# An Influence of Polymer-Alkaline and Nanoparticles as Chemical Additives on the Immiscible Displacement and Phase Relative Permeability

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## Abstract

In this study, a chemical additive made by a combination of polymer, alkaline, and silica nano particles is used to control the oil recovery and relative permeability curves. Various parameters including the type and concentration of polymer, alkaline, and nanosilica particles have been studied. To evaluate the efficiency of these additives, we performed unsteady state displacement experiments under the JBN method and determined the pressure gradient across the core samples. The experimental observations emphasized that by using the appropriate chemical additives the relative permeability of the phases is changed towards higher oil relative permeability values, which results in the oil recovery. The results of this study can improve the chemical flooding for heavy oil recovery.

## 1. Introduction

Excessive water production in oil and gas producing wells are attributed to the higher mobility of water relative to oil which causes high water saturation near the well bore during the producing life of the reservoir (Zaitoun et al., 1991-a). Water production in producing wells can be controlled by using additives which either can form permanent barriers to stop the flow of all fluids, e.g. cements, plastics or silicate gels (Krumrine & Boyce, 1985), and polymeric gels (Liang et al., 1992; Zaitoun et al., 1991-b)or do not require the isolation of zones between water and hydrocarbon, e.g. poly-acryl amides and polysaccharides (Zaitoun & Kohler, 1988; Zaitoun et al., 1991-a; White, 1973).

Detling (1944) tried to improve sweep efficiency in water-flooding process. He presented some water-soluble polymers to improve the viscosity of water. Over the past two decades, 25 additive types, which were usable in various reservoir conditions, were recorded. The first experimental results of using additives to improve the displacement were published in 1964 by Sandifor and Pye. Because of the low cost of water-soluble polymers, these are preferred to other additives such as molasses, glycerin and glycol. Successful reports of field and laboratory applications of water-soluble polymer highlight the polymer flooding as an enhanced oil recovery method (Marker, 1973; Mungan et al., 1966; Gogarty, 1967).

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However, the ionic portion of polymers causes the adsorption on the rock surface, which reduces the permeability of the reservoir rock and thus solution viscosity is reduced. Hence the application of polymer flooding alone is an inefficient method for heavy oil recovery from oil reservoirs. An efficient technique for heavy oil recovery is to design and use a fluid that has the following characteristics ( Wu, 2011): (1) the improvement in the mobility ratio by increasing the viscosity of the displacing solution, and (2) the reduction of interfacial tension (IFT), between oil and the displaced fluid and the creation of an emulsion of oil in brine. To increase the viscosity of the fluid, water-soluble polymers can be used, but this material does not affect the surface tension between oil and displacing fluid.

Moreover, many studies have been reported on improving heavy oil recovery by using chemical fluids containing alkaline materials. The consequence of alkaline addition is oil/alkali interaction, i.e. emulsification, or alkali/rock interaction, i.e. wettability alteration or chemical precipitation due to the interaction with hardness ions in reservoir water (Mayer, 1983) . For example, Atkinson believed that alkaline solutions overcame the pore scale forces and released the residual through a combination of oil, wettability change, and oil–water interfacial tension reduction (Atkinson, 1927).

Mungan (Mungan, 1966) reported laboratory results on wettability effects on caustic flooding. He found that the process worked at 160°F but not at 70°F for the type of crude oil used. Moreover, the water relative permeability became lower after caustic wettability change (Bagci and Turksoy, 2000).

Cooke et al. (Cooke et al., 1974) reported an improvement in water flood oil recovery by using a right combination of caustic and salt. They observed that at a specific pH, salinity, and temperature, the sample converted from water-wet to oil-wet.

Jennings et al. (Jennings et al., 1974) experimentally observed that the mechanism of emulsification and entrapment results in a reduced water mobility and improves both vertical and areal sweep efficiencies particularly in water flooding of viscous oil.

These studies emphasize that alkaline flooding is a complex oil recovery process and tends to be site-specific in terms of process design and dominant recovery mechanism. Johnson (Johnson, 1976) summarized published field data and described the technology. From 1975 to 1979, a number of alkaline field tests were conducted and later to 1981, 41 alkaline flood projects were certified (Bagci, & Turksoy, 2000).

The combination of alkaline and polymer in flooding adds the following properties: (1) alkaline-polymer can reduce the polymer adsorption. It also results in a decrease in alkaline consumption; (2) the presence of polymer in alkaline-polymer solution makes the solution more viscous; (3) the resulting environment may affect the biodegradation process, and (4) the reduction of polymer viscosity due to the presence of alkaline can enhance the fluid injection (James, 2011).

Moreover, the knowledge of nanotechnology can be beneficial in the enhanced oil recovery (EOR). As an example, $SiO_2$ nanopowder can boost hydrophobicity and lipophilicity and affects the rock surface adsorption, and it has a potential to change the rock wettability. It can also reduce the flow resistance between two phases (IFT), enhance oil effective permeability, and reduce injection pressure (Ogolo, 2012; Ju et al., 2006). The effect of this additive on the recovery of light oil in sandstone oil fields showed that increasing the hydrophilic material (HLPN) increased oil recovery compared to water flooding (Ju et al., 2012). Maghzi et al. (2010), studied the effect of silica nanoparticles (HLPN) on polymer flooding for heavy oil reservoirs, which resulted in a 10% increase in oil recovery (Maghzi et al., 2010). Moreover, Parvazdavani et al. studied the effect of silica nanoparticles addition on changing wettability to water-wet and the reduction of the IFT (Parvazdavani et al., 2012). Onyekonwu et al. (2010) investigated the effect of polysilicon nanoparticles (e.g. lipophobic and hydrophilic PSNP (LHPN), hydrophobic and lipophilic PSNP (HLPN), and neutrally wet PSNP

(NWPN)) on oil recovery. They concluded that the wettability alteration and IFT changes are two factors in the NWPN and HLPN flooding (Mike and Naomi, 2010).

In this study, we investigate the effects of the polymer, alkaline, and silica nanoparticles on the relative permeability behavior of oil-polymer, oil– alkaline/polymer, oil-nanosilica/polymer, and oil-alkaline/nanosilica/polymer. Various chemical flooding samples, including polymer, alkaline-polymer, nanopolymer, and alkaline-nanopolymer were designed. The impacts of polymer, alkaline, nanosilica particles on the displacement processes were then examined both in the polymer solution and in the suspension of nanoparticles in an alkaline-polymer solution.

## 2. Experimental setup

The relative permeability measurement method conducted in this study is based on the unsteady methods. Benchtop relative permeameter (BRP 350) has been used for core flooding tests (Vinci Technologies). The system was designed to conduct two-phase (e.g. oil, water, and gas) relative permeability measurements using the unsteady state method. It consists of an injection system, two piston accumulators, a core-holder, a back pressure regulator, an overburden pressure system, a pressure differential measurement system, optionally a video tracker, and the computer system for data acquisition and process control. The injection system consists of a fluid delivery high performance liquid chromatography (HPLC) pump which injects distilled water under transfer vessels in order to inject oil and water at the desired rates. A core holder with a rubber sleeve was used for confining the core. It has separate ports for pressure drop measurements. The core is usually wet-packed and then confined by applying tri-axial stresses. The oil and water are discharged through the back pressure regulator (BPR) and transferred to a U-shape burette. The volume of oil and water base fluid are determined and recorded dynamically by using video tracker. In the procedure of recording the effluent volumes, the system records the differential pressure dynamically across the core by low and high pressure range differential pressure transducers. The operation of core displacement system is controlled through a computer interface. A schematic diagram of the connections in the core displacement apparatus is shown in Figure1.

