

An Experimental Study of Surfactant Alternating CO₂ Injection for Enhanced Oil Recovery of Carbonated Reservoir

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Abstract

Core flooding experiments were conducted with the objective of evaluating near miscible surfactant alternating CO₂ injection and the effect of surfactant concentrations on gas-oil and water displacements in porous media. The core samples were provided from a low permeability mixed wet oil reservoir at 156 °F and 1900 psia. In addition, very few studies of surfactant adsorption on carbonate minerals have been conducted. Hence, the surfactant adsorption on carbonate rock was determined by core flooding and crushed tests. It was found that for the crushed rock, the required equilibrium time is approximately five hours, while it is more than four days for the flow-through tests. Hysteresis effects demonstrated that the irreducible water saturations were 5 to 10% higher than the initial connate water saturation after drainage cycles during 5000 ppm surfactant solution. Furthermore, near-miscible surfactant alternating CO₂ injection process led to a 4-17% increase in the recovery factor in comparison to water alternating gas process.

Keywords: Core Flooding, Adsorption Density, SAG Process, Gas Mobility Control, Mixed Wet

1. Introduction

Sebastien et al. (Duchenne et al., 2014) showed the benefits of using surfactant alternating gas injection to improve the efficiency of CO₂ displacement in porous media. They concluded that implementing the surfactant alternating CO₂ injection may significantly improve volumetric sweep efficiency; thus, the value of gas mobility in the core would be reduced to some value close to the mobility of water. However, the complete evaluation of the process must take into account the possible effect of hysteresis on relative permeabilities throughout drainage and imbibition processes. An alternative option to reduce the mobility of CO₂ is to implement a combination of foaming solution and CO₂ injection. It is well-known that implementing foam will increase trapped gas

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saturation while decreasing oil saturation (Boeije and Rossen, 2014; Kloet, Renkema and Rossen, 2009; Kulkarni and Rao, 2005). This can either improve the sweeping conditions or block CO₂ in more permeable layers. All of these unique properties of the foam imply that its application would be useful in CO₂ flooding (Xing, 2010; Han, 2014). Grigg et al. (2005) demonstrated the usefulness of surfactant-based enhanced oil recovery processes in the petroleum industry (Grigg and Bai, 2005). Foam application involves injecting a surfactant along with water and gas into the reservoir. The economics of the foam flooding depends significantly on the quantity of surfactant required to generate and propagate foam. Since the surfactant is adsorbed on the rock surface, the loss of surfactant from aqueous solutions during the propagation in the reservoirs, especially carbonate reservoirs, is one of the major concerns with chemical oil recovery processes (Li, 2014). Alaei et al. (2013) showed that surfactant loss through partitioning into the crude oil phase and through adsorption onto the rock surfaces is often responsible for more than 90% of the surfactant consumption in the system (Alaei et al., 2013). However, the partitioning of the surfactants, chosen for many foam flooding applications, onto crude oil is almost zero. This amount of surfactant loss in a reservoir represents the largest consumption of chemicals in a flood, and thus it is a major feature governing the economic viability of surfactant alternating CO₂ injection process. That is also possibly the most important factor that can determine the efficiency of a surfactant flooding process (Gao and Sharma, 2012) because the amount of chemicals adsorbed and entrapped in the reservoir has a direct influence on the oil displacement sufficiency (Han et al., 2014; Patacchini et al. 2014). Mogensen et al. (2014) demonstrated that adsorption depends on the nature of the surfactant, temperature, brine salinity, rock type, wettability, and the presence of the residual oil phase (Bennetzen et al., 2014). In addition, adsorption is a function of concentration, the study of which is one of the aims of this study. On the other hand, Sharifzadeh and Rahimpour (2012) concluded that the facility and strength of surfactant adsorption on reservoir rocks are very largely controlled by three factors related to the materials in question: the chemical nature of the species being adsorbed, including the head group (anionic, cationic, nonionic, etc.), the nature of the solid surface onto which the surfactant is being adsorbed, and the nature of the liquid environment (Sharifzadeh et al., 2013). In this study, we use flow zone indicator (FZI) method to identify the major hydraulic flow units existing in the reservoir and report the dynamic and static adsorption of sodium lauryl sulfate SLS (as an anionic surfactant) onto crushed rock and cores, which are cut from one of Iranian low permeability carbonate reservoir rocks to determine the amount of excess surfactant which must be added into the injection stream in the surfactant alternating CO₂ injection tests. Furthermore, the mobility control of CO₂ injection by using surfactant and injectivity is investigated. Likewise, an optimum surfactant concentration corresponding to a very low interfacial tension is determined.

1.1. Application of hydraulic flow unit in reservoir characterization (Weston et al., 2014)

Rock permeability is an extremely important parameter in reservoir characterization and simulation because it influences the rate of production of hydrocarbons, ultimate recovery, and the optimal placement of wells, pressure, and fluid contacts evolution (Green and Willhite, 1998). Thus, the proper determination of the permeability is of paramount importance because it affects the economy of the whole venture of the development and operation of a field. Therefore, permeability is a key parameter in any reservoir characterization and governs its handling and development in great extension (Hayat et al., 2014). All the data sets are gained from routine core analyses and well log data performed in the carbonate reservoir. Flow zone indicator (FZI) method is used to identify the number of hydraulic flow units. The optional number of HFU's which exists in the reservoir can be

determined by applying the sum of square method (Figure 1). The results showed that six HFU's were identified from core data, and each unit has its own mean FZI (Figure 2). Stratigraphic modified Lorenz plots is a plot of cumulative flow capacity versus cumulative storage capacity ordered in stratigraphic sequence, which can be used to define major flow units existing in reservoirs. This method has proved to be suitable for carbonate reservoir descriptions (Guo et al. , 2005). As it is shown in Figure 3, flow unit 3 is considered to be the major production zone because of its thickness and permeability, while flow unit 2 is a major contribution to the total production. Flow unit 4 and 5 correspond to very thin and low permeability zones. Therefore, in core flooding and surfactant adsorption tests, all the sets of core samples are taken from a depth range of flow units 3, 4, and 5.

