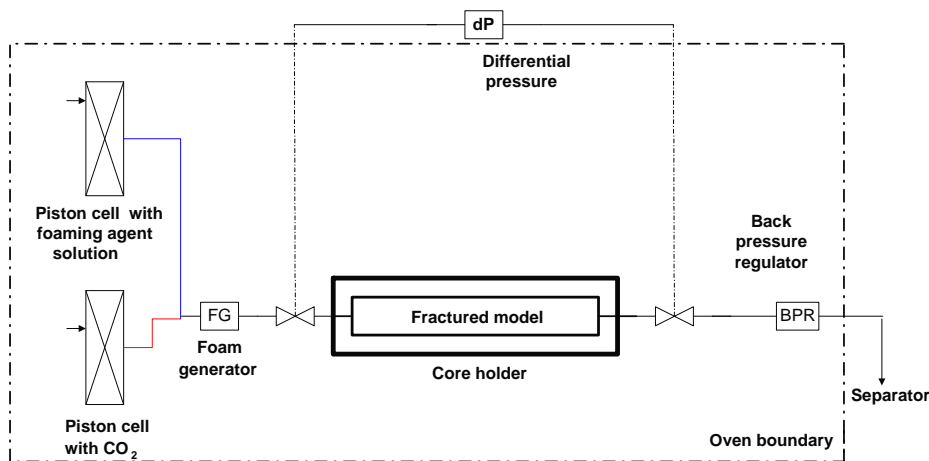

Figure 2. Foam flooding – Experimental set-up

The remaining oil saturations after the floods were also determined. This was conducted by first water flooding the models with SW at a low injection rate until no more CO_2 gas was produced at surface conditions. The system was then de-pressurized and the plugs were demounted. The glass beads in the fractures were then washed-out and the fractures sealed with an epoxy. The accessible water-volumes were determined and the detail is described by Fjelde et al. (2008b)

Analytical methods

Sulphate analyses were done using a sulphate cell test kit (Spectroquant 1.14548.001) (ASTM D516-07). Foaming agents in effluent samples were analyzed by a two phase titration method using Hyamine, a cationic surfactant. The analyses performed in these experiments were done by using the cationic dye methylene blue indicator and chloroform as organic phase (Schmitt, 2001). Lithium analyses were determined using the inductive couple plasma (ICP) method. Thiocyanate in effluent samples were analyzed by diluting an exact sample volume with a mixture of 0.2 M solution of Fe $(NO_3)_3$ dissolved in 1.0 M aqueous HNO_3 solution (Lathi et al.1999). The absorbance was measured using a MERCK KGaA Spectroquant NOVA 400 spectrophotometer at 447 nm. The accessible water-volume was used to determine the remaining oil saturations in the models as described in Fjelde et al. (2008b).

RESULTS AND DISCUSSION

The physical properties of the fluids including interfacial tension, viscosity, pH and densities are given in **Tables 2 and 3**. The absolute permeability of the non-fractured plugs to formation water ranged between 2-3 mD. The porosity of the fractured column filled with 90-106µm glass beads was determined as 0.36 (Scott, 1960), whiles the average permeability of the glass beads was calculated as 6.6D (Bryant et al. 1993). The average permeability of the 45-53µm glass beads in the foam generator was also determined as 1.6D. The specific surface area of chalk as determined by the BET method was 2.0 m^2/g (Strand et al. 2007). The wettability of the plugs by the Sulphate wettability test was determined to be less water-wet after water flooding (Zuta and Fjelde, 2008b).

Fluid property	Stock tank oil/Seawater	Stock tank oil /Foaming agent solution (1.0 wt. %)
IFT, mN/m	28	2.5

Table 2. IFT measurements at 1 atmospheric pressure and 55°C

Fluid properties	Seawater	Foaming agent solution (1.0 wt. %)	Stock tank oil
Density, g/cc	1.01	1.02	0.82
Viscosity, cp	0.52	0.55	5.2
pH, pH units	8.2	7.9	-

Table 3. Density, viscosity, pH measurements at 1 atmospheric pressure and 55 °C

Transport of CO_2-foaming agent in fractured models

The transport of the foaming agent into the models was determined by calculating the retention of the foaming agent in the models during the flow-through experiments. The breakthrough retention and desorption profiles of the foaming agent was determined by plotting the normalized foaming agent and tracer concentrations (C/C_o) versus cumulative pore volumes produced (Fjelde et al. 2008b). The retention of the foaming agent was determined by two different methods; using the area between the foaming agent and tracer profiles generated during the flow-through retention experiments or desorption (after sealing the fracture and injecting with SW followed by methanol). **Table 4** provides an overview of the retention results in both the fractured and non-fractured models. The experiments with the non-fractured models were done as references.

