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Department of Environment, Land and Infrastructure Engineering
Master of Science in Petroleum Engineering

SURFACTANT ALTERNATING GAS FOAM FLOODING STRATEGIES IN SANDSTONE ROCKS

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ABSTRACT

The experimental work conducted in this thesis is a research and investigation on the enhanced oil recovery by the process of Surfactant Alternating Gas Flooding (SAG) basically in Sandstones rocks.

SAG process of EOR is a procedure that requires the injection of surfactant alternatively with gas. This is mainly to initiate a mobility control mechanism rather than the alteration of wettability of the rock. Of the gases used in this procedure, the most common is Nitrogen, which is used both in miscible and immiscible gas injection process in oil reservoir. In heterogeneous reservoir formations, the early breakthrough of gases has a tendency to occur in production wells due to forces of overriding, fingering and channelling, thus foam generated due to the injection of gas into surfactant solutions have been promising towards blocking most high permeability zones in the reservoir and also in the interfacial tension reduction between the oil-water phases thereby resulting in an increased oil recovery efficiency.

Foam is formed when nitrogen gas contacts with surfactant which forms a film known as lamella around the gases, thus initiating an increase in the viscosity of injected gas thus decreasing the mobility of gas during injection. Because of this, the contact between the oil and gas increases as well as the sweep efficiency, although, situations such as surfactant adsorption into the rock surfaces do pose certain challenges of which increases the cost of execution this process.

Several parameters must be considered in design of SAG injection. One crucial parameters considered is SAG ratio that should be in optimum value to improve the flooding efficiency. Another factor to be examined is

the ionic content of the surfactant to be used. Several studies have shown that the interaction of the surfactant with the rock usually causes adverse loss of surfactant due to the attraction of the anionic charged surface of the sandstone rock to ionic charged surfactant thereby leading to the adsorption of most of the surfactant into the rock. In this study, anionic surfactants were used in conducting the experiment and demonstration were made regarding the best ratio that affords the most sweep efficiency during Hydrocarbon production from the reservoir. We conducted experiment on varying ratios of surfactant to gas during SAG process. Prior to that, the best candidate for the surfactant was determined by carrying out a foam test on specific mixtures of different surfactant while considering their critical micelle concentration (CMC), which considers the lowest concentration at which micelle can be formed.

Results showed that the mixture of both surfactant (lauryl sulphate and dodecyl) in solution gave the best foam stability at a concentration of 10g/l. Also, an equal proportion of surfactant solution to gas ration of 1:1 gave the best Oil recovery in the SAG injection process.

Lastly, the SAG injection process was compared with the Water Alternating Gas (WAG) process to investigate which methods yields the best recovery. Results conducted in this thesis showed SAG to give a significant better recovery when compared with that of WAG.

The objective of this thesis work was to identify the best SAG design technique required to optimize Oil recovery in the reservoir by obtaining the best candidate for surfactant utilization during SAG injection process and optimal SAG injectivity conditions for recovery efficiency.

The term injectivity here represents the rate and pressure of the injection process during an EOR operation.

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NOMENCLATURE

Symbols

μ - Viscosity

α - dipping angle

ρ_o - Density of oil

B_o - Oil formation volume factor

K_{rg} - Relative Permeability to Gas

K_{ro} - Relative Permeability to Oil

P_c - Capillary Pressure

P_{nw} - Pressure of non-wetting fluid

P_w - Pressure of wetting fluid

Q -Volumetric Flow Rate

S_o - Oil saturation

S_w - Water saturation

S_g -Gas saturation

S_{oi} - Initial Oil Saturation

S_{or} - Residual Oil Saturation

S_{wi} - Irreducible Water Saturation

T -Temperature

t - Time

V - Velocity

V_o - Volume of oil in rock

V_b - Bulk Volume

V_p - Pore Volume

λ - Mobility ρ_o - Oil Density

σ - Interfacial tension

ΔP - pressure difference across capillary tube

E - Overall recovery efficiency

E_v - Macroscopic or Volumetric displacement efficiency

E_d -Microscopic displacement efficiency

E_s - Areal sweep efficiency

E_i - Vertical sweep efficiency

ABBREVIATIONS

OOIP – Original oil in place

EOR – Enhanced Oil Recovery

FC – Foam capacity

H - Height of the column

M – Mobility

PV –Pore Volume

PVT – Pressure, volume and temperature relation

API – American Petroleum Institute

IFT – Interfacial Tension

SS – Surfactant Solution

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1.0 INTRODUCTION

The experimental work conducted in this thesis is a research and investigation on the enhanced oil recovery by the process of Surfactant Alternating Gas Flooding (SAG) basically in Sandstones rocks. It was fully carried out in the laboratory of the Research Institute at the University of Miskolc, Hungary. It comprises of two major tests, **part one** is foam test which was done to analyse the stability of foam generated and **Part two** displacement test of core-flooding to analyse the SAG process design.

Over the years, hydrocarbon reserves have been under steady production of which has led to the steady decline of the estimated oil in place. The need to meet the world's energy demands in the coming years, calls for greater means on how to recover the remaining oil resources from known reservoirs.

In view of this, mobilization of the crude oil from reservoirs that have already been subjected to secondary recovery methods such as water-flooding and pressure maintenance is initiated by more advanced tertiary methods as seen in Fig. 1. Therefore, the oil industry has thus far implemented means to recover oil from more complicated zones, where the oil has been less accessible over the past, meaning that recovery techniques are constantly advancing. This led to the improvement of techniques applied for enhanced oil recovery, (EOR), which while used today, is constantly undergoing further advancement and improvement, as newer and more improved techniques are being employed. Current articles state that up to two-thirds of the liquid hydrocarbon remains entrapped in the porous media after primary and secondary recovery mechanism have been carried out in an average oil reservoir, (Rosen, 2005).

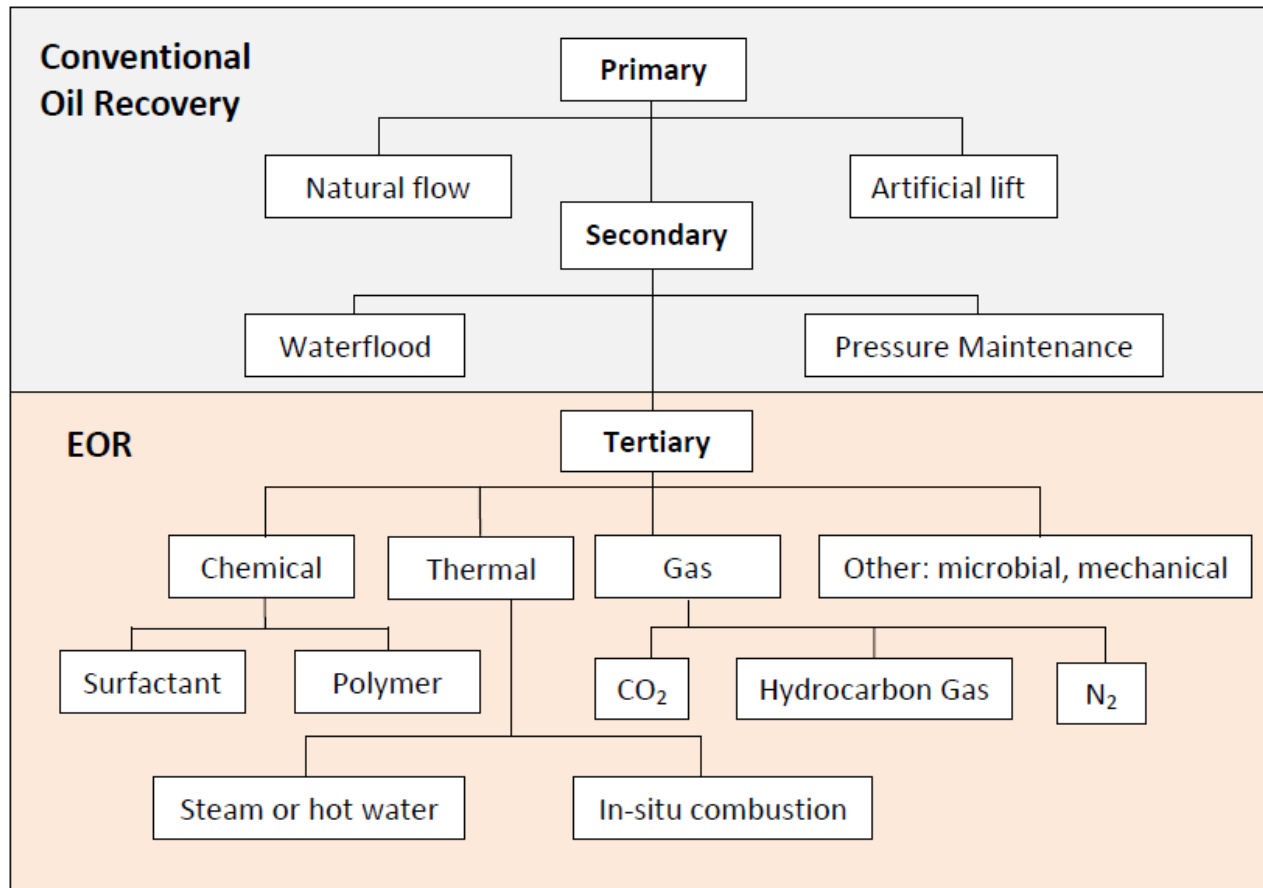


Figure 1. 1 Description of the Oil recovery Mechanisms from the Reservoir

EOR is initiated to optimize the depletion, as the remaining oil is trapped in the pore spaces in the reservoir. A large amount of the world's current oil production comes from mature fields.

The focus of this thesis was on the Surfactant alternating gas method of EOR which has Foam as a technique for gas diversion and has been proven useful in several enhanced oil recovery (EOR) practices (W. R. Rossen, & Wang, M. W., 1999). EOR looks at several different advanced recovery techniques that would be highlighted during this thesis work.

The use of foam for mobility control of gas has been implemented in several fields(Turta, 2002). The Foam was intended to propagate through the reservoir formation and improve sweep efficiency.

1.1 Thesis Organization

This first chapter investigates the background of EOR techniques. Chapter 2 reviews on some methodology involved in this EOR process and a Literature review on past works.

Chapter 3 describes the experimental apparatus and procedure, including the fluids, chemicals and material used for the experimental setup. To accomplish the proposed objectives, foam test which was done to analyse the stability of foam generated and displacement test on core-flooding to analyse the SAG process design were measured and completely carried out.

Chapter 4 outlines the results and discussion that presents a comparison of the results of WAG injection experiment with SAG injection experiments, the mixture of Sodium Lauryl sulphate and Sodium Dodecyl Benzoate surfactant solution with their respective individual solutions.

Chapter 5 lays conclusion on the work with some possible recommendations for future works.

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1.2 PROBLEM STATEMENT

During the process for enhancing Oil production via gas injection projects, we tend to face several challenges in the inefficient utilization of this gas, low sweep efficiency, and low incremental oil recovery due to gravity segregation, channelling and fingering. These are caused by rock heterogeneity as well as the low density and viscosity of the injected gas in heterogeneous formations, where gas tends to breakthrough early into the production wells due to this gravity overriding, fingering and channelling. Surfactant alternating gas (SAG) injection is one of the methods commonly used to reduce this challenge. The Foam which is formed by the contact of Carbon dioxide or Nitrogen and surfactant increases the viscosity of the injected gas. This brings about an improvement in the oil-gas contact, thereby inducing an increase in the sweep efficiency, besides the adsorption of surfactant on rock surface do pose some difficulties. These adsorption phenomena are looked at by considering the chemical characteristics of the surfactant candidate which has the tendency of not being fully adsorbed by the silica formation (sandstone). Several factors must be examined in the design of SAG injection process.

Foam can affect the oil recovery in three ways compared to gas or WAG (Water-Alternating-Gas) flooding:(R. Farajzadeh, Andrianov, A., Hirasaki, G. J., & Rossen, W. R., 2012): by

- (1) Viscosity increase of the displacing fluid (gas) thereby stabilizing the displacement procedure.
- (2) Blocking the high-permeable swept zones and diverting the fluid into the un-swept zones; and

(3) Reducing the capillary forces via reducing the interfacial tensions due to the presence of a surfactant.

Also, in the SAG design, another major challenge in its application, is the collapse of the foam at the foam front in contact with the oil front. We need to look at the stability – longevity of foam when it contacts the crude oil. The foam (i.e. foam films) must remain stable in the porous formation to be an effective recovery or blocking agent. Several experimental works have demonstrated the detrimental effect of oil on foam stability (Andrianov, 2012).

1.3 Study Goals and Objectives

The objective of this thesis study is to ascertain the best SAG design during injection which includes,

1. Identifying the best possible candidate for the surfactant to be used during a SAG injection project. This is considered by carrying out several experimental tests of mixing various classes of surfactant to obtain the best mix in terms of foam stability and longevity when in contact with the oil front. The stability of foam depends on several parameters such as the surfactant concentration, gas diffusion through foam films, salt concentration, gravitational drainage, and capillary pressure (Aronson et al., 1994).
2. Identify the best concentration of the surfactant solution that would result in the best oil recovery as well, not only in terms of adsorption challenges but also in terms of interfacial tension reduction likewise.
3. Demonstrate that oil has a significant impact on foam stability and foam front propagation in a SAG process.

4. Demonstrate that in a SAG process has a better Oil recovery than that of a WAG process.

2.0 METHODOLOGY AND LITERATURE REVIEW

2.1 ENHANCED OIL RECOVERY

Several mechanisms play a major role in the primary production of oil. Primary production in general is known to be rather inadequate, as it only recovers less than 20 % of the original oil in place (OOIP), [Morrow,1991, p.5]. With the goal of improving oil recovery, EOR is introduced, employing more efficient recovery methods. Oil recovery methods usually fall into one of the following three categories:

- ☐ **Primary recovery:** Recovery carried out by depletion
- ☐ **Secondary recovery:** Recovery carried out by either gas or water-flooding
- ☐ **Tertiary recovery:** Recovery involving targeting the residual oil (also known as Enhanced Oil Recovery (EOR))

EOR methods or techniques involve the addition of external energy and materials to a reservoir to control:

- ☐ Wettability
- ☐ Interfacial tensions (IFT)
- ☐ Fluid properties
- ☐ Establish pressure gradients necessary to overcome retaining forces

- Move the remaining crude oil in a controlled manner towards a production well.

2.1.1 EOR Processes

The key goals in EOR operations are to displace or alter the mobility of the remaining oil in the reservoir. The common classifications of different EOR processes are (Green D.W. and Willhite, 1998):

- *Chemical processes*
- *Thermal Processes*
- *Miscible processes*
- *Mobility-control*
- others, (e.g. microbial EOR)

In general, the EOR processes involve an injection of gas or fluids into the oil reservoir, displacing crude oil from the reservoir towards a production well. The injection processes supplement the natural energy present in the reservoir. Interaction occurring with the injected fluid, the rock and oil trapped in the reservoir does create advantageous conditions for oil recovery.

Chemical processes involve an injection of a certain chemical liquid that proficiently creates desirable phase behaviour properties, to improve oil displacement. This principle is shown in figure 1.2. Example of such processes are Surfactant flooding, alkaline flooding and other known alcohol flooding. While in the case of alkaline flooding, chemicals with alkaline properties are put into the reservoir, where they react with certain oil components to generate surfactants in situ. Alcohol processes are novel

processes which so far has only been tested in laboratories and are yet to be applied in the field.

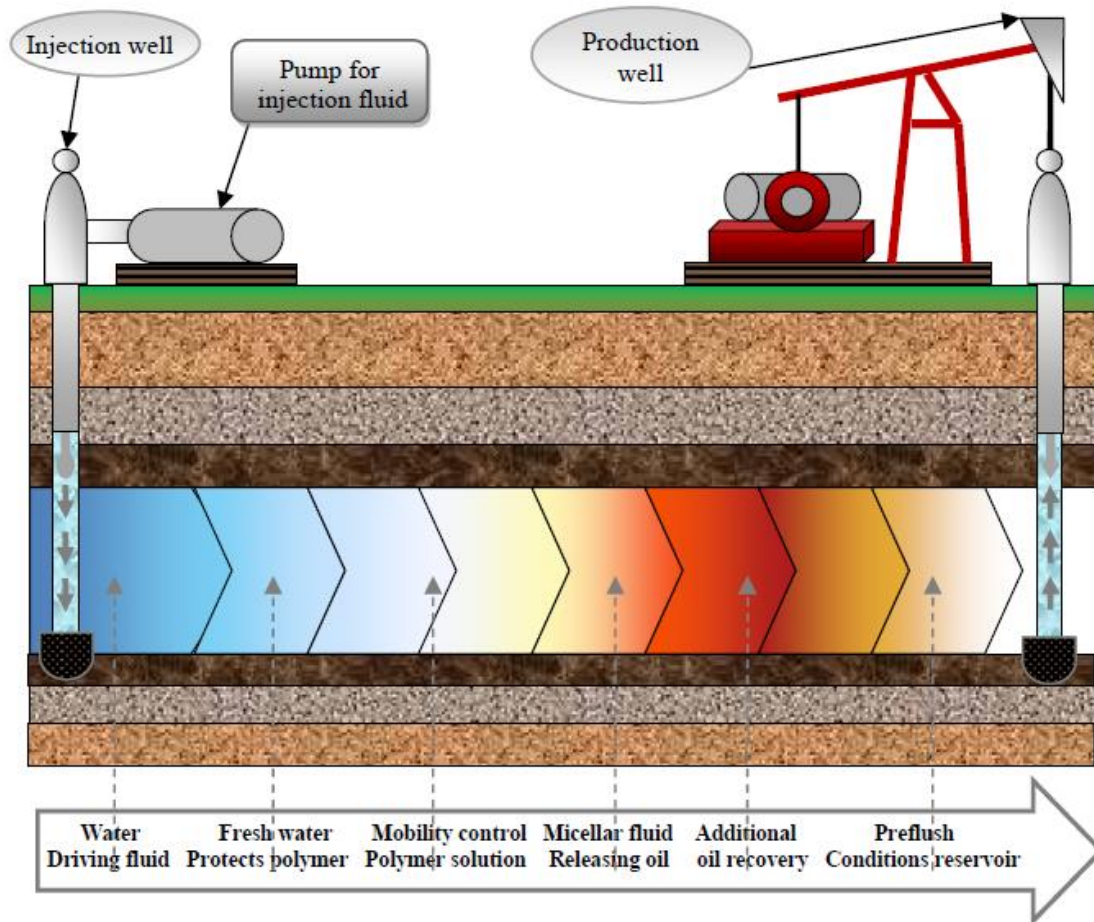


Figure 1. 2. Chemical flooding, which is the injection of water and chemicals.

Thermal processes are typically applied to heavy oils. Thermal recovery processes rely on the use of thermal energy. In this scenario, a hot steam, water or a combustible gas is injected into the reservoir to rise the temperature of the trapped oil and gas, thereby reducing oil viscosity [Green and Willhite, 1998, p.301]. The process is depicted in figure 1.3. The hot stream which is injected into the reservoir enables the flow to the

production wells by increasing the pressure and reducing the resistance to flow.