The physical properties of the reservoir rock sample and the oil used in the experiments are given in Tables 1 and 2. Cores samples with different porosity and permeability have been considered for this work; however, only one sample core given in Table 1 with good porosity and permeability properties for the injection of polymer based solutions in the experimental setup conditions has been used. To prepare chemical solutions, partially hydrolyzed polyacrylamide and a composite polymer (produced by the combination of hydrolyzed polyacrylamide and sulfonated polyacrylamide with the same weight percent) have been selected. Sodium carbonate and sodium hydroxide are used as alkaline and nanosilica as nanoparticles. The properties of these materials are given in Tables 3 and 4.

## 3. Test procedure

To start each experimental run, we first solvent-cleaned the core sample by using toluene and ethanol, dried with hot nitrogen, evacuated, and placed in a high-temperature oven for a reasonable time period. This is to eliminate the effects of the phase hysteresis happening during previous core flooding.
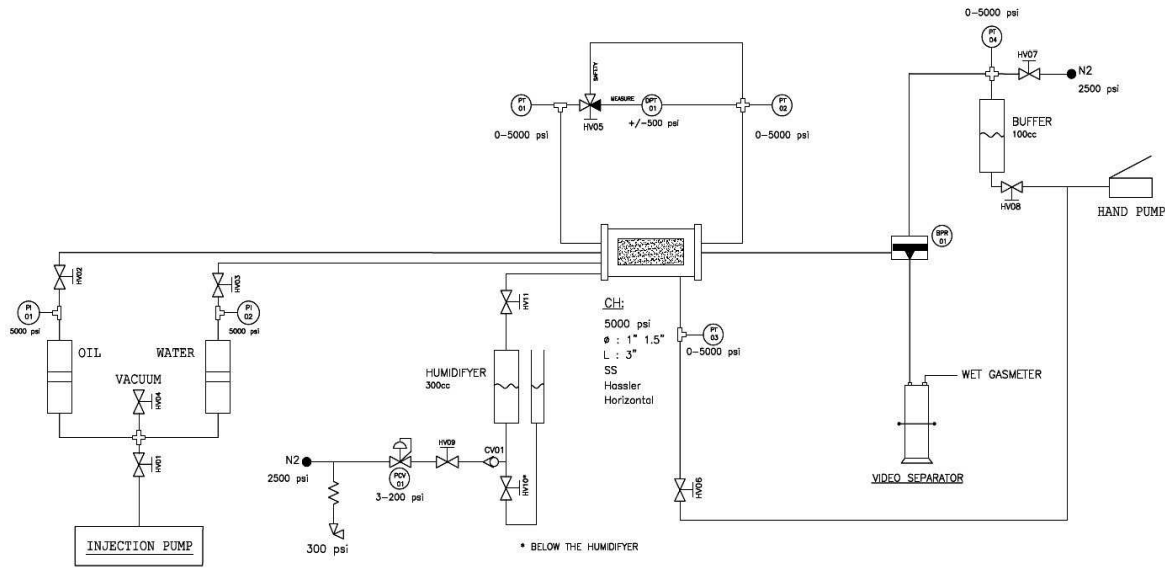
**Figure 1**
A schematic of the core flooding system (Vinci Technology)**.**

**Table 1**
Rock physical properties.

| Rock type | Diameter (cm) | Length (cm) | Porosity (%) | Absolute Permeability (mD) | Pore Volume (cc) | Initial water saturation (%) |
|---|---|---|---|---|---|---|
| Sandstone | 3.8 | 3.308 | 15 | 35.7 | 5.63 | 23 |

**Table 2**
Oil sample properties.

| Oil type | API degree | Viscosity at standard condition (cP) | Density at standard condition (gr/cc) |
|---|---|---|---|
| Dead oil from Bangestan reservoir | 22 | 83 | 0.919 |

**Table 3**
Polymer properties.

| Polymer Type | Molecular weight (million Daltons) | Hydrolysis percent (%) | Sulfonation percent (%) | Apparent viscosity in 80°C (dl/gr) | Diameter (μm) |
|---|---|---|---|---|---|
| HPAM 3530s | 16 | 25-30 | 0 | 19.03 | 0.458 |
| AN 113 | 8 | 0 | 13 | 20.51 | 0.373 |

**Table 4**
Nanoparticles properties.

| Type | Average particle size (nm) | Specific surface area (BET) (m$^2$/gr) | Tamped Density (gr/l) |
|---|---|---|---|
| SiO$_2$ | 14 | 200±25 | ~50 |

As we have only one core sample with suitable properties for core flooding, we have repeated the previously mentioned preparation tests before the new test. When core preparation was completed, the

core sample was saturated with the brine of salinity 10000 ppm (NaCl) within the saturator apparatus. Then, the sample porosity was measured from the weights of the dried and wetted samples. Moreover, we measured the absolute permeability of the core. Afterwards, oil injection rate was set at 0.15 (cm$^3$/min) and the injection continued up to 5 pore volume (PV) to reach the condition of irreducible water saturation. The measured irreducible water saturation value ($S_{wc}$) for the core sample was 0.23. After this step, the chemical fluid was injected at the rate of 0.15 (cm$^3$/min) and the amount of oil and chemical fluid produced were measured dynamically. This was achieved by using a camera tracker. Based on the data available on pressure drop and produced volumes, relative permeability calculations were performed. We used mass balance calculations to determine the phase saturations. Afterwards, we were able to draw the relative permeability against phase saturation. The injection pressure, which was controlled by the BPR, was set at 650 psia. All of the tests have been performed at the ambient temperature (i.e. 23°C) and atmospheric pressure.

## 4. Relative permeability calculation method

The calculation of the phase relative permeability was based on the JBN method, which is an unsteady state displacement based on the Buckely-Leveret theory (Johnson et al., 1959). There are two main assumptions for the validity of this method. Firstly, the velocity of the fluid flow should be high enough to reach equilibrium, and secondly, the velocity should be constant at any cross section of the core. To satisfy these assumptions, the dimensionless capillary number has to be tested at the laboratory conditions. Due to the condition of capillary dominancy, the flow in the core flood test is not capillary dominant (Element et al., 1998).

Moreover, we ignore the gravity effects as the core holder was horizontal. As mentioned before, we have used the JBN method to get the relative permeability results. This method determines the relative permeability curves based on Equation 1. The terms $W_i$ and $I_r$ are determined by using Equations 2 and 3 (Johnson et al., 1959).

$$\frac{d\left(\dfrac{1}{W_i I_r}\right)}{d\left(\dfrac{1}{W_i}\right)} = \frac{f_o}{K_{ro}} \tag{1}$$

$$W_i = \frac{1}{f'} = \frac{1}{df/ds} \tag{2}$$

$$I_r = \frac{u/\Delta P}{u_s/\Delta P_s} \tag{3}$$

$$K_{rw} = \frac{1-f_o}{f_o}\frac{\mu_w}{\mu_o}K_{ro} \tag{4}$$

The relative permeability functions were determined by using the outlet invading phase saturation that can be obtained by using Equation 5 (Johnson et al., 1959).

$$S_2 = S_{ave} - W_i(f_o) \tag{5}$$

where $f_o$ is the fractional flow of oil, and $W_i$ is the cumulative invading-phase injection volume; $I_r$ is the injectivity capacity, and $u$ stands for the flowing velocity; $\Delta P$, $\mu_w$, $\mu_o$, $K_{ro}$, and $K_{rw}$ represent pressure drop, the viscosity of water, the viscosity of oil, a relative permeability of oil, and a relative permeability of water respectively.$u_s$ and $\Delta P_s$ are the values of $u$ and $\Delta P$ at the start of injection. Furthermore, $S_{ave}$ and $S_2$stand for the average and outlet saturation respectively.

