LOW SALINITY WATER FLOODING: FACTS, INCONSISTENCIES AND WAY FORWARD

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ABSTRACT

15 years after the first experimental evidence of increased oil recovery by low salinity water injection (LSWI), clear understanding of the mechanisms has not emerged yet out of more than 500 published laboratory experiments.

Firstly, it is shown that there is increasing experimental evidence that published tertiary LSWI core floods do not often succeed in increasing significantly the recovery within the 2-3 first PVs of tertiary injection, despite strong claims of positive results.
Then, this paper focuses on sandstones and mostly on studies where secondary LSWI performs better than secondary high salinity water injection (HSWI). Even in such cases, some examples show that the efficiency of tertiary LSWI may range from poor to nil. These cases satisfy all "required conditions", such as presence of clay, of connate water, and mixed wettability.

Conditions of existence of a double saturation shock, effects of dispersion in water phase at $Sorw_{HS,}$ and the direction of wettability modification are the hypotheses discussed in this paper to understand poor performance of tertiary LSWI. Some key experimental observations are then compared to these possible explanations. They may explain the vast majority of published studies, but counter examples can also be produced for any single proposed mechanism.

This paper also puts in evidence that some types of experimental measurements have been neglected and would deserve more attention, comments on the effect of interfacial tension and suggests a new approach for investigating the efficiency of tertiary low salinity water flooding.

INTRODUCTION

There is a clear evidence that:

- Spontaneous imbibition by LSWI is able to increase oil recovery compared to high salinity [21, 44, 46, 59]. In such cases, LSWI can be used to increase oil recovery of very heterogeneous matrix reservoirs or highly fractured reservoirs.
- Secondary LSWI is able to increase oil recovery compared to HSWI in a large number of studies [11, 17, 18, 22, 23, 28, 29, 40, 45, 48, 51, 52, 55]. Significant additional oil is often observed at water breakthrough or immediately after. In such cases, LSWI can

be used to increase recovery of undeveloped fields. The comparison of secondary recoveries between LSWI and HSWI also showed cases with either very weak benefit of LSWI [55] or no difference [34] or even negative result [19, 37, 52]. Some authors [20, 51] suggested that LSWI was always successful but they also showed a wide variation in positive results. Other authors [5, 55] highlighted that the main challenge would be to explain the very large scatter in incremental recoveries by LSWI: from nil to ΔSorw = -13 saturation units. Morrow [27] concluded that "*Identification of the sufficient conditions for LSE and understanding the circumstances under which there is little or no LSE remain as outstanding challenges*".

A large number of laboratory studies consist of tertiary LSWI after secondary HSWI. The motivations behind tertiary floods are:

1. Reproduce the saturation history of mature, waterflooded reservoirs and check whether LSWI can be an efficient EOR process,
2. Cope with scarce availability of reservoir cores. Comparison of secondary waterfloods requires at least twin samples or more if different recipes of injected water are tested

Almost all laboratory tertiary LSWI tests start at $Sorw_{HS}$ and consist of continuous injection of low salinity afterwards. A lot of authors conclude that tertiary LSWI has positive effects, based upon final incremental recovery after very long injection periods. In fact this conclusion is much more debatable than for secondary LSWI. If we decide that a realistic, positive effect means 1) The arrival of the oil bank at approximately 0,5-0,6 PV injected or 2) Additional recovery of at least +5%ooip after 1 PV injected, the scene looks quite different:

- Studies showing production of significant incremental oil after a short tertiary injection period of low salinity water are very scarce [20, 22, 38, 45, 51].
- When significant incremental oil is produced during tertiary LSWI, oil is very often delayed or oil is produced at a low pace over several PVs of injection [3, 10, 11, 21, 22, 23, 31, 32, 33, 45, 49, 55, 56]
- Nil or very poor additional recovery by tertiary LSWI has now been largely reported. It has been suggested that such failures were related to use of outcrop cores, rather than reservoir cores [52]. In fact, very poor additional recoveries are shown for both:
    - Outcrop: [16, 19, 28, 34, 35, 40, 41, 43, 52, 53, 55]
    - And reservoir cores [5, 15, 17, 33, 37, 42, 52].
    - Taking into account the overrepresentation of outcrop cores in published laboratory work about LWSI, the conclusion about outcrop versus reservoir cores remains questionable.

