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Water and Surfactant Flooding Experimental Study for Bayou Choctaw Oilfield

H. Trabelsi[1], R. Trabelsi[2], F. Boukadi[3], A. C. Seibi[4]

Petroleum Engineering Department, University of Louisiana at Lafayette, 131 Rex Street Lafayette, 70503 Louisiana.

***Abstract*—This paper presents the effect of water and surfactant flooding on coreplugs and sandpacks using Bayou Chaktaw light oil (γ_o= 0.82, μ_o= 1.5 cp) and heavy brine (γ_w= 1.11, μ_w= 1.35 cp). The idea of using sandpacks and coreplugs is to have a sound assessment on the outcome of both improved oil recovery techniques. Waterflooding results were used to verify BPR Enterprises reservoir simulation study findings. A close agreement was found between sandpack average recovery factor of 71% and reservoir simulation recovery factor of 69%. Surfactant flooding on sandpacks and coreplugs revealed that post waterflooding incremental recovery may vary between a low of 1.6 to a high of 4.6%. Surfactant reservoir simulation has to be performed to substantiate such an outcome. It was also revealed that surfactant X, whose name was not disclosed by BPR Enterprises, is by far the best surfactant active agent. Using surfactant X, the capillary number increased by 25 times.**

***Keywords*—Enhanced oil recovery, Surfactant, Experimental, Case study, Bayou Choctaw**

I. INTRODUCTION

Heavy oil reservoirs are a different subcategory of oil sands, with the oil viscosity at reservoir temperature and pressure ranging between the orders of 50 to 50,000 mPa-s (cp). While this oil is still very viscous, it has limited mobility at reservoir conditions. As much as 20% of the oil may be recovered by solution-gas drive, depending on the ^{o}API gravity, but in many cases the recovery is much lower (Firoozabadi, 2001). At the end of primary production, significant oil still remains in the reservoir when the reservoir energy has been exhausted. This is the target for enhanced oil recovery. In order to recover additional heavy oil after primary production, a fluid (water, gas, steam or any combination of the three) is usually injected to displace oil to the production wells. However, mobility ratio concerning control displacement of viscous oil, and most enhanced oil recovery (EOR) processes focuses on reduction of the oil viscosity to improve the mobility ratio.

The injection of alkalis and/or surfactants into oil reservoirs is not a new technology. As early as in the 1920's, Nutting proposed the injection of alkaline solution into reservoirs for oil recovery (Nutting, 1952).

The injection of a combination of alkali and surfactant was first discussed in the 1950's by Reisberg and Doscher. Since then, chemical injection (surfactant) has become a known enhanced oil recovery technique in many conventional oil applications (Reisberg and Doscher, 1956). However, the key to understanding how surfactant floods lead to improved oil recovery is to inspect the state of the reservoirs at the time of injection. For light oil systems, residual oil at the end of water flooding is trapped by capillary forces, thus reducing the interfacial tension can lead to reduced trapping of oil ganglia (Moore and Slobod, 1956). In heavy oil reservoirs, however, residual oil after water flooding is not mainly due to capillary trapping. Rather, the oil is largely bypassed due to viscous fingering caused by the adverse mobility ratio between oil and water. Therefore, for chemical floods to give improved heavy oil recovery, the surfactant solution must somehow be improving the mobility ratio, and thus giving a more stable displacement of oil to the production wells.

The biggest enhanced oil recovery process task is to optimally increase oil recovery while at the same time reducing cost. Considering numerous available EOR processes, the thermal recovery methods have been the dominant techniques all over the world. Steam flooding has considerable potential for improving oil recovery for high and moderate oil viscosity reservoirs (Cooke *et* al., 1974; Pitts *et* al., 2004; Bryan and Kantzas, 2008). Steam drive projects have been ordinarily applied in sandstone reservoirs. However, several steam floods have also been performed in carbonate reservoirs where surfactant and alkaline floods have shown successful applications (Hammershaimb *et* al., 1983).

