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Full Length Article

Areal sweep efficiency improvement by integrating preformed particle gel and low salinity water flooding in fractured reservoirs

Ali K. Alhuraishawy[a,b], Xindi Sun[b], Baojun Bai[b,*], Mingzhen Wei[b], Abdulmohsin Imqam[b]

[a] Missan Oil Company, Amara, Missan 62001, Iraq
[b] Department of Geoscience and Geological and Petroleum Engineering, Missouri University of Science and Technology, Rolla, MO 65401, United States

A R T I C L E I N F O

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A B S T R A C T

The oil recovery from fractured reservoirs is usually low, which is usually caused by the existence of areal formation heterogeneity. Two existing enhanced oil recovery (EOR) technologies, low salinity water flooding (LSWF) and preformed particle gel treatment (PPG), have recently drawn great interest from the oil industry. We integrated both of these technologies into one process to improve both oil displacement and areal sweep efficiency. The objective of this study was to test how the integrated method could be used effectively to increase oil recovery and control water production. The semi-transparent five-spot models, which were made of sandstone cores and acrylic plates, were built. We investigated the effect of four parameters on the improvement of oil recovery and areal sweep efficiency of oil, including gel strength, water salinity, injection rate, and number of fractures. Two approaches were followed during core flooding, sequential mode and mixed mode. The result shows that PPG and LSW injected together as one mixture improved oil recovery factor more than the first approach. PPGs plugged the fractures and successfully improved areal sweep efficiency; however, they have little effect on displacement efficiency. LWSF increased displacement efficiency but had little or no effect on sweep efficiency. The integrated methods bypassed the limitations of each method when used individually and improved both displacement and sweep efficiency.

1. Introduction

Approximately two-thirds of the oil in place cannot be recovered by conventional technologies. Thus, enhanced oil recovery (EOR) methods are required to recover a sizeable portion of the remaining oil in a well. Mature wells are often abandoned due to low oil production rates as well as the formation of excess water. To recover this remaining unrecoverable hydrocarbon, two new EOR technologies are now being used: Micro-PPG conformance control and low salinity water flooding.

Within the past two decades, there has been an increase in the use of PPGs to improve the sweep efficiency of water flooding. PPGs are composed of a specialized superabsorbent polymer. PPGs can be as small as nanometer size or as large as millimeter size. The use of PPGs solves some problems inherent in an in-situ gelation system. These include a lack of gelation time control, gelling uncertainty due to shear degradation, chromatographic fractionation, or dilution by formation water [10,6,7]. PPGs are manufactured at a surface facility prior to injection. They are later injected into a reservoir. Therefore, gelation does not occur in the reservoir. These gels usually have only one component during injection. They are only slightly sensitive to a reservoir's physicochemical conditions (e.g., pH, salinity, multivalent ions, hydrogen sulfide, and temperature) [6,7]. Particle gels are available commercially in a number of sizes: micro- to millimeter-sized PPGs [12,6,7,38], microgels [42], pH-sensitive crosslinked polymers [4,15], and swelling submicron-sized polymers [27,14]. PPGs differ chiefly in their particle size, swelling time, and swelling ratio. The literature reveals that PPGs, microgels, and submicron-sized polymers are all cost-effective alternatives that reduce water production and improve oil recovery in mature oil fields. Zaitoun et al. [42] demonstrated that the microgels applied to about 10 gas storage wells were able to decrease water production. Cheung [11] effectively used submicron-sized particles in more than 60 wells. Millimeter-sized PPGs can preferentially penetrate into fractures or fracture-feature channels while diminishing gel penetration into unswept zones/matrices. Worldwide, PPGs have been employed in approximately 10,000 wells in water floods and polymer floods to decrease the permeability of fractures or of super-high permeability channels [8].

To improve displacement oil recovery, the use of LSWF has been researched extensively to decrease the residual oil saturation in swept areas. Martin [25] was the first to describe the effect of low salinity

* Corresponding author.
E-mail addresses: akak22@mst.edu (A.K. Alhuraishawy), baib@mst.edu (B. Bai).

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Nomenclature

E_A	areal sweep efficiency
E_D	displacement efficiency
F_{rrw}	water residual resistance factor
$P_{inj.a}$	injection pressure after gel placement
$P_{inj.b}$	injection pressure before gel placement
R.F	oil recovery factor
S_{oi}	initial oil saturation
S_{wi}	initial water saturation
S_{or}	residual oil saturation
WF1	first waterflooding (1.0% NaCl)
WF2	first waterflooding (1.0% NaCl)
LSWF1	first cycle of low salinity waterflooding (0.1% NaCl)
LSWF1	second cycle of low salinity waterflooding (0.01% NaCl)
PPG + 1.0% NaCl	PPG swollen in 1.0% NaCl
PPG + 0.1% NaCl	PPG swollen in 0.1% NaCl.
PPG + 0.01% NaCl	PPG swollen in 0.01% NaCl

water on oil recovery. Using sandstone core samples, he compared an injection of seawater to that of freshwater, finding that oil recovery rose more after the injection of freshwater. However, the potential of LSWF was not established until the work of Morrow et al., published from 1991 to 1999 [19,20,39,36,35]. After that seminal work, research has been conducted by numerous corporations and other groups to discover the relationship between water salinity and oil recovery, especially as it relates to sandstone and carbonate. Numerous laboratory studies have confirmed that LSWF can increase oil recovery in sandstone and carbonate reservoirs [30]. A study by Zhang et al. [43] found that injecting low salinity water into chalk formations led to oil recovery of up to 40 percent of OOIP. Similar data were found by Lager et al. [21] and [26], who discovered that LSWF could increase recovery up to 40 percent OOIP. LSWF can further decrease residual oil saturation when compared to normal water flooding in sandstone formations [26,29,23,40]. The percentage of oil recovery improvement is dependent upon a number of considerations. These include multicomponent ion exchange, clay content, formation water composition, oil

