AN EXPERIMENTAL INVESTIGATION OF LOW SALINITY WATERFLOODING IN BEREA SANDSTONE

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ABSTRACT

Oil recovery by low-salinity waterflooding in secondary and tertiary modes was investigated in the present study. Cores from Berea outcrop sandstone and two types of Minnelusa crude oils were used in the core flooding experiments. Sets of experiments were performed using low-salinity brine flood as a tertiary recovery method where cores were first flooded with high-salinity brine, then flooded with low-salinity brine. In the second set of experiments, low-salinity brine was used in secondary recovery mode where oil saturated cores are directly flooded with low-salinity brine. Oil recovery and the pressure drop across the cores were measured continuously. Conductivity and pH were measured on aliquots of effluent brines.

Increase in oil recovery with low salinity brine as the invading brine was observed in both secondary and tertiary modes (2-14% OOIP) with Berea sandstone. However, higher total oil recoveries (5-14% OOIP) were observed when low salinity waterflooding was implemented as a secondary recovery method. An increase in pH of the effluent brine was observed during the low salinity brine injection in all the experiments.

The level of investigation into the mechanism of low-salinity incremental production has sharply increased in the past two years. Most of the studies focus on core floods using the tertiary mode. Our work contributes systematic coupled secondary and tertiary mode experiments that offer an expanded dataset for all researchers to use in investigation of the mechanisms.

1. INTRODUCTION

Low-salinity waterflooding has been studied widely during the last fifteen years (Morrow and Buckley, 2011) as a one of the most inexpensive and environmentally friendly enhanced oil recovery methods. Low-salinity waterflooding does not need expensive or hazardous chemicals. There are other advantages to this method due to the lower salinity of the injection water which reduces scaling and corrosion of the equipments used in the field (Collins, 2011). Also this method can reduce the potential for reservoir souring. All of these factors contribute in a positive manner to project economics.

Many studies on low salinity injection confirm that this method can improve oil recovery by 2-42% depending on the brine composition, crude oil composition and rock type. However, there are some laboratory and field studies which do not show any increase in the oil recovery from low salinity brine injection. Many researchers have studied the separate effect of recovery in low salinity brine injection in secondary or tertiary recovery modes (Ashraf, 2010). In the following study we performed a comparison of oil recovery by low-salinity brine injection in secondary and tertiary recovery modes.

2. EXPERIMENTAL SECTION

2.1 Material

2.1.1 Crude Oils

Raven Creek and Gibbs crude oils from the Minnelusa formation in Wyoming were used in all the experiments. Crude oil properties are listed in Table 1. Crude oil was centrifuged at 6000 rpm for 2 hours to remove the water and the sediments. Oil was then were filtered and vacuumed for 4 hours to remove the light ends. This process can increase water wetness in the system (Tang and Morrow, 1997). In addition, since some proposed chemical mechanisms postulate that polar components of the oil bind to mineral surfaces, so removing non-polar components will concentrate these active components. Crude oil was stored in amber color bottles at a dark place to avoid the photochemical dissociation.

Table 1. *Crude oil properties at room temperature*

Oil	Density	API	Viscosity (cp)	S. (%)	A. (%)	R. (%)	Asph. (%)	TBN	TAN
Raven Creek	0.8578	33.5	8.0	80.2	15.8	2.6	1.4	0.92	0.074
Gibbs	0.8834	28.7	11.50	61.5	23.4	3.2	10.4	---	---

2.1.2 Brines

Brines were made from the ACS grade chemicals and the distilled water. Compositions of the brines are listed in the Table 2. Synthetic brines were vacuumed for two hours to remove the dissolved gas in the brine before use in the experiments.

Table 2. *Brine composition*

Compound	Formation Brine (mg/l)	Formation Brine (mmol/l)	Low Salinity Brine (mg/l)	Low Salinity Brine (mmol/l)
NaCl	29,803	509.97	298.03	5.0997
$CaCl_2$	2,106	18.9763	21.06	0.1897
Na_2SO_4	5,903	41.5587	59.03	0.4156
MgSO4	84.1	6.987	8.41	0.0699
NaN_3	100.	1.538	1.00	0.0154
TDS	38,753 ppm		387.53 ppm	

2.1.3 Cores

Core plugs were drilled from a Berea block and dried in the oven at 100°C for 48 hours. Cores were cleaned by a brush before measuring air permeability. Permeability of the cores was measured using nitrogen gas flow (confining pressure, 500 psi). Petrophysical properties of the Berea core plugs are listed in Table 3. Core plugs were stored in a desiccator until use.

