TERTIARY POLYMER FLOODING IN EXTRA-HEAVY OIL: AN INVESTIGATION USING 1D AND 2D EXPERIMENTS, CORE SCALE SIMULATION AND PORE-SCALE NETWORK MODELS

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ABSTRACT

The injection of water and/or polymer in extra-heavy oil reservoirs is currently gaining great attention in both the academic and industrial worlds. Water and enhanced water injection schemes represent an interesting alternative in all those cases where thermal methods are either impractical or uneconomic; furthermore several laboratory investigations have already shown that such recovery protocols can provide much higher than expected oil recoveries. On the other hand, because such mechanisms are still poorly understood in virtue of the high fluid complexity, the non Newtonian flow behaviour and the characteristically unstable displacements, it is clear that process optimisation for possible field application remains problematic. Ideally, a combination of efforts would need to be put in place which considers the ensemble of 2-phase flow experiments, simulation at both pore and core scales and rheological measurements.

In this work we present such effort: both 2D (30cmx30cm slab) and 1D (30cm long core) experiments of tertiary polymer injection in extra heavy oil (7000cp at 23°C) were carried out on Bentheimer sandstone to quantify the underlying flow mechanisms, the oil recoveries and evaluate the impact of unstable flow on model geometry. Water (enhanced water) saturation maps were accurately measured by means of X-ray scans enabling the visualisation of flow instability development (viscous fingering) with high resolution. High microscopic recovery to secondary waterflooding (up to 30% after 5 PV injected) was achieved in line with previous published investigations; most importantly a rather impressive further gain after polymer flooding (reaching final recoveries of more than 60%) was obtained. In parallel, both bulk and in-situ rheological measurements were performed at different polymer concentrations and flow rates and a precise rheological model for simulation was constructed and entered in a conventional reservoir simulator. Generic simulations were able to match the regional crossflow observed in 2D experiments. A simulation exercise, conducted with the aid of pore scale modelling (PSM) technology to help gathering two-phase flow data, proved very educational in that it allowed transferring results from one rock geometry to other rock structures.

INTRODUCTION

In order to improve recovery of heavy oil that is still considered as mobile, enhanced or chemical water injection can be proposed. This water can be enhanced by polymer addition, which will increase the solution viscosity, thus reducing the mobility ratio between the heavy oil and the water, resulting in a more homogeneous front and reduced fingering. Alkali and/or surfactant can also be added to the water, to lower interfacial tension between the oil and the water. In general, such techniques go under the name of "chemical injection" and are part of currently investigated EOR practices.

Polymer injection is currently a subject of intense research as it was found that not only low to medium viscosity oils could benefit but successful application is also possible with oil viscosities of several thousand cps. A number of studies (Wassmuth et al. 2007: Asghari and Nakutnyy, 2008; Wang and Dong, 2009) have appeared recently which specifically target the application of polymer flooding technology in the context of extra heavy oils. Such investigations clearly show the potential of polymer flooding technology for extra-heavy crudes as viscous as 10,000cp. On the other hand, rather interestingly, it has been reported that simple water injection can also perform quite well at very unfavourable viscosity ratios and even if breakthrough is nearly instantaneous. In such cases, important oil production is achieved after water breakthrough. Mai and Kantzas (2009) propose that this is due to capillary forces and imbibition in a water-wet context, and that these mechanisms become more important as the rates become lower (if enough time is left for capillary forces to act). In fact pore scale phenomena due to positive capillarity have been verified to be very important by Mehrabi and co-workers (2008) by using glass micromodels. Finally it has to be observed that both polymer flooding and waterflooding in extra heavy oil are characterised by very unfavourable viscosity ratios and that this raises issues on the possibility of representing such displacements with numerical simulation based on continuum equations (Riaz et al, 2007).

It is in this context that the main objectives of this work are set: 1) to verify the potential of oil recovery for a particular rock-heavy crude system subjected to (enhanced) water injection and 2) to provide improved understanding of the dynamics of unstable displacements and their functionality with rock geometry by direct visualisation using X-ray measurements.

