PROCEEDINGS
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Incremental Recovery of Light Oil by Alkaline Injection on Sandstone Core: Laboratory Study

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Abstract

Water flooding was first used for pressure maintenance and has become the most widely used improved-oil-recovery technique. The effect of alkaline on the recovery of crude oil by imbibition and water flooding has been investigated. This study is based on displacement tests in loose-sand cores with light oil. The alkaline injections were initiated after the columns had been reduced to a residual oil saturation by conventional low salinity waterflooding.

Introduction

The objective of this study is to determine the effect of alkaline water on the recovery of oil in loose-sand core. Nutting (1925) proposed flooding an oil reservoir with alkaline sodium carbonate while Leach et al. (1962) have reported that the alkaline water causes a reversal of wetting conditions in some oil-wet reservoirs. During low salinity water flooding, the salinity was reduced much lower than the initial brine salinity. This causes higher pressure drop and more oil was produced. Tang and Morrow (1999) reported this phenomenon as permeability reduction caused by fine migration. Clays are important in the oil recovery process because they occur as small particles adjacent to the sand grains, where they usually contact with water. The permeability of certain oil sands is affected by hydration of clays. Morries, Anne and Gates (1959) found that clays occur in the pore spaces, attached to the sand grains. When these clays hydrated and swell, the pore space will decrease. The mechanism of clay hydration is also suggested by Van Engelhardt and Tunn (1955) that clays attract and strongly hold an appreciable amount of water in their surfaces. This action called as swelling, reduces the effective pore volume and thereby may affect oil recovery in the water flood process.

Data and Method

Experiment was done by first injecting brine, followed by low salinity and then alkaline flooding. When injecting brines, rates varied from 1 cc/min to 3 cc/min. The specified saline water was set at 2000 ppm and 10000 ppm. While the alkaline water has pH 9.7 and 10. The artificial core composition used in the scenarios contains 85% sand and 15% clay. The rate of injection was 0.3 mL/min and the temperature was set at 60 ^{o}C. There are three displacing fluids, alkaline water, low saline and brine. Alkaline water contains sodium bicarbonate with mass of solids 9.073 gr for pH 9.7 and 36.12 gr for pH 10. The oil used has specific gravity 0.79, oil density 52.076 lb/cu-ft, 46 API, kinematic viscosity 3.21 centi-stoke and dynamic viscosity 2.67 centi-poise. There are five major procedures during this lab study such as sample properties measurement, X-Ray Diffraction, imbibition, swelling test and core flooding. Water composition, oil properties and core sample were first noted. XRD test was conducted to determine the mineral composition and it showed kaolinite and illite. Imbibition test is used to analyze areal sweep effects. The wettability of the core is determined by which phase imbibes more. Swelling test was done by inserting clay sample into test tube and then poured the formation water. Swelling was indicated by the addition volume in the tube. Before water flooding is started there is a necessary to do a pre-treatment or pre-conditioning to the cores in order to create an environment close to the real (reservoir) environment. The pre-conditioning steps include the saturation of cores using brine with salinity of 10,000 ppm.

This first step is conducted using an equipment "Hassler core holder" with the confining gas pressure set at 150 psig and temperature set at 60 °C. Having finished, oil is then injected to the core with the same equipment. After pre-conditioning to the cores are finished waterflooding may then be started. Waterflooding with high salinity (10,000 ppm) is first to introduce then followed by low salinity (2,000 ppm) then alkaline injection. The major equipment which were used for this experiment shall be Hassler Core Holder, Injection Syringe Pump, Temperature Controller, and Digital Pressure Indicator. Core flooding scenario for the core was:

- Injecting 10000 ppm brine until 2 PV
- Record the recovery factor
- Injecting 2000 ppm brine till 4.5 PV
- Record oil gain from low saline injection
- Injecting alkaline water until 6.5 PV
- Record oil gain from alkaline injection

The following equation used in recovery calculation showed in Eq. (1), (2) and (3).

Result and Discussion

Figure 1 and Figure 2 shown the result of swelling test for the clay used low salinity and alkaline solution. Addition volume NaCl is 2.3 mL which is higher than and $MgCl_2$ when saturated in 2,000 ppm concentration. Solution of NaCl involve the thickest swelling, followed by solution of $MgCl_2$ and $CaCL_2$.

Coreflood Core-1

This core flooding process is first conducted by formation water 10,000 ppm. Recovery factor from HS water flood is 43.61% when formation water injected about 2 PV. Then coreflood is conducted by 2,000 ppm NaCl about 4.5 PV. Recovery factor after 2000 ppm is 45.85%. Then the coreflood is conducted by alkaline water $NaHCO_3$ pH 10 about 6.5 PV. Recovery factor after alkaline injection is 48.36%. Figure 3 shown the result of coreflood at Core-1. The parameters of coreflooding process were 9.736 mL pore volume, porosity 0.29, permeability 184.55 mD and OOIP 4.7 ml.

Coreflood Core-2

Recovery factor from 10000 ppm brine injection is 35% when formation water injected about 2 PV. Then coreflood is then conducted by 2,000 ppm NaCl about 4 PV. Recovery factor after LS waterflood is 37.02%. Then the coreflood is conducted by alkaline water $NaHCO_3$ fter alkaline injection is 38.13%. Figure 4 shown the result of coreflood at Core-2. The parameters of coreflooding were 9.798 mL pre volume, porosity 0.3078, permeability 177.85 mD and OOIP 4.5 ml.