## 5. Results and discussion

The experiments conducted in this study can be classified into four series. In the first series of experiments, the influences of polymer type and concentration on the two-phase flow relative permeability curves for oil and polymer solutions are studied. The second series of the experiments is to investigate the effect of type and concentration of the alkaline on the two-phase relative permeability curves. In the third series, the effect of nanoparticles concentrations on the relative permeability curves is studied. Finally, in the fourth series of the experiments, the effect of concentration of silica nanoparticles in alkaline/nano/polymer solutions on the relative permeability curves is investigated.

### 5.1. Polymer solution injection

Experiments in this part include:

(1) The injection of hydrolyzed polyacrylamide (HPAAM) solution at a concentration of 500 ppm and a viscosity of 7.23 cP.;

(2) The injection of composition polymer at a concentration of 500 ppm and a viscosity of 5.5 cP; and

(3) The injection of hydrolyzed polyacrylamide solution at a concentration of 1000 ppm and a viscosity of 23.42 cP.

The previous experimental investigation emphasized that the optimum oil recovery in this flooding is observed at polymer concentrations up to 1000 ppm (Mike and Naomi, 2010). This leads us to starting the experimental design with polymer solutions at a concentration of 1000ppm. However, this result in a relatively high oil recovery factor from the core plug sample (see Figure 16 for the recovery of about 70%).

To access the uncertainty in the results due to the small plug size and polymer concentration, we also decided to repeat the test at a concentration of 500 ppm. The first and second experiments are then compared to see the effect of the polymer types (Figure 3). Moreover, the first and third experiments are compared to show the effect of polymer concentration (Figure 4). Since the viscosity of the solutions is different, to compare the results of the experiments, the normalized values of the parameters will be used according to Equations 6 and 7:

$$K_{r,norm} = \frac{K_r}{K_{r(max)}} \tag{6}$$

$$S_{w,norm} = \frac{S_w - S_{w(min)}}{S_{w(max)} - S_{w(min)}} \tag{7}$$

Figure 2 shows that in laboratory conditions hydrolyzed polyacrylamide have a greater ability to oil swept. Indeed, sulfonated polymer will be effective at high reservoir temperatures and in the presence of formation water (Torkaman, 2011).
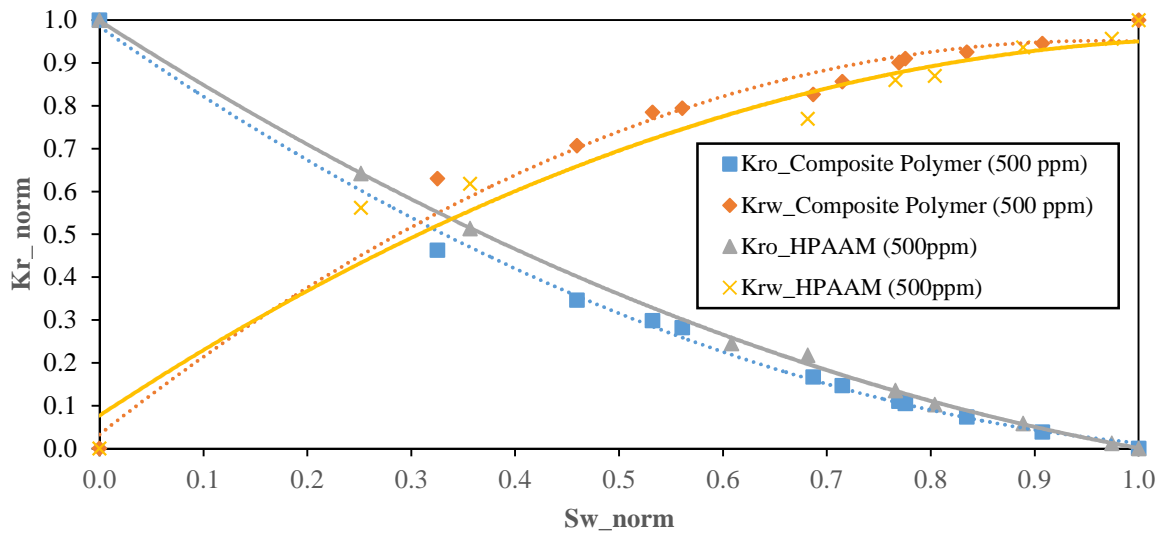
**Figure 2**
The effect of polymer type on the relative permeability curves.

As can be observed from Figure 3, an increase in the polymer concentration causes an improvement in the oil relative permeability at intermediate–to-high wetting phase saturations. This is in line with the previous publications on the enhancement effect of polymer concentration on the oil displacement (Barrufet and Ali, 1994; Zaitoun et al., 1991-a). A justification for a better displacement is possibly due to the increase in the viscosity of polymer solution. Moreover, the water relative permeability behave similarly at intermediate–to-high wetting phase saturation (e.g., $S_{w\text{-norm}} > 0.6$) showing that it is independent of the polymer concentration in the polymer solution; however, at lower wetting phase saturation (e.g., $S_{w\text{-norm}} = 0.4$) the water relative permeability drops at a polymer concentration of 1000ppm. This also helps further oil recovery.
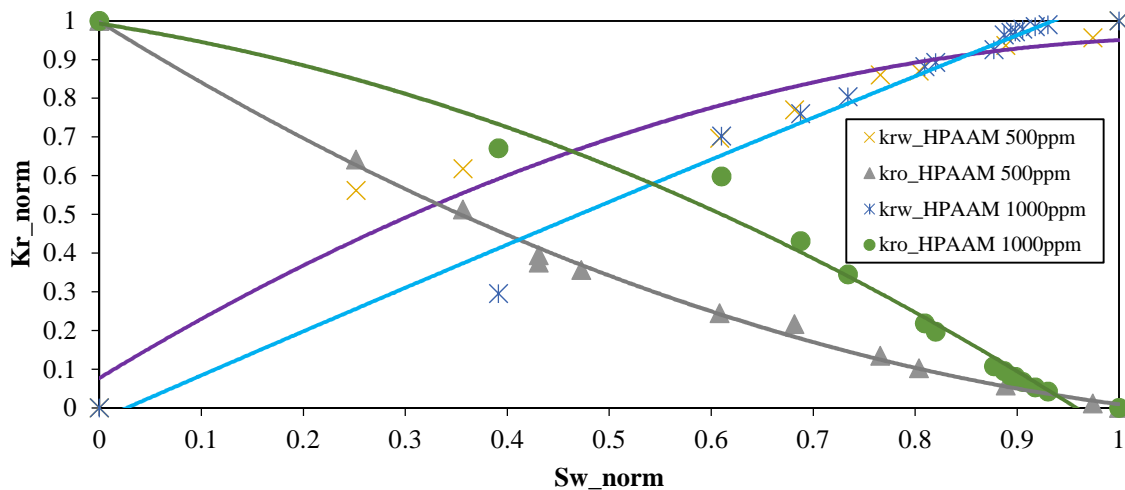


**Figure 3**
The effect of polymer concentration on the relative permeability curves.

It should be emphasized that the relative permeability is plotted against the wetting phase normalized saturation instead of the wetting phase saturation itself as was expected (as also shown in Figure 3). This is to observe the changes in the two phase relative permeability curves

more clearly; the same idea was also used in the literature (Parvazdavani et al., 2012; Bennion and Thomas, 1991)

