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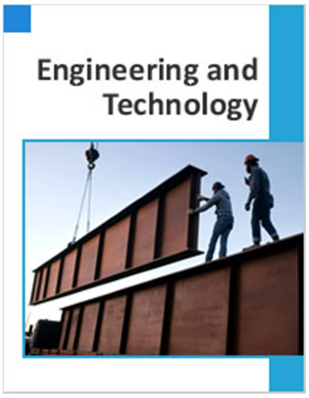

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Effect of pH and Slug Ratio of Alkaline Surfactant Polymer Alternating Gas Flooding on Oil Recovery

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Abstract
Water alternating gas has been acommonplace method for enhancing oil recovery that has been practiced in many parts of the world. Although this process is conceptually sound, its field incremental recovery is disappointing as it rarely exceeds 5 to 10% OOIP. This is due to challenges such as water blocking and high gas mobility. This study seeks to address the mentioned problems and propose ASP alternating gas (ASP-Gas) as a method to improve the WAG process. pH and slug size are significant parameters that determine the efficiency of ASP-Gas in oil recovery. An experiment was conducted to determine their effect on alternating ASP with Gas at room conditions. Sand pack models 100cm long and 2.5cm diameter were used with moderately heavy oil of density 0.85g/cc and viscosity 37cp. Immiscible flooding process was achieved by injecting carbon dioxide gas into the core. The results showed that the pH had a significant effect on oil recovery up to a certain limit, however the pH effect depend on oil properties such as acidity. The optimum recovery (15.4%) eventually was found by injection ofthe slug which consisted of 0.1%wt polymer, 0.1% surfactant and alkaline with pH 11 and slug ratio of 1:1.

1. Introduction

According to Department of Energy U.S.A, the amount of oil produced worldwide is only one third of the total oil available [1]. So by using EOR techniques we can produce more oil as the demand increases while we have a shortage in supply. Although CO_2 flooding is a well-established EOR technique, its density and viscosity nature is a challenge for CO_2 projects. Low density (0.5 to 0.8 g/cm^3) causes gas to rise upward in reservoirs and by pass many lower portions of the reservoir. Low viscosity (0.02 to 0.08 cp) leads to poor volumetric sweep efficiency in heterogeneous reservoirs with high-permeability [2]. Almost all commercial miscible gas injection projects use WAG to control mobility of gas and alleviate fingering problems [3]. Oil Recovery by WAG is better than gas injection alone, and 80% of commercial WAG projects in the US are economic [4]. However, recent studies show that most of the fields could not reach the excepted recovery factor from the WAG process, especially for reservoirs with high-permeability zones or there are naturally fractured [5]. To overcome the issues of gas breakthrough and gravity segregation, a new combination method was proposed. This new method, termed as ASP-GAS, combines features of CO_2 flooding with chemical flooding to produce a chemically enhanced WAG flooding processes. Coupling of ASP with CO_2 is expected to improve the efficiency of the current WAG [3].

The main feature of ASP-GAS is that ASP is injected with water in the whole WAG process [6]. ASP-Gas Processes can be classified in different forms depending on the methods of fluid injection. The most common categorization is the difference between miscible and immiscible injection [7] however, in this experiment immiscible injection was performed since the gas was not miscible with the oil. Some of the ASP-GAS advantages includes better improved sweep and displacement efficiency, pressure support, reduced water handling cost and high production rates [5] which all combined enhanceoil recovery. Therefore, this research aims to study the effect of pH and slug ratio of alkaline surfactant polymeralternating gas flooding on oil recovery.

2. Experiments and Procedures

2.1. Materials and Apparatus

The porous medium used in this experimental set up were PVC tubing pipes with 2.5cm diameter and 100cm long, a total of nine sand packs PVC models were prepared. The PVC consisted of end caps, two 1/8 inch brass fitting. The PVCcap with brass fitting was installed on the end of PVC pipe and both connections were sealed with PVC glue to prevent leakage during flooding.

To ensure that the absolute permeability of 2.33D and porosity of 34% were in desired range similar wet packing methods were used for all the sand packs. In general the set up consisted of a carbodioxide gas cylinder which was the gas source used for injection, pressure gauge calibrated from 0 to 50 psi to determine the pressure difference at the inlet, sand pack porous model to represent the reservoir core, shirking pump which was used for fluid injection and a graduated cylinder for fluid collection as shown in figure 1. The sand used in this study was first cleaned by water then dried under the sun to eliminate any tresses of dirt particularly the mud particles. Then it was sieved to the sizes of 150-350 μm and was dried again in the oven at 70°C overnight to completely remove any water tresses. This experiment was run to simulate relatively heavy oil and industrial paraffin oil. The alkaline used in this study was sodium hydroxide (NaOH), the surfactant used was ORS-41 and polymer used was hydrolyzed poly acromide (HAPM) all sourced from local suppliers 0.1%wt the polymer and surfactant were.

