Journal of Engineering and Applied Sciences 13 (9): 2780-2785, 2018
ISSN: 1816-949X

Numerical Simulation of High Viscous Oil Recovery by Low-Salinity Water Injection

Ilyas K. Turgazinov and Talgat A. Ensepbayev
Kazakh National Research Technical University Named after K.I. Satpayev, Almaty, Kazakhstan

Abstract: Today the recovery factor in sandstone and carbonate reservoirs not exceeds 40% and in several cases not more that 30% (reservoirs with heavy oil). In these cases, traditional waterflooding when formation brine is injected has run out of its possibility. However, depending on the reservoir conditions a number of EOR methods can be applied to improve oil recovery. The low salinity waterflooding is one of the latest Improved Oil Recovery (IOR) methods. In literature it is known as 'Smart wateflood', 'LoSal' and 'Advanced ion Management'. This method implies reduction of the salinity of injected water. This technique demonstrated increased oil recovery up to 40%. Most researches have shown positive results in secondary and tertiary low salinity injection modes. Many mechanisms have been proposed to be behind improved oil recovery due to LSW. However, wettability alteration and fine migration is believed to be main reasons. Complex interactions between oil/brine/rock in carbonate and sandstone rocks don't allow predicting the amount of incremental oil because of LSWF. Nowadays there are only few papers dedicated to the possibility of implementation of LSW in heavy oil sandstone reservoirs. The objective of this study is to use simulator and investigate the injection of low salinity water injection into reservoirs with heavy oil in secondary mode. As a result LSW yielded up to 18% of incremental oil recovery compared to traditional formation brine flooding.

Key words: Low salinity waterflooding, numerical simulation, fines migration, oil production, viscous oil, brine

INTRODUCTION

Low salinity waterflooding is one of the promising methods for enhancing oil recovery in carbonate and sandstone reservoirs. This technique was proposed by Bernard (1967), who injected fresh water into oil bearing core to see whether the oil recovery would rise or not. But this idea didn't bring attention of the industry. Starting from 1990s this concept drew attentions of many researchers. For example, Morrow and his colleagues (Yildiz *et al*., 1999; Jadhunandan and Morrow, 1995; Tang and Morrow 1997, 1999) performed extensive research on the potential of low salinity waterflooding. They concluded that, the low salinity effect takes place only in the rocks with clay when the water salinity was <7000 ppm compared to 150000 for reservoir brine. Several coreflood experiments on Berea and shale sandstone cores performed by Agbalaka *et al*. (2009) suggest that temperature and brine salinity play a significant role in improving oil recovery. Incremental oil recovery was obtained when low salinity (10000 ppm NaCl) was injected compared to high salinity (40000 ppm NaCl). Recovery factor increased when the temperatures increased from low to high. Additional oil recovery from sandstone rocks ranged from 4-30% of OIIP reported by many papers (Lager *et al*., 2006, 2008; Webb *et al*., 2005, 2008).

Al-Adasani *et al*. (2012) reported that they observed LSWF effect from 214 coreflooding tests. On the contrary, the research of Zhang *et al*. (2007) doesn't suggest any incremental oil recovery due to LSWF effect. Thyne *et al*. (2011) also reported unsuccessful coreflood experiments of Minnelusa formation using low salinity waterflood.

The underlying mechanisms of the LSWF are still disputable. The first experiments suggested clay swelling and fine migration due to LSE. Formation damage accounted for improved oil recovery because of the particles plugging high permeable zones, thus enhancing sweep efficiency (Tang and Morrow, 1999). Formation damage is considered undesirable effect as it leads permeability reduction of a reservoir. However, many studies suggest that in particular cases implementing low salinity water may improve oil recovery.

The next mechanism is the pH increase. Some studies reported the pH increase in the effluent samples after coreflooding. This was attributed to calcium dissolution in a low salinity conditions. The pH increase leads to reaction of acidic components in oil thus, generating surfactant which is close to the surfactant flooding, reducing interfacial tension therefore changing wettability state or rock's surface (McGuire *et al*., 2005). But this mechanism demands high acidic number (>0.2 mg KOH/g).

