SPE-173749-MS

Low Salinity Chase Waterfloods Improve Performance of Cr(III)-Acetate HPAM Gel in Fractured Cores

Bergit Brattekås, The National IOR Centre of Norway, Dept. of Petroleum Technology, University of Stavanger; Arne Graue, Dept. of Physics and Technology, University of Bergen, Norway; Randall S. Seright, New Mexico Petroleum Recovery Research Centre, USA

This paper was prepared for presentation at the SPE International Symposium on Oilfield Chemistry held in The Woodlands, Texas, USA, 13–15 April 2015.

Abstract

Polymer gels are frequently applied for conformance improvement in fractured reservoirs, where fluid channeling through fractures limits the success of waterflooding. Placement of polymer gel in fractures reduces fracture conductivity, thus increasing pressure gradients across matrix blocks during chase floods. A gel-filled fracture is re-opened to fluid flow if the injection pressure during chase floods exceeds the gel rupture pressure, thus channeling through the fractures resumes. The success of a polymer gel treatment therefore depends on the rupture pressure.

Swelling of gels, e.g. pre-formed particle gels, due to salinity differences between the gel network and surrounding water phase has recently been observed, but the effect has been less studied in conjunction with conventional polymer gels. Using core floods, this study demonstrates that low-salinity water can swell conventional Cr(III)-acetate HPAM gels, thereby improving gel blocking performance after gel rupture.

Formed polymer gel was placed in fractured core plugs and chase waterfloods were performed, using four different brine compositions of which three were low-salinity brines. The fluid flow rates through the matrix and differential pressures across the matrix and fracture were measured and shown to increase with decreasing salinity in the injected water phase. In some cores, the fractures were re-blocked during low-salinity waterfloods, and gel blocking capacity was increased above the initial level. Low-salinity water subsequently flooded the matrix during chase floods, which provided additional benefits to the waterflood. The improved blocking capacity of the gel was caused by a difference in salinity between the gel and injected water phase, which induced gel swelling. The results were reproducible through several experiments, and stable for long periods of time in both sandstone and carbonate outcrop core materials. Combining polymer gel placement in fractures with low-salinity chase floods is a promising approach in integrated EOR (IEOR).

Introduction

Polymer gel networks and their behavior have been studied in conjunction with a wide range of applications and industries, including medicine (tissue engineering, artificial muscles, sustained-release drug delivery systems), consumer products (disposable absorbent diapers, contact lenses, rubber, clothing and textiles) and the oil and gas industry, and has been a subject of interest for decades. The behavior of polymeric gel under a variety of conditions is therefore fairly well understood, and has been shown to depend on both properties of the gel itself as well as external conditions.

In the oil and gas industry, polymer gels can be utilized for conformance control in fractured or heterogeneous reservoirs: gel is then injected to reside in a high-permeability zone or fracture to divert flow during chase floods. Gel is often placed in a reservoir as a low-viscosity gelant (a solution containing all gel components that has not yet chemically reacted). Depending on composition and conditions, the formulation may mature during pumping close to the wellbore, resulting in pre-formed, high-viscosity gel, which is extruded through fractures. Both placement methods have been studied in detail, and are fairly well understood in water saturated porous media (Liang et al. (1993), Seright (1995, 2001, 2003a), Ganguly et al. (2002), McCool et al. (2009)). Due to the highly viscous and rigid nature once matured, polymer gel can efficiently reduce flow in fractures, and injected chase fluids (water, gas, EOR chemicals, etc.) may be diverted into rock matrix that has not previously been flooded. The success of a chase flood depends largely on the gel's ability to block high-permeability anomalies (i.e., fractures), and is therefore highly dependent on gel properties during subsequent flooding. The rupture pressure of the gel (the pressure at which the gel "breaks" and allows fluids to pass through it) is of special importance; a gel that has ruptured has a decreased blocking capacity and permits a higher degree of fracture flow compared to the intact gel originally in place (Ganguly et al. (2002), Seright (2003b), Wilton and Asghari (2007), Brattekås et al. (2014b)). A gel's ability to reduce conductivity in fractures is directly linked to its mechanical strength and its ability to completely occupy a fracture volume.

Changes in the external conditions around a polymer gel network may alter the gel volume and hence impact the blocking capacity of gel residing in a fracture by controlling the fraction of the fracture volume that is filled by gel, and are therefore crucial to the success of conformance improvement in fractured reservoirs.

Why do polymer gels swell and shrink?