Plugs	Fractured type	k_{abs} or k_{eff}	S_{wi}	S_{orw} [1]	S_{orf} [2]	Retention[3]	Retention[4]
		mD	%	%	%	mg/g rock	
1	Reference	2.05	100	-	-	1.59	1.05
2	Fractured	20.0	100	-	-	0.05	0.85
3	Reference	2.10	16.5	24.4	16.5	2.59	2.32
4	Fractured	19.95	14.5	20.9	15.4	0.07	0.73

Table 4. An overview of the retention results for fractured and non-fractured models ([1] based on volume of oil produced; [2] based on accessible water-volume; [3] based on retention profiles; [4] based on desorption)

Based on the effluent breakthrough profiles, the retention of the foaming agent in the non-fractured model with 100% water-saturation was estimated as 1.59 mg/g rock. In the presence of oil, the retention was determined as 2.59 mg/g rock (**Figure 3**), i.e. an increase of approximately 62.8%. By desorption with SW and methanol, the amount of foaming agent retained was calculated as 1.05 mg/g rock in the absence of oil and 2.32 mg/g rock in the presence of oil (see **Figure 4** for desorption by SW).

The high retention in the presence of oil may be due to adsorption at the oil/water interface. An alternate explanation may the fact that both the foaming agent monomers and oil molecules having a high affinity for the solid-liquid interface, and are both co-adsorbed. Fjelde et al. (2008b) observed high retention of CO_2-foaming agents with different ethoxylation degree on chalk reservoirs in the presence of oil. No measurable phase partitioning of the foaming agent was observed between the water and oil phases after 25 days at 55^oC.

During the injection of the foaming agent solution into the fractured models, an early breakthrough of the foaming agent was expected (**Figure 5**). The area between the retention profiles can therefore not be used to determine the retention of the foaming agent in the fractured models. The retention of the foaming agent in the fractured models would be compared to that of the non-fractured models after desorption with SW and methanol.
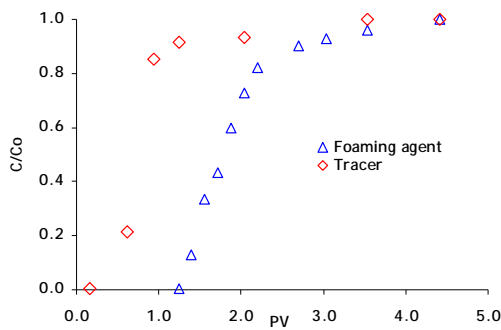

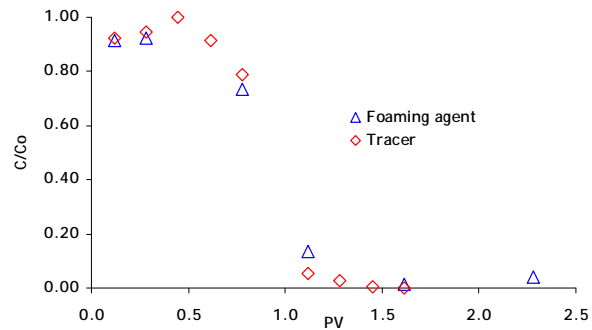**Figure 3. Retention profiles for non-fractured model (Plug 3) at S_{orw}**

Figure 4. Desorption profiles for non-fractured model (plug 3) at S_{orw} during flooding with SW
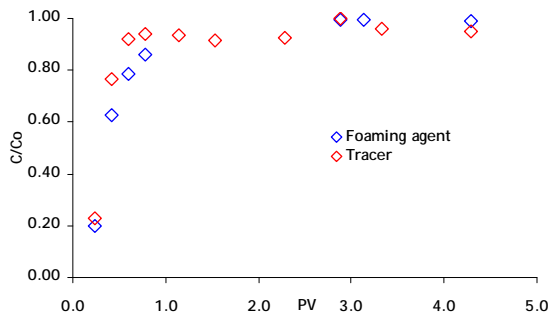

Figure 5. Retention profiles for fractured model (Plug 4) at S_{orw}
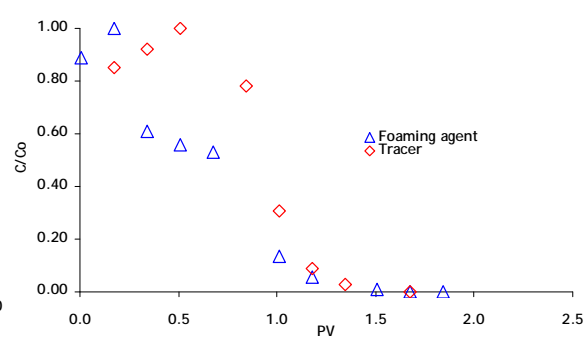