Table 3. *Core properties*

Name	Length (cm)	Diameter (cm)	Permeability (mD)	Porosity (%)	PV (ml)
SA-01	7.583	3.784	284.99	20.83	17.76
SA-02	7.952	3.789	238.22	20.68	18.54
SA-03	7.78	3.786	242.76	20.68	18.11
SA-04	7.614	3.787	267.07	21.04	18.04
SA-05	7.793	3.798	372.02	19.89	17.27
SA-06	7.69	3.783	238.43	20.53	17.75
SA-07	7.524	3.783	277.96	21.30	18.02
SA-08	7.657	3.799	373.13	19.90	17.28

2.2 Experimental Procedure

2.2. Tertiary Mode Experiments

First, core plugs were saturated with formation brine under vacuum then aged at room temperature for 7 days. Porosity was calculated by subtracting dry weight of the core from the weight of the brine saturated core. Next, the core plug was mounted in a Hassler core holder and high-salinity brine (2-3 PV) was injected to establish a constant pressure drop across the core. Pressure drop at different flow rates (0.1, 0.2, 0.3 and 0.4 ml/min) was used to calculate the brine permeability (Kb). To establish the initial water saturation (S_{wi}) the core plug was then flooded with the crude oil (5 PV) (Tang and Morrow, 1997). Volume of brine displaced by the oil was used to calculate the original oil in place (OOIP) and S_{wi}. Oil permeability was measured at S_{wi} by using the same method as brine permeability. Cores were removed from the core holder and aged in an aging cell for 10 days (Tang and Morrow, 1997). After aging, cores were re-mounted in the Hassler core holder and flooded with fresh crude oil for about 5 PV (core was flooded with the same direction used to establish the Swi). After preparation core plugs are flooded with the high-salinity brine (formation brine) at 0.2 ml/min for about 10 PV. Pressure drop across the core was measured continuously during the experiment; oil production was measured at set time intervals. Effluent brine was collected in 8 ml samples by using a fraction collector. Thus, the discrete samples represent an average of dissolved properties for the sampled interval. The pH and the electrical conductivity of the samples were measured immediately. Finally, the core was flooded with the low-salinity brine at 0.2 ml/min for another 10 PV. Oil production, pressure drop across the cores, pH and the conductivity were measured as described in the secondary oil recovery mode.

2.2.2 Secondary Mode Experiments

Cores were saturated with brine, flooded and aged with the oil as described under tertiary mode experiments. The core plugs were flooded directly with low-salinity brine for about 10 PV. Oil production, pressure drop across the core, pH and the conductivity were measured during the low salinity brine injection.

3. RESULTS AND DISCUSSION

All results are summarized in Table 4. Duplicate experiments were conducted to measure the oil recovery from low salinity waterflooding in tertiary mode with the RC crude oil. Core plugs were flooded with approximately ten pores volumes of high-salinity brine to reach residual oil saturation, and then flooded with low-salinity brine (100-fold dilution) to represent tertiary mode application (Figure 1). Duplicate experiments were conducted to measure the total oil recovery when core plugs (aged with RC crude oil) were flooded in secondary mode (Figure 2).

