ISSN 2229-5518

Effect of Adding Surfactant Slug to Polymer Flooding in Cross flow Multi-layered Reservoir

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Abstract—Natural reservoir energy recovers less than one third of the original oil in place (OOIP) leaving substantial part of the oil in the reservoir. Due to high energy demand and difficulties in exploring and developing new oil fields; several enhanced oil recovery methods are being developed in order to optimise production in marginal oil fields. In an effort to understand the effect of adding surfactant slug to polymer flooding in a cross flow multi-layered reservoir, a simulation study was carried out for polymer flood and surfactant/polymer flood at different water cuts of 30%, 50% and 65% in order to compare and predict the incremental oil recovered by each of the two enhanced oil recovery methods. The polymer slug consists of water, calcium, alcohol, tracers and was injected at the rate of 112ft3/day for 1500 days at the different water cuts. Both the polymer and the surfactant floods were carried out for a period of 1500 days using one injection well and one production well. The simulation results show that polymer flooding on the average can recover about 27% of the original oil in place while surfactant-polymer flooding can recover up to 45% of the original oil in place (OOIP). This shows that adding surfactant to polymer can increase oil recovery by about 18% on the average for both single and multi-layer reservoirs provided there is communication at the contact planes.

Index Terms— Enhanced oil Recovery, slug, surfactant-polymer flooding, multilayered reservoir, numerical simulation

1 Introduction

In oil and gas production, the producing reservoir fluid must be driven to the producing well, and then lifted several hundred meters against force of gravity to the surface. Several factors affect the motion of the fluid, these include: frictional force, elevation, force of gravity etc. Therefore energy must be expended to produce hydrocarbon from the reservoir to the surface.

During the producing lifetime of a reservoir, hydrocarbon production may take place in one or more of the reservoir fluid recovery methods. These methods are categorised into: primary recovery, secondary recovery, and tertiary recovery methods.

Primary (natural) recovery refers to oil recovery method under the reservoir natural (in-situ) drive energy, hydrocarbons are driven by the energy locked up in the reservoir and its surroundings without any form of artificial support.

Secondary oil recovery method, otherwise known as supplementary recovery involves an additional processes that are carried out for pressure maintenance to supplement the primary energy present in the reservoir in order to displace more oil towards production well. The secondary recovery processes carried out are basically water flooding and immiscible gas injection.

Tertiary oil recovery method also known as enhanced oil recovery method recovers more oil reserved than the combined total oil production by primary and secondary methods (conventional method) which is generally less than 40% of the original oil in place (Donaldson et al., 1985).

Multi-layered reservoirs are reservoirs composed of two or more layers that may have different formation and fluid characteristics. These reservoirs are usually divided into two: (a) layered reservoirs without cross-flow (commingled systems), where the layers communicate only through the wellbore; and (b) layered reservoirs with cross-flow, where layers communicate at the contact planes throughout the reservoir (Eskandari et al., 2012). The behaviour of a multilayer formation may not be distinguished from the behaviour of a single layer formation even though a multilayer reservoir may have a distinct behaviour without wellbore storage effects (Eskandari et al., 2012). The cross flow would be directed from the layer of low permeability to the layer of higher permeability.

This research work focused on chemical flooding (or improved water floods) which involves any isothermal process that recovers oil by either reducing the interfacial tension (IFT) between oil and water (low IFT processes) or reducing the mobility of the displacing fluid (mobility control processes) (Bourrel, and Schechter, 1988). This includes processes in which both effects are important, and also other effects such as wettability alteration, extraction, or oil swelling may be present. Mobility control processes has been shown to lower the viscosity and/or reduce the permeability of the displacing fluid by the injection of a mobility control agent (polymer) to improve the volumetric and displacement sweep efficiencies

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(Alban and Gabitto, 1997).

Low IFT processes involve the injection of a surface active agent (surfactant), or by the in-situ formation of the surfactant, which lowers the IFT between oil and water. Lowering the IFT decreases the capillary forces and mobilizes a part of the residual oil left behind in the reservoir (Bourrel, and Schechter, 1988). The mobilised oil is then flooded with a drive water towards producing wells.