Despite the fact that steam flood techniques have enjoyed higher efficiency, they tend to suffer from a few disadvantages which negatively affect the overall displacement efficiency of the process. These major drawbacks include (1) channeling of steam through high permeability zones, and (2) gravity override which leads to early water breakthrough. The injection of certain concentration of surfactant into the steam, however, mitigates these downsides, and accordingly leads to improved sweep efficiency and oil recovery.

The injection of chemicals (surfactant) may lead to the formation of oil and water emulsions (oil-in-water or water-in-oil) during the process of flooding the reservoir with the surfactant-added fluid, in this case steam, as documented by some researchers. The favorable conditions that facilitate the formation of oil and water emulsions is the presence of both shear and low interfacial tension, which is the primary by-product of presence of surfactant (Bryan and Kantzas, 2007). In the EOR process of steam flooding, the bulk of the oil/water emulsion is assumed to have been formed at the hot water zone, although some of it may have also been formed at the solvent zone. The formation of emulsion presents another problem of having to break down the emulsion into water and oil and separate these two products. This extra work inevitably adds to cost of production and sometimes having to order specially designed separators that can handle large amount of emulsions. Environmental problems are also another major concern in the surface processing and separation of oil/water or water/oil emulsion.

Although the formation of emulsions has been proposed by Bryan and Kantzas (2007; 2008) to contribute to improved oil recovery in chemical flooding by forming water/oil emulsions that are more viscous than the oil, therefore, leading to improvement in mobility ratio and sweep efficiency. Also recommended was the formation of oil/water emulsion, which was believed to lead to improved oil recovery and sweep efficiency, although through a different mechanism (McAuliffe, 1973; Bryan and Kantzas, 2007; Jennings *et* al., 1974; Liu *et* al., 2006; Mai *et* al., 2009). The suggested mechanism for this type of emulsion (oil/water) is that oil is emulsified into water and the oil droplets either get entrained along with the flowing aqueous phase or plug rock pores and lead to better sweep efficiency. Earlier laboratory work and field applications indicated that injection of a solution of alkaline in water or alkaline into the steam used in steam stimulation operations gave a sensible improvement in oil production (Hammershaimb, 1983; Farouq-Ali and Meldau, 1979; Tiab *et* al., 1982; Blair *et* al., 1080; Al-Khafaji *et* al., 1982; Wu *et* al., 1996).

Studies also specified the applicability of including caustic (sodium soda) in steam flood to diminish the residual oil saturation in the lower portion of the reservoir, which is typically overridden by steam (Tiab *et* al, 2007). The results from these studies exhibited that using sodium soda in steam for steam flooding purposes ultimately leads to improved flow efficiency and accordingly increase the oil recovery when compared to conventional steam flood.

The use of a number of inter-facially active chemicals into some wells in Kern County, California, which was evaluated by Blair *et* al., immediately before and during huff and puff steam cycles, showed important increase in the overall oil production (Blair *et* al., 1980). Two experiments were also performed by Al-Khafaji *et* al. under static and dynamic conditions, respectively (Al-Khafaji *et* al, 1982). The dynamic experiment was principally to inspect heat transfer through porous medium and mobility of surfactant steam flood. The results revealed that steam mobility was reduced when surfactant was utilized. The inference of this discovery is that the mobility lost by the steam (displacing phase) was gained by the oil (displaced phase), which results in improved sweep efficiency and oil recovery.

The basic mechanism of chemical flooding has been inspected and characterized by different researchers. Larson *et* al. characterized the basic mechanisms of chemical flooding as follows: (1) phases composition changing mechanisms, which comprises miscibility, swelling, and solubilization and (2) mechanism altering oleic rate in comparison to aqueous rate through the rock, and this includes wettability alteration, reduction of interfacial tension, and pore plugging, viscosity alteration (Larson *et* al. 1982). Investigations conducted by Ching identified a somewhat different steam flooding mechanism combinations, which includes: solution-gas drive, emulsion drive, steam drive, viscosity reduction, thermal permeability and capillary pressure variations, in-situ solvent drive, thermal expansion and gravity segregation (Ching, 1977). Based on literature reviews, using mixed solution of surfactant and de-emulsifier into the steam drive has not been presented before for improvement of oil recovery and reduction of emulsion generation, which is a major problem in oil EOR techniques based on water/steam flooding.

