ISSN 2522-9400 **European Modern Studies Journal** Vol 7 No 3
available at www.journal-ems.com

DOI: 10.59573/emsj.7(3).2023.26

Enhanced Oil Recovery in a Selected UAE's Tight Carbonate Reservoir by Flooding of Sodium Lauryl Sulfate and High Saline Water

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Abstract. Enhanced oil recovery has become an essential process in oil production due to the large amount of oil that could not be produced by the primary and secondary oil recovery techniques and the increasing demand for oil. The main purpose of the enhanced oil recovery process is to transfer oil in the production wells by the flooding of different fluids to increase the natural energy present in the reservoir and alter the properties of reservoir's properties such as interfacial tension, rock wettability, oil and water viscosity, pH.

Enhanced oil recovery may be divided into the following categories: Thermal methods, Miscible flooding, Microbial enhanced oil recovery (MEOR), Foam flooding, Gas injection, Plasma-pulse, and Chemical enhanced oil recovery.

A process in which one or more pre-selected chemicals are mixed with water or brine and then flooded into the reservoir to increase the oil recovery factor further than water flooding levels is called chemical enhanced oil recovery (Chemical EOR).

In this research the usage of sodium lauryl sulfate (SLS) had been studied as a surfactant to enhance the oil recovery in one of the United Arab Emirates tight carbonate reservoirs. SLS was mixed with various brines to optimize the brine concentration and SLS concentration in brine. Core rock samples were taken from a tight carbonate reservoir in United Arab Emirates, whereas Bu Hassa crude oil used to perform the flooding, IFT, and AMOTT experiments.

It was found that (SLS) has a significant effect on the interfacial tension between crude oil and all types of brine used in this research, especially on the high saline formation brines, where the residual oil saturation was at the minimum. Hence using the proposed technique will save time, money, and the environment.

Key words: Enhanced oil recovery, Chemical EOR, Surfactant flooding, Tight carbonate reservoirs, Sodium lauryl sulfate

Introduction

Chemical methods of enhanced oil recovery (CEOR) are the most common techniques applied in oil fields, they are defined as a process where one or more pre-selected chemical is mixed with brine and then injected through injecting wells into the rock formation to increase the oil recovery factor further than the brine injecting levels. The purpose of (CEOR) is to increase macro and micro sweep efficiency (Lwisa, 2021).

Sweep efficiency is a measure of the effectiveness of an enhanced oil recovery process or method that depends on the volume of the reservoir contacted by the flooded fluid (Pazos, 2020) (Figure 1).

Polymers are usually used to enhance the macro sweeping efficiency as they increase the viscosity of injected brine, meanwhile surfactants have the capability to increase the micro one due to their ability to reduce the interfacial tension (IFT) between oil and brine (Mandal, 2015).

Surfactants are chemicals that lower the surface tension (or interfacial tension) between a gas and a liquid, two liquids, or between a liquid and a solid. Surfactants could act as emulsifiers, cleansing agent, foaming agents, wetting mediators, or dispersants (Lwisa, 2021).

Surfactants are amphiphilic; hence, every surfactant contains an oil-soluble and a water-soluble component (Rosen, 2017). When a surfactant is combined to a mixture of oil and water, it diffuses in water and absorbs at the border between air and water or at the border between oil and water (Rosen, 2017). The group that is oil-soluble will extend out of the water phase into the air or into the oil phase, meanwhile the water-soluble one remains in the water phase (Rosen, 2017).

Surfactants decrease the surface tension of water by making a thin film at the liquid-air border and adsorbing at that interface (Shchukin et al., 2001). After interface boundary is formed, surfactant adsorption is ruled by the distribution of the surfactant within the interface (Vanselow, 2012). Energy obstacles may occur because of electrostatic disgusts or steric (Schowalter, 1978).

Classifications of surfactants are shown in Figure 2.

Equipment

Soxhlet extractor: The Soxhlet extraction apparatus is widely used for cleaning core samples. Toluene was used to clean core samples from oil, then methanol was used to clean salts as well as toluene, so samples were completely cleaned. To ensure complete cleanness samples were examined under UV light to investigate the presence of residual oil, the scene was dark, and no fluorescence observed. The samples tested with drops of silver nitrite and no white deposit was seen so we made sure that they are free of salts (Torsæter, 2000). The extractor is shown in Figure 3.

PoroPerm: The PoroPerm is made by Vinci Technologies. It is used to determine both porosity and permeability to gas of plug-sized core samples. A hydrostatic high-grade stainless steel core holder can be provided for overburden pressure studies (V. Technologies, 2020). The PoroPerm is illustrated in Figure 4.

Core saturator: The manual saturator is made by Vinci Technologies, it enables the user to obtain remarkable saturation of clean, dry core samples. A pump is used to elevate the pressure up to 2,000 psi (V. Technologies, 2020). The Saturator is illustrated in Figure 5.

The Tracker tensiometer: It is used to measure interfacial tension between oil and water. The lower limit of interfacial tension measurement can be less than 0.1 mN/m (TECLIS, n.d.). The Tracker is made by TECLIS and illustrated in Figure 6.

Water and oil flooding system: it is made by Core Laboratories and used to perform all flooding experiments (V. Technologies, 2020). This system is made by Vinci Technologies and shown in Figure 7.

AMOTT cell: As shown in Figure 8, it is used to obtain the wettability of rock core samples. The apparatus is comprised of a sealed glass container and a graduation tube located above it (V. Technologies, 2020).

Materials

Rock core samples: Nine chalky limestone plug core samples were taken from Upper Zacum field, which is an Emirati oil field, they were selected carefully to have similar diameter, length, nature, rock type, porosity, and permeability; so, none of the above properties will have any effect on the results.

The data of selected cores is reported in Table 1, the values of porosity and permeability are too close to each other where the maximum difference in porosity is 5.1 decimal points, and 0.24 mD in permeability. The average values are 16.48 % for porosity with standard deviation equals to 1.86, and for permeability those values are 0.42 mD and 0.077, respectively.

Grain density of all samples is 2.69 gm/cc indicating the samples are clean and dry, and they are limestone.

Crude oil: The crude oil used in this research is taken from Bu Hassa field in Abu Dhabi, UAE. It is categorized as light crude oil since its API gravity is 35.7° (Lwisa & Abdulkhalek, 2018). To remove any contamination and asphaltene, crude oil was filtered under vacuum by using Whatman filter paper No 1, Grade 1: 11 µm.

Brines: Three types of brins were used during the experiments, their properties are shown in Table 2:

– Formation brine (FW): It was synthesized in the lab to match the formation brine of Bu Hassa oilfield. The chemical composition of formation brine is shown in Table 3.
– Sea water (SW): Also synthesized in the lab to match sea water of the Arabian Gulf. The chemical composition of sea water is shown in Table 4.
– Low saline water (LowSal): Obtained by diluting sea water 10 times by distilled water.

Surfactant: Sodium lauryl sulfate (SLS), AKA sodium dodecyl sulfate, is an anionic surfactant commonly used as an emulsifying cleaning agent in house cleaning products (Rosen, 2017). During this research SLS was proved to have a great ability to reduce the (IFT) between crude oil and high salinity brines and it was stable and effective at reservoir temperature, which leads to a considerable enhancement of oil recovery.

Methodology

Measurement of Interfacial Tension (IFT)

The (IFT) was measured at laboratory temperature (23 ºC), three blends of Bu Hassa crude oil and brines at various salinity were prepared and (IFT) measured as base line, then surfactant was added in two different concentrations; 1 cc per liter and 5 cc per liter, (IFT) was measured for all blends.

Results of interfacial tension measurements are reported in Table 5, results are more explained and illustrated in Charts 1, 2, 3, and 4.

Interfacial tension tests are shown in Figures 9 through 17.

Flooding Samples with Oil down to Irreducible Water Saturation (Swi)

After choosing the samples, their porosities and permeabilities were measured, then they were saturated with formation brine by vacuum and pressure method.

Samples were flooded with crude oil to displace brine from the pores, each core was flooded until no brine was produced, so we made sure that they reached the state of (irreducible water saturation, Swi), then samples were placed in container that is filled with the same crude oil and were aged for three weeks.

Once gaining is completed, each sample was flooded with crude oil again to check for any incremental brine production.

At this stage samples were ready to go for water flooding to examine the effectiveness of various brine mixtures.

The values were obtained through the following equations:

- Equation 1
  Volume of original brine in place= (weight of saturated sample-weight of dry sample)/ (brine density)
- Equation 2
  Irreducible water saturation= (volume of brine in place)/ (volume of original brine in place) *100

The oil flooding results are shown in Table 6 and illustrated in Chart 5.

Flooding Samples with Brines down to Residual Oil Saturation (Sor)

To study the effect of brine salinity and surfactant concentration on oil recovery, samples were subjected to several types and systems of water flooding: namely:

- Sample 1B: Formation brine followed by sea water,
- Sample 2B: Formation brine mixed with surfactant at 1 cc/liter followed by sea water.
- Sample 3B: Sea water followed by low saline brine.
- Sample 4B: Sea water mixed with surfactant at 1 cc/liter followed by low saline brine.
- Sample 5B: Low saline brine.
- Sample 6B: Low saline brine mixed with surfactant at 1 cc/liter.
- Sample 7B: Formation brine mixed with surfactant at 5 cc/liter.
- Sample 8B: Sea water mixed with surfactant at 5 cc/liter.
- Sample 9B: Low saline brine mixed with surfactant at 5 cc/liter.

The results were obtained by the following equations:

- Equation 3
  Volume of original oil in place=Volume of produced brine during oil flooding
- Equation 4
  Residual oil saturation= (Volume of residual oil)/ (Volume of original oil in place) *100
- Equation 5
  Oil recovery percentage=100-Residual oil saturation

Amott Tests

To study the spontaneous effect of surfactant concentration on oil displacement, six samples were subjected for imbibition Amott test. Clean and dry samples were saturated with formation brine down to residual oil saturation (Sor) and placed in imbibition Amott tubes, the volume of produced oil was observed daily.

The core samples were left in the tubes for eight weeks, to make sure that no more oil is displaced.

Results of the tests are shown in Table 20.

Spontaneous oil sweating is shown in Figure 18.

Results and Discussion

- Chart 1 shows that sea water has the lowest (IFT) value, however the three values are close to each other as the maximum difference is only 0.75 man/m.
- Chart 2 explains that by adding only 1 cc to a liter of brine the (IFT) values dropped dramatically; for the formation brine it dropped from 5.1 mN/m to 0.82 mN/m, for sea water it dropped from 4.25 mN/m to 0.23 mN/m, and for low saline water in dropped form 4.81 mN/m to 0.41 mN/m. Sea water still has the lowest (IFT) value and had the largest drop ratio as the (IFT) value was reduced by 19 times, where the reduction was only 6 times and 12 times for formation brine and low saline water respectively.
- Chart 3 clarifies that by adding surfactant the interfacial tension continues to drop but not in a significant way; sea water still has the lowest (IFT) value as it scored 0.09 mN/m whereas this value was 0.82 mN/m and 0.41 mN/m for formation brine and low saline brine, respectively. Sea water also recorded the biggest reduction ratio as the (IFT) was reduced by 47 times, where in case of formation brine and low saline brine the ratios were 26 times and 30 times correspondingly.