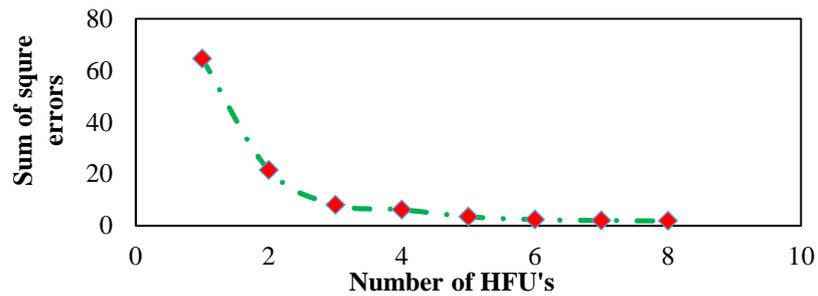


Figure 1
Optimal number of HFU's by using SSE.

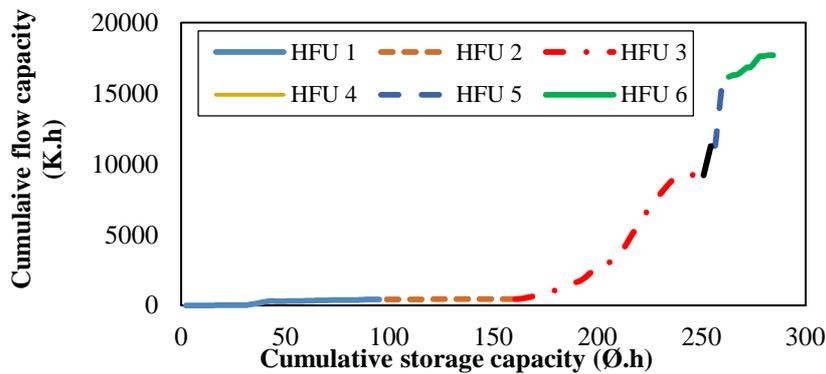


Figure 2
Stratigraphic modified Lorenz plots.

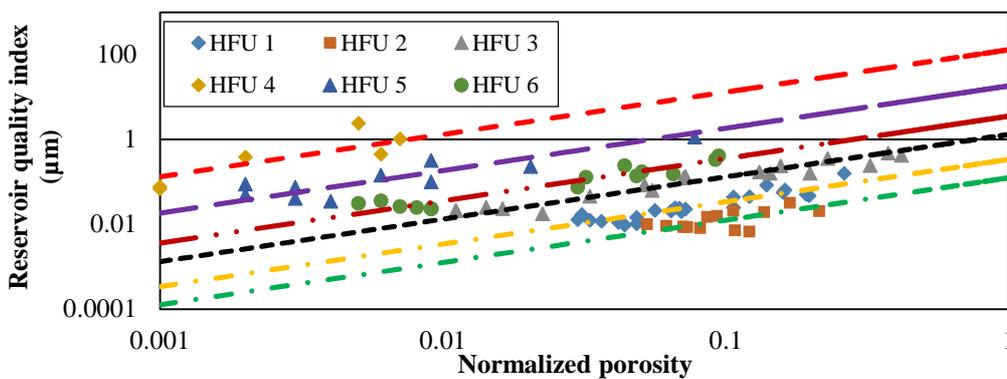


Figure 3
Unit slope lines of six HFU's.

2. Surfactant adsorption

2.1. Experimental setup and procedures

a) Surfactant

The surface charges of minerals depend on pH, and the rock surfaces are more negatively charged as pH generally increases. Because of a high pH (in this case study pH=11), the surfactant used in this case study was sodium lauryl sulfate (SLS); sulfate head group (shown in Figure 4) is hydrophilic and water soluble, while the 12-carbon-long chain is hydrophobic and water insoluble. It is an anionic surfactant as defined by the sulfate head group since it has a negative charge. Therefore, the high pH causes more repulsion between surfactant molecules and rock surfaces, resulting in a decrease in adsorption. To prepare the surfactant solution, a 36000 ppm synthetic/field brine composed of 2.88 wt.% NaCl, 0.36 wt.% CaCl₂, and 0.36 wt.% MgCl₂ was used (Gao and Sharma, 2012).

b) Core samples

Core samples were cut from one of Iranian low permeability carbonate reservoir rocks. The current reservoir pressure and temperature are 1900 psia and 69 °C respectively. The powdered rock was prepared by crushing the corresponding solid core; the maximum size of the particles was determined by passing the crushed rock through a standard number of 35 sieves (~0.5 mm diameter). The core samples for circulating tests were washed and dried in an oven at 120 °C for 24 hrs.

c) Experimental procedures

In the first set of tests, the adsorption of surfactant on reservoir rock is determined by batch equilibrium tests on crushed core material, which are less than 500 micrometer in size. In batch equilibrium tests on a crushed core, a known volume of surfactant solution at a recognized concentration is mixed with a specified mass of crushed rock in a sealed container. All the essential parameters of these experiments are tabulated in Table 1. The container was placed in a shaker and a thermostatic air bath. The samples of surfactant solution were taken every hour from the container in six time steps, and the spectrophotometer technique was used to determine residual concentration at each time step. When a constant concentration is measured for a long period of time, the system is regarded to be at equilibrium and the test is completed. Adsorption is computed from a material balance on the surfactant mass. In the performed experiments, the initial surfactant concentration had different values, namely 500, 1000, 2000, and 5000 ppm, while the solid to the liquid weight ratio was constant, i.e. 1 to 5. All the adsorption experiments on crushed rocks were performed at 50 °C and atmospheric pressure (Shamsijazeyi et al., 2013).

Dynamic adsorption experiments were performed to determine the adsorption densities of carbonate brine-saturated cores via the circulation of a fixed volume of surfactant solution through the core. All the necessary parameters of these experiments are provided in Table 2. The samples of surfactant solution were taken from the flask periodically until no change in surfactant concentration was observed. Initial surfactant concentrations were 500, 1000, 2000, and 5000 ppm, and the solid to the liquid ratio was set at 1:5. The amount of surfactant-free brine in each core at the beginning of the experiment was included in calculations when equilibrium adsorption was determined in the system. All the adsorption experiments were run in reservoir conditions to be valid for surfactant excess calculations in the surfactant alternative CO₂ injection in reservoir conditions (Han and Gu, 2014).