The swelling and shrinking behavior of formed polymer gel networks is well known, and has been attributed to minute changes in external conditions such as temperature, solvent composition, ionic strength and external electric field (Horkay et al. (2000)). The volumetric behavior of a polymer gel after placement in a reservoir, and particularly during chase flood injections is important (Young et al. (1989)), mostly because polymer properties are known to change when in contact with reservoir fluids. For polymer solutions, viscosity and long term stability has been observed to decrease with increasing salinity in the surrounding brine phase (Akstinat (1980), Uhl et al. (1995), Choi et al. (2010), Wu et al. (2012)).

For cross-linked polymer solutions, numerous studies have shown that volumetric changes in a gel after placement in a reservoir can be attributed to *syneresis* (Vossoughi (2000), Romero-Zeron et al. (2008)), where solvent is expulsed from the gel network, or *dehydration*, either from imposing an external pressure gradient on the gel network (Al-Sharji et al. (1999), Krishnan et al. (2000), Wilton and Asghari (2007)) or caused by capillary spontaneous imbibition of solvent from the gel into an oil saturated adjacent porous rock (Brattekås et al. (2014a)). Recent works have also concentrated on swelling and shrinking behavior of polymer gels caused by contrasts in salinity or pH between the gel solvent and formation fluids, which influence the osmotic pressure balance between a polymer gel network and its surroundings. The effect of salinity contrasts has often been demonstrated in studies on PPG (pre-formed particle gel) networks, which show different gel swelling behavior in brines of different salinity (Bai et al. (2007), Zhang and Bai (2011)). Experimental studies performed on bulk volumes of gel demonstrated that volumetric changes in a gel network may occur if the salinity or pH of a contacting aqueous phase differ from the gel solvent (Aalaie et al. (2009), Tu and Wisup (2011)). Tu and Wisup (2011) indicated that volumetric swelling of the gel could improve conformance when the salinity of the formation brine was lower than that of the gel solvent. Aalaie et al. (2009) described the phenomenon as “undesired”, due mainly to the presence of mono - and multivalent cations in oil reservoir water, which may cause de-swelling (shrinking) of the gel network. Few works have yet focused on swelling effects caused by salinity contrasts between injected water and gel solvent during chase waterflooding in gel-filled fracture networks.

This work sought to investigate whether gel swelling caused by salinity contrasts between the gel solvent and injected water phase could improve conformance control in open fractures, and restore matrix flow after gel rupture. Experiments were performed using a HPAM Cr(III)-acetate gel with a high-salinity solvent that was placed in open fractures through sandstone and carbonate core plugs. The gel rapidly ruptured during chase waterflooding, and most of the injected water was produced through the fracture. Low-salinity waterfloods, applying three different brine compositions, were thereafter performed. We found that a reduced salinity in the injected water phase compared to the gel solvent improved the blocking performance of the gel: 1) injection pressures increased during low-salinity floods, and exceeded the initial gel rupture pressure in all experiments, and 2) matrix production rates increased during low-salinity flooding, dependent on the salinity content of the injected water phase. The fracture was in some core plugs completely re-blocked during low-salinity waterflooding. The swelling of the polymer gel network was reversible, and gel blocking efficiency immediately decreased when water of the same composition as the gel solvent was injected.

Experiments

Core preparation

Cylindrical outcrop core plugs were drilled out from larger sandstone and limestone slabs and cut to length. The core plugs were thereafter fractured longitudinally using a band saw, which created smooth fractures. Core and fracture surfaces were washed using tap water and the core halves were dried for a week, first at room temperature and thereafter at an elevated temperature of 60°C. Fractured core plugs were assembled by placing a POM (polyoxymethylene) spacer between two core halves, creating a 1-mm fracture aperture with a calculated permeability of approximately $8.4*10^4$D (Witherspoon et al. (1980)). The fractured cores were coated in several layers of epoxy and facilitated one common inlet for flow (both matrix and fracture) and three outlets (one for each matrix core half and one fracture outlet). Pressure taps were drilled into each matrix core half, approximately 1 cm from the inlet end face. The core setup may be seen in Figure 1.