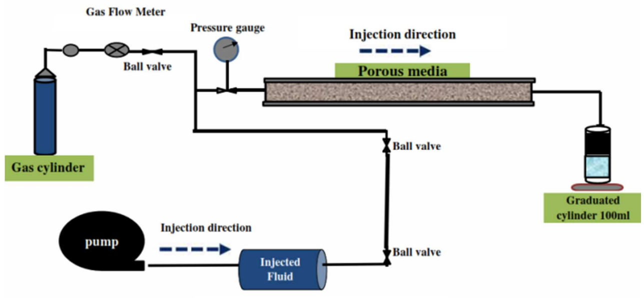

Figure 1. *Experimental laboratory set up.*

2.2. Gas Injection

In most field cases, the injected gas is carbon dioxide (CO_2) because zero emission of CO_2 is required to the environment and this it exists in many reservoirs as a natural gas hence it's injected back. It's for this reason that in this experiment carbon dioxide gas was used. Carbon dioxide is used to enhance the displacement of oil from reservoirs by improving the displacement efficiency. It can also be obtained as a by-product from chemical and fertilizer plants, or it can be manufactured or separated from power plant stack gas.

Even though CO_2 is not miscible with oil on first contact, when it is forced into a reservoir a miscible front can be generated by a gradual transfer of smaller, lighter hydrocarbon molecules from the oil to the CO_2. To measure the volume of CO_2 injected, flow meter was used, the gas was pumped to the test model by manipulating ball valves. In addition the displacing fluids were pumped into one end of the model through injection port and the produced fluids were collected by measuring cylinder. The displaced fluids were displaced out through the other end of the model, collected and measured in cylinder. The fluid produced were water and a mixture of CO_2 and oil.

2.3. Procedure for the Determination the Effect of PH and Slug Ratio on ASP-Gas

The sand pack model was saturated with 20,000 ppm of NaCl as brine, which was injected at a constant rate through the model to prepare the model with pore volume. After the model was 100% saturated, injection was continued until it was steady to measure the absolute permeability of water. Oil was injected at a constant rate through the model to prepare the model with irreducible water saturation and oil was displaced back by water to measure the residual oil saturation.

Water flooding was carried out continued with immiscible CO_2 flooding as secondary oil recovery each with 2.5 PV injection. ASP-GAS process then was carried out as tertiary recovery after immiscible CO_2 flooding. Gas tank had been connected via silicon tube to flow meter and then connected to the end of model. For each ASP-GAS of different pH and slug ratio, about 0.5 PV of fluids were injected. Each ASP-

GAS cycle began with ASP injection and ended with gas injection. The floods were terminated after 2.5 PV fluids were injected. The volume of water and oil produced were recorded. And the processes were repeated using different model with different pH and slug ratio as shown in figure 2.

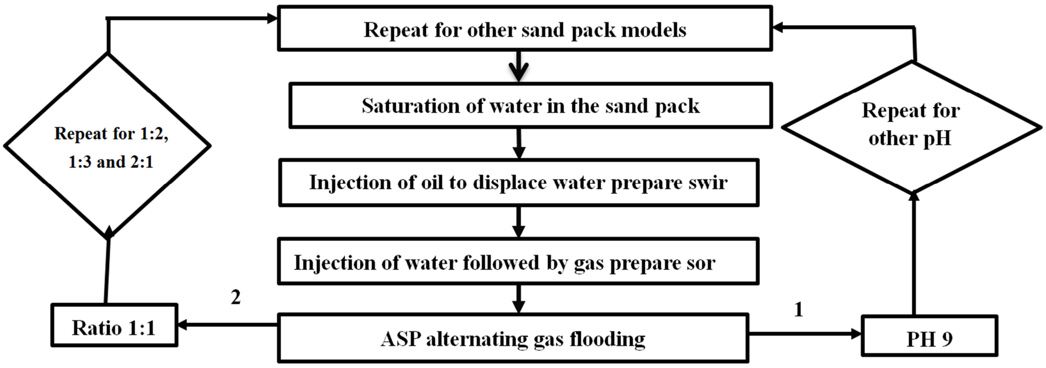

Figure 2. Flow chart of one cycle experiment for both pH (1) and slug ratio (2) of the experiment.

