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# Performance Evaluation of Microscale Displacement Efficiency of Alkaline Surfactant Polymer Injection in Sandstone Cores

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**Abstract**

*The energy industry is saddled with the challenge of meeting up with an ever-increasing global annual energy demand rate. Industry activities over the years have led to an inexorable reservoir production rate decline; hence considerable emphasis is being placed on enhancing the currently available petroleum reserve. Technological advancements have established a way for new assets to be brought to light, based on the effort to improve the recovery of hydrocarbons from a wide variety of fields through Enhanced Oil Recovery. This work focuses on examining the effect of flooding four different light oil saturated sandstone cores, using an alkaline-surfactant-polymer chemical slug to assess the displacement efficiency of the flooding process vis-à-vis some petrophysical properties of the cores. The experiment used Niger Delta Crude Oil, sodium hydroxide (NaOH) as the alkaline, Shell Enordet O242 surfactant and Hengfloc 63020 Polymer, Core samples (Bentheimer, 2 ROBU cores and Berea), and Brine solution. A flow rate 1cc/min was used, and the flooding experiments were done for the four core samples. In the results, it is observed that the ROBU core (Core β) delivered the highest displacement efficiency and best incremental oil recovery. This is closely followed by Bentheimer (Core α), then ROBU (Core γ) despite having the best porosity, before Berea (Core δ). The results show that ASP flooding could be used in a Pilot test on a Niger Delta reservoir similar in Petrophysical properties to the cores used to improve oil recovery.*

## 1. Introduction

Even though Primary oil recovery techniques use different mechanisms, some of which are popularly grouped as Gas drive, Water drive and a combination of both in some cases, the uniqueness of these techniques is that they do not require the natural or original energy of the reservoir to be augmented by any means before oil production is achieved to the surface.

For the Secondary recovery technique, it is not so. This waterflooding supplements the reservoir pressure, thereby increasing oil recovery. Alternatively, injection of dry hydrocarbon gas can be used for pressure maintenance [1]. Typically, only 30% of the oil in a reservoir can be extracted. Still, water injection increases that percentage (known as the recovery factor) and maintains the production rate of a reservoir over a more extended period [2].

Enhanced oil recovery (EOR) involves the injection of certain chemicals to alter the reservoir fluid properties thereby enhancing oil recovery. Density, viscosity, surface tension and so on are some of the reservoir fluid properties that are affected by the EOR processes. It is always the alternative after waterflooding, a secondary recovery technique; hence the term Tertiary recovery is often designated to it. The term quaternary recovery denotes more advanced, speculative, EOR methods in other rare cases. [3,4,5].

The Alkaline-Surfactant-Polymer method is a Chemical Enhanced Oil Recovery (CEOR) method whereby alkali, surfactant and polymer are injected into the same slug. In such methods where all three chemicals are employed in a combination [6,7], the polymers increase the viscosity of injected water, which improves sweep efficiency [8,9,10]. On the other hand, Surfactants decreases interfacial tension between the injected water and the crude oil, thereby enhancing displacement efficiency [11,12,13]. Alkaline chemicals generate soap when reacting with crude oil, which reduces surfactant adsorption on the reservoir rock. The chemical methods aim to reduce the Interfacial Tension between oil and water, generally to displace discontinuous trapped oil that remains after water flooding [14,15,16]. Therefore, in designing the Alkaline, Surfactant or Polymer chemicals used in flooding, it is essential to ensure that factors such as concentration, pH, temperature, salinity, and ionic strength are taken into experimental design techniques.

Early stages of Chemical flooding prove that polymer flooding is a confirmed Chemical EOR technology, in carbonate reservoirs and has been successfully conducted in other reservoir models such as fractured reservoirs, sandstone and carbonate matrix-rock reservoirs, including water-wet, mixed-wetting, and oil-wet reservoirs [17]. Nevertheless, carbonate reservoirs have made a relatively small contribution to polymer flooding in terms of total oil recovered in the United States [18].

Chemical EOR has been used to alter permeability variations in reservoirs before now [17]; hence there is an established relationship between the effect of chemical flooding on reservoir rock models and the total oil recovered after flooding. Foroozanfar [19] describes this specially in the case where injected polymer solutions stack up in extreme permeability fonts and change the direction of subsequently injected fluid to other parts of the reservoir.