Corresponding Author: Ilyas K. Turgazinov, Kazakh National Research Technical University Named after K.I. Satpayev, Almaty, Kazakhstan

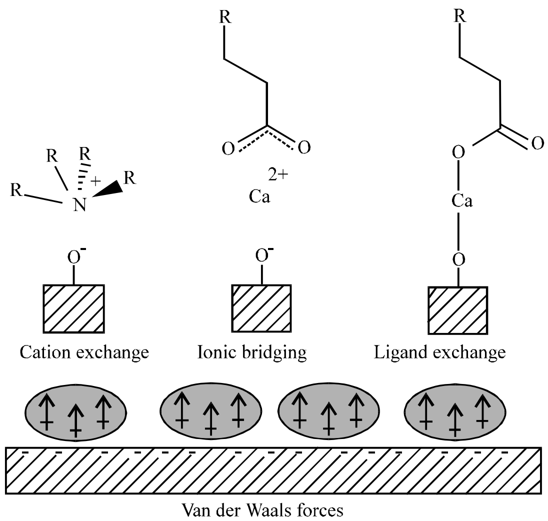

Fig. 1: Clay hydrocarbon bonding (Lager *et al*. 2008)

Multiion exchange mechanism was proposed by Lager *et al*. (2006). Ion exchange occurs between clay minerals and active components of in the oil with the presence of Ca^{2+} and Mg^{2+} ions. This ions serves as the bridge between negative charged clay surface and acid components of oil, thus oil is detached from rock's surface.

Most of the research works proved that wettability alteration is main mechanism behind LSWF in sandstone. Tang and Morrow (1999) and Lager *et al*. (2006, 2008) showed that wettability change is depend on oil composition, presence of clay and concentration of Ca^{2+} and Mg^{2+} ions and salinity concentration should be below 5000 ppm.

There is also another explanation behind wettability alteration occurrence. Lee *et al*. (2010) suggested that when low salinity water is injected, double layer expansion takes place causing wettability change in sandstones. The double layer expansion consists of two layers. The first layer contains ions such as Na^1, Ca^{2+}, while the second "diffuse layer" expands repelling negatively charged oil components, thus changing the wettability. The research of Nasralla and Nasr-El-Din (2012) proved by coreflood on Berea sandstone cores experiments that zeta potential between oil/water interface becomes more negative with the reduction of water salinity, therfore electrical double layer expansion mechanism is primary in enhancing oil recovery by LSWF (Fig. 1).

Modelling low salinity waterflooding: Only a few papers dedicated to modelling low salinity waterflooding. The first research Jerauld *et al*. 2008 based on the change of relative permeability and capillary pressure as the function of the local salinity concentration. The salt was modelled as single component in the water phase. Relative permeability end points interpolation was used based on local salinity to model LSWF. Omekeh *et al*. (2012) further improved the modelling by incorporation of the ion exchange between, calcium, sodium and magnesium together with mineral dissolution. Fjelde *et al*. (2012), also used multiion exchange at the surface to match coreflood results.

MATERIALS AND METHODS

In this study, we use conventional model based on the research of Jerauld *et al*. (2008). To model LSWF an industry standard black oil simulator (Eclipse 100) was used. A two phase oil and water model was used with salt carried in the injecting water. To model LSWF in heavy oil reservoir a set of relative permeability curves were used obtained by coreflood experiments. The saturation end points are interpolated according to Eq. 2-6. Interpolation is based on the empirical dependence with thresholds for high and low salinity brines. The low salinity effect is initiated when below the salinity level of 7000 ppm (Fig. 2).

Salt Models as single component in local aqueous phase. The brine distribution is modeled by solving mass conservation equation in each grid block for the salt Concentration Cs (Eq. 1), at each time step:

$$\frac{d}{dt}\left(\frac{VS_wC_S}{B_w}\right)=\Sigma\left[\frac{T_{ni}k_{rw}}{B_w\mu_{seff}}\left(\delta P_w-\rho_w gD_z\right)\right]C_S+Q_wC_S \quad (1)$$

$$S_{wco}=FS^L_{wr}+(1-F)S^H_{wco} \quad (2)$$

$$S_{wcr}=FS^L_{wcr}+(1-F)S^H_{wcr} \quad (3)$$

$$S_{wmax}=FS^L_{wmax}+(1-F)S^H_{wmax} \quad (4)$$

$$K_{wr}=FS^L_{wr}+(1-F)k^H_{wr} \quad (5)$$

$$K_{ro}=Fk^L_{ro}+(1-F)k^H_{or} \quad (6)$$

where, F is weighting function of the salt concentration:

