FIELD AND LABORATORY OBSERVATIONS OF REMAINING OIL SATURATIONS IN A LIGHT OIL RESERVOIR FLOODED BY A LOW SALINITY AQUIFER

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ABSTRACT

Increase in microscopic oil recovery with decrease in brine salinity has been first put in evidence by Tang & Morrow in 1998. Conflicting laboratory results have been published since and there is little field evidence yet of the benefits of waterflooding with dilute brine.

Field observations of remaining oil saturations in a watered-out sandstone, light oil bearing reservoir, produced by depletion and low salinity aquifer encroachment are presented in this paper. Finally, these results are compared with early core water flood results where the injected brine had the same salinity (17,000 ppm) as the resident brine in the oil leg.

A sound estimate of the amount and vertical location of remaining oil was deemed to be critical. The evaluation process consists of:

- Well production tests to confirm the watercut in the zone of interest, as well as the salinity and the composition of flowing brine,
- A single-well tracer test (SWTT) which was conducted on a watered-out producer,
- Direct measurements of oil saturation from cores cut with water-base muds in a new well drilled in the watered-out zone
- A suite of logs, including resistivity, carbon/oxygen and NMR tools

This paper focuses on the comparison between ROS data from direct cores measurements in the waterflooded zone, SWTT results and laboratory core flood results.

The well production tests showed that the zone of interest was watered-out. The produced brine salinity was about 2.5g/l. Thus, the salinity of the brine originating from the aquifer had significantly lower salinity than the original salinity of the resident brine. The interpretation of resistivity data in clean aquifer zones on downflank wells confirms that this reservoir has been flooded by a low salinity aquifer.

Special attention was devoted to the estimation of possible oil flushing from the cores during coring and expulsion due to gas expansion as the core is lifted to the surface. This paper also describes the dedicated coring equipment used to ensure that all mobile oil will be recovered. It is concluded that the residual oil saturation obtained by the single well tracer test is in very good agreement with those determined by direct core measurements in the waterflooded area, but is significantly lower than the core flood results obtained with the injected brine having the same salinity as the resident brine (17,000 ppm).

Finally, the mechanisms which might explain this excellent microscopic efficiency, as well as the large discrepancy with laboratory water floods, are discussed.

INTRODUCTION

Injection of low salinity water has been shown to increase the oil recovery both during secondary and tertiary laboratory water floods (Bernard, 1967; Tang and Morrow, 1997). Several laboratory studies have been published over the past 10 years, showing scattered additional benefits (Lager et al., 2007). Several explanations were proposed: fines migration (Tang and Morrow, 1999), generation of surfactants from the crude oil at elevated pH, (McGuire et al., 2005), cation exchange between the mineral surface and the invading brine (Lager et al., 2006). However, several counter examples exist for each proposed mechanism (Tang and Morrow, 1997; Lager et al., 2006; Cissokho et al., 2009) and the laboratory experimental results remain sometimes unpredictable (Zhang and Morrow, 2006).

Injection of low salinity water has extensively been performed at the field scale in the 60s, and again in the 80s prior to field pilots of chemical EOR (Trantham et al., 1978). However, there is limited field evidence that the injection of low salinity brines leads to very good or enhanced oil recovery.

Robertson (2007) compared the recovery from fields using either low or high salinity water injection. Although he concluded that the recovery is higher when low salinity is injected, he also pointed out the difficulty of distinguishing the effect of microscopic versus volumetric efficiencies in this comparison. McGuire et al. (2005) reported the results of single well tracer tests after injection of high salinity first and low salinity water later. He showed two successful tests where the remaining oil saturations decrease from 21% and 43% after high salinity water flood, down to 13%, and 34%, respectively, after low salinity water flooding. But he also reported two less convincing examples where the remaining oil saturation decreased by 4 saturation units only. With such low differences, the non uniqueness of the interpretation of the single well tracer tests becomes a significant concern. Lager et al. (2008) reported field results of low salinity water injection after depletion, high salinity water injection and miscible injection. He highlighted a measurable drop in WOR and an increase in oil production.

