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Coupling Low Salinity Water Flooding and Steam Flooding for Sandstone Reservoirs; Low Salinity-Alternating-Steam Flooding (LSASF)

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Abstract

Low salinity water flooding and steam flooding are two novel combination flooding methods that were combined due to the important role of both methods in increasing oil recovery (especially heavy oil). Low salinity flooding was examined by many laboratory and field works and showed an interesting result. Steam flooding was tested on heavy oil fields and the heavy oil recovery increased by reducing oil viscosity. Although the steam showed an improvement in heavy oil recovery, the density difference between steam and heavy oil raised a problems with steam gravity override, channeling, and early breakthrough. For that reason, we developed the low salinity alternating steam flood (LSASF) in order to gather the benefits of low salinity, reduce oil viscosity by steam, and prevent the steam problems mentioned earlier. The laboratory experiments showed that the optimum scenario was Scenario (3). The shorter the injected cycles, the more oil recovery.

This combination of echnology can solve the steam flooding problems and support the steam by LS water, which has the ability to increase oil recovery.

Introduction

There are significant amounts of heavy oil reserves that have been found worldwide such as in Canada and the United States. Those hydrocarbons cannot be produced unless the viscosity is reduced. Many techniques have been used to enhance the oil recovey. One of those techiniques uses thermal processes. Thermal techniques were used to reduce heavy oil viscosity and surface tension in order to produce the oil more easily. Thermal EOR/IOR methods can be classified into (1) cyclic steam injection, (2) steam flooding, (3) in-situ combustion, (4) solar thermal, (5) SAGD…etc. Many steam flooding and steam cyclic stimulation projects have been conducted worldwide to increase heavy oil recovery. Farouq Ali (1974) listed the projects that have been done in California, Venzuela, and other oilfields. The projects were successful in increasing oil recovery by applying heat and reducing the oil viscosity. By 1970, the oil production rate was 30,000 B/D from California oil fields and increased up to 150,000 B/D after 12 years using steam techniques (Matthews 1983).

The steam flooding method is not always the optimum solution for the viscous oils. By the time the problems of steam projects seemed obvious such as steam channeling and gravity override (Hong 1990). Steam can propagate through high-permeability channels in the reservoirs and cause an early steam breakthrough, which is not favorable in flooding projects. Similarly, the density difference between the steam and viscous oil causes a gravity override, and in turn, the steam project fails. WAG was the best solution to overcome the previously mentioned steam problems. WAG was suggested as a technique to improve gas injection sweep efficiency by injecting the gas and the water sequentially to control the mobility of the displacement.

WASP is similar to the WAG process used for gasfloods in that two fluids with widely different densities are injected alternately over more than one cycle. WASP decreases channeling tendencies and gravity override of the gas phase, thus enhancing the vertical conformance of the reservoir. The main difference between WAG and WASP is that the gas phase in WASP is condensable and at a much higher temperature than that of the liquid phase. WASP reduces/eliminates steam breakthrough because water that is injected after steam causes the steam zone to collapse while tending to pass the reservoir. In turn, more vertical thermal fronts are formed (Hong 1992).

Low salinity water, on the other hand, was used in this work because of its effect on recovering oil from sandstone based on the work of many authors (Tang and Morrow 1999; McGuire et al. 2005; Lager et al. 2006; RezaeiDoust et al. 2009; Ligthelm et al. 2009; Austad et al. 2010; Aksulu et al. 2012; Al-Saedi and Brady et al. 2018). To our knowledge, no studies have been performed that use both LS water and steam in the same process. Alternating the steam with water can reduce the gravity override and channeling problems. Using LS water instead of normal water can also increase oil recovery by altering the sandstone wettability towards more water-wet and can also improve the microscopic sweep efficiency.