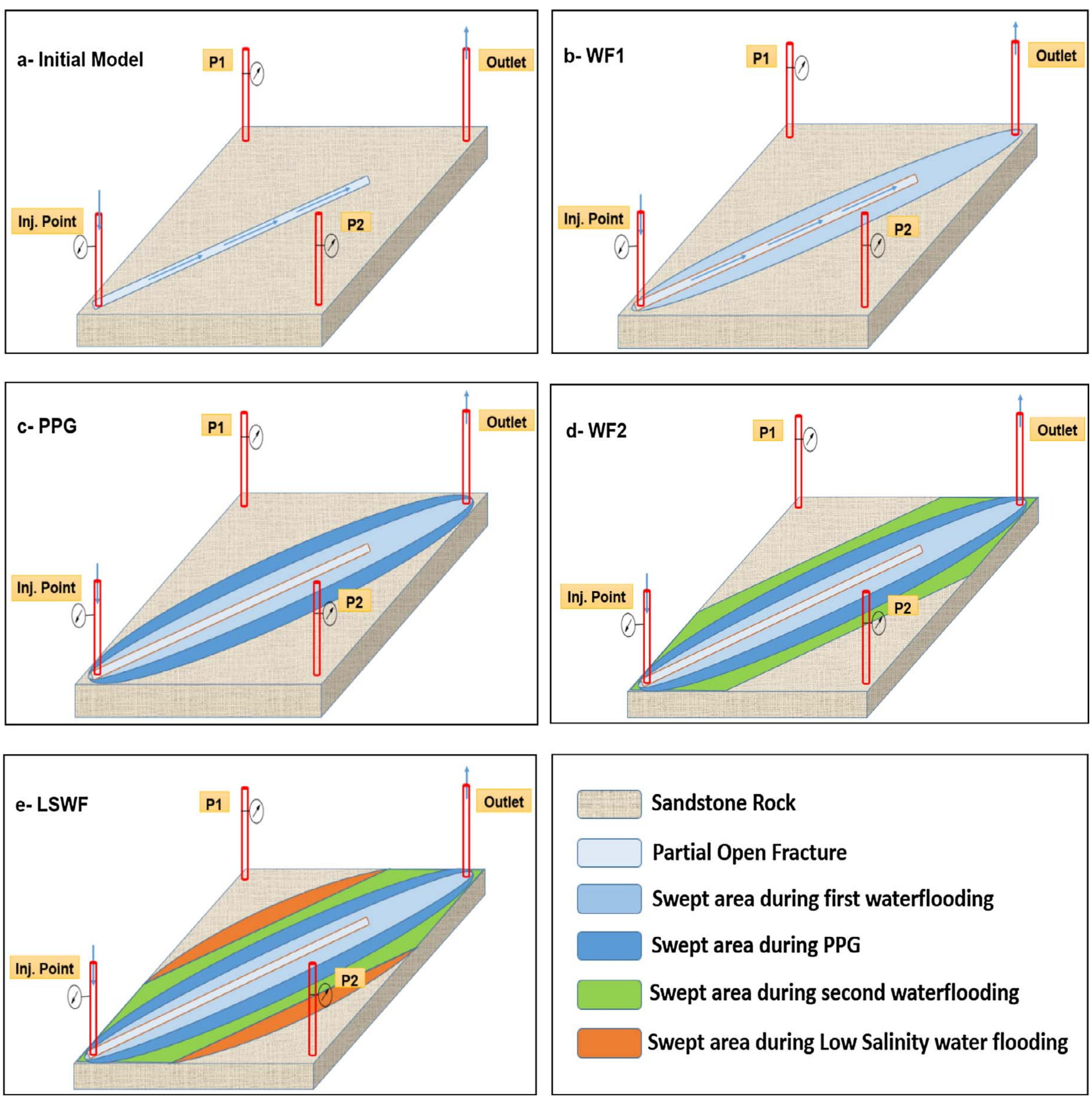

Fig. 1. Schematic showing the PPGs mechanism's injection in the partial open fracture.

composition, and initial water saturation. The positive effects of LSWF have been attributed to numerous factors: (1) the migration of fines [35], (2) interfacial tension reduction [26], (3) multicomponent ionic exchange [21], (4) pH-driven wettability change [21]; [26]), (5) double-layer expansion [23], (6) desorption of organic material from clay surfaces [5], (7) wettability alternation [40], (8) mineral dissolution [3], and (9) microscopically diverted flow [33,34]. All of these factors modify rock wettability from oil-wet or intermediate/water-wet. The result is that residual oil saturation decreases, improving total oil recovery. Hence, enhanced oil recovery is achieved by LSWF because it improves the microscopic displacement efficiency.

The degree of oil recovery is dependent on both the displacement efficiency (ED) and the sweep efficiency (ES). Using LSWF for EOR can improve the displacement efficiency; however, LSWF has little if any effect on the sweep efficiency. PPGs scarcely influence the displacement efficiency because they can only be used to plug fractures or high-permeable channels, which enhances the sweep efficiency. Brattekas et al. [9] studied combining low salinity waterflooding with in-situ gel. They observed that low salinity waterflooding added a benefit to the improved blocking capacities of an in-situ gel. Alhuraishawy et al. [1] studied coupling low salinity water flooding and preformed particle gel to enhance oil recovery for fractured carbonate reservoir. They concluded that combining low salinity water flooding with PPGs is a viable technique for improving oil recovery in fractured carbonate reservoirs. This current research extends our previous work to test the integration of this technology in fractured sandstone rocks and develops a semi-transparent model which can image fluid flow in consolidating rocks by using transparent gel. Experiments were conducted to assess the effect of four key factors: salinity of the injection water, salinity of the water used to swell the PPGs, number of fractures, water flow rate. Their influence on the amount of oil recovery and the water residual resistance factor (Frrw) will be determined by using fractured five-spot sandstone models.

2. Mechanisms of the proposed method

The swelling ratio of preformed particle gel is strongly affected by water salinity [18]. As the water salinity decreases, the gel swelling ratio increases significantly. For example, at a salinity of 10,000 ppm, one kind of PPG can swell about 40 times, but when the salinity decreases to 2500 ppm, the same PPG can swell up to 200 times, a fivefold difference. As the swelling ratio rises, the gel volume increases; however, the gel strength also decreases. PPGs work well because they only enter fractures, thus reducing their permeability. In contact with low water salinity, the PPG increases in size. This reduces the amount of water that can flow through the fracture. PPGs lower fracture conductivity and force the low salinity water into the matrix, allowing more oil to be recovered. This research will investigate two injection process methods for combining PPGs treatment and LSWF. Fig. 1 shows the process of first injection mode, the PPGs and LSWF were injected sequentially. The PPGs are first injected into the fractures so that their conductivity can be decreased; afterward, cycles of LSWF are injected into the fracture model. Because the fracture was plugged initially by the PPGs, it is theorized that the majority of the injection volume of the LSW will flow into the matrix. In the second injection approach, the PPGs are swelled in a low water salinity solution. Then, this solution is injected into the fracture together with the PPGs. The PPGs decreased the fracture conductivity meanwhile the LSW is forced into the matrix thus enhancing the oil recovery.

3. Experimental approach

3.1. Materials

3.1.1. PPGs

A super absorbent crosslinked polymer with a mesh size of 20–30 was used as the preformed particle gel for this study. The particles were synthesized by a free radical process using acrylamide, acrylic acid, and N,N'-methylene-bisacrylamide. When it contacts with water, it can swell several to a few hundred times of its original size (as shown in Fig. 2). When we pour water into the test-tube, the particle will swell to those much. High to 130 °C with long-term stability (more than 1 year below 130 °C).

3.1.2. Brine

Sodium chloride (NaCl) was used to prepare different concentrations of brine, 1.0%, 0.1% (LSWF1), and 0.01% NaCl (LSWF2).

3.1.3. Oil

A mineral oil was used which has the following properties: API: 36°, density: 0.845 g/cc, and viscosity: 37c.p.

3.1.4. Sandstone rock

Berea sandstone was obtained in the form of 21 × 21 × 1.8 cm.

3.2. Core preparation

Five core slabs were prepared for the core flooding tests. The permeability of the cores was measured and listed in Table 1. The average core porosity was 15%. The core and fracture dimensions are summarized in Table 1. All slabs were initially saturated with 100% brine (1.0 wt% NaCl). The distance between the injector and producer points was 28 cm. The cores were put inside the oven for 72 h under 475 °C in order to overcome the clay content [24]. After that, we measured the permeability using 1.0%, 0.1%, 0.01%, and 0.001% NaCl, respectively, for extra sandstone core sample and the injection pressured was

a) Dry Microgel

b) Microgel after swollen in brine

Fig. 2. Microgel before and after being swollen in sea water.

Table 1
Core slabs properties.

	Initial Core Dimensions Before Fracture								Fracture Dimensions				
Core #	Length (cm)	Width (cm)	Thickness (cm)	Pore Volume (cm3)	Swi%	Soi	Ø%	K md	Length (cm)	Width (cm)	Thickness (cm)	Number of Fractures	Total Fractures Volume (cm3)
1	21	21	1.8	129.08	32	68	14.5	50.5	19.5	0.25	1.8	1	8.775
2	21	21	1.8	134.83	31.63	68.37	15	50	19.5	0.25	1.8	2	17.55
3	21	21	1.8	136.7	32.24	67.76	15.5	51	19.5	0.25	1.8	1	8.775
4	21	21	1.8	131.28	32.22	67.78	15	49	19.5	0.25	1.8	1	8.775
5	21	21	1.8	130.4	31.2	68.8	16	50	19.5	0.25	1.8	1	8.775
6	21	21	1.8	132.2	30.4	69.6	15.5	51	19.5	0.25	1.8	1	8.775

stabilized for all these brine concentrations.

3.3. Fracture model description

The schematic of the model is shown in Fig. 3. The model was made with a transparent acrylic board, which provided a transparent window that could be used to observe the fluid flow and gel transport. This model was constructed using two acrylic plates with a rubber O-ring between them. Bolts and nuts were used to fix the two plates. A long square pocket (22 cm wide, 22 cm long, and 2 cm deep) was drilled in the center of one side of one of the acrylic plates; Transparent gel was used to fix a piece of sandstone core into this pocket. There were 5 inlets/outlets on the model. During the water flooding and gel treatment, only two of the ports were used, one was an injector, and another one was a producer. These two ports were set at corners along the diagonal line to simulate a 5-spot scenario. The rest were shut in and used as monitoring ports, P1 and P2 (Fig. 4). The core of the model was made with sandstone. Two fracture models were designed (Fig. 5): one was made up of a model with only a single fracture and another model with parallel fractures.

The following procedure explains how the fracture models were made:

- Measure the permeability and porosity of the core
  The core was vacuumed, and dry weight of the model was measured. 1.0 wt% NaCl was injected into the core to make sure the whole core was saturated with 1.0 wt% NaCl. The wet weight of the model was measured. Flow rates and associated pressure data were recorded, and permeability was calculated. The weight difference was used to calculate porosity.
- Build initial oil saturation
  Since the core had already been saturated with brine, oil was injected to displace water in order to build irreducible water saturation (S_{wi}) and initial oil saturation. Oil and water production were collected to calculate the OOIP and S_{wi}. These steps were repeated using different ports to make sure the whole core was saturated homogeneously.
- Create fractures
  The saturated core was taken out from the model. After that, saw was used to create a uniform partial open fractures in the prepared cores to simulate a fracture model as shown in Fig. 5.

