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Application of Low Concentration Surfactant Enhanced Water-Alternating-Gas Flooding

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SUMMARY

Large amounts of oil left in the petroleum reservoir after primary and secondary enhanced oil recovery methods have brought about the implementation of several tertiary means of oil recovery. Increment of oil recovery can support the world's oil supply. Water alternating gas injection has been a very popular method of gas injection to improving volumetric sweep efficiency. Although water alternating as injection has been shown to improve oil recovery, this process suffers inherent challenges such as water blocking, mobility control in high viscosity oil and gravity segregation. To combat these problems associated with water alternating gas flooding, the use of surfactant has been employed in water alternating gas injection. Due to the high operational cost arising from chemical cost in surfactant alternating gas injection, a new technique which involves the injection of low concentration surfactant before water alternating as flooding has been proposed. This work investigates experimental and numerical oil recovery potential of surfactant enhanced water alternating gas flooding. The distinctive feature of this technique is that instead of injecting surfactant slugs alternatively with gas, which will result to using a greater amount of surfactant, a low concentration surfactant is injected into the reservoir before water alternating gas flooding. The aim is to evaluate the performance of this technique as a low cost and effective means of chemically enhanced oil recovery by combining both mechanisms of surfactant reduction of water-oil interfacial tension and creation of foam with gas. This study begins with surfactant evaluation to characterise surfactants compatibility with reservoir brine and oil. Then followed by series core flooding experiments which include waterflooding, gas flooding, water alternating gas flooding and surfactant-enhanced water alternating gas flooding. Core flood data was history matched for water alternating as flooding and surfactant-enhanced water alternating as flooding via commercial simulator by inputting relative permeability curves, rock, fluid properties and interfacial tension. The results showed that experimentally, surfactant enhanced water alternating as flooding had the highest oil recovery when compared to conventional enhanced oil recovery methods. History matching of core flood experiment predicted similar increment in oil recovery during surfactant enhanced WAG. The effectiveness of this technique is based on the injection pattern after the initial surfactant injection and oil recovery potential is similar to that of surfactant alternating gas flooding.

Introduction

The majority of oil companies today are focusing on improving oil recovery factor (RF) from their oilfields as well as keeping an economic oil rate. The reasons for this are that discoveries of new oilfields are becoming increasingly difficult as the majority of the sedimentary basins containing oil have already been explored and new discoveries tend to be smaller when compared to the fields that have been explored. Basins that remain unexplored are found in remote and environmentally sensitive areas of the world (e.g. the Antarctic and the Arctic) (Muggeridge *et al*, 2013).

Enhanced oil recovery (EOR) involves different processes that result in the increase of oil extracted from the petroleum reservoir after the initial stage of primary oil and secondary recoveries. These processes include chemical flooding (surfactant and polymer), gas flooding (nitrogen and carbon dioxide), or thermal flooding. Fluids injected into the reservoir compliment the natural energy or interact with the reservoir rock /oil system creating a condition favourable to improved oil recovery (Green and Willhite, 1998).

It is generally known that a large quantity of oil remains in the oil reservoir after primary and secondary recovery processes due to the heterogeneity of the petroleum reservoirs and difference in permeabilities encountered in the different layers. Another explanation for this is the presence of capillary forces and mobility issues caused by the trapping of the residual oil (Ahmadi and Shadizadeh, 2013). It is has been established that an estimated 65% of the original oil in place is still left trapped in the swept zones, as residual oil (Hosseini-Nassab *et al*, 2015).

The concept of enhanced oil recovery earned recognition as the global demand for oil supply increased over the years and this has been a key factor to maximise and extend the production life of existing oil fields. The economic potential of providing new methods of increasing oil production and EOR projects is essential and it, therefore, represents a subject of great interest, which proposes a means of optimising oil production (Majidaie *et al*, 2012). The efficiency of an EOR process is based on the macroscopic and microscopic sweep efficiencies. While the microscopic efficiency can be influenced by interfacial tension, contact angle, rock heterogeneity and fluid densities affect the macroscopic displacement efficiency (Kulkarni, 2003).

Gas injection is known to be the second largest enhanced oil recovery technique due to the availability of gas (Hinderaker *et al*, 1996). Theoretically, injection of gas into the petroleum reservoir can produce 100% of the oil in place (Lake, 1989). However, high gas mobility, low gas density, and reservoir heterogeneities decrease the sweep efficiency and oil recovery. This happens because the gas injected rises to the top of reservoir due to its low density and causes oil override, which in turn leads to early gas breakthrough. In addition, the high gas mobility leads to viscous instability, which increases gravity override, making reservoir heterogeneity much worse by creating high mobility flow paths (Renkema and Rossen, 2007). For this reason, enhanced oil recovery methods such as water alternating gas flooding and the use of gas thickeners have been employed.

