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Evaluation of Selected Salts for Potential Application for Optimized Salinity Water Fooding in Niger Delta Crude Oil-Rock Systems: A Laboratory Approach

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Abstract

This work has assessed the comparative performance of four salts (NaCl, K_2SO_4, $CaCl_2$, and $MgSO_4$) in the optimized salinity water flooding mode. This was done by carrying out core flooding tests using crude oil, brines and cores sourced from a Niger Delta field. Inter-facial Tension tests were also performed on each crude brine system to understand the specific role of fluid-fluid interaction. The results obtained from the study are quite interesting as additional recovery ranging from 5–26% were obtained in the secondary and tertiary mode.

Keywords: improved oil recovery, optimized salinity, water flooding, Niger delta

1. INTRODUCTION

Water flooding both green and brown oil reservoirs has been practiced for over 100 years [1]. This is done to improve the overall recovery efficiency of the field [2]. However before embarking on such a capital-intensive project, it is necessary to evaluate the potential benefit from the scheme by carrying out core flood tests in the laboratory. This is normally done using the actual reservoir fluid, reservoir core and where possible, the process is designed to mimic the prevalent reservoir conditions such as temperature, pressure and overburden stress. If the results from the laboratory tests are promising, the next step would be to carry out a pilot test such as a Log-Inject-Log (LIL) Test, a Single Well Chemical Tracer Test (SWCTT) [3].

Prior to embarking on field scale deployment, detailed economic must be carried out to rank the profitability of the project compared to other alternatives. This is usually done to justify the investment in the project.

A key explanation for the observed increase in recovery from LSWF by many researchers as evidenced in literature [4–6] is the IFT reduction arising from increased pH, [4]. In many of the LSWF research efforts preceding McGuire, the pH of the effluent brine was observed to have increased compared to the pH of the injected brine. After experimentation, a proposal for a possible mechanism for the additional recovery arising from LSWF was then postulated as Alkaline flooding - reduction in IFT. The reason for the increase in pH was explained to be due to the dissolution of carbonates in the LSW. And as a result of the increase in the pH, some acidic components in the crude oil were believed to react with the increased pH brine resulting in the production of surfactants within the pore network [4]. This results in the reduction of IFT and a decrease in the formation of crude oil-in-water emulsion [4]. Together, both processes enables for the production of additional oil. However, many other researchers have presented experimental evidence debunking the mechanism proposed by McGuire. Lager, Webb, Black, Singleton and Sorbie, [7] achieved increased recovery using LWSF with a pH which was less than 7. They also observed no relationship between acid number and increased recoveries. Another research team obtained results which were contrary to that of Mcguire as he obtained increrased oil production using LSWF but observed little or no change in the pH of the effluent water. Infact for one set of their experimnets, they even reported a decrease in pH, which was also associated with an increase in recovery over HS waterflooding [8]. LWSF of cores from the Tensleep formation produced increased oil recovery but this was associated with little or no change in the pH of the effluent brine, [6].

The fractional flow is represented by:

$$f_w = \frac{1 + \left(\frac{k k_{ro} A}{q \mu_o}\right)\left(\left(\frac{\partial P_{cow}}{\partial x}\right) - \triangle \rho g \sin\theta\right)}{1 + \frac{k_{ro}\mu_w}{k_{rw}\mu_o}} \quad (1)$$

Equation (1) shows the fraction flow of water in an oil-water system. Assuming a flat reservoir with $\theta = 0$, then Eq. (1) is reduced to:

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Table 1: Petrophysical Properties and Saturation Profile.

Core Name	Length, cm	Diameter, cm	PV, cc	BV, cc	Porosity, %	K, abs, md	Swi, %	Soi, %
Core A	4.4	3.5	12.0	42.4	20.00%	298.1	5.83%	94.17%
Core B	4.4	3.5	10.0	42.4	23.00%	274.0	3.70%	96.30%
Core C	4.4	3.5	9.3	42.4	22.00%	268.0	10.75%	89.25%
Core D	4.7	3.5	12.6	45.2	20.00%	293.0	3.97%	96.03%

Figure 1: Sandstone Core Samples.

$$f_w = \frac{1 + \left(\frac{k k_{ro} A}{q \mu_o}\right)\left(\left(\frac{\partial P_{cow}}{\partial x}\right)\right)}{1 + \frac{k_{ro}\mu_w}{k_{rw}\mu_o}} \tag{2}$$

A major reservoir management activity is to propose best practices that delay water breakthrough and when it does occur, minimize the fractional flow of water and consequently optimize the oil rates and estimated ultimate recoveries (EUR). To reduce the fractional flow of water in Eq. (2), the following can be done:

1. Increase the water viscosity - polymer flooding.
2. Reduce the capillary pressure by reducing the oil-water interfacial tension - Surfactant flooding

Recall that capillary pressure is given by:

$$P_{cow} = \frac{2\sigma_{ow}\cos\theta}{r} \tag{3}$$

The implication is that for a given Crude-Brine-Rock system, if σ_{ow} is reduced, the oil-brine capillary pressure would consequently reduce and f_w would also reduce. The IFT is also related to the relative permeability and affects the concavity of the curves. The higher the IFT, σ_{ow}, the more the concavity. The converse also holds true. For a perfectly miscible system, the IFT is zero and the relative permeability curves are straight lines.