$$F=\frac{\left(S_{orw}-S_{orw}\right)}{\left(S^H_{orw}-S^L_{orw}\right)} \quad (7)$$

$$S=\frac{\left(S_o-S_{orw}\right)}{\left(1-S_{wr}-S_{orw}\right)} \quad (8)$$

Simulation model: A 3D sector model was constructed with the following characteristics NX = 40; NY = 40; NZ = 10; DX = DY = 4 m; DZ = 13 m. The low salinity

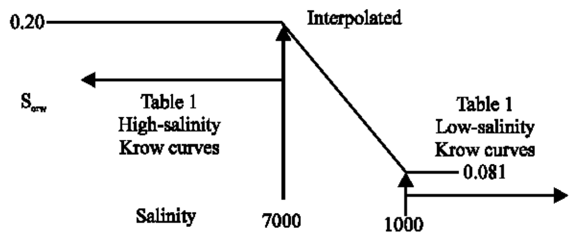

Fig. 2: Dependence of relative permeability on salinity (Jerauld *et al*., 2008)

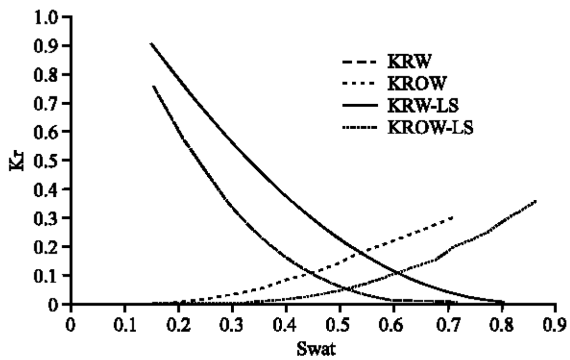

Fig. 3: Relative permeability for brine and low salinity water injections

Table 1: Model properties

Parameters	Values
Reservoir pressure (MPa)	4
Oil viscosity (μPa·s)	0.5
Porosity	0.3
Permeability (mdarcy)	500
Anisotropy coefficient (k_x/k_z)	0.1
Water density (kg/m^3)	1.00
Water viscosity (μPa·s)	1.00
Water compressibility (1/MPa)	0.0005
Oil formation volume factor	1.00
Density of oil (kg/m^3)	926

Table 2: Salinities of brine and LSW

Variables	Values
Formation brine (ppm)	93000
LSW injection (ppm)	100

relative permeability curves is used in all models; other reservoir properties common to the model is listed in Table 1.

The relative permeability interpolation depends on the dimensionless parameter F. In the high salinity case F = 1 in low salinity case F = 0. As the brine and LSW mixes the salinity in grid blocks changes, thus this parameter sets relative permeability thresholds. The relative premeabilities were obtained by coreflood experiments (Fig. 3 and Table 2).

RESULTS AND DISCUSSION

This is homogenous model consisted of 10 layers. The injection period was 10 years. Injection and production wells are set on the corners of the sector model. The first case dedicated to model water injections with different salinity (100 and 93000 ppm). The results can be seen in Fig. 4 and 5. In this case oil recovery for low salinity waterflooding is twice as much as brine injection and additional oil recovery are around 18 and 10%, respectively. The incremental oil recovery is believed to be related to wettability change and fine migration. The second case is dedicated to study low salinity water injection in tertiary mode. In this case LSWF was injected after initial brine injection. LSWF can be effective after preflush of brine when the oil saturation decreases up to 50%. As a result incremental oil recovery was 10%. In second case overall oil recovery is higher than that of the first case. The increase in recovery can be attributed to mixing between low and high salinity water, so, the displacement profile is more stable than that of injection water separately. Usually injected amount of water reaches 2-3 PV.