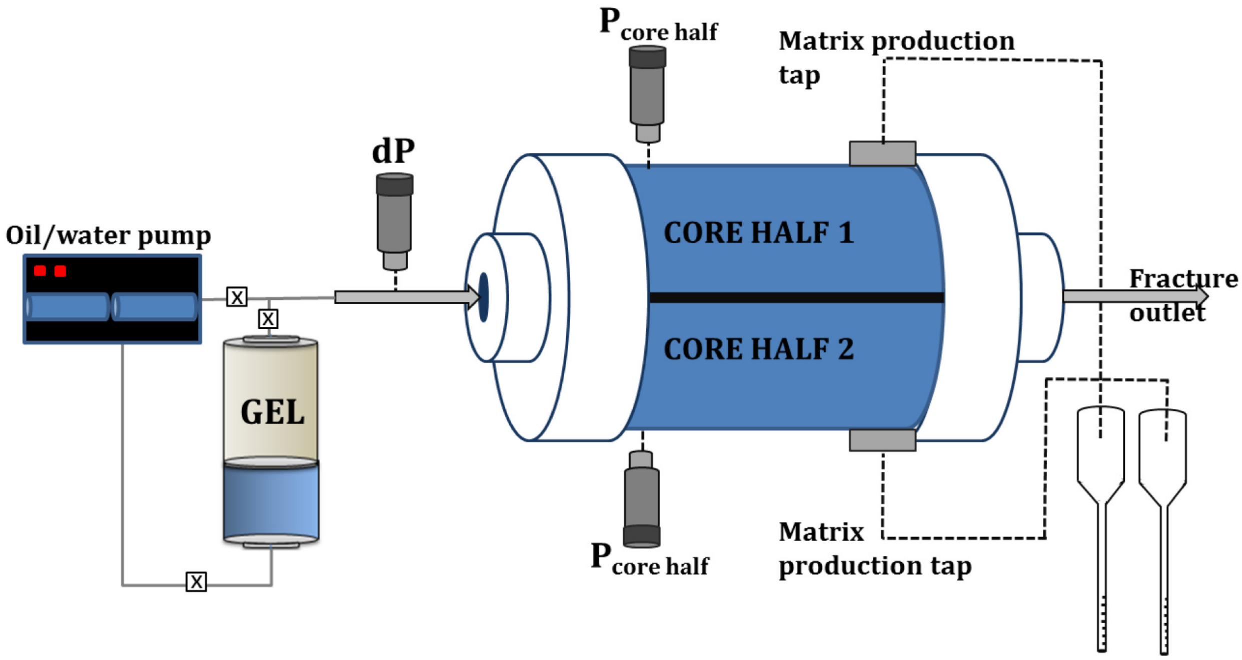

Figure 1—Schematic setup of the fractured core plug and experimental equipment.

Two outcrop core materials were used:

1. Bentheimer sandstone from the Gildenhausen quarry outside of Bentheim in Germany: a quite homogeneous sandstone with typical properties of K=1.2D (permeability) and Φ=23% (porosity) (Schutjens et al. (1995), Klein and Reuschle (2003)).
2. Edwards limestone originating in west Texas. The core material has previously been described by Tie (2006) and Johannesen (2008), and is heterogeneous with a trimodal pore size distribution consisting of both microporosity and vugs. The permeability and porosity values vary between samples, but is typically in the range of K=3 -28mD and Φ=16-26%.

Five fractured core plugs were used in this study: two consisting of Edwards limestone (Core 1_EDW and Core 2_EDW), one consisting of Bentheimer sandstone (Core 1_BS), and two composite core plugs where a sandstone and a limestone core half were assembled and separated by the open fracture (Core 1_EDW_BS and Core 2_EDW_BS). The cores were saturated directly by mineral oil (n-decane) under vacuum, and porosity was calculated from weight measurements. The permeability of the cores could not be explicitly measured due to the experimental setup, but a relative measure for core matrix conductivity was found by flooding n-decane from the inlet and through each of the matrix outlets separately while measuring the absolute and *in-situ* pressure drops. An overview of the fractured core plugs used in this study may be found in Table 1.

Table 1—Core plug properties

Core ID	Length [cm]	Diameter [cm]	Pore volume [mL]	Porosity [%]	Conductivity contrast	Gel inj. [PV]	Gel break-through [FV]
1_EDW_BS	7.34	5.03	37.25	28.14*	48.4	21.3	5.4
2_EDW_BS	7.25	5.02	39.08	29.79*	42.9	20.3	3.0
1_EDW	7.18	4.78	33.36	25.89	None	23.8	4.4
1_BS	6.94	5.15	35.99	24.89	None	22.1	4.4
2_EDW	14.74	4.89	67.66	24.50	None	11.7	1.6

*mean value

Experimental schedule

The experimental schedule consisted of two separate steps: 1) a gel placement, and 2) a subsequent waterflood. Through both experimental steps, the pressures across the core and in each core half were recorded and fluid production rates from the matrix and fracture outlets logged. The experimental setup may be viewed in Figure 1.

Gel placement Gel preparation: The polymer gel used in the experiments was a commercially available HPAM crosslinked by Cr(III)-acetate. Gel was prepared by mixing polymer in brine at 5000-ppm concentration. 417-ppm Cr(III)-acetate was thereafter added to the polymer solution, and the gelant (non-crosslinked gel solution) was placed in an accumulator and aged at 41°C for 24 hours (5 times the gelation time). Gel injections and subsequent waterfloods were performed at ambient conditions, and the mature gel was allowed to cool down to room temperature before gel injection started. In this work, the gel solvent was high-salinity formation water from a North Sea chalk reservoir (see Table 2).