Figure 4 compares the pressure gradient across the core sample in this series of experiments. At the start of injection, the initial pressure gradient increases, and after reaching the breakthrough point pressure, gradient fell until reaching a constant value. In addition, as the viscosity of the polymer solution increased, the pressure required to inject the solution into the core rose.
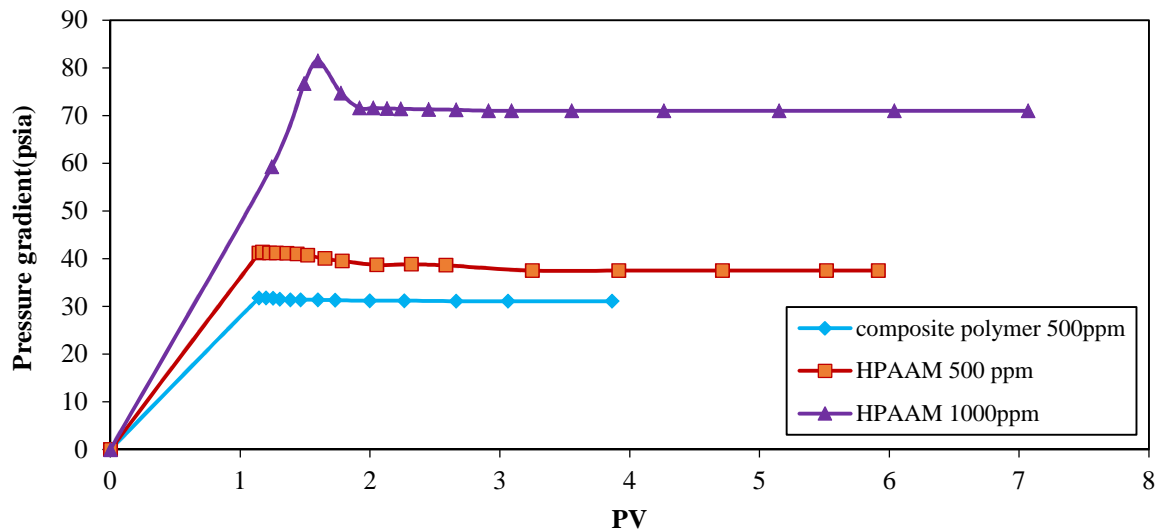


**Figure 4**
The change in the pressure gradient across the core during polymer solution injection experiments.

## 5.2. Alkaline/polymer solution injection

In this series of experiments, the following tests were considered to investigate the effect of alkaline type and concentration in alkaline/polymer solution:

(1) The injection of a solution of composite polymer (500 ppm) and sodium carbonate ($Na_2CO_3$) at the concentration of 1 wt.%;

(2) The injection of a solution of composite polymer (500 ppm) and sodium hydroxide (NaOH) at the concentration of 1 wt.%;

(3) The injection of a solution of composite polymer (500 ppm) and sodium hydroxide (NaOH) at the concentration of 0.5 wt.%.

The previous experimental investigation emphasized that the optimum oil recovery in this flooding is observed at sodium hydroxide concentrations up to 1-2 wt.% (Mike and Naomi, 2010). This leads us to starting the experimental design with an alkaline concentration of 1 wt.%. This resulted in a relatively high oil recovery factor (about 73%) from the core plug sample. To evaluate the uncertainty in the results due to the small plug size and alkaline concentration, we also decided to use a lower alkaline concentration of 0.5 wt.%.

Figure 5 shows the effect of alkaline on the relative permeability curves. Adding alkaline to the polymer solution has two obvious effects on the relative permeability curves for oil and aqueous phases**.** The first observed effect is the displacement of the intersection point of two relative permeability curves. By adding alkaline to the polymer solution, the intersection point becomes close to the normalized saturation of 1, which indicates the strong water-wet condition; however, in this

case, because of interfacial tension effects on the flow pattern, we cannot say that this phenomenon is only due to the wettability changes. The second effect is concavity shift of the aqueous phase relative permeability curve. The reason for this change can be due to the alkaline effect on the interfacial tension between fluids.
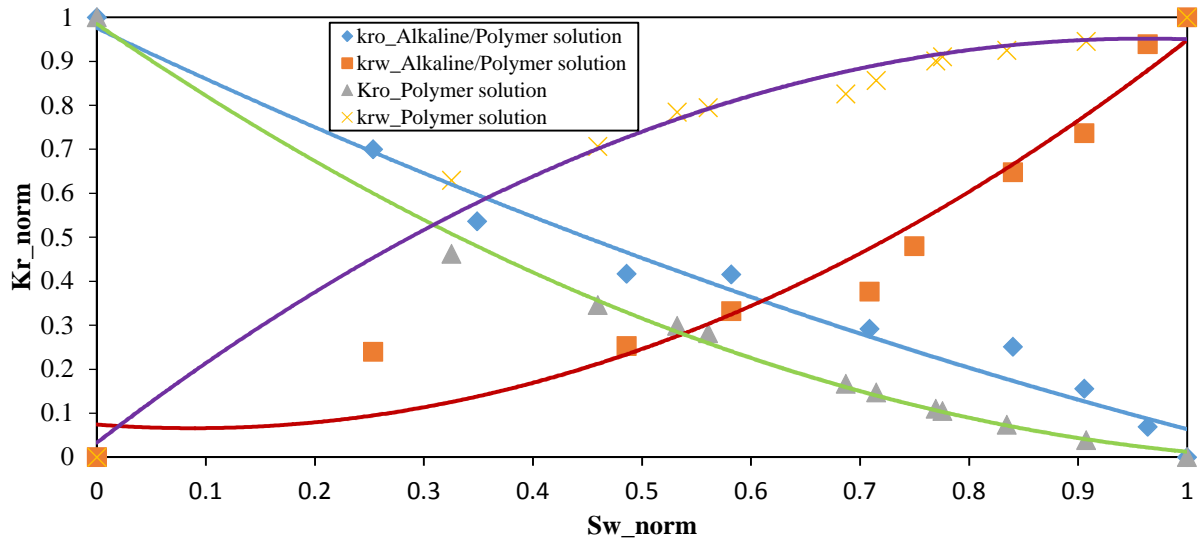


**Figure 5**
The effect of alkaline on the relative permeability curves.

Figure 6 shows the effect of alkaline type on the relative permeability curve. The comparison of the curves shows that sodium hydroxide is a stronger alkaline compared with sodium carbonate, and it has a greater ability to swept oil in place because oil relative permeability curves increase and the relative permeability of aqueous phase is reduced. In addition, the oil relative permeability curve endpoints are higher in the injection of a solution containing sodium hydroxide, which is an affirmation of the higher power of sodium hydroxide compared to sodium carbonate.
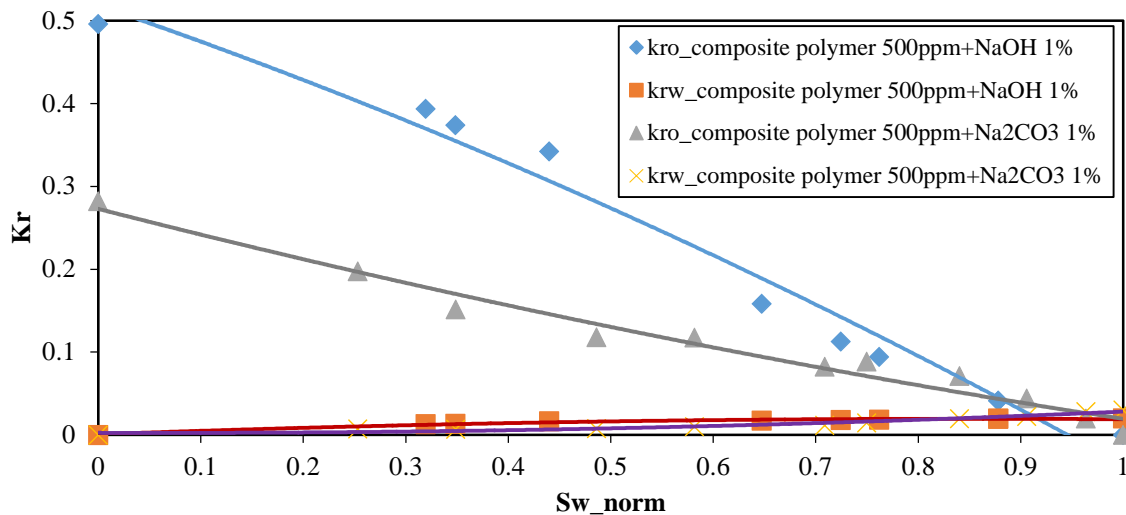