It is so important to mention that the reduction in (IFT) values when adding surfactant was the highest in case of formation brine, as it was reduced by 4 times (from 0.82 to 0.19 mN/m), this value was only 3 for the other two brines.

- Sample 1B: Formation brine followed by sea water; the results are shown in Table 7 and 8.

No big enhancement was observed after flooding with sea water, the residual oil saturation was reduced from 30.8 to 29.1 which means the oil recovery was enhanced by 1.71 %.

The detailed flooding experiment is shown in Table 21 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 8.

- Sample 2B: Formation brine mixed with surfactant at 1 cc/liter followed by sea water; the results are shown in Table 9 and 10.

The residual oil saturation reduction is still low, it moved from 14.3% down to 12.5%, which means that the oil recovery was enhanced by only 1.82%, still low.

The tremendous change was in the primary (Sor), in the first case when the sample was flooded with formation brine, (Sor) was 30.8% and dropped to 14.3% when surfactant was added to that brine, the concentration of surfactant is 1 cc/liter, but the oil recovery jumped from 69.2% to 85.7%.

The detailed flooding experiment is shown in Table 22 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 9.

- Sample 3B: Sea water followed by low saline brine; results are reported in Table 11 and 12.

The results are near to the first case where the first (Sor) is 27.1% and reduced to 26%, so oil recovery was enhanced by 1.10%

The detailed flooding experiment is shown in Table 23 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 10.

- Sample 4B: Sea water mixed with surfactant at 1 cc/liter followed by low saline brine; results are shown in Table 13 and 14.

It is obvious that the surfactant has no effect on oil production when mixed with sea water. By using sea water alone, (Sor) reached 27.1% and reduced by little amount when surfactant added to reach 24.8%, which is still high. Flooding the sample with low saline water after this mixture did not make a significant difference as well, and the final oil recovery was 76.4.

The detailed flooding experiment is shown in Table 24 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 11.

- Sample 5B; results are reported in Table 15.

It is easy to conclude that low saline water has a better effect on oil recovery than formation brine and sea water as residual oil saturation reached 21.8% whereas it stopped at 30.6% when formation brine was used and 27.1% in sea water flooding case. However, low saline water is still so far from reaching the (Sor) point that happened when formation brine was mixed with surfactant at 1 cc/liter.

The detailed flooding experiment is shown in Table 25 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 12.

- Sample 6B: Low saline brine mixed with surfactant at 1 cc/liter; results are shown in Table 16.

Adding 1 cc/liter surfactant to low saline brine enhanced the oil recovery from 78.2% to 80.3% which is not significant and still far from 85.73 % which recorded by injecting Formation brine mixed with surfactant at 1 cc/liter.

The detailed flooding experiment is shown in Table 26 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 13.

- Sample 7B: Formation brine mixed with surfactant at 5 cc/liter; results reported in Table 17.

The results show that this mixture is the best so far, that residual oil saturation is the lowest and scored 10.0% which means the 90.0% of oil was recovered in one flooding cycle. Surfactant is more effective when mixed with saline brines. That is promising towards saving money and time.

The detailed flooding experiment is shown in Table 27 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 14.

- Sample 8B: Sea water mixed with surfactant at 5 cc/liter; results reported in Table 18.

The test clarified that in case of lower salinity of water, the effectiveness of surfactant declines dramatically when its concentration increases. That is the opposite of what happened in the formation brine case.

The detailed flooding experiment is shown in Table 28 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 15.

- Sample 9B: Low saline brine mixed with surfactant at 5 cc/liter; results reported in Table 19.

This test emphasis the previous conclusion about the surfactant effectiveness because the residual oil saturation stopped at high values and recorded 36.4%, means that only 63.65% of oil has been recovered, it is even lower that what recovered by flooding formation brine alone.

The detailed flooding experiment is shown in Table 29 while the cumulative oil production/ total oil production VS Time is illustrated in Chart 16.

- Residual oil saturation and oil recovery factors of all up mentioned methods are illustrated in Chart 6 and 7 respectively, the highest (Sor) was obtained in low saline brine mixed with surfactant at 5 cc/liter, and the lowest was achieved in formation brine mixed with surfactant at 5 cc/liter, (Sor) values were 37.15% and 10.00% respectively.

On the contrary, the lowest oil recovery was 62.83% and the highest was 90.00% in the mentioned flooding methods, respectively.

All information of cumulative oil production/ total oil production VS Time is illustrated in Chart 17.

The above-mentioned results are also correct for spontaneous oil displacement, Amott test makes clear that surfactant is more effective when mixed with formation brine and it gets better if its concentration is increased, meanwhile the opposite happened with sea water and low saline brine mixtures. The sweated-out oil increased form 0.8 cc to 1.2 cc when concentration elevated from 1 cc/liter to 5 cc/liter for formation brine mixture, but almost no changes occurred with other mixtures and concentrations, and the volume did not exceed 0.4 cc in case sea water and surfactant at 5 cc/liter, while it was less than that in low saline brine mixtures and stopped at 0.2 cc.

Conclusion

High saline water flooding, also known as (formation brine flooding) may help to recover up to 71% if used alone.

Sea water flooding, this technique may be applied in offshore and near sea reservoirs where reaching and mobilizing sea water is easy. The method is able to recover 74% of oil in place.

Low saline water flooding is a widely studied method, it aims to reduce the interfacial tension (IFT) between oil and brine. In this technique brine is desalinated or diluted so the salt concentration becomes 5000 ppm (5 gram/ liter), which reduces the IFT down to 11 mN/m. The method has a major drew back, that requires a huge amount of fresh water to desaline formation brine (concentration 163 gram/ liter) or sea water (50 gram/ liter) down to 5 gram/ liter).

However, the low saline water flooding may recover about 78% of oil in place.

Sodium lauryl sulfate is safe to be used with minimum precautions, significantly reduced the IFT between oil and ultra-high saline formation brine which is naturally available on well site in vast amounts.

No other additives are required.

No desalination is needed; hence no fresh water is required and 90% of oil in place was produced by using only one flooding process, which results in cost reduction.

It was found that (SLS) has a significant effect on the interfacial tension between crude oil and all types of brine used in this research, especially on the high saline formation brines, where the residual oil saturation was at the minimum.

Hence using the proposed technique will reduce the cost, expenses, the amount of fresh water required to prepare low saline brines and smart brines, it also has a positive impact on the environment.

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Figures

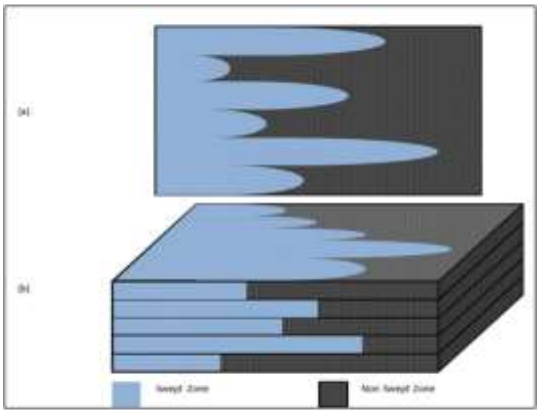

Figure 1: Swept areas.

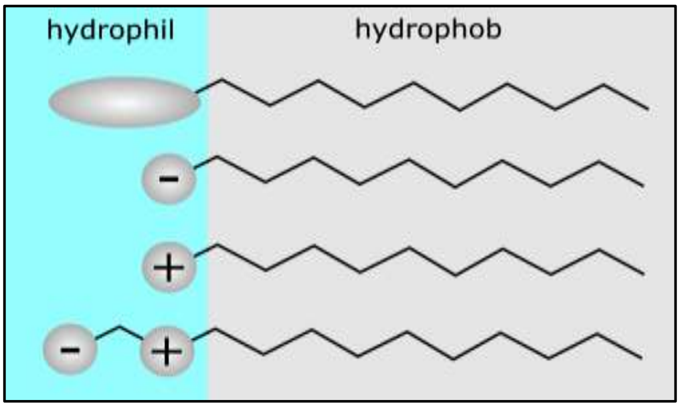

Figure 2; Surfactant classification according to the composition of the head: nonionic, anionic, cationic, and amphoteric.