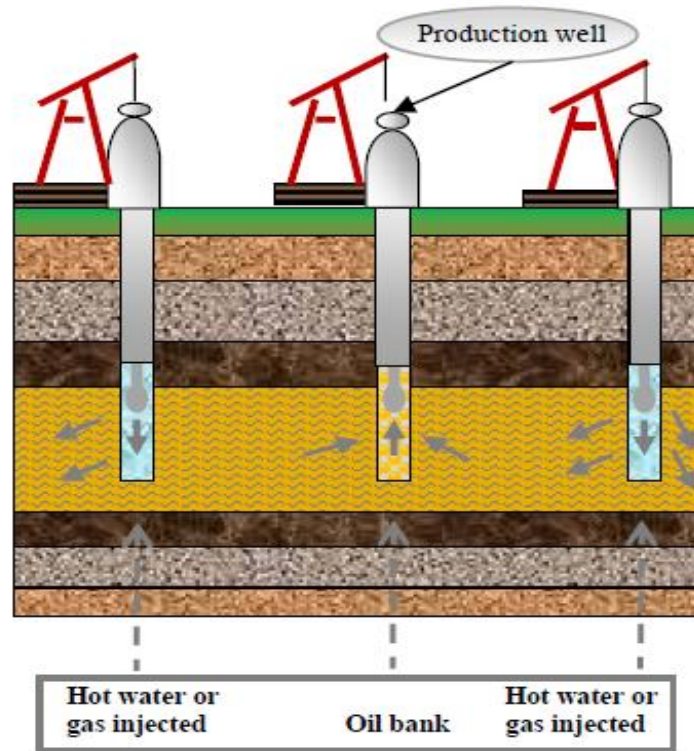


Figure 1. 3 Thermal process of EOR. Mobilization of the trapped oil towards the reservoir

Miscible processes are based on the injection of a gas or fluid, which is miscible with the crude oil at reservoir conditions, to mobilize the crude oil in the reservoir. The process is illustrated in figure 1.4. This process relies on the alteration of the mechanisms either in the injected phase or in the reservoir oil phase. The injection of CO₂ as a liquid will entail extraction of the heavier hydrocarbons from the reservoir oil, which will allow the displacement front to become miscible (Holm, 1986).

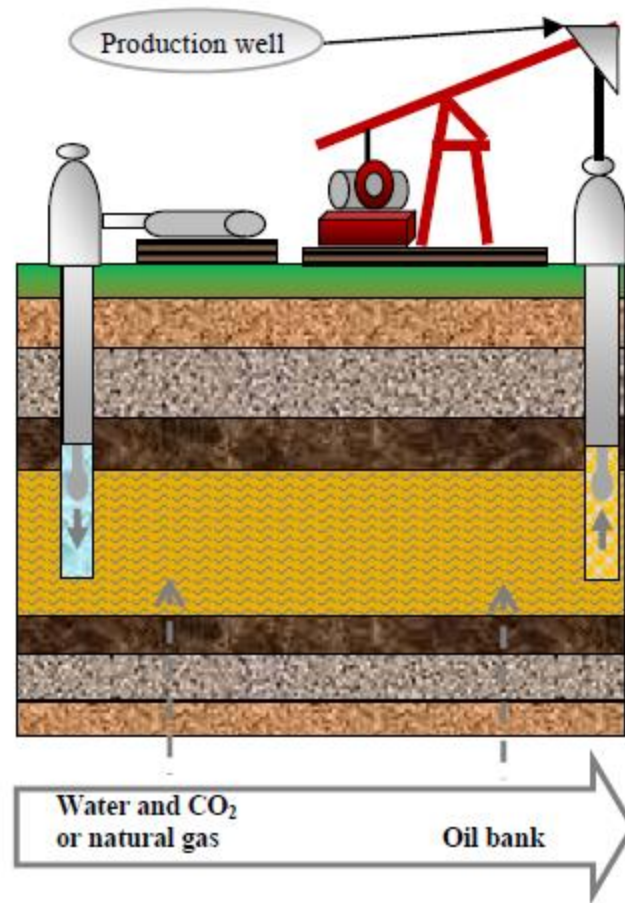


Figure 1. 4 Miscible process control, where the injected fluid does mix with oil. In this process, the oil is supposed to be mobilized while mixed with either injected gas or fluid.

Mobility-control is a process based on maintaining favourable mobility ratios between crude oil and water, by increasing water viscosity and decreasing water relative permeability. Can improve sweep efficiency over water-flooding during surfactant processes.

2.2. EOR STRATEGY (Principles of EOR)

2.2. 1 MOBILITY CONTROL

In EOR operations, the one common aspect which poses a challenge of which has a considerable influence on the result is the ability to control the flow of the displacement fluid, so-called mobility control. Since flow pattern prediction is very uncertain, predicting oil recovery becomes difficult. These uncertainties challenge EOR processes. While it is desirable to design the most efficient process in order to increase oil recovery, the economic feasibility of the EOR process is more crucial than any other aspect, in order to commercialize the process (Sharp, 1975).

The study of EOR methods and process requires one to fully understand the movement of fluids in and out of the porous media, velocities of their movement and the recovery factor of what was produced.

The overall efficiency of an EOR process comprises microscopic efficiency and macroscopic efficiency, written as:

$$E = E_D \times E_V$$

Where E is overall efficiency (fraction), E_D is microscopic displacement efficiency (fraction), and E_V is macroscopic volumetric efficiency (fraction).

Microscopic efficiency quantifies recovery on the pore scale. Good miscibility between fluids, decreasing interfacial tension between the fluids, oil volume expansion, and reducing oil viscosity can improve this efficiency. With this, we going to be considering various definitions of these terms as well as the fractional flow of displacement of fluids in the reservoir, displacement front.

2.2.2 MICROSCOPIC DISPLACEMENT EFFICIENCY

Assuming we are to regard a constant oil density, the displacement efficiency for oil can be defined as oil initially in place that is recovered from the reservoir volume due to displacement by an immiscible fluid in these places in the rock where the displacing fluid contacts the oil.

$$E_D = \frac{\text{Amount of oil displaced}}{\text{Amount of oil contacted by displacing fluid}}$$

E_D ranges from 0 to 1. The rate at which E_D gets to 1 is accountable by the initial conditions, the displacing fluid, and the amount of displaced fluid. Rock, rock-fluid properties and fluids also affect the displacement efficiency.

Basically, the understanding of EOR displacements starts with a clear grasping of the knowledge of the displacement of one fluid by another immiscible fluid. The law of simultaneous flow of immiscible fluids, as known as fractional flow in porous media for two phases was solved by Buckley and Leverett (1942).

The fraction of water in the flowing stream at any point of the flooded rock is:

$$f_w = \frac{q_w}{q_{tot}} \dots\dots\dots (1.1)$$

where q_w = flow rate of water and q_{tot} = total flow rate of fluid in the system

which when applying the generalized Darcy equation into this equation,

$$q_o = -k \frac{k_{ro}}{\mu_o} A \left(\frac{\delta p_o}{\delta l} - g p_o \sin \alpha \right) \quad (1.2)$$

$$q_w = -k \frac{k_{rw}}{\mu_w} A \left(\frac{\delta p_w}{\delta l} - g p_w \sin \alpha \right) \quad (1.3)$$

by subtracting both eqn. 1.2 & 1.3 with the inclusion of following the capillary pressure equation:

$P_c = p_o - p_w$ and the addition of $q_{tot} = q_o + q_w$

We obtain:

$$\frac{1}{kA} \left[q_w \left(\frac{\mu_w}{k_{rw}} + \frac{\mu_o}{k_{ro}} \right) - q_t \frac{\mu_o}{k_{ro}} \right] = \frac{\partial P_c}{\partial l} - g(\Delta p \sin \alpha) \quad (1.4)$$

By implementing the water fraction $f_w = \frac{q_w}{q_{tot}}$ and dividing eqn by q_t we obtain the fractional flow equation:

$$f_w = \frac{\frac{\mu_o}{k_{ro}} + \frac{kA}{q_t} \left(\frac{\delta P_c}{\delta l} - g \Delta p \sin \alpha \right)}{\frac{\mu_w}{k_{rw}} + \frac{\mu_o}{k_{ro}}} \quad (1.5)$$

f_w is a function of water saturation, thus an oil of medium viscosity and density, the fractional flow curve is represented qualitatively as :

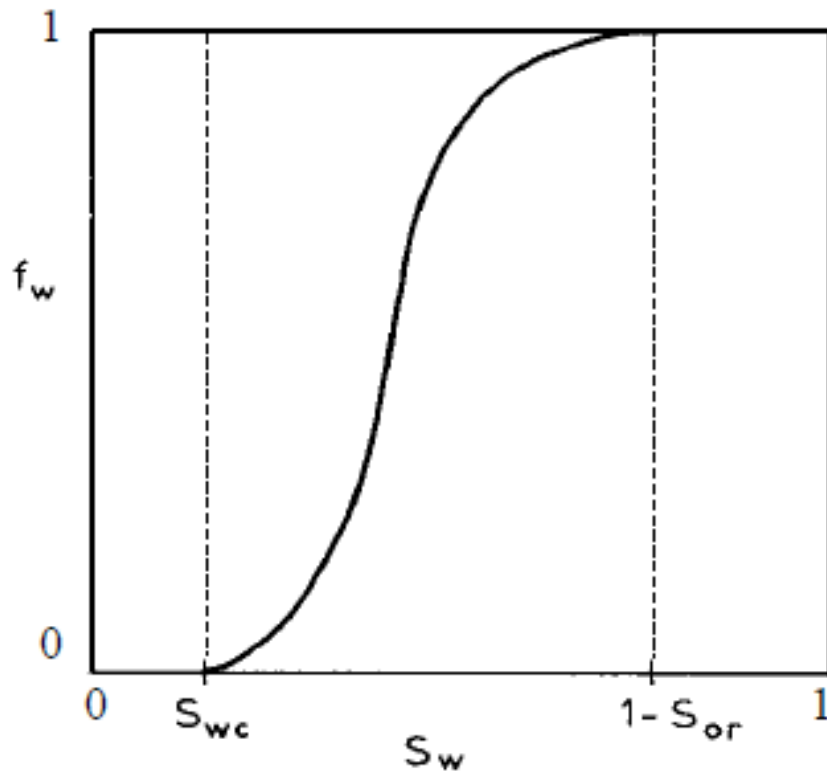


Figure 2. 1: Fractional flow curve (Verga 2012)

From the fractional flow equation, it can be seen that:

1. A higher oil viscosity results in a less efficient displacement as the water fraction subsequently becomes high as vice versa.
2. A higher apparent velocity of the displacing front results in a less efficient displacement, where apparent velocity of displacing front $= \frac{q_t}{A}$

Thus, as the total flow rate is reduced, the apparent velocity of displacing front is also reduced.

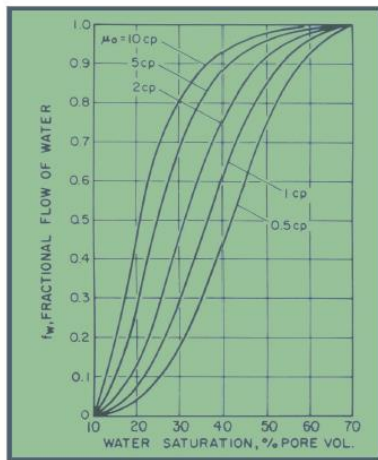


Figure 2. 2: Effect of oil viscosity on f_w (Verga 2012)

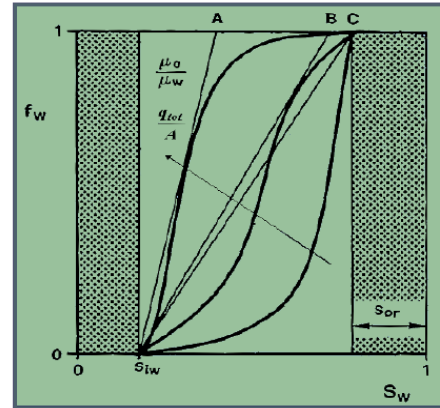


Figure 2. 3: Effect of flow velocity on f_w

The forces acting on the fractional flow are categorized in three terms:

$$F_w(S_w) = \underbrace{\frac{\lambda_w}{\lambda_w + \lambda_o}}_{(1.)} + \underbrace{\frac{\lambda_w \lambda_o \Delta p g \sin \theta}{(\lambda_w + \lambda_o) v}} + \underbrace{\frac{\lambda_w \lambda_o}{(\lambda_w + \lambda_o) v} \frac{dP_c}{dx}}$$

Viscous term

Gravitational term

Capillary term

λ_w = water mobility

λ_o = oil mobility

k = absolute permeability

Δp = density differences

v = apparent front velocity

and as thus, to have a profitable productivity from the reservoir, the viscous term should be minimized which thereby increase the oil productivity by either increasing μ_o / μ_w or increasing k_{ro} / k_{rw} .

2.2.3 MACROSCOPIC DISPLACEMENT EFFICIENCY

Areal sweep is influenced by injection/production well pattern, reservoir permeability heterogeneity, mobility ratio, and relative importance of gravity and viscous force. Vertical sweep is controlled primarily by gravity segregation caused by density difference, mobility ratio, vertical to horizontal permeability variation, and capillary forces

2.2.4 Areal Displacement Efficiency: The oil recovery for gas injection exploitation strategy mainly depends on the displacement efficiency, and this displacement efficiency is largely affected by gas and oil, mobility ratio (M) defined as:

$$M = \frac{k_{rg} / \mu_g}{k_{ro} / \mu_o} \quad (1.7)$$

Where the incorporation of the maximum end-point relative permeabilities means that, by direct application of Darcy's law, the mobility ratio represents

$$M = \frac{\text{maximum velocity of the displacing phase}}{\text{maximum velocity of the displaced phase (oil)}}$$

In eqn. 1, relative permeabilities, k_{rw} and k_{ro} is for water and oil, respectively, while viscosities, μ_w and μ_o are of water and oil,

respectively. Mobility ratio plays a crucial role in the displacement behaviour of this method.

With a mobility ratio of $M > 1$, the displacement becomes unfavourable as the displacing fluid will finger or tongue or channel through the oil, leading to an early water breakthrough, this is due to the increase of the front velocity as can be seen in figure 2.4.

Secondly, with a mobility ratio of $M < 1$, the front velocity decreases as the front moves along the layer thereby initiating a piston-like displacement of oil in a homogenous core-flooding experiment, resulting in a more stable displacement as the advancing displacing fluid is more stable as shown in figure 2.5

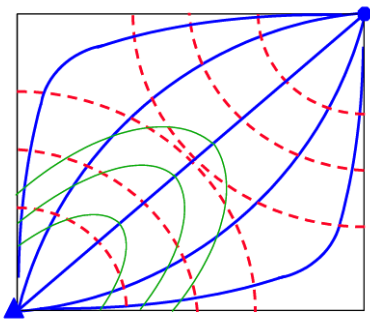


Figure 2. 4: Increasing front velocity as $M > 1$
front velocity as $M < 1$

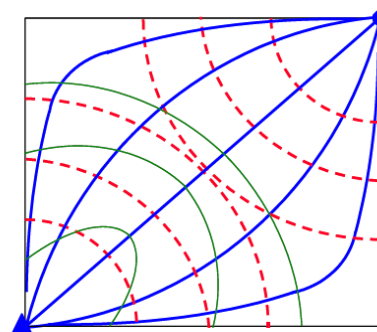


Figure 2. 5: Decreasing

(Verga 2012)

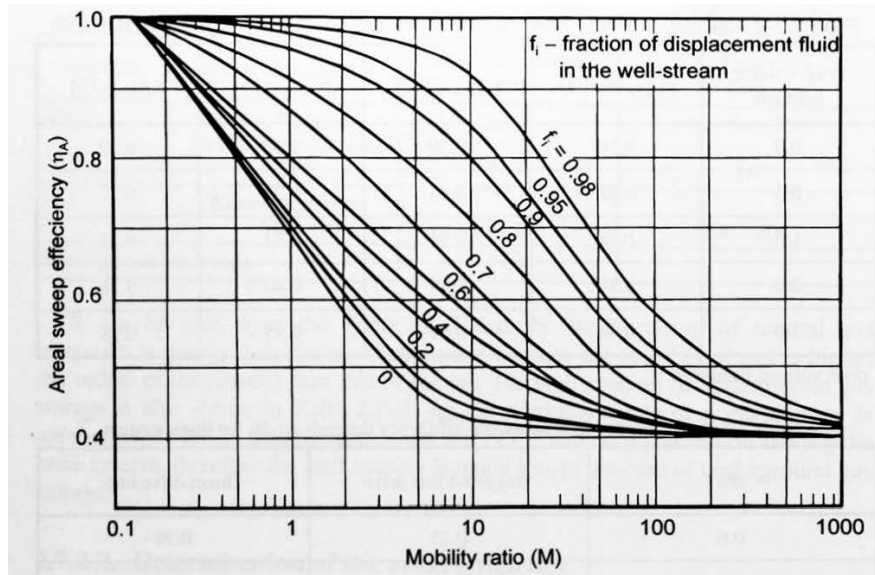


Figure 2. 6: Sweep –out pattern efficiency as a function of mobility ratio (Slobod, 1952)

2.3.0 EOR MOBILITY CONTROL METHODS

2.3.1 Water Alternated Gas (WAG)

A process known as WAG injection is also a method to initiate this mobility control of gas injection using water, thereby stabilizing the displacement front. This is by the injection of water and gas in alternating volume, to displace the oil in a reservoir. Gas injection is usually more efficient than water injection in terms of microscopic displacement of oil. WAG is imperatively a more preferred alternative to pure gas injection because it combines improved displacement of the gas flooding with an improved macroscopic sweep of water injection. Apart from mobility control, other advantages of using the WAG process is regarding it being environmentally favourable when it comes to reinjection of gas for storage purposes (Christensen, 2001)

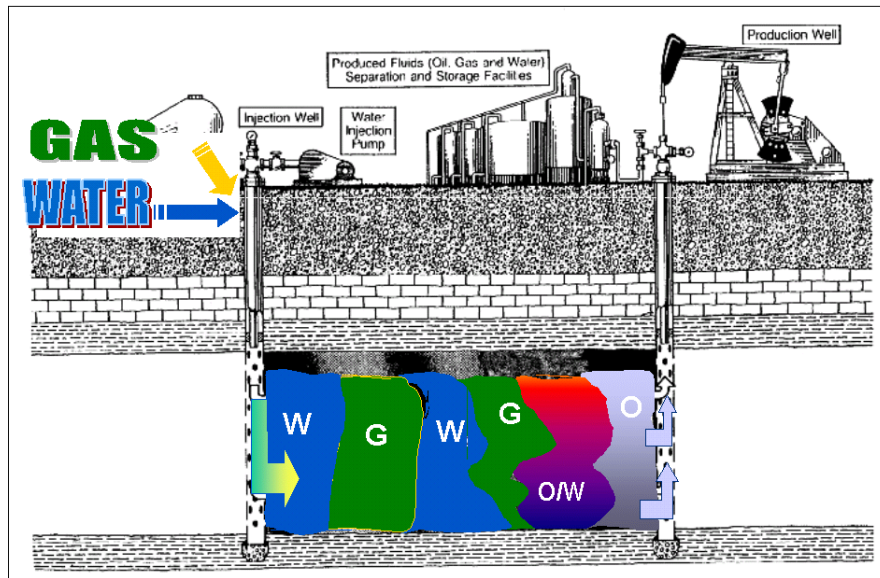


Figure 2. 7: *Schematics of a water-alternating-gas flood for enhanced oil recovery (U.S Department of Energy, 2013)*

Immiscible/miscible: The WAG process can either be immiscible or miscible. Deciding on which should be used is reportedly based on availability and economic considerations. Looking at a total of 60 projects being reviewed by Christensen (2001), 79 % were applying miscible WAG injection, mostly at onshore reservoirs. Most of these projects were repressurized so that reservoir pressure exceeds minimum miscibility pressure of the fluids. In a WAG injection process, the first gas slug could potentially dissolve into the oil, resulting in a favourable change in the fluid viscosity/density relations at the displacement front. This results in the displacement becoming near-miscible (Christensen, et al., 2001).