THE EXPERIMENTS

Preparation

Two experiments of tertiary polymer flooding in extra heavy oil were performed in different laboratories: the facilities at CIPR for the 2D experiment, using a 2D slab of dimensions 30cmx30cmx2cm and the facilities at TOTAL for the more conventional cylindrical core geometry 30 cm in length. In both cases the rock material was homogeneous Bentheimer sandstone. For the 2D slab, rails distributors were glued on the inlet and outlet faces with each rail connected by a central port which distributes the liquid through a groove of dimensions 300mmx1.5mmx1.5mm. Plate and distributors are covered with two layers of epoxy. Each rock sample was dried at 80 °C and vacuum saturated with 7g/l NaCl brine. Oil drainage was performed with the same reservoir heavy oil, diluted with 18% of iododecane, followed by aging for 3 weeks at 50°C.

The final Swi was reached at oil breakthrough, measured to be 5% in the 1D core and 7% in the 2D slab.

The industrial polymer used is the SNF Flopaam 3630S. The polymer solution was created by successive steps: first a concentrated mother-solution (5000ppm at the target salinity) was prepared and stored 2 hours in the refrigerator (nitrogen blanketed), then it was diluted at the target concentration with salinity brine, homogenized and filtered (at 6cc/hr, nitrogen blanketed). The two polymer solutions were created independently (in different labs) and at different times since the 2D experiment was performed a few months before the 1D one; therefore it was essential to ensure that the viscosity of the two solutions was equivalent, regardless of the concentration. The first experiment (2D slab) was performed with a polymer concentration prepared to give a rheometer viscosity of 58.0 cP at 10s-1 shear rate and 23.6 cP at 70s-1 in a 6g/L NaCl +1g/l NaHCO3 solution at 23°C. These viscosity values became the target for the solution to be used in the following 1D experiment; in this case it was found that the corresponding concentration, into a 6g/L NaCl +1g/l NaHCO3 solution at 23°C was 1650ppm, which gave a rather representative 61.6 cP at 10s-1 and 24.9 cP at 70s-1.

The two experiments were carried out with injection from the bottom at the conditions of the laboratory: T=23°C for the 2D experiment and T=21°C for the 1D experiment. This slight difference in temperature had consequences on the viscosity of the reservoir heavy oil as this was found to vary by 1000cp/°C; in practice, the 1D experiment was performed with a more viscous oil.

Production in the 2D experiment was assessed by X-ray captures on the production test tubes. With adequate calibration, these captures allowed us to compute the proportion of heavy oil and water in every production test tube. Watercut was hence calculated for each test tube and recovery calculated as a cumulative value, meaning that it depended on the results of the previous test tubes. For the 1D experiment, production was also collected in small test tubes (around every 2 days) but was instead measured by UV spectrometry on the tubes, using a method recently developed in house.

Injection rates (reported in Table 1) were chosen appropriately for the two rock geometries to be at representative reservoir values and to have an identical propagation pace of the injected front, meaning that the injection rate divided by the surface of injection was the same. The quantities injected were designed equally in terms of PV (Pore Volume). Due to a pump dysfunction, the first injection of the 1D experiment (WATER 1, in Table 1), was performed at 0.75 cc/hr instead of 0.95 cc/hr; this was noticed quickly and modified in the following waterflood (WATER 2).

Recovery results

The objectives for performing these experiments were to gain insight and confirm reported experimental results in the literature regarding simple water flooding of heavy oil, the evaluation of the performance of tertiary polymer flooding for a particular reservoir heavy oil, and the investigation of the impact of the geometry of the rock flooded, whether it is a core (1D, one dimension) or a slab (2D). In this case, such experiments can show to what extent 1D core flooding is representative of the field mechanisms, compared to a 2D experiment.