3. Result and Discussion

3.1. The Effect of pH on ASP-Gas

Since similar packing methods were used, the oil recovered initially by water flooding in preparation of the cores with irresidual oil saturation for all models was relatively the same as shown in figure (3). Injection of ASP-Gas with different pH resulted into increase in oil recovery up to a certain value were the increase in pH had no effect on oil recovery as shown in figure (4), the optimum pH was 11 and beyond this oil recovery started todecrease, this signifies an optimum concentration of alkaline which gives maximum oilrecovery this is supported also by [8], in there study however, they conclude that this depends on the acidity of the oil, the higher the acidity of the oil the higher the recovery.

In this study, the acidity of the simulated oil was low, the recovery increase was mainly due to the addition of polymer and surfactant in ASP. The polymer improves the mobility ratio by reducing viscous fingering which is normally due to less viscous water by passing more viscous oil while the surfactants improves the displacement efficiency by reducing the IFT between oil and water [9].

The drop in the graph in figure (4) was due to the precipitates that were formed as a result of the alkaline reacting with the formation brine and hence blocking the pores which resulted into less oil flow [10]. Figure (4), also shows that increasing the alkaline beyond an optimum value may have no impact on the oil recovery since as the concentration of the alkaline increase, corrosion and scaling occur combined with the precipitation of the alkaline as it reacts with brine, this limits the overall oil recovery [11]. An optimum pH is a basis to avoid using excess alkaline which may lead to scaling, precipitation and corrosion of tubing pipes which results into lower displacement efficiency hence low recoveries. Also, injecting too much gas result in a gas tongue forming at the top of the reservoir (gas override) and this may lead to poor horizontal and vertical sweep efficiency [12]. Injecting too much gas may also induce a very early gas breakthrough since gas possesses a very high mobility and this may negatively impact the success of ASP-Gas injection.

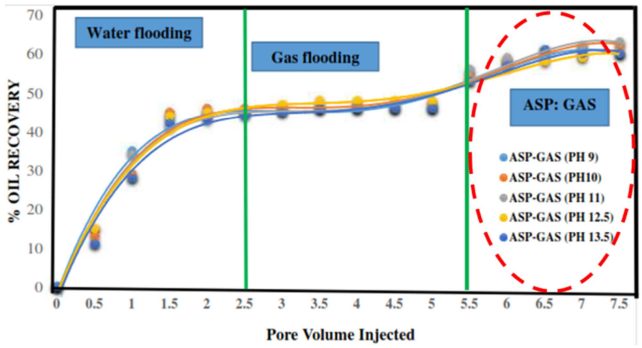

Figure 3. Incremental Oil Recovery at Different pH condition.

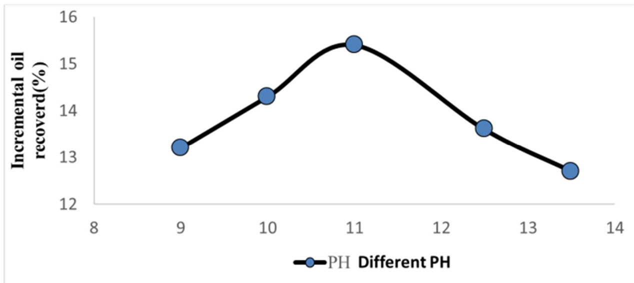

Figure 4. Incremental OIIP, % at Different Ph.

3.2. The Effect of Slug Size on Oil Recovery Using ASP-Gas

ASP-Gas performance is significantly affected by reservoir heterogeneity, rock wettability, fluid properties, miscibility conditions, trapped gas, injection techniques, and well operational parameters it should be noted that the Performance of an ASP-Gas process is largely affected not only by the injection parameters, including slug ratio, injection rate, and cycle time, but also by the production parameters, including, Production rate and bottom hole pressure at the producer [5]. In particular, ASP-Gas ratios are crucial factors that affects the oil recovery and have an optimum value in a hydrocarbon reservoir. During water flooding process, at first, 2.0 PV, oil recovery for all four

ASP -Gas ratios were relatively increasing with constant rate because the water that was injected acted as a piston-like displacement by evenly sweep of the front of the oil as shown in figure (5), at this time, maximum oil recovery was obtained. After 2.0 PV, the graph is relatively constant and there is less increase in oil recovery. This is due to the occurrence of gravity segregation where the injected water tends to flow at the bottom part of the model only. This occurs due to the water which has a higher density than oil.