In this paper we report field and laboratory observations of remaining oil saturations in a watered-out sandstone, light oil bearing reservoir, produced by depletion and low salinity aquifer encroachment.

RESERVOIR DESCRIPTION:

Field description

The field includes hundreds of hydrocarbon accumulations in a deltaic area. Its structure is an anticline divided in two main zones by a major fault. Deltaic sandstone reservoirs are structurally stacked and compartmentalized in 196 layers. The covered area is 40 km².

The field structure and geological content come from a large sedimentary deposition during a phase of strong deltaic progradation from the Middle to the late Miocene. These sediments are delta plain to prodelta with abundant coals and organic shales. The structure's dip is 9° on average.

Reservoir characteristics:

This study concerned a sandstone reservoir with a gross thickness of 12m starting at 1591mSS. The following table lists its main characteristics:

Porosity	Permeability	Initial pressure	Temperature	Initial oil viscosity	Connate water salinity
30%	500-5000 mD	2300 psi	83°C	1.03	10-15 g/l

Table 1: Reservoir and fluid properties

The average clay content in this reservoir is around 7 % by mass.
Analyses in XRD were perfomed to determine the whole rock mineralogical composition on seventy eight core cut-offs. Despite the large permeabilities, an average of 7% weight of clays and micas was found. Both kaolinite and illite are present, kaolinite being predominant. Coal clasts are common and lignite is present in laminations.

Reservoir history:

In the reservoir, the oil production started in 1977 by natural depletion. The reservoir pressure decreased down to 1500 psi, well below the bubble point pressure. The first water breakthrough occurred in 1980 and the water-cut increased, showing that the aquifer was encroaching into the reservoir. Since 1990, the wells have been produced at very high water cuts. Fig. 1 shows the production history. No water or gas injection was performed.

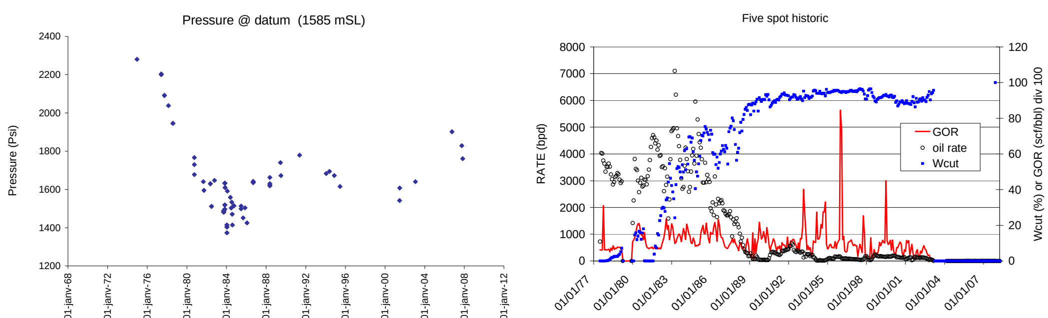

Figure 1: Pressure and production historic of the reservoir

In the 1980’s, this reservoir was selected for an EOR surfactant pilot, with a five-spot well design (Fig. 2). Wells were drilled between September 1983 and January 1984. One well was cored with water base mud. Two wells produced immediately at more than 95% water cut. A third well reached 95% water cut six months after being put on stream. The fourth well, updip from the main historical producer in this sector, produced at 70% watercut for 18 months, and then watered-out. The EOR pilot was never carried out due to unfavourable oil prices.
This location has been envisioned in 2006 for a new chemical EOR pilot. The new strategy is an inverted five spot pattern, with one injector in the centre and four producers in the corners. The in-situ measurement of the remaining oil saturation in the 5-spot area was part of the pre qualification program for an EOR pilot.