Methodology

Core Preparation and Flooding. Numerous Berea sandstone cores were saturated with a synthetic formation water (FW). The water was displaced with 3 pore volume (PV) (each direction) high viscosity oil to achieve residual S_w and was then allowed to age for five weeks at 90°C with crude oil in a closed container. These cores were then flooded with 2 PV high salinity (HS) and then followed by 2 PV low salinity (LS) water at room temperatures. The HS water was identical to the formation water (FW), while the LS water was diluted 100x (symbolized d_{100HS}) from the HS water. The flow rate was 0.5 ml/min. HS water was injected into the cores until residual oil saturation (S_{or}) was reached. After maximum oil recovery with HS, LS water was then injected until no more oil was produced and injection pressure stabilized. The new combined technology was conducted by four scenarios on four cores: (1) 1 PV steam followed by 2 PV LS water, (2) 0.5 PV steam + 1 PV LS water + 0.5 PV steam + 1 PV LS water, (3) 0.25 PV steam + 0.5 LS water + 0.25 steam + 0.5 LS water, (4) Huffed 0.9 PV steam and puffed in half hours, then injected 0.5 LS water + 0.5 steam + 0.5 LS water.

Crude Oil and Brines. A reservoir's crude oil was dilevered by Colt Energy from Kansas. The oil viscosity was 600 cp and the density was 0.83 at 20°C. Reagent-grade salts were prepared with deionized water to make FW and LS water. The compositions of brines are listed in Table 1. We aimed to add the same divalent cations concentration (Ca^{2+} and Mg^{2+}) in FW in order to avoid any other factors that might affect the oil recovery.

Porous Media. Core samples were cored from the same Berea sandstone block (similar petrophysical properties) and dried overnight in the oven at 90°C. The cores' descriptions are listed in Table 2. The XRD test shows 5% kaolinite present in the core. The cores were saturated for two days under vacuum in the HS water. The permeability was measured using HS water. The porosity of the cores was measured from the weight difference before and after saturating the cores in HS water.

Setup. The simple model made of sandstone cores and a core holder was built to displace the crude oil with HS and LS water, as shown in Figure 1. Schematics of the model used to test the new novel combination of low salinity water flooding and steam flooding in these experiments are presented in Figure 2.

Table 1— Brines Composition (mmol/L)

Brines	Na^+	Mg^{2+}	K^+	Cl^-	Ca^{2+}	TDS	PPM	IS	Mono. ions	Diva. ions
FW/HS	1500	89	33	1880	89	108460	108.46	2.06	0.507	0.066
LS (d_{100HS})	1.5	0.089	0.033	1.88	0.089	1085	10.85	0.0206	0.787	0.383

Table 2—Mineralogy and petrophysical properties

Core	Quartz, %	Kaolinite, %	Diameter, cm	Length, cm	K, md	Porosity, %
Senario#1				14.32		
Senario#2				14.25		
Senario#3	95	5	2.54	14.30	100	20
Senario#4				14.30		
Senario#5				14.78		