Table 2—Brine compositions, used for gel preparation and chase waterflooding.

	Formation water (FW)	LowSal1	LowSal2	LowSal3
NaCl [g/L]	40	1	0.5	0
$MgCl_2*6H_2O$ [g/L]	34	0	0	0
$CaCl_2*2H_2O$ [g/L]	5	0	0	0
Brine salinity [ppm]	79170	1000	500	0

Gel injection: Mature gel was injected into the fractured cores through the accumulator, using a two-cylinder pump and a constant injection rate of 200 mL/h. During mature gel injection, the gel itself will only progress through the open fracture, but gel solvent may leave the gel and flood the matrix during a leakoff process (Seright (2003a)). Volumetric recordings of fluid production from the matrix and fracture outlets were performed, and gel breakthrough at the fracture outlet recorded. A total of 800 mL of gel was injected into each core. After gel placement, the cores were shut-in for 24 hours with all inlets and outlets closed.

Waterflooding Waterfloods were performed to measure the blocking capacity of the gel residing in the open fractures. Matrix outlets were open during waterflooding and fluid production from each core half, and from the fracture outlet, was recorded. The main purpose of initial waterflooding was to rupture the gel in the fracture and measure the rupture pressure, PR. During continued waterflooding after gel rupture, the majority of injected water flows through the fracture without displacing the oil in the matrix. We investigated whether gel swelling caused by salinity differences between the injected water phase and gel solvent could improve conformance control in wide fractures and restore matrix flow. Different brine compositions were used during waterflooding, including formation water and three different low-salinity brines, and are listed in Table 2. The waterflood schedule was specific for each fractured core, and an overview is given in Table 3. The pressures across the fractured core plugs as well as *in-situ* matrix pressures were measured during waterfloods. Volumetric recordings of fluid production from the matrix and fracture outlets were also performed. Pressures and production rates combined gave insight to gel blocking capacity and changes in gel performance due to low salinity-induced gel swelling.

Table 3—Waterflood schedules for each core.

Core ID	Inj. rate [ml/h]	Duration [h]	Brine injection sequence				
1_EDW_BS	6 - 499	44	1) LowSal3				
2_EDW_BS	6 (const)	886	1)FW	2)LowSal1	3)LowSal2	4)LowSal3	5)FW
1_EDW	6 (const)	166	1)FW	2)LowSal1	3)LowSal2	4)LowSal3	5)FW
1_BS	6 (const)	210	1)FW	2)LowSal1	3)LowSal2	4)LowSal3	5)FW
2_EDW	6 (const)	ongoing	1) LowSal3				

Results and Discussion

Gel placement

The first experimental step was gel placement, where mature gel was injected through each fractured core plug at a constant injection rate of 200 mL/h (equivalent to 305-330 ft/D when all flow is confined to the fracture). Mature gel is confined to fractures during injection, however, solvent may leave the gel in the fracture and leakoff into the matrix (Seright (2003a)). This behavior causes the gel in the fracture to concentrate and become more resistant to applied pressure gradients, and is an important distinction from *in-situ* gelation systems, where the gel concentration in the fracture and adjacent matrix is uniform after placement.

The behavior of the gel during extrusion through a fracture, specifically the extent to which solvent leaves the gel, has important implications for gel blocking efficiency during chase floods (Brattekås et al. (2013), Brattekås et al. (2014b)), because solvent leakoff tells us something about the gel's tendency to concentrate and form wormholes. Lower leakoff rates than Seright's filter cake model (Seright (2003a)) were observed during gel extrusion in all core plugs in this study. Still, several pore volumes (PV) of water left the gel during extrusion and reduced the matrix saturation from 100% oil saturation to the residual oil saturation (S_{or}) within two hours of gel injection initiation. At S_{or}, shrinkage of the gel due to capillary spontaneous imbibition will not occur (Brattekås et al. (2014a)). Gel breakthrough occurred between 3 and 5.5 fracture volumes (FV) of gel injected (tabulated in Table 1). We assume that fresh gel extruded through concentrated gel in wormholes for the remaining injection period (ranging from 110-220 FV).