To determine the effect of slug ratios of ASP-Gas on oil recovery, a pH 11 was used in the ASP formulation since it was the optimum compared to other pH. The slug ratio of ASP-GAS 1:1 gave an optimum recovery (15.4%) in comparison to other slug ratios because of the improvement of sweep and displacement efficiency by the ASP that was alternated with gas and they were both injected with equal pore volume.

With high proportion of gas in relation to the chemical slug, the mobility ratio of the displacing phase may be greater than 1 and results into poor macroscopic sweep efficiency which in turn result into a reduced overall oil recovery. However alternating ASP with gas the mobility ratio(M) reduces to a value less than one which increases the sweep and displacement efficiency that results into increase in oil recovery. The recovery from the slug ratio containing ASP: GAS (2:1) still from figure (5) is seen to exceed that of 1:1 this is because of the high volume of ASP injected that exceeds the injected gas hence gas channeling to the higher permeable zones is blocked by the ASP slug this allow uniform sweep for the injected slug that results into increased oil recovery. But also this ratio requires large volume of chemical to be injected and on this note, its field application needs to be economically justified before it's recommended for field use. On the other hand, the effect of injection cycles as shown in figure (6) and (7) indicated that oil recovery increased as the ASP-Gas cycles increased regardless pH or different slug ratio of ASP-Gas, this was also supported by a research conducted by [13] shows that the oil recovery increased as WAG cycle increased.