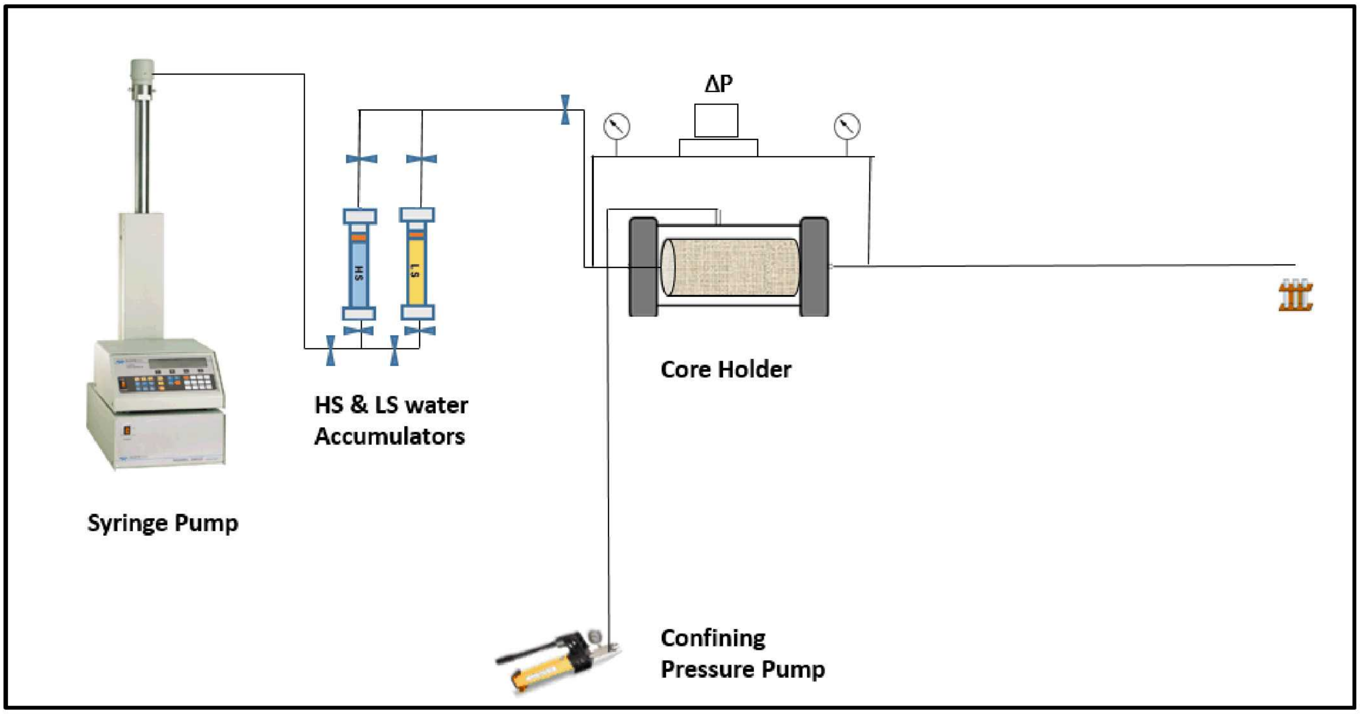

Figure 1—CoreFlood Setup.