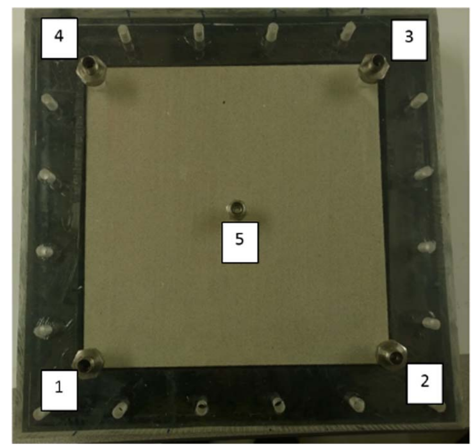

Fig. 4. Schematic of the fracture model.

4. Experiments procedure

Two approaches were followed during core flooding. In the first approach, Micro-PPG was injected first into fractures. Then, cycles of low water salinity were injected into fracture model. In the second approach, Micro-PPG and LSW were injected together as one mixture, as illustrated in the following procedure:

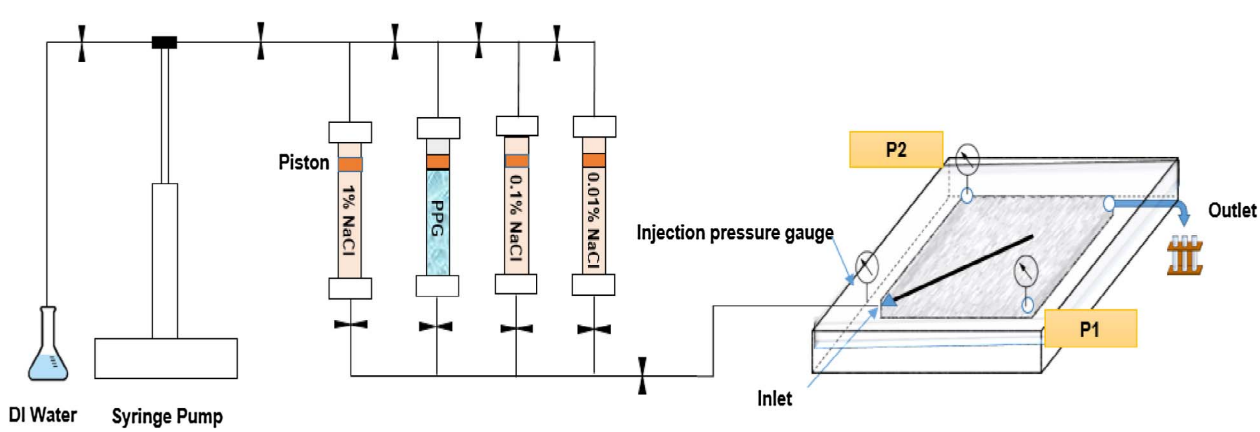

Fig. 3. Schematic diagram of the experimental apparatus.

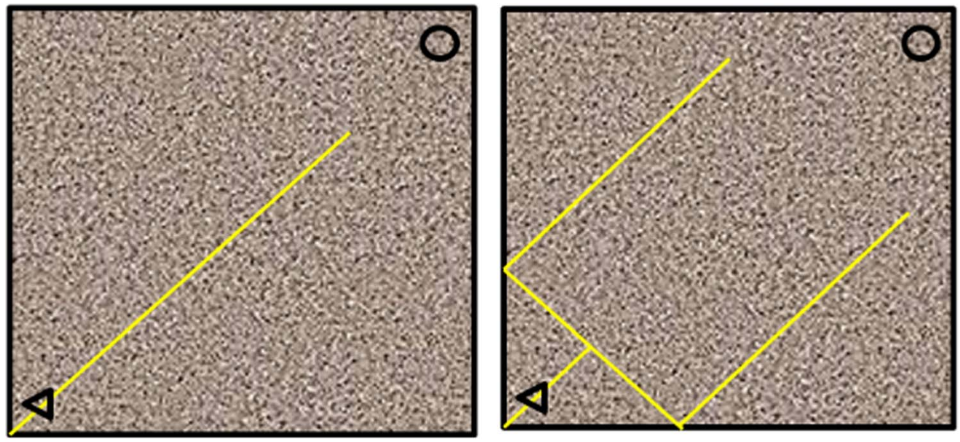

Fig. 5. Fractures design; (a) one straight partial open fracture, (b) two parallel partial open fracture.

4.1. First approach (sequential mode) procedure

- Initial water preflush
  Brine (1.0 wt% NaCl) was injected into the fracture inlet at a 2.0 ml/min. to simulate secondary recovery conditions and detect any oil production from the matrix outlet.
- Micro-PPG placement
  PPGs (20–30 mesh size) were selected for the PPG treatment. The PPGs were swollen in a brine solution (1.0 wt% NaCl) and then injected into the fracture at a flow rate of 2.0 ml/min until the injection pressure reached 150 psi.
- Second water chase
  The second batch of brine (1.0 wt% NaCl) was injected into the model at a 2.0 ml/min. to test the PPGs plugging efficiency and displace any movable oil. After a stabilized pressure was reached with no more oil recovery, 0.1 and 0.01 wt% NaCl was injected, respectively as a sequential mode, to investigate the effect of low salinity water flooding. For each part of the low salinity water flooding, the stabilized pressure was reached, and no more oil was recovered before starting the next part. Monitoring pressure was recorded to see how PPG and LSWF can improve the area sweep efficiency by diverting the water bath into the matrix.

4.2. Second approach (mixed mode)

The same procedures, which were used in the first approach, were applied except the PPGs were swollen in three different water salinities, 1.0%, 0.1%, and 0.01% NaCl. Different brine injection rates (1, 2, 4, 6, and 8 ml/min) were designed to investigate their effects on the oil recovery factor and the water residual resistance factor.

5. Results and discussion

5.1. Micro-PPG followed by low salinity waterflooding (sequential injection approach)

Core #1 (Table 1) was used in these investigations. Fig. 6 illustrates the oil recovery and water cut during different brine injection cycles for single partial open fracture. The oil recovery factor was 6% during the first waterflooding, and it's increased quite small during the injection cycles. The incremental oil recovery was 6.57% at the end of second waterflooding due to the decrease of fracture conductivity achieved by placing the Micro-PPG inside. Therefore, the water cut decreased from 100% to 90% during gel injection and earlier of second waterflooding. The decrease of fracture conductivity resulted in increased the stabilized injection pressure from 58.7 psi to 96.3 psi as shown in Fig. 7. When the injection cycle changed to low salinity waterflooding, the oil

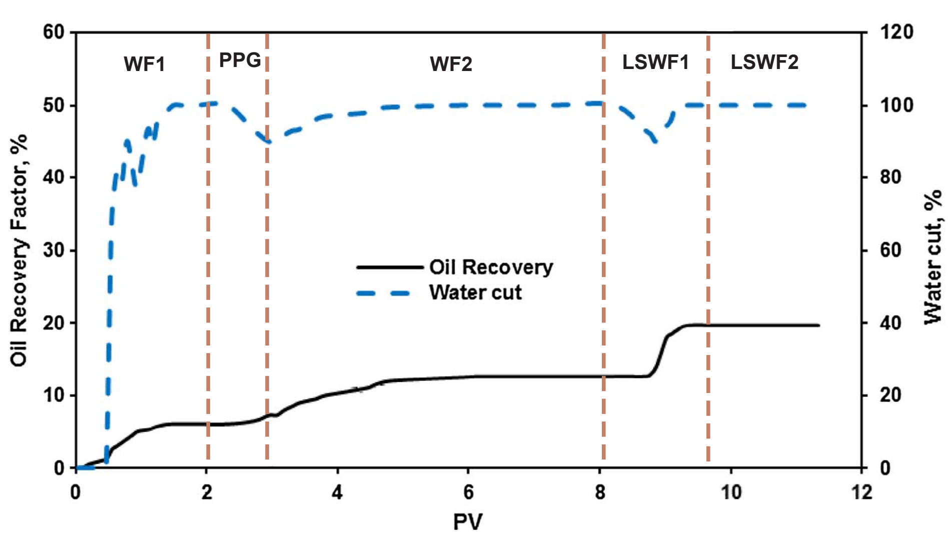

Fig. 6. Oil recovery factor and water cut during different injection cycles for single partial open fracture (Core#1).