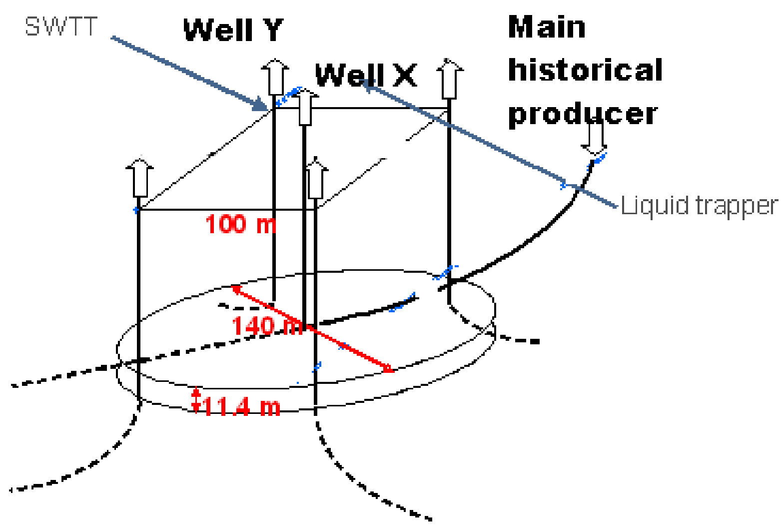

Figure 2: 5-spot area

ESTIMATION OF REMAINING OIL SATURATION:

A sound estimate of the amount and vertical location of remaining oil was deemed to be critical. The evaluation process consists of:

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- A single-well tracer test (SWTT) which was conducted on a watered-out producer,
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- A suite of logs, including resistivity, carbon/oxygen and NMR tools

Well tests and brine salinities:

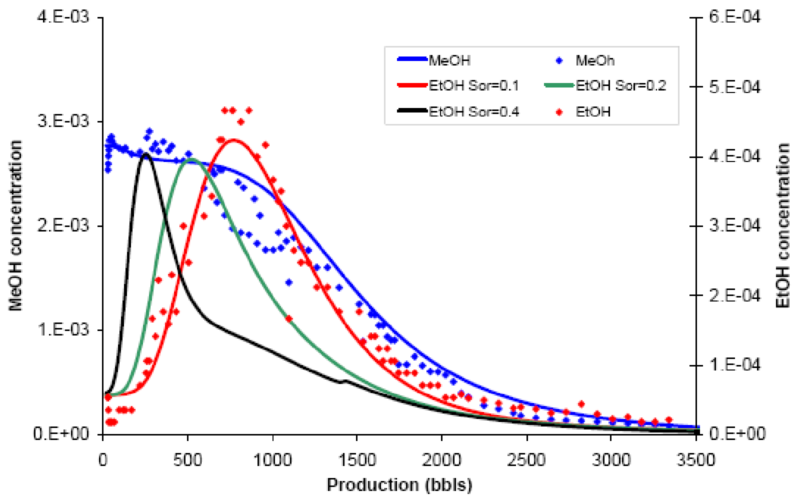
- Connate water salinity: log interpretations and water analyses all indicated a connate water salinity of 10-15g/L
- Aquifer salinity: The salinity was derived from both the interpretation of resistivity logs in a clean interval of a downdip aquifer well and regional synthesis of produced brine analysis from aquifers. Rwa-derived and SP-derived salinities were both equal to 2.65 k ppm.
- Produced brine salinity from the oil leg: The initial water composition coming from the five-spot area in 1984 was deemed to be a mixture of the connate water and water from the aquifer, with a salinity of 6.5g/l. The salinity of the produced water progressively decreased to 4g/l. Tests in 2007 showed that Well Y, on which the tracer test was run later, was producing at a water cut higher than 99%, confirming that the oil was immobile in the 5-spot area. The salinity of the produced water was 3.5 g/l. This confirmed that the reservoir had been swept by water originating from the low salinity aquifer.

Single Well Tracer Test

The SWTT is a well-known method used for many years to estimate the residual oil saturation in the near well area (Deans, 1971, Deans et al., 1986; Tomich et al., 1973). Sor estimation by SWTT is a unique method in terms of depth of investigation (5 to 10 meters) and relatively free of near well-bore effects. This method is based on chromatographic separation of reacting/partitioning and non-reacting/non-partitioning tracers in the test zone. During the test, the fraction of the reacting tracer that does not partition into the oil phase undergoes hydrolysis and produces a secondary non-partitioning tracer.