It is also evident in the adsorption of surfactant in the surfactant flooding process, whereby surfactant encounters the reservoir rock or core and brine thereby leading to a loss of surfactant at the solid-liquid interface. The type and characteristics of the porous rock present affects adsorption of surfactant into a porous media. It has been reported [20] that the adsorption of petroleum sulfonate can be reduced in the presence of Dow pusher polymer and tripolyphosphate. The adsorption of sulfonates on oil-wet cores was found to be greater than on water-wet cores [21].

Aside from adsorption and permeability, Chemical EOR has shown a high degree of sensitivity to reservoir heterogeneity, it is therefore pertinent study and examine the microscale effect of chemical flooding in different reservoirs. This would aid a more meaningful larger and wider scale application of chemical flooding in such reservoirs as well more effective outcome. This work focuses on examining the effect of flooding four different light oil saturated sandstone cores, using an alkaline-surfactant-polymer chemical slug to assess the displacement efficiency of the flooding process vis-à-vis some petrophysical properties of the cores such as porosity and permeability. Relatively, the optimal application of each type of ASP flooding depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity, and fluid properties such as API gravity and viscosity.

## 2. Materials & Methodology

*2.1 Materials*

This experiment was carried out with the following materials: Crude oil which was obtained from Niger Delta (Nigeria), sodium hydroxide (NaOH) as the alkaline source with the purity of 98%, Hengfloc 63020 as the polymer component from Hengju Beijing (China), Shell Enordet (enhanced oil recovery detergent) O242 as the surfactant, four core samples were used for this experiment namely Bentheimer Sandstone, ROBU cores (two different porosity and permeability classes) and Berea core. Cores labelled α, β, γ, and δ respectively were used in the experiment. Core α is a homogenous model rock, Bentheimer. Core β is a model rock, ROBU. Core γ is a model rock ROBU but with a different porosity class. Core δ is a Berea core.

*2.2 Apparatus*

Equipment used to carry out this experiment consists of a magnetic stirrer, Vacuum pump, beakers, measuring cylinders, core holders, heating jackets, Teledyne Isco pumps for pumping fluid and the chemical slug into the cores, pressure transducer for measuring pressure of fluids, viscometer for viscosity measurements.

*2.3 Methodology*

*2.3.1 Preparation of reagents*

a. Brine preparation: The solution was prepared from a combination of sodium Chloride and distilled water in a beaker, which was then mixed with a magnetic stirrer for some minutes until all the salt crystals were dissolved to form a uniform solution. The brine for making up the solution consists of distilled water and 1.5wt% of sodium chloride.

b. Chemical Slug preparation: The chemical slug used in this experiment consisted of different concentrations of surfactant, alkali and polymer freshly prepared using a magnetic stirrer. The preparation of polymer solution needs special attention. It was prepared with a minimum degree of agitation. Chemical concentration of ASP agents used in this experiment are 1.5% NaOH, 0.03wt% Hengfloc63020 polymer, 0.3% Shell Enordet 0242 surfactant. The chemicals were measured using the electronic weighing balance. The viscosity of the ASP solution is 2.1cp. The chemical slug used in all core experiments was freshly prepared to avoid mechanical degradation.

c. Core preparation: The dry weight of the cores (weight before brine saturation) was measured with digital mass balance. The Cores were vacuumed in a saturation chamber for about 12 hours until there was no more gas in the chamber.

*2.3.2 Fluid properties determination*

Properties of the fluid (oil) in this experiment were measured and listed as follows: Viscosity 2.5cp, Temperature($25^0$C), Specific gravity 0.8921, API gravity 42.86. Crude oil has a blackish-brown color, making it easier to visually distinguish from the water. The Oil was filtered through a 5-micron mesh to remove any form of fines that may clog the pore network of the core.

*2.3.3 Core properties determination*

The dimensions of the core samples were measured, and the Bulk volume was determined by the expression below:

$$V_b = \pi D^2 h/4 \tag{1}$$

*2.3.4 Brine Saturation*

Then, the cores were saturated with the brine and were also pressurized to 1000psi for 24 hours in a high-pressure vessel to ensure proper saturation. Brine was injected at constant flow rate and the water permeability was measured. The wet weight of the cores (weight after brine saturation) was then measured. The difference between the wet and the dry weight of the core samples is then converted to pore volume, using brine density. The Porosity of the cores were determined using:

$$\Phi = (W_w\text{-}W_d/\rho)/V_b = V_p/V_b \tag{2}$$

*2.3.5 Oil saturation*

Oil saturation was done at 1cc per minute by oil displacing water through each of the cores until no water production to attain initial Oil saturation; effective water permeability was determined as well. The volume of the water displaced was used to evaluate the volume of initial oil in place and consequently initial water saturation.