Figure 6. Desorption profiles for fractured model (Plug 1) at S_{orw} during flooding with SW

The transport of the foaming agent from the fracture into the matrix was determined to be slower in the fractured models with viscous flooding of the models. In the absence of oil, the retention was calculated as 0.85 mg/g rock. Whiles in the presence of oil, the retention was determined as 0.73 mg/g rock (**Figure 6**). Thus, the retention of foaming agent both in the absence and presence of oil were in the same range. The relatively low retentions in the fractured models may be due to the slow transport of the foaming agent from the fractures into the matrices. This increases the time required for the matrices to be fully saturated. However, the system reaching retention equilibrium would depend on parameters such as the injection rate, diffusion controlled transport of the foaming agent from the fractures into the matrices.

Foam flooding experiments

The flooding experiments were conducted to investigate the potential of CO_2-foam in improving sweep efficiency in fractured water flooded chalk models at 340 bar and 55°C. Additional experiments were carried out on non-fractured models and used as references. **Table 5** lists the properties of the fractured and non-fractured models and the residual oil saturations based on the oil produced before and after the flooding experiments. The residual oil saturations after water flooding ranged between 21.7-23.7%. The remaining oil saturations after the floods were estimated by two different methods; based on the cumulative oil produced and the accessible-water volumes and they were in the same range.

Model properties/Models	Plug 5	Plug 6	Plug 7	Plug 8
Fluid type	CO_2		CO_2-foam	
Model type	Fractured	Non-fractured	Fractured	Non-Fractured
PV, cc	31.7	30.7	31.8	31.3
K_{eff}, mD	19.93	19.95	19.94	19.97
S_{wi}, %	15.7	14.4	14.5	14.1
S_{orw}[1], %	22.2	23.7	21.7	22.3
S_{or}(CO_2, foam)[2]	15.5	4.3	3.6	2.2
S_{or} (CO_2, foam)[3]	13.2	5.0	3.0	2.5
Oil recovery, % S_{orw}	31.2	81.8	83.9	90.1

Table 5 Model properties and residual oil saturations before and after CO_2-foam and CO_2 injections (*[1]based on volume of oil produced; [2] based on volume of oil produced; [3] based on accessible water-volume*)

The accuracy of the method was estimated as ± 1.0% of the pore volume. The cumulative oil production profiles during the dynamic experiments are as shown in **Figures 7 and 8**. The oil productions are based on residual oil saturations (S_{orw}) after water flooding. During the flooding processes, the rapid evaporation of volatile components was expected, however this was expected to be rather low since stock tank oil was used.
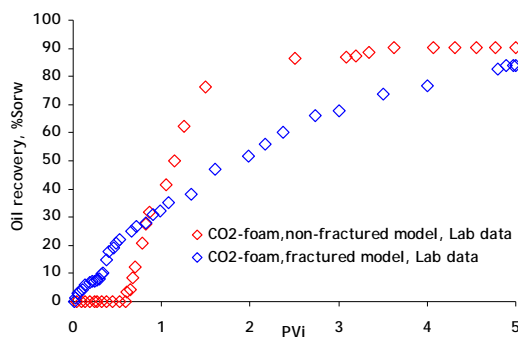
Figures 7. Oil recovery (% S_{orw}) profiles for CO_2-foam in fractured (Plug 7) and non-fractured (Plug 8) models respectively.
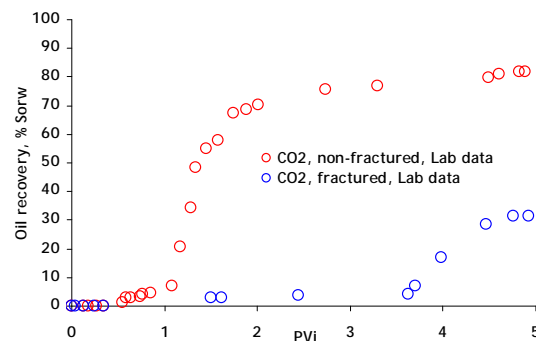
Figure 8. Oil recovery (% S_{orw}) profiles for pure CO_2 in fractured (Plug 5) and non-fractured (Plug 6) models respectively.

The flashed CO_2 gas was also expected to evaporate very quickly and therefore the volumes of the produced fluids collected in the graded measuring cylinders at room temperature and 1 atmosphere were used as estimates of the fluids produced.