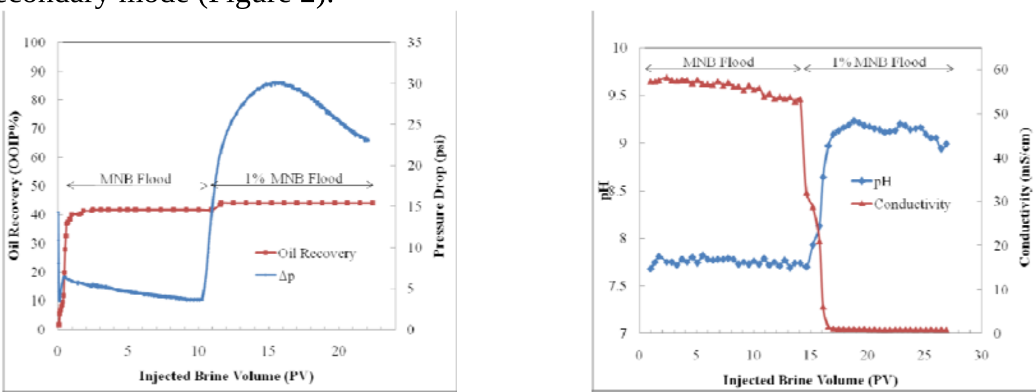

Figure 1. Oil recovery, pressure drop, conductivity and the pH variation during the experiment with core SA-01 (core plug was flooded in tertiary mode).

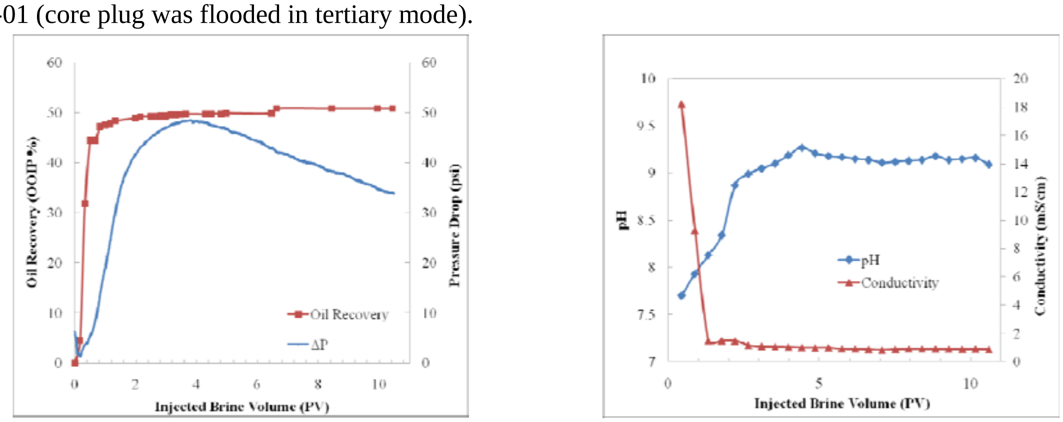

Figure 2. Oil recovery, pressure drop, conductivity and the pH variation during the experiment with core SA-03 (core plug was flooded in secondary mode).

About 41% (OOIP) of oil was recovered during the high-salinity brine flood (Figure 1) in the tertiary mode experiments. Conductivity of the effluent brine decreased slightly during the high -salinity brine flood while pH was nearly constant. When the brine was switched to low salinity, pH of the effluent increased from 7.7 and stabilized at around 9. Pressure drop across the core increased and more oil (about 2% OOIP) was recovered during the low -salinity brine flood. The secondary mode experiment (Figure 2) shows similar pressure, pH and conductivity changes. However oil recovery was about 51% OOIP. Using the average of the duplicate experiments, the increase is about 17% or 7.4% OOIP more oil in secondary mode compared to the tertiary mode experiments.

Duplicate experiments were also performed with Gibbs (GBS) oil (Figures 3 and 4). Pressure drop and conductivity variations during the tertiary mode floods were similar to the experiments with RC crude oil. The pH of the effluent increased from 7.5 and stabilized at around 8. About 50% (OOIP) of the oil was recovered during the high-salinity brine injection. Low-salinity brine injection produced an additional 5% (OOIP) oil.