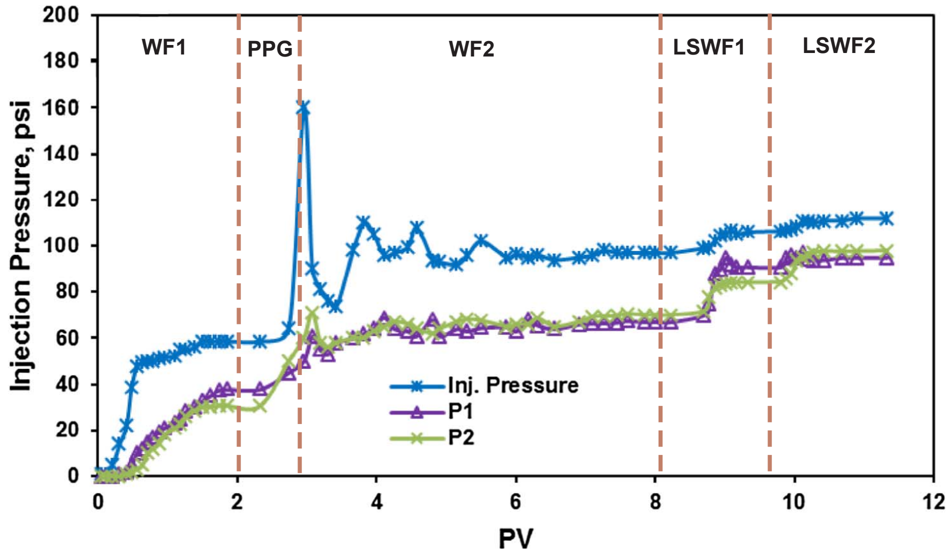

Fig. 7. Injection and monitoring pressures (Pinj, P1, and P2) during different injection cycles for single partial open fracture (Core#1).

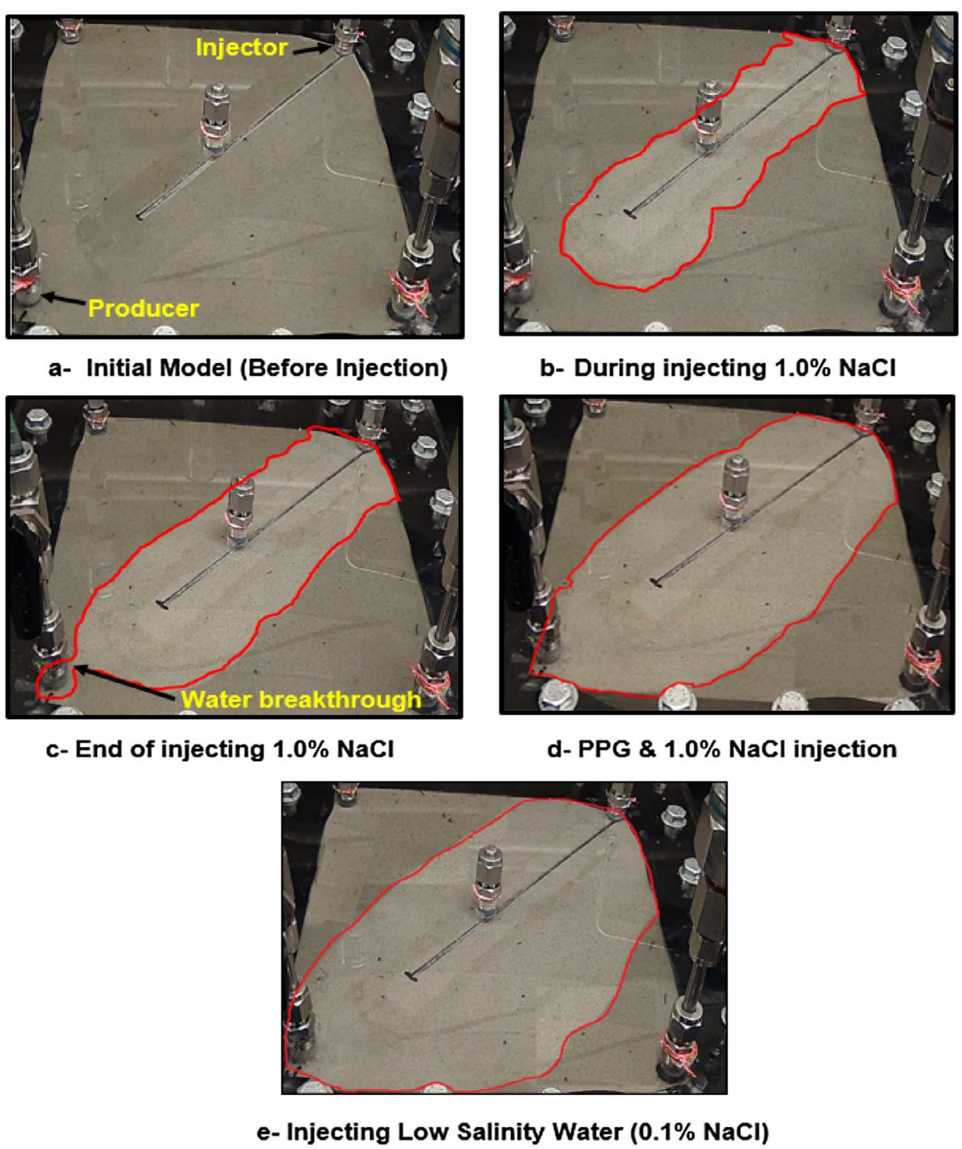

Fig. 8. Swept area during different water flooding cycles.

recovery improved by 7%, the water cut decreased from 100% to 90%, and the stabilized injection pressure increased by 10 psi. This might be caused by improved fracture plugging efficiency because the PPG size increased as the brine concentration decreased [18]. The results show that monitoring pressure increased dramatically as brine concentration decreased. For example, the P1 changed from 67 psi to 91 psi and P2 changed from 69 psi to 92 psi when the concentration of injected brine decreased from 1.0% NaCl to 0.1% NaCl. According to increased P1 and P2, the sweep efficiency increased due to increase the amount of water which flowed toward P1 and P2. The pressure differences between injection pressure and monitoring pressures were almost 28.5 psi during the second waterflooding and reduced to 15 psi when low salinity waterflooding applied. That means the connectivity between the injector and monitoring pressures (P1 and P2) improved and, in turn, improve the swept area. Brattekas et al. [9] observed that low salinity waterflooding added a benefit to the improved blocking capacities of the gel. Therefore, the water residual resistance factor (Frrw) increased during low salinity waterflooding cycles and it was less than 2.1. Frrw was 1.8, 1.9, and 2.05, when the salinity of injected brine was 1.0%, 0.1%, and 0.01% NaCl, respectively. It means the fracture is not plugged particularly well and that the water is still channeling down the fractures. [16,17] indicate that the gel particle formed a gel pack inside the fracture and it's partial blocked it. The water residual resistance factor was calculated based on the following equation:

$$\text{Frrw} = \frac{\text{Injection pressure after gel placement}}{\text{Injection pressure before gel placement}} = \frac{Pinj.\ a}{Pinj.\ b} \tag{1}$$

Also, we can observe the improvement of the swept area during the second water flooding and the low salinity waterflooding cycles, as shown in Fig. 8. From Fig. 8**b**, we can visualize how waterflooding can displace the oil (the red border is the swept area by water) until the water breakthrough from producer with approximate 30% swept area (Fig. 8**c**). After water breakthrough, PPG was injected to plug the fracture and the same brine concentration was injected after PPG (Fig. 8**d**) which resulted in about 60% swept area. Then cycle of low salinity water was injected and the swept area increased to 70% (Fig. 8**e**). Referring to the oil recovery result in Fig. 6, the oil recovery factor was 6% associated with 30% swept area during first water flooding and the oil recovery factor improved by 6.57% with improvement in swept area by 30% (60% total swept area). During low salinity waterflooding, the oil recovery improved by 7% with 10% improvement in swept area. Even though the improvement in swept area was small compared with first and second waterflooding, the incremental oil recovery during low salinity waterflooding was high. The reason was the low salinity water improved the displacement efficiency by reducing residual oil saturation [26,29,23,40] while the low salinity waterflooding has a little effect on sweep efficiency.