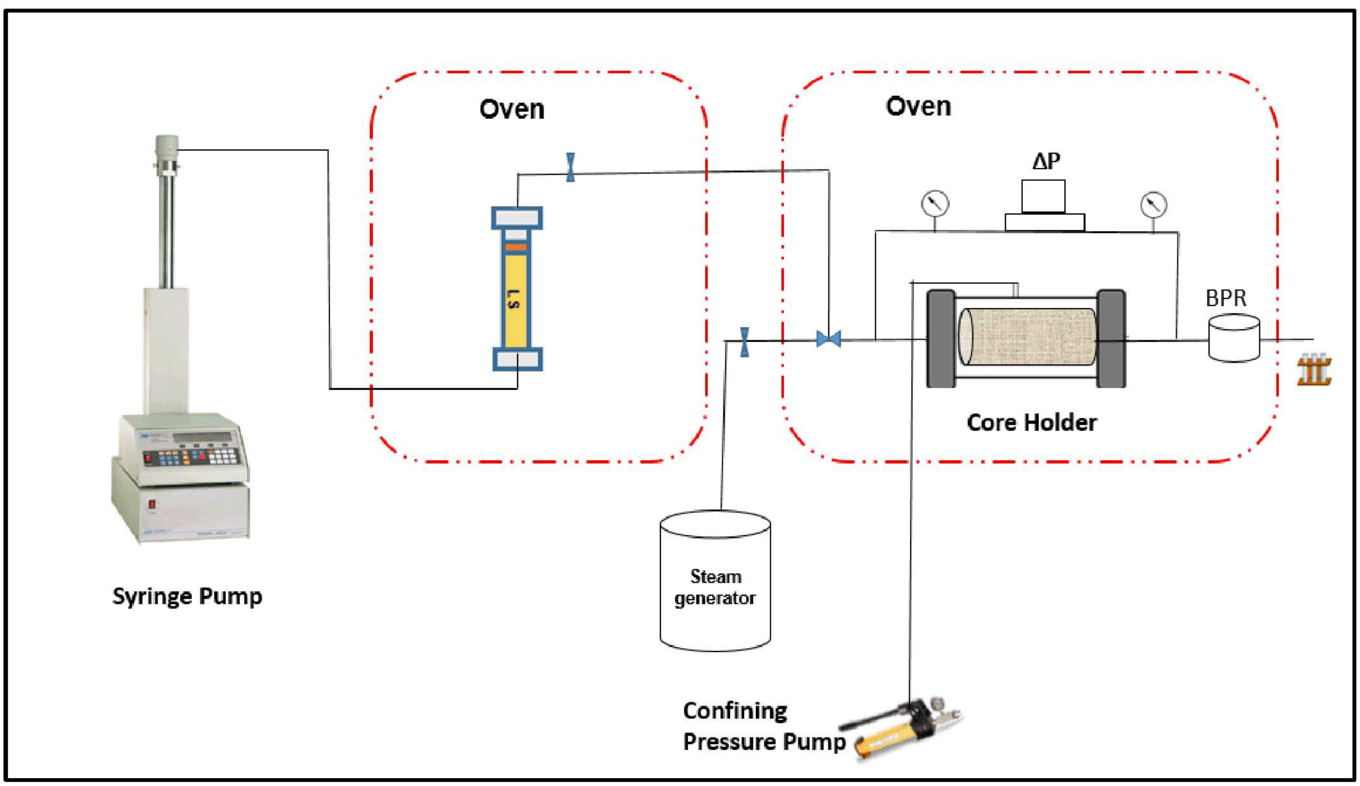

Figure 2— LSASF CoreFlood Setup.

Results and Discussion

The sandstone core was sampled from the same Berea sandstone block. The petrophysical parameters were very homogenous. The permeability and porosity were ~100 md and ~20%, respectively. The crude oil had a viscosity up to 600 cp. As previously stated, the cores were successfully flooded with 2 PV HS (FW) followed by 2 PV LS water. The new novel combination flood was coupled due to the important role of both methods in increasing oil recovery (especially heavy oil). Four scenarios were applied in this work as follows:

Scenario#1:

The core was flooded with FW and about 41.9% of the original oil in place (OOIP) was recovered. The oil recovery was increased by 2.8% of OOIP when the injected fluid was switched to LS water (Figure 3.a). After reaching the residual oil saturation, the scenario of the new combination starts. The injected fluid switched to steam and a whole PV was injected into the core with incremental recovery about 1.86% of OOIP. Upon switching to LS water (90°C), the ultimate oil recovery increased by 3.7% of OOIP.

The injection pressure increased continuously up to 426 psi while injecting FW until the pressure stabilized at 180 psi. The largest pressure occurred while injecting FW because of the displacement of the heavy oil. The highest injection pressure during LS water flooding was at 194 psi, and the pressure stabilized at that point. The injection pressure decreased slightly during steam and LS water flooding (Figure 4.a).

The pH observations show an upward shift in effluent pH between HS and LS water. The reason behind this shift is traditionally ascribed to the exchange of H^+ for Ca^{2+} on clay and quartz surfaces. The effluent pH was 7.09 for FW and 8.95 for LS water. The pH shift during steam + LS water flooding was similar in magnitude to that observed in the LS water effluent (Figure 5.a).

Scenario#2:

The secondary and tertiary oil recovery was similar to that observed in **Scenario#1**. The ultimate oil recovery during FW flooding was 41.8%, while it increased by 2.7% of OOIP with LS water flooding. As pointed out previously, this scenario injected 0.5 PV steam + 1 PV LS water + 0.5 PV steam + 1 PV LS water. There was no additional recovery during the first and second steam flooding. The first LS water flooding caused an additional oil recovery of 2.6%, while the second LS water cycle (after steam flood) increased the recovery up to 10.6% of OOIP providing a total recovery of about 57.8% of OOIP. This recovery was greater than in **Scenario#1** (48.4%) with the same injection of pore volume as in **Scenario#1** (7 PV) (Figure 3.b). The injection pressure and pH were quite similar as in **Scenario#1**.

The injection pressure readings (Figure 4.b) during the FW were the higher among the other readings due to the heavy oil displacement. The pressure was 406 psi during FW flooding until reaching 178 psi and then stabilized at that magnitude. During LS water flooding the injection pressure started to decline until it stabilized at 105 psi. The injection pressure was kept at the same tone for the next cycle steam + LS water flooding.