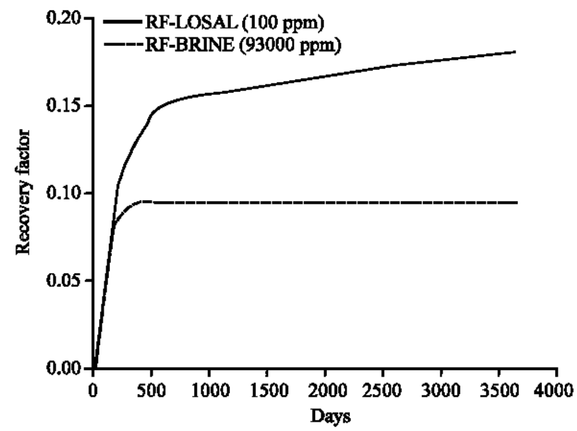

Fig. 4: Comparison of incremental oil recovery from LSW injection (fresh water 100 ppm and brine 93000 ppm)

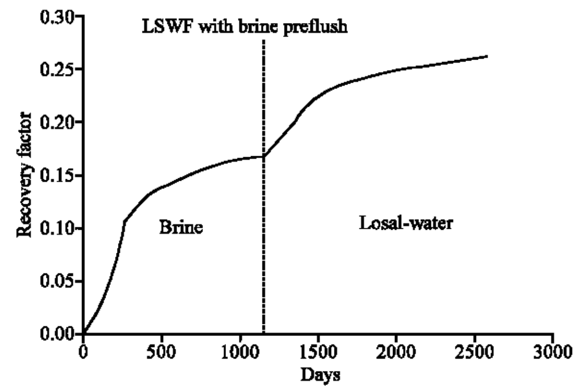

Fig. 5: Total oil production and oil recovery with brine preflush

Impact of oil viscosity: The influence of oil viscosity is found to be considerable during LSWF. Oil viscosity was shifted from 1, 100 and 300 μPa•s. Figure 6 shows the simulation result. As it can be seen from the Fig. 7 and 8 the most effective result has been obtained for the 1 μPa•s oil viscosity and less for high viscosity because of unfavorable mobility ratio. The most part of the trapped oil can be displaced by wettability alteration. Howeverin the sandstone reservoirs with high viscous oil LSWF can be effective because of fine migration.