Several studies have been conducted to improve these problems associated with gas injection. Caudle and Dyes (1958) worked on improving miscible gas displacement and observed that the sweep efficiency of gas injection process could be improved by decreasing the mobility behind the flooding front. They achieved this by injecting a water slug alternating with a gas slug (WAG). The water slug was able to reduce the relative permeability to gas and thus reduce the total mobility. In their method, they proposed that a miscible slug should be introduced into the reservoir by a simultaneous injection of water and gas in a proper ratio. To avoid problems associated with injectivity and other operational limitations related to the simultaneous injection of fluids, an injection scheme involving the alternate injection of gas and water was utilised.

Despite the satisfying results of alternative injection of water and gas, which helps to control gas mobility, the reduction of oil-gas contact in the presence of water decreases the WAG effectiveness (Syahputra *et al*, 2000). It has been shown in recent studies that most of the fields where water alternating gas was employed could not reach the expected recovery from water alternating gas injection (Sharma and Rao, 2008). The average oil recovery in miscible and immiscible WAG was 6.4% and 9.7

% of the original oil in place (Christensen *et al*, 2001). Some studies also have reviewed the main problems associated with WAG injection process and determined that the main issues are water blocking phenomena and WAG mobility control. The water isolates the residual oil from coming in contact with the gas. Due to the high interfacial tension (IFT) that exists between water and oil, it is impossible for water to displace the trapped oil from the pore spaces (Kulkarni, 2003; Rao *et al*, 2004). It has been suggested the use of chemicals such as surfactant and polymers in water- alternating- gas flooding to improve the efficiency. Saleh *et al* (2013) conducted surfactant-alternating gas flooding experiments in their study in other to create foam to overcome the water blocking effect experience during WAG. Their results showed that oil recovery with surfactant alternating gas flooding was higher when compared to water-alternating-gas flooding.

Majidaie *et al* (2014) conducted a numerical and experimental study of chemically enhanced water alternating gas flooding (CWAG). They developed a new technique involving the injection of alkaline, surfactant and polymer additive as a chemical slug, which was injected during WAG process to minimise the water-blocking effect by interfacial tension reduction, and improving mobility ratio with the polymer. The results they obtained showed that the CWAG achieved 26.6% more than twice the oil recovery from conventional water alternating gas flooding. The improvement in oil recovery was attributed to the presence of surfactant, which creates a very low interfacial tension that reduces the blocking effect.

Salehi *et al* (2014) studied the removal of oil by conducting surfactant –alternating- gas flooding (SAG) experiments. They also evaluated the effect of SAG ratio on oil recovery and compared their results to conventional waterflooding, gas flooding, and water alternating -gas -flooding. Their results showed that oil recovery in SAG is related to the SAG ratio and recovery factor for SAG was higher compared to WAG, waterflooding and gas flooding. The improvement of recovery factor for SAG was because of foam creation, which arises as nitrogen gas meets surfactant. Foam increases the gas viscosity hence controlling the mobility of gas, which eventually displaces oil in a piston manner.

Abdi *et al* (2014) worked on improving oil recovery during waterflooding and water alternating gas flooding in the presence of asphaltene depositions on the rock using non-ionic surfactant. The presence of asphaltenes in oil reduces recovery factor during production. Their results showed an incremental oil recovery when a non-ionic surfactant was introduced into the injection water. The increase in oil recovery was due to the non- ionic surfactant restoring the water-wetness of the rock. As the presence of asphaltene in the oil changes the rock wettability to oil wet.

Harsen *et al* (1995) performed numerical simulations to study the effect of introducing surfactant into injection brine during water alternating gas flooding in heterogeneous reservoirs. Their results showed that an improvement in oil recovery efficiency was achieved when surfactant was introduced compared to the conventional water alternating gas flooding. They concluded that foam formed during surfactant injection with gas blocks the highly permeable region on the reservoir and the advantage of this method over water alternating gas flooding are the reduction in gas-oil ratio and diversion of water that ultimately leads to increase oil recovery rate.

Memon *et al* (2016) investigated the impact of foaming surfactant in water alternating gas (SAG) flooding by conducting core flooding experiments using different surfactant blends. The results they obtained showed that the increase in oil recovery during SAG flooding is because of the control of CO_2 mobility by the surfactant.

The different works published in the literature have shown that surfactant can improve the efficacy of water alternating gas flooding and improve oil recovery. This study proposes a new method known as surfactant enhanced water alternating gas flooding. This process involves injecting low concentration surfactant into the reservoir before conducting water alternating gas flooding. The objective is to demonstrate the EOR potential of this method experimentally and numerically in oil recovery and compare to other conventional recovery methods such as water-alternative gas flooding (WAG) experimentally. The experimental study will compare oil recovery of surfactant enhanced WAG to waterflooding, gas flooding and water alternating as flooding. While the Numerical study will be used to history match oil recovery for WAG and surfactant enhanced WAG and comparing oil recovery predictions from simulation by history matching of core flood data using Eclipse reservoir simulator.