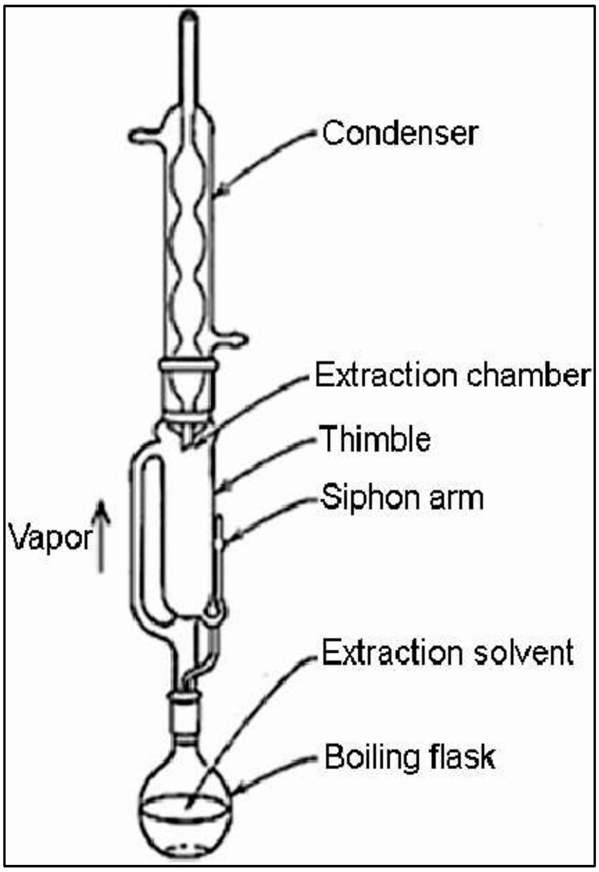

Figure 3: Soxhlet extractor

Figure 4: The PoroPerm

Figure 5: The manual saturator

Figure 6: The Tracker

Figure 7: Core flooding system

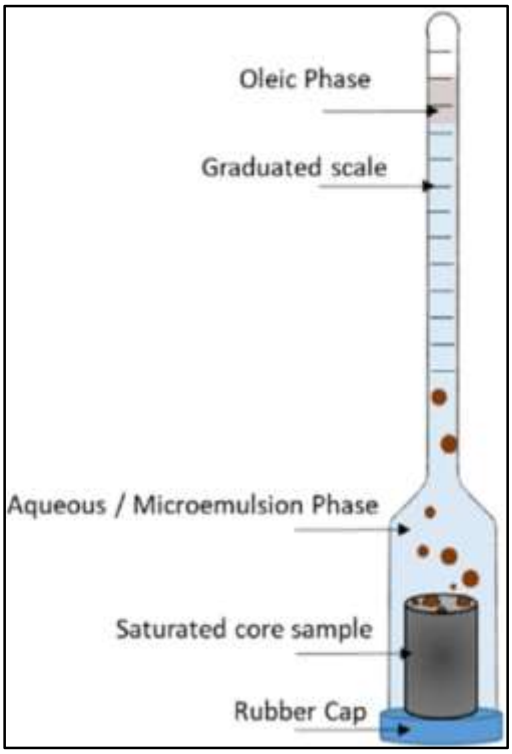

Figure 8: Imbibition AMOTT tube

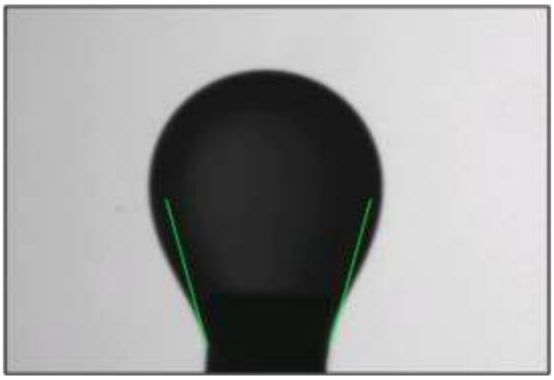

Figure 9: IFT, Formation brine

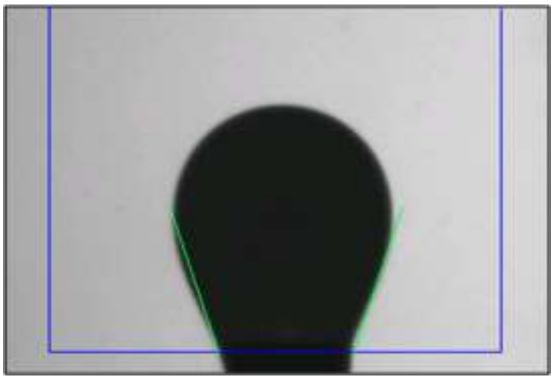

Figure 10: IFT Sea water

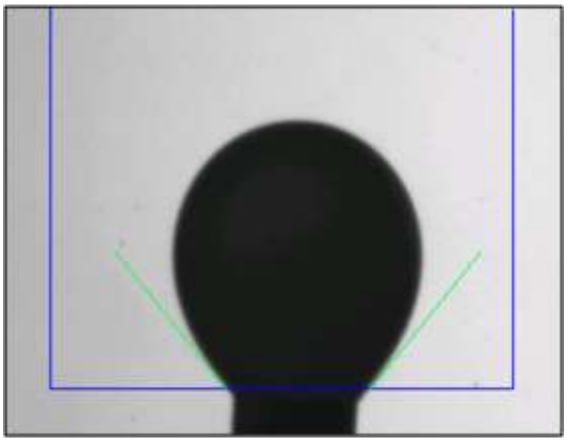

Figure 11: IFT, Low saline brine

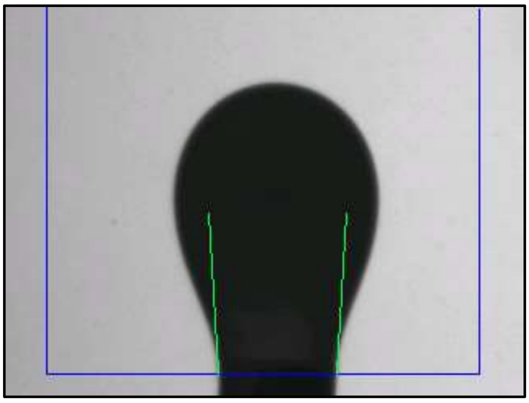

Figure 12: IFT, Formation brine mixed with surfactant at 1 cc/liter.

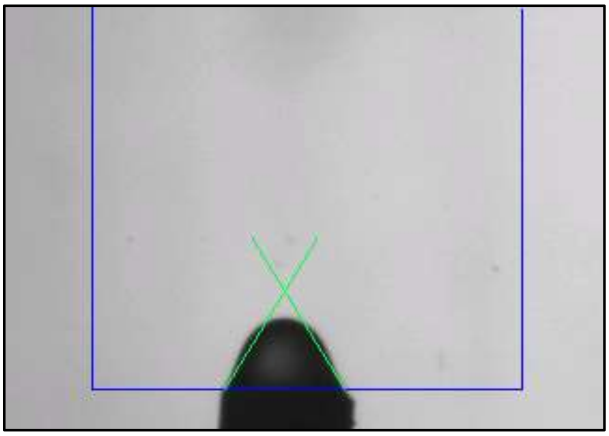

Figure 13: IFT, Sea water mixed with surfactant at 1 cc/liter.

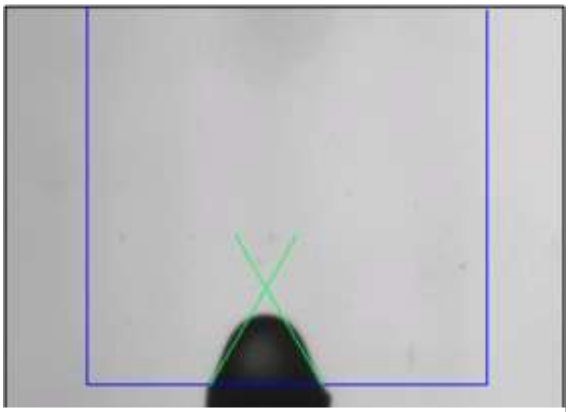

Figure 14: IFT, Low saline brine mixed with surfactant at 1 cc/liter.

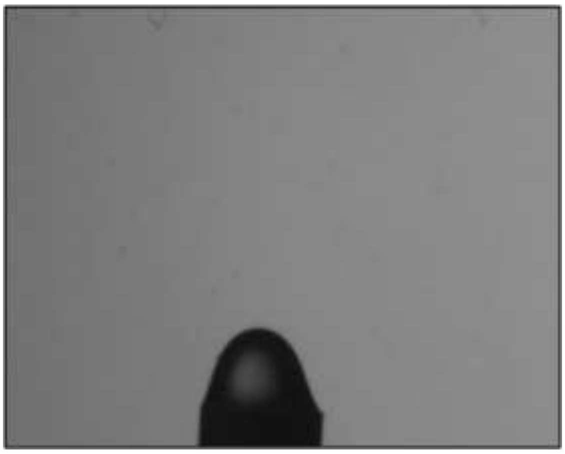

Figure 15: IFT, formation brine mixed with surfactant at 5 cc/liter.

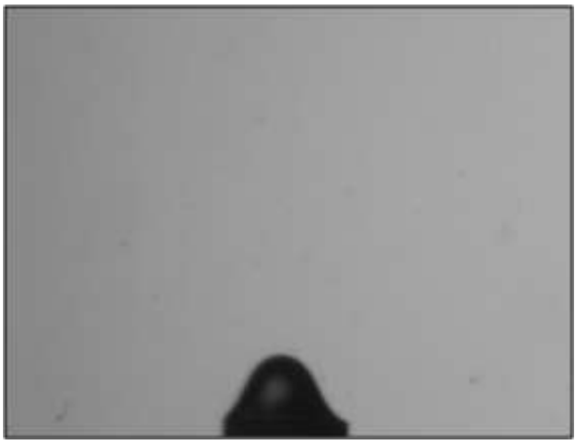

Figure 16: IFT, Sea water mixed with surfactant at 5 cc/liter.

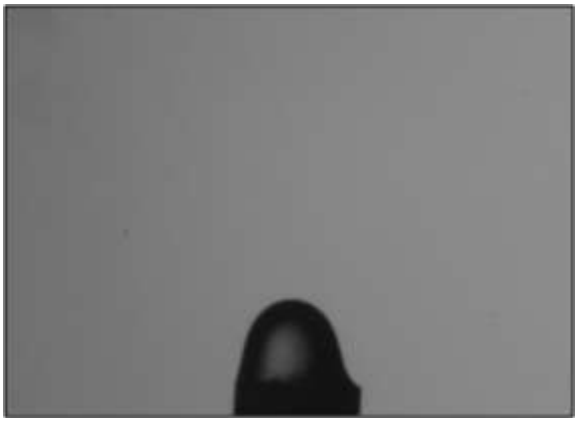

Figure 17: IFT, Low saline water mixed with surfactant at 5 cc/liter.

Figure 18: Amott test

Charts

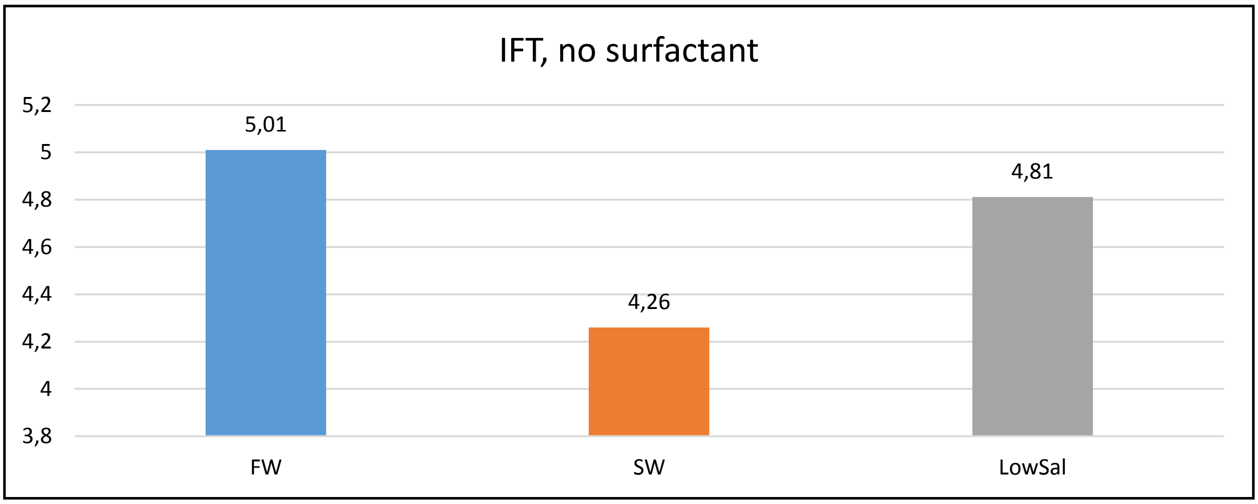

Chart 1: IFT values, no surfactant added.