Figure 5.b shows a significant pH jump with LS water and steam + LS water flooding, likely from ion exchange. The pH behavior and magnitude were similar to that in **Scenario#1**.

Scenario#3:

The injected pore volume in this scenario was half of the injected pore volume in **Scenario#2**. The injected pore volume design was 0.25 PV steam + 0.5 LS water + 0.25 steam + 0.5 LS water. As depicted in Figure 3.c, secondary water injection resulted in a 40% oil recovery of OOIP. The incremental oil recovery was 2.8% of OOIP. After injecting 0.25 PV of steam, no additional oil recovery was observed. The injected 0.5 LS water increased the recovery by 8% of OOIP. No increased oil recovery was observed during the first steam injection, while the second LS water flooding added an additional recovery of 11.9% of OOIP. Figure 4.c shows a normal pressure trend with injected pore volume compared with the previous scenarios.

Scenario#4:

The flooding procedure differs from the previous scenarios by huffing steam to the core after the secondary and tertiary processes. The steam was huffed by 0.9 PV for half an hour and then puffed, and the procedure then was 0.5 LS water + 0.5 steam + 0.5 LS water injected. The oil recovery by injecting FW was 42% OOIP, while the incremental oil recovery was 3% of OOIP when switching from FW to LS water. During the huffing process, the core holder was closed from two ends. The incremental ultimate oil recovery was 7% of OOIP during first LS water flooding (after huff and puff). After injecting 0.5 PV steam, the additional recovery was 2% OOIP. Upon switching the injection fluid to LS water, and after injecting 0.5 PV of LS water, the incremental oil recovery was 6% OOIP (Figure 3.d). The pressure readings were much lower than the other scenarios because of the huffing process, which led to a decrease in the viscosity of oil (Figure 4.d). The pH observation was similar to that in other scenarios (Figure 5.d).

It can be observed from the four scenarios, the shorter the flood cycles, the greater the oil recovery. The total injected pore volume in **Scenarios#1** and **2** was 7 PV, while it was 5 PV in **Scenarios#3** and **4**. Even though the pore volumes were greater in both **Scenarios#1** and **2**, the total oil recoveries were smaller than in **Scenarios#3** and **4**. The short cycles of steam and LS water provided a thermal expansion to the oil in addition to reducing oil viscosity. The larger cycles provided reducing oil viscosities only; for that reason, the recoveries were smaller in **Scenarios#1** and **2**. When comparing **Scenario#1** and **Scenario#2**, **Scenario#2** had a larger recovery due to the double cycles of steam and

LS water flooding. The total oil recovery from **Scenaro#1** was 50%, while it was 57.8% OOIP from **Scenario#2**. It is likely that **Scenario#3** had an oil recovery greater than in **Scenario#2** due to reducing the injected pore volumes, although the cycles were in the same manner because a thermal expansion of the oil was provided. The total oil recovery from **Scenario#3** was 62.3% of OOIP. **Scenario#4** had an oil recovery close to that in **Scenario#3**. The total oil recovery was 60%. Huffing steam to the core helped to reduce oil viscosity much more than just flooding the steam as in the other scenarios. Comparing **Scenario#4** with **Scenario#2**, the procedure and the injected pore volume were similar, but the recovery was greater in **Scenario#4** because of the steam huff effect. However, the proposed scenarios improved the vertical conformance of injected steam, but in different ranges.

Conclusion

Coupling LS water flooding with steam is a feasible technique for improving heavy oil recovery. This combination technology can resolve the steam problems and alter the steam by using LS water, which has the ability to increase oil recovery. Steam can reduce oil viscosity. LS water can alter the wettability towards more water-wet. The results of this work showed significant additional oil recoveries after the cores reached the residual oil saturation. The interesting and promising results show that we can obtain up to 15% recovery of original oil in place after the secondary and tertiary treatments. This novel method could stop production of uneconomical steam by altering the steam with LS water. The fuel consumption could also be minimized by applying this technique.