Conclusions

The alkaline injection process appears to be capable of recovering residual oil by alkaline flooding. Solution of alkaline with pH 10 present higher incremental oil about 2.51% while solution of alkaline with pH 9.7 present 1.11%. Fine migration is detected due to an increase in pressure when injection fluid changes from low salinity to alkaline solution are carried out.

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$$S_{wi} = \frac{V_{wp}}{V_p} \quad (1)$$

$$OOIP = V_b \phi (1 - S_{wi}) = V_p (1 - S_{wi}) \quad (2)$$

$$RF\ (\%) = \frac{V_{op}}{OOIP} x100\% \quad (3)$$

S_{wi} = Saturation of water initial, fraction
V_{wp} = Volume of water produced, mL
V_p = Pore volume, ml
V_b = Bulk volume, ml
Φ = Porosity, fraction
RF = Recovery factor, %
V_{op} = Volume of oil produced, mL
OOIP = Original oil in place, ml

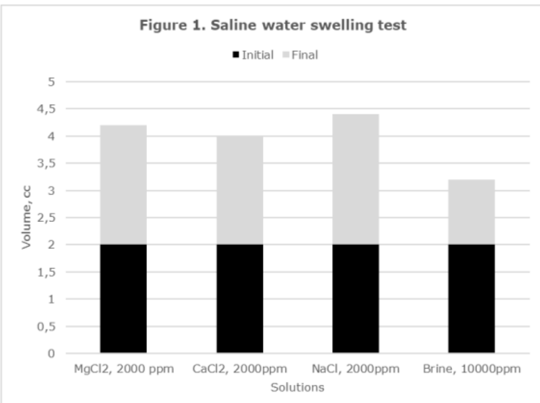

Figure 1 Saline water swelling test result

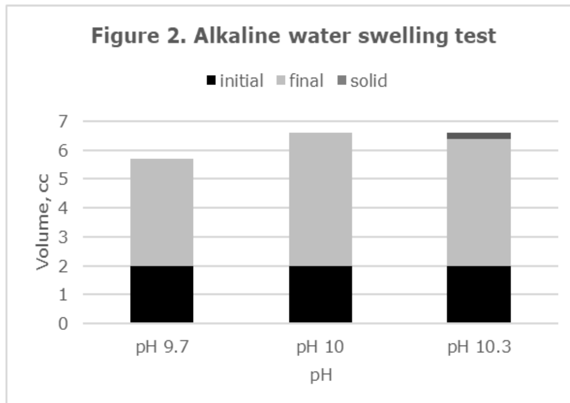

Figure 2 Alkaline water swelling test result

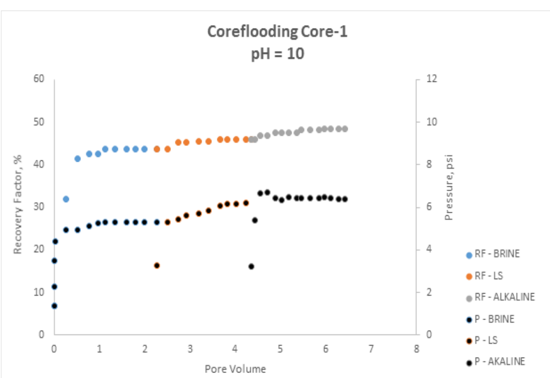

Figure 3. Result of Coreflooding core-1

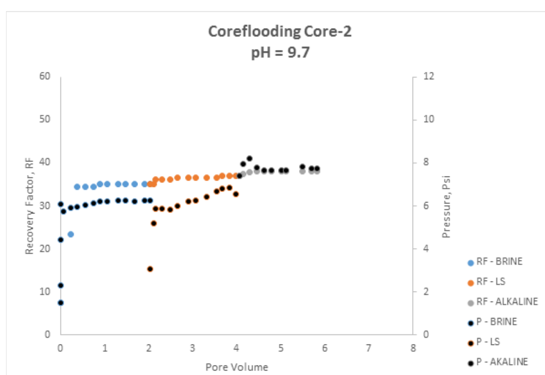

Figure 4. Result of coreflooding core-2

Table 1. Content of the brine, low saline and alkaline water

Fluid	ppm	pH	mass of solids (gr)
Brine	10000	-	25.435
NaCl	2000	-	5.087
Alkaline-$NaHCO_3$	-	9.7	9.073
		10	36.12

Table 2. Oil properties

Parameter	Value	Unit
SG @60°C	0.79	
Oil Density @60°C	52.0765	lb/cuft
API @60°C	46.0	°API
Kinematic Viscosity	3.21	centi-stoke
Dynamic Viscosity	2.67	centi-poise

Table 3. Parameters data for coreflood core-1

Parameters	Value	Unit
Rate	0.3	ml/min
T	60	°C
PV core	9.736	ml
Porosity	0.2913	
Brine Permeability	184.5528	mD
OOIP	4.7	ml

Table 4. C Parameters data for coreflood core-2

Parameters	Value	Unit
Rate	0.3	ml/min
T	60	°C
PV core	9.798	ml
Porosity	30.78	%
Brine Permeability	177.85	mD
OOIP	4.5	ml