Materials and Method

Rock sample: Berea sandstone cores were used for core flooding experiments. The core samples are specifically made for laboratory experiments and they are homogenous. The properties of the core samples are given in table 1. Four different core samples were used for the experiments. Berea sandstone is a sedimentary rock with grains predominantly sand-sized and made up of quartz sand bound together by silica. They are considered to be very good candidate for enhanced oil recovery experiments**.**

Table 1 *Core properties.*

Property	Sample A	Sample B	Sample C	Sample D
Absolute Permeability (mD)	100	112	100	105
Length (cm)	10.16	10.14	10.12	10.16
Diameter(cm)	2.49	2.48	2.47	2.49
Porosity	0.180	0.183	0.184	0.181

Crude oil: North Sea crude oil sample is used for the experiments**.** Crude oil properties are shown in table 2

Table 2 *Crude oil properties.*

Viscosity@60°C	21
Density	0.926

Nitrogen: The gas used for this experiment is an industrial grade nitrogen gas from BOC gas.

Surfactant: Surfactants used are alcohol alkoxy sulfate and internal olefin sulfonate. Alcohol alkoxy sulfate and internal olefin sulfonate are anionic surfactants and are compatible with the sandstone core sample used.

Brine: A synthetic brine was prepared in the laboratory containing several salts with monovalent and divalent ions. The composition of the brine is given in table 3

Table 3.1 *Brine composition.*

Salts	**Concentration (g/litre)**
$NaCl$	56.6
$CaCl_2.2H_2O$	6.3
KCl	0.56
$MgCl_2.6H_2O$	8.16

Apparatus

Coreflood apparatus: The core flood apparatus used for the experiment comprises of different components. These components are described below and a schematic of the core flood apparatus is shown in figure 1

Injection system: A dual Teledyne pump with a working maximum pressure of 7000psi was connected to the accumulators in the core flood apparatus. The function of the pump is to push water from the bottom of the accumulator which will move the piston inside the accumulator hence pushing the fluids out of the accumulator through the tubing and then into the core sample.

Gas flow controller: A Bronkhorst gas flow controller was used to control the gas flowrate.

Differential pressure transmitter: A Bronkhorst pressure transmitter was used to measure differential pressure. The pressure transmitters were connected to the injection and production point in the core flood system.

Core holder: The core sample placed in a core holder and kept in a horizontal position. It has a rubber sleeve in which the core sample is placed in. Hydraulic oil was used to apply overburden pressure compressing the sealed rubber sleeve to ensure fluid flowing through the core sample.

Backpressure regulator: A backpressure regulator is connected to the outlet where production of fluid is collected. A backpressure of 30psi was applied to control the pressure in the core flood system during the experiment.

Fluid collection: Effluent was collected using a test tube at different times. The test tube was used to quantify oil recovery.

Gas meter: A Bronkhorst gas meter was connected to the test tube used for effluent collection to determine gas breakthrough and measure the volume of gas produced after breakthrough.

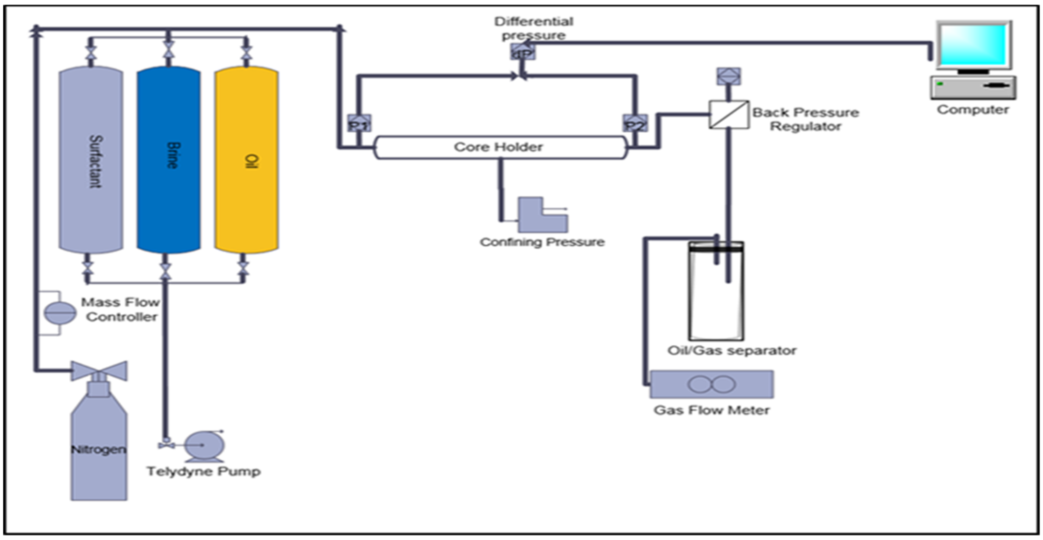

Figure 1 *Schematic of core flood apparatus.*

Procedure for Experiment

Surfactant phase behaviour

Surfactants were evaluated based on their ability to form a stable microemulsion phase. Microemulsions are thermodynamically stable and clear dispersion of water and oil when combined with surfactant solution (Walker *et al*, 2012)

Windsor (1985) discussed the classification of microemulsion phases. Microemulsion was classified into three different types; type I also known as the lower phase microemulsion, type II (upper phase microemulsion) and type III (middle phase microemulsion). The type III is the most desirable for enhanced oil recovery (Sheng, 2015)

Two different surfactant formulations were tested with the crude oil. The essence of this experiment was to determine the surfactant interaction with brine and oil in creating a microemulsion phase and to select a formulation that will give a high solubilisation ratio at optimal salinity. A high solubilisation ratio corresponds to a low interfacial tension.