The overall objectives of this research work is to simulate a multi-layered oil reservoir (with cross flow) using polymer flooding and surfactant-polymer flooding types of enhanced oil recovery (EOR) with view to understand the effect of adding surfactant slug to polymer flooding.

2 Methodology

The reservoir was simulated using UTChem simulator; with the aim of optimising the reservoir productivity by first, injecting polymer slug and then a surfactant slug. UTChem is a 3-D multiphase and multicomponent chemical flooding simulator software, used for chemical flooding and contaminated aquifers remediation. It uses an IMPEC (implicit pressure explicit concentration) solution scheme. First, it solves pressure equations implicitly for aqueous phase pressure and then conservation equations for concentrations are solved explicitly. Phase saturations and concentrations are then solved in a flash routine. For reservoir temperature an energy balance equation is solved explicitly.

The energy balance equation comprises heat flow between the reservoir and the over-burden and under-burden rocks. The major physical phenomena modelled in the simulator are: adsorption for oil, surfactant and polymer, capillary pressure, cation exchange, diffusion, equilibrium and non-equilibrium organic dissolution in aqueous phase, gel properties (viscosity, permeability reduction, and adsorption), interfacial tension, organic biodegradation capability, polymer properties (shear thinning, viscosity, inaccessible pore volume and Permeability reduction and relative permeability (Pope and Nelson 1978; John et al., 2004).

The simulator takes into consideration the aqueous phase (water and electrolytes), chemical species (polymer, surfactant, alkali, tracers e.t.c), oleic phase (crude oil), and gaseous phase. These phases could form up to three phases in equilibrium, i.e. aqueous, micro-emulsion, and oleic phases depending on factors such as effective salinity and surfactant concentration (UTChem, 2000).

The following assumptions are integrated into UTChem: application of Darcy's and Fick's dispersion laws; fluids and rocks are slightly compressible; polymers, tracers and electrolytes do not occupy pore space; pressure does not affect fluid phase behaviour; solid phases are immobile and surfactant, polymer, co-surfactant, alcohol, are treated as a single phase (UTChem, 2000).

2.1 Simulation Process

The simulation was carried out on a two layer reservoir (i.e. reservoir with two different permeability in both X and Y directions). A grid number of 11X11X2 was chosen for the simulation. The reservoir simulated has a length of 250 feet, thickness 10 feet, and width 250 feet. Due to the computational limitations associated with the simulator, the time step limitations as well as the memory constraint associated with the simulator led to the averaging out of reservoir properties.

Alcohol propoxy sulphate (C16-17-7PO-SO4) combined with co-surfactant Internal Olefin Sulphonate (C15-18-IOS) in the ratio 3:1 surfactant was used. Flaaten et al. (2008) showed that these surfactant-surfactant combinations in this ratio give thermal stability and good oil recovery for light oils. The function of co-solvent is to promote polymer-surfactant compatibility so as to prevent the formation of liquid crystals, gels and macro emulsions (Zhao et al., 2008). HPAM polymer was used due to its thermal stability at high temperatures (Seright et al., 2009) and because it maintains its viscosity even at high salinities (Flaaten et al., 2008).

Both the polymer and the surfactant floods were carried out for a period of 1500 days using one injection well and one production well

Table 1: Input data for simulation

Property	Value
Reservoir grid block size	250 X 250 X 10 ft.
Number of grid blocks	11 X 11 X 2
Average permeability(X)	X1 500mD X2 100mD
Average permeability(Y)	Y1 500mD Y2 100mD
Average permeability(Z)	50mD
Average porosity	0.30 constant
Average temperature	190^0f
Average pressure	3000 psi
Water viscosity	0.86 cp
Oil viscosity	4.0 cp
Rock compressibility	0.0000121 psi/ft
Polymer viscosity parameter	AP1 81; AP2 2700; AP3 2500
IFT correlation parameter	Healy and reed correlation
Residual saturation at low capillary number	0.37; 0.35; 0.37
Residual saturation at high capillary number	0; 0; 0
Injection rates	112 ft^3/day

ISSN 2229-5518

Chemical slug composition	1%wt surfactant; 33000 ppm Nacl; 2000ppm polymer

The simulation was run at different water cuts for the two processes (i.e. surfactant and polymer floods). Table 1 provides a summary of the parameters used for the simulation run.