Waterflooding

Varying the salinity of the injected water phase In three core plugs (1_EDW, 1_BS and 2_EDW_BS), waterfloods were performed using a constant injection rate of 6 mL/h, and a varying salinity in the injected water phase. Waterfloods were initiated using formation water with the same composition as the gel solvent. During injection of formation water, initial gel rupture was achieved and the rupture pressure measured. After gel rupture, the pressure gradients across the core and in both core halves were allowed to stabilize before altering the composition of the injected water. The salinity of the injected water was reduced stepwise throughout waterflooding: brine changes were performed when one piston of the two-piston pump was at its end point, without stopping or disconnecting the pump. Thus, all measurements were dynamic for the duration of waterflooding. The experiments in this section were terminated after formation water had been injected a second time. The results are shown in Figure 2 (Core 1_BS), Figure 3 (Core 1_EDW), and in Figure 4 and Figure 5 (Core 2_EDW_BS).

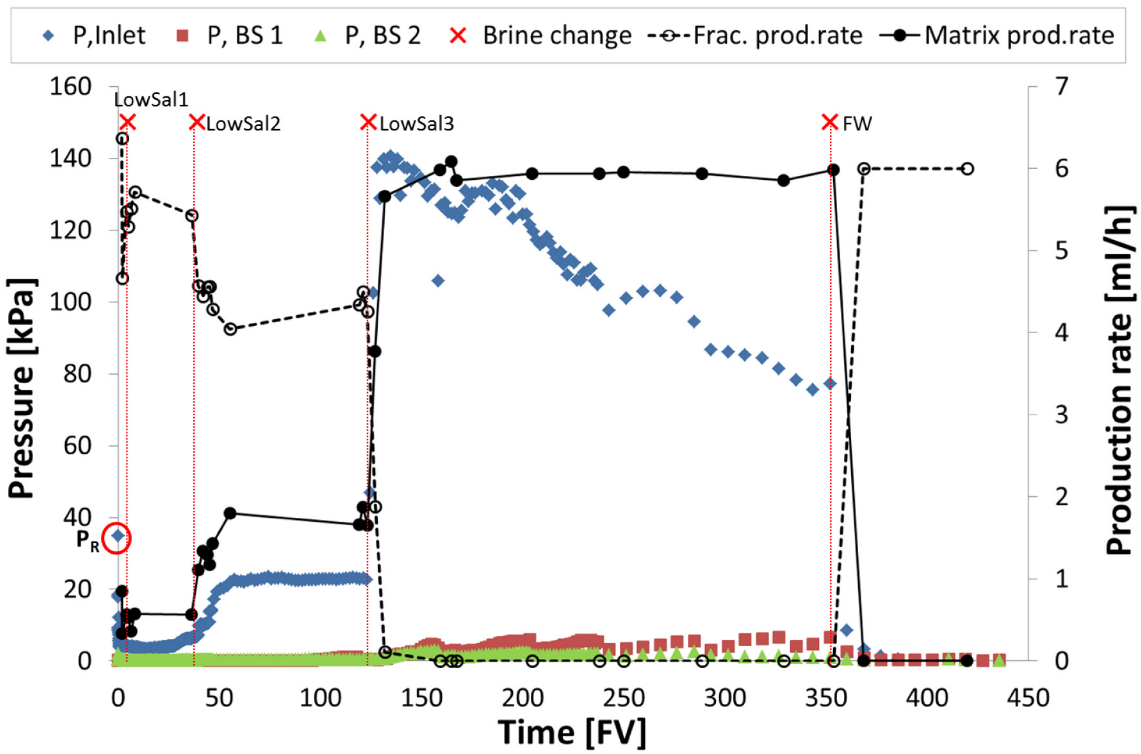

Figure 2—Measured differential pressures (left y-axis) and production rates (right y-axis) across the fracture and matrix core halves during sequential water injection in Core 1_BS.