**Figure 6**
The effect of alkaline type in alkaline/polymer solution on the relative permeability curves.

Figure 7 shows the effect of alkaline concentration on the relative permeability curves. With increasing the concentrations of sodium hydroxide dissolved in alkaline polymer solution the ability of solution to enter smaller pores increases, which results in increased oil swept.
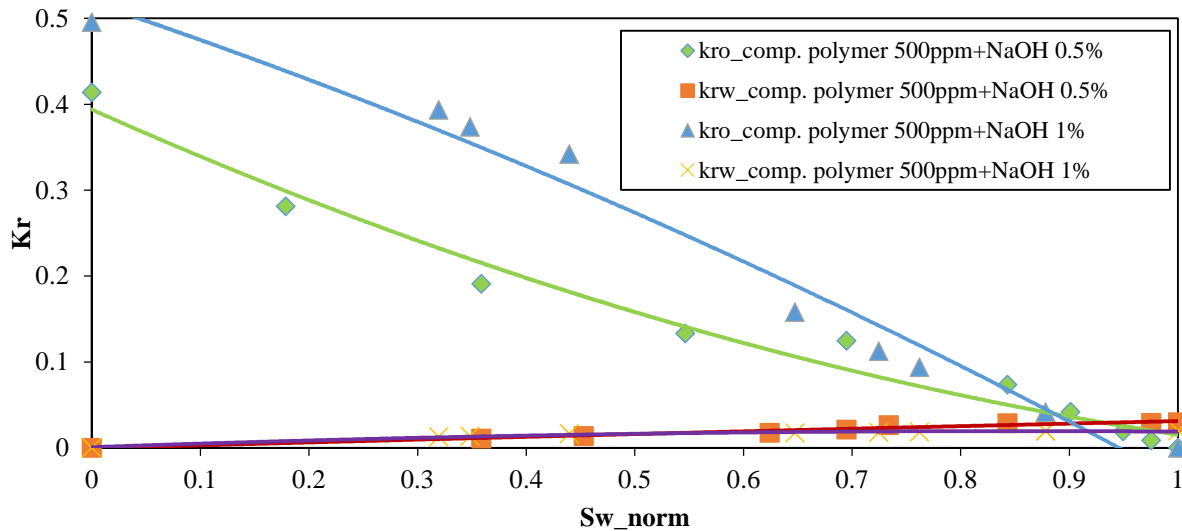


**Figure 7**

The effect of alkaline concentration in alkaline/polymer solution on the relative permeability curves.

Figure 8 displays the change in the pressure gradient between the core outlets. At the start of injection, pressure gradient increases initially and drops after reaching the breakthrough point; however, after a while, it grows again. This increase may be due to the adsorption of alkaline on the rock surface and probably due to plugging the pores. With increasing concentrations of alkaline and alkaline strength, the time of pressure gradient reduction is shorter and consequently, the final pressure gradient increasing rate will be more severe.
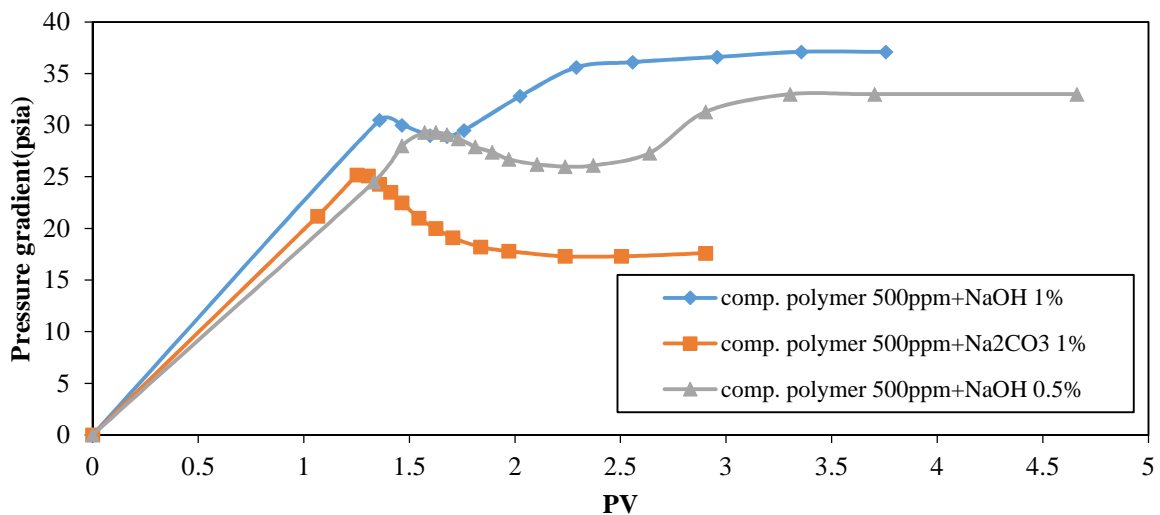


**Figure 8**

The change in the pressure gradient across the core in alkaline/polymer solution injection experiments.

### 5.3. Injection of nanosilica suspension in polymer solution

In this series of experiments, to investigate the effect of silica nanoparticles concentration in the injection of silica nanoparticle suspensions in polymer solution, the following tests were considered:

1  The injection of composite polymer (500ppm) and nanosilica at a concentration of 0.1 wt.%, and

2  The injection of composite polymer (500ppm) and nanosilica at a concentration of 0.2 wt.%.

The previous experimental results emphasized that the optimum amount of the nanoparticles is of 3g/l less (Mike and Naomi, 2010). Hence, in the experimental design for this study, we used two concentrations in this range. Figure 9 shows the effect of adding silica nanoparticles to the solution on the relative permeability curves. Adding nanoparticles to the polymer solution affect the intersection point of two relative permeability curves and the concavity direction of the aqueous phase relative permeability curve. Therefore, these curves are similar to the ones obtained from the injection of alkaline/polymer solution; thus we can state that silica nanoparticles, similar to alkaline materials, affected the wettability of reservoir rock and the interfacial tension between reservoir fluids.
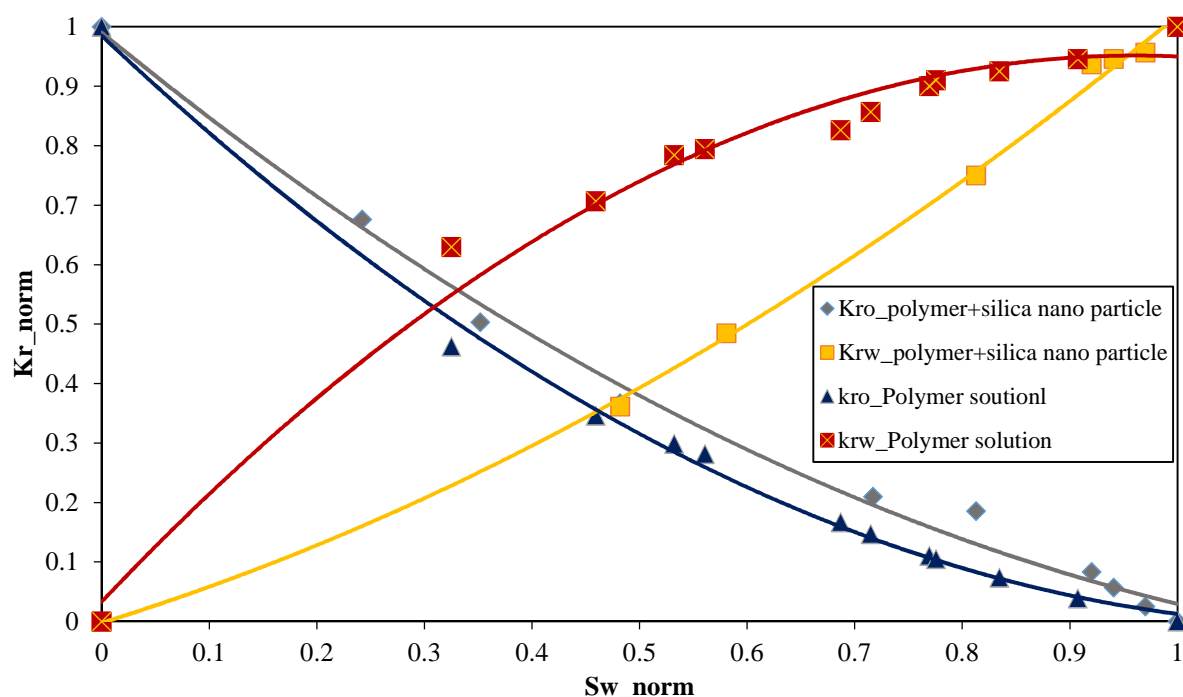


**Figure 9**
The effect of nanoparticles on the relative permeability curves.

Figure 10 illustrates how the concentration of silica nanoparticles affects the relative permeability behavior. This emphasizes that there will be no significant change in the oil recovery and relative permeability curves. An observed slight change is probably due to the phase hysteresis caused by plugging some pores in the previous experiments.

Figure 11 shows the change in the pressure gradient between the two ends of the cores. At the start of injection, similar to the previous cores, the pressure gradient first increases, remains unchanged for a short time after reaching the breakthrough point, and then again continues to increase. This increase may be due to the adsorption of silica nanoparticles on the rock surface, and thus possible pore plugging. The pressure gradient, in the second test, has changed significantly. Due to the constant production conditions in these experiments, as well as more pressure gradient in the second

experiment, we can state that increasing the silica nanoparticles only increases the adsorption and does not affect the output results.
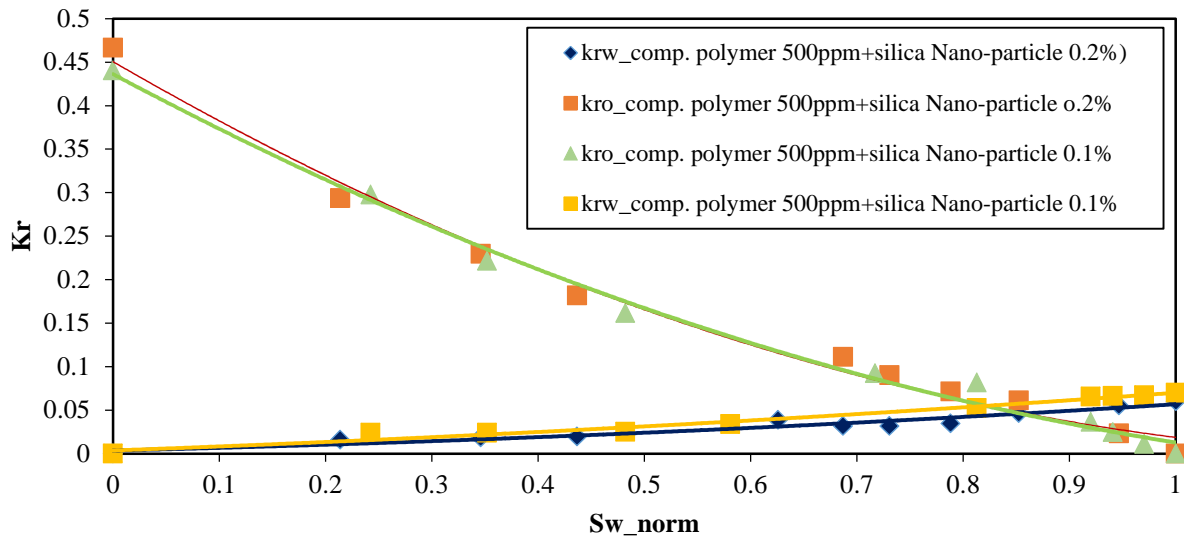


**Figure 10**
The effect of silica nanoparticle concentration on the relative permeability curves.
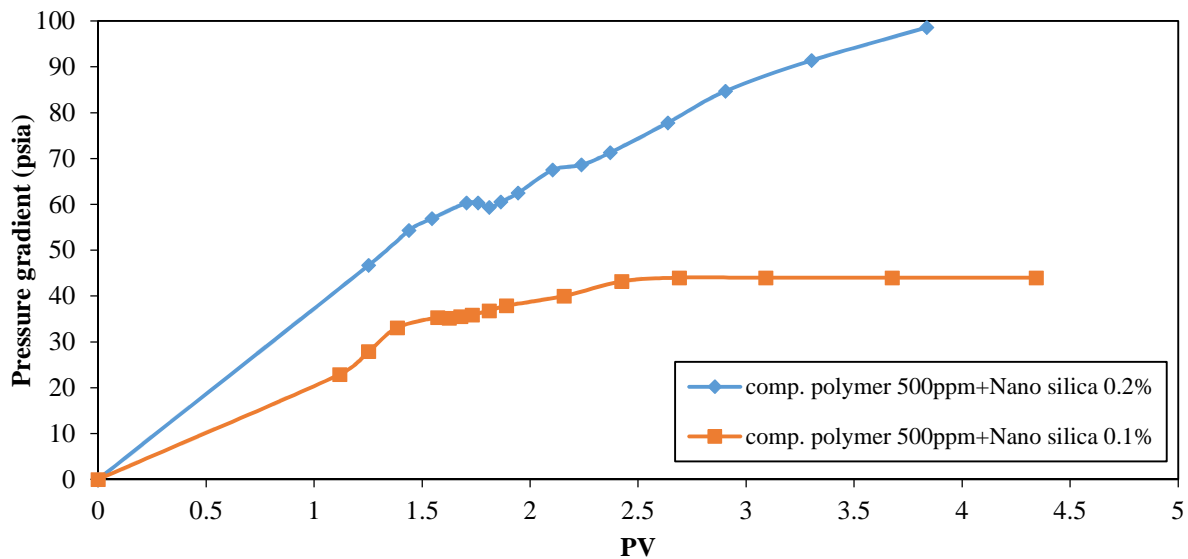


**Figure 11**
The change in the pressure gradient across the core in the injection experiments containing silica nanoparticle suspensions in a polymer solution.

## 5.4. Injection of nanosilica suspension in an alkaline-polymer solution

The experiments in this series of tests include (1) injecting a solution of composite polymer (500ppm), sodium carbonate (1 wt.%), and silica nanoparticles at a concentration of 0.1 wt.%, and (2) injecting a solution of composite polymer (500ppm), sodium carbonate (1 wt.%) and silica nanoparticles at a concentration of 0.2 wt.%, which were conducted to evaluate the effect of nanosilica concentration in an alkaline/polymer solution.