We start the analysis of the experiments by noting that a very acid pH had been measured in the experiment that was carried out first (on the 2D slab) which was attributed to the combined effect of the added iodo-decane, the epoxy coating of the slab and the Bentheimer reaction with the injected water. Therefore, after 1.37 PVs of water injection, the salinity has been changed from 7g/l NaCl to 6g/l NaCl + 1g/l NaHCO3, to create a pH buffer. The later 1D experiment was therefore also carried out in these conditions. Figure 1(a) shows the cumulative productions and watercuts for the two experiments. Figure 2(a) shows the measured differential pressures. Note that, as the 1D polymer flood was not achieved after an equivalent PV of water injected as the 2D experiment, there is a notable shift between the 2D and the 1D recovery profiles for the polymer phase. In order to better analyze the polymer flood only, the same plots are given in Figure 1(b) and Figure 2(b) with the difference that the abscissa takes only into account the PVs of polymer injected.

The conclusions drawn from these experiments were the following:

- Early waterflood breakthrough (0.03PV in the 2D and <0.1PV in the 1D) due to very disadvantageous viscosity ratio.
- Quick water-cut rise (90% after 0.5PV)
- A very long production period at a high and stable water-cut (Figure 1(a)).
- A recovery of 26.4% and 30.7% at the end of water flooding (5.1PV) for the 2D and 1D respectively; the effect of dimensionality appears important (considering also that the viscosity ratio in the 1D core is less favorable).
- The polymer flood showed an impressive additional gain of recovery of 36.7% and 29.8% after around 3 PVs injected in the 2D and 1D geometries respectively, despite a still disadvantageous mobility ratio. Final oil recovery thus rose to 63.1% and 60.5% for the 2D and 1D geometries respectively (Table 2).
- The effect of geometry is less important if one considers the polymer flooding phase only (Figure 1(b)).

Analysis of displacement: waterflooding phase

The conclusions outlined above about the dimensionality effect find a confirmation when looking at X-ray measurements. Figure 3 shows key X-ray scans of the water injection phase ((a) and (b)) and polymer injection phases ((c) and (d)) for the 2D geometry (these are gray scale images depicting blacker points for the oil and whiter for the water, the reference being the initial situation at Swi). The 2D waterflood is characterised by an initial phase of water fingering development with the central finger propagating at a slower pace (Figure 3(a)). The observed patterns indicate a non-water-wet state, as capillarity tends to override fingering in a water-wet state even at adverse mobility ratio (Skauge et al,

2011). For this case of aged Bentheimer, after breakthrough, the central finger becomes thicker and thicker with most oil recovery coming from the central region by the end of the waterflood (Figure 3(b)). Considering the macroscopic homogeneous nature of the rock material, this non uniform distribution is initiated from small scale heterogeneity. All porous media are heterogeneous at a μ m or sub- μ m scale. Similar flow pattern is

observed both in earlier miscible and immiscible displacements, Skauge et al (2009 and 2011). It is possible to draw an analogy of this displacement with the 1D experiment by plotting the saturation profile in the core (thanks to the numerous X-ray core captures) versus the length of the core, at various PVs injected; a quantitative 1D saturation profile can then be compared against the qualitative 2D gray-scale images. In Figure 4(a), it can be seen that oil saturation decreases in a uniform manner along the 1D core; there is no visible front as would be the case for a piston like displacement. Consequently, the interpretation of these saturation profiles is that the water injected quickly breaks through at the core outlet, channelling through one or more preferential paths. As the injection goes on, this (these) preferential pathway(s) widens which results in an increase of water saturation homogeneously all along the core (note that the signal becomes more and more noisy as the experiment goes on, which comes from a technical deviation of the X-ray capture). Therefore Figure 4(a) confirms for the 1D core the preferential pathway displacement mechanism that has been seen in the 2D experiment (Figure 3(b)).