This works has carried out a comparative assessment on the potential benefits of deploying optimized salinity water flooding using crude oil and brine from field X in the Niger Delta. Four salts were selected based on their availability in the Nigerian market for potential application and each was employed to flood various cores. Optimized salinity flooding involves the injection of diluted brine into the reservoir to improve oil recovery. The optimal brine salinity is usually determined in the laboratory during core flooding. Typically, a brine with a starting salinity is injected until no additional oil is recovered from the outlet for a sustained period (circa. 6 minutes at 0.5 ml/min). At this point, the injection fluid is switched to a lower salinity brine (0.5 times the initial salinity level), and additional recovery is noted and recorded. Once no more oil is recovered, the next salinity brine (0.5 times the previous) is introduced until no more additional is recovered following subsequent dilution. The optimal salinity brine is that which results in the highest additional oil recovered per PV of brine injected.

2. EXPERIMENTAL PROCEDURE

This research adopts an experimental approach to exploring the specificities of the LSWF mechanisms in the context of Niger Delta. Cores, crude oil and synthetic brine were sourced from Niger Delta fields to carry out the experiments. The breakdown of the individual experimental steps are presented following. The specific steps are outlined below;

- core characterization,
- brine preparation,
- measurement of interfacial tension,
- core flooding,

2.1. Characterization of Cores

In order to effectively characterize and understand the petrophysical properties of the cores, the cores were cleaned using a Soxhlet extractor shown in Fig. 3. Next, the cores were then dried and weighed after which the length and diameter of the cores were obtained using a caliper and a micrometer screw gauge. This was done to enable for the area and bulk volume to be calculated. Thereafter, the porosity and permeability of the cores were obtained using a liquid porosimeter and permeameter. The results for each core are presented in Table 1.

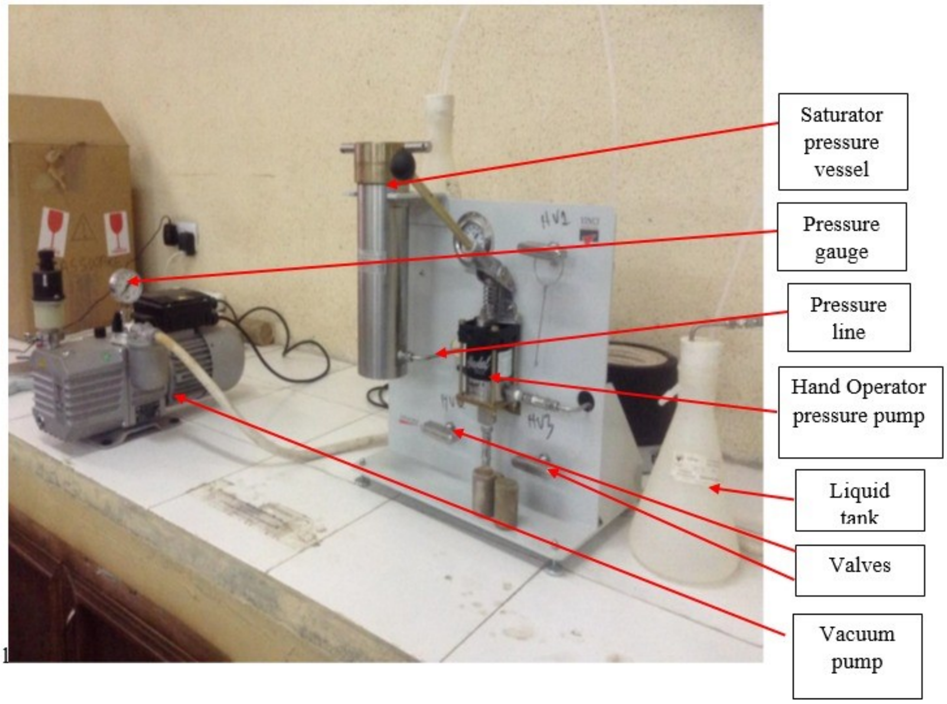


Figure 2: Manual Core Saturator.

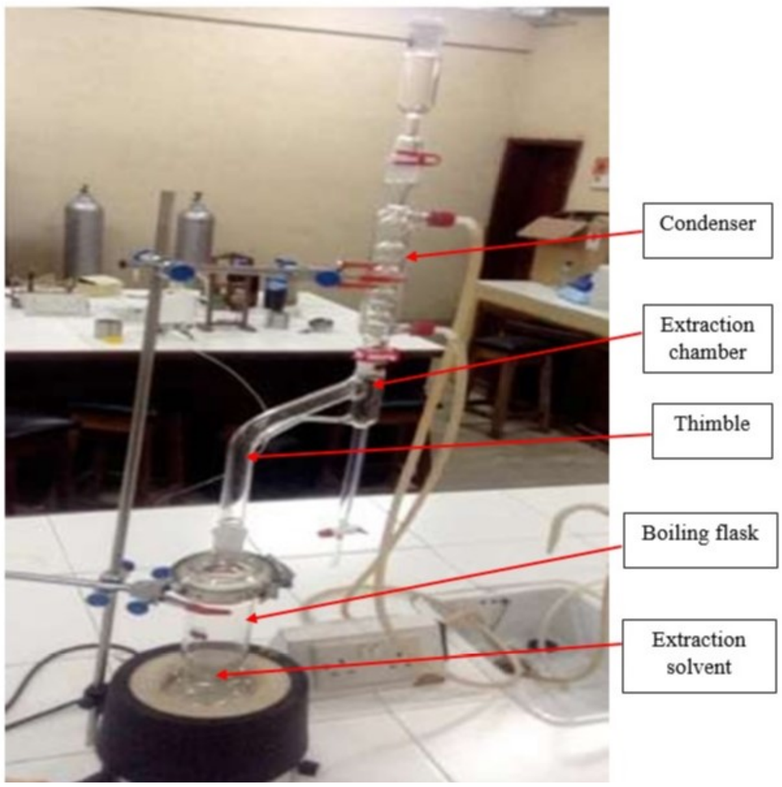


Figure 3: Soxhlet Extractor for Core Cleaning.