II. Experimental Methodology And Numerical Simulation Study

A. Laboratory Experiment

A total of 18 sandpacks have been prepared. Fourteen are made of coarse mesh size (60). Four are made of finer sands with mesh size of 20. The sandpacks were packed, put under vacuum and packed again making sure that evacuated air is replaced by sand.

Four core plugs were also used. The core plugs were drilled out with fresh water from available core slabs. The core holder is also fitted with a hydraulically operated hand pump to apply pressure on the sleeve with the core in it.

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This is primarily to apply overburden pressure on the core so as to simulate reservoir condition as much as possible and to prevent fluid by-pass during core flooding. To prevent heat loss, two precautionary steps were taken: (1) Calibrated heater tapes are wrapped around the stainless core holder to maintain an average temperature of 170 °F, which is close to reservoir temperature. (2) The steam generator and its transport line, and the core holder were also insulated by fiber glass jacket to minimize heat loss from the core holder.

The steam generator is a simple 4 feet long stainless steel tube of 0.25-inch inner diameter. The tube, bent into a series wavy curls to minimize space used and allow enough residence time for steam to become superheated before being injected into the core, has one end attached to the syringe pump and the other end attached to the core holder. The stainless tube was wrapped and completely covered with heating belt, which will be connected to an electricity source. This is for the purpose of steam and surfactant –added steam flood experiments. The heating belt is disconnected from electric power source during water or surfactant flooding. Water or surfactant solution (depending on the experiment being run) will be pumped through the tube into the core placed in the core holder. The surfactant and de-emulsifier used in this study is a pre-blended commercial anionic surfactant/de-emulsifier.

B. Preliminary Experiments

Porosity and Permeability Measurement:

Using the TPI-219 Helium porosimeter, porosity of Berea sandstone cores were measured, after coreplugs were vacuum-dried to evacuate any form of moisture and fines in the pores. Coreplug porosity varied between 20 and 28%. Sandpack porosity was measured using pack dry and saturated weight difference. Sandpack porosity ranged between 32 to 39%. Coreplug's absolute permeabilities were also measured by flowing brine (NaCl = [20,000 ppm]) through the core holder at three different flow rates of 0.5, 1.0 and 1.5 ml/min. The corresponding injection pressures were recorded for each flow rate, the exit pressure being atmospheric. Using Darcy's model, an average permeability was calculated by plotting selected flow rates as a function of observed pressure drops.

$$q = \frac{KA}{\mu}\frac{dp}{dl}$$

An average value of 28 md was obtained. The core was fully saturated with 50,000 ppm Potassium Chloride (KCl) solution. Values of permeability were calculated for each experiment based on the well established steady-state flow condition of brine injection.

Table 1 below shows the results of the permeability measurement obtained using Darcy's equation above.

TABLE I
RECORDED DATA IN PERMEABILITY MEASUREMENTS

Core #	1	2	3	4
pore pressure (psi)	10	10	10	10
confining pressure (psi)	100	100	100	100
low flow rate (cc/min)	0.14	0.10	0.17	0.97
high flow rate (cc/min)	1583	1577	1583	1557
low ΔP (psi)	5.68	5.84	4.49	8

Initial Oil and Irreducible Water Saturation Estimation: The coreplugs and sandpacks were first saturated with brine. Oil was then injected at a steady flow rate of 1 ml/min in the coreplugs and 5 ml/min in the sandpacks to replicate oil migration and reduce water saturation to its irreducible state. Irreducible water saturations varied between 19 and 24%. Sandpack irreducible water saturations ranged from as low as 4% to as high as 30%.