The production of oil was expected to be governed by viscous flow in the fractures and molecular diffusion of CO_2 as the dominant mass transfer mechanism from the fractures into the matrices. The transport of CO_2 into the matrix was expected to swell the oil and cause a reduction in oil viscosity as well as a reduction in the CO_2-STO interfacial

tension. In the initial stage of oil production, the transport of CO_2 would mainly occur by lateral liquid-liquid diffusion between the under-saturated oil in the matrix block and the saturated oil with CO_2 on the inner surface of the matrix block. Oil production by gravity drainage was expected to be rather low due to the mode of injection and size of the models used.

The co-injection of CO_2 and foaming agent solution in the models, recovered a significant amount of oil from both the non-fractured and fractured models (**Figures 7 and 8**). Approximately 90.1% of additional oil after water flooding was produced from the non-fractured model and close to 84% of oil from the fractured model after 5 PV of CO_2-foam injections. In the case of pure CO_2 floods, close to 82% of oil was produced from the non-fractured model. A significant amount of water was also produced during the injection of pure CO_2 into the non-fractured model. In the fractured model, the breakthrough of CO_2 occurred rather fast resulting in a small amount of oil, approximately 31.2% been produced. The high oil production during CO_2-foam injection in a similar fractured model with the same effective permeability therefore means that CO_2-foam is highly effective in sweeping the fractured model delaying CO_2 breakthrough, and thereby improving the oil production rates. The high oil production is due to pre-generated foam blocking the fracture and diverting a significant fraction of the CO_2 into the matrix. This diversion of CO_2 generates significant reduction in CO_2 mobility and enables more of the CO_2 and foaming agent to be transported from the fracture into the matrix which drastically improves the oil recovery efficiency.

History-matching of CO_2-foam flooding experiments

The commercial reservoir simulator STARS developed by the Computer Modeling Group (CMG) was used to history-match the CO_2-foam experiments. The foam model in STARS is based on the limiting-capillary-pressure concept and assumes that foam creation and coalescence mechanisms occur relatively fast compared to flow. It is a local-steady model and assumes that whenever a CO_2-foaming agent solution and CO_2 co-exist, foam is generated. In addition, the STARS foam model accounts for foam effects on CO_2 mobility by modifying the gas relative permeability (Renkema and Rossen, 2007).

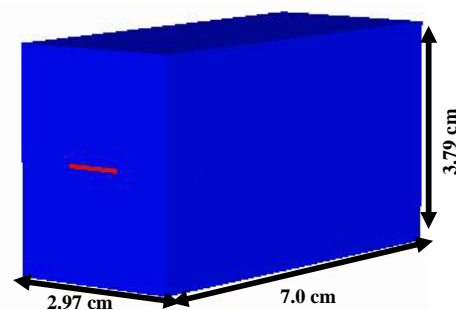| Matrix	Length	7.0 cm
	Breadth	2.97 cm
	Height	3.79 cm
Fracture	Area	0.07 cm^2
	Length	7 cm
Porosity	Matrix	40%
	Fracture	36%
Permeability	Matrix	3 mD
	Fracture	2.7 D
	Effective matrix-fracture permeability	20 mD
Pore volume		31.6 cm^3

Figure 9. Simulation model with fracture (red block)

Table 6. Fractured model parameters

A 3D Cartesian model (**Figure 9**) with dimensions of 7.0cm*2.97cm*3.79cm and properties as listed in **Table 6** was built and used in the mechanistic study. The effective

matrix-fracture permeability of 20mD (determined from the laboratory for the fractured column filled with 90-106µm glass beads) used in the mechanistic study was calculated from a matrix permeability of 3mD (also measured from the laboratory) and fracture permeability of 2.7D. Sensitivity analyses were carried out to select the optimum number of grid blocks to be used history-matching the laboratory foam experiments. The 3D simulation model was represented by 200*1*41 grid blocks whiles the refined grid blocks were used to represent the fracture, and given the same area as in the laboratory model.

CO_2-foam studies were performed on both fractured and non-fractured models with connate water saturations of 78 % and residual oil saturations of 22.0 % after viscous water flooding. The displacing fluids were injected at the same rates as used in the flooding experiments with the fractured chalk model at the same effective permeability of 20 mD as used on the laboratory experiments. CO_2-foam was continuously injected at a gas fractional flow rate of 90%; a fixed CO_2 rate of 0.1 reservoir Rml/min (18.72 surface Sml/min) and the 1.0 wt% active foaming agent solution was injected at 0.011 Rml/min. Fluids were produced from the other end at a constant bottom hole pressure of 340 bar.