Table 2: Crude-Brine IFT at 27°C.

Salinity, PPM	**Crude A_NaCl**	**Crude A_K_2SO_4**	**Crude A_$CaCl_2$**	**Crude A_$MgSO_2$**
10000	62.6	55.3	51.9	55.5
5000	60.5	54.6	46.5	53.2
2500	58.5	54.5	44.8	51.9
1250	55.3	52.6	43.6	48.9

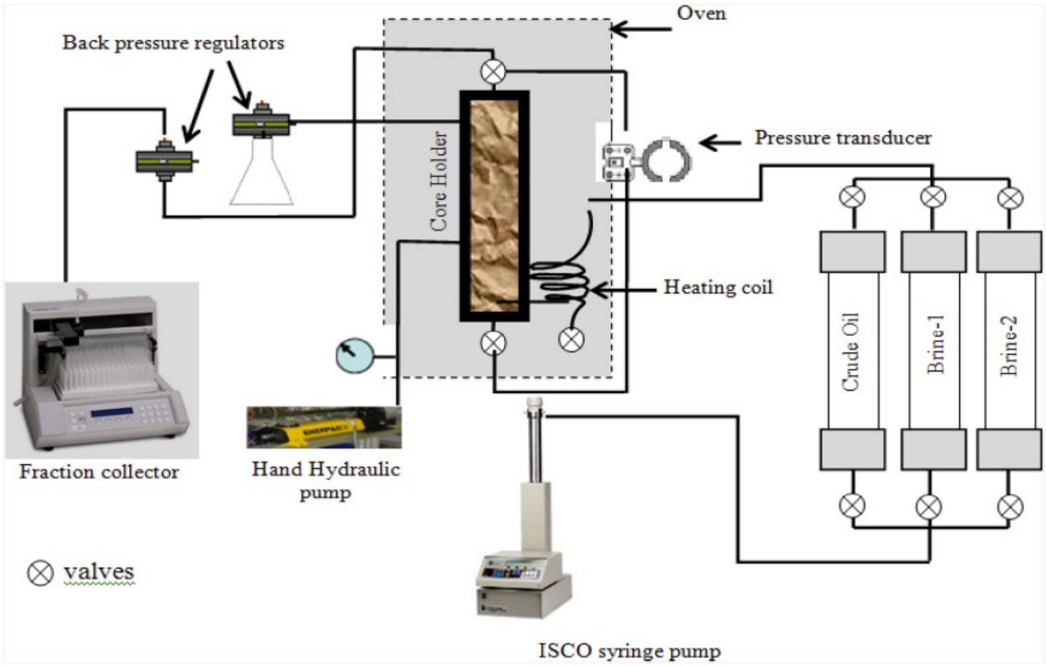


Figure 4: Layout of Core Flooding Apparatus.

Table 3: Crude Oil Properties at 27°C.

Density, kg/m^3	API Gravity	Colour	Viscosity, cp
897	26.25	Greenish Brown	0.59

Table 4: Reduction in Residual Oil vs Salininty.

Salinity	NACL	K_2SO_4	$CACL_2$	$MGSO_4$
10000	43.42%	33.50%	45.59%	26.19%
5000	8.25%	9.70%	18.71%	18.41%
2500	2.42%	3.60%	4.19%	9.76%
1250	3.92%	1.10%	2.90%	1.83%
625	1.00%	1.00%	1.40%	0.00%
Total OPTSWF	15.58%	15.40%	27.20%	30.00%
Grand Total	59.00%	48.90%	72.79%	56.19%
Remaining Sor	41.00%	51.10%	27.21%	43.81%

2.2. *Brine Preparation*

The following salts were used in this study: NaCl, K_2SO_4S, $CaCl_2S$, and $MgSO_4S$. Brine was prepared from the solid salt by dissolving the solid salt in appropriate volumes of distilled water. After which the resulting mixtures were filtered, labelled and stored in plastic cans. brines were formulated to have concentrations of 10,000 ppm, 5000 ppm, 2500 ppm, 1250 ppm and 625 ppm. (Note: 10g of salt in 1 liter of distilled water makes 10,000 ppm. Subsequent concentrations are prepared by diluting with distilled water).

2.3. *Interfacial Tension (IFT)*

For each crude oil-brine system to be flooded, the crude-brine interfacial tension was measured using the force tensiometer. The results of the IFT tests are presented in Table 2.

2.4. *Crude Oil Properties*

Table 3 contains the properties of Crude oil A.

2.5. *Core Flooding*

The layout of the core flooding apparatus is shown in Fig. 4.

In order to fully saturate the cores with brine, the cores were loaded into the core saturator and was saturated with brine for 6 hours. Next, the saturated cores were then loaded one after the other into the Hassler core holder of the flooding equipment and was flooded with crude oil at a rate of 0.5 ml/min until no additional water was observed in the effluent from the core. The back pressure was set to 50 psi during all flooding procedures. The corresponding pressure drop, effluent oil and water volumes were noted and recorded during all experiments. The brine concentration was reduced to the next salinity level indicated in 2.2 after no additional oil production was observed for 6 minutes of continuous brine injection. This was done by switching the brine accumulators. The pH of the effluent brine was also measured and noted. The flooding was stopped after obtaining maximum recovery from lowest brine salinity (625 ppm). The pressure was then bled off and the core retrieved from the core holder.