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Nomenclature

LSASF: Low Salinity-Alternating-Steam Flooding

IS: Ionic strength

Mono ions: Activity coefficient for monovalent ions

Diva ions: Activity coefficient for divalent ions

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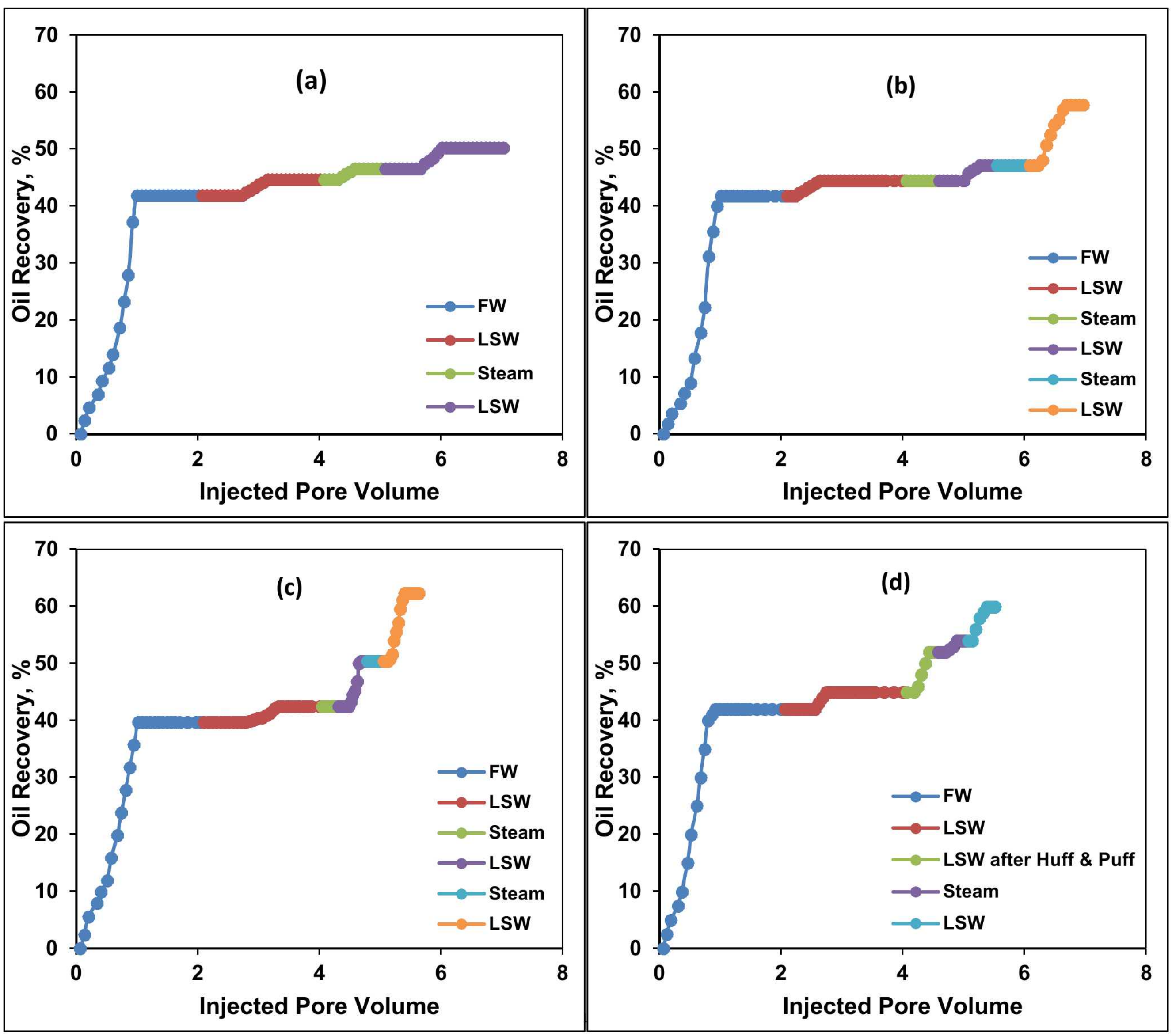

Figure 3—Oil recovery (a) Scenario#1 (b) Scnario#2 (c) Scenario#3 (d) Scenario#4.