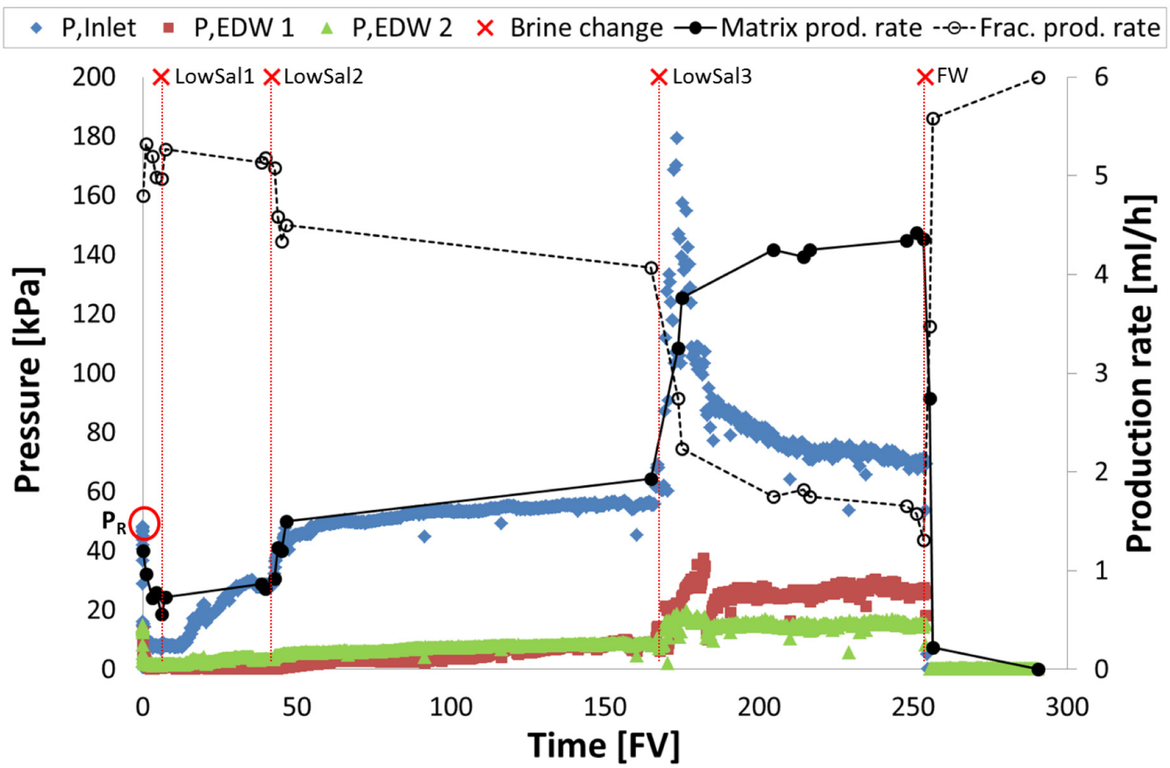

Figure 3—Measured differential pressures (left y-axis) and production rates (right y-axis) across the fracture and matrix core halves during sequential water injection in Core 1_EDW.

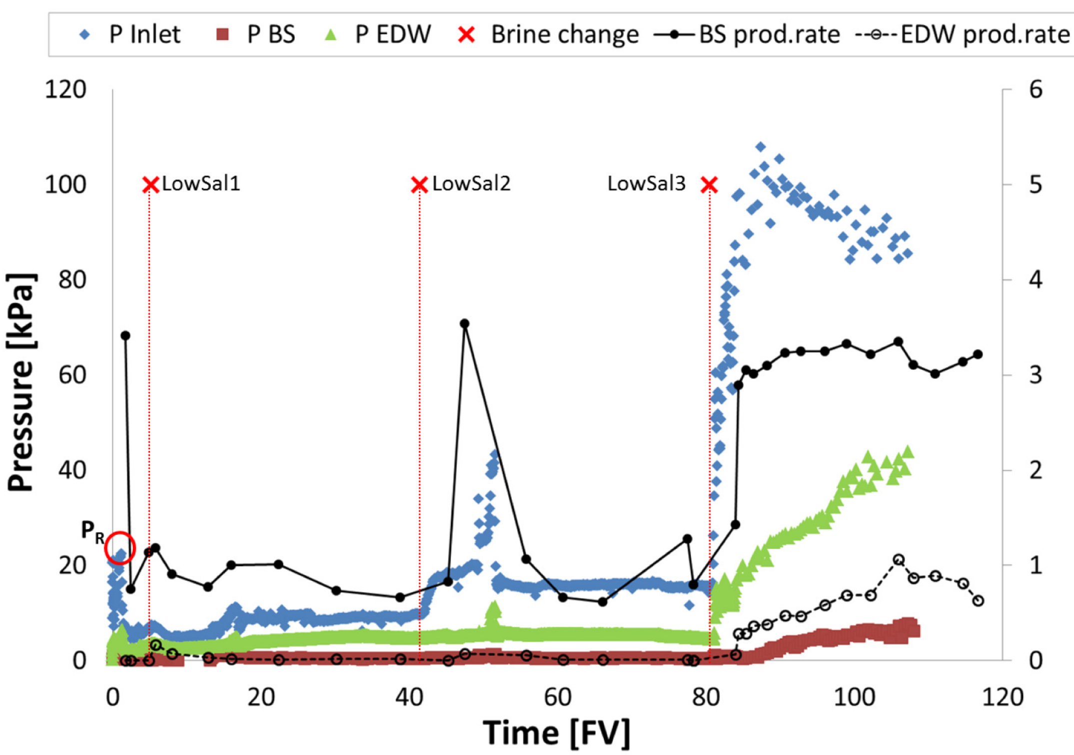

Figure 4—Measured differential pressures (left y-axis) and production rates (right y-axis) across the fracture and matrix core halves during the start of sequential water injection in Core 2_EDW_BS.