TABLE II
CORES #1-4 EXPERIMENTAL RESULTS

Core #	1	2	3	4
Weight (g)	41.10	33.90	36.00	43.00
Length(cm)	4.03	3.81	3.79	4.06
Diameter(cm)	2.50	2.42	2.52	2.54
Weight after WS (gm)	45.60	39.30	41.30	47.60
V_{brine} in the core (ml)	4.03	4.83	4.74	4.11
Weight after OS (gm)	43.60	37.10	39.10	45.60
V_{oil} in the core (ml)	3.05	3.90	3.78	3.17
Recovery oil (ml)	2.20	2.65	2.80	2.40
Recovery oil using sf (fraction)	0.10	0.15	0.10	0.18
V_{bulk} (cc)	19.78	17.52	18.90	20.57
ϕ (fraction)	0.20	0.28	0.25	0.20
A (cm^2)	4.91	4.60	4.99	5.07
k (Darcies)	0.0033	0.0023	0.0049	0.0159
k (millidarcies)	3.28	2.30	4.96	15.99
S_{wi} (fraction)	0.24	0.19	0.20	0.23
S_{oi} (fraction)	0.76	0.81	0.80	0.77

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Water Flooding Experiments: All 18 sandpacks and 4 coreplugs used in this study were 100% saturated with Bayou Choktaw's brine (γ_w=1.11 and μ_w=1.35 cp at room temperature). Bayou Choctaw's oil with a specific gravity of 0.82 (API=41^o) and a viscosity of 1.5 cp at room temperature was later injected at steady state in order to establish irreducible water saturation state and mimic oil migration in the Bayou Choctaw reservoir. Brine was injected to emulate a waterflooding operation. Injection continued until a water-cut of 100 was observed. Oil-water viscosity ratio (1.5/1.11) is very close to 1. Sandpcaks and Berea tend to be water-wet under the present experimental conditions (coreplugs dried in oven and sandpacks were never aged in oil). The relative permeability of water to oil (k_{rw}/k_{ro}) is small, since kros tend to be much higher that krws. Consequently, the mobility ratio ($M=\frac{\mu_o}{\mu_w}\frac{k_{rw}}{k_{ro}}$) becomes less than 1 favoring oil mobility over water. It was observed during sandpack waterflooding that waterfronts were stable and that no water fingering, channeling or bypassing took place. No premature water breakthrough was detected and a piston-like displacement developed yielding substantial recoveries.

Figure1 is an illustration of the pressure and production profiles for core #1. Pressure profile indicates that breakthrough took place sometime between 10 and 15 minutes since the beginning of the waterflood, just before the 15-minute mark. Minimal post-breakthrough recovery was observed between 15 and 20-minute mark, proving that coreplugs were indeed water-wet.

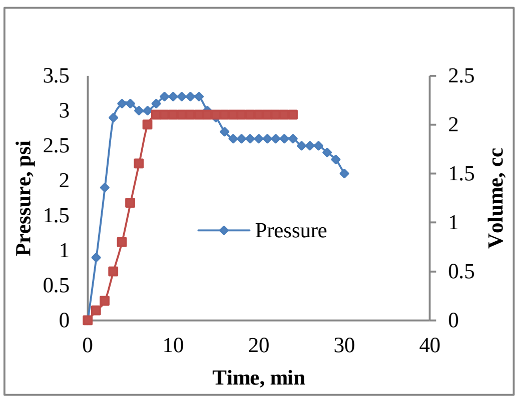

FIGURE 1 CORE #1 WATERFLOODING PRESSURE AND PRODUCTION PROFILES

Figure 2 below indicates an earlier breakthrough, just after the 5-minute mark. Post breakthrough recovery in this particular core plug was significant.

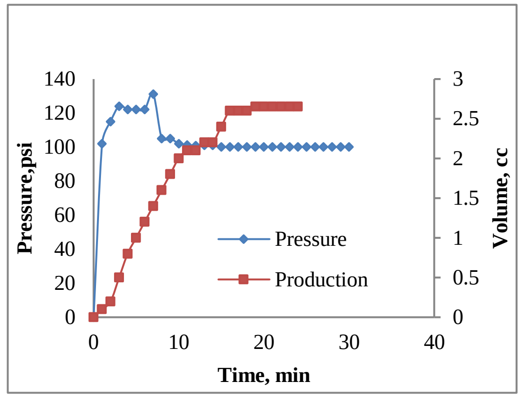

FIGURE 2 CORE #2 WATERFLOODING PRESSURE AND PRODUCTION PROFILES

In Figure 3, a late breakthrough (between 10 and 15 minutes) took place. Post breakthrough recovery was also substantial; suggesting that coreplug #3 is of intermediate wettability.