Fig. 9 shows improvements in oil recovery during low salinity water flooding which can be explained that when the low salinity waterflooding was injected after PPGs were placed into the partial open fracture, the preformed particles gel size increased as its swelling ratio increased. So the low salinity water injection after PPG improved the plugging efficiency and most the injected water diverted to matrix [9,18,1]. This improved plugging efficiency led to improved sweep efficiency.

The stabilized injection pressure, monitoring pressure, and water residual resistance factor values increased when the salinity of the injected water changed from 1.0% NaCl to low salinity. This supports our explanation that the low salinity waterflooding improved the plugging efficiency. The fracture conductivity was decreased due to the increased plugging efficiency during low salinity waterflooding, and a small amount of injected brine was diverted to the matrix. The pressure waves of the injected brine reached P1 and P2, as shown in Fig. 8, which caused the sweep efficiency to improve.

The number of fractures has an important effect on areal sweep efficiency. Cores # 2 (Table 1) were used to study the impact of increasing fracture numbers on the areal sweep efficiency. Figs. 10 and 11 illustrate the oil recovery factor with water cut and pressures profiles

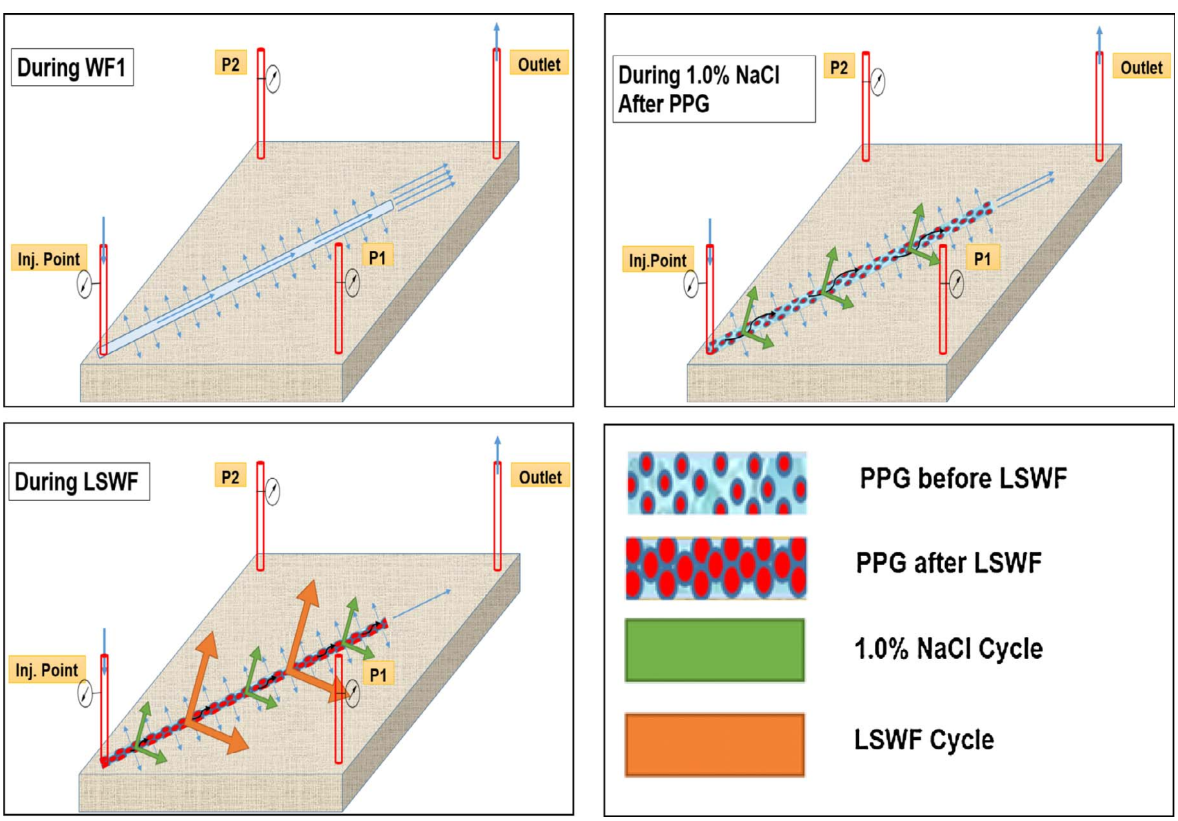

Fig. 9. Improved sweep efficiency during low salinity waterflooding.

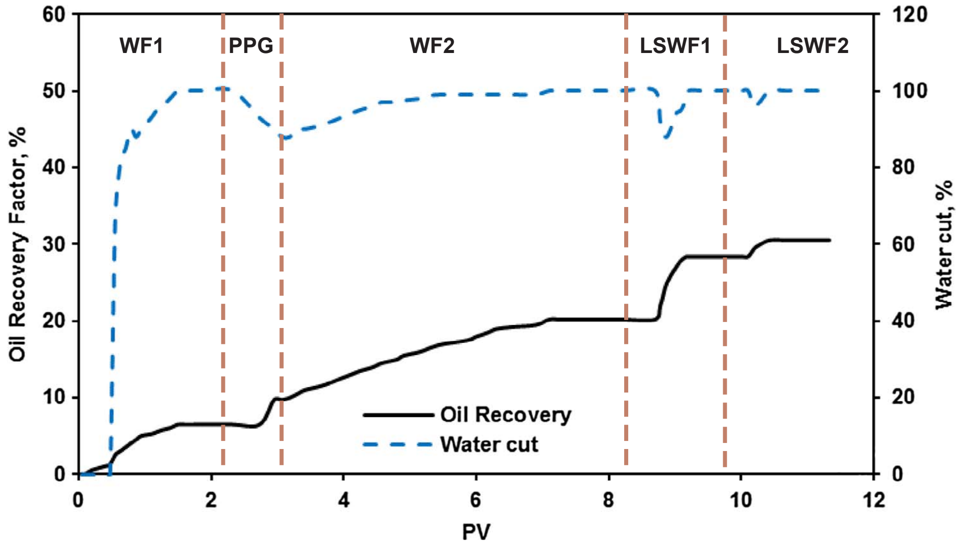

Fig. 10. Oil recovery factor and water cut during different injection cycles for parallel partial open fracture (Core#2).

for parallel partial open fractures, respectively. Overall, these figures show that both the oil recovery factor and incremental oil recovery factor were slightly higher for parallel partial open fractures than a single partial open fracture. The remaining oil saturation was 69.37% in parallel partial open fractures rock while it was 80.3% in single partial open fracture rock. The oil recovery factor and water cut were almost the same from both single and parallel partial open fracture during first waterflooding (oil recovery was 6.06% and 6.45%, respectively); however, the incremental oil recovery occurred more than two times for parallel partial open fractures than for single partial open fracture during PPG treatment and almost two times during second waterflooding cycles. The low salinity waterflooding improved the oil recovery factor and reduced the water cut in the parallel partial open fractures better than in the single partial open fracture, especially during the LSWF2 cycle. The incremental oil recovery for single partial open fracture during LSWF2 was zero, but it was 2.14% for parallel partial open fractures.

The injection and monitoring pressures (P1 and P2) are illustrated in Fig. 12. This figure shows, for all injection pressure, P1, and P2, the pressures for the single partial open fracture were higher than the monitoring pressure for the parallel partial open fractures during different injection cycles. This might be because the brine injected into the fracture took three paths into the single partial open fracture, while it took five paths into the parallel partial open fracture. Therefore, the amount of brine that reached P1 and P2 were greatest in the single partial open fracture. The low salinity waterflooding had a greater effect on the monitoring pressures for the single partial open fracture than it did for the monitoring pressures of the parallel partial open fractures. Injection pressure, P1, and P2 were stabilized at 90 psi, 65.3 psi, and 63.4 psi, respectively, at the end of second waterflooding, while the pressures reached to 102 psi, 78 psi, and 75 psi, respectively, during the LSWF2 (0.01% NaCl). This means more brine moved to P1 and P2 direction. This resulted in the improvement of the oil recovery factor in the parallel partial open fractures better than in the single partial open fracture, especially during the LSWF2 cycle due to increase in the swept area by injected brine, as illustrated in Fig. 13.