Injection Gas: Hydrocarbons and non-hydrocarbons gases such as Nitrogen, and Carbon dioxide are the most used gases in a WAG method. Most offshore projects use hydrocarbon gas in their WAG injection process due to the vast availability of this gases directly from production wells. Reports from articles showed that 24 out of 60 reviewed fields had used hydrocarbon gas and some Nitrogen gas (Christensen, et al., 2001).

Injection Pattern: The five-spot injection pattern is the most used for WAG onshore. Four injection wells are placed in a box-like shape, with the producing well in the centre (Dai, 2013), as can be seen from Figure 2.8.

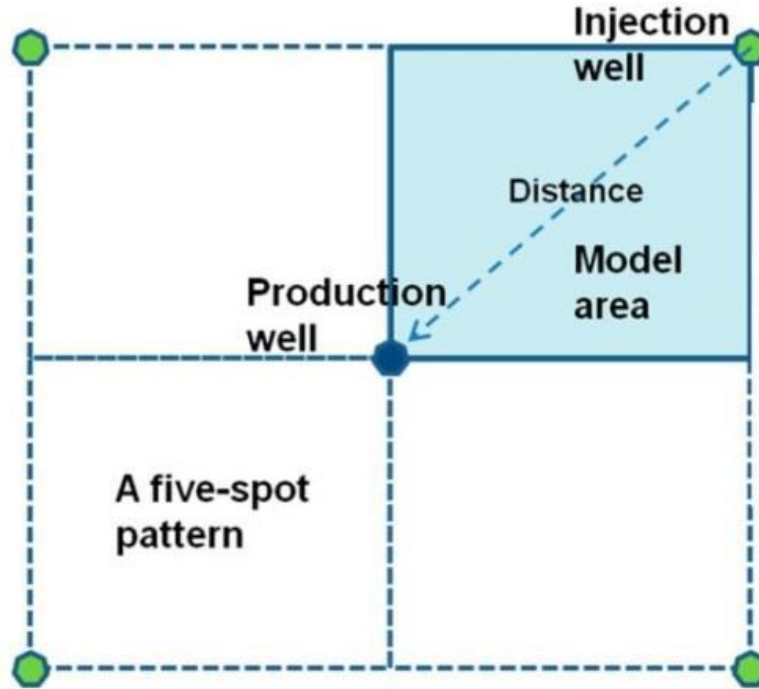


Figure 2. 8: Schematics of a five-spot well pattern consisting of four injection wells and a production well in the centre (Dai, et al., 2013)

WAG Ratio: It is very important to find the optimum WAG ratio before starting the injection process. In field applications, the widely used WAG ratio is 1:1, implying that the gas and water cycles are equal in quantity. It is influenced by the rock's wetting state (Zahoor, 2011). Water-wet bead packs have shown optimum WAG ratio of 0:1 (gas injection), while oil-wet packs imply that 1:1 is the optimum WAG ratio (Rogers, 2001). Typical cycle times range from months to a year (NETL, 2011). Recovery efficiency has been proven to be a function of both the injection rate and the WAG ratio (Al-Shuraiqi, 2003). Injecting below the optimum WAG ratio (more gas than water) creates viscous instability. On the other hand, injecting above the optimum WAG ratio (more water than gas) has shown a tendency to

stabilize the process, but lower the efficiency of displacement as production becomes prolonged (Rogers, 2001).

2.3.2| FACTORS INFLUENCING INJECTION PROCESS

Some simple relations will be presented that provides insight into the advantages of WAG injection.

The overall efficiency of an EOR process comprises microscopic efficiency and macroscopic efficiency.

Gas injection is good in giving a high value of microscopic efficiency. Immiscible gas injection can give residual oil saturation up to 50% while miscible gas injection theoretically can reduce oil saturation to 0%.

Macroscopic volumetric efficiency is defined as the fraction of the reservoir volume which is contacted by an injected fluid. As explained previously, it can be divided to areal and vertical sweep.

Volumetric Sweep Efficiency: The oil recovery for Water alternate gas injection exploitation strategy mainly depends on the displacement efficiency, and this displacement efficiency is largely affected by gas and oil, mobility ratio (M).

Mobility ratio plays a crucial role in the displacement behaviour of this method. A mobility ratio of $M > 1$, makes the displacement process unfavourable due to the fingering or channelling of gas through the oil, thereby bypassing it which results in an early gas breakthrough, caused by the high velocity of the gas. Thus, this challenge led to the introduction of a method known as Surfactant Alternating gas (SAG) that induces a mobility control of gas, where the gas relative permeability is greatly

reduced due to the formation of foam. The effective viscosity of the gas is increased thereby initiating a piston-like displacement of oil in a homogenous core-flooding experiment whereby $M < 1$ resulting in a more

stable displacement. Foam leaves the water relative permeability and viscosity unaltered.

In addition to mobility ratio, heterogeneity, such as high permeable layers in the reservoir, may also cause the sweep to become inefficient in terms of the WAG methods.

Miscible gas injection has good microscopic sweep efficiency but poor macroscopic sweep efficiency because of viscous fingering and gravity override (Al-Shuraiqi, et al., 2003). However, water-flooding is less susceptible to gravity segregation and unstable displacement fronts. The disadvantage, however, is its poor oil recovery efficiency whereby large volumes of residual oil left behind, which makes it a less than optimal injection strategy.

Bypassing Mechanisms: there is the need to clearly comprehend all important bypassing mechanisms that is encountered in the WAG process, as explained by (Stern, 1991).

1. Viscous fingering is a phenomenon that occurs due to the macroscopic heterogeneities as well as mobility contrasts between oil and solvent. Because of these heterogeneities, the solvent finds a preferred path where most of it flows through as shown in Fig 2.9. This result is a minimal additional oil being recovered. This bypassing mechanism can be counteracted through mixing between solvent and oil, reducing mobility contrast at the displacement front.

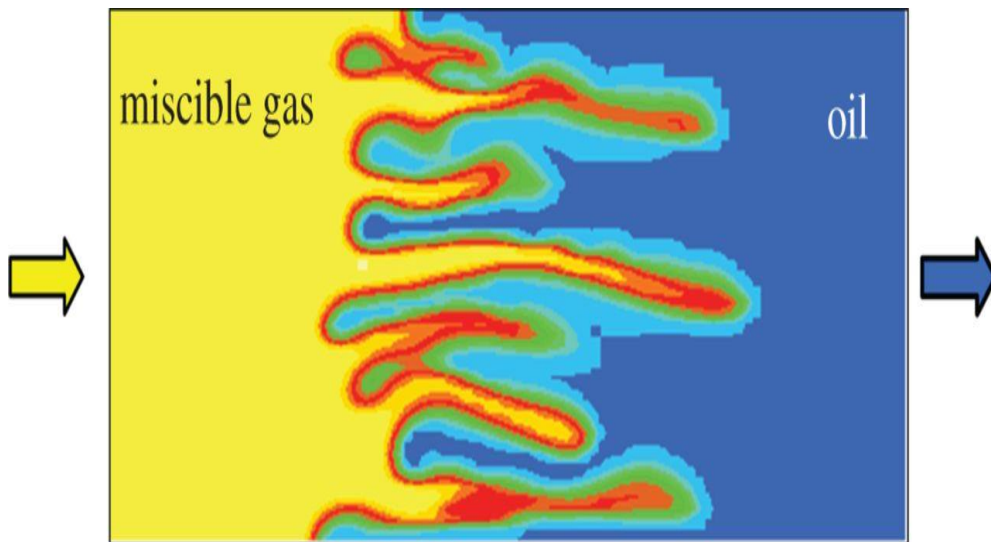


Figure 2. 9: Simulation diagram of viscous fingering

Gravity Segregation: During the WAG injection cycle, fluids do segregate themselves as seen in Figure 2.10, once there is a significant occurrence of vertical permeability and clear evidence of density differences between the respective fluids thus resulting in gases moving upwards and away from the wells, while water moves downwards. (Johns, 2013).

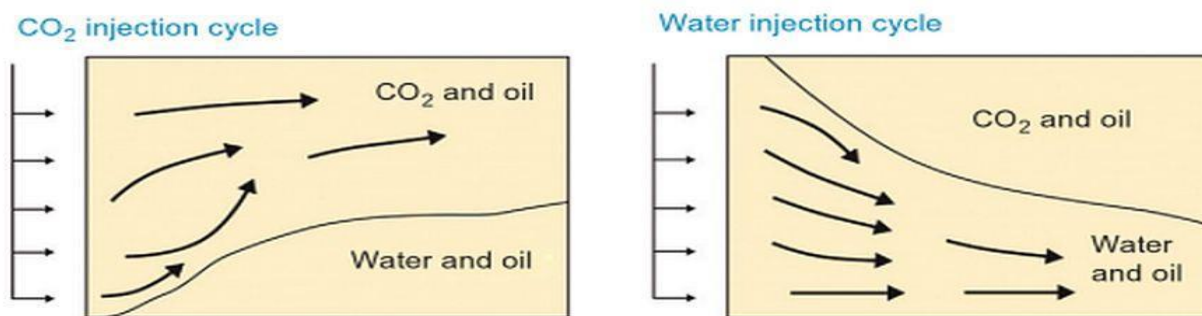


Figure 2. 10: Showing as gas move upwards and water downwards during a WAG, owing to the nature of their densities (Johns & Dindoruk, 2013).

2.4 SURFACTANT-ALTERNATING-GAS (SAG)

2.4.1 | GENERAL DESCRIPTION

Foam is generated when and injected gas encounters a surfactant solution, thereby resulting to the reduction of the injected gas viscosity. Although foam can improve sweep efficiency, direct injection of pre-generated foam would not be practical because of its poor injectivity. Experiences from the field suggests that its injectivity can be improved by alternating slugs of gas and surfactant, resulting in foam creation inside the porous media (R. Farajzadeh, Risjwijk, Eftekhari, A., Hajibeygi, H., Meer, J. v., Vincent-Bonnieu, S., et al. , 2015). This is referred to as surfactant-alternating-gas (SAG) and is operationally like WAG.

Problems such as early gas breakthrough caused by override, fingering and channelling of gas can be mitigated by SAG injection process because of its foam generation which directly reduces gas mobility (Larry Lake and Rossen, 2014).

The primary purpose of this process is to deliver gas to contact a greater volume of the reservoir which results in an increased microscopic displacement efficiency (Larry Lake and Rossen 2014). The Loss of surfactant due to adsorption is one critical factor to be considered when bearing in mind the economic feasibility of the SAG injection process.

In this regard, the concentration of the surfactant to be used must be Before SAG can be optimized, the concentration of surfactant must be augmented before the SAG injection process can be optimized (Salehi, et al., 2014).

2.4.3| SAG DESIGN

It is of utmost importance to consider certain factors before choosing the appropriate foam injection strategy. The options are surfactant-alternating-gas, co-injection or pre-formed foam. Operating fields often consider reservoir pressure, permeability and the expected duration of surfactant injection as very important. For the SAG process, it is mainly applied in high-pressure formations that possess low permeability that ranges from medium to low surfactant concentrations (Turta & Singhal, 2002).

Surfactant Selection: One critical factor to note in foam flooding is in the selection of a suitable surfactant. Considering the reservoir formation rock determines which surfactant to be chosen. This is to prevent large amounts of surfactants to adsorb to the surface of the rocks. A cationic surfactant, for instance, has a positively charged head group and negatively charged tail and cannot be used in a sandstone formation because its positively charged head would bind towards the negatively charged sandstone surface leading to a great loss of surfactant as they are being adsorbed into the surface of the rock. However, it can be used in a carbonate formation as the surfaces have a positive charge which repels its positively charged head.

Fixed-Rate or Fixed-Pressure: Fluids can either be injected at fixed injection rates or fixed injection pressure. It has been reported by Shan & Rossen (2002) that SAG injection is optimized at fixed maximum-allowable injection pressure for a homogeneous reservoir. This is solely based on minimizing both injection time and gravity override, and to keep at minimal the increase in injection well pressure. Injecting gas at maximum pressure allows for effects of gravity slumping for the surfactant to partially reverse. Gas could also override the

surfactant due to their density differences as discussed in the case of WAG, whereby gravity may pull the surfactant solution downwards and the gas upwards. The process of fixed injection pressure is also very insensitive to foam properties (Shan, 2002). For heterogeneous reservoirs, (Renkema, 2007) concluded that a maximum-fixed-pressure also renders the best results. However, different slug injection strategies were recommended.

It has been detected that the utilization of SAG at fixed injection pressures are rarely affected by gravity override as much as continuous foam injection or SAG at fixed injection rates. Rather, gravity override can be overcome without reaching excessive injection pressures (Shan & Rossen, 2002).

Single- or Multi-Cycle: One important factor to take note of in the designing of a SAG injection process in the field is the slug sizes. Single-cycle SAG talks about a process where one large slug of surfactant is injected, followed by one large slug of gas. The other process is called multi-cycle SAG. This is where slugs of surfactant are alternated with slugs of gas in two or more cycles (Renkema & Rossen, 2007).

Simulation results, based on fractional flow theory from (Shan & Rossen, 2002), deduced that the optimal injection strategy that gives a better sweep efficiency in the reservoir is the injections of a single large slug of surfactant followed by a large slug of gas. In the single-cycle SAG, the piston-like sweep helps to push surfactant ahead, optimizing surfactant propagation in the reservoir. These cases were concluded for a homogeneous reservoir model (Shan & Rossen, 2002).

2.5 FOAM

2.5.1 | DEFINITION

Foam is constituted by of a gas dispersed in a continuous liquid phase where the gas pockets are separated from each other by thin liquid films called lamellae as shown in figure 2.11 (L. L. Schramm, 2005). The junction that connects three lamellae is referred to as a plateau border (NETL, 2011). Foam is generated when there is a liquid disturbance where the liquid contains a small amount of foaming agent, known as *surfactant*, is contacted by a gas. A surfactant is essential to generate foam and keep it stable. Without it, foams are unstable and quickly break down (Sheng, 2013). Foam can substantially induce a mobility control on the gas by triggering a reduction in gas flow in porous media, which forces gas to sweep pores that it would not have reached without foam [Farajzadeh, R. 2012].

There are three methods to inject foam into porous media: (1) co-injection of gas and surfactant solution, (2) alternating injection of surfactant solution and gas slugs (SAG) and (3) the injection of pre formed foam(foam generated outside the porous media by using a foam generator at the surface)(Jensen, 1987).

The amount of gas volume present in a foam connotes the quality of the foam. Bubble size refers to the average diameter and distribution of bubble sizes. Foam quality and its bubble size are the most phenomenon used in characterizing a foam. There is a correlation between the quality of foam and its bubble size. As the bubble coalesces, the foams become less stable, resulting in a lower foam quality (Sheng, 2013).

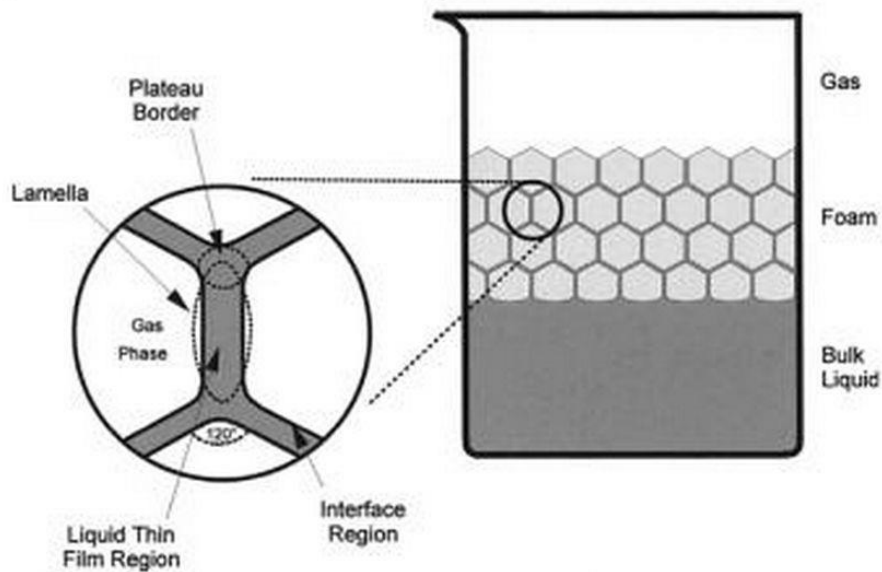


Figure 2. 11: A container filled with gas and liquid, with surfactant solution, generates foam if mixed. Gas bubbles are separated by thin liquid films (lamellae) stabilized by surfactants (Schramm, 2005).

2.5.2| STABILITY

Foams are not stable, they eventually will collapse over time. Stability of foam is dependent on several factors presented by (Sheng, 2013), which will be discussed.

2.5.3. General bulk foam stability theory

Foams apparently consist of gas bubbles which are trapped in a liquid. In this research the liquid consists of water, which comprises of surfactant and electrolyte (NaCl). A thin foam films formed does consist of two monolayers of surfactant molecules, with the aqueous phase in between. The repulsive forces between the surfactant monolayers cause static stability. The charged groups at the interface will cause an electrostatic repulsive force between ionic surfactants. For non-ionic surfactants static stability is achieved by the overlap of hydrophobic tails which cause steric repulsion (Katgert, 2008.).

Foams stays stable for a finite period. There are three (interlinked) mechanisms that contribute to the destabilization and finally destruction of foam. The three mechanisms are: Coarsening, liquid drainage and collapse.