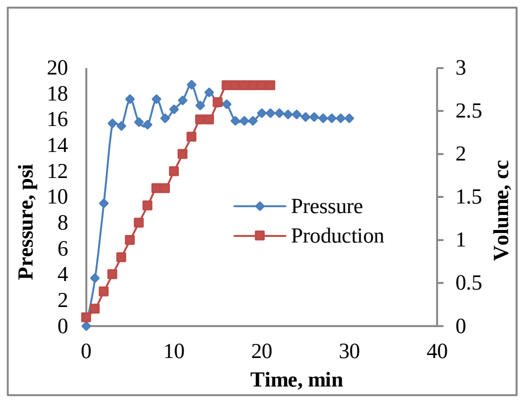

FIGURE III CORE #3 WATERFLOODING PRESSURE AND PRODUCTION PROFILES

In Figure4, production profile indicate that breakthrough took place right after the 10-minute mark and post-breakthrough was not as substantial as in coreplugs #2 and #3. Pressure profile right after breakthrough should have dropped.

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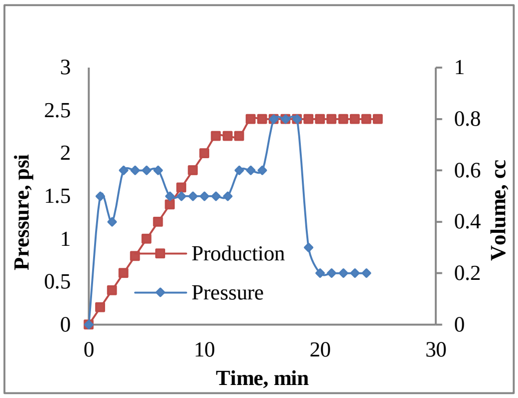

FIGURE IV CORE #4 WATERFLOODING PRESSURE AND PRODUCTION PROFILES

Figure 5 below summarizes recovery factors in the tested coreplugs. Recovery out of coreplug #4 was the highest at 90% (k_{abs}=15.99 md). Measured recoveries out of coreplugs #3, #1 and #2 are 74%, 72% and 68% for respective rock permeabilities of 3.5, 3.28 and 1.11 md, respectively. These latter recoveries are comparable to reported waterflooding recoveries out of Choctaw. The stated field average waterflooding recovery is about 69%.

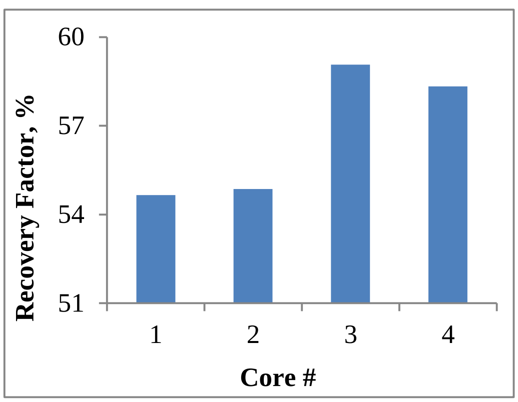

FIGURE V COREPLUGS WATERFLOODING RECOVERY FACTORS

The following figure is another illustration of pressure profile in one of the tested sandpacks. A smoother curve is observed. Water breakthrough time took place at around 20 minutes after the start of the flood.

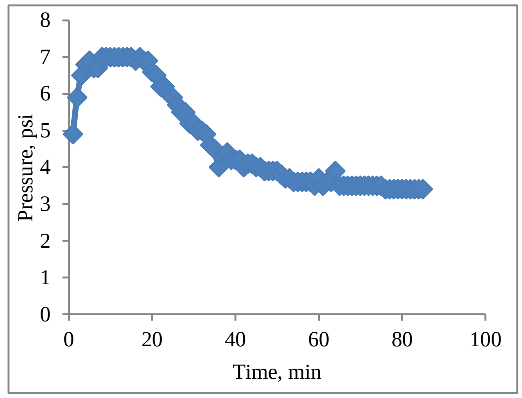

FIGURE VI EXAMPLE SANDPACK WATERFLOODING PRESSURE PROFILE

Figure 7 below show a bar graph of sandpack waterflooding recovery factors. The recovery factors ranged between 60 and 80% with an average of 71%, comparable to reported Bayou Choctaw waterflooding recovery of 69%.