5.2. Micro-PPG and low water salinity mixed together (mixing injection approach)

Cores # 3, 4, 5 and 6 (Table 1) were used to investigate the effects of gel strength, water injection rates, and pure low salinity waterflooding

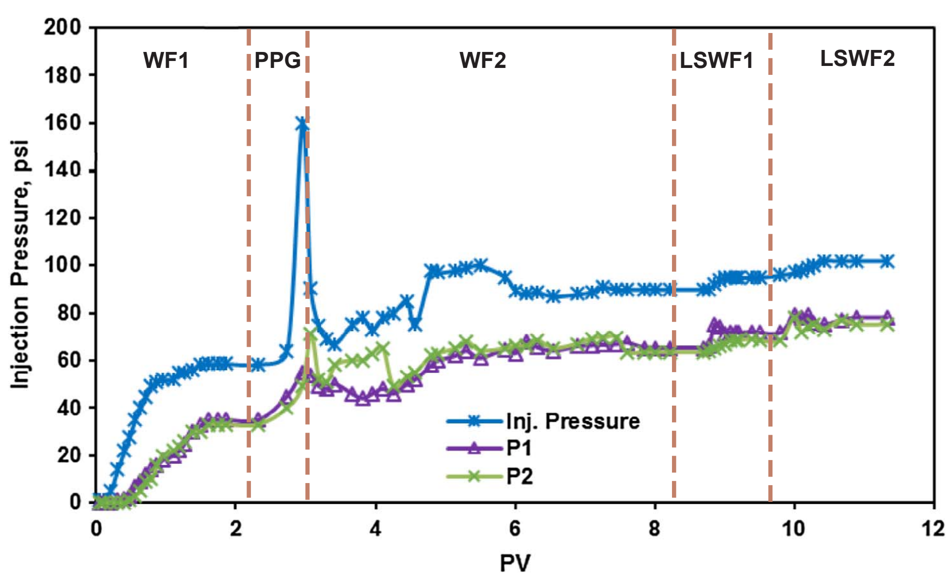

Fig. 11. Injection and monitoring pressures (Pinj, P1, and P2) during different injection cycles for parallel partial open fracture (Core#2).

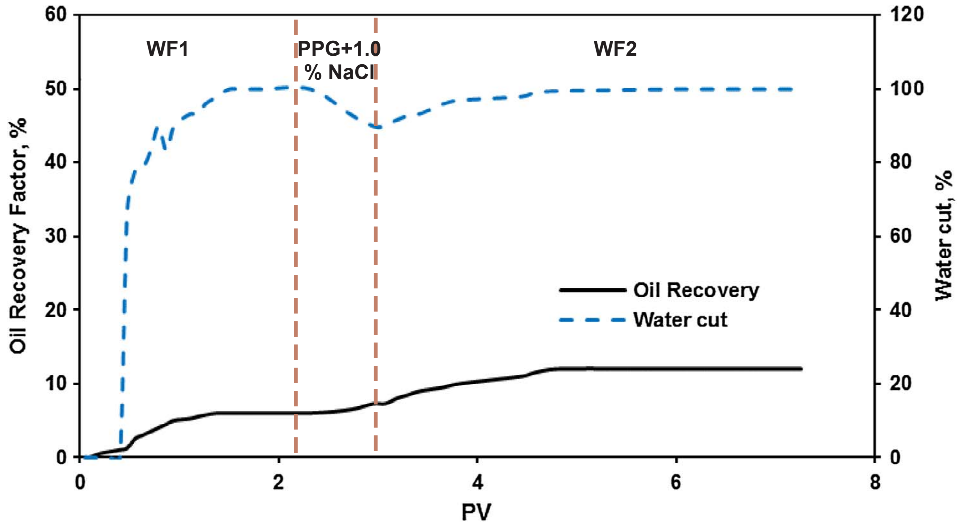

Fig. 12. Oil recovery factor and water cut when PPG swollen in 1.0% NaCl (Core#3- single partial open fracture).

and pure PPG treatment versus low salinity PPG. Three NaCl solutions of 1%, 0.1%, and 0.01% were used to prepare PPG and resulted in 42, 100, and 160 (ml/ml) PPG swelling ratio, respectively. So the dry PPG size increased 160 when 0.01% NaCl used to swell the PPG. The increased in swelling ratio means the PPG hold more water and when the PPG injected into the fracture, these amount of water will force into matrix [45]. Figs. 12–17 illustrate the oil recovery factor with water cut and pressures profiles during different injection cycles when PPG swollen in different brine concentrations, 1.0%, 0.1%, and 0.01% NaCl, respectively. The oil recovery factor was almost the same from the three experiments during first water flooding, 6.06%, 6.2%, and 6.15%, respectively. During gel treatment, a significant increase in oil recovery and monitoring pressures, and decrease in water cut were observed when injecting PPGs swelled in low salinity water even though the final PPG injection pressure was the same as PPG swollen in 1.0 and 0.1% NaCl because low salinity water was forced much into the matrix during the PPG injection. The incremental oil recovery increased to 1.23%, 3.5%, and 7.5% for water salinity of 1.0%, 0.1%, and 0.01% NaCl, respectively. The oil recovery continued to increase during the second waterflooding. The incremental oil recovery factor increased as water salinity decreased, 5.34%, 9.19%, 10.6%, respectively. The pressure differences between injection pressure and monitoring pressures during the second waterflooding were 30 psi, 17.5 psi, and 12 psi when PPG soled in 1.0%, 0.1%, and 0.01% NaCl, respectively. That indicates that the connectivity between the injector and monitoring pressures (P1 and P2) much improved when 0.01% NaCl was used to swoll the PPG and, in turn, improve the swept area.

Overall, the total oil recovery factor was 12%, 18.89%, and 24.45%, and water cut decreased to 91%, 84%, and 78% when PPG swollen in 1.0%, 0.1%, and 0.01% NaCl, respectively.

Plugging efficiency to water flow increased as the brine salinity decreased, which helped to increase the oil production. The Frrw was 1.78, 2, and 2.27 for 1.0%, 0.1% and 0.01% NaCl, respectively. It means the fracture is not plugged particularly well and that the water is still channeling down the fractures. Imqam and Bai [16] indicate that the gel particle formed a gel pack inside the fracture and it's partially blocked it. Additionally, at different flow rates, the Frrw decreased with increased flow rates, as shown in Fig. 18. At low flow rate, the highest Frrw was obtained when PPG was swollen in 0.01% NaCl, and the lowest Frrw was obtained at 1.0% NaCl. However, at a high flow rate greater than 6 ml/min., the Frrw was the same for all the brine concentrations, and no significant effect of flow rate could be reflected on the Frrw.

The gel strength is the most important factor in controlling reservoir

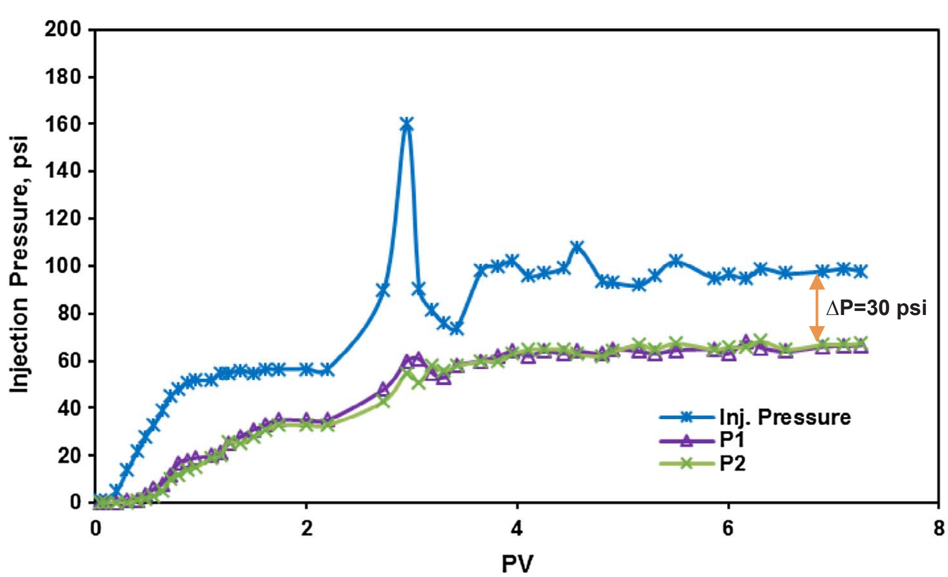

Fig. 13. Injection and monitoring pressures (Pinj, P1, and P2) when PPG swollen in 1.0% NaCl (Core#3- single partial open fracture).