Microemulsion phase behaviour was investigated by mixing aqueous phase (surfactant and co-surfactant) at different brine salinities with oil. Equal volumes of oil and surfactant solution are introduced into a 5ml pipette. The formation of micromeulsion phase was investigated by shaking the pipettes by hand and kept in the oven. Volume change of microemulsion was recorded at different time intervals.

The water and oil solubilisation parameters are defined as the ratio of water and oil solubilised in the microemulsion phase to the ratio of the surfactant present in the microemulsion phase. When type III microemulsion phase is formed, the amount of water and oil solubilised. When type II microemulsion is present, the amount of water and oil solubilised in a microemulsion phase is equal. The point of intersection of the water and oil solubilisation ratio curves is known as the optimal solubilisation ratio and optimal salinity (Levitt *et al*, 2006).

A high solubilisation ratio is an indication of low interfacial tension created by the surfactant. To determine the value of low interfacial tension, Huh (1979) proposed a relationship between solubilisation ratio and interfacial tension. This relationship is given below

$$\gamma = \frac{C}{\sigma^2}$$

Where C is a constant and is approximately 0.3 dynes for most crude oil. σ is the solubilisation ratio and γ is interfacial tension (Fuseni A *et al*, 2013).

Coreflooding experiment

Core cleaning: The core was cleaned using toluene and methanol in a soxhlet. Toluene and methanol were used to clean the sample in the soxhlet and the flushed with distilled water to bring the core sample back to its original state. The samples were kept in the oven to dry.

Core sample preparation: The weight of the dry core sample is measured using a weighing balance and a calliper is used to measure the diameter and the length of the core sample. The core sample is saturated in brine and kept in a vacuum to displace air from the core sample and enhanced saturation.

Porosity and permeability measurement: The first step of the experiments is to measure the porosity and absolute permeability of the core sample. The porosity of the core sample was estimated using the equation below

$$\text{Porosity} = \frac{\text{Pore Volume}}{\text{Bulk Volume}}$$

Absolute permeability was measured by flooding the core sample with brine at different flowrates and Darcy's equation was used to estimate core permeability. Darcy's equation is given below

$$\text{Absolute permeability} = \frac{Q\mu L}{A\Delta P}$$

Where Q is the flowrate, μ is viscosity, L is length, A is area and ΔP is differential pressure.

Core saturation with brine: The first experiment for core flooding is brine injection into the core sample to attain 100% water saturation. The sample was flooded at different flowrates to obtain the absolute permeability. The flowrates range from 1cc/min to 8cc/min.

Oil injection

Crude oil was injected at a flowrate of 0.5ml.min into the core sample until water is no longer produced. This was done to obtain irreducible water saturation. The process of displacing water with oil simulates the initial condition of a reservoir in which it was originally 100% water saturated before oil migration. This process is known as drainage. The irreducible water saturation (S_{wi}) and original oil in place can be calculated form this process.

$$S_{wi} = \frac{(\text{Pore Volume} - \text{Water displaced})}{\text{Pore volume}}$$

$$\text{Original oil in place(OOIP)} = \text{Pore volume}(1 - S_{wi})$$

Water flooding

Brine was injected into the core sample at 0.1ml/min until there is 100% water cut. The residual oil saturation (S_{or}) was calculated using the equation below

$$S_{or} = \frac{(\text{OOIP} - \text{Total volume of oil produced})}{\text{Pore volume}}$$

The equation for calculating recovery factor is given below

$$\text{RF} = \frac{\text{Volume of oil produced}}{\text{OOIP}} \text{ X } 100$$

Gas flooding

After oil injection into the core sample to establish irreducible water saturation, gas was injected into the core sample at a flowrate of 5ml/min until gas break through. Residual oil saturation was estimated at gas break through.

WAG and surfactant enhanced WAG

Water flooding was conducted on the core sample at a flowrate of 0.1ml/min until water breakthrough and then followed by one cycle of water and gas injection.

To study the performance of surfactant in WAG, a low concentration surfactant was injected into the core sample already saturated with oil. This is followed by a cycle of gas and the water injection.

Numerical simulation

A simulation study was conducted to compare experimental oil recovery factor of WAG and surfactant enhanced water alternating gas flooding with the experimental recovery. Eclipse 100 reservoir simulation software was used to run the simulation. The grid block dimensions were selected to be representative of the core sample used for experiment. Reservoir fluid and rock properties are presented in table 4. The synthetic model built comprises of two wells, one injection, and one production. For all simulations, the injection rate was fixed for 6.43scc/hr for water injection and 360scc/hr for gas injection. The porosity and permeability values are assumed to be constant all through the model and the reservoir is assumed to be homogeneous. Interfacial tension for surfactant enhanced alternating as flooding was calculated using solubilisation ratio from surfactant phase behaviour experiment.