Analysis of displacement: polymer flooding phase

The 2D X-ray gray-scale images (Figure 3(c) and (d)) show that the polymer injection both maintains the flow unstable (fingering development visible at the sides) and creates a piston-like displacement, with an oil front. The zones previously poorly swept by the water injection are now recovered by polymer. X-ray oil saturation profiles for the 1D core also behave differently than for the waterflooding phase (Figure 4(b)); at 0.26 PVs injected, the X-ray measurement shows clearly the creation of an oil bank, which is being displaced in the injection direction. Moreover, if we compare similar pore volumes injected (at 0.186PV and 0.26PV in the 2D and 1D experiments respectively) the status of advancement of the oil bank of each experiment are comparable (around halfway of the length). In conclusion, there are strong similarities both on waterflood and polymer flood in 1D and 2D, though detailed fingering mechanisms may be influences of the sample geometry. For the polymer flood, the piston like displacement sweeps efficiently the whole area available, but the displacement is actually complex as Figure 5 indicates. Figure 5(a) and (b) correspond exactly to the same situation after 0.134PV of polymer injected. But for (a), the image shows the regions where saturation has changed respectively to the very beginning of the waterflood (condition at Swi, with white regions indicating where water saturation has increased) whilst (b) shows the regions where saturations have changed respectively to the end of the waterflood. Therefore (b) shows in white the regions where water saturation has increased and in black the regions where it has decreased due to polymer injection only. It can be concluded that as polymer displaces the lateral regions, the oil saturation increases consistently around the central region (Figure 5(b) and especially 5(d)) exactly where a thick finger resulted from the previous waterflood.

SIMULATION

An important target for the work presented in this paper was to assess the potential of simulation to reproduce at the same time both the 2D and the 1D experiments. Two important questions stand out: 1) to what extent would a conventional reservoir simulator

be able to reproduce the complex features of the unstable displacement as observed during the waterflooding phase? 2) In any case, what are our chances of predicting experiments in different geometries? Work is currently being done to answer the first question by using different methods; nevertheless, it can already be concluded that neither the type of digitation nor the formation of the thick finger can be reproduced appropriately, which would confirm the analysis and the discussions of Riaz et al (2007), on the limits of numerical simulation based on continuum equations. However, as illustrated in Figure 6, numerical simulation can handle the polymer induced crossflow between high oil saturation zones and water channels as observed experimentally in Figure 5. The blue coloured region resembles an established water channel (Sw=0.9). The simulations aimed at testing the displacement of oil from the region with high oil saturation (So=0.9) into the water channel, an action that would be favourable with respect to viscous forces, but will act against capillarity. The generic simulation study shows similar crossflow as in the experiment. Work not reported in this paper (for the sake of brevity) clearly shows that such crossflow is, as expected, more extensive for an oil-wet case and least for the high capillary pressure water-wet case.

Riaz et al (2007) also advocate that a more comprehensive approach should be adopted for immiscible displacement at adverse mobility, which could also include pore scale arguments. This was attempted in this work and is described below.

Pore Scale Modelling (PSM)

Two small mini plugs of the Bentheimer sandstone utilized for the 2D experiments have been X-ray imaged. Figure 6(a) shows a 2D slice of a 3D tomographic dataset of Bentheimer sandstone (micro-CT X-ray imaging performed at the facilities and with the procedures described in Sakellariou et al (2007)). The size of the 3D digitized sample is 1930x1910x1875 voxels with a resolution of 2.74µm. The micro-tomography images were utilized to build a representative pore network by using the E-Core technology (Øren et al, 2006). In particular, in the case of the work presented here, the micro-CT images were treated as "thin sections" and the process based method for rock model construction (Figure 7(b)) was utilized. A network model was then extracted (Figure 7(c) and 2-phase flow simulations (Figure 7(d)) were performed at the pore scale at three different wettabilities (strongly water-wet, mixed-wet and strongly oil-wet). These sets of relative permeabilities and capillary pressures were entered directly in a reservoir simulator for the successive simulation of the 2D tertiary polymer flooding experiment. The (Kr, Pc) set corresponding to strongly water-wet conditions was then finally selected as it reproduced better the production data of the 2D experiment, in particular for the waterflooding part. This conclusion is quite important: the best numerical representation of the experiment is given by considering in the simulation water-wet conditions even though the observed patterns indicate a non water-wet behaviour. The following explications can be proposed:

1. The PSM quasi-static approach utilized in this work cannot be used in industrial workflows involving highly unstable flows.