Figure 12 shows the effect of adding silica nanoparticles in the alkaline/polymer solution. The presence of silica nanoparticles in the alkaline/polymer solution enhances the oil relative permeability curves, but it reduces aqueous phase relative permeability. In such a case the alkaline effects are strengthened and will be resulted in enhanced oil recovery.
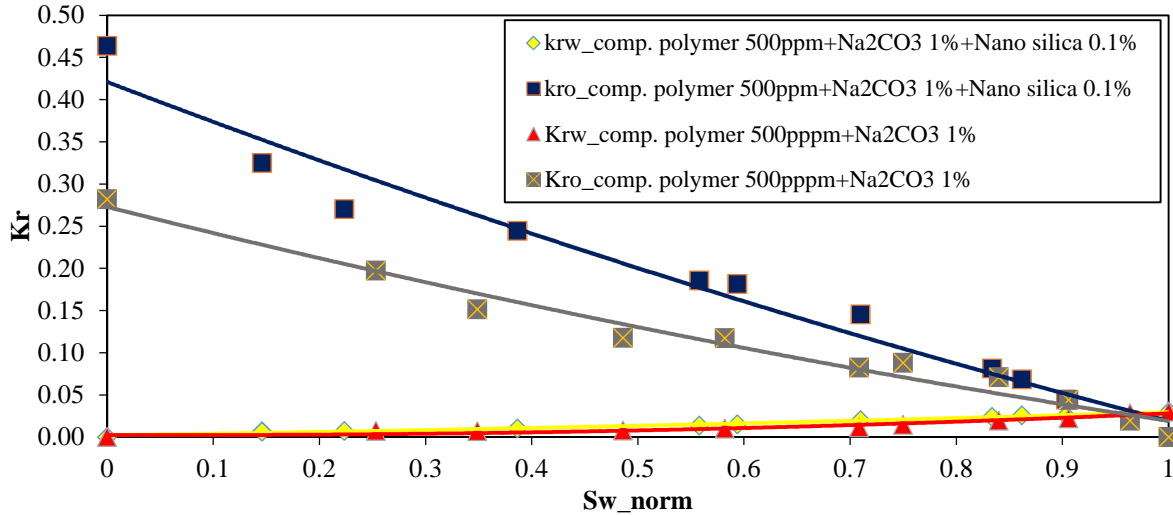


**Figure 12**

The effect of nanoparticles in the alkaline/polymer solution on the relative permeability curves.

Figure 13 depicts the effect of silica nanoparticle concentration on the relative permeability curves.

Again, the variation of the concentration of silica nanoparticles will not alter the displacement process and the resulting relative permeability behavior significantly. The observed change in the curves may be regarded as the consequence of phase hysteresis.
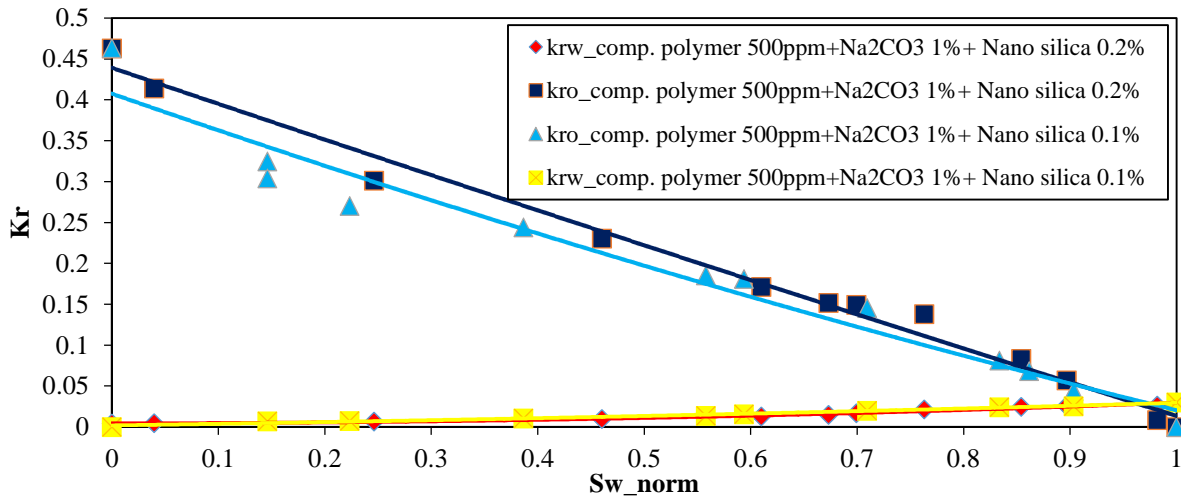


**Figure 13**

The effect of silica nanoparticle concentration on the relative permeability curves of silica nanoparticle suspensions in the alkaline/polymer solution.

Figure 14 displays the change in the pressure gradient between the two ends of the cores. After reaching the breakthrough point, the pressure gradient will be decreased. However, after a short time, it will begin to rise again. The process of reduced pressure gradient, after reaching the breakthrough, shows the decrease in the adsorption of silica nanoparticles on the surface of a rock. Thus, the

presence of an alkaline, with nanoparticles, could well control the adsorption of the nanoparticles on the surface of rock. Figure 15 illustrates this phenomenon.
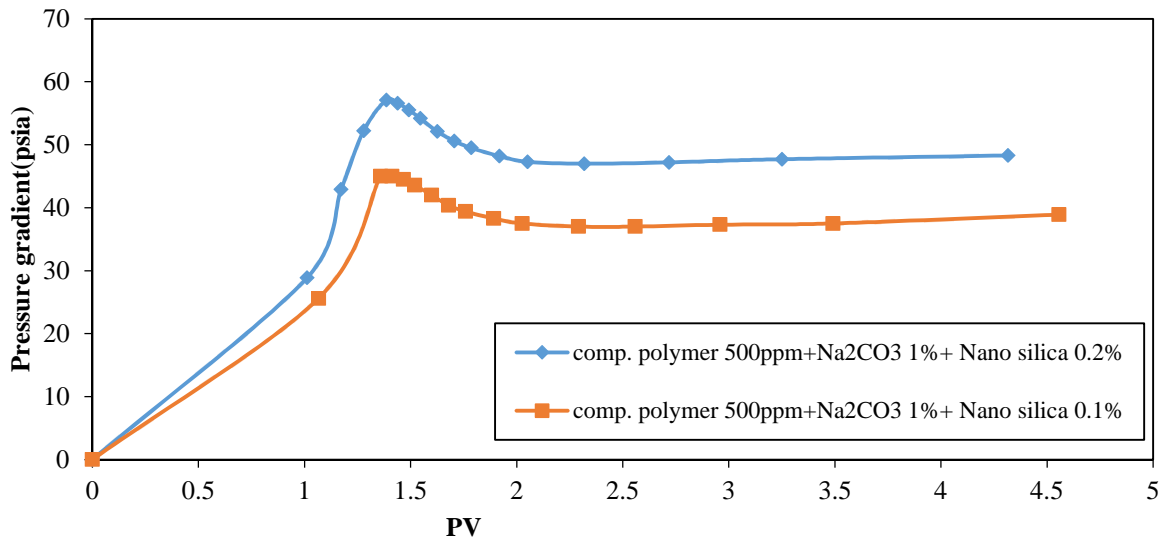