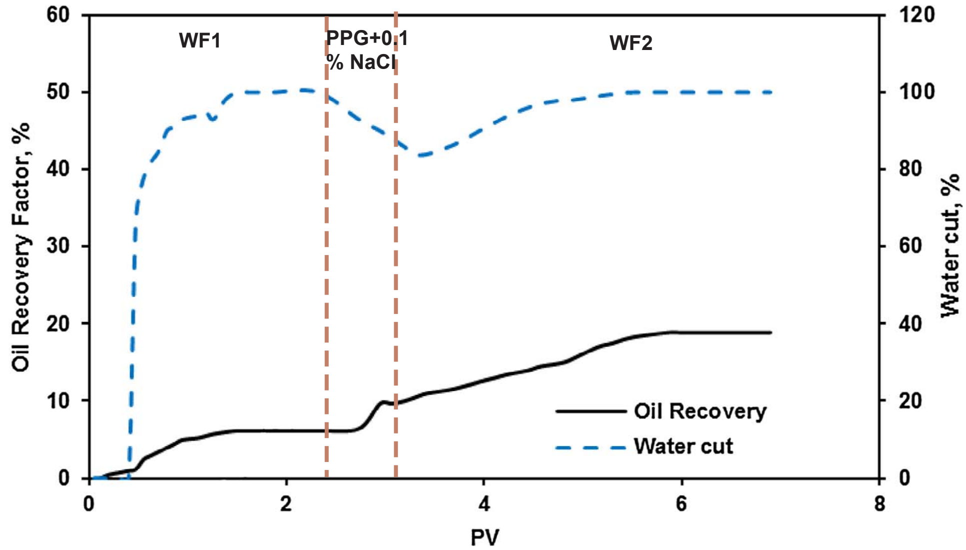

Fig. 14. Oil recovery factor and water cut when PPG swollen in 0.1% NaCl (Core#4- single partial open fracture).

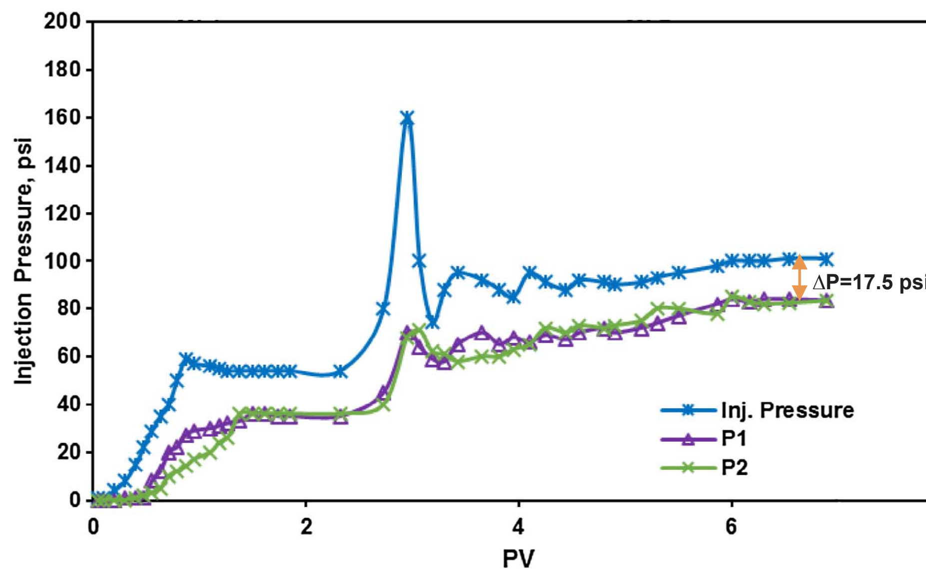

Fig. 15. Injection and monitoring pressures (Pinj, P1, and P2) when PPG swollen in 0.1% NaCl (Core#4- single partial open fracture).

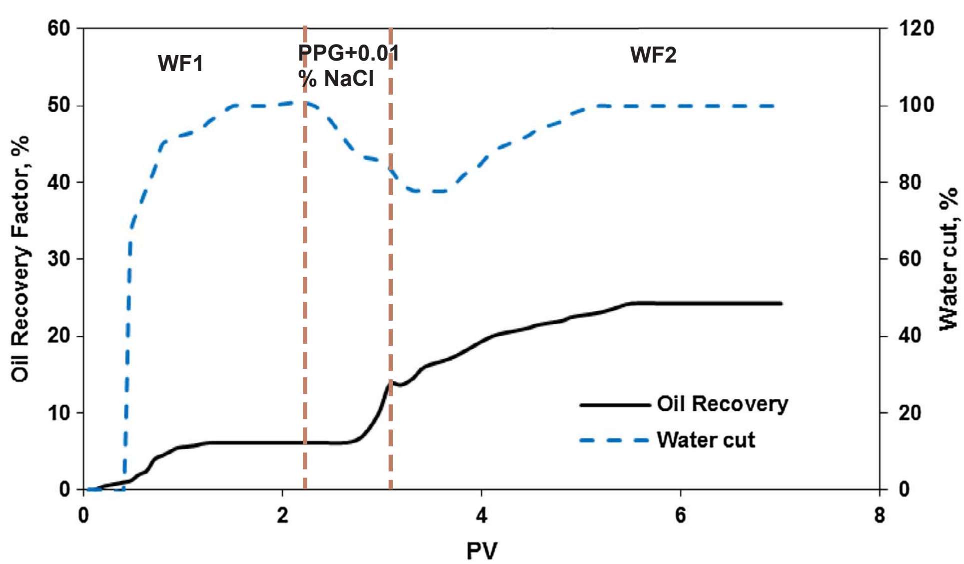

Fig. 16. Oil recovery factor and water cut when PPG swollen in 0.01% NaCl (Core#5-single partial open fracture).

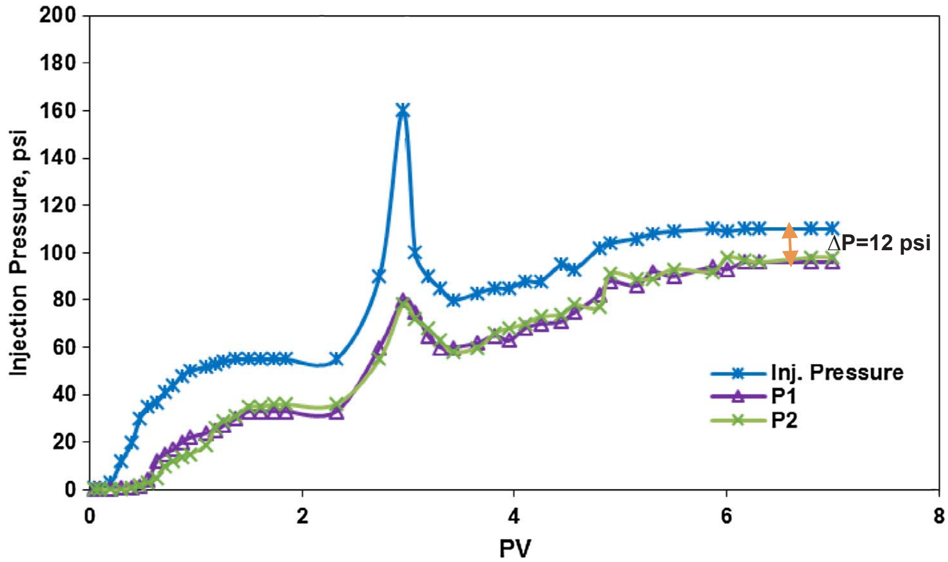

Fig. 17. Injection and monitoring pressures (Pinj, P1, and P2) when PPG swollen in 0.01% NaCl (Core#5-single partial open fracture).

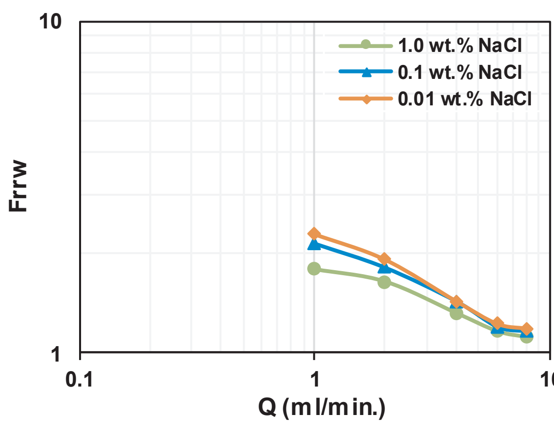

Fig. 18. Water residual resistance at different flow rates and different brine concentrations used to swell PPG.

Table 2
Oil recovery from matrix, associate areal sweep efficiency and Sor results for core # 1.