The entire effluent sample was taken at designed intervals for surfactant analysis. In the case of the flow-through test, the output pressure exerted by BPR was 1900 psia.

Table 1
Surfactant adsorption onto crushed cores.

Test No.	Core mass [g]	Ratio S:L	Mass of Surfactant Solution [g]	Initial SLS Concentration [ppm]	Duration of The Experiment [hrs]	Residual SLS Concentration [ppm]	SLS Adsorption Density [mg/g]
1	175.6	1:5	878	5000	5	4585	2.075
2	100	1:5	500	2000	5	1648	1.76
3	100	1:5	500	1000	5	778	1.11
4	100	1:5	500	500	5	344	0.78

Table 2
Surfactant Adsorption by Circulation of Surfactant Solution through Carbonate Cores.

Test No.	Pore Volume [cc]	Permeability [md]	Core mass [g]	Ratio S:L	Mass of Surfactant	Initial SLS Concentration	Duration of the experiment [hrs]	Residual SLS concentration	SLS Adsorption density [mg/g]
1	17.5	0.68	205	1:5	1025	5000	102.5	4644	1.724
2	18.3	0.8	212	1:5	1060	2000	106	1689	1.502
3	17.5	0.68	205	1:5	1025	1000	102.5	806	0.927
4	18.3	0.8	212	1:5	1060	500	106	378	0.588

2.2. Results and discussions

a) Adsorption density onto crushed carbonate cores

Static adsorption experiments were run to analyze the adsorption of SLS onto carbonate crushed cores. Table 1 summarized the SLS adsorption values and conditions measured in the crushed carbonate core system by using Equation 1. The results from the experiments with crushed carbonate cores indicate that the adsorption was near completion in about two hours for initial SLS concentration of 5000 ppm and completed (90 % of the maximum adsorption) in more than two hours for the basic concentration of 2000, 1000, and 500 ppm (see Figure 4). The adsorption experiments with a weight ratio of surfactant solution to crushed carbonate cores equal to 1:5 showed that with an increase in the surfactant concentration the SLS adsorption density increases from 0.78 mg/g to 2.075 mg/g over the range of initial surfactant concentrations from 500 ppm to 5000 ppm (Table 1). It was found that SLS adsorption density increases when the surfactant concentration rises. At a lower

surfactant concentration and monomers, the adsorption was occurred onto substrate due to the electrostatic interaction between the head group charge and the net charge present onto the surface of rock. Afterwards, a sharp increase in adsorption density is observed (see Figures 4 and 5) which is, due to the formation of surface aggregates, called colloids (surface colloids), including hemi-micelles, admicelles, etc. These surface aggregates are formed due to lateral interactions between hydrocarbon chains and surface monomers. Due to the additional driving force originating from the lateral interaction of monomers, the adsorption density increases sharply. After that, the adsorption density increases at a lower gradient because the solid surface is electrically neutralized by the adsorbed surfactant monomers, and adsorption only happens due to lateral interactions. At the end, the surfactant reached critical micelle concentration (CMC); therefore, any further increase in surfactant concentration contributed to micelle formation in solution, and adsorption was thus constant. At this stage, the surfactant molecules adsorbed onto the surface with reverse orientation resulted in the decreasing hydrophobicity of the particles. After reaching an adsorption density of 1.76 mg/g at 2000 ppm of surfactant concentration, adsorption increases only slightly with increasing the availability of surfactant. In general, it was found that the adsorption density in this system is a function of SLS concentrations, SLS available in the system, and solid to the solution ratio.

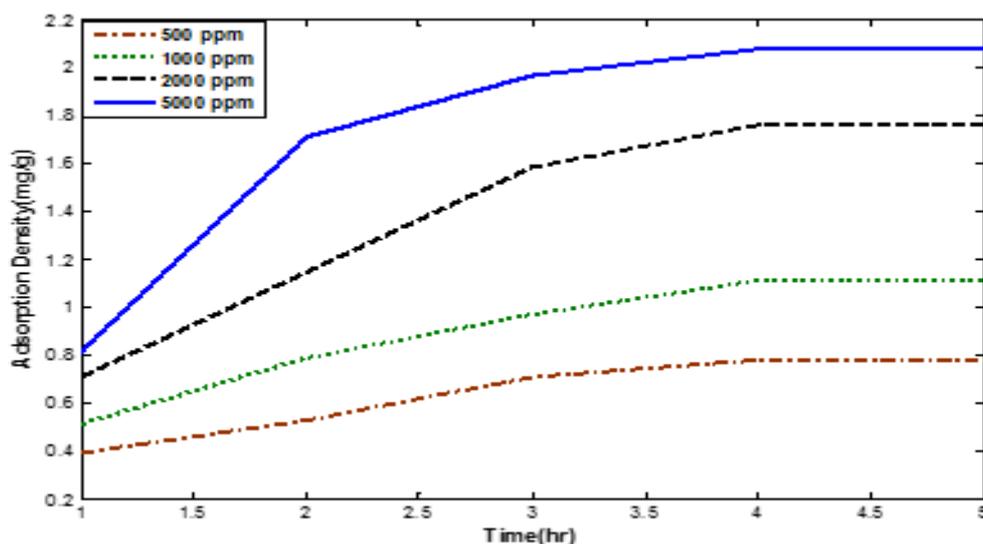


Figure 4

Adsorption density onto crushed core at surfactant concentrations of 5000 ppm, 2000 ppm, 1000 ppm, and 500 ppm.

b) Adsorption density during circulating tests

In these series of experiments, the adsorption of surfactant in a carbonate core was investigated by the circulation method. Adsorption values and conditions measured during the circulation experiments are listed in Table 2. All of these floods were run in reservoir conditions, namely 69 °C and 1900 psia. Figure 5 presents the adsorption density in carbonate cores as a result of different surfactant concentrations by using a mass balance. Moreover, as it is shown in this figure, the time required for SLS adsorption to achieve equilibrium by circulation through brine saturated cores was about four days for brine saturated cores compared to five hours or less for the crushed rock. Therefore, the difference in the adsorption densities, due to the circulating system, might be interpreted as the

inability of surfactant aggregates formed on the solid outside the near-surface adsorption to resist surface washing by the flow of liquid in a porous space.