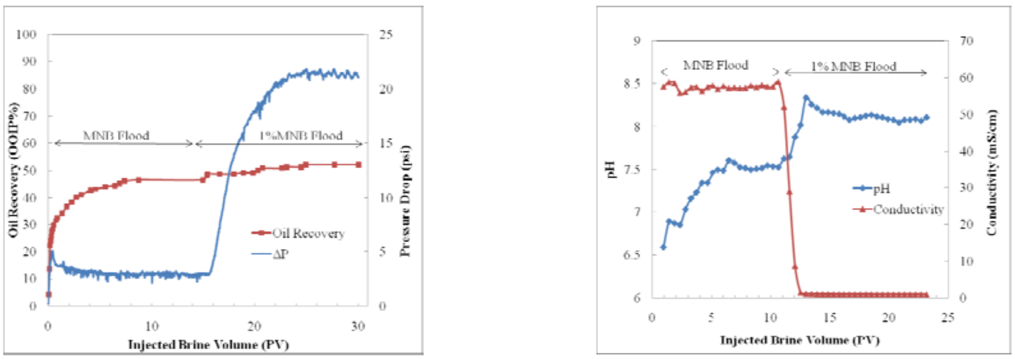

Figure 3. Oil recovery, pressure drop, conductivity and the pH variation during the experiment with core SA-05 (core plug was flooded in tertiary mode).

About 59% (OOIP) oil was recovered during the low-salinity brine injection. The pH of the effluent initially increased to about 9.5 then gradually decreased to about 8.6. Using the average of the duplicate experiments, the oil production is about 15% or 7.8% OOIP greater in secondary mode compared the tertiary mode experiments with GBS oil.

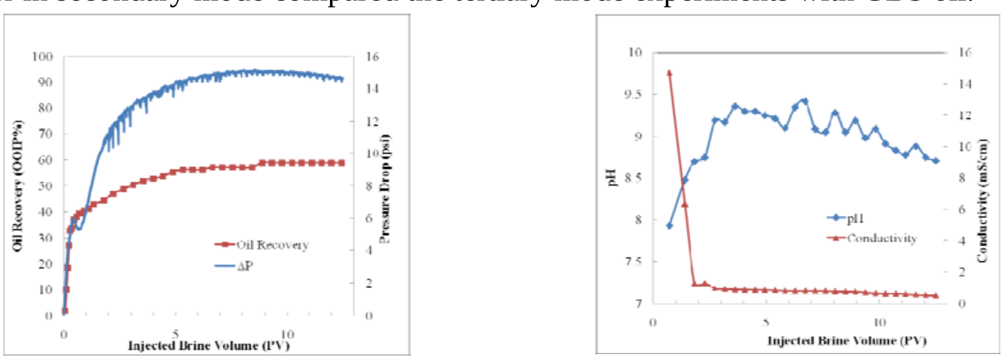

Figure 4. Oil recovery, pressure drop, conductivity and the pH variation during the experiment with core SA-07 (core plug was in secondary mode).

Results in Table 4 show that experiments using the RC oil showed about 7% OOIP more oil was recovered when the low-salinity brine injection was used in secondary mode. Similar increases in the oil recovery were observed with the GBS oil when low-salinity brine injection was used as a secondary recovery method compared to the tertiary mode experiments.

Table 4. *Summary of experimental results.*

Core	Oil	K_b (mD)	S_{wi}	R_o	R_{ot}	R_T
SA-01	RC	106.70	29.08	41.67	2.38	44.05
SA-02	RC	77.80	40.83	39.54	4	43.54
SA-03	RC	71.71	39.11	50.78	N/A	50.78
SA-04	RC	105.96	28.50	51.45	N/A	51.45
SA-05	GBS	209.17	32.28	46.58	5.56	52.14
SA-06	GBS	124.53	28.50	53.15	trace	53.15
SA-07	GBS	101.26	33.95	58.82	N/A	58.82
SA-08	GBS	227.71	28.19	62.10	N/A	62.10

4. CONCLUSIONS

Secondary mode and tertiary mode core flooding experiments were performed using two Minnelusa formation crude oils. Incremental oil recovery from low-salinity brine injection was observed in all the tertiary mode experiments. The incremental recovery is coincident with the decrease in salinity and increase in pH.

Higher total oil recovery (7.3-7.9% OOIP) was observed when low-salinity brine injection was used in secondary mode experiments compared to the total oil recovery in tertiary mode experiments for the same oil.

NOMENCLATURE

MNB Synthetic Minnelusa brine
1%MNB Low salinity brine
OOIP Original Oil in Place
S_{wi} Initial water saturation, %
S_{or} Residual oil saturation, %

K_a Air permeability
K_b Brine Permeability
R_o Oil recovery, %OOIP
R_{ot} Tertiary oil recovery, %OOIP
R_t Total oil recovery, %OOIP

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