It is worth noting that the three necessary conditions, as defined in [27] for positive effect of LSWI, were almost always satisfied in these studies.

In the following, the possible reasons of the poor performance of tertiary LSWI are investigated. Unfortunately, the vast majority of these experiments are not accompanied by any other type of tests: neither secondary LSWI nor wettability, etc. It prevents detailed analysis. Therefore, this paper focuses mainly on the scarce laboratory studies which: 1)

Report both secondary and tertiary LSWI 2) Show larger oil recovery by LSWI than by HSWI on secondary floods. These studies represent crude oil/brine/rock systems where LSWI effect does exist in secondary mode and we can eliminate debates about causes which trigger positive low salinity effect.

FACTS, HYPOTHESES AND INCONSISTENCIES

Existence of a Double Saturation Shock

Firstly, we might hypothesize that the evolution of oil production during tertiary LSWI, starting at $Sorw_{HS,}$ strongly depends on conditions which control the existence of a double saturation shock [30], particularly on fractional flows for secondary high and low salinity water floods. When reviewing literature LSWI results, viscosity ratio and secondary water/oil relative permeabilities (Krs) for both LSWI and HSWI would be necessary to evaluate these conditions for each study. In fact, they are almost never reported. However, coarse estimation can be done when the viscosity ratio and the evolution of differential pressure during secondary floods are reported.

Simulations in figure *1a* have been performed using a set of Krs for secondary water floods where ΔSorw = -0,1 between high and low salinity waters:

- With favorable fractional flows, here μ_o/μ_w =2, an oil bank is created in tertiary mode by LSWI and breaks through rather early, at about 0,5-0,6 PV injected, as suggested also by other simulations [26] or analytical calculations.
- At unfavorable conditions, here for μ_o/μ_w=7, the oil bank vanishes. Incremental oil is delayed and is produced very slowly. It represents the slow arrival at the outlet of the spreading wave related to the LSWI. For µo/µw=18, tertiary oil production is postponed to very late times.

Experimental observations of a clear oil bank during tertiary LSWI are very scarce in the literature. When this behavior is reported [20, 22, 45, 51], lack of information often prevents the comparison of experimental conditions with theoretical estimations about the existence and stability of the second saturation shock. Oil banking during tertiary LSWI is consistent with low viscosity oils and with the type of Kr curves for secondary floods shown by Webb in [51] on three reservoirs: very small difference in Krw(Sorw) between HS and LS despite significant reduction in residual oil saturation: ΔSorw~ -0,05 to -0,07.

In fact, most of published tertiary LSWI have been carried out at large [16, 31, 32, 33, 35] to very large (µo/µw~18 [40], ~23 [49], ~32 [55], ~40 [52, 53], ~54 [56]) viscosity ratios. They might explain the absence of oil bank, the delayed oil bump if any, as well as very slow oil production. Shehata [40] performed tertiary LSW on Bandera sandstone. Significant benefits were clear in secondary mode by LSWI: ΔRec~+9% oip. The delayed arrival of the oil bump, after 1,5 PV injected in figure *1b*, is consistent with the unfavorable viscosity ratio. In the same study, he obtained even better results in secondary mode on Buff Berea: ΔRec~+16% OIP, but no tertiary incremental oil by LSWI. Again, this is consistent with large viscosity ratio.

More surprising are some rare core floods where a fast and strong oil bank is reported in conditions where it should disappear. Loahardjo's [22] cores 2065/1 R1/C1 and 2060/1 R1/C1 did produce a strong oil bank at 0,42 PV tertiary LSWI despite very unfavorable viscosity ratio ($\mu o/\mu w$~30). However a 5-10 fold increase in differential pressure is reported immediately after starting LSWI, which may be related to dispersion of kaolinite with salinity shock. Although endpoints are not explicitly reported, it shows that $Kw(Sorw_{LS}) << Kw(Sorw_{HS})$, despite $\Delta Sorw\sim -0{,}05$. This reduction in total mobility might contribute to the stabilization of tertiary saturation front.