Reservoir properties		**Fluid properties**	
Grid size (cm)	10 x 2.5 x2.5	Oil density (g/cm³)	0.926
Grid	10 x1x1	Water density (g/cm³)	1
Kx x Ky x Kz (mD)	110	Oil viscosity (cp)	21
Pressure (psi)	34.023	Connate water saturation	0.25
Temperature (°C)	60	Initial oil saturation	0.75

Results and discussions

A phase behaviour experiment was conducted for alcohol alkoxy sulfate and internal olefin sulfonate as primary surfactants. Alcohol alkoxy sulfate formed viscous microemulsion phases and internal olefin sulfonate gave a very low solubilisation ratio. Both surfactants were combined and another phase behaviour experiment was conducted. The result is shown in Figure 2. A stable microemulsion phase was formed using 0.2 vol % concentration of surfactant. The plot in figure 2, shows that the interaction with aqueous solution and oil achieved a high solubilisation ratio which creates low interfacial tension between water and oil. The microemulsion phase formed was non-viscous indicating a low viscosity that is required for the microemulsion phase to prevent clogging the porous medium during injection.

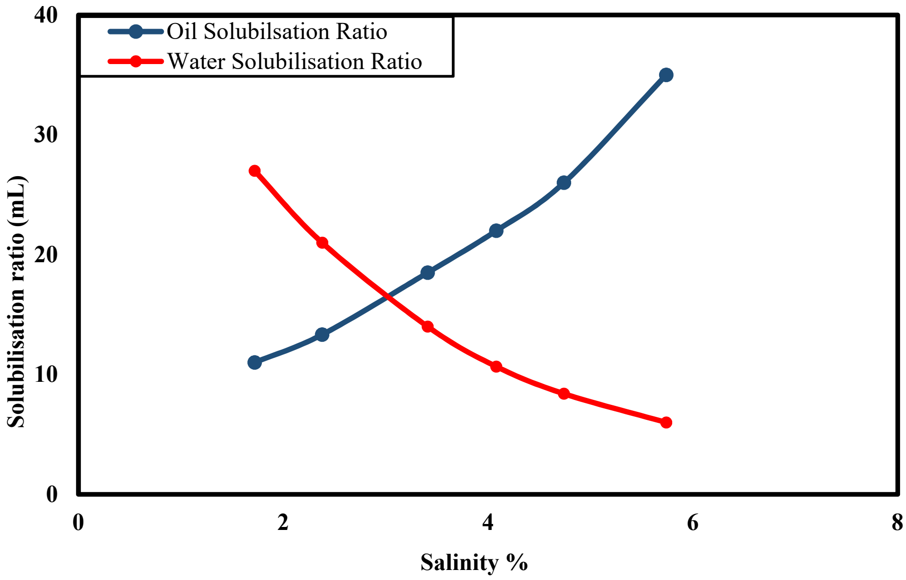

Figure 2 *Solubilisation ratio against salinity for microemulsion phase behaviour experiment.*

Oil recovery comparison

Figure 3 shows the cumulative oil production from four different displacement experiments. The experimental results show that highest oil recovery was achieved with surfactant enhanced oil recovery. Gas flooding had the lowest oil recovery factor of 18.75%. Low recovery in gas flooding is due to gas overriding the oil because of the high-density difference between both fluids. Early gas breakthrough was observed in the gas flooding experiment. Gas breakthrough was observed at 0.30 pore volume of gas was injected into the core sample. Waterflooding had higher oil recovery compared to gas flooding. The oil recovery factor of water flooding was 30%. Low oil recovery in water flooding is as a result of high interfacial tension between oil and water which causes oil trapping in the sample. Water alternating gas flooding had an oil recovery of 42.5% while surfactant enhanced water alternating gas flooding had the highest oil recovery of 54.75% Surfactant enhanced water alternating gas flooding combines both mechanisms of reduction of interfacial tension and gas trapping by surfactant to improve sweep efficiency and oil recovery. Oil recovery rate increase in surfactant enhanced WAG compared to conventional WAG.