Coarsening is the diffusion of gas from one gas bubble to another bubble. The pressure over the gas liquid interface can be described by Laplace's formula. The Laplace formula states that the pressure difference between gas inside the bubble, and liquid outside of the bubble, is inversely related to the bubble radius (R) see Eq. (2), therefore the pressure in smaller bubbles is higher than in larger bubbles, and therefore gas will flow from relative small bubbles to large bubbles. Liquid drainage is the situation whereby there is liquid film that is situated between the two foam bubbles and in the plateau, borders starts flowing downward due to gravity and due to capillary suction in the plateau borders. Over time, foam bubbles will have less liquid between each other.

Collapse is the phenomenon of two bubbles merging when in contact to form a single foam bubble

$$P_c = P_{gas} - P_{liq} = \frac{2\sigma}{R} \text{ for Spherical bubbles (2)}$$

Effect of Oil: One critical issue concerning foam injection in reservoirs is the stability of foam in the presence of oil. In order to achieve good mobility control, it is important that foam remains stable when contacting the oil (Simjoo, 2013). The spreading of oil over the foam film results in the breaking of the film over time as the oil displaces the water in the film. Afterwards, an unstable oil film is left behind that breaks easily. The destabilization of foam by oil do occur in several ways: (1) Surfactants partitioning in the oil phase, reducing the surfactant concentration at the gas-water interface. (2) Oil spreads on the foam lamellae, displacing the interface originally stabilizing the foam (Farajzadeh, et al., 2012). (3) Oil generating emulsions which allows drops to break out and rapture the stabilizing interface. (4) Oil droplets blocking certain parts of the porous media where bubble snap-off is inhibited, thus preventing foam

generation to occur. Lighter oils are known to destabilize foam the most. Foams with intermediate to low tolerance for oil may be adequate if injected into low oil saturation zones for mobility control (Schramm, 2005). Currently, there have been researches ongoing, to find the right design of surfactant that produces a foam which is quite stable at the oil front when in contact with the oil. These are known as foam boosters.

2.6. FOAM FIELD AND LABORATORY APPLICATION

Eson and Cooke (1989) were the first to review field applications of EOR foams, and later Hanssen et al. (1995) published more advanced EOR foam reviews.

The Snorre field operated by Statoil was the world's largest foam EOR application in the oil industry, with injection of 2000 tons of commercial grade alpha olefin sulfonate (AOS) surfactant and consisting of three injectivity tests, one full scale SAG test and one full scale co-injection test (Sheng, 2013). The objectives of the field trial of Snorre SAG project were to (1) increase the sweep efficiency while carrying out a gas injection, (2) minimize the amount GOR produced in production well P-39.

Many gas injection projects are facing problems that involve inefficient utilization of gas, reduced sweep efficiency and minimal oil recovery. This is mainly caused by channelling, fingering and gravity segregation. These phenomena are often attributed to low viscosity and density of the injected fluid, as well as heterogeneity of the reservoir. By use of in situ foam generation, achieved through co-injection of gas and surfactant, or surfactant-alternating-gas, these drawbacks can be mitigated (Farajzadeh, et al., 2012).

In 1958, Bound and Holbrook patented the gas-drive process, using a surfactant to improve sweep efficiency by a generation of foam (Boud, 1958). Foam mechanisms and flow behaviour has been studied extensively since then.

SAG injection into carbonate rocks has been studied (Gandomkar, 2012), demonstrating an increase in microscopic sweep efficiency, which is caused by in situ foam generation. Gas displacement efficiency has been reported by others to improve during a SAG injection (Albrecht, 1970), (Yaghoobi, 1998), (Salehi, et al., 2014).

The success of gas diversion in a SAG process has been shown to depend on steady-state (constant saturation) foam behaviour at very high foam quality (Xu., 2003).

Salehi, et al. (2014) showed the importance of optimization of surfactant type and concentration as well as SAG ratio to get optimal recovery results. SAG, with no previous injections, recovered more oil than water-flooding, gas injection and WAG.

In this project, the effect of SAG ratio on the recovery efficiency of oil was determined at a laboratory experimental scale. This work displays that recovery from SAG is dependent on the SAG ratio at certain temperature and pressure. Also, the stability of the foam was investigated to determine the rate of decay of the foaming agent with respect to reservoir temperature and pressure. Although, the SAG process being a continuous and dynamic injection process, the rate of collapse was not much of a challenge in relation to the adsorption of the surfactant by the rock. This challenge was looked at as well by practically conducting various candidates of surfactant

with the right chemical structure that deters it from being adsorbed fully by the sandstone rock. Also, optimizing of surfactant concentration decreases the cost of surfactant due to lower adsorption of surfactant on sandstone rock.

3. LABORATORY EXPERIMENTAL APPARATUS AND PROCEDURE

The experiment conducted for this project was done at the laboratory of Miskolc institute. Firstly, the best surfactant candidate for the SAG test was conducted by the chemistry laboratory team after considering the nature of surfactant that get that has low affinity in getting adsorbed by the rock. A cationic surfactant is easily adsorbed onto the reservoir rock, thus an anionic surfactant Sodium lauryl sulphate (anionic surfactant) mixed with Dodecyl Benzoyl Sulfonate was used after some rigorous testing to ascertain its viability. Due to its negative charge, it could not be attracted to the also negatively charged surface of the silica rock. The blend of surfactant used was a mixture of Sodium dodecyl sulphate, synonymously sodium lauryl sulphate, (anionic surfactant) with Sodium dodecyl benzenesulfonate which is an organic compound. Both classes of surfactant in the experimental work for this project was conducted in two major phases.

n-decane (nC16) was utilized in investigating the influence of oil on foam stability. We used 50 ppm of oil-soluble red dye to dye the oil, which helped us visualize the oil in the foam and surfactant solution. This dye has no chemical interaction with the experiment conducted. All the measurements and tests are carried out at atmospheric pressure and at ambient temperature (22 ± 1 °C).

Surfactant	Charge	CMC(g/l)	Molar Weight(g/mol)
Na (+) Lauryl Sulphate (-)	anionic	0.2	288
Na (+) Dodecyl Benzene	Anionic	0.17	348

Sulphate (-)			
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Table 3. 1: *References of surfactant with their charge, CMC and molar weight*

Surfactant solutions	Concentration (g/l)
Sodium lauryl sulphate	0.6; 1.0; 5.0; 10
Dodecyl Benzoyl Sulfonate	0.6; 1.0; 5.0; 10.0
Dodecil Benzol Szulfonate + Sodium lauril sulfate	5.0, 10.0

Table 3. 2: showing the investigated surfactant mixtures. The mixture of Dodecyl Benzoyl Sulfonate + Sodium lauryl sulphate consisted of equal concentration each.

3.1. EXPERIMENTAL SET-UP FOR FOAM TEST

3.1.1. Surface- and interfacial-tension measurements

The critical micellar concentration (CMC) of the anionic surfactant used in this experiment was determined by measuring the surface tension using the ring methods with a tensiometer. All measurements were performed at 22°C and atmospheric pressure, with an average of 5 measurements per surfactant. The investigated solutions were in 100 cm³ beakers. Reference measurements were performed on demineralized water.

The force required to pull a platinum wire ring off the interface of the liquids is measured to the interfacial tension. The ring is fully immersed in the solution and gradually lifted upwards. As the ring approaches the interface, it raises a meniscus of the liquid which will eventually tears off. The force which is required in pulling up the ring alongside the meniscus is thereby measured by the computer as the surface or interfacial tension. If the measurement is performed on an aqueous solution, the wire ring is carefully rinsed with de-mineralized water and dried with a soft tissue.

3.1.2. Foaming in absence of oil

The Foam-Column instrument, shown in Figure 3.1, was used to find the foaming and stability properties of the surfactants. To generate foam, nitrogen gas was used with a purity of 99.98% (less than 0.5 ppm O₂). Foam was generated by the sparging of nitrogen gas through the glass column. The nitrogen gas was released into the column at a fixed flow rate (0.5l/min) in a surfactant solution which contained the same initial volume for all experiments (50 cm³).

During the foaming process, when the foam volume becomes equal to the target value of 400 cm³, the gas flow will stop automatically. The top of the foam column was determined by an eye gauge and precision.

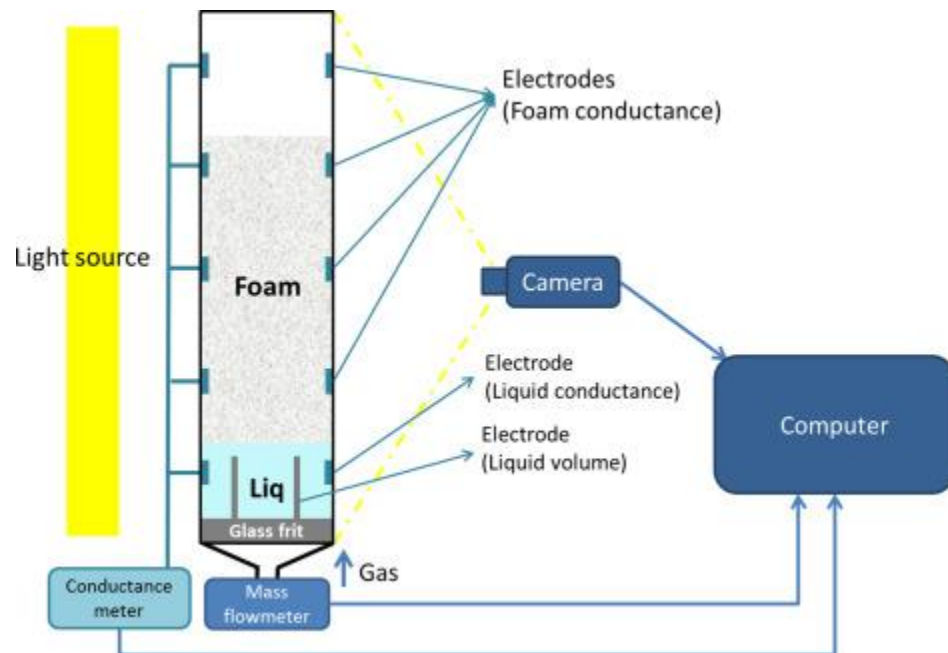


Figure3. 1: Schematic diagram of the foam-scan equipment used in performing the foamability of surfactant.

The following parameters were measured in the Foam-Scan set-up: foam volume generated during gas sparging (foamability), the collapse of foam volume after gas injection (foam stability). The foam capacity (FC) describe the foamability of the surfactant solution. This is deduced by the ratio the foam volume generated after gas injection to the total gas volume injected. If discovered that the injected gas is not adequately retained in the foam, this implies that the foam is not stable during the foaming process.

. The foam volume is calculated by using the height of the foam column and the height of the liquid column.

3.1.3. Foaming in presence of oil

In this part of the experiment, a manual column chamber was used, whereby we prepared 50 cm³ surfactant solution, and 2cm³ oil in the column, which were thoroughly mixed before sparging with Nitrogen gas at a rate of 0.5l/min. During the experiment, the foam volume was measured as well as the liquid volume over time which was used to calculate the drainage rate of the foam in the presence of oil. |This was used in comparing with that of the test without oil, to analyse the influence of oil on the stability of foam with the selected surfactants.

3.2 DISPLACEMENT TEST EXPERIMENTAL SETUP AND PROCEDURE

A displacement test for analysing all the strategies of EOR core flooding techniques was carried out, which included basically process of WAG and SAG flooding process.

3.2.1 EQUIPMENT

- 1. Back pressure regulator (BPR), pressurized by nitrogen, to maintain a high pressure in the system.*
- 2. Accumulator used to provide high pressure injection*
- 3. Manometer for measurement of pressure in the accumulator.*
- 4. Pumps (centrifugal pump) used to displace fluids in the core.*
- 5. Pressure transducer for application of confinement pressure to the core holder by injection of pump water into the sleeve.*
- 6. Hassler Core holder chamber contain both the heating chamber to conduct experiment*
- 7. Pressure readers for measurement of differential pressure between inlet and outlet of the core.*
- 8. Computer used during the permeability measurement to plot data.*
- 9. Graded cylinders.*

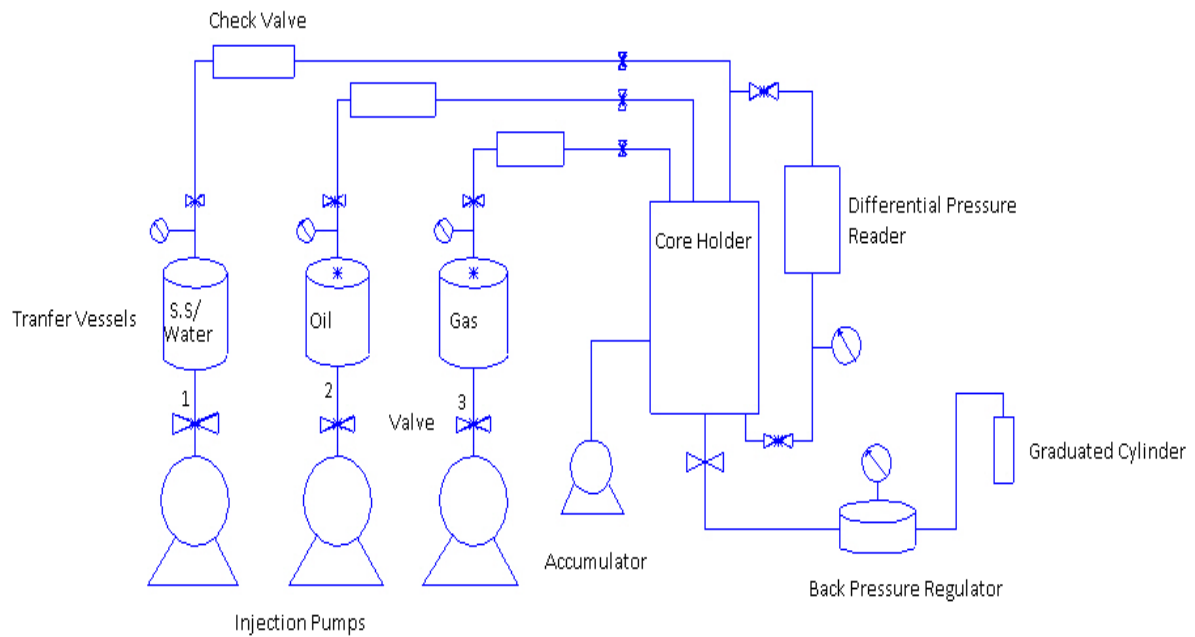


Figure3. 2: Schematic diagram of core flooding apparatus

3.2.3 PREPARATION OF CORES

The core-flooding experiments are a simulation of the reservoir field. Thus, the core is being saturated with oil, and measurement of porosity and absolute permeability are taken.

Next, the cores were set to dry in room temperature by being placed in a heating cabinet of 50°C for two days. After being dried, the cores were weighed, and then measurement of both the length and diameter were taken using a calliper. During the initial phase of the experiment, the pore volume and permeability of each cores have been calculated. Afterwards the cores are loaded into the core-holder where a sleeve is present in the

core holder to compress the cores together and avoid having any sort of annular flow during the flooding process.

3.2.4. Porosity Measurement:

By saturating the cores under vacuum, weight difference before and after saturation could be used to calculate porosity. The cores were placed inside a glass bulb, which is connected to another spherical glass bulb on top, separated by a valve. This contains a fluid that was used to saturate the core. Both glass bulbs were separately connected to a condensing chamber that was connected to a vacuum pump. If brine is the saturating fluid, both the sample and the brine would be vacuumed, but if decane is the saturating fluid, only the sample would be vacuumed.

After the core was saturated, it was weighed again. Porosity (ϕ) was then calculated using the following equation:

$$\phi = \frac{ws - wd}{\rho vb}$$

Where, Ws = weight of saturated sample, Wd = weight of dry sample, ρ = density of the fluid and Vb = bulk volume of the sample

3.2.5 Permeability Measurement

The cores are first saturated with water and in that process the effective permeability is calculated thereof by taking time interval readings of Δp at every 5ml (cm³) of water flowed out of the cores from the outlet of the core-holder.

To calculate k , we apply Darcy equation:

$$k = \frac{q\mu l}{2\pi r\Delta p}$$

where k = permeability

q = flowrate (100cm³/hr)

l = length of core

Δp = change in pressure from inlet to outlet

Afterwards, k was calculated for each interval of Δp and q

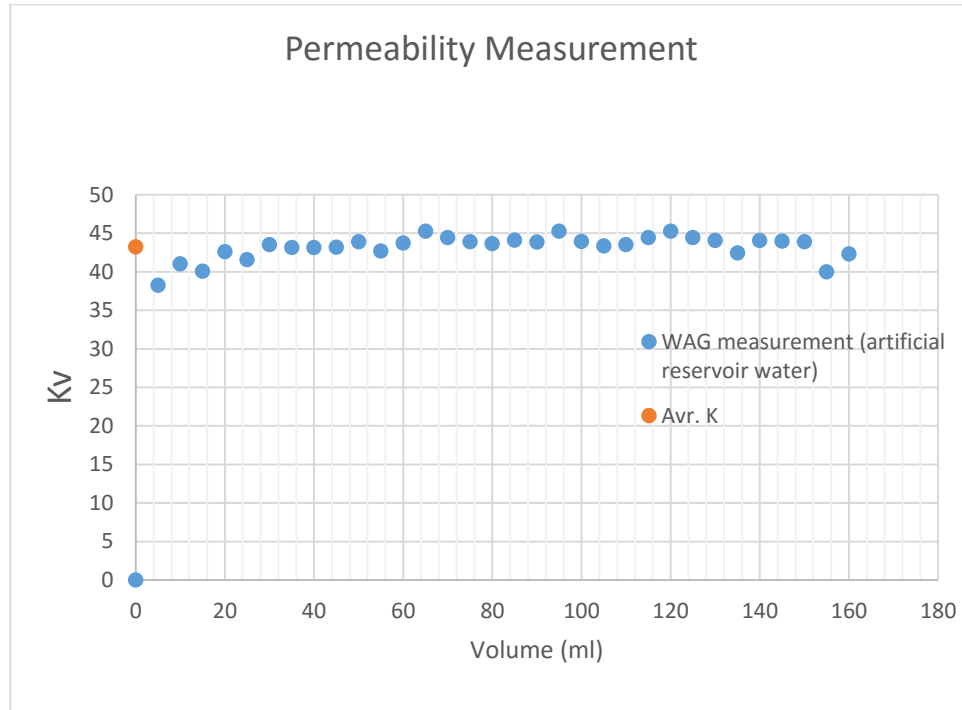


Figure3. 3: Average permeability of core sample used in displacement test.