The operations consist firstly of injection of a slug containing ester plus isopropanol followed by a methanol slug to push the ester into the test zone which is well away from the near well-bore region. A soaking time is allowed for hydrolysis of the fraction of ester in the aqueous phase to form an acetate and ethanol. The latter serves as a secondary non-partitioning tracer. Finally, the test zone is back produced and tracers' concentrations are monitored by gas chromatography.

The tracer answer is a function of oil saturation and flow distribution between the three reservoir layers, acetate partitioning coefficient, Kd, and hydrolysis rate, Kh. History match of the tracer test on Well Y is shown in Fig. 3. (Wood et al., 1990). The results of the single well tracer test performed on Well Y are reported in detail by Romero (2009). No core data is available on this well. Despite a very homogeneous profile of log derived porosity, a three layer reservoir model was used, with a contrast of permeability*height of 6.18 and 12.36. The interpretation of the test resulted in residual oil saturation of about 10% in the main flowing layer. Fig. 3 shows that Sor=10% gives an excellent match of experimental concentrations (EtOH Sor=0.1). Sensitivity runs for EtOH Sor=0.2, and Sor=0.4 are also shown. The saturation uncertainty is below 1% for the highest permeable zone. From the large differences between sensitivity runs and experimental data, it is concluded that there is little uncertainty in the Sor value of the main flowing layer.



Layer	Sor
1	0.1
2	0.2
3	0.23

Figure 3: Evolution of ethanol profile for Remaining Oil Saturations of layer 1 ranging from 0.1 to 0.4

Estimation of in-situ remaining oil saturation from cores:

The very low residual oil saturation derived from the interpretation of the SWTT on well Y triggered new investigations. A new well was drilled in the middle of the 5 spot area and cored over the full reservoir height, with excellent core recovery. One of the objectives of this well X was a direct estimation of remaining oil saturation by Dean Stark extraction from rock samples, cored with water base mud. This method of measurement gives the oil saturation at the surface conditions, but includes two major uncertainties: oil flushing while coring and oil losses during the trip out if using conventional coring. Those two parameters were minimized by combining a low core invasion strategy and a dedicated coring tool called "Liquid trapper ™" from CORPRO to recover and quantify the expelled oil during the trip out.

Low invasion:

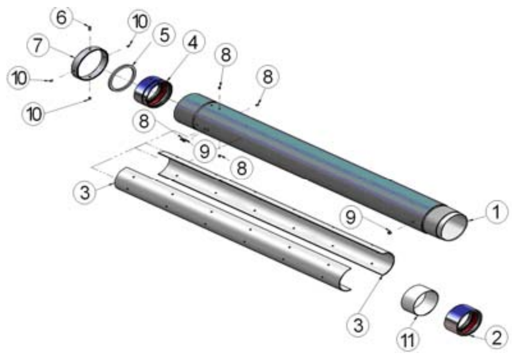
A low invasion strategy was applied and based on the water-mud optimisation to minimize its composition and the minimal pressure over balance at the coring depth. The over balance reduction was minimized using one of the lowest water based mud density available (S.G.=1.1). The mud salinity was chosen far from the one of the reservoir and CaCo3 was used as a natural tracer. Special low invasion coring bit was used.

Liquid trapper ™ description:

The liquid trapper ™ coring tool samples a 3½ inch core and traps liquids expelled from the core during the pull out trip. Its aim is to isolate the core in series of one meter section and seal it to prevent any liquid losses. Each individual section (Figure 4) consists of a standard inner tube and two half-moon liners initially filled with mud. These half-moon liners are perforated, allowing the expelled liquids from the core to flow into the annulus between the half moon and the inner-tube. This chamber is sealed by two inflatable seals, one at the top of the section the other one at the bottom, and has a total volume of around 1.2 liters. Once the coring is completed, initially compressed seals are activated from the surface by dropping a ball which seals the chamber through the action of the mud pressure.