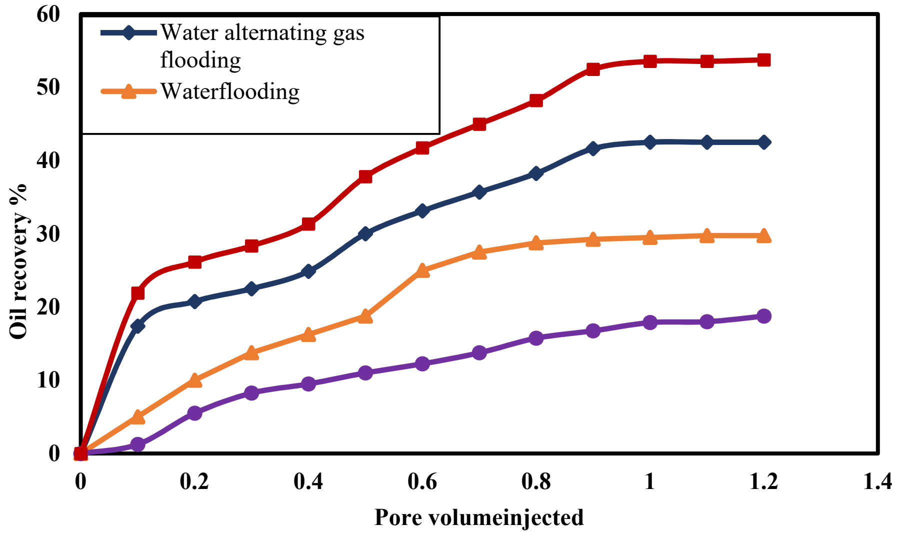

Figure 3 *Comparison of experimental oil recovery.*

Comparison of oil recovery for surfactant enhanced water alternating gas flooding and surfactant alternating as flooding

This experiment was conducted to compare the oil recovery potential of surfactant enhanced water alternating gas flooding to the conventional surfactant alternating gas flooding. For surfactant alternating gas flooding, a surfactant concentration of 0.6vol% was used as compared to 0.2vol% used in surfactant enhanced water alternating gas flooding. The result shown in figure 4 indicates that although the oil recovery for surfactant alternating gas flooding was 10% higher, the rate of oil production at different times during the experiment were similar. Gas breakthrough for surfactant enhanced water alternating gas flooding was quicker compared to water alternating gas flooding. The percentage of oil recoveries for both techniques are quite close. This shows that the surfactant enhanced water alternating gas technique is as effective as surfactant alternating gas injection using higher surfactant concentration.

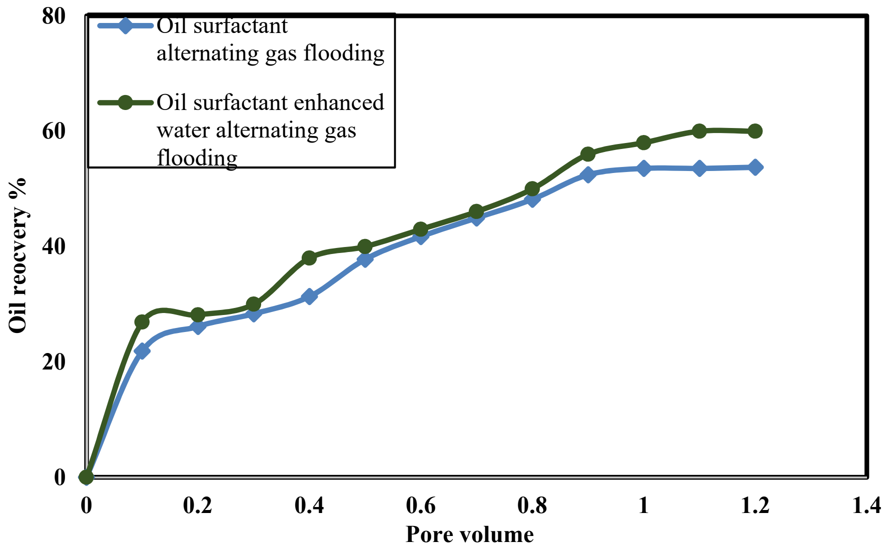

Figure 4 *Oil recovery plots for surfactant enhanced water alternating gas flooding and surfactant alternating gas flooding.*

History matching of core flood experiment

During the history matching, relative permeability curves were obtained from two-phase water/oil, surfactant/oil, and gas/oil displacement experiment. Corey correlation was used to obtain the relative permeability curves. Surfactant interfacial tension was obtained from phase behaviour experiment and this was used to calculate capillary number for surfactant enhanced WAG simulation. Adsorption capacity of the surfactant on the core sample was also considered in building the surfactant enhanced WAG model. A view of the reservoir model is shown in figure 5.

Figures 6 and 7 show a satisfactory match of core flood data for oil recovery and experimental pressure. The simulation results also show an increment in oil recovery in surfactant improved WAG as compared to WAG. The simulation results confirmed that injecting low concentration surfactant before WAG leads to increase in oil recovery when compared to conventional WAG.