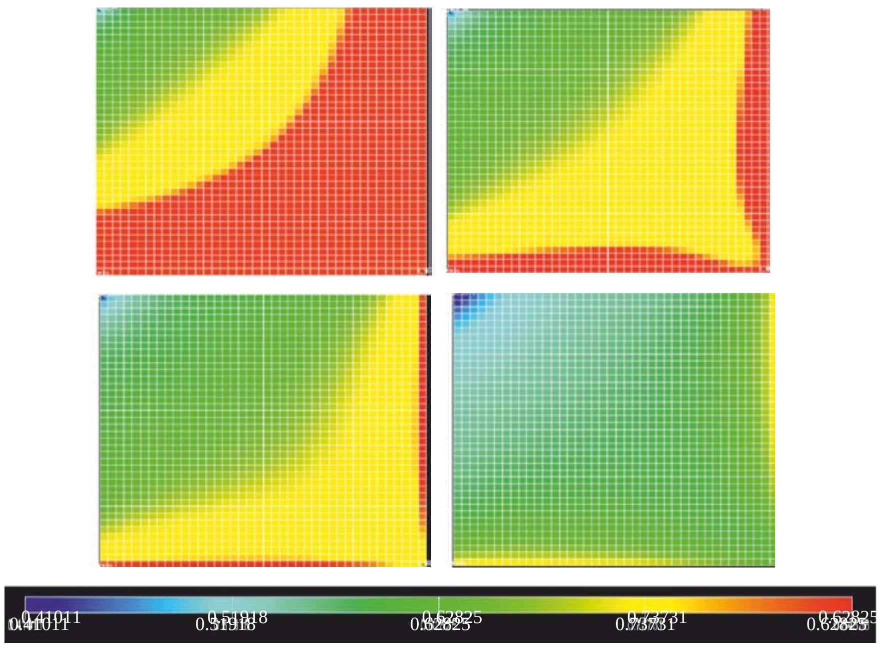

Fig. 6: Oil saturation during LSW injection

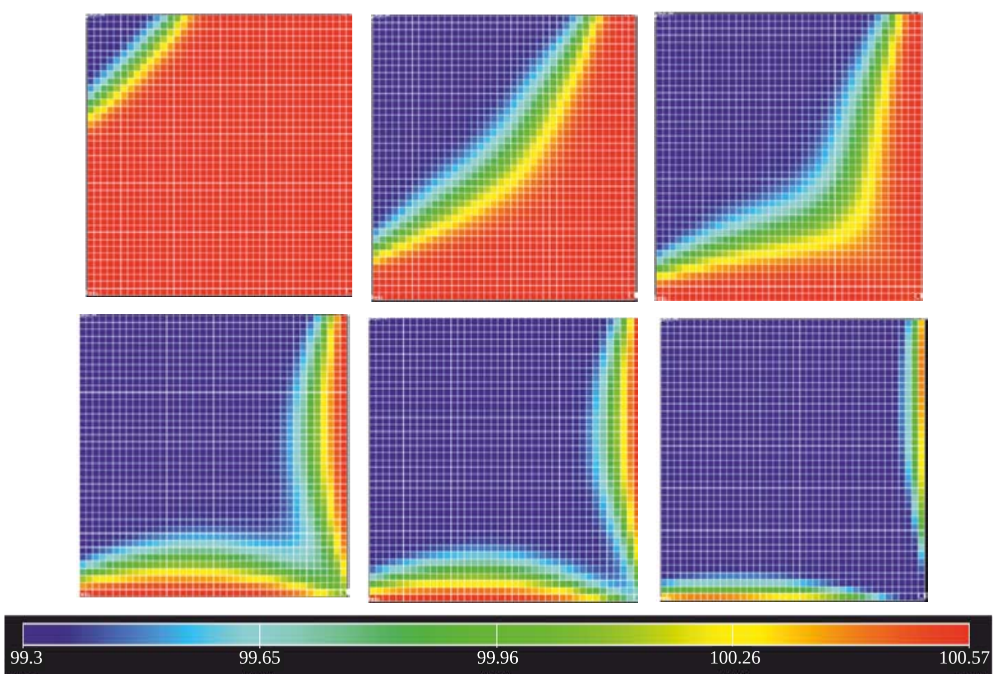

Fig. 7: Salt concentration during LSW injection

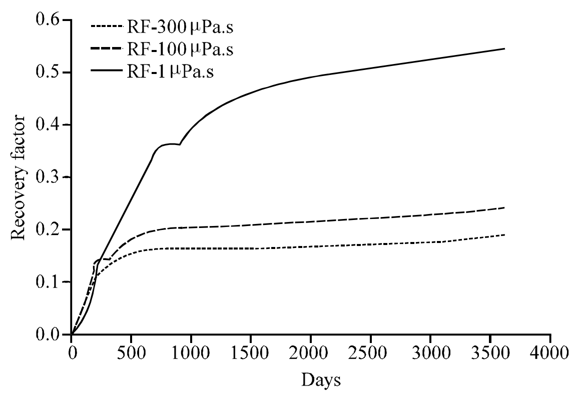

Fig. 8: Comparison of oil recoveries with various oil viscosity (1, 100 and 300 µPa•s)

CONCLUSION

Low salinity waterflooding were performed in Karazhanbas sandstone sector model with high viscous oil. The objective of this study was to investigate the high viscous oil recovery by injection LSW. A laboratory experiment was conducted to obtain relative permeability plot. Numerical modeling shows that 8% incremental oil recovery is obtained by LSW. The wettability alteration and fine migration is believed to be the main mechanisms.

Injecting water salinity significantly influences on oil recovery. Fresh water injection can be effective in reservoirs with high viscous oil. However, less viscosity is still favorable for total recovery.

Brine preflush before LSW injection yields more oil recovery than the injection of LSW at the start of oil production. In this study the gravity effect hasn't been considered. As this study showed effectiveness of injecting LSW onlyin reality LSW should be considered thoroughly with other EOR techniques such as polymer or surfactant flooding to reach synergetic effect.

ACKNOWLEDGEMENTS

The researchers would like to acknowledge proffessor Irina Panfilova for her help with experimental work. LEMTA (Laboratory of Energetics, Theoretical and Applied Mechanics, UMR 7563) at University of Lorraine for providing the ECLIPSE Software.

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