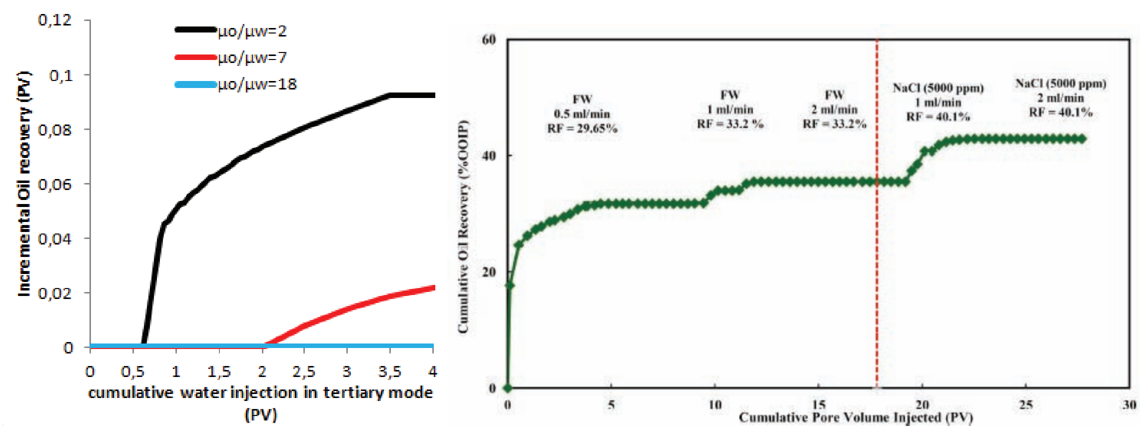

Figure 1: a) simulations of tertiary LSWI as a function of viscosity ratio b) delayed oil recovery during tertiary LSWI from Shehata, 2014

Can we assume that the evolution of oil production during tertiary LSWI is only controlled by the fractional flows at high and low salinities?

Cissokho [11] presented positive results of secondary LSWI compared to HSWI, and a wide range of results in tertiary LSWI on companion sandstone samples with the same reservoir oil. Unreleased results and analysis are offered in the following. Two tertiary LSWI at different temperatures, (DU3-D-9, $\mu o/\mu w=5{,}4$; DU3-0-5, $\mu o/\mu w=7{,}5$) showed large differences in the amount and timing of incremental oil by LSWI, as illustrated in figure *2a*. It can hardly be explained by conditions related to the existence of a double saturation shock, as the most significant bump in tertiary oil production is observed for:

- The coreflood with the largest viscosity ratio,
- For DU3-0-5, where evolutions of differential pressure show that $Kw(Sorw_{HS})=Kw(Sorw_{LS})$, whereas the smallest oil bump is observed for DU3-D-9, where $Kw(Sorw_{HS})>Kw(Sorw_{LS})$

It shows that other parameters than the fractional flows at high and low salinities also control the tertiary behavior during LSWI.

Effect of Dispersion in Water Phase at Sorw$_{HS}$

We might also hypothesize that the evolution of oil production during tertiary LSWI depends on dispersion in the water phase.

During tertiary LSWI (1g/l) by Cissokho on samples DU3-0-5 (fig. *2b*), salinity shock arrives at the outlet almost simultaneously as the oil bump, after approximately 1 PV injected. The evolution of chloride concentration shows that 2 PV of LSWI are required before the produced brine has decreased below 2g/l. The threshold salinity which triggers tertiary incremental oil is 2,5 g/l in this set of experiments [11]. This observation shows that dispersion at Sorw$_{HS}$ is significant and might delay the effect of LSWI.