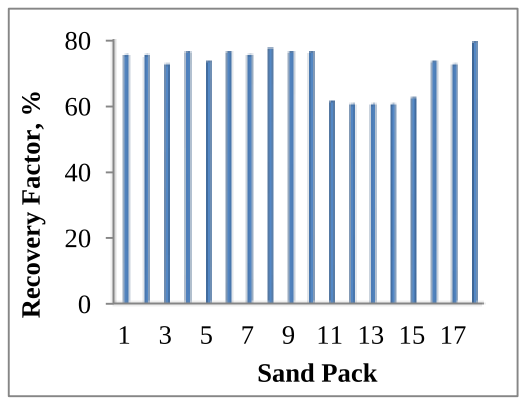

FIGURE VII SANDPACK WATERFLOODING RECOVERY FACTORS

Surfactant Flooding:

The primary objective of this study was to investigate the applicability of surfactant flooding in Bayou Choctaw field. This proposed technique is expected to decrease the residual oil saturation and free trapped oil to recovery.

The oil-water interfacial tension was measured at 42.45 mN/m using the Sigma 702 tensiometer. Surfactant/oil interfacial tension is tabulated below:

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TABLE III
SURFACTANT INTERFACIAL TENSIONS AND DENSITY

Surfactant type	Soap	Corobia mixture	X
Interfacial tension (mN/m)	22.26	1.93	1.73
Density	1.06	1.09	1.04

Interfacial tension has dropped considerably reducing the capillary number by 25 times (42.45/1.73) for the best surfactant (X). This will help free up substantial amount of bypassed oil following the performed waterfloods. No interfacial tension measurement was made on Xylen; tensiometer could not read it.

Figure 8 illustrates core #1 surfactant flooding experiment. Breakthrough took place before the 5-minute mark. Incremental post breakthrough recovery was also observed.

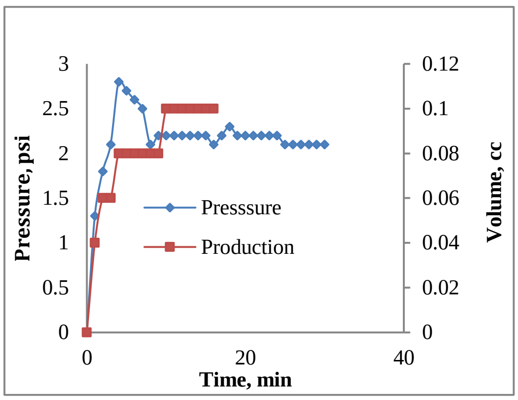

FIGURE VIII CORE #1 SURFACTANT FLOODING PRESSURE AND PRODUCTION PROFILES

Figure 9 show pressure and production profiles of coreplug #2. Despite an early breakthrough, due to the relatively reduced permeability of the coreplug (kabs=2.30 md), significant incremental oil recovery was observed.

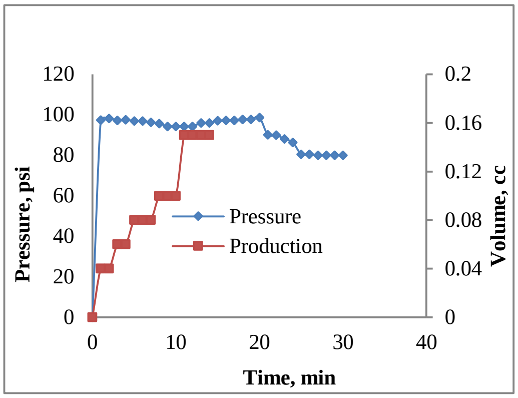

FIGURE IX CORE #2 SURFACTANT FLOODING PRESSURE AND PRODUCTION PROFILES

Figure 10 below is another illustration of surfactant flooding on coreplug #3. The pressure profile is not consistent with the observed production levels.