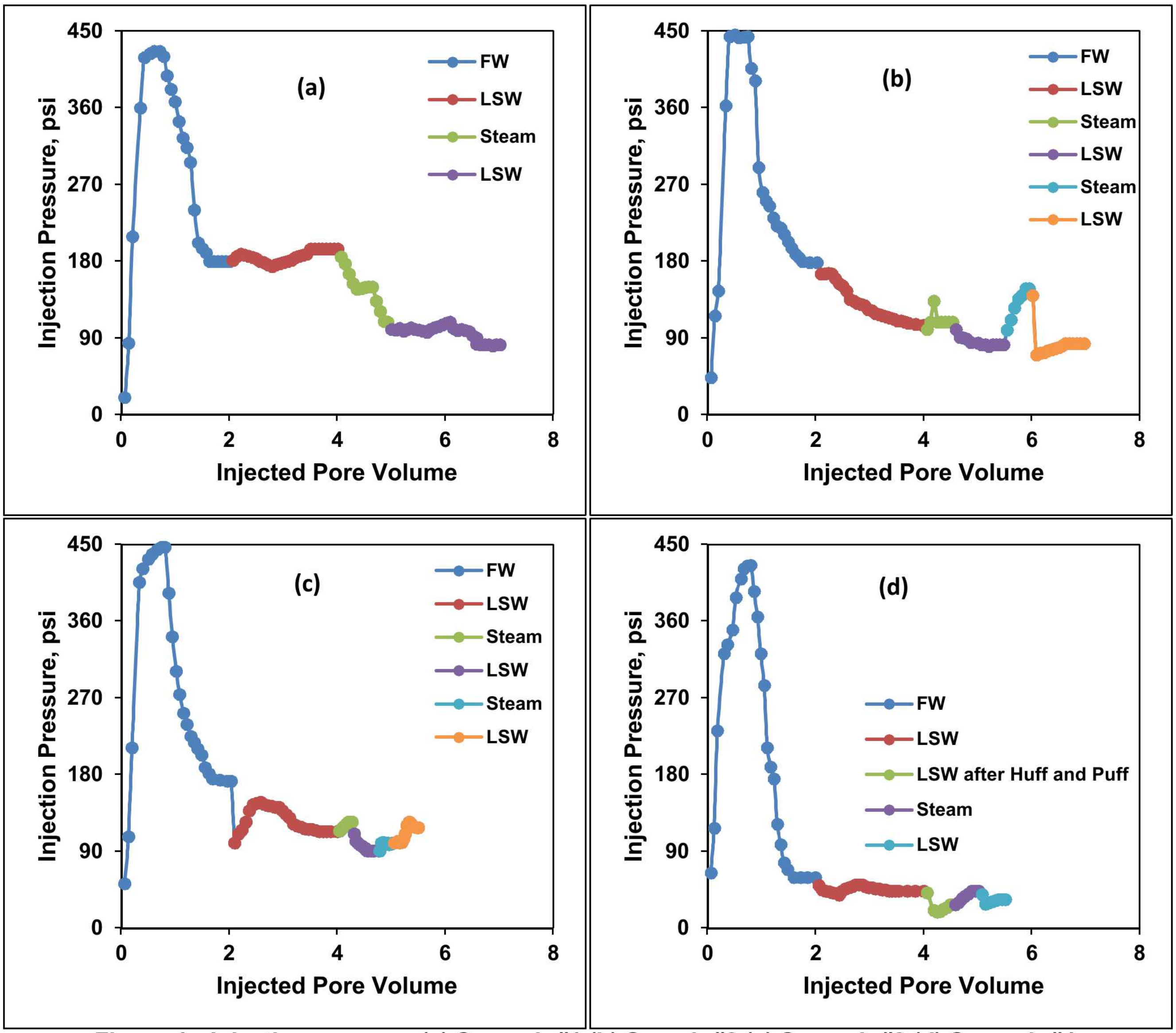

Figure 4—Injection pressure (a) Scenario#1 (b) Scnario#2 (c) Scenario#3 (d) Scenario#4.