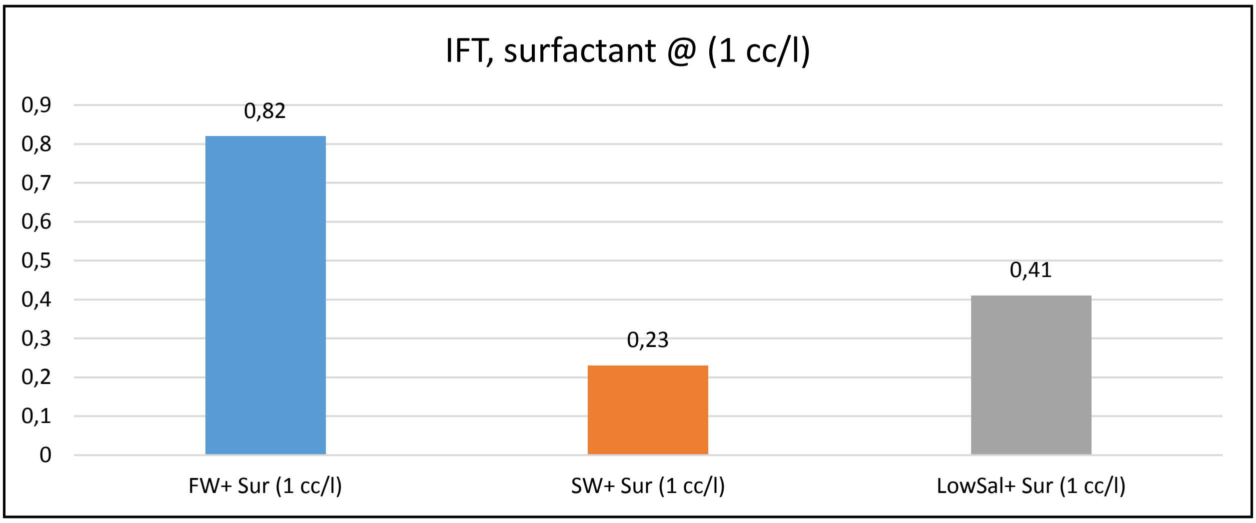

Chart 2: IFT values, surfactant concentration at 1 cc/liter

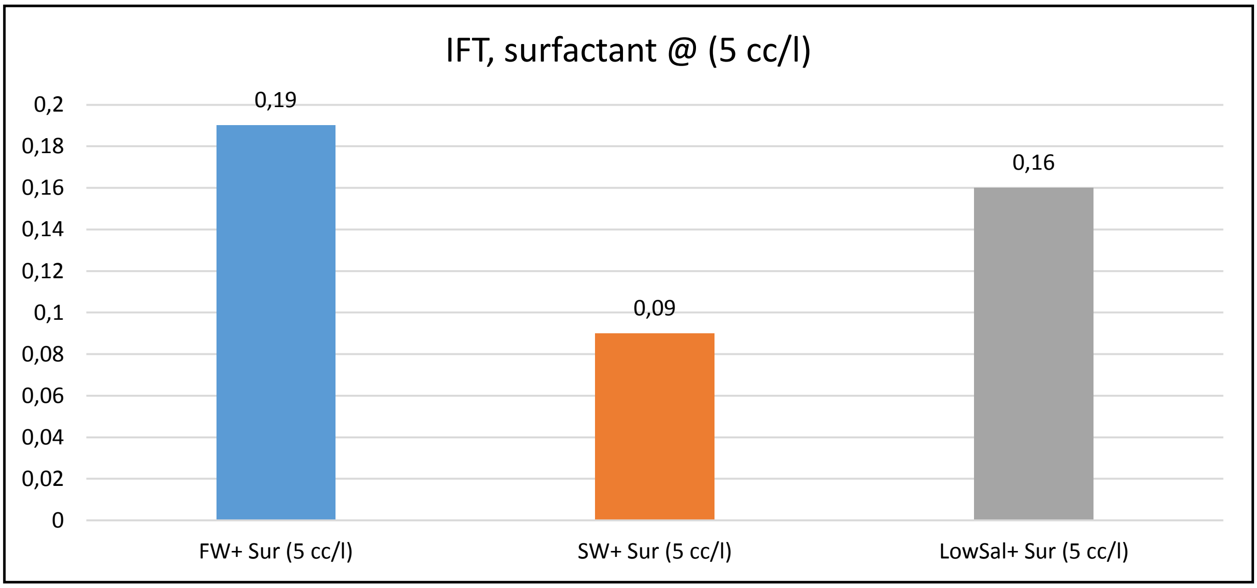

Chart 3: IFT values, surfactant concentration at 5 cc/liter

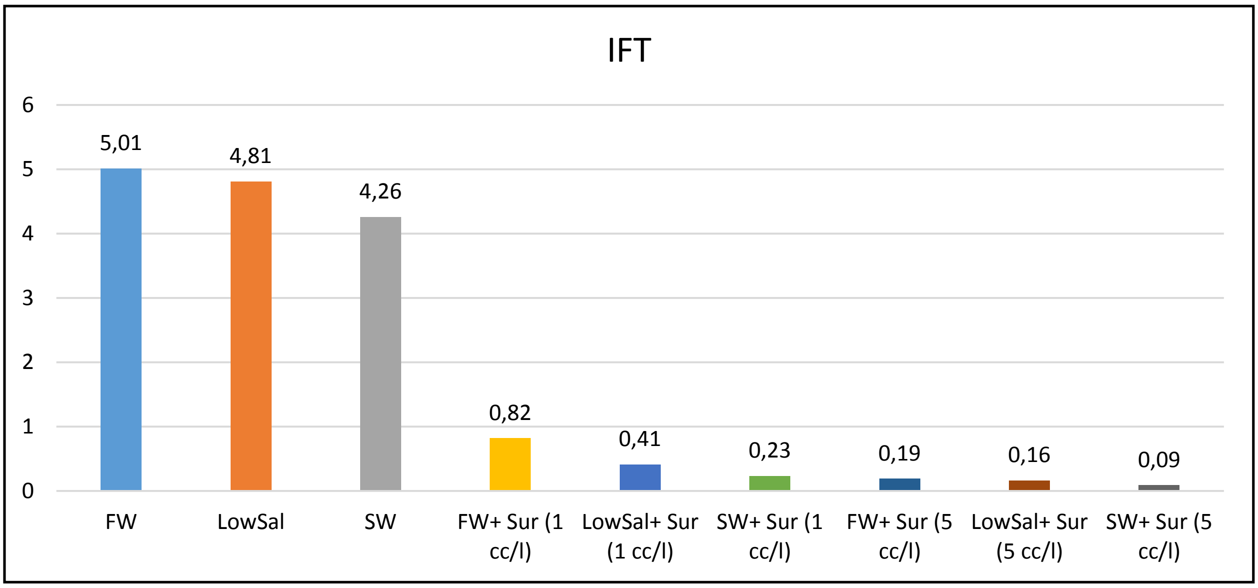

Chart 4: IFT values for all mixtures

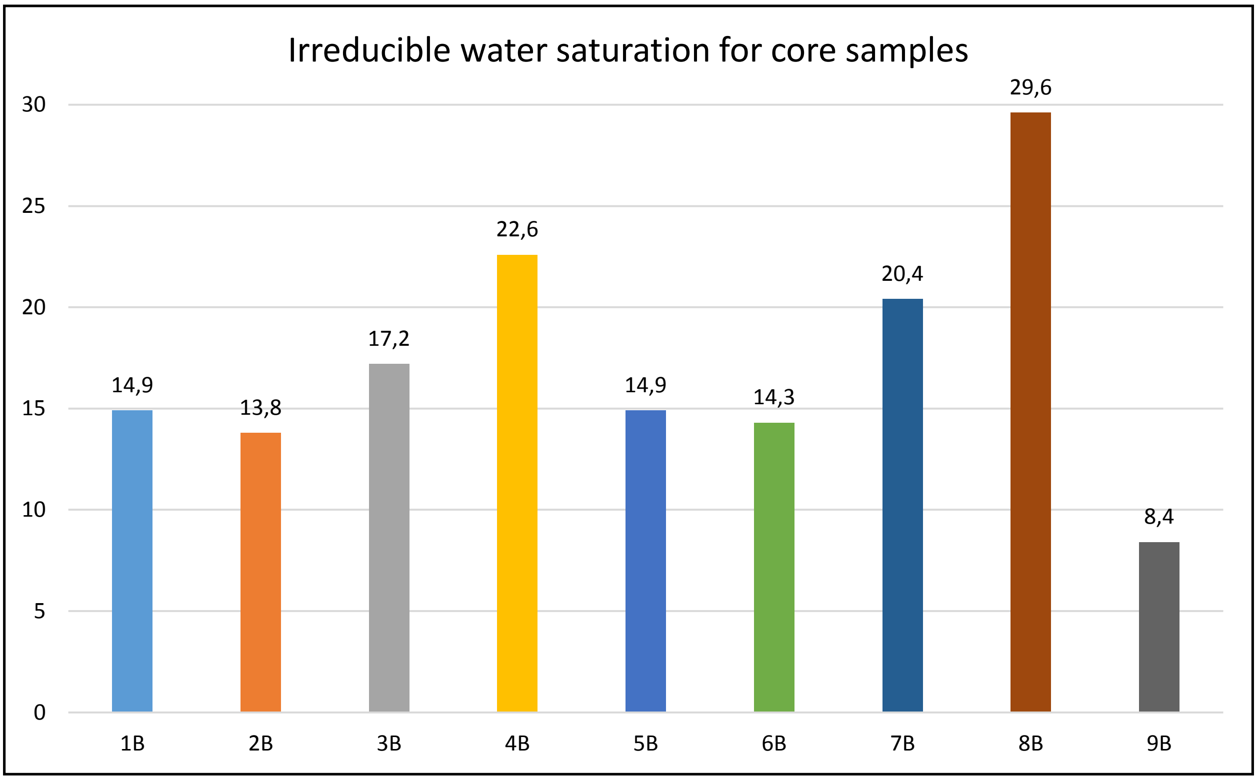

Chart 5: Irreducible water saturation after oil flooding

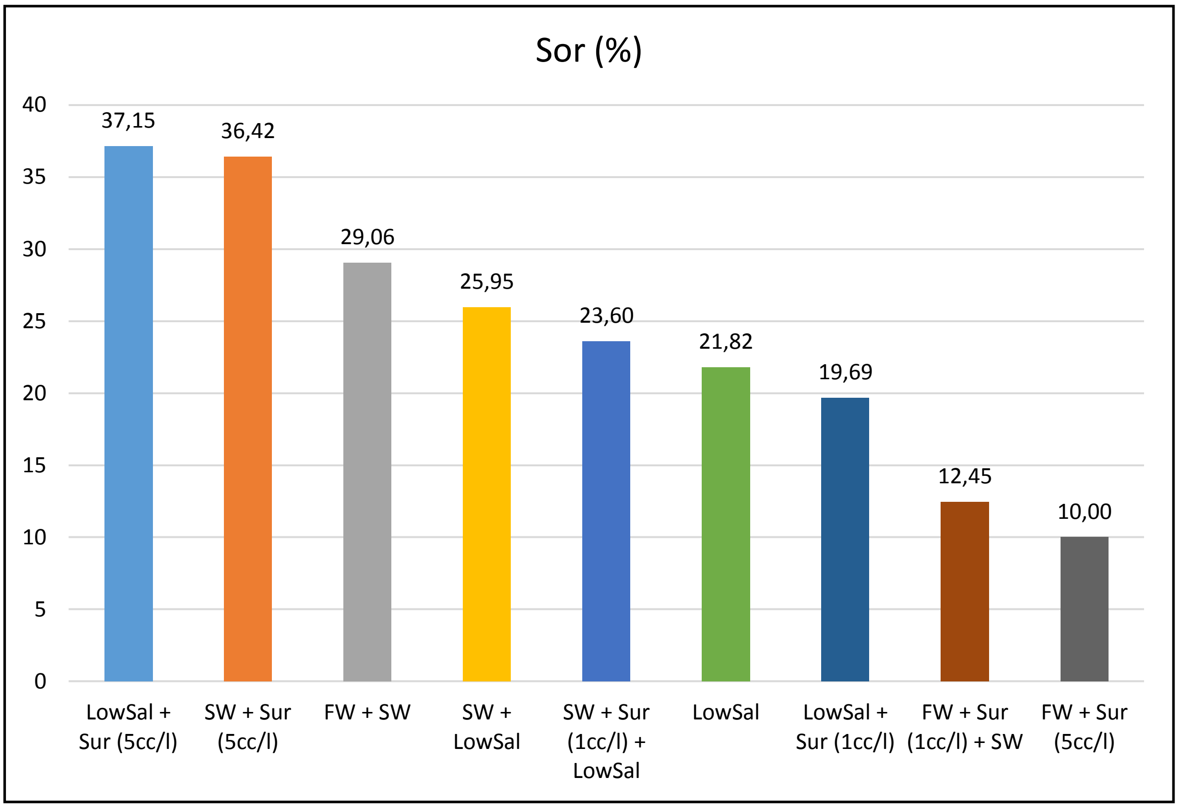

Chart 6: Residual oil saturation for all samples

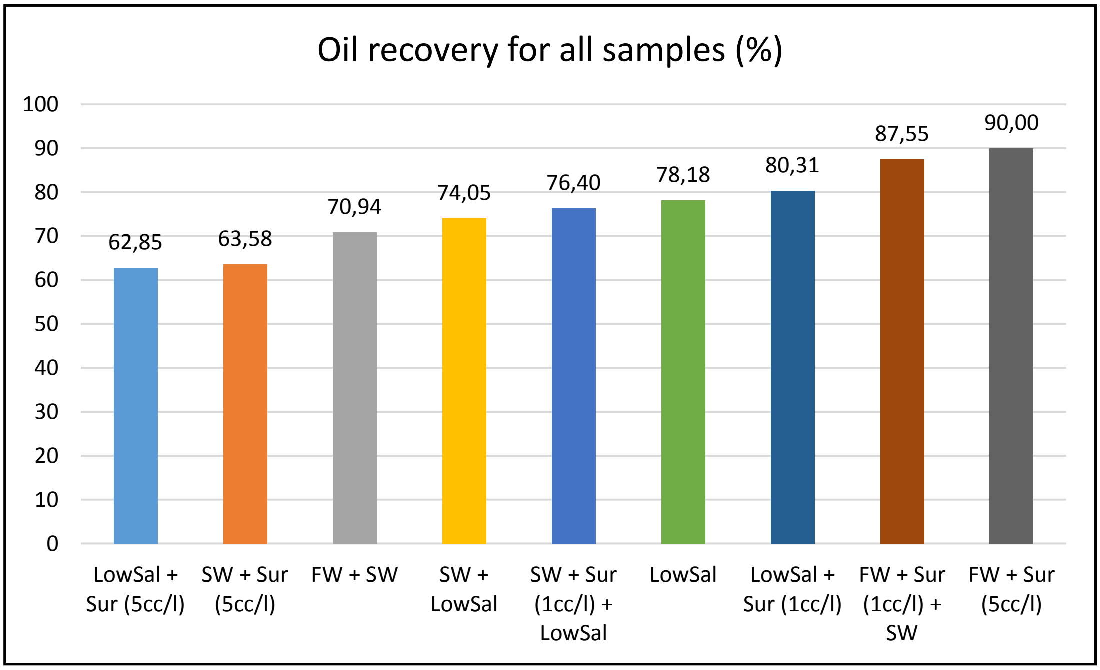

Chart 7: Oil recovery for all samples (%)