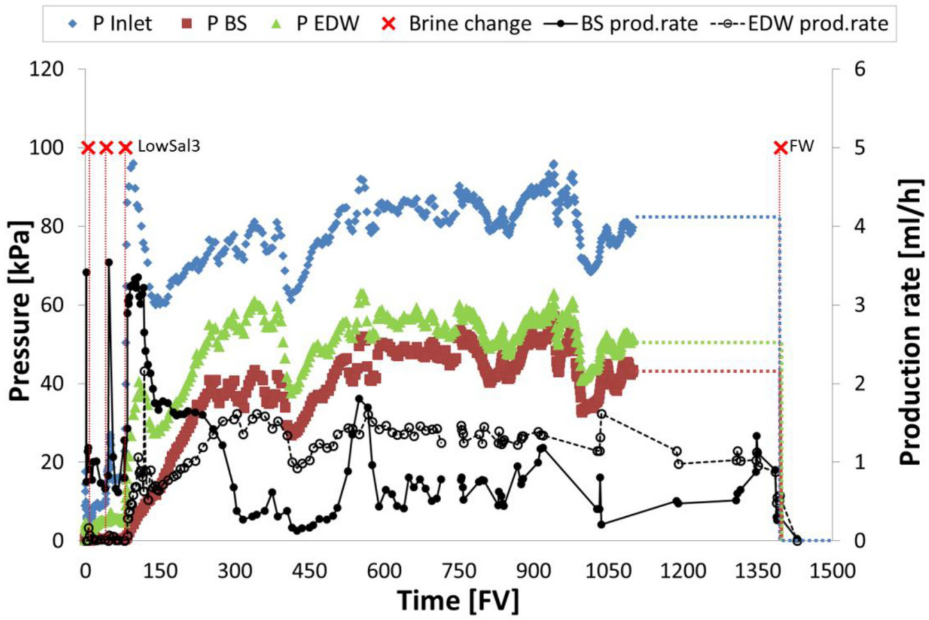

Figure 5—Measured differential pressures (left y-axis) and production rates (right y-axis) across the fracture and matrix core halves for the duration of water injection in Core 2_EDW_BS. The pressure logging tool failed after t=1100 FV water injected. The pressure profiles for the remainder of the experiment were recorded by visual inspection, and are indicated in the dotted blue, green and red lines in the figure.

The rupture pressures (P_R) were measured with both the matrix and fracture outlets open and were recorded at 5.03 kPa/cm (Core 1_EDW), 6.44 kPa/cm (Core 1_BS) and 3.10 kPa/cm (Core 2_EDW_BS), which is slightly higher than previously measured rupture pressures after gel placement at the same gel injection rate (Brattekås et al. (2014b)). This deviation is probably caused by the experimental design (open matrix outlets) as previous work was performed with only the fracture outlet open. The rupture pressures are indicated by red circles in the figures. After gel rupture and system stabilization, water-flooding continued applying *LowSal1* water as the injected phase. *LowSal1* had the highest salt content of the three low- salinity water compositions, at 1000-ppm NaCl. During *LowSal1* injection, a slight increase in injection pressure occurred in all three cores, being most prominent in Core 1_EDW. A corresponding, minor drop in fracture production rate was also observed. After approximately 10 PV *LowSal1* injected, the systems stabilized, and pressures and production rates remained close to constant until more than 40 PV total of *LowSal1* water had been injected. At *LowSal2* initiation, a more prominent increase in pressures and matrix production rates was observed in all cores. In Cores 1_BS and 1_EDW, an abrupt drop in fracture production rate occurred, indicating that the gel blocking capacity increase as the gel swells and fill a larger volumetric section of the fracture. Further decrease in the salinity of the injected water phase, utilizing the *LowSal3* water composition, caused further swelling of the gel and an abrupt increase in injection pressure and matrix production rate occurred. In all three cores, the injection pressure increased up to more than three times higher than the initial gel rupture pressure. The fracture production rates dropped abruptly as the injection pressure increased: in Cores 1_EDW and 2_EDW_BS, approximately 33% of the fluids were transported through the fracture after the system had stabilized during *LowSal3* waterflooding, while the remaining 67% of water flooded the matrix. In Core 1_BS the fracture was efficiently sealed off by low-salinity water injection and all fluids were produced through the matrix. This indicates that injection of low-salinity water not only improve gel performance after rupture compared to injection of higher salinity water (e.g. sea water or formation water), but greatly enhance gel performance above the initial level. In Core 2_EDW_BS more than 1200 FV of *LowSal3* were injected to investigate the long term stability of the gel blocking ability. The pressure gradients and production rates remained stable for this period, although with small fluctuations, and loss of gel blocking capacity with time and high water throughput was not indicated.