3 Results and Discussion

The simulation runs were carried out for polymer flood and surfactant/polymer flood at different water cuts of 30%, 50% and 65%. Polymer slug, water, calcium, alcohol, tracers and other chemicals were injected at the rate of 112ft^3/day for 1500 days at different water cuts.

Figure 1 is the result of polymer injection at 30 percent water cut. It shows the plot of cumulative oil recovered in barrels against injection days. From the figure, oil recovery commenced from the 10th day of injection to 501st day at the rate of 20 barrels per day. But from 502nd day to 1500th day the recovery dropped down to about 11.8 barrels per day, this drop is believed to be as a result of polymer breakthrough and reduction of oil bank after about 10,400 barrels has been recovered.

Figure 2 shows the plot between cumulative oil recovered versus pore volume. From the plot, 0.85 pore volume injected recovered about 11,900 barrels of oil with 30% water in the produced fluid. Figures 3 and 4 show the graphs of percentage of original oil in place (OOIP) recovered against injection days and pore volume respectively. At the end of the designed injection period (1500 days) about 50% of OOIP is recovered and this is equivalent to 0.85 pore volume injected at 30% water cut.

When the percentage of water in the produced fluid is increased to 50%, the percentage oil recovery dropped down significantly. The plot of cumulative oil recovered against period of injection show a significant drop in rate of oil recovery as compared to the case of 30% water cut. The rate of oil recovery dropped down to 9.72 barrels per day from the 10th to 501st day and 4.2 barrels from 502nd to 1500th day at 50% water cut. Above 5055.7 barrels of oil was recovered after injecting 0.85 pore volume with 50% water in the fluid produced. At the end of the designed injection period about 30% of the original oil in placed is recovered. After injecting 0.85 PV about 30% of OOIP is recovered at 50% water cut.

An increase in water cut leads to a decrease in oil production, and this can lead to an uneconomical production. At 65% water cut, feasible oil recovery did not start until the injection period reached 800th day. From 801st day oil recovery continues to increase until the end of the designed injection period and recovers 113 barrels. 0.85 PV recovered only 113 barrels at 65% water cut. Only 10% of the OOIP is recovered at end of 1500 days with 65% water cut. 0.85 PV recovered only 10% of OOIP at 65% water cut.

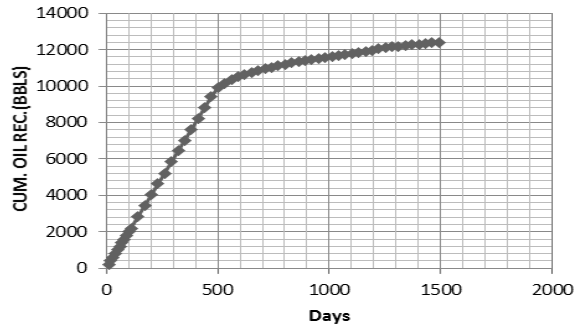

Figure 1: Cumulative oil recovered versus number of days for polymer flood @ 30% water cut

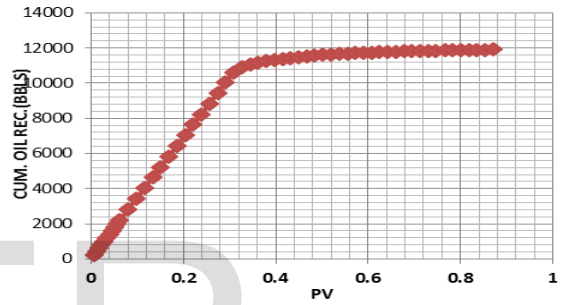

Figure 2: Cumulative oil recovered versus pore volume for polymer flood @ 30% water cut