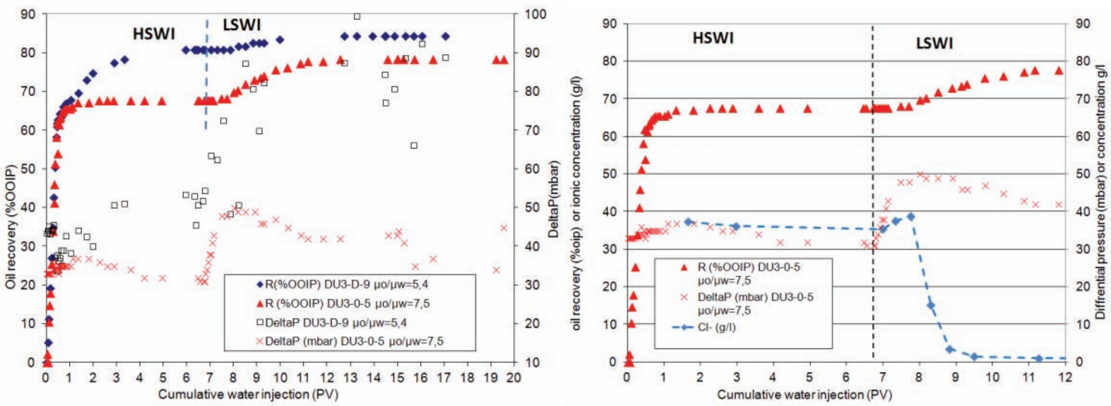

Figure 2: a) Evolution of tertiary recovery during LSWI at slightly different viscosity ratios b) Evolution of recovery, differential pressure and salinity during secondary HSWI and tertiary LSWI

Figure *3a* shows the comparison of results of tertiary LSWI carried out by Cissokho on samples DU3-0-5 and DU3-A-4. Although there is indirect evidence of the salinity shock through the increase in differential pressure as soon as the low salinity water contacts the sample in both experiments, there is no incremental oil in tertiary LSWI on DU3-A-4. Figure *3b* shows the comparison between the normalized concentrations during brine tracer tests which have been performed on sample DU3-A-4 at Sw=1 and at Sorw [11]. At Sw=1, the effluent curve is symmetrical and injected concentration was produced after 1,7 PV of injection. It confirms that the core is rather homogeneous. At Sorw, the effluent curve is largely skewed, and injected concentration was not produced before more than 3,5 PV of injection. It shows again that dispersion at Sorw might be quite significant, even in homogeneous rock samples. This observation is in agreement with previous studies, such as tests PF8A and PF8C in [24]. It shows that residual oil distribution is responsible for increased dispersion. Significant incremental oil on DU3-0-5 by tertiary LSWI may be correlated to limited dispersion in water phase at Sorw$_{HS}$ whereas much larger dispersion on DU3-A-4 correlates with no tertiary recovery.

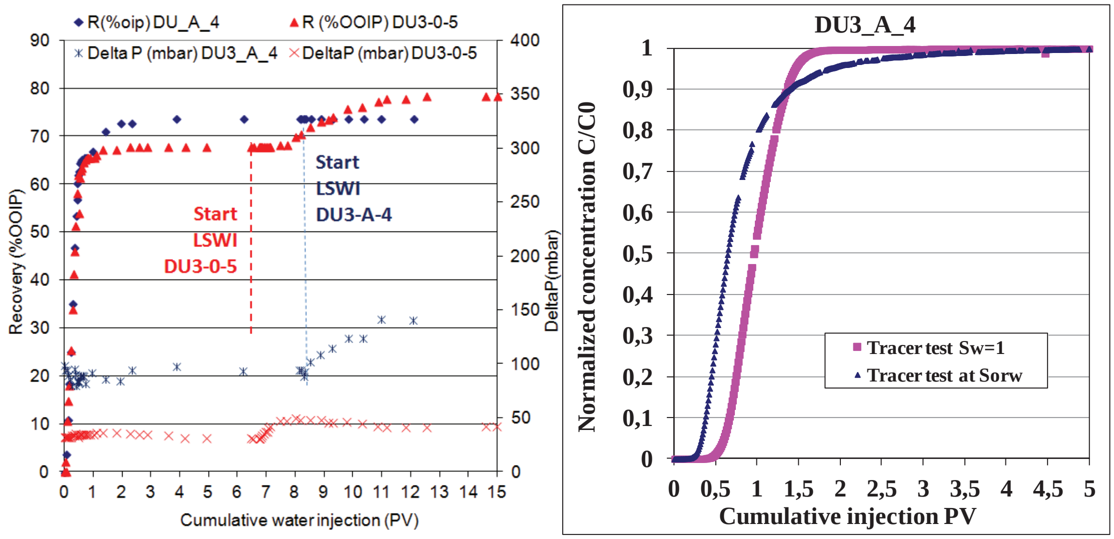

Figure 3: a) recovery during secondary and tertiary LSWI; b), tracer tests at Sw= 1 and at Sorw (from Cissokho)