The simulation results were in quantitative agreement with the results obtained from the laboratory foam flooding experiments. The rate of oil recovery was faster in the non-fractured model at the same reservoir conditions, and similarly for the fractured model at the same effective permeability after 5PV. The injection of CO_2-foam in the non-fractured model recovered approximately 84.9% (as against 90.1% in the laboratory experiments) of additional oil after water flooding whiles it recovered about 80.4% of additional (83.9% in the laboratory model) in the non-fractured model. However, the oil production rates were faster at the early stages of the experiments in the fractured model than in the non-fractured model (**see Figure 10**). During the injection of foam, a major part of CO_2 will be dispersed within the foaming agent solution. This will decrease the mobility of CO_2 and increase the effective viscosity of CO_2. However, because CO_2 is miscible with the oil at the reservoir conditions used, more of the CO_2 will be in contact with the oil improving the oil recovery efficiency. The viscosity of foam at the flooding conditions was about 0.95 cp whiles that pure CO_2 was 0.04 cp.
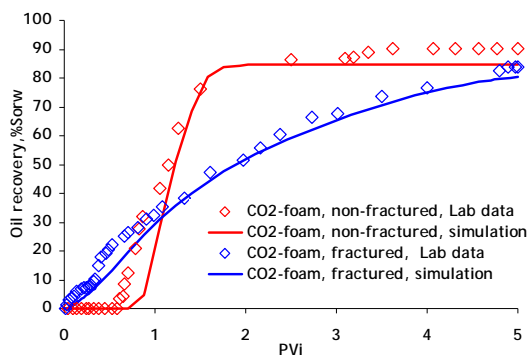

Figure 10. Comparison of simulated and laboratory CO_2-foam in non-fractured and fractured models
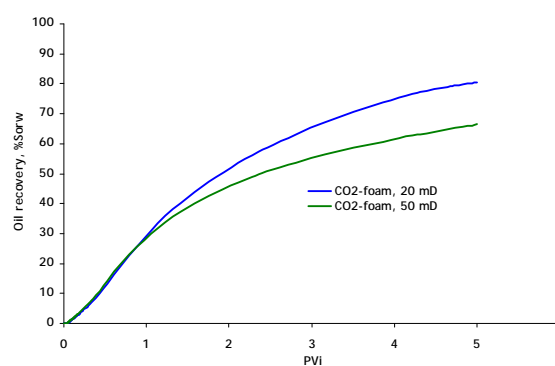
Figure 11. Simulated CO_2-foam in fractured models with different effective permeability

The effect of higher effective fracture permeability on CO_2 mobility and oil recovery efficiency during CO_2-foam injection in a fractured model was also studied. **Figure 11** shows the effect of two different effective permeability; 20 and 50 mD on oil recovery efficiency. Thus, the higher effective permeability reduces the oil production rates and the ultimate oil recovery at a fractional gas flow rate 0.90.

CONCLUSIONS

Based on the experimental and simulation results, the following conclusions can be made;

1. Laboratory foam flooding experiments show that CO_2-foam can recover more oil than pure CO_2 injection in non-fractured as well as in fractured models at the same effective matrix-fracture permeability.
2. The results from the simulation of CO_2-foam in fractured and non-fractured models were in quantitative agreement with the results obtained from the laboratory foam flooding experiments.
3. Simulated CO_2-foam results show that increasing the effective permeability of the fractured model decreases the rate of oil production and the ultimate oil recovery at the same gas fractional flow rate.
4. CO_2-foam is highly effective in fractured reservoirs as it serves a blocking agent and decreases the mobility of CO_2 and increases the effective viscosity of the CO_2.
5. The transport of the CO_2-foaming agent from the fracture to the matrix is slower in the fractured models than in non-fractured models with viscous flooding, although equilibrium retention was not attained.
6. CO_2-foam can be used to improve macroscopic sweep efficiency and recover more oil from fractured chalk reservoirs with low matrix permeability.

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NOMENCLATURE

C = effluent foaming concentration during flooding, mg/g
C_o = initial concentration of foaming agent solution, mg /g
FW = formation water
k_{abs} = absolute permeability to formation water, mD
k_{eff} = effective permeability of fractured model, mD
PV = pore volume, ml
S_{orw} = residual oil saturation after water flooding, % PV
S_{or} (CO_2, foam) = residual oil saturation after CO2 or foam flooding, %PV
S_{orf} = residual oil saturation after aqueous foaming agent flooding, % PV
SW = seawater
SWT = seawater with tracer

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