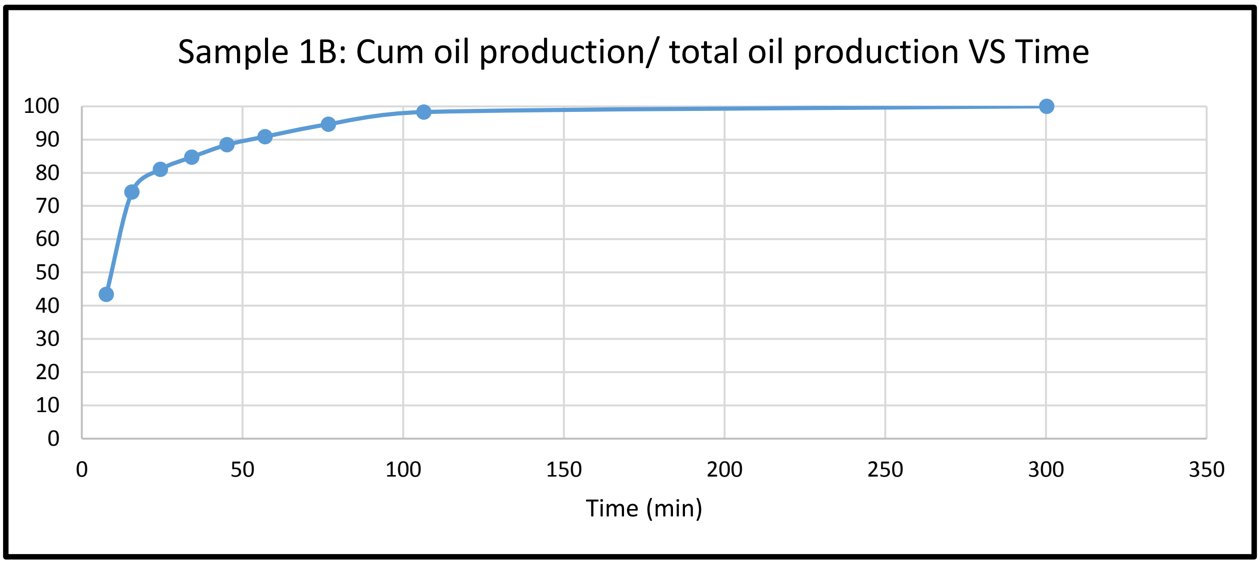

Figure 8: Sample 1B: Cum oil production/ total oil production VS Time

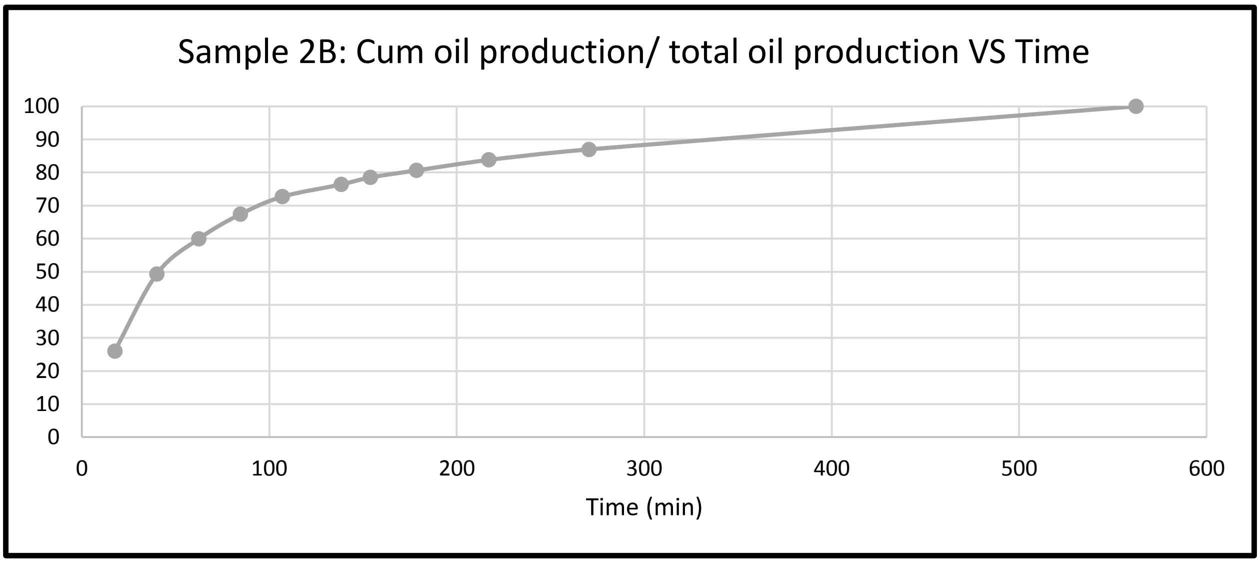

Figure 9: Sample 2B: Cum oil production/ total oil production VS Time

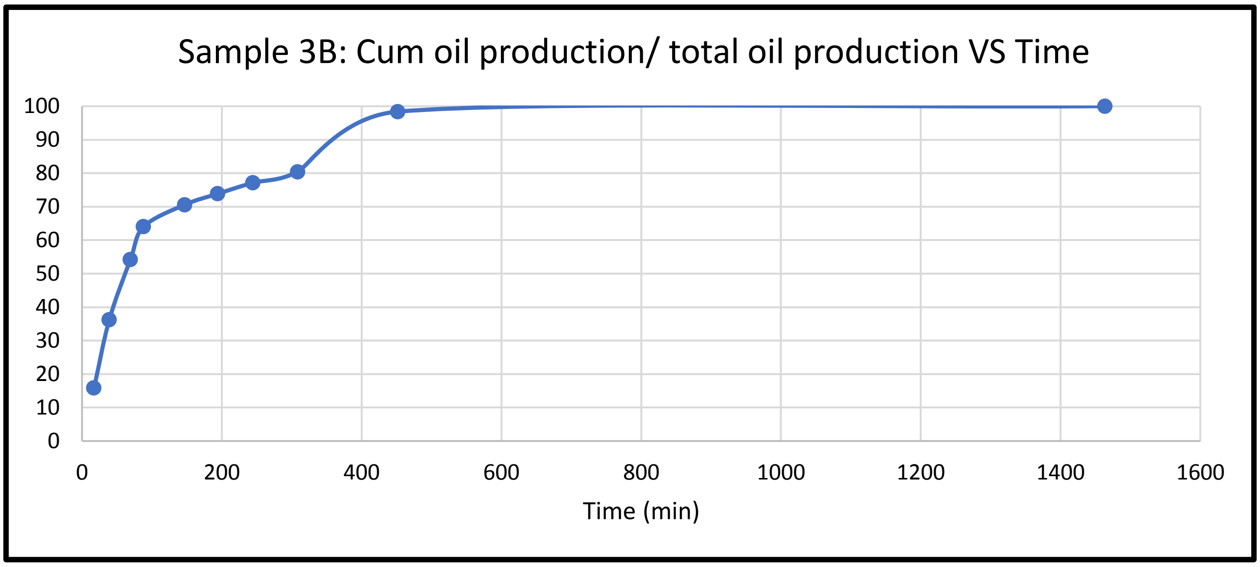

Figure 10: Sample 3B: Cum oil production/ total oil production VS Time

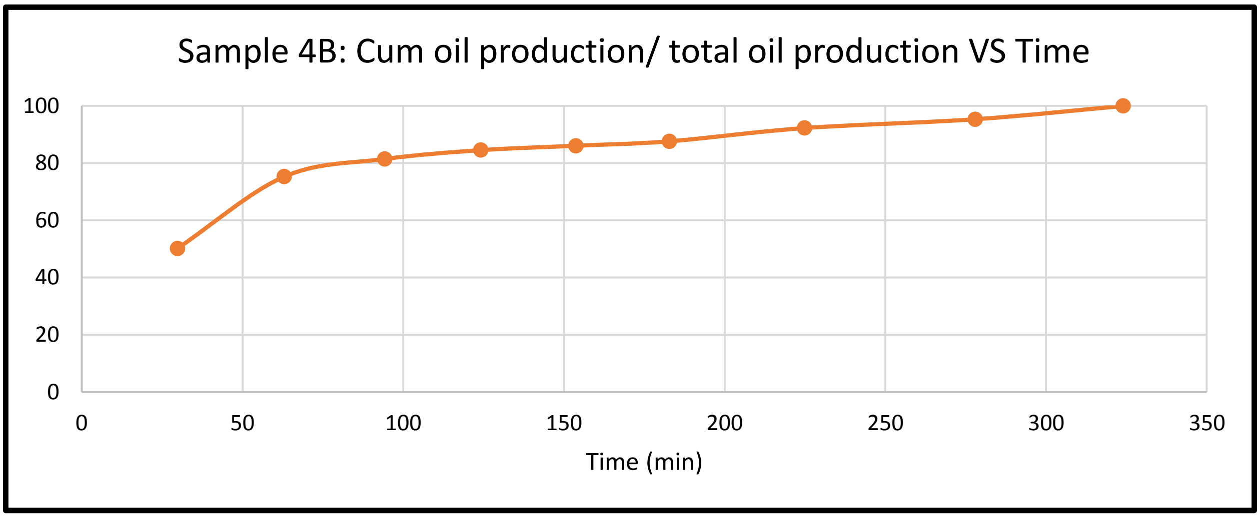

Figure 11: Sample 4B: Cum oil production/ total oil production VS Time

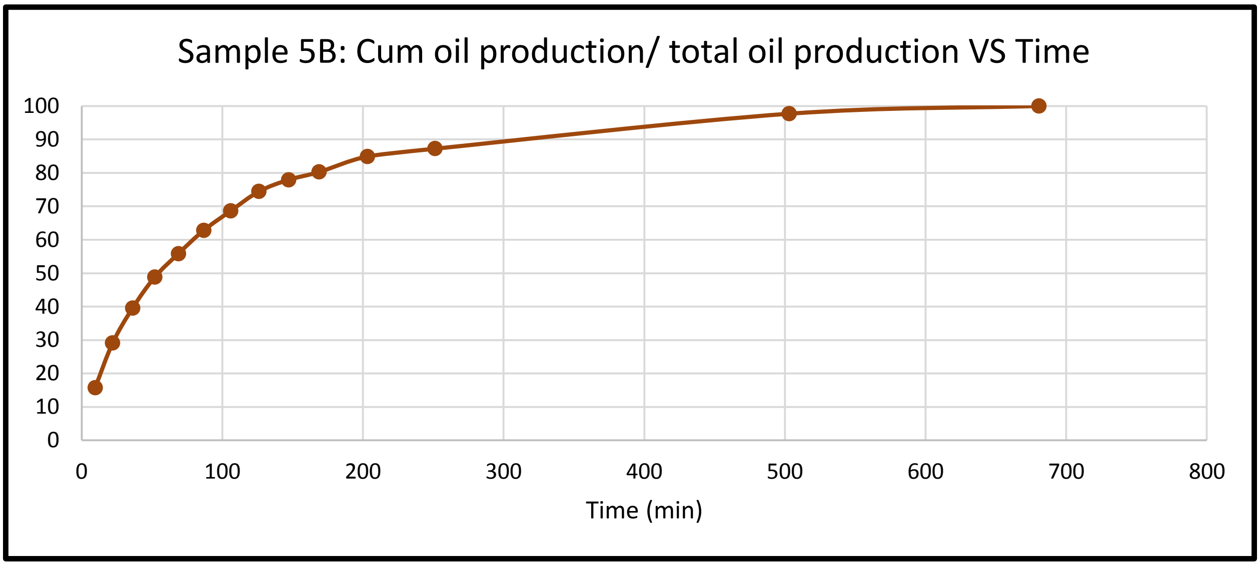

Figure 12: Sample 5B: Cum oil production/ total oil production VS Time

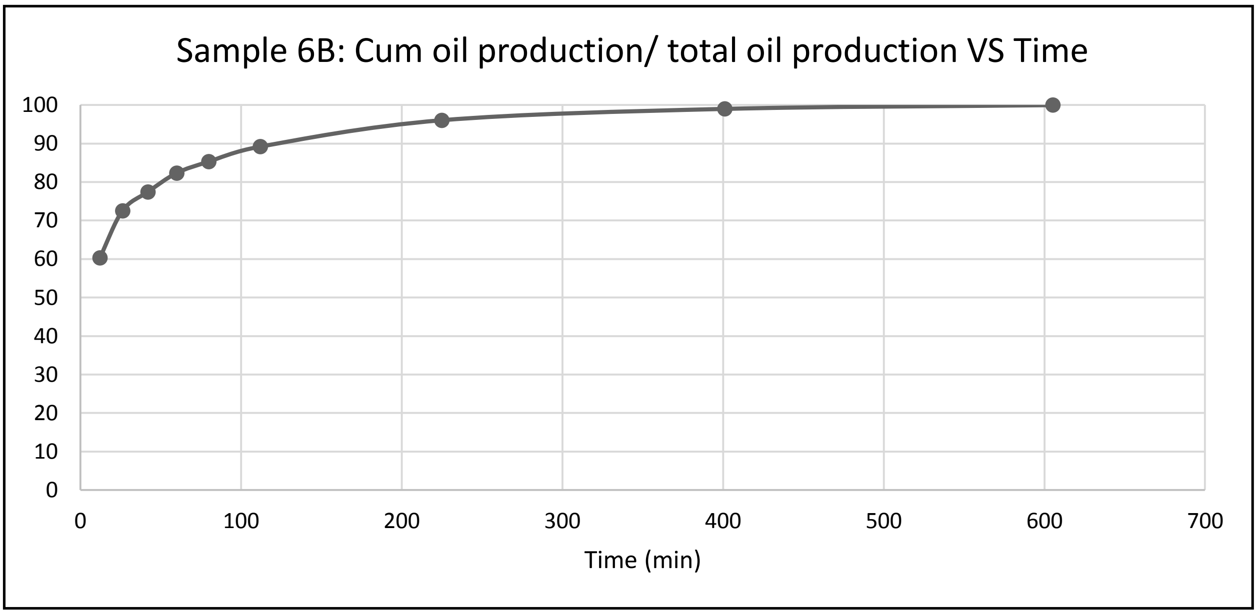

Figure 13: Sample 6B: Cum oil production/ total oil production VS Time

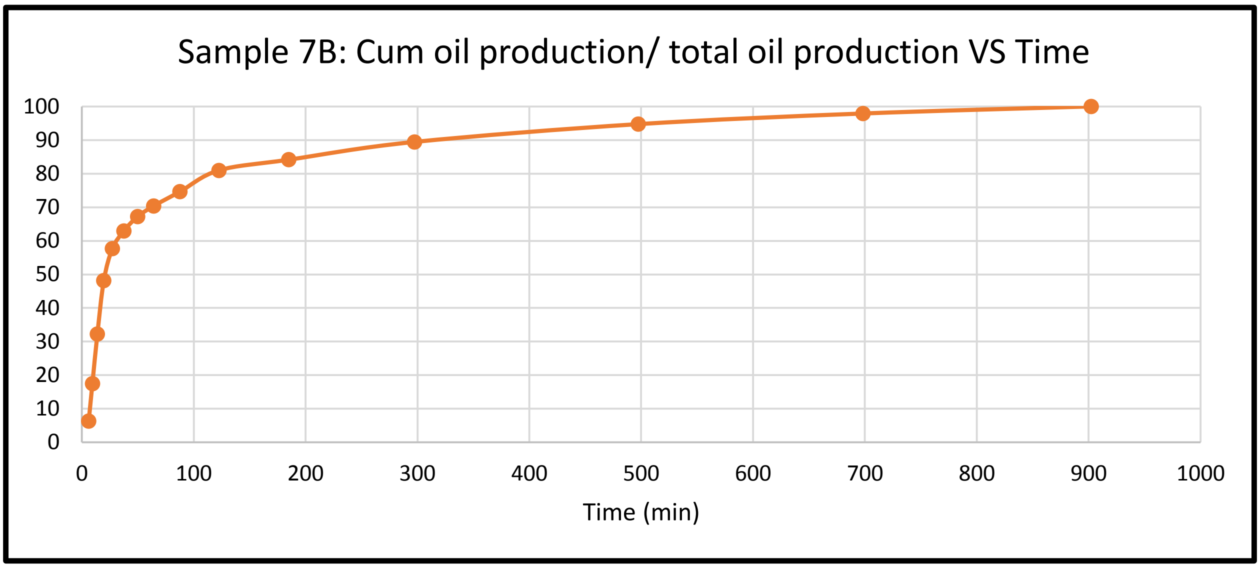