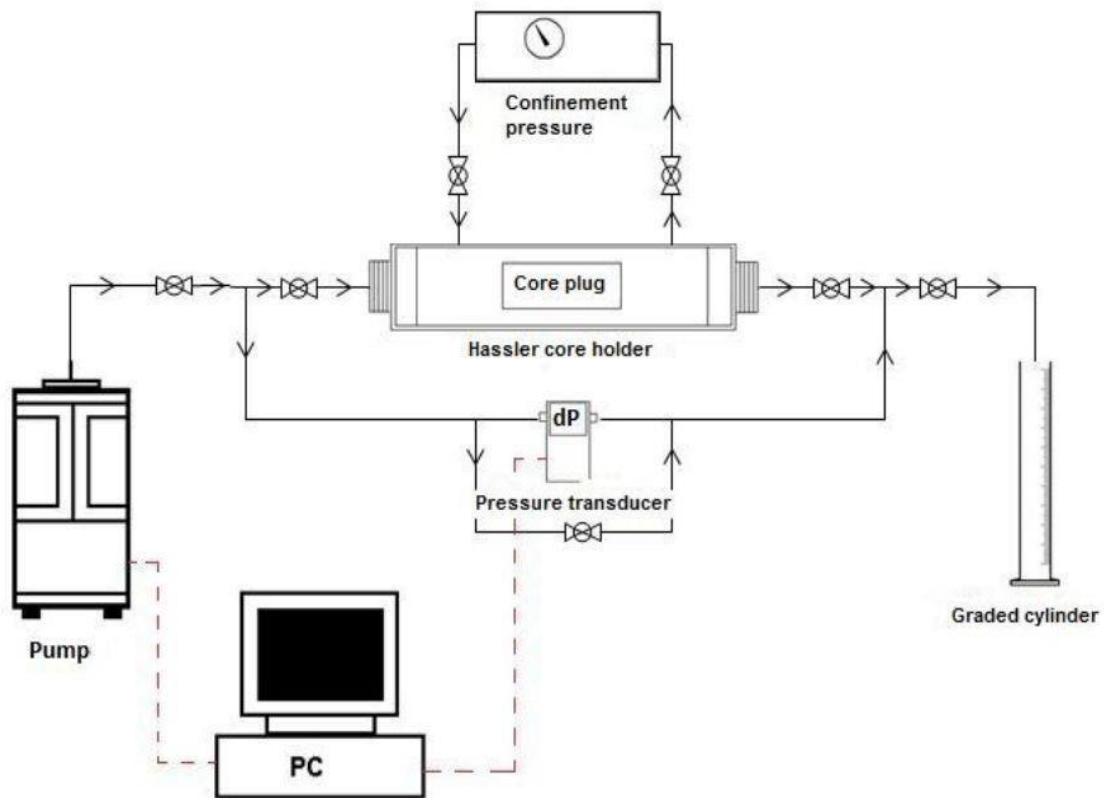


Figure3. 4: Setup used for Permeability measurement

WAG and SAG:

Both WAG and SAG foam flooding were conducted using Nitrogen at immiscible conditions. In these experiments, the core holder was mounted vertically, and cores contained no spacer. The core holder chamber was heated to 70° c to approach reservoir conditions and the pressure for the experimental work is set at 105 bars likewise.

At the point whereby, the core has been fully saturated with brine water, we then subsequently flood the cores with oil until we reach irreducible water saturation (this is detected when no more water is coming out from the system, whereby we assume the core is almost fully saturated with

water which gives us the initial OOIP in the core system). After approaching full oil saturation in this case. After a completed oil saturation is achieved, a sequence of gas and water slugs was injected into the core. A WAG ratio of 1:1 was used for all experiments. The rate was at 20cm³/h but was kept constant throughout each one. Nitrogen was then injected by use of pump 3, while brine was injected using pump 1. First, a gas flooding was started by closing valve 1 and opening valve 3. When a certain fraction of the pore volume (0.5 PV) had been injected, valve 3 was closed and valve 1 was opened. Then the same amount of brine was injected before switching back to Nitrogen, and so on. The injection of alternating slugs continued until oil production from the core stopped.

	First Cycle		Second Cycle	
Injected PV	0.5	0.5	0.5	0.5
Fluids	Nitrogen	Surfactant	Nitrogen	Surfactant

Table 3. 3: *Proportion of injected fluids in SAG process of ratio 1:1*

During the proceed with the flooding process for oil production with the WAG process by alternatively injecting slugs of gas with slugs of 0.5 PV of water into the system till we reach irreducible oil saturation. All the effluent samples are collected in a test-tube of 10ml each. The collected samples in the test-tubes are emulsion mixture of both water and oil, thus the actual oil recovery is calculated by separating the oil form the water in the sample through emulsion breaking treatment by the addition of Nacl and drying.

Afterwards the process is repeated with SAG foam flooding process and the effluent samples is also collected and the oil recovery calculated likewise.

Production from the core continued by use of alternating slugs of surfactant (pump B) and gas (pump A) with a ratio of 1:1. The SAG process was carried out in the same way as the WAG, but an additional test was conducted with an increase in the surfactant volume of 2:1 and 3:1, afterwards results were compared.

During core flooding with SAG process, we inject gas at a constant pressure whereby the pressure reducer equipment helps to maintain pressure at the decided value at each interval during the flooding process we take readings of our Δp at each step of volume flooded out.

4. RESULTS AND DISCUSSION FOR FOAM TEST

4.1. Bulk foam in absence of oil

Foams are more stable when the foam volume remains unchanged for longer duration of time. In this test, foam was generated after sparging gas into the surfactant solution for three minutes. After sparging, the foam gradually decays and decreases in height. Liquid drainage is one of the reasons for this significant decrease in foam height as the foam thins which results as the liquid drains out of its plateau borders. Figure 4.1 and 4.2 shows half-life time of the foam and the relative volume of foam over a period respectively. The foam stability is analysed by the half-life time (time at which half of the foam volume has collapsed after being generated) and the relative volume with respect to time, which was tested from 0-30 mins. We conducted this experiment on four different surfactant solution concentration, to determine also the influence of surfactant concentration on the half-life time and relative volume.

The foam generated from the mixture of dodecyl benzoate and lauryl sulphate, showed more stability than in their individual state. The foam of both surfactant mixture at 10g/l showed the highest stability than all others. The foam volume is periodically measured manually.

Foam collapses quickly when there has been a significant drainage of the liquid out from the plateau borders. Figure 4.1 shows the foam stability of the surfactant solutions studied. It seen from the data of surfactant concentration vs. halftime that there is a direct relationship between foam stability and surfactant concentration. An increase in surfactant concentration increased foam stability significantly.

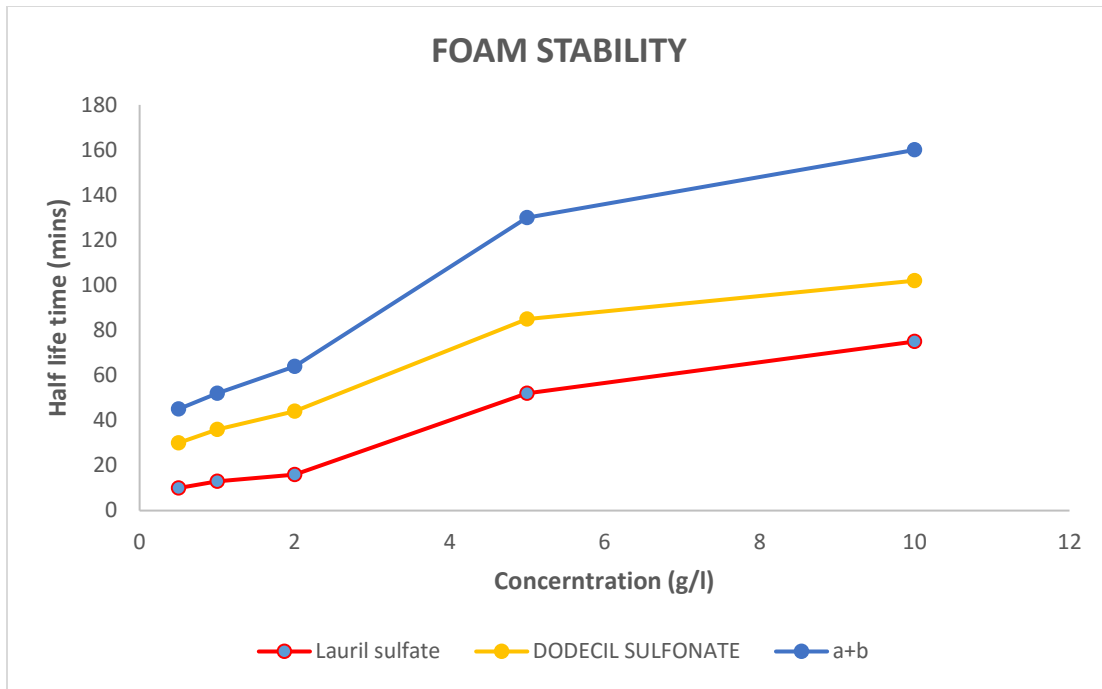


Figure 4. 1: Half-life time of different concentrations of the surfactant solutions.

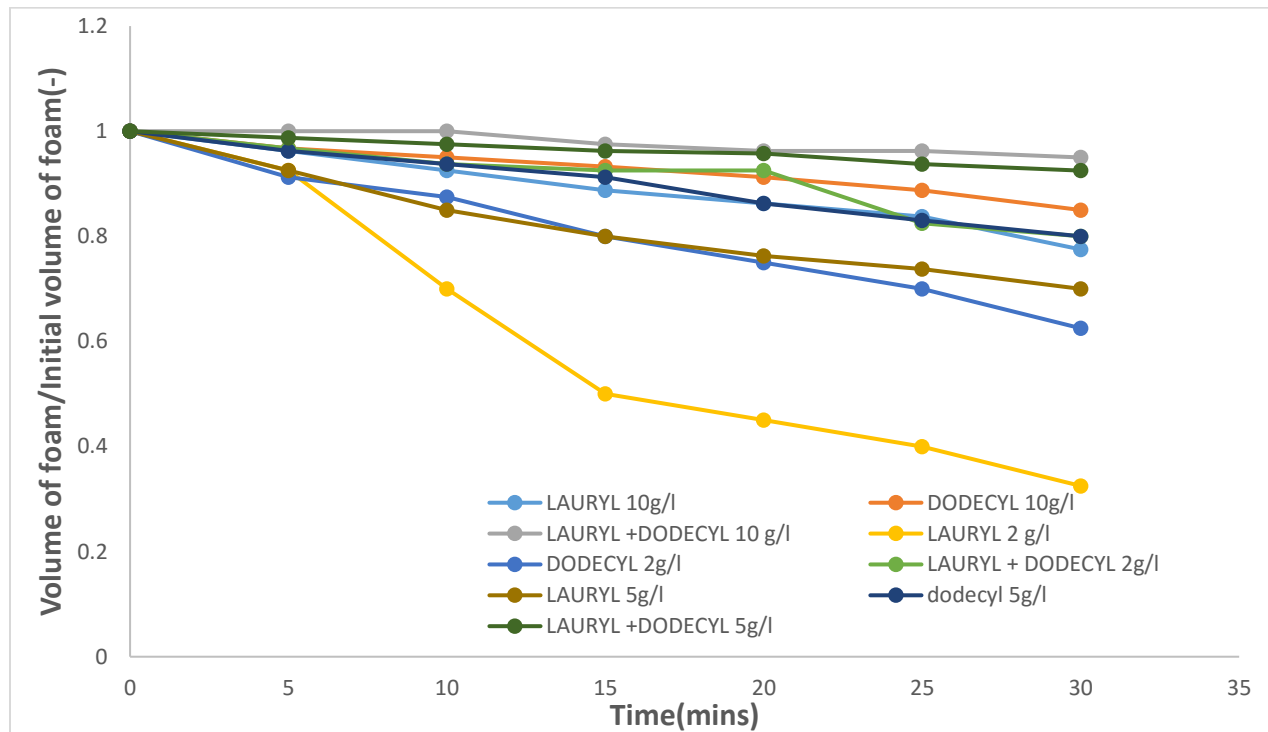


Figure 4. 2: Relative volume of foam with respect to time for the different concentration of the surfactant solutions.

4.1.2. Foam in presence of oil

Foam stability with respect to the presence of oil in the fluid mixture was investigated to find a surfactant solution that would generate a more stable foam. The mechanism surrounding foam stability in the presence of oil was being emphasized in previous chapters in terms of the entry of an oil drop causing an aqueous film thinning and oil spreading on the gas-water interface. If the entry condition is favourable and the oil drop can exhibit a spreading behaviour, the gas-water interface is expected to expand. The expansion results in thinning of the film around the foam which eventually causes the film to rupture. If there happens to be no occurrence of spreading, in which the oil forms a lens at the gas-water interface, the foam film is likely to rupture as soon as there is the entry of an oil drop into both surfaces of the lamella. Under this condition, the oil drop spans the film by making an unstable bridge. The presence of oil has an adverse effect on the foam stability as seen in Fig 4.3.

Also, the surface tension, the interfacial tension (IFT) with hexadecane, of the three tests with surfactant solution used were measured. These values are provided in Table 3. The surface tension and IFT was lowest for the mixture of lauryl and dodecyl, when compared to their individual surfactants solution, this having established the fact that all mixtures did show a significant reduction in IFT as their individual concentration is increased. Fig 4.4 gives an illustration of the influence the concentration of each surfactant solution must the interfacial tension of the system. The foam generation from surfactant mixture of Lauryl and dodecyl foam lasted longer simply because it was more stable and had a higher initial foam height as shown in figure 4.5.

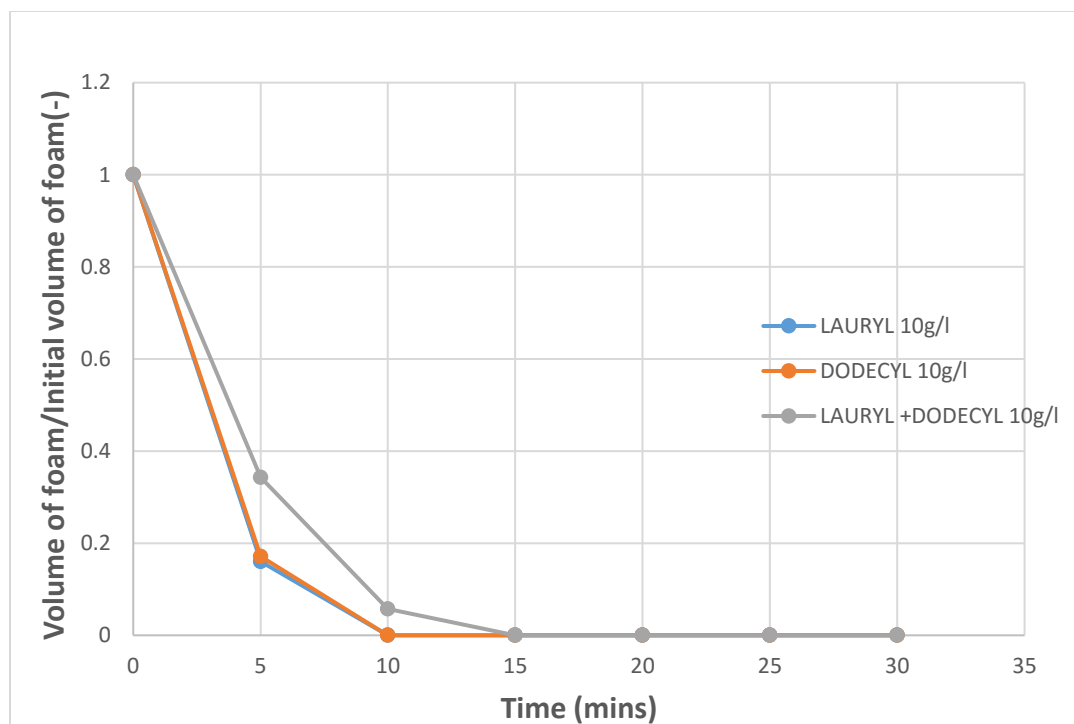


Figure 4. 3: *Relative volume of foam with respect to time for the different concentration of the surfactant solutions in the presence of oil.*

Surfactant	Surface Tension (mN/m)	Interfacial Tension (mN/m)
Na Lauryl Sulphate	33.65	3.48
Na Dodecyl Benzol Sulfonate	31.24	2.13
Na Dodecil Benzol Sulfonate + Sodium lauryl sulfate	28.57	1.45

Table 4. 1: *Representation of the surface tension (σ) of the surfactant solutions, and their interfacial tension (IFT) with oil.*

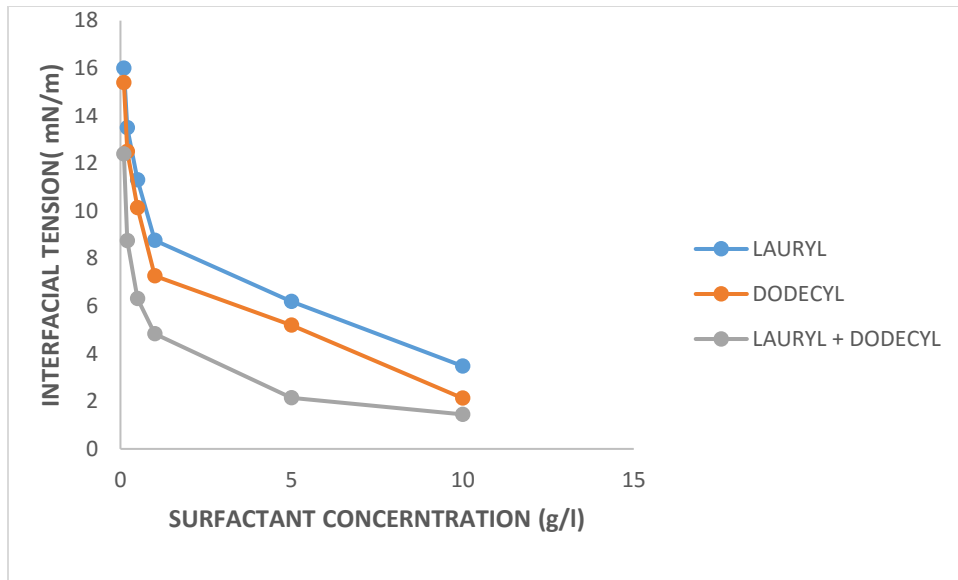


Figure 4. 4. *IFT at different surfactant concentrations.*

Figure 4.5 shows the foam volume after the injecting gas into the surfactant solution for 10 minutes. Surfactants, at a chosen concentration of 10 g/l which produced foam with a high initial volume after 10 minutes of sparging gas into the column, are considered to have a good foamability. Surfactants, which produced foam with a low initial volume, are considered to have a poor foamability. Figure 4.6 indicates the comparison between the stability of foam in the absence and presence of oil in the foam test for some selected surfactant solution concentration, which indicates that the mixture of both lauryl and dodecyl at 10g/l is the most stable candidate both in the absence and presence of oil.