3. RESULTS AND DISCUSSION

The procedure described in section 2 was employed for the four salts and the results are presented in Fig. 5 to Fig. 14. For this particular crude oil-brine-rock system, NaCl appears to yield the highest additional recovery per PV injected in

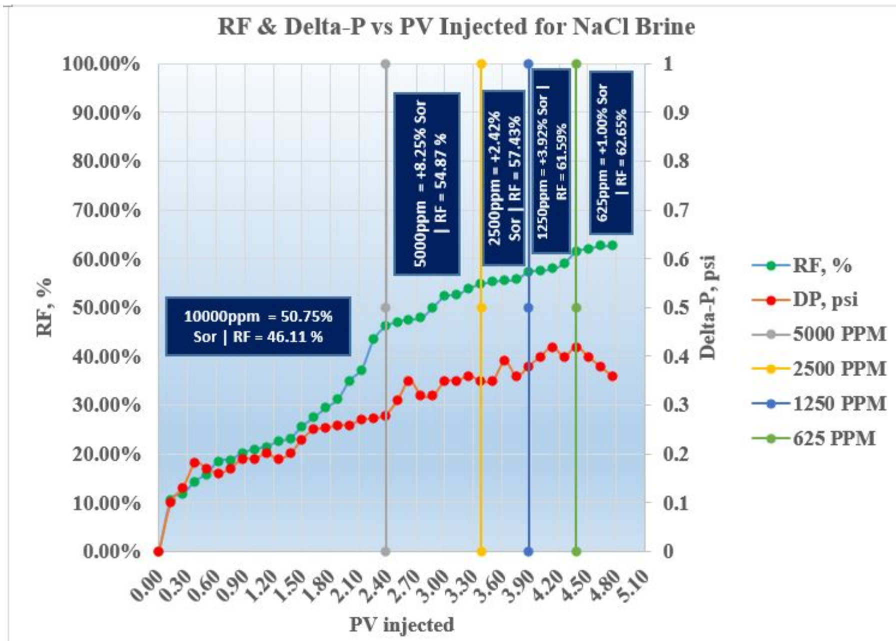


Figure 5: NaCl - Recovery Factor and Delta-P Versus PV Injected.

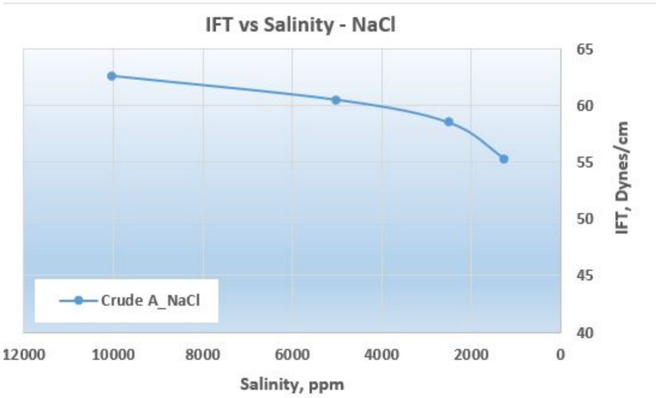
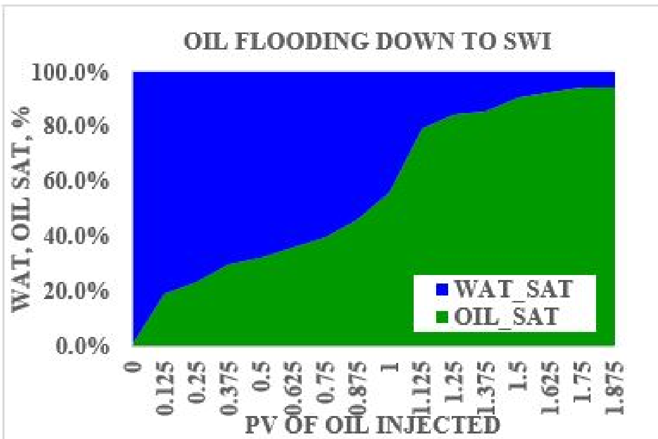
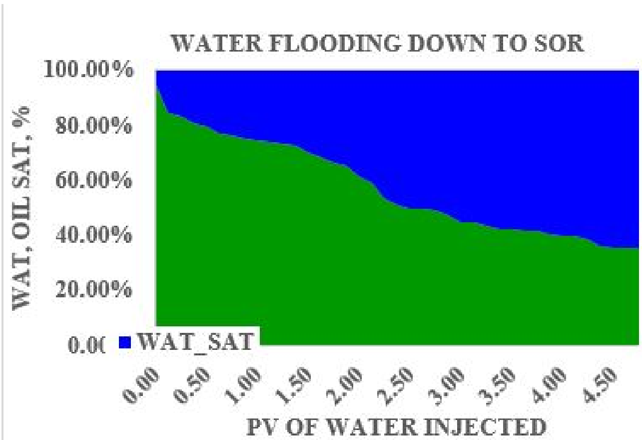


Figure 6: NaCl - IFT Vs Salinity for Crude A.



(a) NaCl - Average Saturation Within Pore - Drainage



(b) NaCl - Average Saturation Within Pore - Imbibition

Figure 7: (a) NaCl - Average Saturation Within Pore - Drainage and (b) NaCl - Average Saturation Within Pore - Imbibition.

the tertiary mode. This was closely followed by $CaCl_2$, $MgSO_4$, and finally K_2SO_4 (Fig. 13). The correct order in increasing additional recovery per brine injected would be represented thus: K_2SO_4 < $MgSO_4$ < $CaCl_2$ < NaCl. A very interesting observation is the relationship between the IFT and salinity as seen in Fig. 6, Fig. 9, and Fig. 14. This observed reduction in IFT may likely be responsible for the additional oil recovery seen as the salinity of the invading brine is reduced.