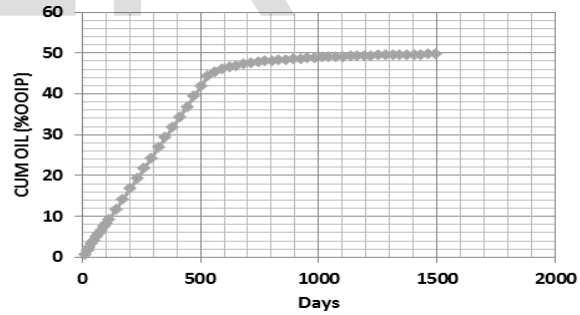

Figure 3: Cumulative oil (%OOIP) versus number of days for polymer flood @ 30% water cut

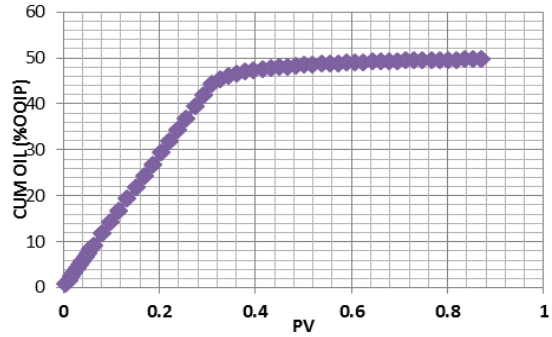

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Figure 4: Cumulative oil (%OOIP) versus pore volume for polymer flood @ 30% water cut

Figures 6-8 are plots of output response from the simulation showing the results of adding surfactant to the polymer at 30% water cut.The output show that oil recovery increased to about 14960 barrels at 30% water cut. Similarly, 0.85 PV recovered about 14960 barrels with 30% water cut.

At end of the injection period 69% of the original oil in place was recovered with 30% water cut and 62.3% OOIP was recovered after injecting 0.85 PV. This occurred as a result of reduction in interfacial tension between the oil and the driving fluid caused by adding surfactant slug to the polymer. At the end of the injection period (i.e. 1500 days) 8075 barrels were recovered which is equivalent to 47% of the original oil in place for 50% water cut. When the level of water in the produced fluid is increase to 65%, oil recovery did not start until the 412th day of injection and 0.22PV has been injected. Increasing the amount of drive water increases oil sweep speed but decreases the ratio of oil in the fluid produced in both the two cases.

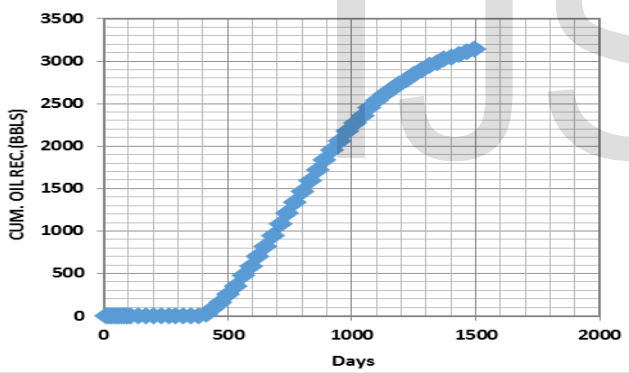

Figure 5: cumulative oil recovered versus number of days for surfactant/polymer flood @ 65% water cut

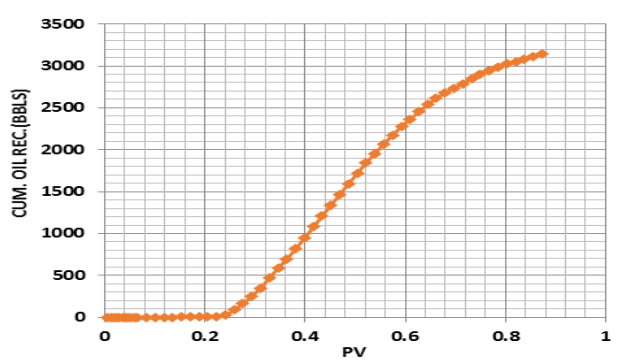

Figure 6: Cumulative oil recovered versus pore volume for surfactant/polymer flood @ 65% water cut