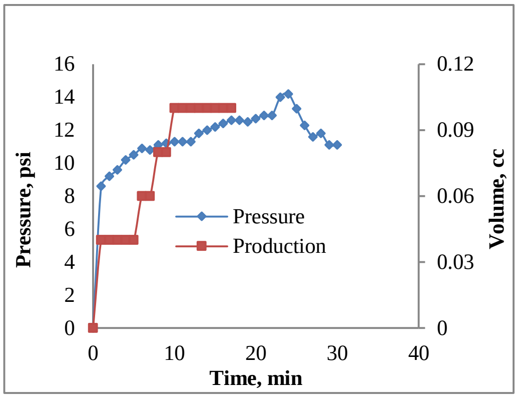

FIGURE X CORE #3 SURFACTANT FLOODING PRESSURE AND PRODUCTION PROFILES

Figure 11 demonstrates both pressure and production profiles for coreplug #4. The observed recovery is the highest among all tested coreplugs due to a high matrix permeability of 15.99 md.

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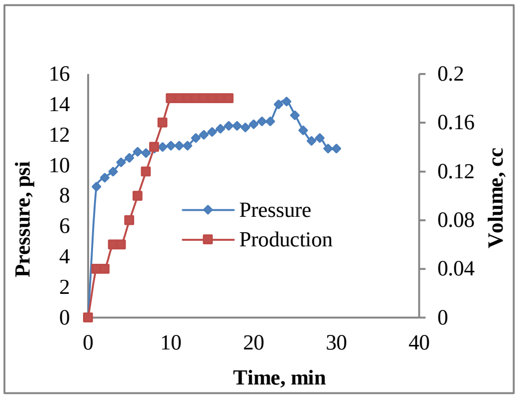

FIGURE XI CORE #4 SURFACTANT FLOODING PRESSURE AND PRODUCTION PROFILES

The following table recaps recovery factors with both brine and surfactant. Coreplug #4, being the more permeable, yielded the best combined waterflood and surfactant recovery (see Figure 12 below).

TABLE IV
SUMMARY OF COREPLUG EXPERIMENTS RECOVERY FACTORS

Core #	RF with brine, %	RF with surf, %
1	54.66	2.48
2	54.86	3.11
3	59.06	2.11
4	58.33	4.37

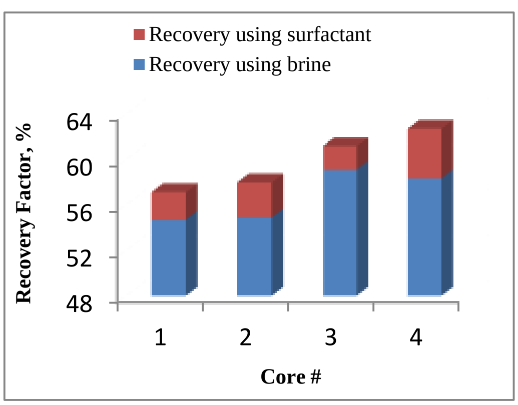

FIGURE XII COREPLUG COMBINED BRINE SURFACTANT RECOVERY

Figure 13 below indicates that surfactant X (BPR did not want to disclose the name) was the best type of surfactant. The surfactant had the lowest interfacial tension (1.97 mN/m).

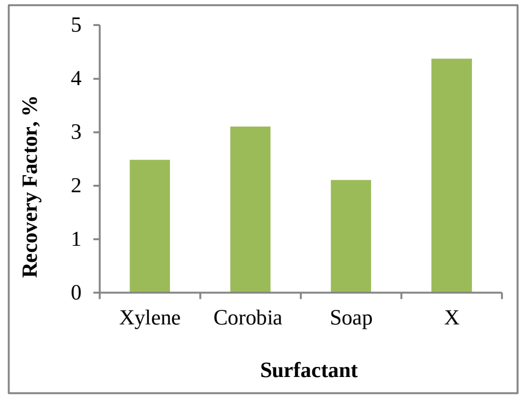

FIGURE XIII SURFACTANT RECOVERY FACTORS

The following figures 14-16 illustrate sandpack surfactant recovery. These recoveries are slightly higher than those yielded by the less permeable coreplugs. The sandpack surfactant recovery factors ranged from a low of 1.6 to a high of 4.6%.