Again, it appears that there is relationship between the steepness of the IFT vs salinity curves in Fig. 14 and the observed additional recoveries in the secondary and tertiary mode. For instance, the K_2SO_4 IFT vs salinity curve in Fig. 9 appears to be essentially flat and the corresponding observed additional recovery vs PV of brine injected in . 8 also has a gentle slope upwards. The final recovery is also quite low at circa 50%. As for NaCl, $MgSO_4$ and $CaCl_2$, the IFT vs Salinity curves show a better response to the reduction in

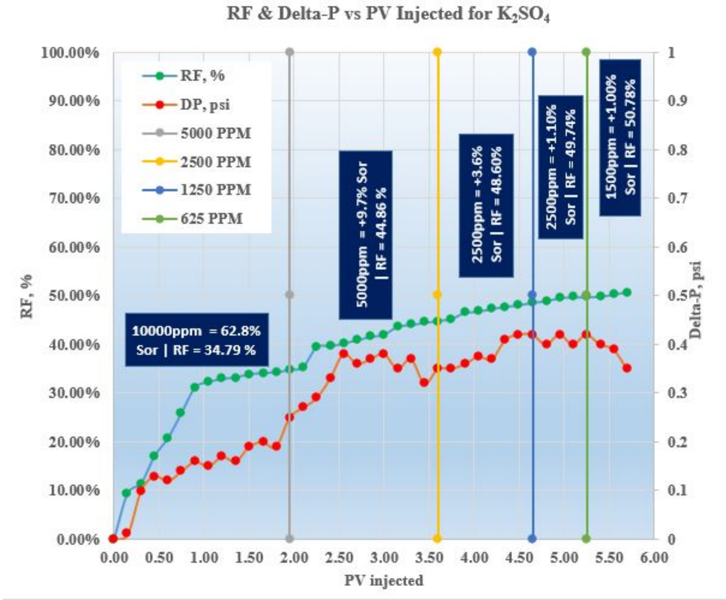


Figure 8: K_2SO_4 - Recovery Factor and Delta-P Versus PV Injected

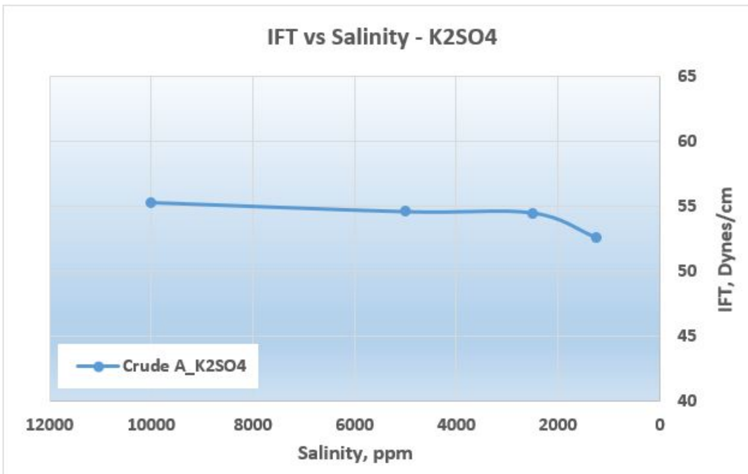
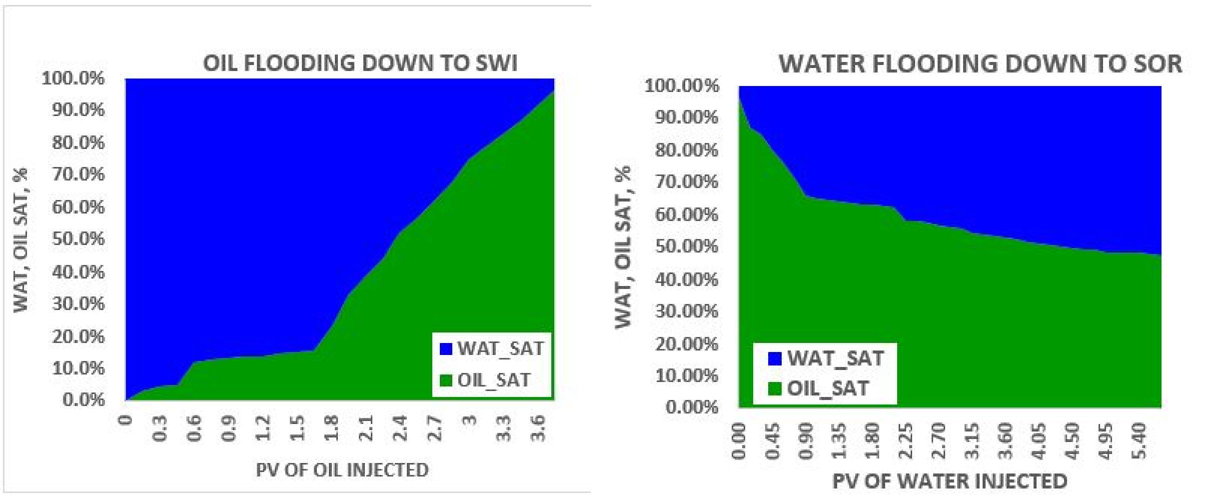


Figure 9: K_2SO_4 - IFT Vs Salinity For Crude A.



(a) K_2SO_4 - Average Saturation Within Pore - Drainage.

(b) K_2SO_4 - Average Saturation Within Pore - Imbibition.

Figure 10: (a) K_2SO_4 - Average Saturation Within Pore - Drainage and (b) K_2SO_4 - Average Saturation Within Pore - Imbibition.