Figure 14: Sample 7B: Cum oil production/ total oil production VS Time

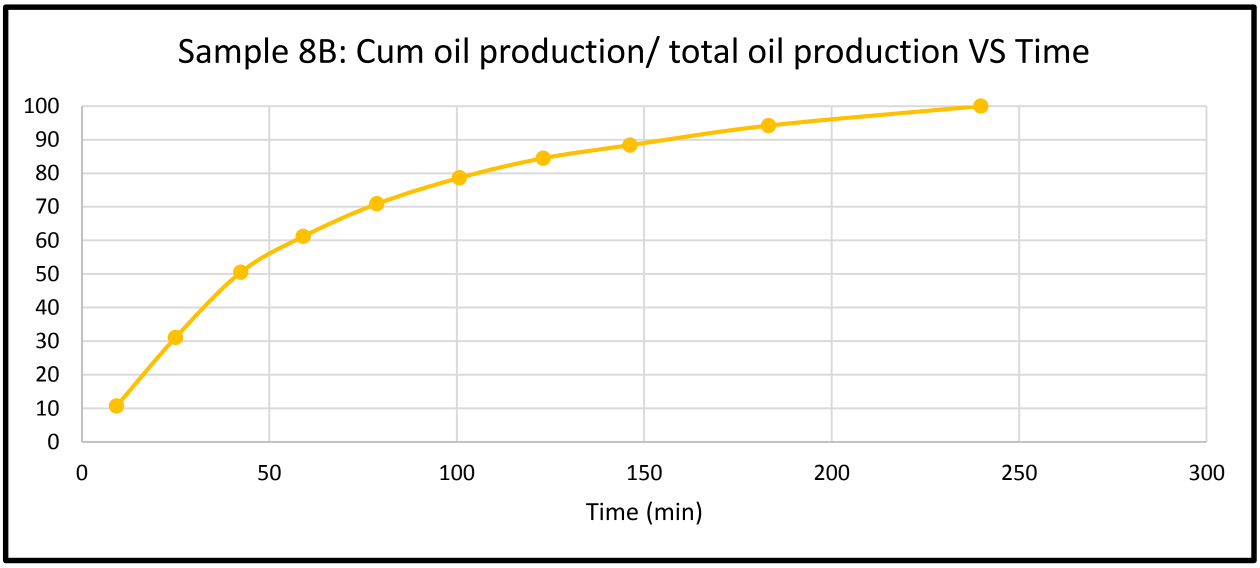

Figure 15: Sample 8B: Cum oil production/ total oil production VS Time

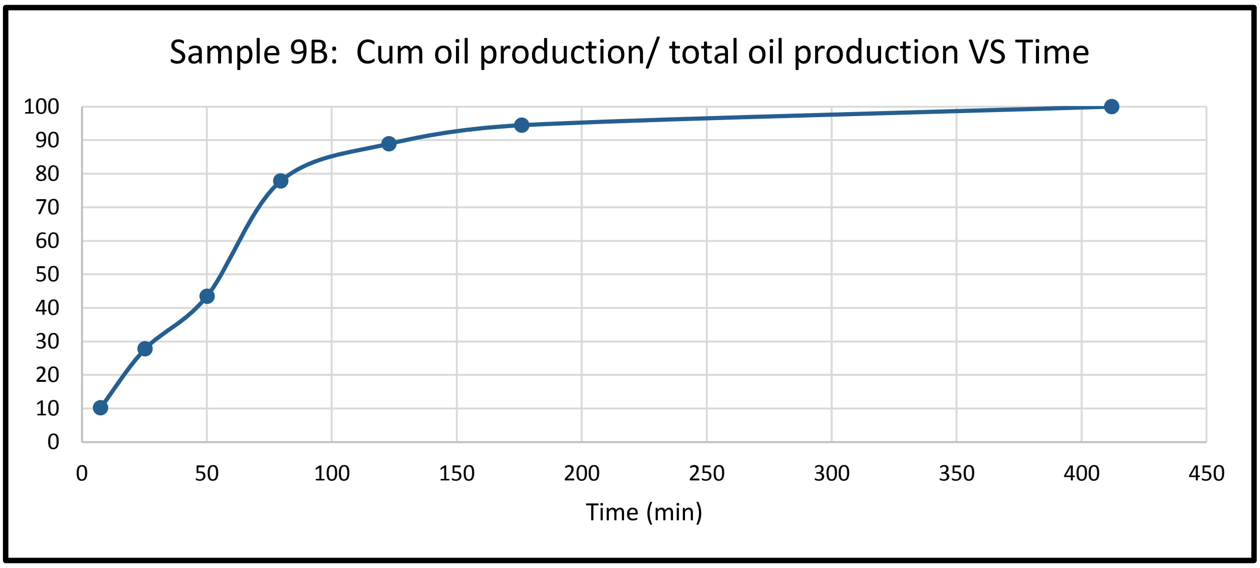

Figure 16: Sample 9B: Cum oil production/ total oil production VS Time

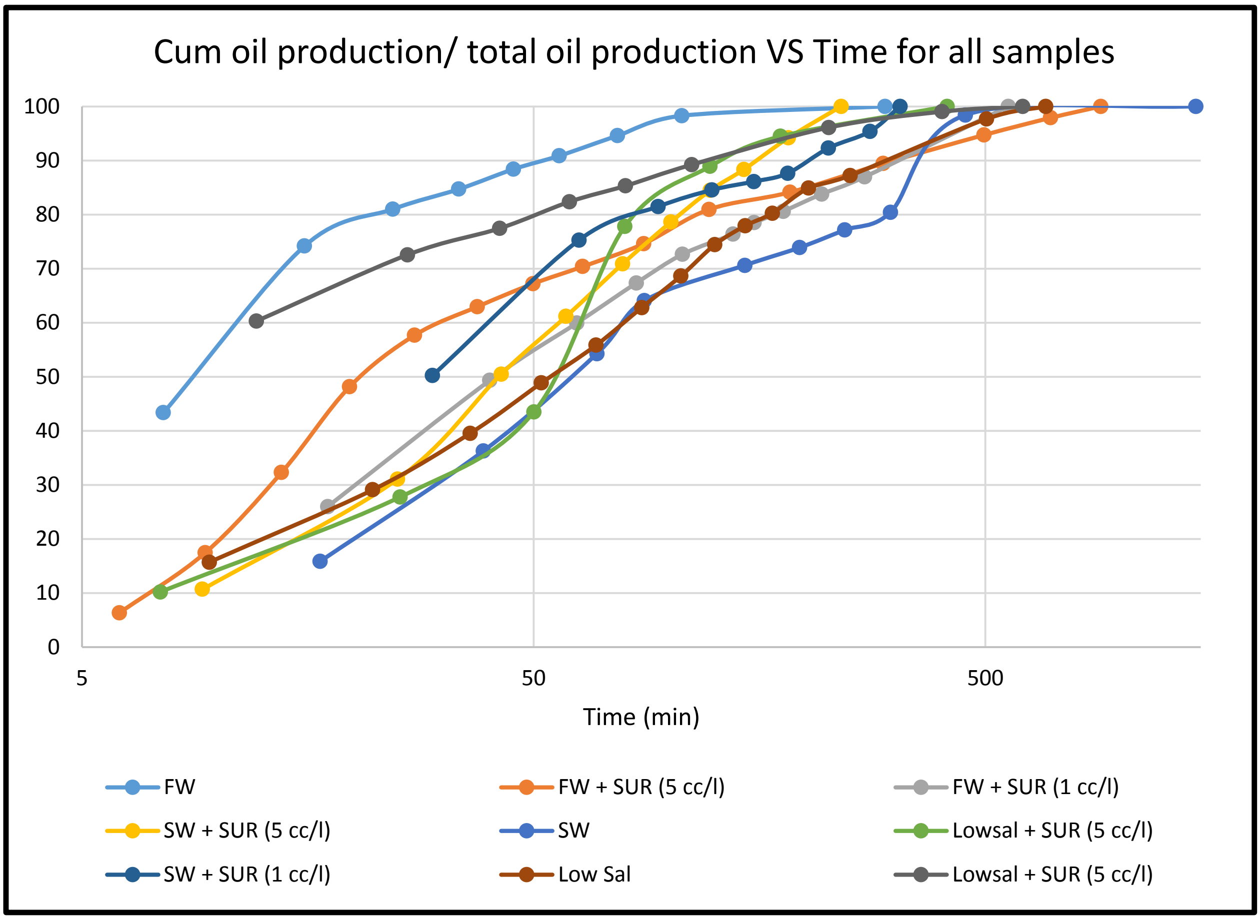

Figure 17: Cum oil production/ total oil production VS Time for all samples

Tables

Sample ID	Length (cm)	Diameter (cm)	Pore Volume (cc)	Grain density (gm/cc)	Porosity (%)	Permeability (md)
1B	6.500	3.799	13.75	2.69	18.7	0.55
2B	6.861	3.799	12.77	2.69	16.4	0.38
3B	6.515	3.806	10.15	2.69	13.7	0.41
4B	6.595	3.800	11.10	2.69	14.8	0.38
5B	6.931	3.790	12.93	2.69	16.5	0.48
6B	6.973	3.792	14.82	2.69	18.8	0.31
7**B**	6.488	3.805	13.20	2.69	17.9	0.61
8B	6.856	3.837	11.50	2.69	14.5	0.41
9B	6.518	3.805	9.39	2.69	12.7	0.42

Table 1: Basic data of core samples

Brine ID	Concentration (ppm)	Density (gm/cc)	Viscosity (cP)
Formation brine (FW)	162,746	1,118	1.45
Sea Water (SW)	53,292	1,037	1.04
Low Saline Water (LowSal)	5,329	1,007	1.01

Table 2: properties of brines

Chemicals	Concentration (gm/l)
Na2SO4 (Anhy)	0.40
NaHCO3 (Anhy)	0.54
MgCl2.6H2O	10.72
CaCl2 (Anhydrous)	44.28
NaCl	131.03

Table 3: Chemical composition of formation brine

Chemicals	Concentration (gm/l)
NaHCO3 (Anhy)	0.17
KCl	1.28
CaCl2 (Anhydrous)	1.91
Na2SO4 (Anhy)	5.83
MgCl2.6H2O	17.83
NaCl	37.71