During the trip out, the expelled liquid from the core goes into the chamber and due to the gravity separation is confined between a gas cap and the water-based mud. As the seals are designed to handle 3 bars of pressure drop, as soon as this limitation is reached a gas release at the top starts. The upper section allows gas release in the mud flow. Once the operation is completed, the tubes are cut and sealed on the rig floor and sent to a laboratory for analysis by liquid extraction.

The liquids were recovered and the oil quantification was performed using tetrachloroethylene extraction and infrared spectroscopy. The overall oil volumes measured were negligible (<0.1% of the total core pore volume per section). Thus, no correction to the Dean Stark measurements was needed for expulsion of oil during trip out.



Item Number	Title	Quantity
1	STD IT SECTION – LT	1
2	SEAL ASSEMBLY – PIN	1
3	ALUMINIUM HALF MOON LINER	2
4	SEAL ASSEMBLY – BOX	1
5	SEAL SPACER	1
6	SHEAR PIN VALVE M5 (BRASS)	1
7	IT VALVE RING	1
8	GRUB SCREW M5 x 8 – STEEL	4
9	GRUB SCREW M10 x 8 – STEEL	2
10	GRUB SCREW M5 x 8 – BRASS	3
11	HALF MOON SUPPORT RING	1

Fig. 4 : Detailed view of a Liquid Trapper ™ 3.4ft section

Saturation from the Logs

To access to the fluid saturation a large ELOG acquisition program was performed. A sequence of: Reservoir Saturation Pro Tool / Magnetic Resonance eXpert Tool (run + stations) / Pump-Out / MRX (stations) / RST / Log While Drillling was designed to mitigate the uncertainties on the residual oil saturation. The pump out was set in the middle of the log sequence to look for saturation evolution and mobile oil due to the pump out.

The main conclusions from the log interpretation of the selected water flooded zones are below with respect to each tool:

- Conventional Wireline E-Logs: There is excellent agreement between the porosity derived from Neutron-density logs and the core measurements. The main uncertainties of the saturation interpretation from resistivity tool in a waterflooded area have long been known: unknown salinity and temperature in the near wellbore area, hysteresis in Archie exponent between drainage and imbibition. Using the produced brine salinity during the test of Well Y, the reservoir temperature and the drainage Archie exponent, the remaining oil saturation derived from resistivity log interpretation ranges from 40% to 50%. This result is much larger than the ROS derived from SWTT or measured on cores. To get agreement with both types of results, the Archie imbibition exponent must be increased, up to 3 to 5. We are not aware of such a large difference in Archie exponent between drainage and imbibition at high water saturations in the literature.

- RST: The major uncertainty on the Sigma-derived Sw comes from the low contrast in salinity in the invaded zone and the degree of invasion. A 90 k ppm salinity water based mud has been chosen to increase the accuracy of the capture Sigma. A run was performed after the pump out. From this data, a minimum of water saturation of 60 % was computed based on a 90 k ppm salinity. But this interpretation is based on the run after a pump out decreasing the reliability of assuming a salinity of 90 k ppm. Thus, in the log interpretation, variation of salinity ranging from 50% to 70 % was tested. This gave Sor ranging from 0 to 20 %. Because of the large impact of salinity on the saturation it was concluded that this approach did not give a reliable estimate of Sor.

- MRX scanner logs: Several stations were applied. Oil saturations,were low, ranging from 4% to 19% (see Table 2). These oil saturations are more consistent with the experimental core data,

	apparent Soil (%) from D - T maps :		
station m MD	1.5" shell	2.7" shell	4" shell
1592	11	12	16
1593	4	4	6
1600	15	15	19

Table 2 : Saturation deduced from the MRX scanner

But the MRX-derived total porosity is 5 to 8 PU off the core porosity. This very large discrepancy in porosity remains unexplained and thus casts doubts on the MRX derived saturations.