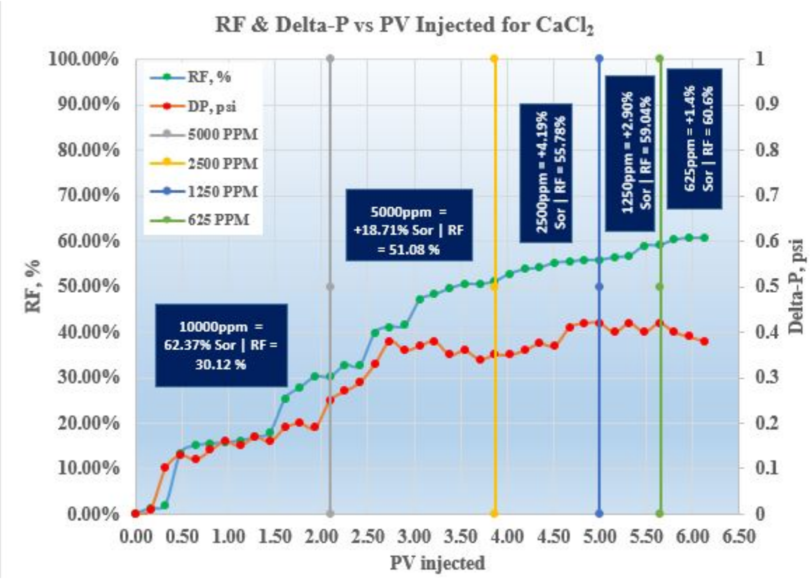


Figure 11: $CaCl_2$ - Recovery Factor and Delta-P Versus PV Injected.

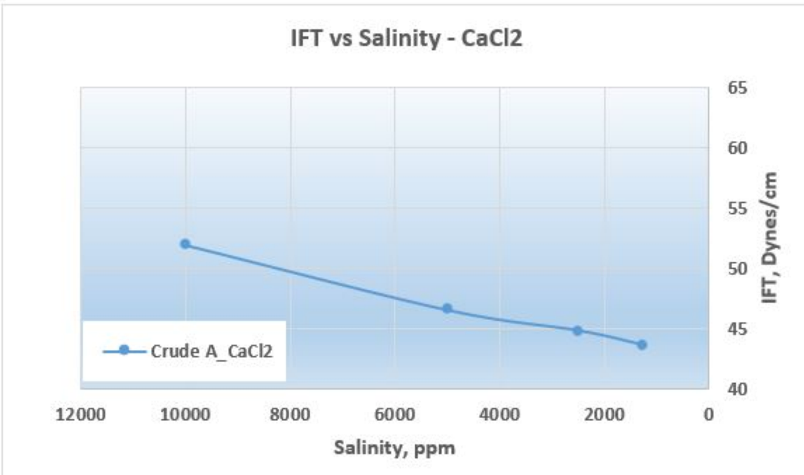
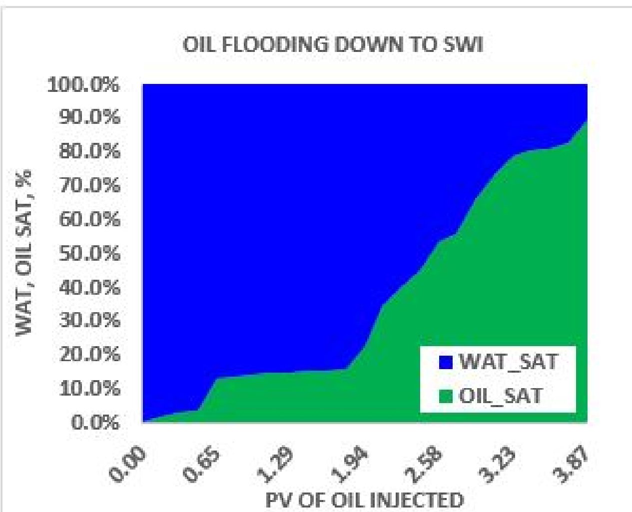
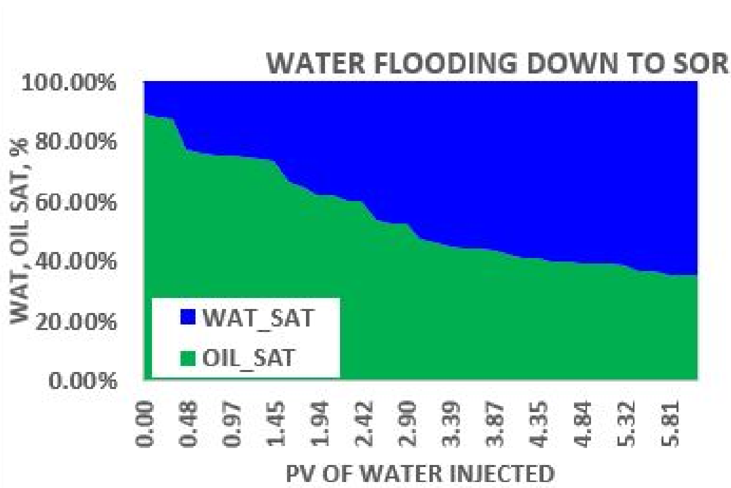


Figure 12: $CaCl_2$ - IFT vs Salinity For Crude A.



(a) $CaCl_2$ - Average Saturation Within Pore - Drainage.



(b) $CaCl_2$ - Average Saturation Within Pore - Imbibition.

Figure 13: (a)$CaCl_2$ - Average Saturation Within Pore - Drainage and (b) $CaCl_2$ - Average Saturation Within Pore - Imbibition.