*2.3.6 Alkaline-Surfactant- Polymer Flooding Experiments*

The core flooding system consisted of several components such as a core holder holding the core(s) in place, Teledyne isco pump which could be run independently or in pairs, a measuring cylinder.

Four separate flooding experiments were carried out with the injection of the prepared Alkaline-Surfactant-Polymer slug as above into the four core samples used, at a flow rate of 1cc/min was used for the injection. Effluents (oil + ASP slug) produced were collected in measuring cylinders, the volume of oil and ASP fluid collected were measured separately for the duration. Flooding continued until the volume of oil produced was visibly insignificant. The core flooding process was carried out at a room temperature of 25˚C.

The same processes were performed for all the cores (Bentheimer, Berea, and two types of ROBU cores).

*2.3.7Displacement efficiency ($E_d$) determination*

This is the fraction of oil that has been recovered from zones swept by the Alkaline-Surfactant-Polymer slug [22], mathematically,

$$E_d = (S_{oi} - S_{or}) / S_{oi} \tag{3}$$

*2.3.8 Core & Flooding Raw Calculation*

These calculations are for results that are stipulate by equations from laboratory results; Bulk volume was determine by Eq (1) given the measured length of core and diameter of core in the laboratory. The measured wet and dry weight were used in Eq (2) to stipulate the porosity of the cores. Eq (3) was used after the flooding had been completed and saturations determined respectively to obtain the displacement efficiency.

## 3.0 Results and Discussions

The data obtained from the experiment are presented in this section. The properties of the cores are reported in Table 1 below. The table also consists of the results from waterflooding and ASP flooding of the different core models.

Table 1: Core samples and their measured properties and flooding results.

| Type | Symbols | Core α | Core β | Core γ | Core δ |
|---|---|---|---|---|---|
| Core properties | | Bentheimer | ROBU | ROBU | Berea |
| Diameter | D (cm) | 3.5 | 3.61 | 3.61 | 3.48 |
| Length | L (cm) | 8.25 | 7.08 | 6.99 | 7.29 |
| Wet weight | $W_w$ (g) | 91 | 67.02 | 70.69 | 84.76 |
| Dry weight | $D_w$ (g) | 72.58 | 47.84 | 44.91 | 65.14 |
| Bulk volume | $V_b$ ($cm^3$) | 79.33 | 72.58 | 71.59 | 69.62 |
| Pore volume | $V_p$ ($cm^3$) | 18.42 | 19.18 | 25.78 | 19.62 |
| Porosity | Φ (%) | 23.21 | 26.43 | 36.01 | 28.18 |
| Permeability (Brine) | P (mD) | 1300 | 3662 | 2178 | 1870 |
| Oil Initially in place | OIIP (cc) | 16.8 | 17.05 | 22.43 | 12.75 |
| Initial oil saturation | $S_{oi}$ (%) | 91.21 | 88.89 | 87.01 | 64.98 |
| Initial water saturation | $S_{wi}$ (%) | 8.79 | 11.11 | 12.99 | 35.02 |
| Oil recovery after waterflooding | $OR_W$ (cc) | 10.18 | 8.7 | 11.86 | 6.63 |
| Oil recovery after waterflooding | $OR_W$ (%) | 60.6 | 51.03 | 52.88 | 52 |
| Oil recovery after ASP flooding | $OR_{ASP}$ (cc) | 6.39 | 8.18 | 9.8 | 4.95 |
| Oil recovery after ASP flooding | $OR_{ASP}$ (%) | 38.04 | 47.98 | 43.69 | 38.82 |
| Displacement Efficiency | $E_d$ (%) | 96.53 | 97.96 | 92.72 | 80.88 |

The ASP flooding experiment is shown to study the fluid flow mechanism of ASP flooding to enhance both displacing efficiency and sweeping efficiency through analyzing production performance. The summary of the core flooding results was presented in Table 1, Figure 1 and Figure 2.