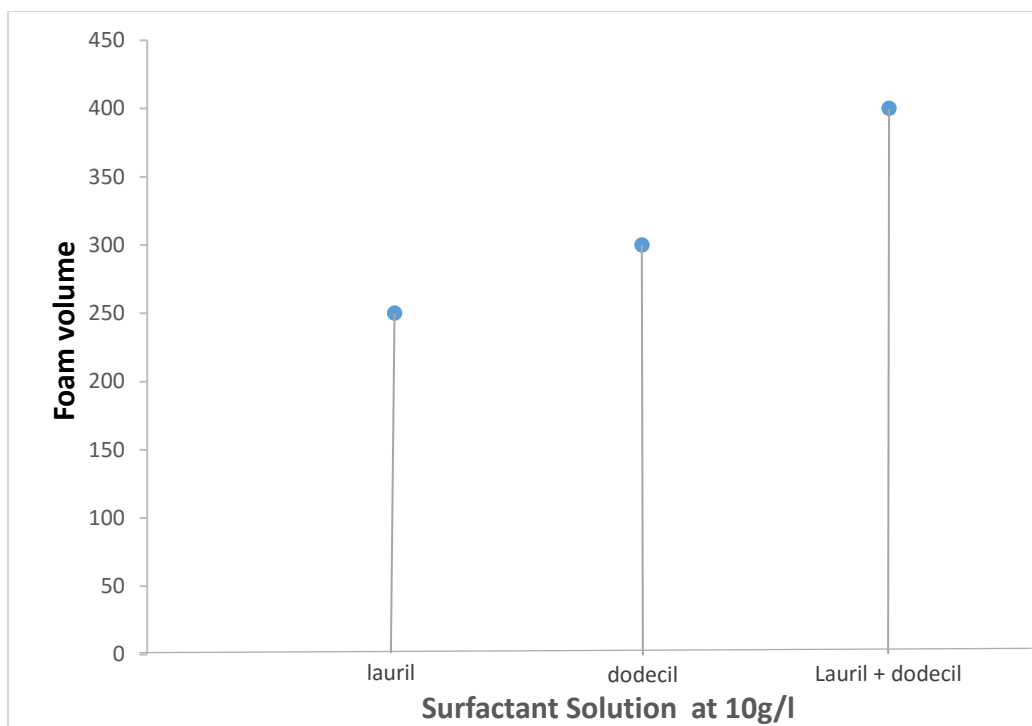


Figure 4. 5: *Initial Volume of foam in the presence of oil*

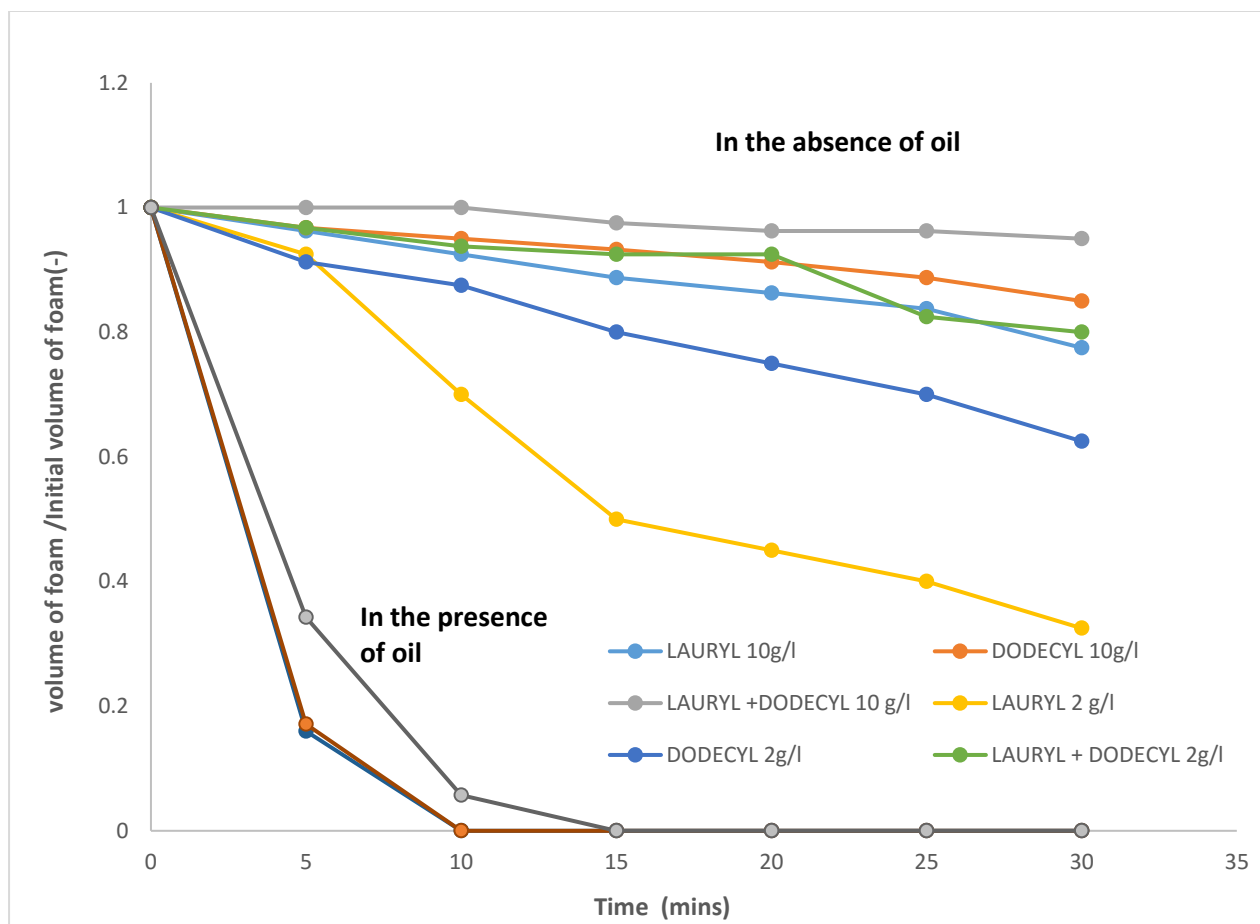


Figure 4. 6: Comparison between the foam stability of different surfactant solutions in the absence and presence of oil

4.2 RESULTS AND DISCUSSION FOR DISPLACEMENT TEST

Results and discussion will be presented in this section

4.2.1 INJECTION METHODS

4.2.2 Influence of injection volume ratio in SAG injection process

In this stage, the process was divided in two sections to help analyse the outcome of injection fluid volume ratio on the SAG injection process. In the first section, the focus was on how the increment of the surfactant solution volume in the displacement fluid could influence the SAG test and in second, on how the increment of the Nitrogen gas volume in the displacement fluid could influence the SAG test. An equal volume of surfactant solutions and Nitrogen gas is termed 1:1, while as the amount of surfactant solution is increased with respect to the gas is termed 2:1 and 3:1, while as that Nitrogen gas is increased in the ratio 1:2 and 1:3.

4.2.3 Higher surfactant solution volume on SAG displacement fluid

From figure 4.11, shows the oil recovery of all SAG displacement fluid ratio (1:1, 2:1, 3:1, 1:2, 1:3) employed during the experimental process. The most significant oil recovery (OOIP, %- original oil in place) was attained at a SAG ratio of 1:1.

In this section, a decrease in oil recovery during SAG displacement test was detected due to the increase of the surfactant solution volume in the displacement fluid. This was a result of the following:

1.Early breakthrough effluent fluid containing high amount of surfactant solution.

Figure 4.7 shows a representation of SAG displacement fluid ratio of 1:1, 2:1 and 3:1 with their respective cumulative breakthrough of surfactant

solution during the test. Considering this figure, result showed an early surfactant solution breakthrough in the effluent stream which is because of its increase in volume in the SAG injection fluid used. The time for the effluent solution to breakthrough affects the oil recovery directly. Thus, delaying the breakthrough time directly improves the macroscopic (sweep) efficiency and increases oil recovery.

Oil recovery in any displacement process is directly influenced by the amount of reservoir volume which contacted by the injected fluid. The measure of this contact is termed as the volumetric displacement (sweep) efficiency, E . The fraction of the reservoir Pore volume (PV) that is invaded by the injected fluid is known as the macroscopic efficiency that is directly known as the Volumetric sweep efficiency.

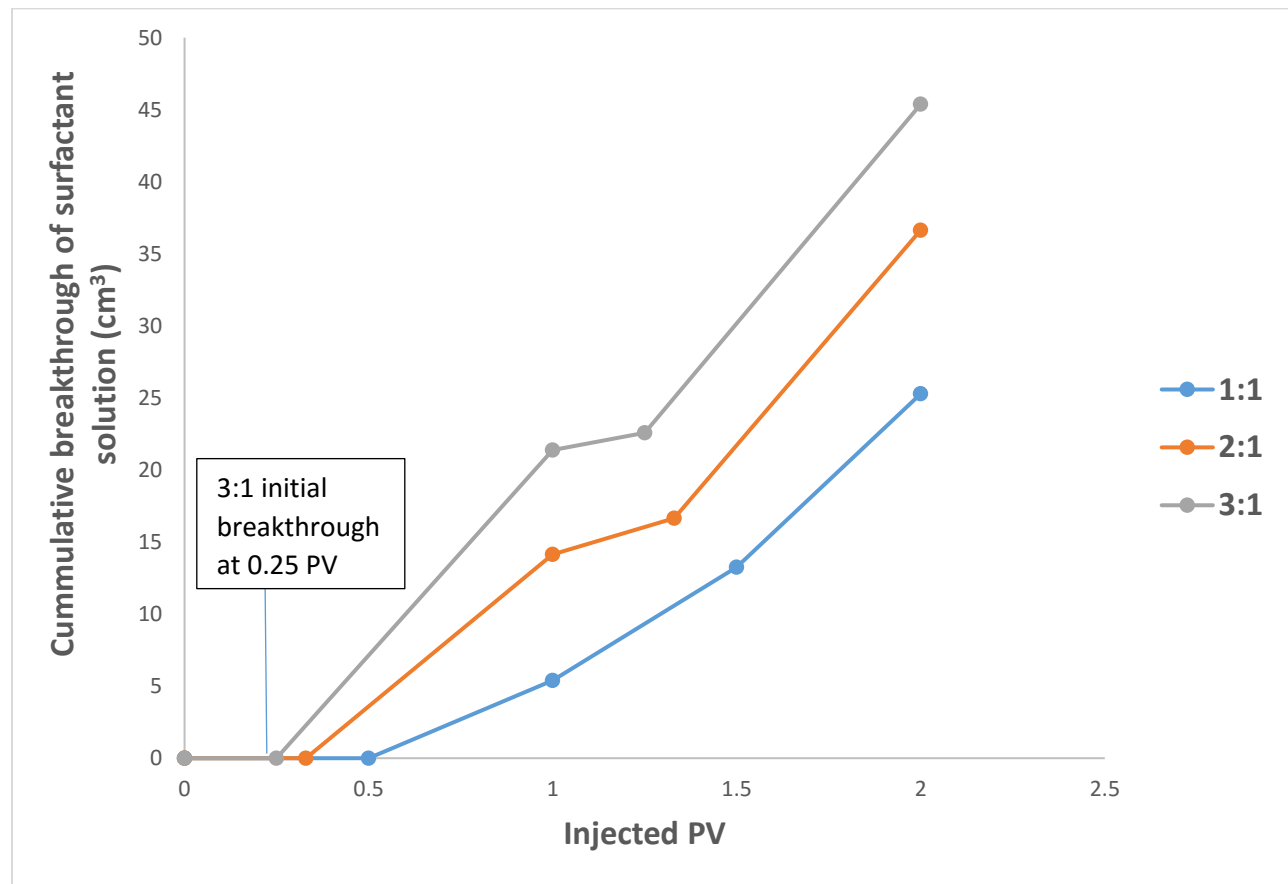


Figure 4. 7: Total breakthrough of Surfactant solution with a higher SS to gas ratio.

In the process of increasing the amount (volume) of the surfactant solution in the SAG fluid ratio, there will be a lower fraction of Nitrogen gas in the injection fluid, thus resulting in the gas phase to be dispersed in the liquid phase and less gas bubble to be held inside of the foam, therefore reducing the macroscopic efficiency.

Foam is formed as the surfactant solution is contacted by the Nitrogen gas. The foam that is generated increases the viscosity of the gas and increases the contact time of gas and oil, thus decreasing the breakthrough time of gas, thereby improving the displacing efficiency.

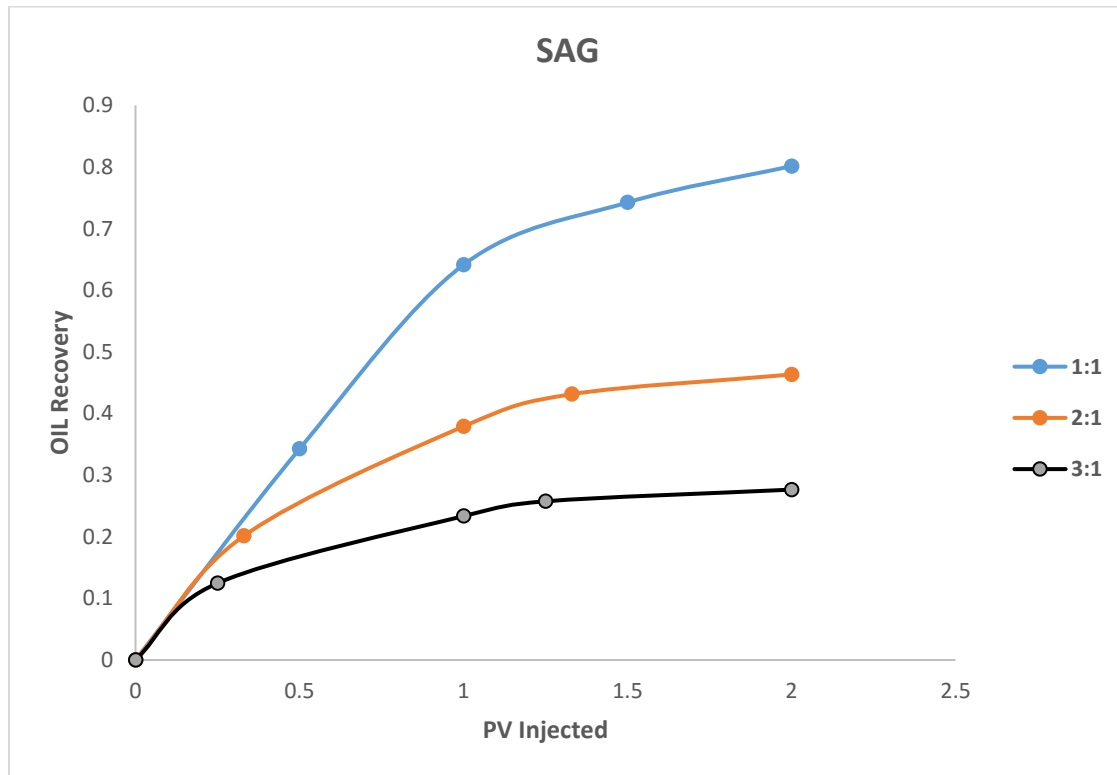


Figure 4. 8: Oil recovery during test with an increase of surfactant solution volume in ratio 1:1, 2:1,3:1.

4.2.4. Influence of gas volume Increase in SAG process

From the figure 4.10 we see a comparative analysis of the oil recovery with different SAG ratios of 1:1, 1:2, and 1:3. As represented in figure 4.10, the oil recovery tends to decline as the amount of gas in the displacement fluid increases with respect to that of the surfactant solution. This is because of a decrease in the sweep efficiency of the displacement fluid on the system occurs due to the large amount of gas in the system. The proportion of the surfactant solution with respect to the gas volume is not proportional enough for adequate mobility control to be initiated whereby it mobility tends to be high resulting in a low fraction of the reservoir PV to be invaded by it. Furthermore, this larger amount of Nitrogen gas in SAG fluid ratio results in an early breakthrough of gas due to its high mobility that delays the breakthrough time of oil and reducing oil recovery afterward.

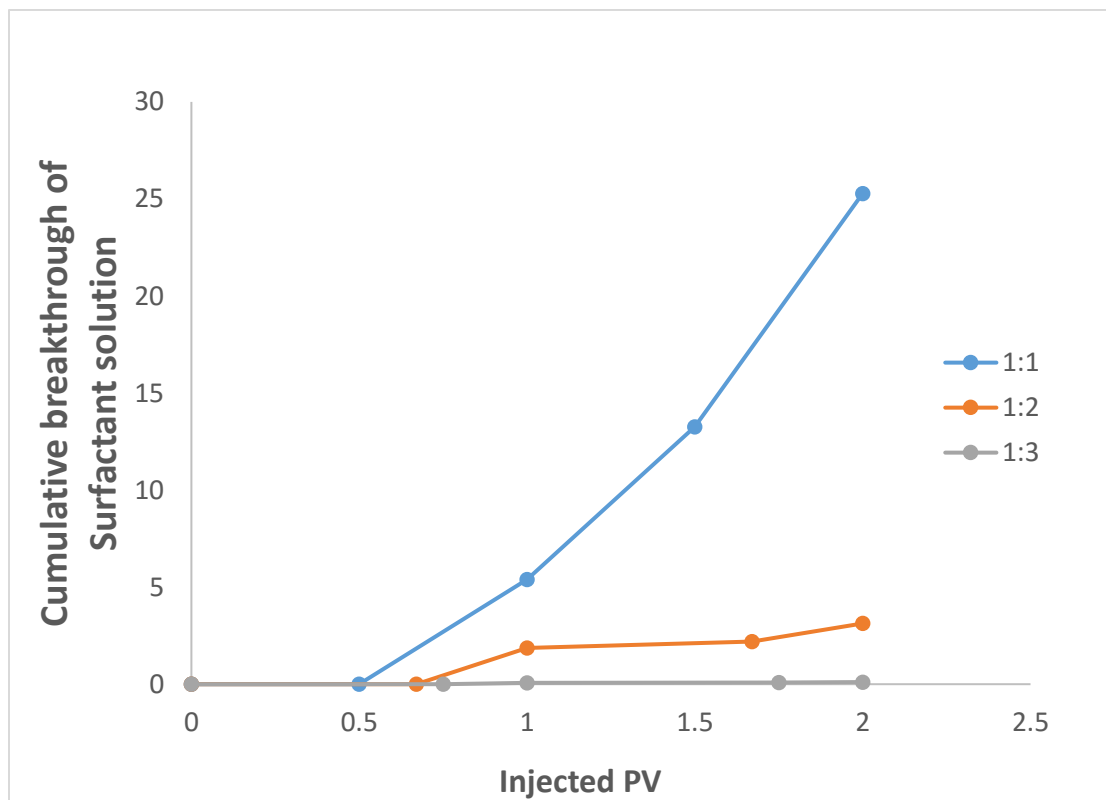


Figure 4. 9: Total breakthrough of SS with increase in gas volume

. In figure 4.9, it is seen that there is a very low breakthrough of surfactant solution with the SAG ratio of 1:3 which is due to reduction of the amount of surfactant solution that was injected. Although, gas breakthrough occurred earlier in this case likewise. Fig. 4.11 illustrates the oil recovery obtained from all tested SAG ratios. This figure indicates that by increasing the SAG ratio in either way (i.e. gas or surfactant solution), invariably decreases the oil recovery. Furthermore, Oil recovery was seen to be highest in the equal volume of Surfactant solution to Nitrogen gas (1:1).