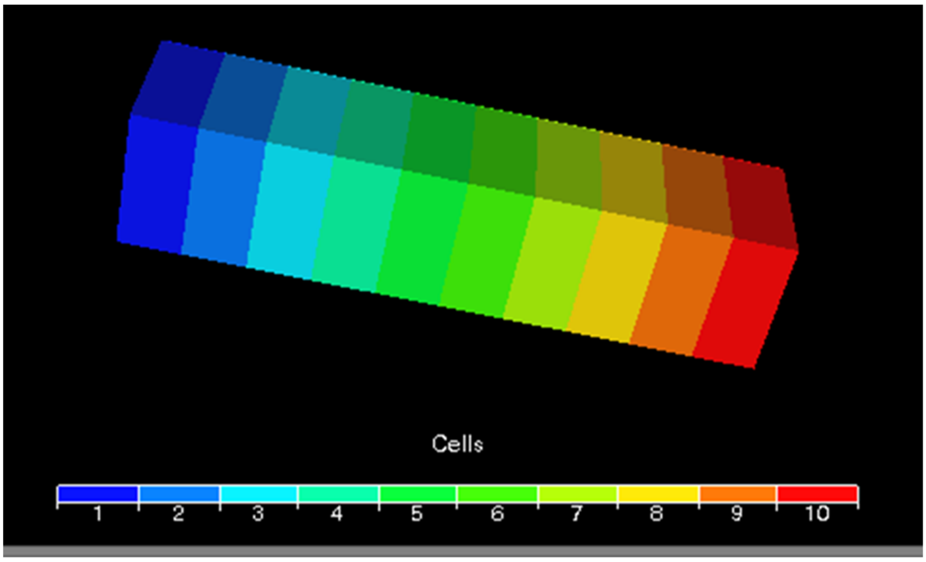

Figure 5 *Synthetic reservoir model for surfactant enhanced water alternating gas flooding.*

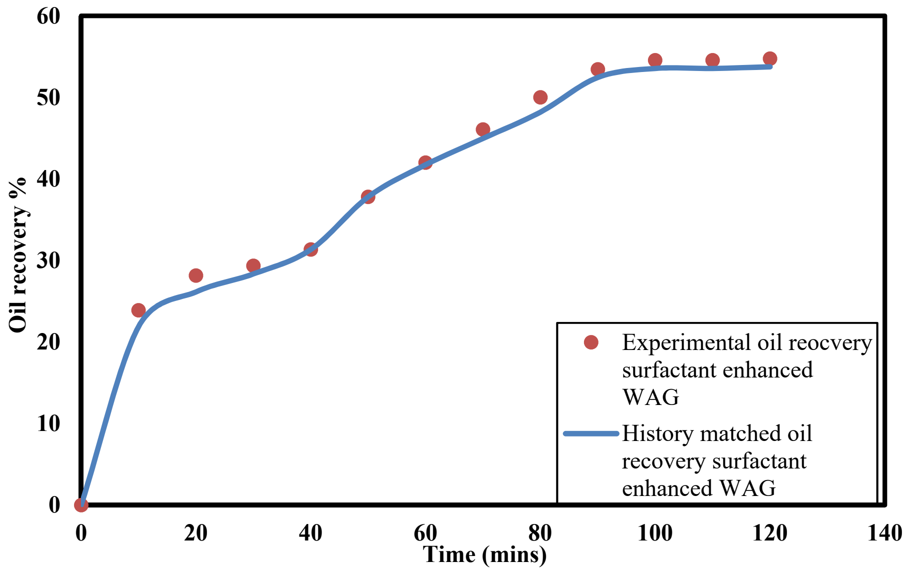

Figure 6 *History matched oil recovery WAG.*

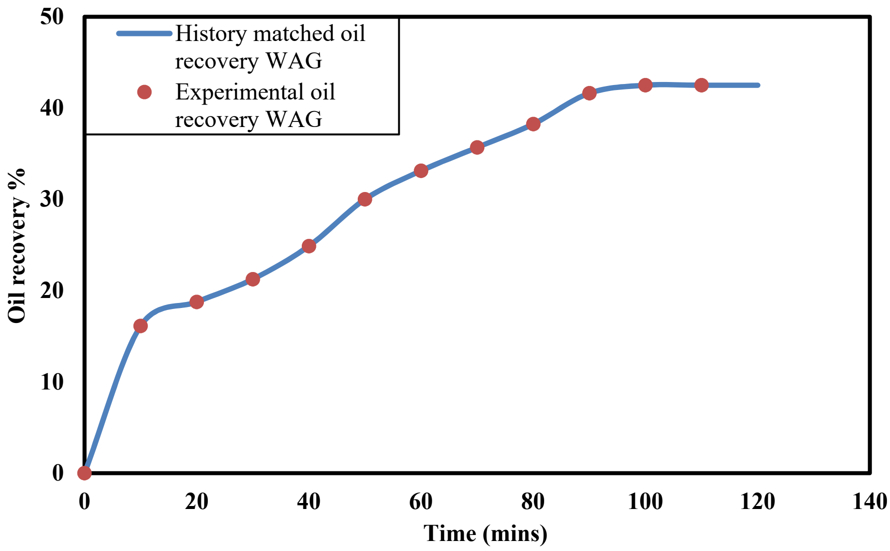

Figure 7 *History matched oil recovery surfactant Enhanced WAG.*

Figure 8 shows history matched pressure gradient obtained from numerical simulation. The Pressure gradient shows that during initial water injection, before WAG, the pressure increased but began to decline during gas injection and then second water injection. In the surfactant enhanced WAG, initial pressure during the surfactant injection was lower compared to WAG and then when followed by gas injection, pressure began to increase and there was continuous increment until the injection of water after the gas injection. The increase in pressure was because of the gas and surfactant interaction during displacement. Formation of foam when gas interacts with surfactant can lead to increase in pressure.