Nasralla [28] shows water floods on four companion Berea sandstone samples, with different brine salinities: 174, 55, 5,5 Kppm as well as distilled water. Distilled water injection recovered +19% oip in secondary mode than the injection of 174Kppm brine, as shown in figure *4a*. At the end of each secondary flood, tertiary injection of distilled water was performed over several PVs, but never exhibited any incremental oil. Although the viscosity of crude A is measured at ambient temperature only: 7,2 cP, the usual extrapolation at core test temperature: 100°C suggest that the viscosity ratio may partially explain the very poor performance of tertiary LSWI. Moreover, the evolution of ionic composition during tertiary LSWI shows (fig *4b*) that the composition of injected water (deionized water) is not reached at the outlet after more than 5 PV injected, on these 15 cm long cores. Reported information does not allow to separate core heterogeneity from added dispersion by residual oil, but clearly shows strong dispersion at $Sorw_{HS}$. Strong dispersion in brine phase at $Sorw_{HS}$ delays the decrease towards very low salinity all over the core. It suggests that the combined effect of unfavorable viscosity ratio and strong dispersion at Sorw might totally suppress positive effect of tertiary LSWI, even when secondary floods put in evidence very significant benefits.

Which factors may have large effects on brine/brine displacement at Sorw?
Single phase dispersion might already be large. Sample heterogeneity along flow axis would be a major cause. Rock characteristics may also have strong effects: 15 fold differences in single phase dispersion coefficient between various outcrop sandstones at the same velocity have been reported [13]. Berea sandstone (300 mD) exhibited the sharpest displacement front and the least amount of tailing. Wide pore-size distributions in sandstones lead to higher dispersion coefficients [6].

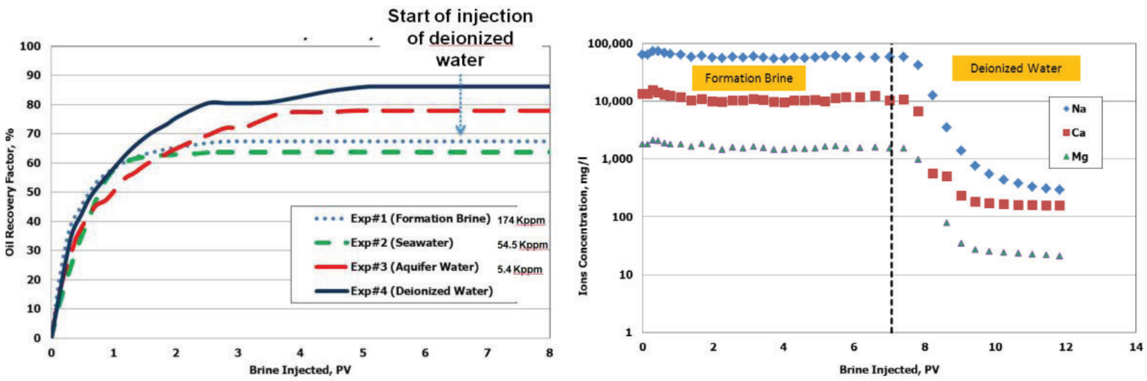

Figure 4: a) Comparison between HS, LSWI in secondary and tertiary modes; b) evolution of ionic concentration during tertiary LWSI ; from Nasralla, 2011

However, single phase tracer tests are almost never reported in experimental studies devoted to tertiary LSWI. This is surprising, particularly when authors specify that samples are taken parallel to bedding.

Core lengths might also have a significant impact, as dispersive flows depend on the ratio between the dispersion length and the length of the system. In that respect, short cores (5, 7,5 cm) are most at risk. Assuming a dispersion length of 6-7mm at $Sorw_{HS}$, consistently with observations made in [50] on mildly wet sandstone, this ratio would approach or exceed 0,1 for 5 and 7,5 cm long cores. It might be even worse when HSWI is carried out at unfavorable viscosity ratios which trigger water fingers. This is a significant concern for a large number [10, 16, 19, 31, 32, 35, 41, 49, 52, 53, 55, 56] of tertiary LSWI studies. On the other hand, too short core lengths cannot be systematically called to explain the absence of any tertiary response during LSWI. Shehata [40] performed tertiary LSWI, observed significant benefits in secondary mode, but no incremental oil during tertiary LSWI on 50 cm long cores.