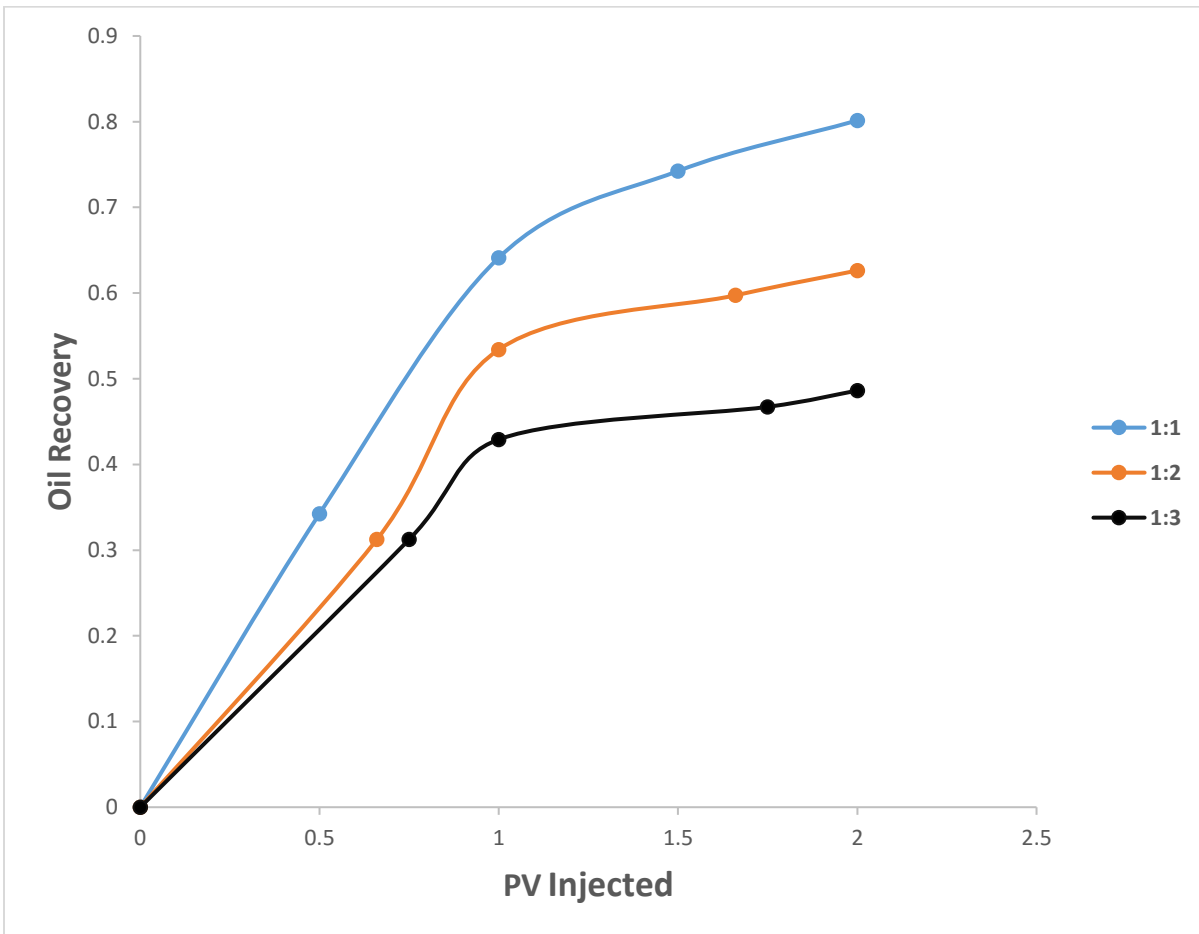


Figure 4. 10: Oil recovery during test with an increase of Nitrogen gas volume in ratio 1:1, 1:2 and 1:3.

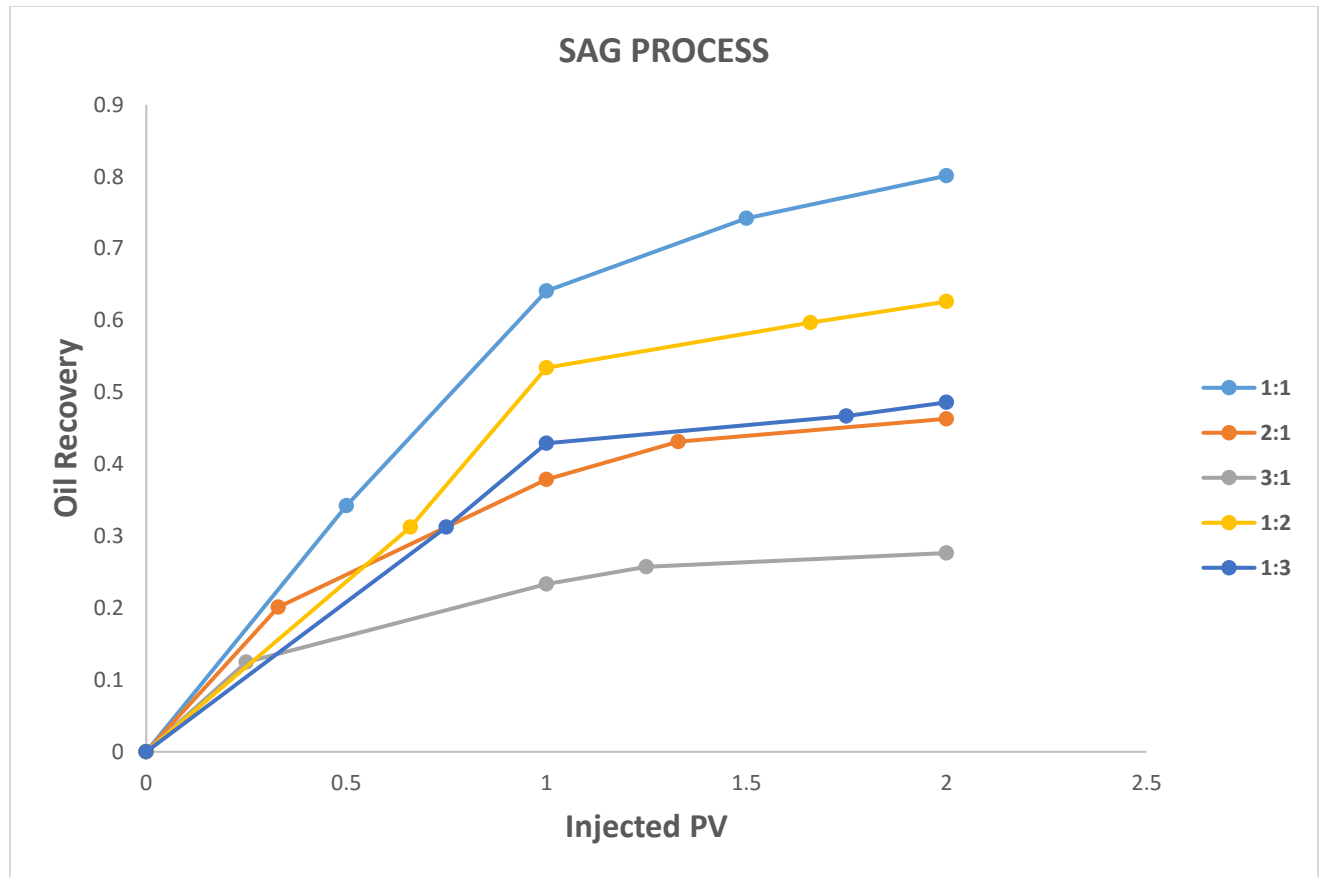


Figure 4. 11: Representation of all experimented SAG ratio and their respective Oil recoveries

4.2.5. SAG and WAG recovery comparison

Fig. 4.12 shows the oil recovery of SAG injection with that of WAG process, where the oil recovery of SAG and WAG are about 80% and 61% respectively.

During the SAG injection process, Δp was low in the first injection of gas until the injection of surfactant solutions, whereby the Δp was high for ratio 1:1 as shown in Fig 4.13 As more surfactant is injected, large differential pressures occurs as N_2 disperse in the surfactant solution, generating in situ foam. Oil is being produced throughout the pressure increase because

viscous forces become stronger and able to sweep more of the oil. Viscous-induced forces are created in the system as foam generation takes place inside the core.

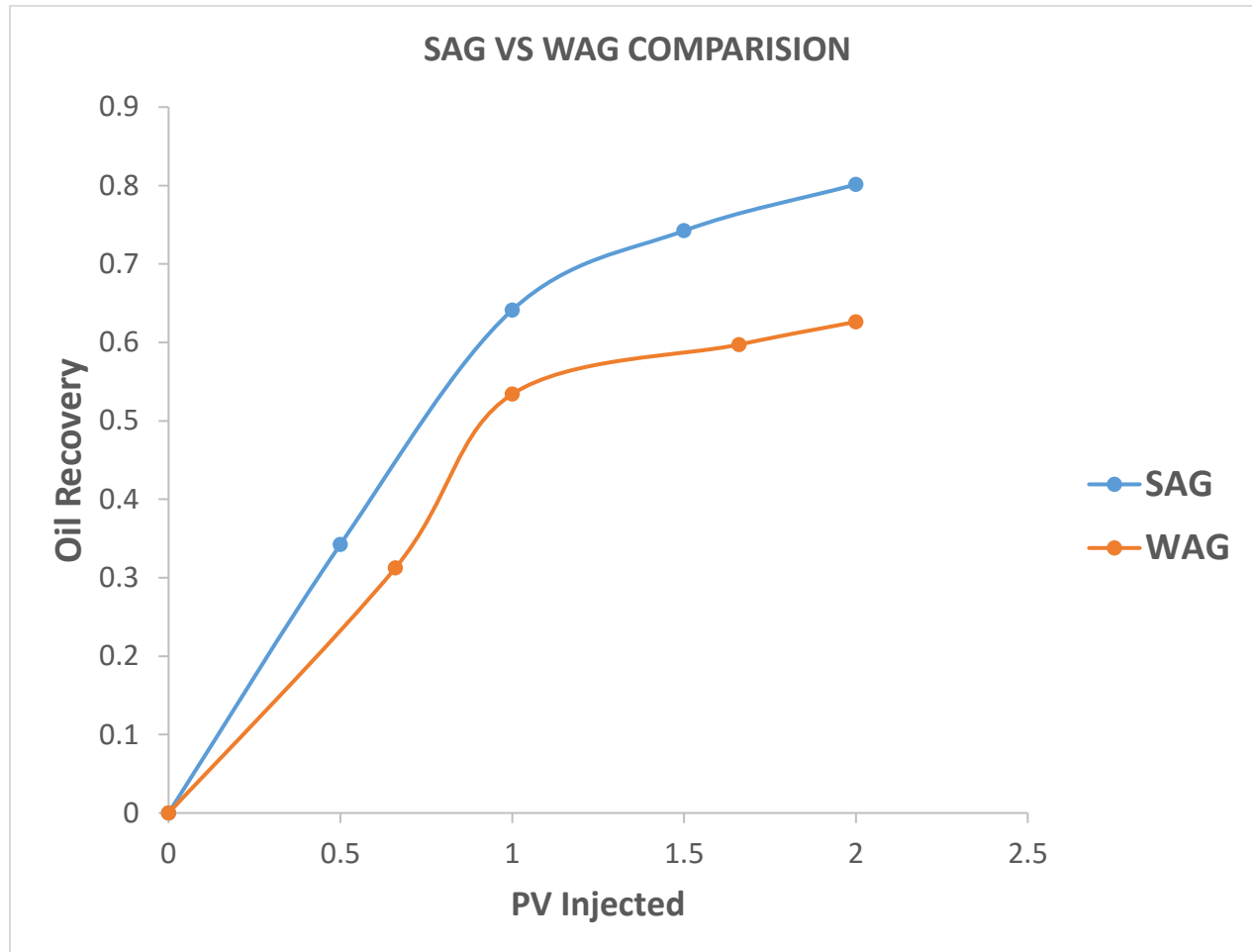


Figure 4. 12: Comparison of Oil Recovery of WAG and SAG process

There are also effects of swelling of oil and reduction of interfacial tension of gas-oil and water-oil by surfactant. Because of these processes, oil recovery increases further in core-flooding with SAG than what can be seen for core flooding with WAG. But, the rate of oil production decreased with N_2 breakthrough and Δp decreased as N_2 production spiked this could be termed as the reduction of mobility control of gas which is one key

phenomenon that retards gravity overriding which could lead to early gas breakthrough. To obtain a better and high oil recovery in the SAG process, it seemed best to inject at a higher pressure because of the increase in the viscosity of the injected fluids which decreases the transmissibility in the pore spaces of the core.

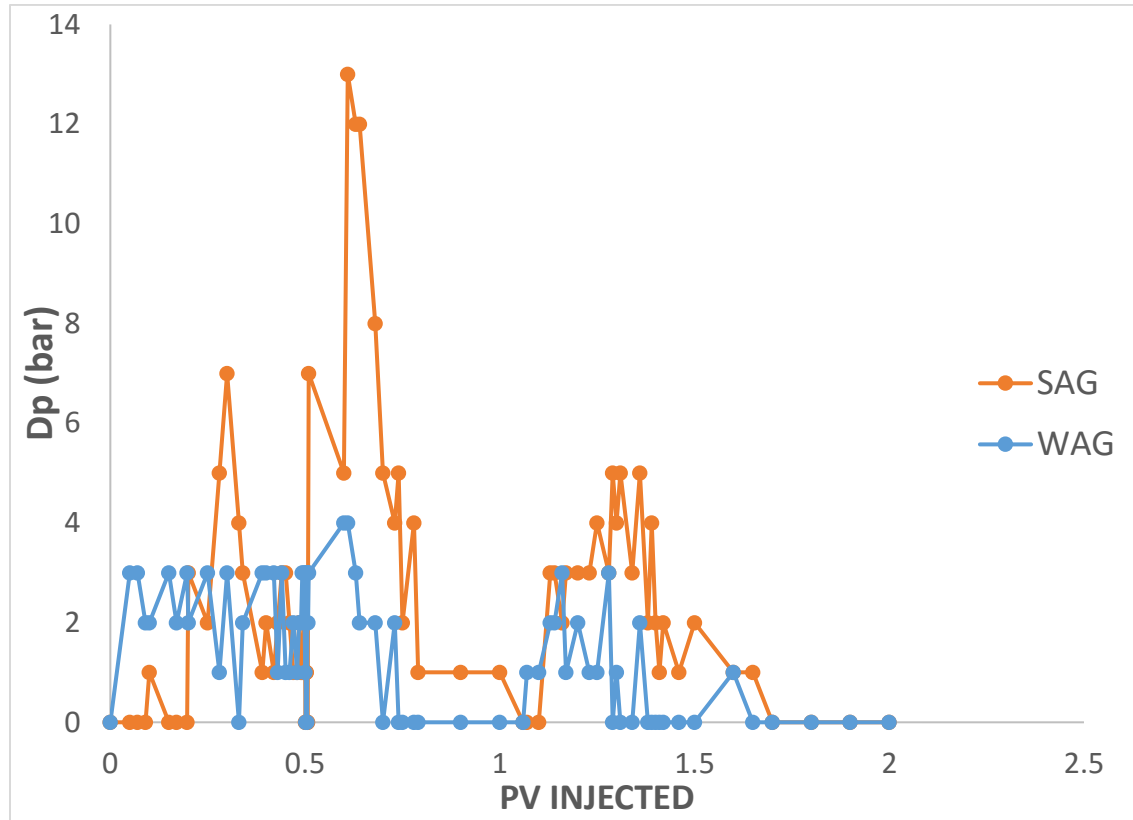


Figure 4. 13: Pressure profile of SAG and WAG injection

In comparison to WAG where the injection pressure was lower due to high permeability of the porous media and better transmissibility as we have lower density and viscosity of gas which enables it to flow easily.

5.0 CONCLUSION

Two anionic surfactants (Sodium Lauryl sulphate and Sodium Dodecyl benzoate) were tested in a laboratory study in a series of surfactant-alternating-gas tests to evaluate the effect of surfactant type, concentration, injection scheme on oil recovery. The foam generation, foam stability as well as interfacial tension of these surfactants with oil phase were analysed.

From the experimental results in this project, the following conclusions can be drawn:

- Results from foam stability tests of air injection show that foam stability can be significantly improved by increasing surfactant concentration. The mixture of dodecyl and lauryl showed a significant improvement in the stability of foam when compared with their individual state.
- The IFT decreased with an increase in surfactant concentration. However, lower interfacial tension is favourable to generate stronger foam during the gas injection cycle which leads to higher oil recovery.
- The differential pressure is significantly lower for the WAG compared to SAG during all core-flooding experiment. This is as a direct result of flow resistance in the core, which appears to be very small in the WAG process.
- The pressure difference signifies that foam was generated in situ all through the SAG injection, which entails that mobility of N_2 was further reduced by SAG.
- From the experiment, the weakest SAG recovery method appears to be the SAG 3:1, with the earliest breakthrough and the lowest total recovery

of 27.65 % of OOIP. The increase of the surfactant solution in the SAG fluid ratio resulted in the decrease of the breakthrough time for oil thereby resulting in the reduction of macroscopic efficiency of the system.

- Also, the increase of the nitrogen gas in the SAG ratio, resulted in also decreasing the breakthrough time for oil, thereby resulting in a reduction of oil recovery.
- The observed results can be explained by considering that SAG accelerated oil production, compared with WAG injections, due to;
 - (i) the foam generation that initiated a reduction in the mobility of the injected gaseous phase and the reduction of the interfacial tension of the system.
 - (ii) A higher tertiary recovery was also achieved, with 80.1% OOIP as compared to 60.8 % OOIP of the WAG process. This shows that foam delays N₂ breakthrough more effectively than WAG.

5.1 RECOMENDATION FOR FURTHER WORK

1. Surfactant adsorption has shown a significant negative impact on the performance and economics of foam. Batch equilibrium and circulating tests can be conducted to evaluate surfactant adsorption on the rock surface. Also, sacrificial surfactant with ionic charges could be introduced to act as a sacrificial adsorption additive to

reduce the adverse effect of the adsorption of the valuable surfactant used during the EOR process.

2. The Berea Core should be aged over time with an aging device. This would improve and create a stronger oil-wet system and by so doing, the oil recovery can be analysed to ascertain which gives a better result.
3. Co-injection process of injecting surfactant alongside gas should be used as it shows signs of improving the final oil recovery more than that of SAG.
4. Applying larger slugs rather than the injection of smaller slugs could yield a better oil recovery in terms of both WAG and SAG.