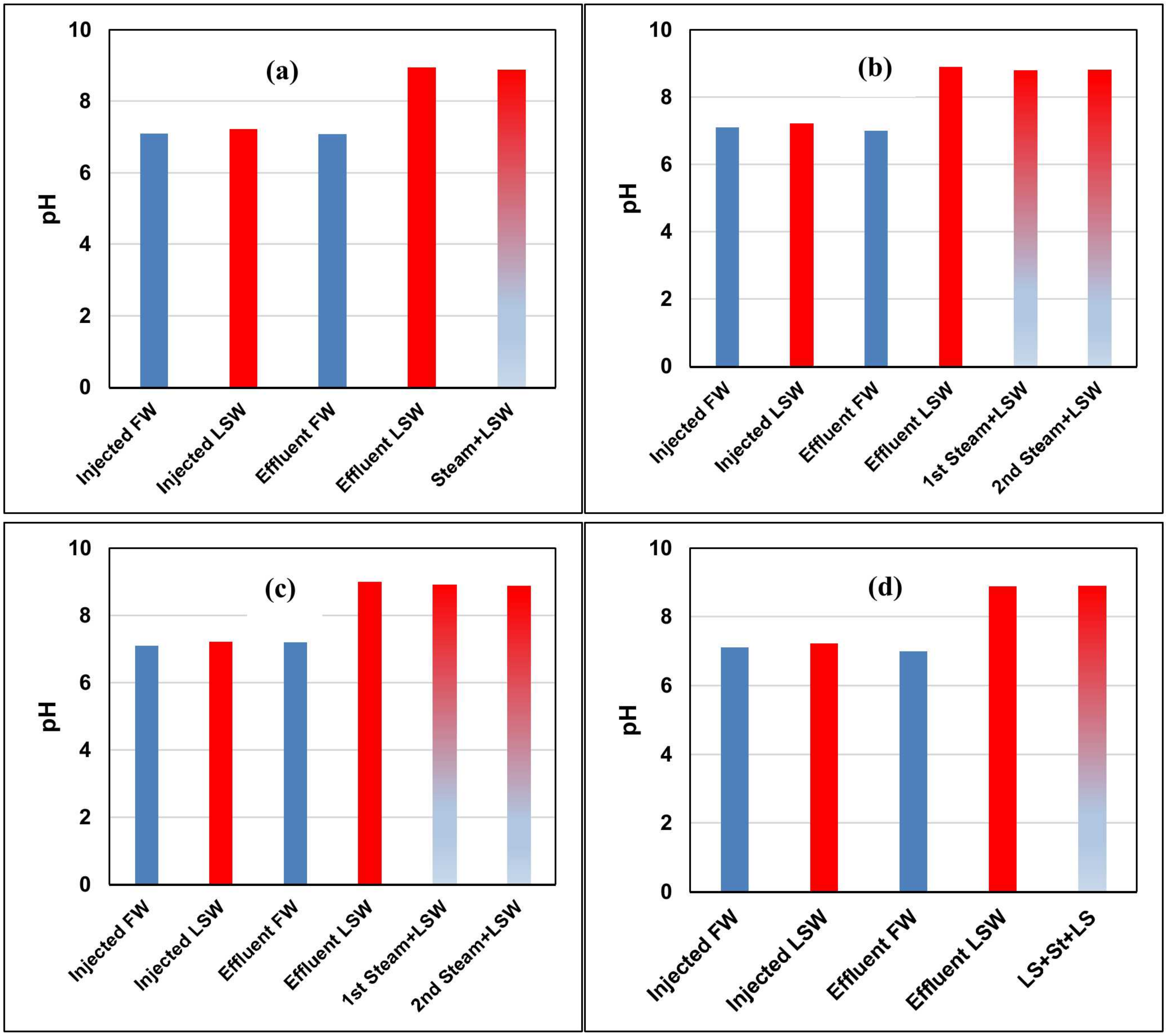

Figure 5—Injected and Effluent pH (a) Scenario#1 (b) Scnario#2 (c) Scenario#3 (d) Scenario#4.