The eighth row on the table consists of the porosity values determined by the pore volume and the bulk volume of the cores. Bearing in mind that the cores are sandstone cores we see that the average core porosity is about 28.46% where **Core α** comes in with the least porosity of about 23.21% while **Core γ** comes in with the highest porosity of 36.01%. This is a conforms with porosity ranges in literature for Niger Delta formation, Alaminiokuma and Ofuyah [26] reveal in their study of porosity and permeability regimes for typical Niger delta reservoirs that porosity ranges for hydrocarbon bearing reservoirs is about 29% to 45%. They also revealed [26] that permeability values for a typical hydrocarbon bearing sandstone in Niger delta could range 2200mD to about 5789mD, meanwhile we observe in Table 1 that our cores have permeabilities in that range, particularly **Core β** and **Core γ** with permeabilities of 3662mD and 2178mD respectively. A permeability of 1870 mD was observed for **Core δ** and **Core α** about 1300mD these values are not too distant from the lower class of the range. It is important to note that the permeability values were determined through and during brine injection. Given this relative similarity in petrophysical properties of our experimental model cores with literature, our study becomes a highly reasonable simulation to real life industry and field scenarios.

The subsequent rows beneath the permeability row as tabulated respectively above in Table 1 show results for flooding experiments and relevant calculations for (Core **β**), 3 (Core **γ**), and 4 (Core **δ**) as should be outlined, the raw calculations for **Core α** as o model can be found in the appendix section.

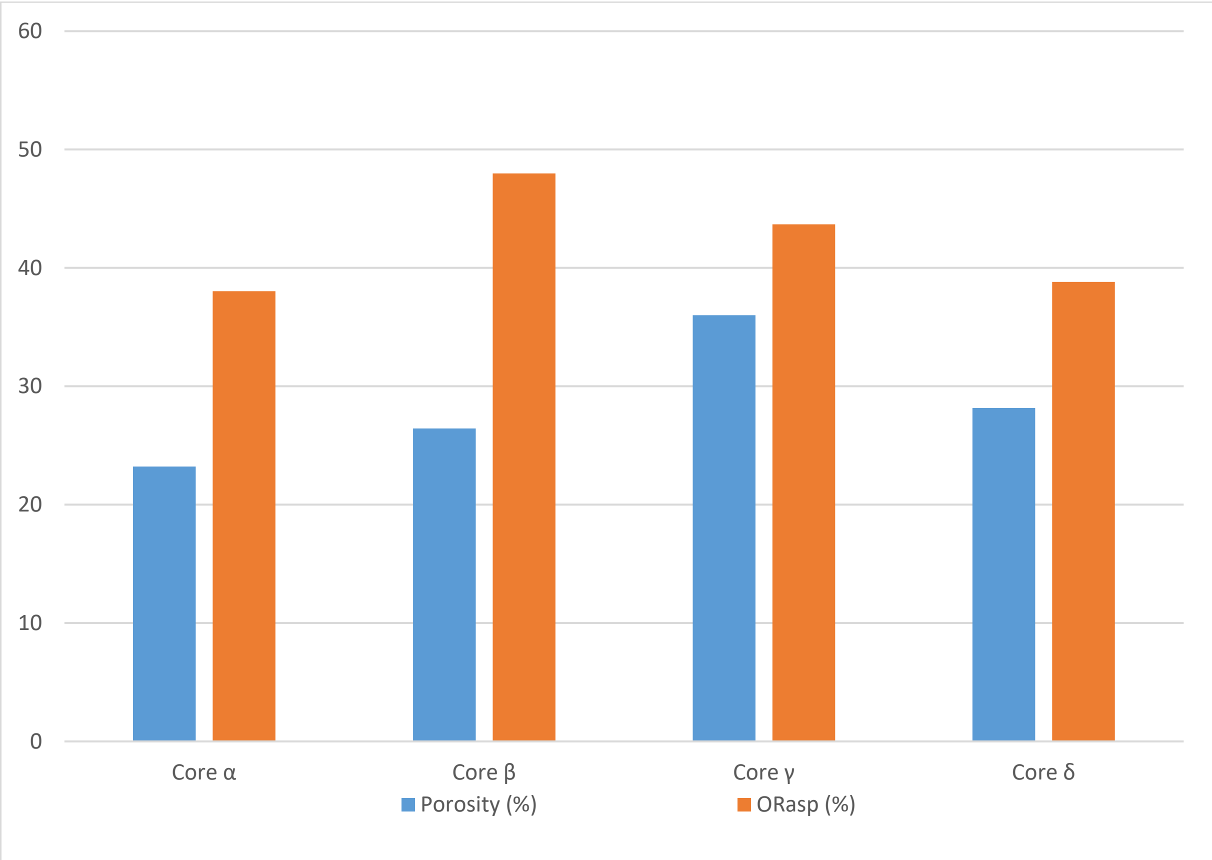


Figure 1: A chart showing the relationship between the core porosity and the incremental oil recovery percentage after ASP flooding ensuing