Conclusions on the estimation of remaining oil saturations

The residual oil saturation obtained by the single well tracer test (~10%) is in a very good agreement with those determined by direct core measurements in the waterflooded area (9-15%). Both sources of data are deemed robust and reliable: 1) The narrow range of core permeability observed on well X gave even more confidence in the previous interpretation of the SWTT of the neighbouring, uncored well Y; 2) The risk of sweep of remaining oil in cores by the mud filtrate was minimal, as the well tests proved that the zone was at residual oil saturation before coring; 3) The remaining oil saturations were obtained on cores from a new well, avoiding issues related to the possible near-wellbore effects of long term producing wells. With both techniques, the residual oil saturation is low. On the other hand, the interpretation of different logs was inconclusive. Taking into account large discrepancies between core data porosity (MRX) or saturation (resistivity) and the large sensitivity to unknown parameters, the estimated saturations are regarded as invalid. Fig. 5 shows a final selection of valid log and core data.

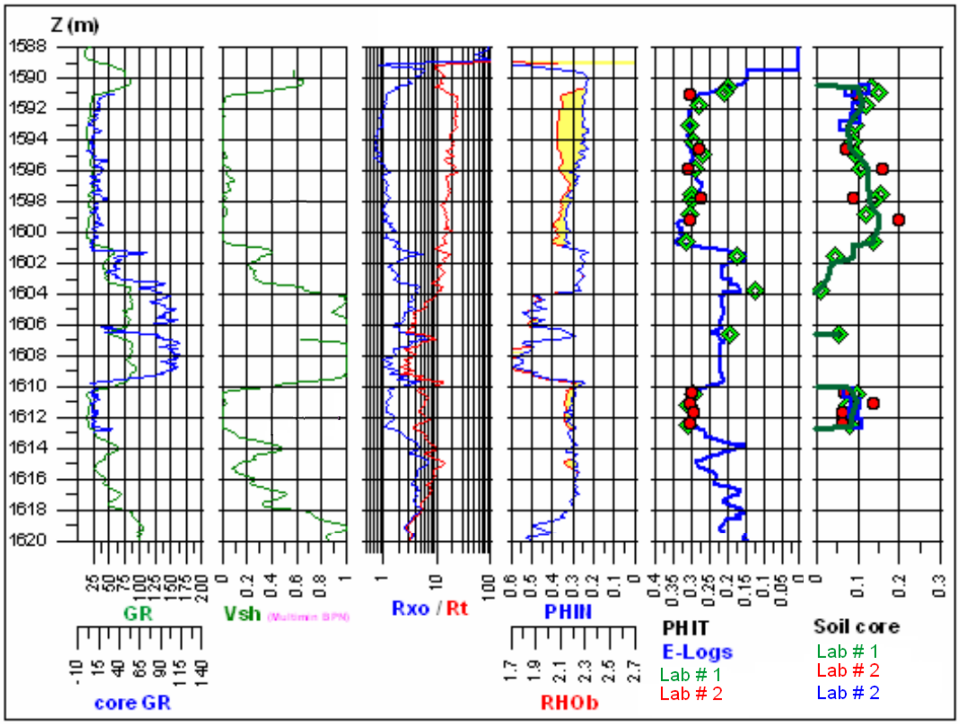


Figure 5 : track #1 : log and core gamma ray ; track #2 : VSH ; track #3 near and deep resistivity track #4 : Neutron & density logs ; track #5 log and core total porosity track ; track #6 core oil saturation.

DISCUSSION

SWTT interpretation and direct measurements on cores taken in the same water flooded area showed low in-situ residual oil saturations. These results are compared with earlier laboratory data. All core floods were unsteady-state water floods on cores that had been cleand with mild solvents. The cores were taken with water base mud.