In general, the surface charge of carbonate rock is more positive and less negative than that of sandstone. These negatively charged molecules are readily adsorbed onto positively charged rock surfaces. As a result, a higher adsorption of anionic surfactant in carbonate rock is attributed to an electrostatic mechanism of adsorption (Liljeblad, 2007). After reaching an adsorption density of 1.5 mg/g at a surfactant concentration of 2000 ppm, adsorption increases only slightly with increasing the availability of surfactant. Values of the adsorption density on carbonate cores were significantly lower in the circulation experiments compared to those measured in crushed rock. Since these were prepared from the samples of the same rock sample, the differences might be explained from the energy required for mono- versus multi-layer adsorption.

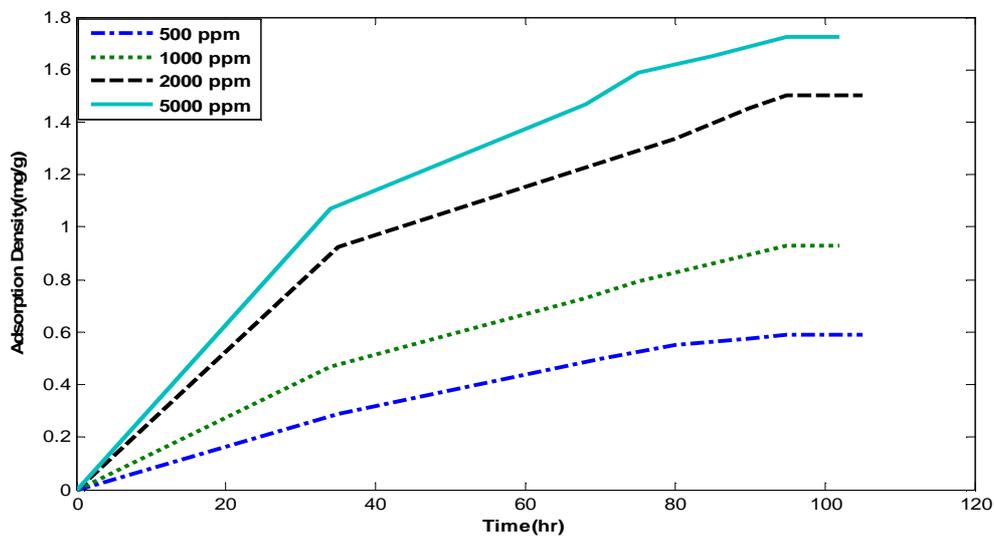


Figure 5

Adsorption by circulation of surfactant solution through carbonate cores at surfactant concentrations of 5000 ppm, 2000 ppm, 1000 ppm, and 500 ppm.

3. Surfactant alternating CO₂ injection process

3.1. Experimental details

a) Rock and fluid specifications

The tests were performed on mixed wet carbonate rocks of a low permeability oil reservoir. The rocks are heterogeneous, and a number of fractures and different white colored minerals can be seen in their formations. Although the cores are naturally fractured, their absolute permeabilities are less than 1 mD due to the obliquity of fractures with the direction of flow and their poor connectivity. The properties of the core samples used in the SAG floods are given in Table 3. Fluids used for the tests were live oil, synthetic/field brine (36000 ppm), and carbon dioxide. The reservoir fluid was prepared from a wellhead dead oil sample, recombined with production gas to obtain a saturation pressure of 1900 psia, corresponding to a solution gas-oil ratio (R_s) of 300 SCF/STB. Synthetic/field brine was

made of NaCl (28800 ppm), CaCl₂ (3600 ppm), and MgCl₂ (3600 ppm). The commercial surfactant used was sodium lauryl sulfate, which acts as an anionic surfactant.

Table 3
The properties of the core samples used in the SAG floods.

Carbonate Cores No.	Length (cm)	Diameter (in)	PV (Winsauer and McCardell, 1953)	Porosity (%)	Permeability (mD)	Connate Water (%)
1	12.0	1.5	17.9	13.15	0.91	24
2	12.0	1.5	18.1	13.3	0.70	24
3	12.0	1.5	18.2	13.4	0.79	24
4	12.0	1.5	17.8	13.1	0.84	24

b) Core flooding setup and experimental procedures

The designed setup for conducting core flooding experiments mainly consisted of HPLC pumps, high-pressure core holder, constant-temperature air bath, fluid transfer vessels, BPR, overburden pressure pump, DP, and a visual separator. Core holder and transfer vessels were perfectly mounted in a particular stand inside the constant-temperature air bath (Figure 6). As the pump fluid was injected to the bottom of transfer vessels, fluids inside them were injected into the core. Out coming fluids from the core after passing BPR, used to adjust pressure of the system, were collected in the visual separator. Overburden pressure was supplied by a special hand pump. Some pressure gauges and electronic pressure transducers were used to monitor the pressure of transfer vessels as well as the inlet and outlet of the core holder. The core permeability was then calculated at a constant flow rate by recording the pressure drop between the inlet and outlet sides by using a differential pressure measuring device with an accuracy of 0.07 kPa (DP) and after that using Darcy's equation (Asgari et al., 2014; Morsy et al., 2014). The calculations of the core permeability are presented in appendix A.