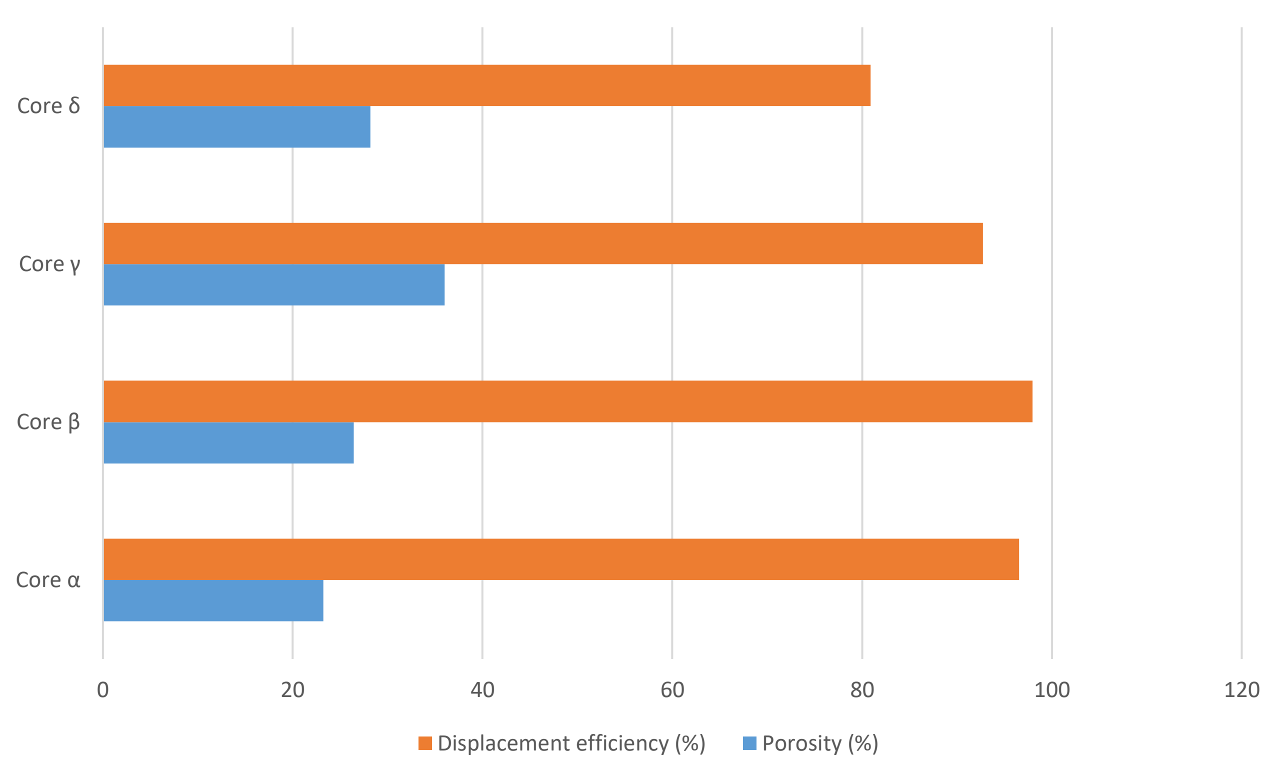


Figure 2: Chart showing the relationship between the porosity of core samples and resultant displacement efficiency of the ASP flooding on each core

As illustrated above, Figure 2 shows a graph of different core samples (Core **α, β, γ** and **δ**) and their various displacement efficiencies while Figure 1 shows their oil recovery after ASP flooding

<u>Porosity</u>

The flooding results from Table 1 and illustration from Figure 1 and 2 shows that core **γ** despite having the highest porosity amongst other cores neither gave the highest recovery after waterflooding nor highest incremental oil recovery and displacement efficiency. Rather, it is core **β** with a porosity lower than that of cores **γ** and **δ** that gave the highest recovery. Pore plugging, and trapping [23] are some mechanisms by which the porosity of the medium is hindered from optimal production. These can be caused by the adsorption of surfactant used in this experiment. Still on adsorption [24], the Alkali used in the preparation of the ASP slug, Sodium Hydroxide in recent years has been infamous for very high levels of adsorption and reservoir plugging [25]. Therefore, it is recommended that for correlation's sake, multiple samples of a particular formation should be tested on a micro-scale to establish a probable model between permeability, the porosity of core type and laboratory EOR results before intended use on a larger scale.