- 2. Trying to simulate complex unstable flows with a Darcy based approach (reservoir simulator built on continuum equations) has limitations that lead to these consequences (wettability not being respected).
- 3. A combination of what above.

Core Scale Simulation

Both bulk and in-situ (on Bentheimer rock, using the approach described in Wang and Dong, 2009) rheological measurements were carried out on the polymer solution utilized in the experiments including polymer solution viscosity vs shear rate and Darcy velocity, adsorption and RRF. These were then utilized to build the polymer model input of the reservoir simulator (Figure 8(a) shows the viscosity behaviour of the polymer solution as entered in the simulator). The results of the procedure described above is shown in Figure 9(a), 10(a) and 11(a) which show the history match for production, differential pressure and watercut respectively for the 2D slab experiment (although we do not show it, we report that these simulations do not reproduce the digitations observed in the 2D X-ray images). The relative permeabilities (and Pc) utilized for the match are those shown in Figure 8(b); as it can be seen, the waterflooding part can be reproduced almost directly with the relative permeabilities issued by the pore network model in water-wet and guasistatic conditions whilst adjustments were needed to reproduce the polymer flooding part. Note that the Sor directly issued from pore scale simulation of waterflooding was utilized for the whole tertiary polymer flood. This is noted in relation to the comments of Kamaraj et al (2011) who discuss whether polymer does or does not reduce Sor (compared to a waterflood). The relative permeability to water is instead decreased compared to the one issued from quasi-static water-wet simulation (again, we specify this as Seright (2010) has discussed whether polymer solutions could increase Krw).

Figures 9(b), 10(b) and 11(b) show the simulation/prediction of the 1D experiment (and relative experimental profiles) obtained by utilizing the (Kr, Pc) set of the 2D history match, in an attempt to answer the second question reported above (i.e. prediction of an experiment in a different geometry). We can conclude that whilst the final recovery of the full 1D experiment is decently reproduced, the recovery during the waterflooding part alone is underestimated whilst the recovery of the polymer flooding part is instead overestimated. These results seem to be due to the fact that the digitations are different in the two geometries, which also caused different spatial distributions of saturation at the onset of the polymer flood. For the same reason, the differential pressure of the 1D core experiment is greatly underestimated by simulation. This outcome would point to the fact that it is necessary to reproduce the digitations of the 2D experiment to have a reliable extrapolation; unfortunately, although work is still in progress, it has so far not been possible to reproduce those digitations (even by imposing non water-wet conditions).

CONCLUSIONS

We have presented the results of two experiments for tertiary polymer flooding in extra heavy oil carried out at reservoir rates in different rock geometries and have evaluated the possibilities to reproduce the experiments with common reservoir simulators. It was seen that both waterflooding experiments have shown high recoveries (considering the very unfavourable viscosity ratio), with almost 31% of oil recovered in the 1D geometry. An extended period of production at near 100% watercut was observed. The polymer flooding was very successful with recoveries over 60% in both cases.

X-ray measures allowed the visualisation of the fingering behaviour in the 2D slab both during the water and the polymer flood and confirmed that both experiments were characterized by early breakthrough, many fingers formed, with finger thickening in the later stage of the waterflood and more piston like sweep in the polymer flood.

Although the two experiments did show very similar mechanisms, recoveries after waterflood were somewhat lower for the 2D experiment compared to 1D. However, this fact should not be overemphasized as experimental setup and conditions vary slightly. The

polymer flood was seen to be less sensitive to experimental differences and geometry effect.