Early laboratory work was performed on a nearby well, located less than 70 and 140 m away from wells X and Y respectively. More recent water floods were carried out on cores from a deeper well. The following table lists the main characteristics and the results of the tests. In all tests, the salinity of the connate and injected brines was identical.

	porosity	conditions	oil	Brine salinity	So@Krow=0.0001	No. of Tests
Early work	0.31 - 0.34	laboratory	refined	17g/l	0.2 – 0.32	4
Recent work	0.22-0.25	Reservoir P&T	crude	9 g/l	0.26 -0.37	3

Table 3: Residual oil saturation measurement on reservoir cores from SCAL studies

It shows that the residual oil saturation achieved on cores after displacement by water when the injected brine has the same salinity as the resident brine ranges from 20 to 37%, far above the measured in-situ oil saturations by SWTT and core analysis. Two possible mechanisms might explain this excellent microscopic efficiency, as well as the large discrepancy with laboratory water floods:

- Three phase flow
- Waterflood by low salinity brine combined (or not) with gravity segregation

Three phase flow might have occurred during production, as reservoir pressure decreased significantly below bubble point pressure. If the secondary gas-cap swept the zone before the aquifer encroached into reservoir, the remaining oil saturation might be a three-phase residual oil saturation and not a residual oil saturation to water. It has long been documented that water flood in the presence of gas might result in low residual oil saturation. The only indirect clue that this sequence might have happened in the 5-spot area is a possible gas effect on the porosity logs at the top 3 meters of the interval, as well as the large discrepancy between core and MRX derived porosity. However, there is no evidence of a vertical gradient in core ROS. Moreover, water broke through in January 1978 on the main historical producer of this zone, when the reservoir pressure was only 300 psi below initial pressure and reached 40% water cut within a year, without any evidence of large GOR increase during the initial production period. Reservoir simulations were also performed at the reservoir scale to estimate a potential three phase flow in the five spot area (gridding 25*25*1m – Sorw=0.25). Even without any aquifer support, gas cap expansion does not reach the five-spot area. Finally, we cannot disregard a three–phase effect on the uppermost 4 meters of the reservoir interval (1591 – 1595 m). However, it is very unlikely that this effect applies to the lower half of the reservoir (1596 -1601m) and (1610 – 1612 m).

Two favourable factors might explain very good microscopic efficiency of the aquifer encroachment into this reservoir as well as the large discrepancy with laboratory water floods:

- The displacing brine is reported to have low salinity ranging between 2.5 and 3.5 g/l.
- The high permeability rock contains a significant amount of clays and micas.

The same combination was deemed to be the key of improved oil recovery by dilute brine injection on the high permeability Berea model rock (Tang and Morrow, 1999). Laboratory results (Cissokho et al., 2009) clearly show that the injected brine salinity must be below a salinity threshold to achieve additional recovery by dilute brine displacement. The large discrepancy between the core flood Sorw and the in-situ residual oil suggest that this salinity threshold is between 9 and 3 g/l for this reservoir, which is consistent with literature results.

The remaining oil saturation to water in 1984 might have been further reduced by gravity to give the current very low Sorw values. Vertical segregation across the full reservoir interval is deemed unlikely due to the abundance of lignite streaks, which might reduce dramatically the overall vertical permeability. However, along the bedding, oil segregation towards the top of the structure might have been efficient, should the low salinity brine displacement have shifted the wettability towards increased water-wetness. In such case, modification of the curvature of the oil relative permeability might have helped segregation of oil within thin sand units towards the top of the structure.

CONCLUSIONS

Single well tracer test and coring with the Liquid Trapper ™ tool proved to be the most reliable approaches to assess the in-situ remaining oil saturation. ROS from both sources in the same water flooded area are in very good agreement, in the range of 10 - 15%, but is significantly lower than the core flood results obtained with the injected brine having the same salinity as the resident brine. The interpretation of saturation from different logs was deemed to be inconclusive.

Two possible mechanisms might explain this excellent microscopic efficiency, as well as the large discrepancy with laboratory water floods. The very low Sorw at the very top of the reservoir interval could be the consequence of a three phase effect and the very low Sorw observed in the lower half of the reservoir interval could be related to the low salinity of encroaching aquifer.

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