<u>Oil recovery by waterflooding</u>

It is interesting to note that core **α** gave the highest oil recovery after water flooding, this, therefore, means that core **α** is the best candidate for water flooding operations among the four core samples. As an observation result, ASP flooding brings a higher oil recovery and lower water cut than traditional water flooding. However, the incremental amount is not similar since geologic characteristics have strong effects on the ASP process. Unlike water in waterflooding, [13] Surfactant reduces the capillary pressure in the reservoir while polymer increases the viscosity of the injected fluid to improve mobility control [10,14].

Oil recovery by ASP flooding

Figure 1 shows a graph of the oil recoveries of the various core samples after ASP flooding showing the best rock core sample to be used by merely reading the chart. The case in Figure 1, Core **β** showed the highest increment in oil recovery, from the graph, it is evident that Core **β** (ROBU rock) shows better recovery than the other cores. This high oil recovery was due to the cooperative effect between alkali, surfactant, and polymer to emulsify and mobilize the crude oil. This increases both the displacement efficiency and sweep efficiency [10].

Displacement Efficiency

From the graph in Figure 2, Core **β** shows the highest displacement efficiency with a value of 96.67% followed by Core **α**, then Core **γ**, before Core **δ**. The ROBU rock (Core **β**) gave the best incremental oil recovery and displacement efficiency when Alkaline-Surfactant-Polymer (ASP) flooding was applied.

Overall, this laboratory study shows that ASP chemical flooding process has a great potential for recovery of Niger Delta Oil in reservoirs [26] with similar petrophysical properties as outlined earlier in the beginning of this discussions.

## 4. Conclusion

Based on the findings and results of the Alkaline-Surfactant-Polymer flooding carried out on the four core samples, the core flood study showed Alkaline Surfactant Polymer (ASP) flooding subsists as a reliable enhanced oil recovery option for incremental recovery of reservoirs within the Niger Delta with porosity range of and fluid properties as the cores considered above. The ASP slug recovered over 47.98% of Oil in (Core β) ROBU rock, 43.69% in the second ROBU (Core **γ**), and 38.82% in the Berea (Core **δ**), while cores β, **γ** and **δ** are worthy of consideration for flooding at raised temperature, in the case of this experimental results above, Core **β** (ROBU) produced the best results despite its relatively low porosity amongst other cores, hence it simulates the best petrophysical properties for applicability of enhanced oil recovery and displacement efficiency using ASP flooding in reservoirs of similar geology.

**Nomenclature**

$S_{oi}$ = saturation of oil at start of flood.
$S_{or}$ = volume of oil remaining after flood.
$\Phi$ = porosity
$V_p$= pore volume (cc)
$V_b$= Bulk volume (cc)
$W_w$ = core wet weight (g)
$W_d$ = core dry weight (g)
$\rho$ = Brine density (g/cc)
D = diameter of Core
H = length of Core

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**Appendix**

Core & Flooding Raw Calculation

Experiment 1 – CORE α

Length of core **α** (cm) = 8.25 Diameter of core,D (cm) = 3.50

Bulk volume, $V_b$ ($cm^3$) = π $D^2h/4$ = 79.33

Wet weight of core (g) = 91

Dry weight of core (g) = 72.58

Pore volume, $V_p$ ($cm^3$) = $W_w$-$W_d$/ρ where density of brine, ρ is taken as 1.00g/cc

$V_p$=91- 72.58 =18.42 $cm^3$

Porosity, Φ = $V_p/V_b$ = 18.42/ 79.33 = 0.2322 = 23.22%

Volume of water = pore volume = 18.42cc

Volume of water recovered during drainage (oil saturation)

Assuming volume of oil injected = volume of water recovered =16.80cc

OIIP =16.80cc = 16.80/ 18.42 =0.9121 =91.21% OIIP

$S_{wi}$ = 1- $S_{oi}$ = 1- 0.9121 = 0.0879 = 8.79%

Oil recovered after water flooding (Or.w) = 10.18cc = 10.18/18.42 = 0.6060 = 60.60%

Oil recovered after ASP flooding (Or.asp) = 6.39cc = 6.39/18.42 = 0.3804 = 38.04%

Displacement efficiency, $E_d$ = ($S_{oi}$ – $S_{or}$) / $S_{oi}$ = 96.53%

For the 1st experiment with Core **α** of Pore volume 6.58cc after core preparation, initial oil saturation was about 91.21%. The injection of the ASP slug led to an increase in recovery of 38.04% OIIP. The displacement efficiency after ASP was 96.53%.