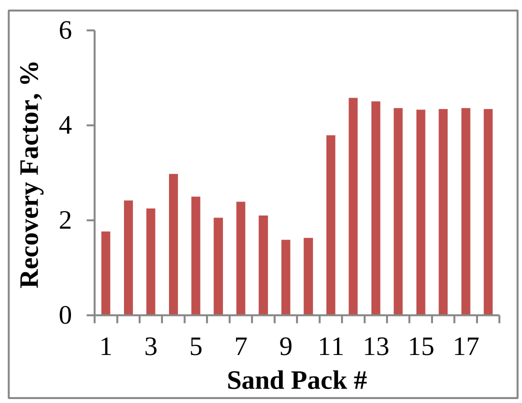

FIGURE XIV SANDPACK SURFACTANT RECOVERY FACTORS

Figure 15 below summarizes sandpack surfactant recovery factors. Soap has been used on 3 sandpacks. Corobia mixture has been used on 5. Being the most expensive, Xylene was performed on only two. Surfactant X was tested on the remaining 8 sandpacks, since it exhibited the lower interfacial tension among all tested surface-active agents.

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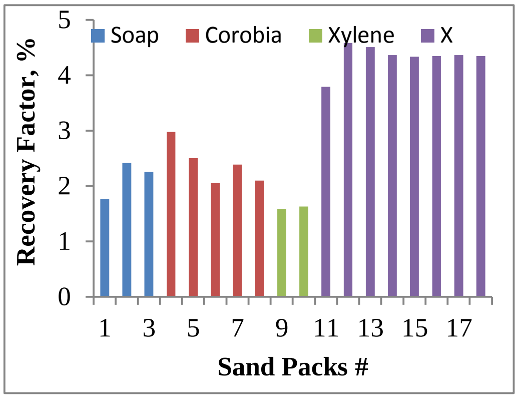

FIGURE XV SURFACTANT RECOVERY FACTORS

The Figure below is another sketch of sandpapck combined recovery factors following waterflooding and surfactant flooding.

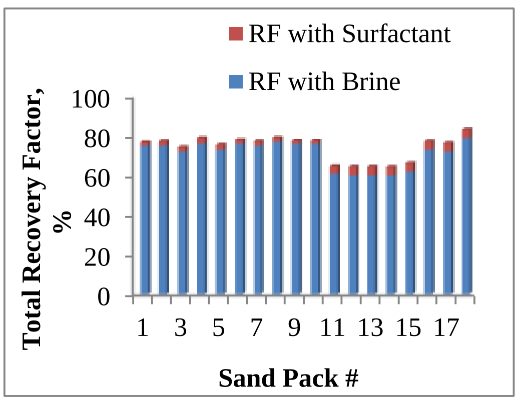

FIGURE XVI SANDPACK COMBINED RECOVERY FACTORS

III. CONCLUSIONS

The laboratory data obtained here demonstrate the potential of success of waterflooding as well as surfactant-added waterflooding. The following conclusions are made:

1. The results from the sandpacks waterflooding experiments verified the reservoir simulation waterflooding study on Bayou Choctaw field. Waterflooding experiments average recovery in sandpacks was found to be around 71%. Reservoir simulation experiments predicted an average recovery factor of 69 %.
2. Surfactant-added waterflooding was performed on four coreplugs with average permeability (6.6 md) much lower than Choctaw's (150 md). The idea was to get a conservative idea on surfactant flooding outcome. Experimental results revealed the addition of an average incremental recovery of about 4%. This has to be verified with reservoir simulation to make a better judgment on the performance of a future surfactant flood.
3. Surfactant X was the best surfactant among the four we tested. The incremental recovery was about 4%.

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