Others parameters may also have an effect on the evolution of salinity during laboratory tertiary LSWI. Difference in viscosity between secondary HSW and tertiary LSW may reach unfavorable values of viscosity ratios up to 1,5-1,6. This range of viscosity ratio may trigger fingering in the water phase during tertiary LSWI and the salinity profile might be smeared. Flow velocity might also be important, as dispersion coefficient may increase as interstitial velocity increases, both at Sw=1 [4] and at Sorw [36].

Effect of Wettability Modifications Between HSWI and LSWI

Published tertiary LSWI results are very rarely accompanied by secondary HSWI or wettability tests. None is reporting a full Amott Harvey or USBM test. In the absence of wettability tests, it is often assumed that LSWI shifts systematically wettability towards more water wet, based on observations of increased recovery during LSW spontaneous imbibition compared to HSW. Evolution of Krs between LSW and HSW is then guessed according to this assumption. In fact, this spontaneous recovery might be sometimes misinterpreted as demonstrated below using Zhou's results [57]. Zhou changed the wettability of Berea sandstone by changing the length of aging time at 88°C with Prudhoe Bay crude oil. Three data sets are reported, showing the same behavior as shown in figures *5a, b*. Water imbibition rate decreases, but final oil recovery by imbibition increases as the ageing time increases from 0 to 24 hours. In the same way, waterflood oil recovery increases as the ageing time increases from 0 to 24 hours. It is obvious that outcrop samples cannot become more water wet by increasing ageing time with reservoir oil... It clearly means that increase in recovery by spontaneous water imbibition does not always mean more water-wet. Zhou's experimental results were successfully simulated using distribution of contact angles [0-89°] in [14]. Consequently the very similar results of LSWI by Tang [46, 48, 49], within the water-wet domain, might have been misinterpreted, and might not represent a systematic shift towards water wet. Moreover, other sources of information, such as adhesion maps [7] or flotation tests clearly show increased oil adhesion, when salinity decreases. This topic is addressed in a companion paper [12].

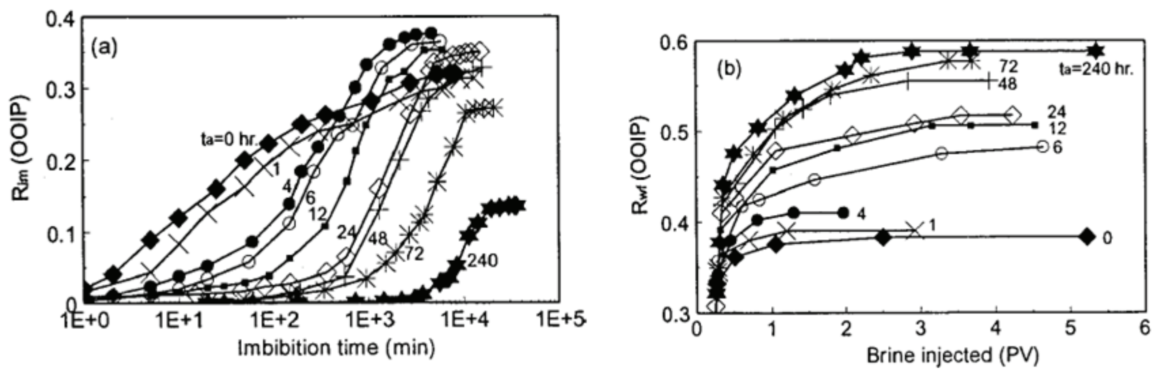

Figure 5: evolution of spontaneous (left) and forced (right) oil recoveries as a function of ageing time (from Zhou, 2000)