Stage	Oil Recovery from matrix,%	E_A, %	S_{or},%	Δ S_{or},%
WF1	6.06	30	54.26	
PPG&WF2	12.63	60	53.68	0.58
LSWF	19.71	70	48.86	4.82

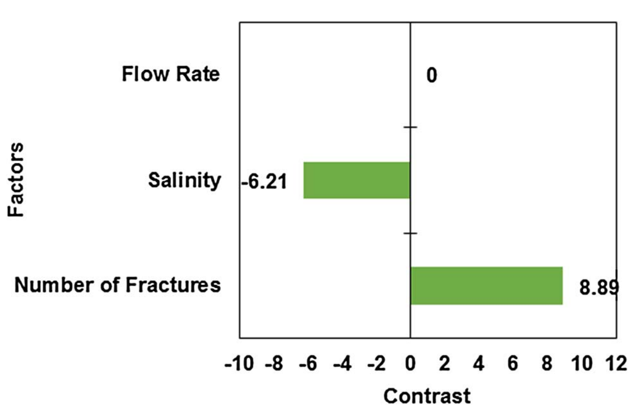

Fig. 19. Contrast Plot shows the effect of flow rate, brine salinity, and a number of fractures in oil recovery factor.

conformance [18]. The gel strength decreased with the decrease in brine salinity, and the gel became deformable. The PPG size increased with the decrease in brine salinity that used to swell the PPG due to the increased swelling ratio. As a result, the plugging efficiency increased with the decreased brine salinity. So the PPG became bigger and more deformable, which reduced the spaces between the preformed particles gel and, in turn, reduced the fracture conductivity. Therefore, more water was forced into the matrix during the PPG injection during PPG swelling in lower salinity water causing, the incremental oil recovery factor to increase.

6. Significant findings

In this part, we addressed the new findings compared to the earlier works. The most important finding is we can visualized how PPG and waterflooding can improve sweep efficiency and helps us to calculate the swept area. Then calculate the residual oil saturation (Sor) to figure out how PPG and low salinity waterflooding affect both displacement and sweep efficiency. The oil recovery factor from the matrix, associate areal sweep efficiency, and residual oil saturation during sequential injection cycles at different stages are listed in Table 2. The areal sweep efficiency after first waterflooding (WF1) is 30%. The Soi is 68%, and the oil recovery from the matrix is 6.06%. Based on the equations below, the Sor after WF1 is 54.26%, which means that more than half of the oil is left in the swept area. Fingering problem and vertical heterogeneity may be the reasons that cause the high Sor. Similarly, the Sor after PPG& WF2 is 53.68%. As indicated by high Sor, the microscopic sweep efficiency is low both in WF1 and PPG&WF2 stages. Even the areal sweep efficiency increased 30% after PPG&WF2; the low displacement efficiency caused a low oil recovery increment, which is only 6.57%. After the LSWF, the areal sweep efficiency increased 10% while the oil recovery from the matrix increased 7%. As observed, the PPG&WF2 stage decreased the Sor by 0.58% with a 30% increase in areal sweep efficiency while the LSWF has a 4.82% reduction of Sor associated with a 10% increase in areal sweep efficiency. With lower increased in areal sweep efficiency (10%), the low salinity water flooding can lower the residual oil saturation. We successfully developed a semitransparent model which can image fluid flow in consolidating rocks by using transparent gel. So the PPG treatment can improve sweep efficiency (E_A) and has little effect of displacement efficiency (E_D), whereas low salinity waterflooding can improve displacement efficiency and has little effect on sweep efficiency. Therefore, the coupled method bypasses the limitations of each method when

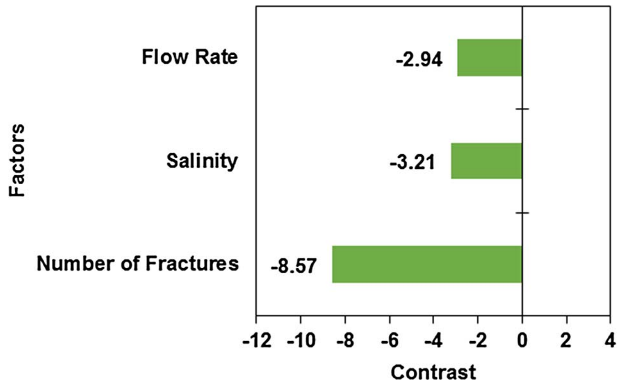

Fig. 20. Contrast Plot shows the effect of flow rate, brine salinity, and a number of fractures on Frrw.

used individually and improves both displacement and sweep efficiency.

$$R.\ F.\ = E_A \times E_D \tag{2}$$

$$E_D = \frac{S_{oi} - S_{or}}{S_{oi}} \tag{3}$$

$$R.\ F.\ = E_A \times \frac{S_{oi} - S_{or}}{S_{oi}} \tag{4}$$

Another significant finding, referring to our previous results, is mixed injection (second approach) resulted in higher oil recovery than sequential injection (first approach). The improved oil recovery during PPG treatment with gels swelled in 0.01% NaCl was 7.5%, but it was only 1.23% with the PPG swelled in 1.0% NaCl because the 0.1% NaCl resulted in higher swelling ratio (160 ml/ml) than 1.0% NaCl swelling ration (42 ml/ml). The increased in swelling ratio means the PPG hold more water and when the PPG injected into the fracture, these amount of water will force into matrix and, in turn, increased oil recovery factor [45]. Also, the improved oil recovery during second waterflooding was 10.6% in mixed mode, while it was only 5.34% in sequential mode because the low salinity water which used to swell the gel (PPG) increased the gel plugging efficiency and most injected water would diverted to matrix and then improve the swept area [9]. The improved recovery during the PPG injection in mixed mode was due to a large amount of low salinity brine forced into the matrix, which improved sweep efficiency and reduced the interfacial tension and released more oil drops. The Frrw result also showed that when using the PPG swelled in low water salinity (mixed mode), a higher water residual resistance factor occurred which, in turn, improved the sweep efficiency.

Overall, the mixed injection mode resulted in higher oil recovery factor (24.25%) than the sequential injection mode (19.7%). In contrast to the mixed injection mode which required three cycles of injection with a total of 7 pore volume injection, the sequential injection mode required five cycles with a total of 11.3 injected pore volume. Therefore, the mixed injection mode is the best choice because it resulted in the highest oil recovery with less injected pore volume.

Statistical analysis was conducted to elucidate the relationship between the different investigated parameters on the oil recovery factor and water residual resistance factor including flow rate, brine salinity, and a number of fractures. According to the Pareto plot obtained from the statistical analysis (Figs. 19 and 20), the number of fractures had the most influence on the oil recovery factor. The oil recovery factor increased as the number of fractures increased and brine salinity decreased; however, the flow rate did not show any effect on oil recovery factor. The number of fractures was also the most important factor affecting Frrw. The Frrw increased as the number of fractures, brine salinity, and flow rate decreased.

7. Conclusions

A series of core flooding tests using fractured sandstone core models were conducted to identify whether the combined process of PPG treatment and low salinity water flooding can better improve oil recovery than the single injection method. Two oil recovery approaches were evaluated: 1) the 5-cycle sequential injection approach where micro-PPG was prepared with 1.0% NaCl water and 2) the 3-cycle mixed injection approach where micro-PPG was prepared with different NaCl concentrations. The results yielded the following conclusions:

- Combining PPG treatment and LSWF technologies together could increase more oil recovery from fractured sandstone than applying individually. Low salinity water flooding can improve displacement efficiency, and PPG can improve sweep efficiency. The incremental oil recovery factor was increased when the micro-PPGs swelled in low water salinity during micro-PPG treatment.
- The plugging efficiency, stabilized injection pressure, monitoring pressure, and water residual resistance factor—all increased when the salinity of injected water decreased. The water residual resistance factor decreased as the flow rate, and brine concentration increased. However, at high flow rate, greater than 6 ml/min., the Frrw was the same for all the brine concentrations with no significant effect of flow rate on Frrw.
- The parallel partial open fractures model gave a higher oil recovery factor than a single partial open fracture model, and LSWF improved the oil recovery factor in the parallel partial open fractures better than the single partial open fracture.
- The mixed injection mode, which required three cycles with a 3.15 injected pore volume, resulted in higher oil recovery factor (24.25%) than the sequential injection mode (19.7%), which required five cycles with a 5.79 injected pore volume.
- We successfully developed a semitransparent model which can image fluid flow in consolidating rocks by using transparent gel.
- The statistical analysis results showed that the number of fractures had a higher influence on the oil recovery factor followed by brine salinity. However, the flow rate did not show any effect on the oil recovery factor. The number of partial open fractures is the factor that strongly influences Frrw while the flow rate is the least influential factor among the three.

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