**Figure 14**
The change in the pressure of gradient across the core in the injection experiments containing silica nanoparticle suspensions in the alkaline/polymer solution.
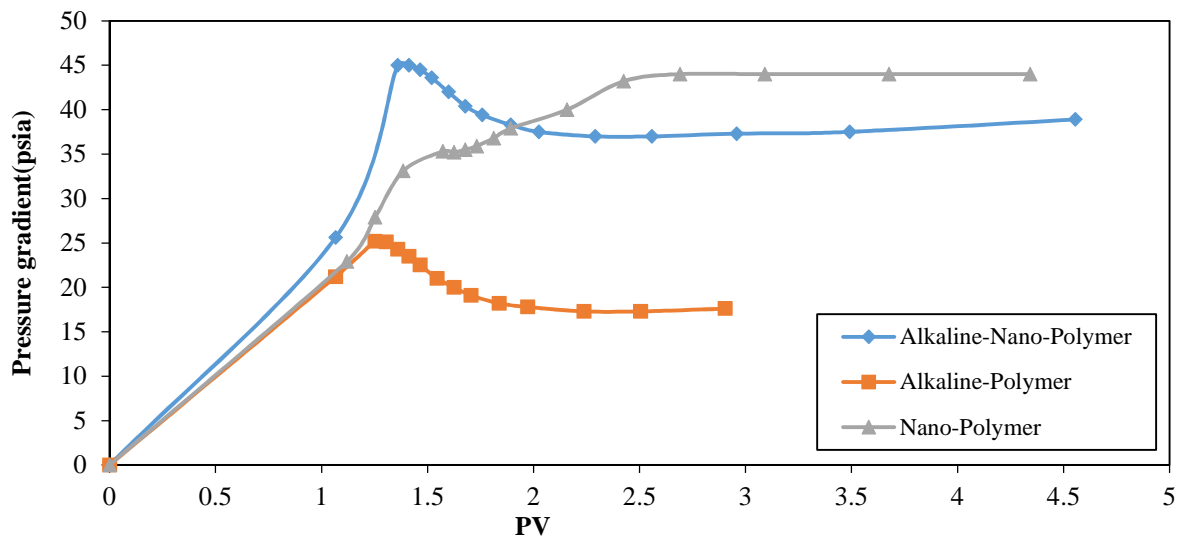


**Figure 15**
The change in the pressure of gradient across the core in the injection experiments containing alkaline/polymer, nano/polymer, and alkaline/nano/polymer solution.

## 6. Displacement efficiency of the experiments

The amount of oil recovered during these series of experiment was measured and the results are shown in Figure 16. Adding alkaline or silica nanoparticles to the polymer solution and silica nanoparticles to the alkaline/polymer solution increases oil recovery because chemical solutions in both microscopic and macroscopic scales improve the recovery; for example, by better sweeping the oil toward the small pores and controlling the viscosity and consequently the mobility. As was

discussed in section 6 by designing the tests with different chemicals on the same core sample (see Figures 5-13), the effect of rock variability is removed; hence, the changes in the relative permeability behavior is probably due to the viscosity or interfacial tension changes happening by the addition of the chemical additives. It is helpful to investigate the effect of interfacial tension changes on the oil recovery by choosing appropriate additives, which is the aim of our future studies.

Moreover, oil composition is another parameter that can affect this kind of flooding. Every components of the oil composition may be sensitive to the type of chemical additives and needs further investigation. In this study, the oil composition was not available and we were not able to investigate the role of oil composition in the relative permeability behavior in the presence of chemical additives.
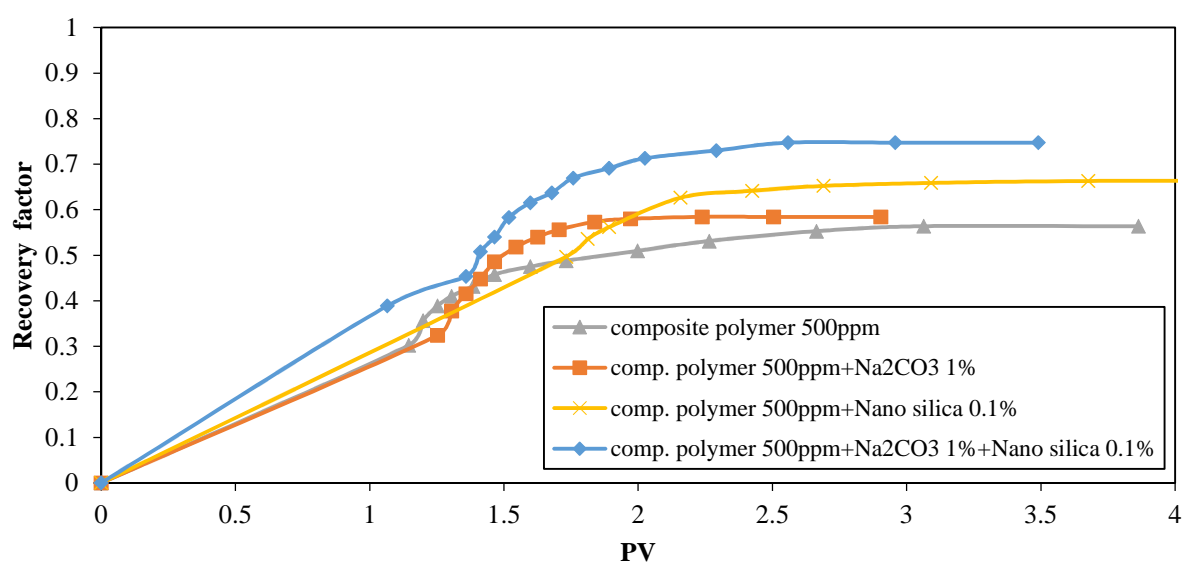


**Figure 16**
Recovery factor during 4 series of experiments.

## 7. Conclusions

In this study, two-phase relative permeability behavior due to flooding chemical solutions, polymers, alkaline/ polymer, nano/polymer, and alkaline/nano/polymer was examined through laboratory investigations. The following conclusions can be drawn:

- With increasing polymer concentration in polymer solution, the mobility ratio of two phases and thus the observed oil recovery improved; however, the increase in the oil recovery is associated with increasing the injection pressure.
- In laboratory conditions, we observed that the use of hydrolyzed polymer solution improves the oil recovery in the presence of low salinity water.
- By adding alkaline into the polymer solution, which gives lower viscosity, in situ petroleum soap is generated; hence, the required injection pressure dropped, the relative permeability of wetting phase fell, and the direction of concavity of this curve was changed, which led to less oil trapping and improved oil recovery.
- In the experiments with a higher concentration of alkaline, oil relative permeability curve variations was greater than the wetting phase, indicating the ability of solution to sweep more oil.

- The trend of pressure gradient in alkaline/polymer injection, after reaching the breakthrough point, was first descending; it then rose to reach a constant value.
- With the addition of a small amount of nanosilica to the polymer solution, the required operating pressure increased, the relative permeability of wetting phase dropped, and the direction of concavity of this curve changed; thus the oil recovery was enhanced. An increment of pressure gradient probably is due to the large surface area of these particles, which causes blockage of pore throats.
- With the addition of silica nanoparticles to alkaline/polymer solution, pressure gradient first dropped and then increased slowly; thus oil recovery was improved.

## Nomenclature

| | |
|---|---|
| $f$ | : Fraction of displacing phase in flowing stream |
| $f_o$ | : Fraction of displaced phase in flowing stream |
| $I_r$ | : Relative injectivity |
| $K_{ro}$ | : Relative permeability of oil |
| $K_{rw}$ | : Relative permeability of water |
| $S_{ave}$ | : Average wetting phase saturation |
| $S_w$ | : Wetting phase saturation |
| $S_{w2}$ | : Wetting phase saturation at outlet face of porous body |
| $u$ | : Average velocity of approach toward entering sand face = $q/A$ |
| $W_i$ | : Cumulative injection in pore volume |
| $\Delta P_s$ | : Differential pressure at start of injection |
| $\mu_o$ | : Oil viscosity |
| $u_s$ | : Average velocity at start of injection |
| $\mu_w$ | : Water viscosity |

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