Then, in the absence of full wettability test or of any comparison between secondary LSWI and HSWI, there is a doubt about the direction of change of wettability when the rock is contacted by LSWI. Figure 6 shows simulations results of incremental recovery during tertiary LSWI when the viscosity ratio equals 2. Two cases are compared: LSWI might change wettability towards either more water wet ($Sorw_{HS}$=0,3; $Sorw_{LS}$=0,2; $Krw(Sorw_{HS})$ = $Krw(Sorw_{LS})$ =0,3), as often assumed in the absence of both secondary LSWI Krs and wettability tests, or less water-wet, ($Sorw_{HS}$=0,3; $Sorw_{LS}$=0,2; $Krw(Sorw_{HS})$=0.3 $Krw(Sorw_{LS})$ =0,6) as suggested by the general trend of adhesion maps. In such a case $Krw(Sorw)_{LS}$ can be much larger than $Krw(Sorw)_{HS.}$ Capillary pressure is not taken into account.

The reduction in Sorw during secondary floods is 10 saturation units in both cases. Even with a very favorable viscosity ratio, tertiary incremental is delayed and poor if LSWI shifts wettability towards less water wet. Note that situation is totally consistent with experimental results on secondary waterfloods [59]: when the initial wettability is within the water-wet domain, a shift towards less water wet increases secondary recovery, but may lead to poor recovery in tertiary LSWI. Moreover, shifting towards less water wet may increase dispersion within the water phase, as observed in [36, 50].

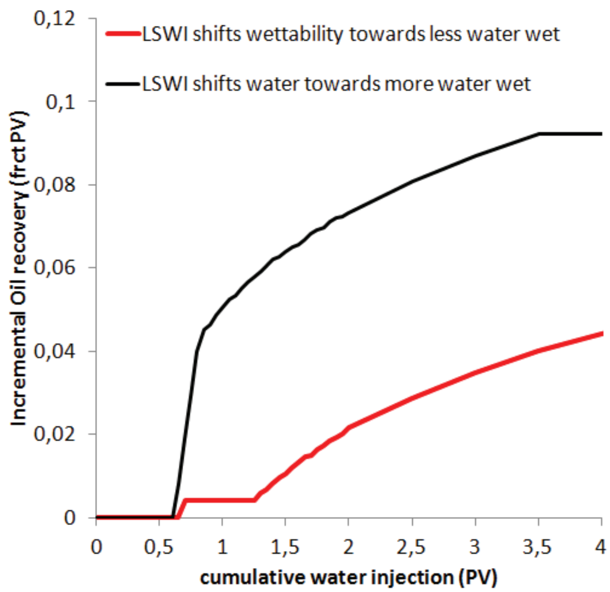

Figure 6: simulations of tertiary LSWI as a function of direction of wettability change

CONCLUSIONS AND WAY FORWARD

Conditions of existence of a double saturation shock, effects of dispersion in water phase at $Sorw_{HS}$, and uncertainty in the direction of wettability change may explain a lot of experimental studies, where tertiary LSWI performs poorly. Counter examples can also be produced for any single proposed mechanism, but their combination deserves further attention. The absence of relevant experimental data in published studies is the main difficulty when trying to decipher the causes of poor tertiary LSWI results. An ideal set of experiments should incorporate:

- A brine/brine tracer test at Sw=1 on each rock sample used for corefloods
- Secondary HS and LS water floods, including evolution of recovery, differential pressure, in situ saturations, as well as salinities after breakthrough
- Full Amott Harvey wettability tests for both HS and LS brines. The negative part of the forced imbibition capillary pressure curves can be derived from the forced displacements if carried out by centrifugation.
- Tertiary LS water flood including evolution of recovery, differential pressure, as well as salinities and ionic compositions
- Fluid characteristics at test temperature and pressure, including the evolution of water-oil interfacial tension (IFT) as a function of salinity. This last item has received very little attention. However, several studies [9, 47, 54, 25, 2] reported decrease in IFT as salinity decreases. Based on conventional understanding of oil mobilization, water-oil IFT must be reduced by several orders of magnitude to mobilize oil and the reductions

of IFT with salinity are often deemed too small to have any significant effect. On the other hand, when successful, tertiary LSWI illustrates that oil can be mobilized at very low capillary numbers. In that respect, small variations of IFT should deserve attention.

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