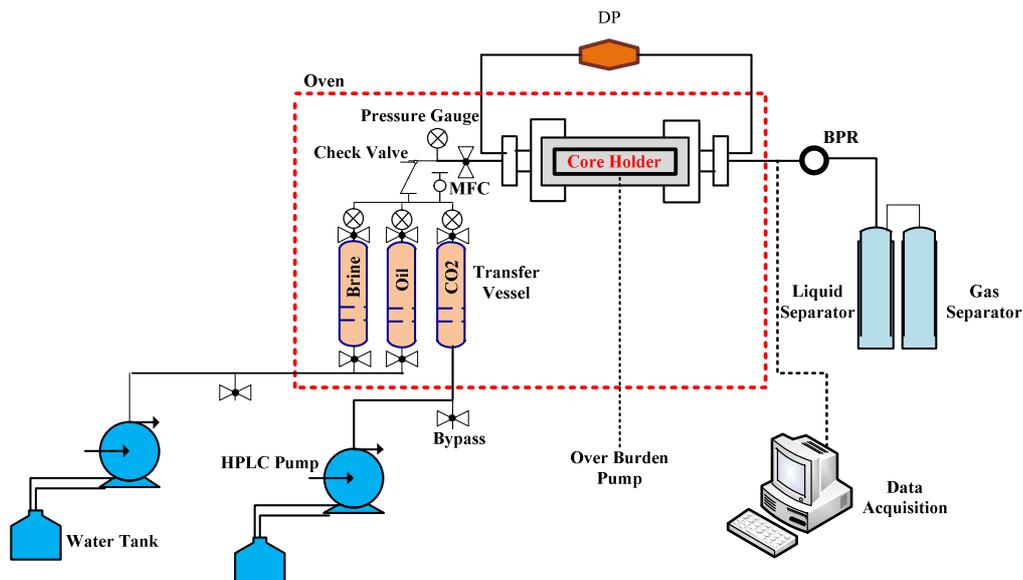


Figure 6

A Schematic of the core flooding laboratory setup.

Then, it was flooded with live oil (10 Pore Volume) at low flow rates to reach pore water saturation in reservoir conditions. All the core flooding tests started with the samples saturated with live oil and pore water, and then the SAG injection followed. Relevant process variables such as water and gas slug size, number of SAG cycles, water and gas rates, cumulative water and gas injection, and WAG ratio (ratio of water to gas volume in a WAG cycle in reservoir conditions) are listed in Table 4. All the core flooding experiments were run at frontal advance rates of 1 foot per day. At a rate of 0.24 cc/min and in reservoir conditions, namely 69 °C and 1900 psia, core holder overburden pressure was maintained at 2700 psia (Sorbie and van Dijke, 2010).

Table 4
All Parameters which Were Used in SAG Processes.

Test No.	Water and Gas Slug Size	SAG Ratio	No. of SAG Cycles	Cumulative water Injection (Winsauer and McCardell, 1953)	Cumulative Gas Injection (Winsauer and McCardell, 1953)	Gas Rates (cc/min)	Water Rates (cc/min)	Surfactant Concentration ppm
1	3.58	1:1	5	17.9	17.9	0.25	0.30	5000
2	3.62	1:1	5	18.1	18.1	0.25	0.30	2000
3	3.64	1:1	5	18.2	18.2	0.25	0.30	1000
4	3.56	1:1	5	17.8	17.8	0.25	0.30	500

3.2. Results and discussion

a) Minimum miscibility pressure (MMP) estimation

CO₂ was used in order to estimate the MMP of the field. MMP was calculated by slim-tube simulation. The estimated MMP for CO₂ was 2100 psia; it was also measured by the vanishing interfacial tension (Gelfand and Levitan, 1951) method and compared with the slim-tube method; Undoubtedly, 2100 psia was considered as the MMP. Therefore, all the core flooding experiments were performed at the current reservoir pressure of 1900 psia. Then, it can be concluded that the near-miscible foam assisted water alternating CO₂ injection process is achieved during these core flooding experiments. Shyeh-Yung (1991) reports that residual oil saturation was decreased almost linearly with increasing pressure in CO₂/West Texas crude/mixed-wet carbonate core during gas flooding tests (Shyeh-Yung, 1991). He finally found that CO₂ mobility decreased with dropping pressure. Therefore, he concluded that near-miscible process had a better mobility control than a miscible process.

b) Surfactant alternating CO₂ injection

The wettability of reservoir rock controls the distribution of oil and water and affects their movement through pore space. In other words, fluid distributions in porous media are affected not only by the forces at fluid-fluid interfaces, but also by forces at fluid-solid interfaces. Chemical enhanced oil recovery methods such as surfactant flooding are used in oil wet and mixed wet naturally fractured

reservoirs to enhance oil recovery. This method cannot be successfully implemented in the field unless all the mechanisms involved in this process are fully understood. Surfactant can act in several ways to enhance the oil production. Lowering interfacial tension between oil trapped in small capillary pores and the water surrounding those pores may allow the oil to be mobilized via buoyancy forces. Altering the matrix wettability toward water-wet may increase the spontaneous imbibition of water. This change in rock wettability leads to positive capillary pressure and results in higher brine counter-current imbibition; therefore, a higher oil production rate is achieved (Bennetzen et al., 2014; Xing et al., 2010). The core flooding experiments were conducted with the objective of evaluating near miscible modes of SAG injection and studying the effect of surfactant concentration on gas-oil and water displacements and on trapped oil saturation in porous media. Figure 7 illustrates the oil recovery versus pore volume injection of SLS and CO₂ for the initial surfactant concentration ranged between 500 to 5000 ppm. In the five-cycle SAG process, adsorption is taken into account, and additional surfactant volume was added to the system. This is calculated by multiplying the adsorption density by total rock mass in each test. Recovery factor values are a function of SLS concentration, and these values rose with increasing the SLS concentration. This figure depicts the oil recovery attribution to near miscible SAG injection. The initial oil saturation, S_{oi} was 76% of the pore volume; five cycles of SAG injection produced 74.5 to 87% of original oil in place during core flooding tests. The SAG injection results in a complex saturation pattern as both gas and water saturations increase and decrease alternatively. This results in special demands for the relative permeability description for the three phases (oil, gas, and water). In addition, the results showed significant hysteresis effects in the irreducible water saturations (S_{wir}), and were 5 to 10% higher than the initial connate water saturation after drainage cycles during 5000 ppm surfactant solution; water hysteresis occurs after CO₂ injection. The injected CO₂ and oil bank develop a new minimum value of irreducible water saturation that does not go back to the original connate water saturation. SAG injection results illustrate that macroscopic efficiency increased due to gas mobility control. Therefore, it forces more gas into the less permeable zones and thus increases the gas sweep efficiency and oil recovery up to 17% in comparison to water alternating gas injection process (Figure 8).