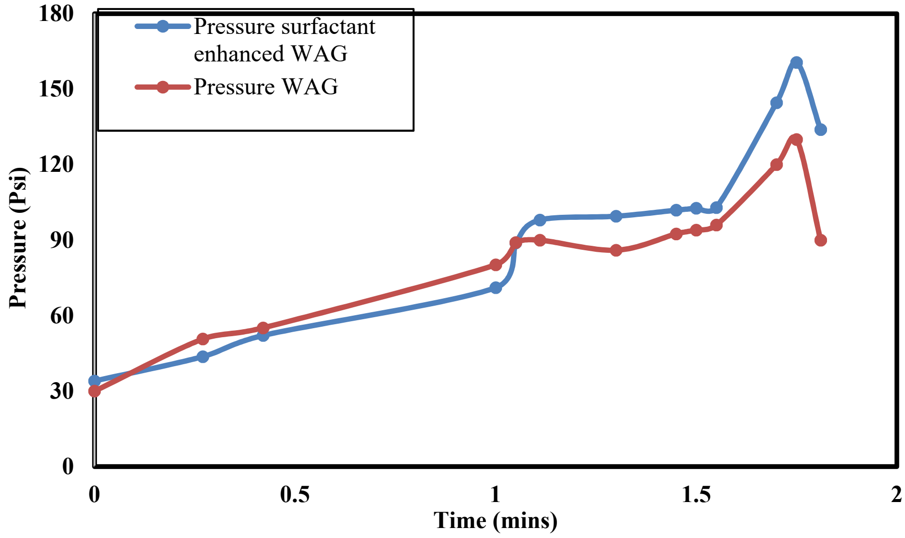

Figure 8 *Comparison of pressure in Surfactant enhanced WAG and WAG.*

Effect of injection pattern on oil recovery

The history matched result was used for sensitivity analysis by changing the injection slug pattern for surfactant enhanced WAG. This was done to study which slug pattern yields better oil recovery. Both slug patterns started with water flooding. The sequence of injection is shown below

First injection pattern

Surfactant	Gas	Water

Second injection pattern

Surfactant	Water	Gas

The result in figure 9 shows that injecting gas after surfactant yields more oil recovery compared to injecting the water before surfactant. This is because when gas is injected immediately after surfactant, it causes increase in gas trapping and the creation of foam, which increases the gas viscosity. This allows an effective sweep efficiency. The oil recovery after the initial surfactant flooding with gas was higher compared to when water was injected after the surfactant flooding. This is because the injection of water after surfactant flooding decreases the surfactant concentration and then reduces contact between gas and surfactant that increases the gas viscosity.

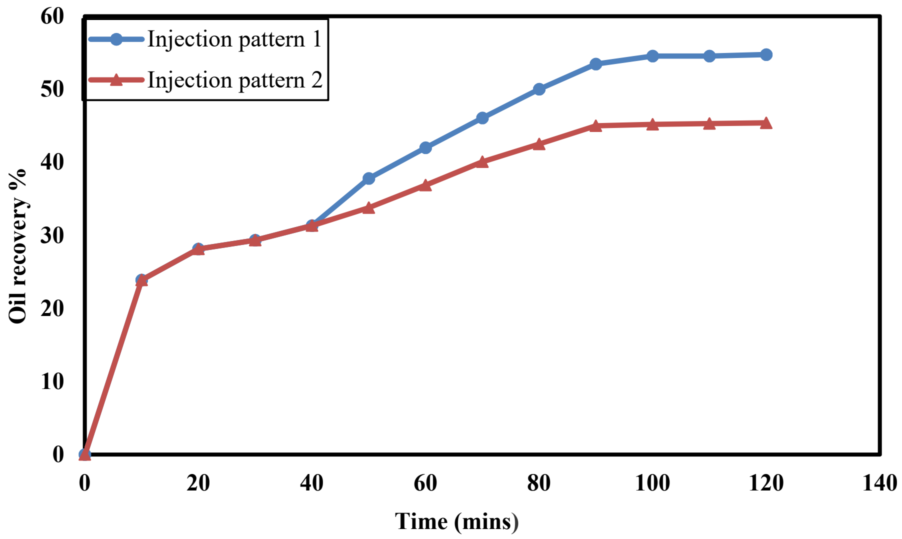

Figure 9 *Oil recovery comparison for injection pattern.*

Conclusions

In this work, a new enhanced oil recovery technique surfactant enhanced water alternating gas flooding has been proposed to improve oil recovery in water alternating gas flooding by injecting low concentration surfactant before WAG. The conclusions made from this study are as follows

- Optimum surfactant formulation to form stable microemulsion phase was obtained by using introducing internal olefin sulfonate as a co- surfactant with alcohol alkoxy sulfate.
- The surfactant enhanced water alternating gas flooding improves oil recovery compared to the conventional enhanced oil recovery methods.
- Injection sequence is a very important parameter when using this method. Injection of gas immediately after the surfactant flooding is more efficient than injection water after surfactant.
- Surfactant enhanced water alternating gas flooding combines the reduction of interfacial tension and controlling of gas mobility to improve oil recovery. The low interfacial tension reduces the water blocking effect experienced in water alternating gas flooding.

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