Table 4: Chemical composition of sea water

Crude oil	Brine ID	IFT (mN/m)
Bu Hassa	Formation brine	5.01
Bu Hassa	Sea water	4.26
Bu Hassa	Low saline brine	4.81
Bu Hassa	Formation brine+ surfactant @ 1 cc/liter	0.82
Bu Hassa	Sea water+ surfactant @ 1 cc/liter	0.23
Bu Hassa	Low saline brine+ surfactant @ 1 cc/liter	0.41
Bu Hassa	Formation brine+ surfactant @ 5 cc/liter	0.19
Bu Hassa	Sea water+ surfactant @ 5 cc/liter	0.09
Bu Hassa	Low saline brine+ surfactant @ 5 cc/liter	0.16

Table 5: IFT results for all mixtures

Sample ID	Original brine in place (cc)	Produced brine (cc)	Brine in place after flooding (cc)	Irreducible water saturation, Swi (%)
1B	13.75	11.70	2.05	14.9
2B	12.77	11.00	1.77	13.8
3B	10.15	8.40	1.75	17.2
4B	11.10	8.60	2.50	22.6
5B	12.93	11.00	1.93	14.9
6B	14.82	12.70	1.12	14.3
7B	13.20	10.50	2.70	20.4
8B	11.50	8.10	3.40	29.6
9B	9.39	8.60	0.79	8.4

Table 6: Results of oil flooding

Sample ID	Flooding with formation brine			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
1B	11.70	8.10	3.60	30.8

Table 7: Flooding sample 1B with formation brine to Sor

Sample ID	Flooding with sea water at Sor			
	Oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
1B	3.60	0.2	3.40	29.1

Table 8: Flooding sample 1B with sea water at Sor

Sample ID	Flooding with formation brine mixed with surfactant at 1 cc/liter			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
2B	11.00	9.43	1.57	14.3

Table 9: Flooding sample 2B with formation brine mixed with surfactant at 1 cc/liter

Sample ID	Flooding with sea water at Sor			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
2B	1.57	0.20	1.37	12.5

Table 10: Flooding sample 2B with sea water at Sor

Sample ID	Flooding with sea water			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
3B	8.4	6.12	2.28	27.1

Table 11: Flooding sample 3B with sea water

Sample ID	Flooding with low saline brine at Sor			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
3B	2.28	0.10	2.18	26.0

Table 12: Flooding sample 3B with low saline brine at Sor

Sample ID	Flooding with sea water mixed with surfactant at 1 cc/liter			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
4B	8.60	6.47	2.13	24.8

Table 13: Flooding Sample 4B with sea water mixed with surfactant at 1 cc/liter

Sample ID	Flooding with low saline bine at Sor			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
4B	2.13	0.10	2.03	23.6

Table 14: Flooding Sample 4B with low saline brine at Sor

Sample ID	Flooding with low saline brine			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
5B	11.00	8.60	2.40	21.8

Table 15: Flooding sample 5B with low saline brine

Sample ID	Flooding with low saline water mixed with surfactant at 1 cc/liter			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
6B	12.70	10.20	2.50	19.7

Table 16: Flooding sample 6B with low saline brine mixed with surfactant at 1 cc/liter

Sample ID	Flooding with formation brine mixed with surfactant at 5 cc/liter			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
7B	10.50	9.45	1.05	10.0

Table 17: Flooding sample 7B with formation brine mixed with surfactant at 5 cc/liter

Sample ID	Flooding with sea water mixed with surfactant at 5 cc/liter			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
8B	8.10	5.15	2.95	36.4

Table 18: Flooding sample 8B with formation brine mixed with surfactant at 5 cc/liter

Sample ID	Flooding with low saline brine mixed with surfactant at 5 cc/liter			
	Original oil in place (cc)	Produced oil (cc)	Residual oil (cc)	Residual oil saturation, Sor (%)
9B	8.60	5.41	3.20	37.2

Table 19: Flooding sample 9B with formation brine mixed with surfactant at 5 cc/liter

Sample ID	Brine ID	Volume of produced oil (%)
1B	Formation brine mixed with surfactant at 1 cc/liter	0.8
2B	Sea water mixed with surfactant at 1 cc/liter	0.3
3B	Low saline brine mixed with surfactant at 1 cc/liter	0.1
4B	Formation brine mixed with surfactant at 5 cc/liter	1.2
5B	Sea water mixed with surfactant at 5 cc/liter	0.4
6B	Low saline brine mixed with surfactant at 5 cc/liter	0.2

Table 20: Results of Amott test

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
8	0.5	417	0.05	3.51	3.51	43.3
16	0.5	515	1.50	2.50	6.01	74.2
24	0.5	454	3.95	0.55	6.56	81.0
34	0.5	412	4.70	0.30	6.86	84.7
45	0.5	383	5.20	0.30	7.16	88.4
57	0.5	358	5.80	0.20	7.36	90.9
77	0.5	333	9.70	0.30	7.66	94.6
106	0.5	308	14.70	0.30	7.96	98.3
300	0.5	246	100.06	0.14	8.10	100

Table 21: Sample 1B, Formation brine flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
18	0.13	650	0.05	2.45	2.45	26.0
40	0.14	650	0.80	2.20	4.65	49.3
62	0.17	650	2.50	1.00	5.65	59.9
84	0.19	650	3.30	0.70	6.35	67.3
107	0.21	650	4.00	0.50	6.85	72.6
138	0.22	650	4.65	0.35	7.20	76.4
154	0.24	650	5.30	0.20	7.40	78.5
178	0.25	650	5.80	0.20	7.60	80.6
217	0.26	650	9.80	0.30	7.90	83.8
271	0.29	650	14.80	0.30	8.20	87.0
562	0.37	650	100.07	1.23	9.43	100

Table 22: Sample 2B, Formation brine mixed with surfactant at 1 cc/liter, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
17	0.07	650	0.05	0.97	0.97	15.8
39	0.07	650	0.25	1.25	2.22	36.3
69	0.07	650	0.0	1.10	3.32	54.2
88	0.07	650	1.90	0.60	3.92	64.1
147	0.08	650	2.80	0.40	4.32	70.6
194	0.09	650	3.80	0.20	4.52	73.9
244	0.09	650	4.30	0.20	4.72	77.1
308	0.09	650	5.60	.0.20	4.92	80.4
452	0.11	650	13.20	1.10	6.02	98.4
1464	0.10	650	101.10	0.10	6.12	100

Table 23: Sample 3B, Sea water flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
30	0.11	650	0.05	3.25	3.25	50.2
63	0.13	650	2.38	1.62	4.87	75.3
94	0.16	650	4.10	0.40	5.27	81.5
124	0.18	650	4.80	0.20	5.47	84.5
154	0.19	650	5.40	0.10	5.57	86.1
183	0.22	650	5.90	0.10	5.67	87.6
225	0.26	650	9.70	0.30	5.97	92.3
278	0.23	650	15.00	0.20	6.17	95.4
324	0.57	650	101.50	0.30	6.47	100

Table 24: Sample 4B, Sea water mixed with surfactant at 1 cc/liter flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
10	0.14	650	0.05	1.35	1.35	15.7
22	0.13	650	0.95	1.15	2.50	29.1
36	0.19	650	1.70	0.90	3.40	39.5
52	0.20	650	2.30	0.80	4.20	48.4
69	0.22	650	2.90	0.60	4.80	55.8
87	0.23	650	3.40	0.60	5.40	62.8
106	0.24	650	4.00	0.50	5.90	68.6
126	0.25	650	4.50	0.50	6.40	74.4
147	0.27	650	5.20	0.30	6.70	77.9
169	0.28	650	5.80	0.20	6.90	80.2
203	0.29	650	9.60	0.40	7.30	84.9
251	0.33	650	17.80	0.20	7.50	87.2
503	0.42	650	101.50	0.90	8.40	97.7
681	0.52	650	100.30	0..20	8.60	100

Table 25: Sample 5B, Low saline brine flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
12	0.50	303	0.05	6.15	6.15	60.3
26	0.50	263	5.75	1.25	7.40	72.5
24	0.50	241	7.50	0.50	7.90	77.5
60	0.50	219	8.50	0.50	8.40	82.4
80	0.50	198	9.70	0.30	8.70	85.3
112	0.50	169	15.30	0.40	9.10	89.2
225	0.50	104	91.40	0.70	9.80	96.1
401	0.50	87	88.00	0.30	10.10	99.0
605	0.50	84	102.00	0.10	10.20	100

Table 26: Sample 6B, Low saline brine mixed with surfactant at 1 cc/liter flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
6	0.5	404	0.00	0.60	0.60	6.3
9	0.5	457	0.00	1.05	1.65	17.5
14	0.5	490	0.15	1.40	3.05	32..3
20	0.5	501	0.50	1.50	4.55	48.1
27	0.5	454	2.20	0.90	5.45	57.7
38	0.5	431	3.60	0.50	5.95	63.0
50	0.5	398	4.60	0.40	6.35	67.2
64	0.5	377	5.70	0.30	6.65	70.4
88	0.5	349	9.60	0.40	7.05	74.6
122	0.5	323	14.40	0.60	7.65	81.0
185	0.5	299	27.70	0.30	7.95	84.1
297	0.5	274	52.50	0.50	8.45	89.4
497	0.5	280	100.00	0.50	8.95	94.7
698	0.5	256	101.50	0.30	9.25	97.9
902	0.5	250	101.80	0.20	9.45	100

Table 27: Sample 7B, Formation brine mixed with surfactant at 5 cc/liter flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
9	0.13	650	0.00	0.55	0.55	10.7
25	0.15	650	0.00	1.05	1.60	31.1
42	0.17	650	0.50	1.00	2.60	50.5
59	0.19	650	1.45	0.55	3.15	61.2
79	0.23	650	2.50	0.50	3.65	70.9
101	0.22	650	3.60	0.40	4.05	78.6
123	0.27	650	4.70	0.30	4.35	84.5
146	0.29	650	5.80	0.20	4.55	88.2
183	0.30	650	9.70	0.30	4.85	94.2
240	0.30	650	14.70	0.30	5.15	100

Table 28: Sample 8B, Sea water mixed with surfactant at 5 cc/liter flooding, detailed

Time (min)	Flow (cc/min)	Pressure (psi)	Water produced (cc)	Oil produced (cc)	Cum oil (cc)	Cum oil/ total oil (%)
7	0.07	650	0.00	0.55	0.55	10.2
25	0.07	650	0.10	0.95	1.50	27.8
50	0.08	650	0.70	0.85	2.35	43.5
80	0.08	650	0.15	1.86	4.21	77.8
123	0.09	650	2.40	0.60	4.81	88.9
176	0.01	650	3.70	0.30	5.11	94.4
412	0.11	650	5.50	0.30	5.41	100

Table 29: Sample 9B, Low saline brine mixed with surfactant at 5 cc/liter flooding, detailed