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APPENDIX A: Permeability calculation data

$$Q = \Delta v / \Delta t$$

Table A1: Representative data for Permeability calculation

Time (secs)	Volume (ml)	Δp (bar)
0	0	0
3m06s	5	1.330
6m04s	10	1.295
9m10s	15	1.269
12m09s	20	1.240
15m14s	25	1.230
18m13s	30	1.214
21m15s	35	1.204
24m18s	40	1.198
27m22s	45	1.190
30.24s	50	1.184
33.31	55	1.185
36.34	60	1.182
39.31	65	1.181
42.31	70	1.183
45.34	75	1.177
48.38	80	1.178
51.40	85	1.178

54.43	90	1.179
57.40	95	1.181
1.00.43	100	1.176
1.03.48	105	1.179
1.06.52	110	1.181
1.09.52	115	1.183
1.12.48	120	1.187
1.15.47	125	1.189
1.18.47	130	1.192
1.21.53	135	1.198
1.24.52	140	1.199
1.27.51	145	1.202
1.30.50	150	1.204
1.34.06	155	1.207
1.37.10	160	1.215

APPENDIX B: FOAM STABILITY EXPERIMENT DATA

Table B1: Interfacial Tension results for all surfactant solutions concentration

	Concentration (g/l)	0.1	0.2	0.5	1	5	10
Surfactant Type		Interfacial Tension					
Lauryl Sulphate		16	13.5	11.3	8.77	6.2	3.48
Dodecyl Benzoate		15.4	12.5	10.14	7.27	5.2	2.13
Lauryl Sulphate + Dodecyl Benzoate		12.4	8.75	6.32	4.83	2.15	1.45

Table B2 : Half-life time result calculation at different concentration for a surfactant solutions

	Concentration (g/l)	0.5	1	2	5	10
Surfactant Type		Half Time (mins)				
Lauryl Sulphate		10	13	16	52	75
Dodecyl Benzoate		30	36	44	85	102

Laury Sulphate + Dodecyl Benzoate						
		45	52	64	130	160

Table B3: Foam stability test in the absence of oil for Lauryl Sulfonate

LAURYL						
	CONCERNTRATION	0.5	1	2	5	10
TIME		VOLUME HEIGHT OF FOAM				
0		400	400	400	400	400
2		320	350	360	380	390
6		260	310	320	360	380
10		200	270	280	340	370
14		130	180	210	330	360
18		80	130	190	310	350
22		20	90	170	300	340
26		0	50	150	290	330
30		0	20	130	280	310
34		0	0	110	270	320
38		0	0	90	260	310
42		0	0	70	250	300
46		0	0	50	240	290
50		0	0	30	230	280
54		0	0	20	190	270
58		0	0	0	170	260
62		0	0	0	150	240
66		0	0	0	120	230
70		0	0	0	90	220
74		0	0	0	70	210
78		0	0	0	50	190
82		0	0	0	40	170
86		0	0	0	20	150
90		0	0	0	0	130
94		0	0	0	0	100

98		0	0	0	0	80
102		0	0	0	0	60
106		0	0	0	0	50
110		0	0	0	0	30
114		0	0	0	0	20
118		0	0	0	0	0

Table B4: Foam stability test in the absence of oil for Dodecyl Benzoate

		DODECYL				
	CONCERNTRATION	0.5	1	2	5	10
TIME		VOLUME HEIGHT OF FOAM(CM3)				
0		400	400	400	400	400
2		350	350	370	390	390
6		310	330	360	380	385
10		290	300	350	370	380
14		270	280	330	360	375
18		250	260	310	350	370
22		240	250	290	340	360
26		230	240	270	330	350
30		200	230	250	320	340
34		180	220	230	310	330
38		160	190	220	300	320
42		140	170	210	290	310
46		120	150	180	280	300
50		100	140	170	270	290
54		80	120	150	260	280
58		60	90	130	250	275
62		40	70	120	240	270
66		20	50	100	230	260
70		0	30	90	225	255
74		0	20	70	220	245
78		0	0	60	215	240
82		0	0	40	210	230
86		0	0	30	190	235

90		0	0	20	170	230
94		0	0	0	160	220
98		0	0	0	140	210
102		0	0	0	130	200
106		0	0	0	110	180
110		0	0	0	90	160
114		0	0	0	70	140
118		0	0	0	50	120
120		0	0	0	30	100
126		0	0	0	20	90
130		0	0	0	0	70
134		0	0	0	0	50
138		0	0	0	0	30
142		0	0	0	0	20
146		0	0	0	0	0

Table B5: Foam stability test in the absence of oil for Lauryl Sulfonate +Dodecyl Benzoate

		LAURYL +DODECYL				
	CONCERNTRATION	0.5	1	2	5	10
TIME	VOLUME HEIGHT OF FOAM(CM3)					
0		400	400	400	400	400
2		370	385	390	400	400
6		360	380	385	395	400
10		350	370	375	390	395
14		340	365	370	385	390
18		330	350	360	385	390
22		320	330	340	380	385
26		300	310	330	375	385
30		280	290	320	370	380
34		260	275	310	365	375
38		240	250	300	360	370
42		230	235	290	355	365
46		170	230	280	350	360
50		150	220	270	345	355
54		130	190	260	340	350
58		110	170	240	335	345
62		90	150	220	330	340

66		70	130	200	325	335
70		50	110	180	320	330
74		30	90	160	315	325
78		0	70	140	310	320
82		0	50	120	300	315
86		0	40	100	295	310
90		0	30	80	290	305
94		0	20	70	280	300
98		0	0	50	270	295
102		0	0	40	260	290
106		0	0	30	250	285
110		0	0	20	240	280
114		0	0	0	235	275
118		0	0	0	230	270
0		0	0	0	220	265
126		0	0	0	210	260
130		0	0	0	200	255
134		0	0	0	190	250
138		0	0	0	180	245
142		0	0	0	170	230
146		0	0	0	160	225
150		0	0	0	150	220
154		0	0	0	140	215
158		0	0	0	130	205
162		0	0	0	120	195
166		0	0	0	110	185
170		0	0	0	100	175

Table B6: Foam stability test in the presence of oil for Lauryl Sulfonate

LAURYL						
	CONCERNTRATION	0.5	1	2	5	10
TIME		VOLUME HEIGHT OF FOAM				
0		25	40	90	140	250
2		0	0	0	40	100
6		0	0	0	0	20
10		0	0	0	0	0
14		0	0	0	0	0

Table B7: Foam stability test in the presence of oil for Dodecyl Benzoate

			DODECYL			
	CONCERNTRATIO N	0.5	1	2	5	10
TIME		VOLUME HEIGHT OF FOAM(CM3)				
0		30	60	140	230	350
2		0	20	60	80	140
6		0	0	0	20	50
10		0	0	0	0	0
14		0	0	0	0	20
18		0	0	0	0	0

Table B3: Foam stability test in the presence of oil for Lauryl Sulfonate + Dodecyl benzoate

			LAURYL +DODECYL			
	CONCERNTRATION	0.5	1	2	5	10
TIME		VOLUME HEIGHT OF FOAM(CM3)				
0		90	90	180	300	400
2		0	30	130	270	380
6		0	0	70	240	360
10		0	0	20	150	300
14		0	0	0	70	270
18		0	0	0	20	205
22		0	0	0	0	120
26		0	0	0	0	50
30		0	0	0	0	0

APPENDIX C: Results of WAG and SAG Displacement test

Table C1: WAG DISPLACEMENT TEST (1:1)

Measurement		WAG
Parameter	Unit	
Sample parameters		
V _t	cm ³	233.58
V _p	cm ³	39.22
□	-	0.1679
condition 60 °C 105 bar		
k _v	mD	44.66
q/□p _{avg.}	cm ³ /s/bar	0.0233
Displacement of water using oil		
A	-	0.219778
B	-	1.185400
S _{omax}	-	0.8436
S _{wi}	-	0.1564
N	cm ³	29.90
First Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
□S _w	-	0.5490
S _{wmax}	-	0.7867
ΔE _{DG}	-	0.3411
First water stage of the displacement		
□V _i	V _p	0.5
ΔE _{DW}	-	0.1839
Second Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
ΔE _{DG}	-	0.0621
Second water stage of the displacement		
□V _i	V _p	0.5
ΔE _{DW}	-	0.0211

$E_{Di} = E_{DG} + E_{DW}$	-	0.6082
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Table C2: SAG displacement measurement (1:1)

Measurement		SAG
Parameter	Unit	
Sample parameters		
V _t	cm ³	234.69
V _p	cm ³	35.79
ϕ	-	0.1525
condition 60C 105 bar		
k _v	mD	39.08
q/ ϕ p _{atlag}	cm ³ /s/bar	0.205
Displacement of water using oil		
A	-	0.081131
B	-	1.079362
S _{omax}	-	0.9265
S _{wi}	-	0.0735
N	cm ³	31.80
First Nitrogen stage of the displacement		
A	-	0.71249
B	-	1.505984
ϕ S _w	-	0.6640
S _{wmax}	-	0.7700
ΔE_{DG}	-	0.3425
First Surfactant stage of the displacement		
ϕ V _i	V _p	0.5
ΔE_{DS}	-	0.2988
Second Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
ΔE_{DG}	-	0.1011
Second Surfactant stage of the displacement		

$\square V_i$	V_p	0.5
ΔE_{DW}	-	0.059
$\square \square E_{Di} = \square \square DG + \square \square DS$	-	0.8014

Table C3: SAG displacement measurement (1:2)

Measurement		SAG
Parameter	Unit	
Sample parameters		
Vt	cm ³	234.69
Vp	cm ³	35.79
\square	-	0.1525
condition 60 °C 105 bar		
k _v	Md	39.08
q/ \square p _{atlag}	cm ³ /s/bar	0.205
Displacement of water using oil		
A	-	0.081131
B	-	1.079362
S _{omax}	-	0.9265
S _{wi}	-	0.0735
N	cm ³	31.80
First Nitrogen stage of the displacement		
A	-	0.71249
B	-	1.505984
$\square S_w$	-	0.6640
S _{wmax}	-	0.7700
ΔE_{DG}	-	0.3125
First Surfactant stage of the displacement		
$\square V_i$	V_p	0.5
ΔE_{DS}	-	0.2216
Second Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
ΔE_{DG}	-	0.0632
Second Surfactant stage of the displacement		
$\square V_i$	V_p	0.5

ΔE_{DW}	-	0.029
$\square\square E_{Di} = \square\square_{DG} + \square\square_{DS}$	-	0.6263

Table C5:SAG displacement measurement (1:3)

Measurement		SAG
Parameter	Unit	
Sample parameters		
Vt	cm ³	234.69
Vp	cm ³	35.79
\square	-	0.1525
condition 60C 105 bar		
k _v	mD	39.08
q/ $\square p_{atlag}$	cm ³ /s/bar	0.205
Displacement of water using oil		
A	-	0.081131
B	-	1.079362
S _{omax}	-	0.9265
S _{wi}	-	0.0735
N	cm ³	31.80
First Nitrogen stage of the displacement		
a	-	0.71249
b	-	1.505984
$\square S_w$	-	0.6640
S _{wmax}	-	0.7700
ΔE_{DG}	-	0.3125
First Surfactant stage of the displacement		
$\square V_i$	V _p	0.5
ΔE_{DS}	-	0.1167
Second Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
ΔE_{DG}	-	0.0380

Second Surfactant stage of the displacement		
$\square V_i$	V_p	0.5
ΔE_{DW}	-	0.019
$\square \square E_{Di} = \square \square DG + \square \square DS$	-	0.4862

Table C6: SAG displacement measurement (2:1)

Measurement		SAG
Parameter	Unit	
Sample parameters		
V_t	cm^3	234.69
V_p	cm^3	35.79
\square	-	0.1525
condition 60°C : 105 bar		
k_v	mD	39.08
	$cm^3/s/bar$	0.205
Displacement of water using oil		
A	-	0.081131
B	-	1.079362
S_{omax}	-	0.9265
S_{wi}	-	0.0735
N	cm^3	31.80
First Nitrogen stage of the displacement		
A	-	0.71249
B	-	1.505984
$\square S_w$	-	0.6640
S_{wmax}	-	0.7700
ΔE_{DG}	-	0.2013
First Surfactant stage of the displacement		
$\square V_i$	V_p	0.5
ΔE_{DS}	-	0.1777

Second Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
ΔE_{DG}	-	0.0523
Second Surfactant stage of the displacement		
$\square V_i$	V_p	0.5
ΔE_{DW}	-	0.032
$\square \square E_{Di} = \square \square_{DG} + \square \square_{DS}$	-	0.4633

Table C7:SAG displacement measurement (3:1)

Measurement		SAG
Parameter	Unit	
Sample parameters		
V_t	cm^3	234.69
V_p	cm^3	35.79
\square	-	0.1525
condition 60C 105 bar		
k_v	mD	39.08
$q/\square p_{atlag}$	$cm^3/s/bar$	0.205
Displacement of water using oil		
A	-	0.081131
B	-	1.079362
S_{omax}	-	0.9265
S_{wi}	-	0.0735
N	cm^3	31.80
First Nitrogen stage of the displacement		
A	-	0.71249
B	-	1.505984
$\square S_w$	-	0.6640
S_{wmax}	-	0.7700
ΔE_{DG}	-	0.1247
First Surfactant stage of the displacement		
$\square V_i$	V_p	0.5
ΔE_{DS}	-	0.1088

Second Nitrogen stage of the displacement		
A	-	0.650711
B	-	1.821366
ΔE_{DG}	-	0.0240
Second Surfactant stage of the displacement		
$\square V_i$	V_p	0.5
ΔE_{DW}	-	0.019
$\square \square E_{Di} = \square \square_{DG} + \square \square_{DS}$	-	0.2765

Where ΔE_{DW} = Oil recovery of water phase

ΔE_{DG} = Oil recovery of gas phase; V_p = pore volume; N = Original oil in place (OOIP);

A, B are displacement constant;

Somax= maximum oil saturation

S_{wi} = irreducible water saturation

V_t = total volume of core sample

K_v = average effective permeability of core

Table C 8: Surfactant breakthrough data in with increase in Surfactant solution volume

PORE VOLUME	BREAKTHROUGH VOLUME (CC)		PORE VOLUME	BREAKTHROUGH VOLUME (CC)		PORE VOLUME
0	0		0	0		0
0.5	0		0.33	0		0
1	5.395		1	14.15		1
1.5	13.265		1.33	16.65		1
2	25.285		2	36.65		2

Table C9: Surfactant breakthrough data in with increase in Gas volume

PORE VOLUME	BREAKTHROUGH VOLUME (CC) 1:1	PORE VOLUME	BREAKTHROUGH VOLUME (CC) 1:2		PORE VOLUME	BREAKTHROUGH VOLUME (CC) 1:3
0	0	0	0		0	0
0.5	0	0.67	0		0.75	0
1	5.395	1	1.86		1	0.07
1.5	13.265	1.67	2.2		1.75	0.09
2	25.285	2	3.13		2	0.11

Table C10: Experiment #3, WAG FLOODING (G-W-G-W)

Time(mins)	Pore Volume	Dp
0	0	0
5.37	0.05	3
7.52	0.07	3
10.06	0.09	2
11.14	0.1	2
16.11	0.15	3
18.25	0.17	2

21.15	0.197	3
21.47	0.2	2
27.24	0.25	3
30.06	0.28	1
32.21	0.3	3
35.43	0.33	0
36.51	0.34	2
42.27	0.39	3
43.35	0.4	3
45.10	0.42	3
46.17	0.43	1
47.24	0.44	3
48.32	0.45	1
49.39	0.46	1
50.46	0.47	2
51.54	0.48	1
52.07	0.485	2
53.01	0.49	2
53.33	0.493	3
53.36	0.497	3
54.09	0.5	1
54.08	0.501	3
54.29	0.502	0
54.01	0.503	2
54.11	0.504	2
54.22	0.505	0
54.33	0.506	3
54.44	0.507	3
54.54	0.508	2
55.05	0.509	3
64.42	0.6	4
65.50	0.61	4
68.04	0.63	3
67.12	0.64	2
73.01	0.68	2
75.16	0.7	0
78.38	0.73	2
79.45	0.74	0
80.53	0.75	0
84.15	0.78	0
85.22	0.79	0
97.03	0.9	0
107.37	1	0

114.21	1.06	0
115.29	1.07	1
118.11	1.1	1
121.33	1.13	2
122.40	1.14	2
124.55	1.16	3
126.02	1.17	1
129.24	1.2	2
132.07	1.23	1
134.21	1.25	1
137.43	1.28	3
138.51	1.29	0
139.58	1.3	1
141.05	1.31	0
144.27	1.34	0
146.02	1.36	2
148.17	1.38	0
149.24	1.39	0
150.32	1.4	0
151.39	1.41	0
152.47	1.42	0
157.16	1.46	0
161.06	1.5	0
172.19	1.6	1
177.16	1.65	0
182.53	1.7	0
193.27	1.8	0
204.00	1.9	0
215.14	2	0

Table C11 : Experiment #4 : SAG FLOODING (G-S-G-S)

Time(mins)	Pore Volume	Dp
0	0	0
5.37	0.05	0
7.52	0.07	0
10.06	0.09	0
11.14	0.1	1
16.11	0.15	0

18.25	0.17	0
21.15	0.197	0
21.47	0.2	3
27.24	0.25	2
30.06	0.28	5
32.21	0.3	7
35.43	0.33	4
36.51	0.34	3
42.27	0.39	1
43.35	0.4	2
45.10	0.42	1
46.17	0.43	2
47.24	0.44	3
48.32	0.45	3
49.39	0.46	2
50.46	0.47	1
51.54	0.48	1
52.07	0.485	2
53.01	0.49	1
53.33	0.493	1
53.36	0.497	2
54.09	0.5	1
54.08	0.501	0
54.29	0.502	0
54.01	0.503	1
54.11	0.504	1
54.22	0.505	0
54.33	0.506	0
54.44	0.507	0
54.54	0.508	3
55.05	0.509	7
64.42	0.6	5
65.50	0.61	13
68.04	0.63	12
67.12	0.64	12
73.01	0.68	8
75.16	0.7	5
78.38	0.73	4
79.45	0.74	5
80.53	0.75	2
84.15	0.78	4
85.22	0.79	1
97.03	0.9	1

107.37	1	1
114.21	1.06	0
115.29	1.07	0
118.11	1.1	0
121.33	1.13	3
122.40	1.14	3
124.55	1.16	2
126.02	1.17	3
129.24	1.2	3
132.07	1.23	3
134.21	1.25	4
137.43	1.28	3
138.51	1.29	5
139.58	1.3	4
141.05	1.31	5
144.27	1.34	3
146.02	1.36	5
148.17	1.38	2
149.24	1.39	4
150.32	1.4	2
151.39	1.41	1
152.47	1.42	2
157.16	1.46	1
161.06	1.5	2
172.19	1.6	1
177.16	1.65	1
182.53	1.7	0
193.27	1.8	0
204.00	1.9	0
215.14	2	0