Pore scale modelling and laboratory rheological experiments to study the rheological behaviour in bulk and in Bentheimer rock were then carried out to aid in the effort of simulating the experiments with conventional reservoir simulators. In this paper, it was noted that the observed type of fingering was not reproduced by simulation and remains an open issue. Nevertheless it was checked whether a representation of the results in one geometry by conventional history match could allow (with identical Kr, Pc) prediction in the other geometry; this prediction exercise showed that the overall final recovery of the experiment was fairly well reproduced but that the recoveries of the two floodings, taken separately, were underestimated (waterflood) or overestimated (polymer flood) by around 15%.

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			2D	1D
Geometry	Length	mm	299	298
	Porosity		24%	22%
Injection Flow Rate	Injection Area	mm ²	6118.2	1963.5
	Injection Rate	mL/h	3.00	0.95
	Front Pace (=Q/S)	mm/h	0.490	0.483
Permeability	Kw sw=1	Darcy	2.8	2.45
	Ko (Swi Before ageing)	Darcy	2.1	1.8
	Ko (Swi After ageing)	Darcy	1.2	1.6
Fluids	Swi		7%	5%
	Concentration Flopaam	ppm	~1650	1650
	Viscosity polymer at 10s-1	cP	58.0	61.6
	Viscosity polymer at 70s-1	cP	23.5	24.9
	Viscosity Oil @21°C	cP	9000	9000
	Viscosity Oil @23°C	cP	7000	7000

Table 1. Characteristics of the experiments.

Table 2. Final recovery data.

	1D Core			2D Slab		
INJECTION	Additional PV	Total PV	Total RECOVERY	Additional PV	Total PV	Total RECOVERY
WF1:7g/L NaCl	1.54	1.54	23.6%	1.37	1.37	17.3%
WF2:6g/L NaCl+1g/L NaHCO3	3.90	5.44	30.7%	3.73	5.10	26.4%
PF : 6g/L NaCl + 1g/L NaHCO3 + 1650ppm S3630	3.34	8.78	60.5%	3.18	8.28	63.1%



Figure 1. Oil recovery and water cut of the 2D and 1D tertiary polymer flooding experiments vs PV injected (a); oil recovery and water cut of the 2D and 1D experiments for the polymer part only, i.e. Vs PV of polymer solution injected (b).



Figure 2. Measured differential pressure of the 2D and 1D tertiary polymer flooding experiments vs PV injected (a); measured differential pressure for the polymer part only, i.e. Vs PV of polymer solution injected (b).



Figure 3. X-ray images of the 2D rock at 4 key stages of water (a) and (b) and polymer (c) and (d) injection. The arrow at the left indicates the sense of injection.



Figure 4. Evolution of oil saturation vs 1D core length at different PVs injected (reported to the right in each Figure) of the waterflood (a) and of the polymer flood (b).



Figure 5. Gray scale images at given PVs of injected polymer depicting blacker points for the oil and whiter for the water, the reference being the initial situation at Swi for (a) and (c) and the water saturation at the end of the waterflood for (b) and (d). (a) and (c) show -in white- regions of increasing water saturation; (c) and (d) show -in black- regions of increasing oil saturation.





Figure 6. Simulation of exchange between a high Sw (waterflooded) and low Sw region (oil region). Left initial saturation, right after 0,1 PV polymer injected.

Figure 7. A 2D slice of a micro-tomographic dataset of the Bentheimer rock (a); the reconstructed pore scale model (b); the extracted network (c) and twophase simulation in the extracted network.



Figure 8. Non-newtonian behaviour for the polymer solution as entered in the reservoir simulator (a); Kr/Pc set as issued directly by the pore scale model (PSM) and as utilized in the simulations showed in Figure 9, 10, 11.



Figure 9. History match of the recovery of the 2D slab experiment (a) and extrapolation (with same (Kr, Pc)) to the 1D core experiment.



Figure 10. History match of the differential pressure of the 2D slab experiment (a) and xtrapolation (with same (Kr, Pc)) to the 1D core experiment.



Figure 11. History match of the watercut of the 2D slab experiment (a) and extrapolation (with same (Kr, Pc)) to the 1D core experiment.