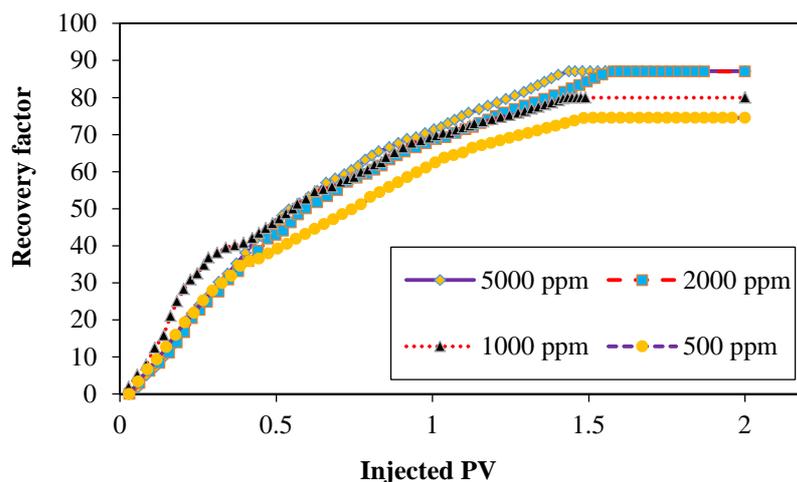


Figure 7

Recovery factor values versus pore volume injection at surfactant concentrations of 5000 ppm, 2000 ppm, 1000 ppm, 500 ppm.

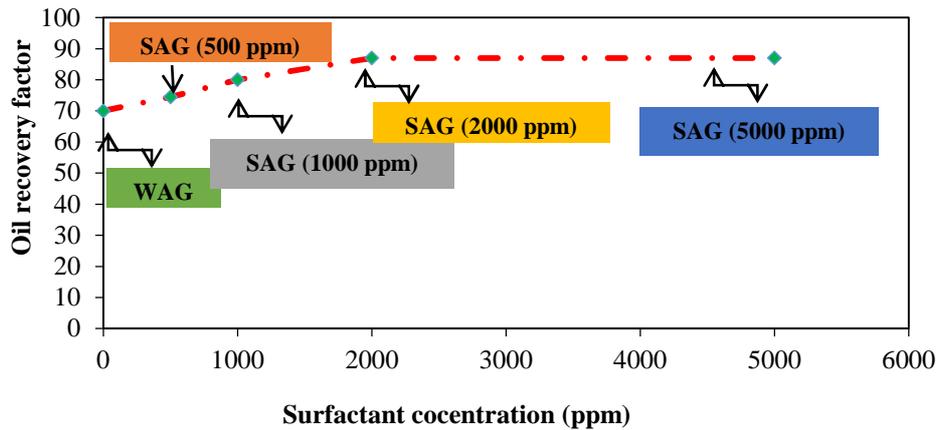


Figure 8

Oil recovery factors.

Figures 9 to 13 indicate that the performance of the produced free gas by the SAG process is a function of surfactant concentration; the differences between gas breakthrough are also shown in these figures. In case of a surfactant concentration of 500 ppm, gas breakthrough occurred earlier than other cases. Hence, many investigators have been studied the impact of trapped gas on residual oil saturation (Delclaud, 1991; Firoozabadi and Ramey Jr, 1988; Holmgren and Morse, 1951; MacAllister, Miller, Graham, and Yang, 1993). The reduction in residual oil saturation (Bennetzen et al., 2014) has been observed to follow the relation of $S_{or} = S_{orw} - a \times S_{gt}$, where a quantifies the effect. Data reported by MacAllister et al. (1993) for Baker dolomite indicate that a is 0.25 for mixed-wet condition. Gas trapping depends on wettability and the relative amounts of the other two phases, and it can be lower in three-phase flow (MacAllister et al., 1993). This implies that gas relative permeability depends not only on gas saturation but also on the relative amounts of the other two phases. Trapped-gas saturation influences SLS solution injectivity and the amount of surfactant solution diversion in the SAG process. There is extensive trapping of gas in the high-permeability layers, which diverts water to lower-permeability layers, thereby improving sweep efficiency. CO₂ trapping plays an important role in the mobilizing and displacement of residual to water flooding oil. The cumulative GOR is varied from 35.5 to 53% during core flooding tests. Figure 13 indicates a significant delayed in gas breakthrough by increasing the SLS concentration from 500 to 5000 ppm. As a result, mobility was lower after CO₂ injection than before, indicating that mobility control was good; also injectivity was reduced immediately after surfactant injection indicating foam generation.

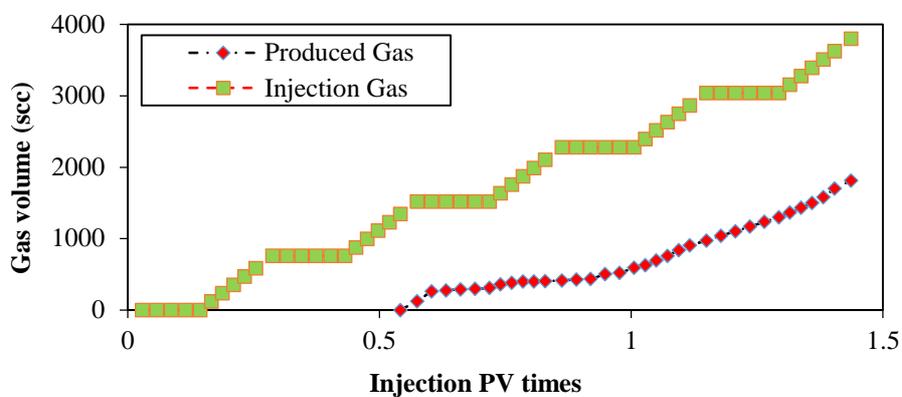


Figure 9

Cumulative produced free and injected gas at a surfactant concentration of 5000ppm.