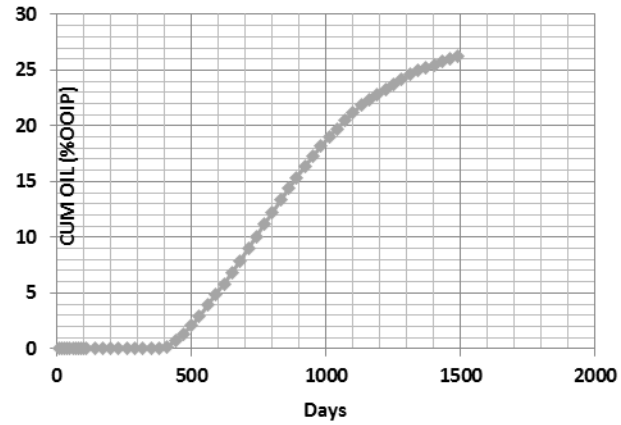

Figure 7: Cumulative oil (%OOIP) versus number of days for surfactant/polymer flood @ 65% water cut

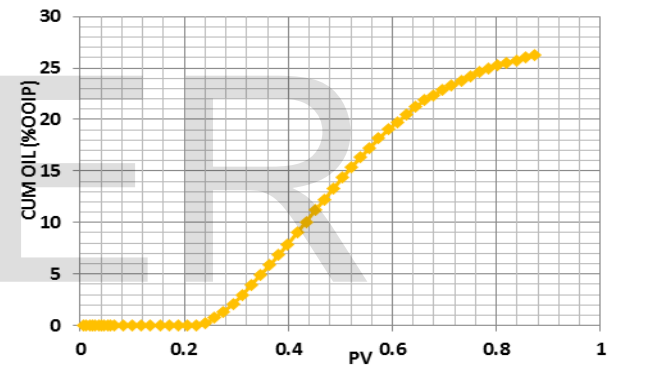

Figure 8: Cumulative oil (% OOIP) versus number of days for surfactant/polymer flood @ 65% water cut

Table 2 below is a summary and comparison between the results obtained from polymer and surfactant-polymer flood simulation runs. In polymer flooding; oil recovery is achieved by mobility control process while in surfactant-polymer flooding; oil recovery is achieved by both mobility control process and low interfacial tension process.

Table 3 shows the incremental percentage and barrels of oil recovered by adding surfactant to the polymer. This occurred as a result of reduction in the interfacial tension between the displacing fluid/agent and the displaced fluid.

4 Conclusions

Simulation results in this study show that introducing a substance (i.e. surfactant) that lowers the interfacial tension

between oil and water to a mobility control process (i.e. polymer flooding) has a positive impact on the amount of oil recovered from the OOIP. Polymer flooding recovered only 27% of OOIP while surfactant-polymer flooding recovers up to 45% of OOIP. Results of the simulation further shows that good oil recoveries is achieved at all water cuts modelled for both polymer and surfactant-polymer and that the behaviour of cross flow multi-layered reservoir in response to chemical flooding is similar to single layer reservoir. However, the nature and the degree of communication between the layers affect the recovery time.

Table 2: Simulation Results Summary

Parameter	Polymer	Surfactant-Polymer
Cumulative oil recovered (Barrels) @ 30% water cut	11900.00 BBLS	15006.00 BBLS
Cumulative oil (%OOIP) @ 30% water cut	49.73%	62.68%
Cumulative oil recovered (Barrels) @ 50% water cut	5055.70 BBLS	8073.30 BBLS
Cumulative oil (%OOIP) @ 50% water cut	29.60%	47.21%
Cumulative oil recovered (Barrels) @ 65% water cut	112.38 BBLS	3148.00 BBLS
Cumulative oil (%OOIP) @ 65% water cut	0.94%	26.30%

Table 3: Effect of Adding Surfactant to Polymer on Oil Recovery

Water cut	Cumulative oil in barrels	Cumulative oil % OOIP
30%	3106.00	12.95%
50%	3017.60	17.61%
65%	3035.62	25.36%

Polymer exhibited very good stability and integrity at high reservoir temperature. This is evident by good mobility control; and very good sweep efficiency of the polymer drive. High interfacial activity and stability of the surfactant slug lead to the mobilisation of residual oil within the reservoir at different water cuts.

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