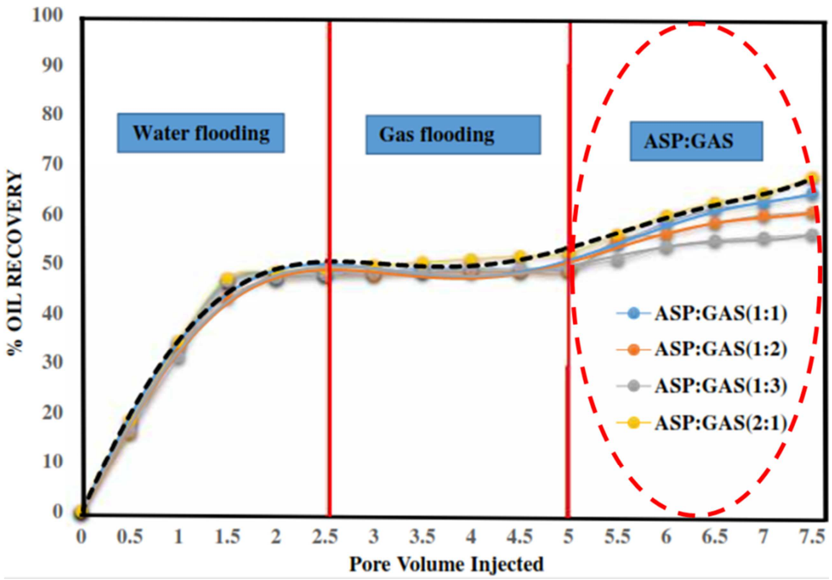

Figure 5. *Oil recovery with different slug ratios.*

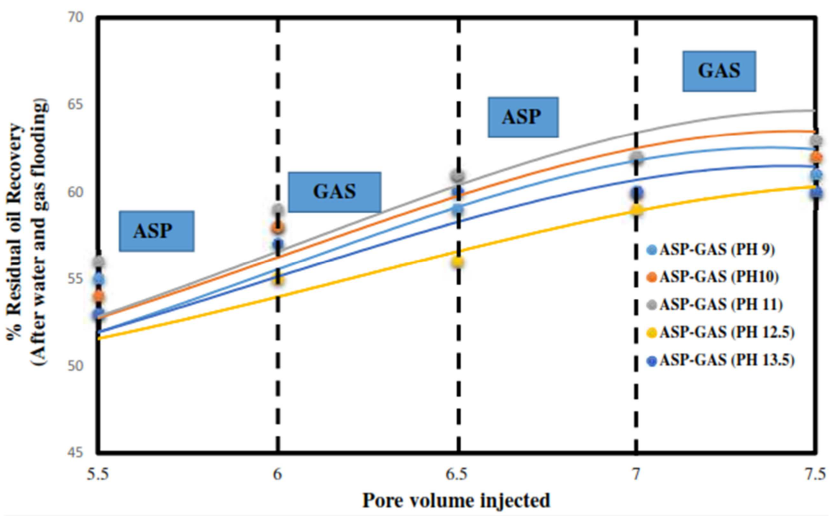

Figure 6. *Incremental oil recovery with different cycles at different pH.*

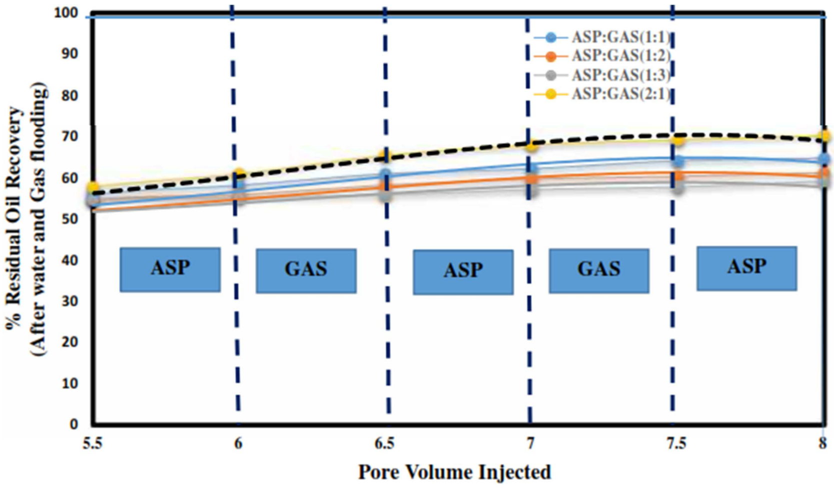

Figure 7. *Incremental oil recovery with different cycles and different slug ratios.*

3.3. Effect to Mobility Ratio, M and Capillary Number Nca in This Study

Mobility ratio can be termed as favorable or not favorable, favorable refers to the case were mobility ratio is less than one ($M \leq 1$) [14], whereas unfavorable mobility ratio indicates that mobility ratio is greater than one ($M > 1$). In this study, the mobility ratio shifted from unfavorable to favorable because of the polymer that was used in ASP that improved the viscosity of the displacing fluid and there was penetration of displacing fluid into the oil bank since there was no early water and gas breakthrough [15], which in turn resulted into improved oil recovery. On the other hand, Capillary number, Nca represents the relative effect of viscous forces versus surface tension acting across an interface between two immiscible liquids. The magnitude of capillary forces is determined by IFT, wettability, condition and pore geometry in which the trapped phase blobs exists. For a flowing fluid, if $Nca \geq 1$, then viscous forces dominate over interfacial forces. However if $Nca \leq 1$, then viscous forces are negligible compared with interfacial forces and the flow in porous media is dominated by capillary forces. Viscous force is set by permeability of the medium, applied pressure drop and viscosity of the displacing phase. In this study, interfacial forces was dominant. For maximum efficiency, the capillary number should be minimized while maximizing mobility ratio. From table1there was less change in capillary number. Capillary number being the ratio of viscous force to interfacial force, the reduction in IFT was mainly due to the constant 0.1wt% surfactant concentration that was used in ASP formulation not the alkaline that was added to change the pH, hence Nca was almost in the same range. This was because of the acidity of the oil which was low and the alkaline had less impact on IFT reduction. However the capillary number of 10^{-3} is still high and improved the displacement efficiency which increased the oil recovery [16].

Table 1. *Capillary Number of Different IFT conditions.*

Type of oil	Oil viscosity, cp	IFT (mN/m)	Velocity, cm/s	Nca
Oil(pH 9)	37	67	0.0103	5.68×10^{-3}
Oil(pH 10)	37	55	0.0103	6.93×10^{-3}
Oil(pH11)	37	46	0.0103	8.285×10^{-3}
Oil(pH12.5)	37	44	0.0103	8.6×10^{-3}
Oil(pH13.5)	37	44	0.0103	1.54×10^{-3}

4. Conclusions

From this study, the injected slug consisting of 0.1%wt polymer, 0.1% surfactant and alkaline with pH 11 and slug ratio 1:1 was the optimum, additional recovery of 15.4% of the oil originally in place was obtained. This indicates that there is always an optimum alkaline concentration in ASP-Gas beyond which there is no significant recovery of oil and this mainly depends on the oil properties such as viscosity and acidity. The slug ratio 1:2 gave (11.2%) and finally 1:3 gave (8.4%). However the slug ratio, 2:1 gave highest recovery than all the previous slug ratios though but it requires economic justification before being applied due to the quantity of chemicals injected hence. In this study also injection cycle had an effect on the oil recovery, the recovery increased as the injection cycles increased.

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