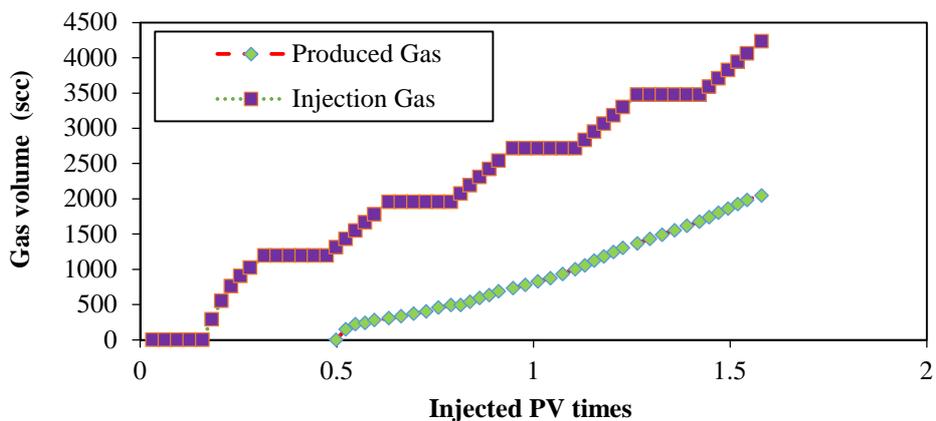


Figure 10
Cumulative produced free and injected gas at a surfactant concentration of 2000ppm.

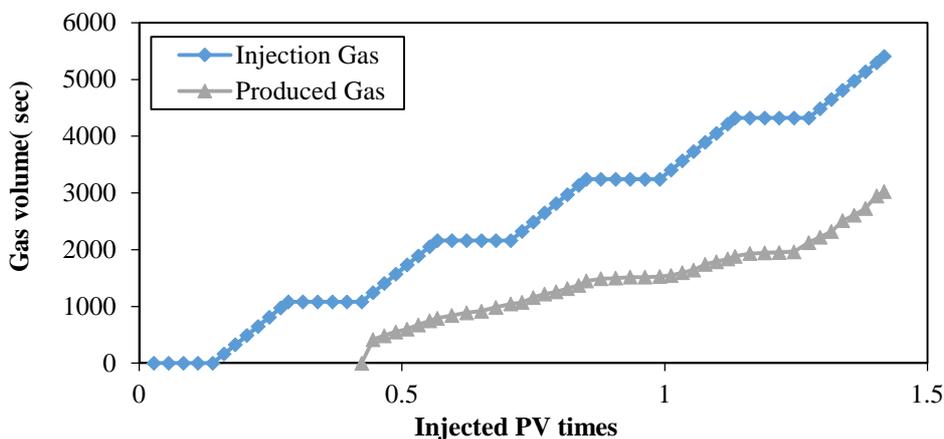


Figure 11
Cumulative produced free and injected gas at a surfactant concentration of 1000 ppm.

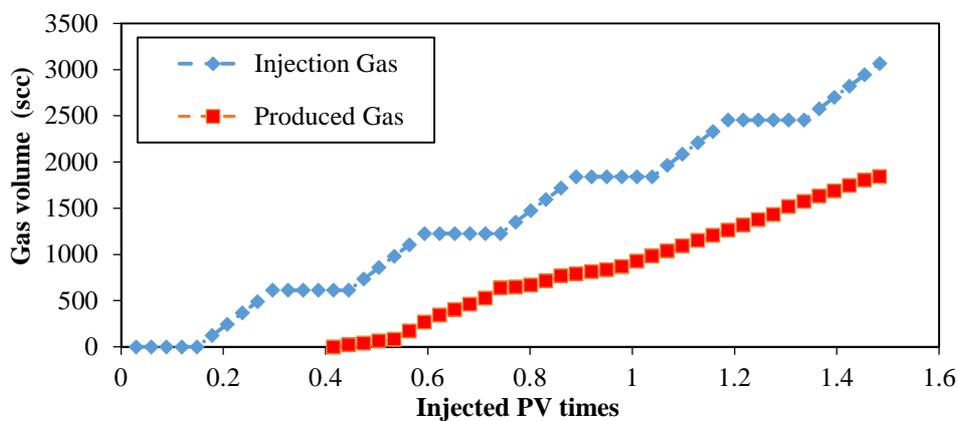


Figure 12
Cumulative produced free and injected gas at a surfactant concentration of 500 ppm.

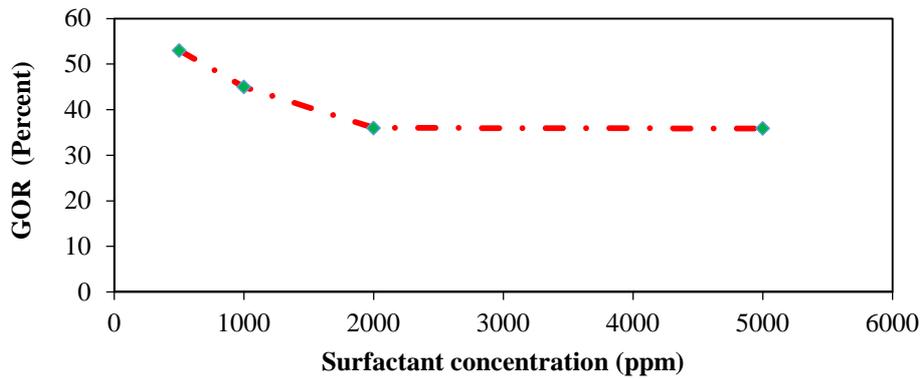


Figure 13
Gas mobility control for several surfactant concentrations.