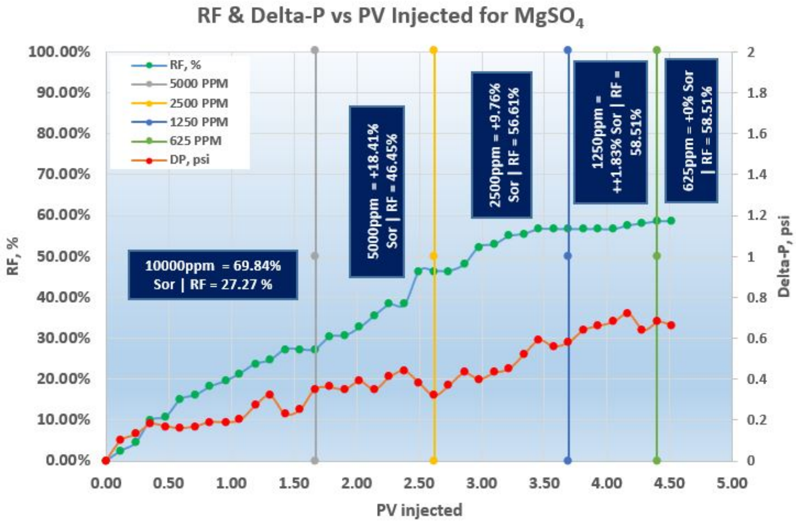


Figure 14: $MgSO_4$ - Recovery Factor and Delta-P Versus PV Injected.

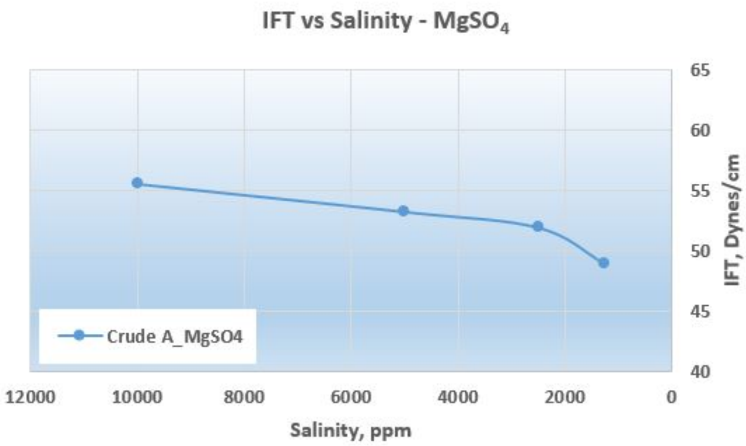
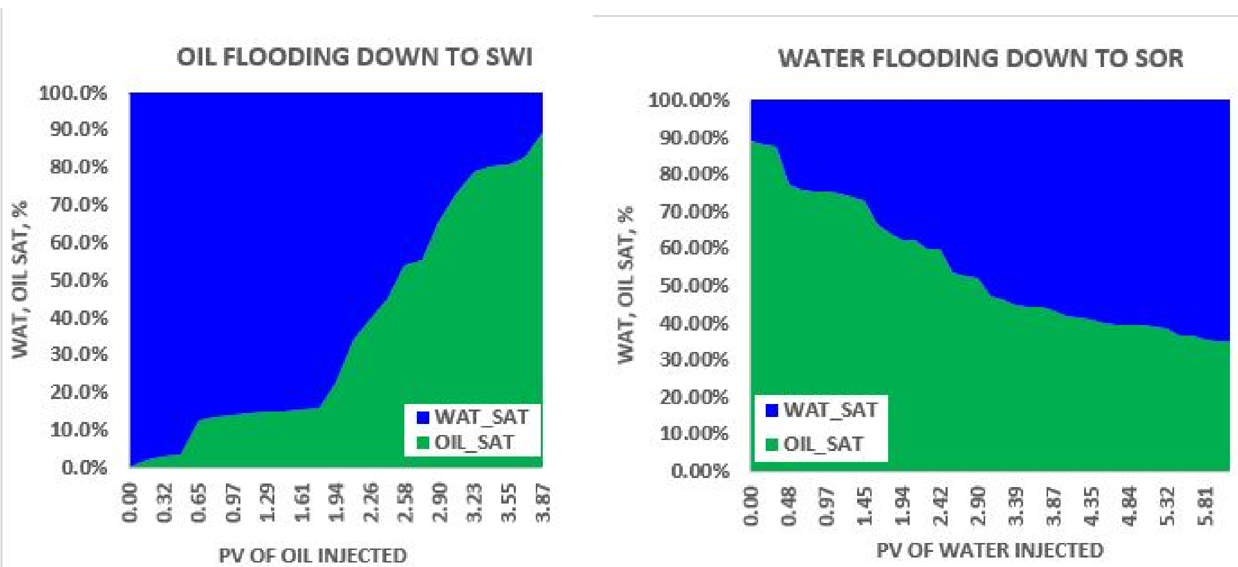


Figure 15: $MgSO_4$ - IFT vs Salinity for Crude A.



(a) $MgSO_2$ - Average Saturation Within Pore - Drainage.

(b) $MgSO_2$ - Average Saturation Within Pore - Imbibition.

Figure 16: (a)$MgSO_2$ - Average Saturation Within Pore - Drainage and (b) $MgSO_2$ - Average Saturation Within Pore - Imbibition.

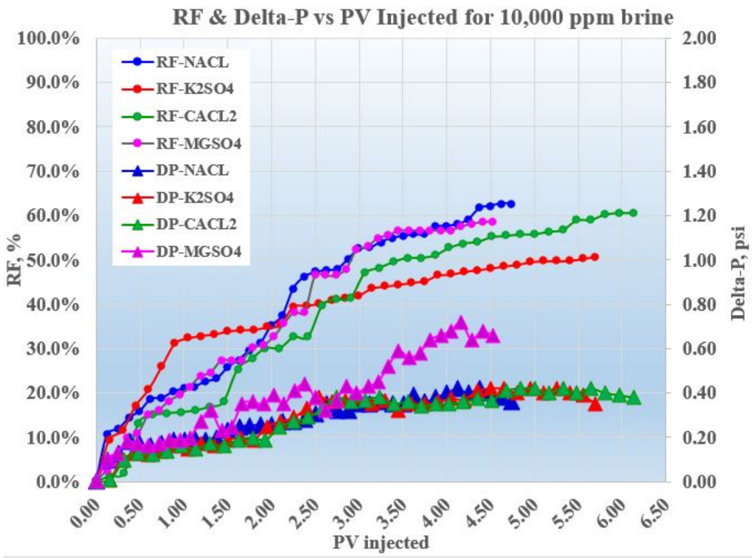


Figure 17: FOUR SALTS - Recovery Factor and Delta-P Versus PV Injected.

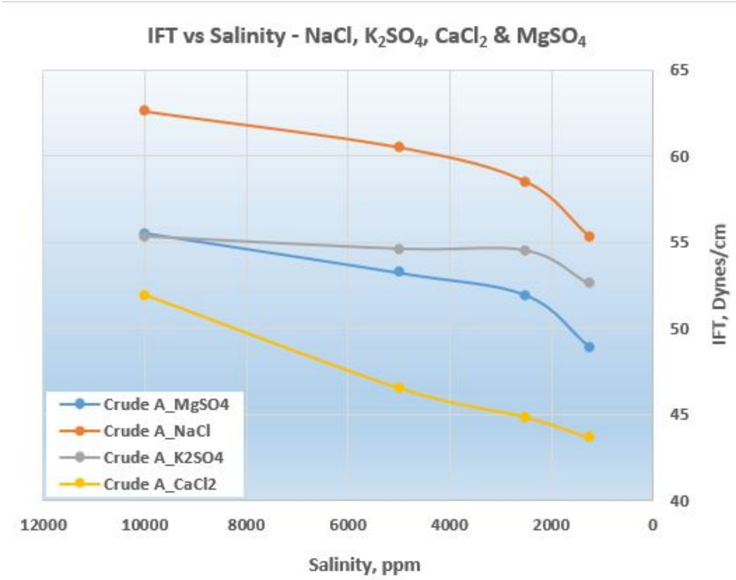


Figure 18: All Salts - IFT Vs Salinity for Crude A.

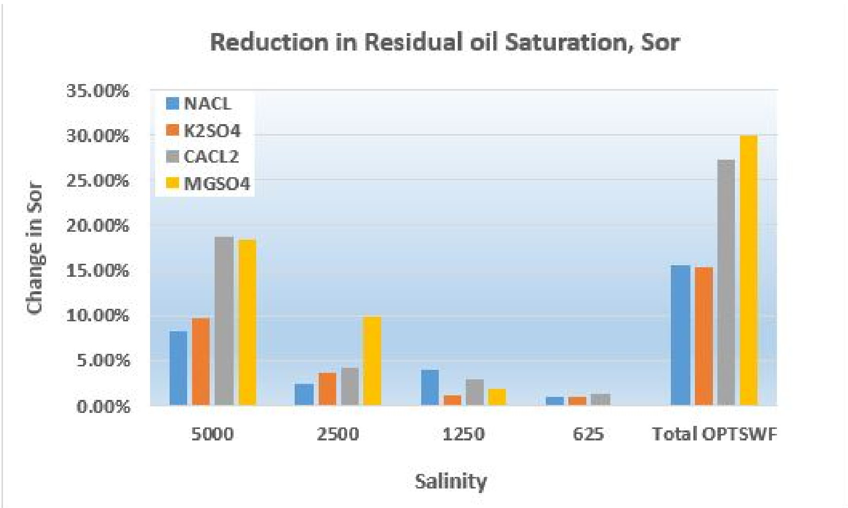


Figure 19: Reduction in residual oil saturation vs salinity.

salinity (Fig. 14).

4. CONCLUSION

This work has experimented on the comparative performance of four salts for potential use in optimized salinity flooding of Niger delta Crude-Brine-Rock-System (CBRS). Calcium chloride does best in terms of reduction in residual oil saturation in both the secondary mode while Magnesium Sulphate does best in the tertiary mode. However, the performance of Magnesium Sulphate in the secondary mode was very poor with only 26.19% reduction in residual oil saturation. Overall, Calcium Chloride does best, this was followed by sodium chloride, Magnesium Sulphate and the worst was Potassium Sulphate. It is important to note that the bulk of additional recovery occurs between 5000 ppm and 1250 ppm salinity whereas only a negligible fraction of the additional recovery in the tertiary mode is obtained below 1250 ppm. From the results of this research, it is most likely that a major mechanism underlying the observed low salinity effect is due to interfacial tension reduction by the dilution of brines leading to reduced capillary forces in the system which gives rise to the mobilization of additional oil.

The following areas can be taken up for further studies

1. Run experiments and switch from 10000 ppm straight to 2500 ppm and another straight to 1250 ppm

2. Generate correlation(s) relating crude, brine and rock properties to the observed LSE from the laboratory studies

3. The flooding has considered only a single crude oil - brine pair. Can different crude oils be used and also mixtures of the brines to understand specific fluid-fluid interactions that could arise.

4. Hybrid IOR schemes like surfactant combined with OPSWF can also be investigated to further reduce the residual oil saturation post tertiary flooding.

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