Figure 14 shows the injection pressure versus injected PV time at four different concentrations of SLS. The injectivity during the first slug of surfactant solution was similar, as expected, to the water injectivities during water injection. The injectivity and pressure data taken before SAG reveals that the injectivity increases with injection pressure. The injection pressures are higher than the injection pressure measured in extended gas-injection periods before the foam treatment. The reduction of the mobility ratio can be achieved by reducing the relative permeability of the fluids. The reduced permeability of the gas phase can be achieved by alternate injection of water and gas. This reduced injectivity is taken as a sign of foam generation, and the water injectivity seems to increase again in the second cycle. This is interpreted as a sign of foam being dried out by the injected gas during first cycle. In the second SLS slug, the injection pressures were higher than those in the first slug. This is explained by the presence of foam in the formation when the surfactant solution enters. At the same time, the injectivity indexes for the second surfactant slug decreased in comparison to the first slug. After gas and water breakthrough, the injection pressure increased at a small rate. The same applies to the other surfactant slugs. The experimental results indicate that there is an optimum surfactant concentration at 2000 ppm which corresponds to a very low interfacial tension (IFT) in these conditions. As it is shown in Figure 8, after reaching a recovery factor of 87% at an SLS concentration of 2000 ppm, recovery factor did not change by increasing the SLS concentration.

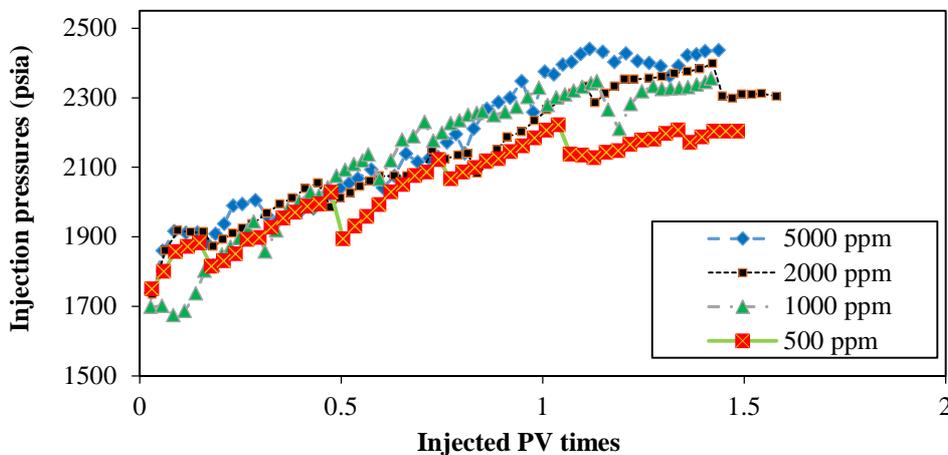


Figure 14
Injection pressure at surfactant concentrations of 5000 ppm, 2000 ppm, 1000 ppm, and 500 ppm.

Figure 15 shows water and oil production rates during 5000 ppm surfactant solution test. Generally, the maximums of oil rate and the minimums of water rate curves meet each other at the same time. This means that after the breakthrough, the majority of oil production occurs when the gas comes out from the core. This may be due to foam generation into the core and the decreased mobility of the gas in the higher permeability zones, thereby raising gas microscopic efficiency. As mentioned above, the breakthrough time is difficult to be detected by recovery curve and by the pressure drop curve, but since the water rate curve shows a sharp increase, it could be a good evident for water breakthrough time.

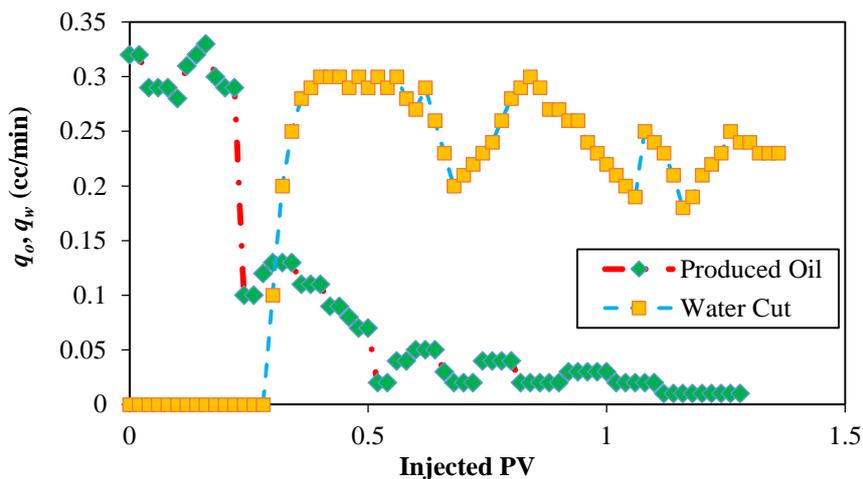


Figure 15

Oil and water production rates.

4. Conclusions

According to the results obtained, the following conclusions can be drawn:

1. The oil recovery tests which were conducted at 1900 psia would be assumed as near miscible SAG injection tests since the MMP of CO₂/oil was about 2100 psia.
2. Near miscible SAG injection increases the sweep efficiency of gas and oil recovery up to 17% in comparison to WAG process. Furthermore, the results of these tests showed that the studied reservoir is a good candidate of near-miscible SAG injection.
3. Flow unit 3 is considered to be the major production zone because of its thickness and permeability.
4. The irreducible water saturations were 5 to 10% higher than the initial connate water saturation after drainage cycles during using 5000 ppm surfactant solution.
5. Values of the adsorption density on carbonate cores were significantly higher in the crushed rock experiments, varied from 0.78 mg/g to 2.075 mg/g, compared to those measured in the circulation experiments; this was attributed to higher surface area of the crushed rock.
6. After the breakthrough, the majority of oil production occurs when the gas comes out from the core.

Nomenclature

BPR	: Back-pressure regulator
CMC	: Critical micelle concentration
DP	: Differential pressure transducers
MMP	: Minimum miscibility pressure
SAG	: Surfactant alternative gas
SLS	: Sodium Lauryl Sulfate
WAG	: Water alternative gas

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