A decreasing trend in injection pressure was observed during *LowSal3* waterflooding of Core 1_EDW and Core 1_BS. The decrease in pressure had no apparent effect on the matrix and fracture production rates, nor on the measured *in-situ* pressures, and is believed to be caused by erosion of the gel layer between the inlet injection point and the matrix: this will aid water to more efficiently enter and flood the matrix, without influencing the gel blocking capacity in the fracture.

The final step in the waterfloods in this section was injection of formation water (*FW*). When *FW* entered the fractured cores, injection pressures immediately decreased to a low value, and fluid production through the fractures commenced. Less than 10 FV of *FW* was injected before the effects of low-salinity flooding on the gel were eliminated and the gel blocking capacity was minimized. The gel swelling caused by salinity differences between the gel solvent and injected water phase therefore appears to be reversible, and gel swelling effects, which cause improved fracture blocking, depend on continuous injection of water with a lower salinity than the gel solvent.

Direct waterflooding by low-salinity water In Core 1_EDW_BS and Core 2_EDW, waterflooding after gel placement was performed using the *LowSal3* brine composition (distilled water) only- thus the injected water phase differed in composition from the gel solvent for the duration of waterflooding. The results are shown in Figure 6 (Core 1_EDW_BS) and Figure 7 (Core 2_EDW). The rupture pressures were measured at 6.4kPa/cm and 4.8kPa/cm, respectively, which is comparable to the measured rupture pressures after gel placement in the previous section.

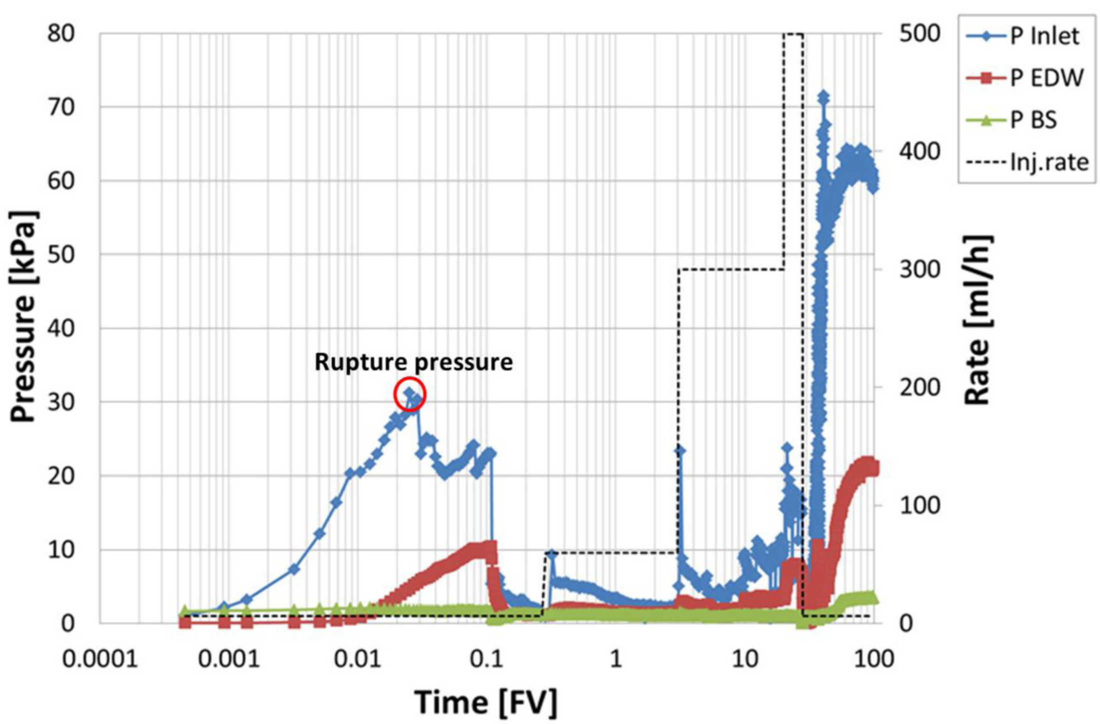

Figure 6—Measured differential pressures across the fracture and matrix core halves during low-salinity water injection in Core 1_EDW_BS. The x-axis is given in logarithmic scale, to better see the results from short term waterflooding (t = 0-28 FV injected).

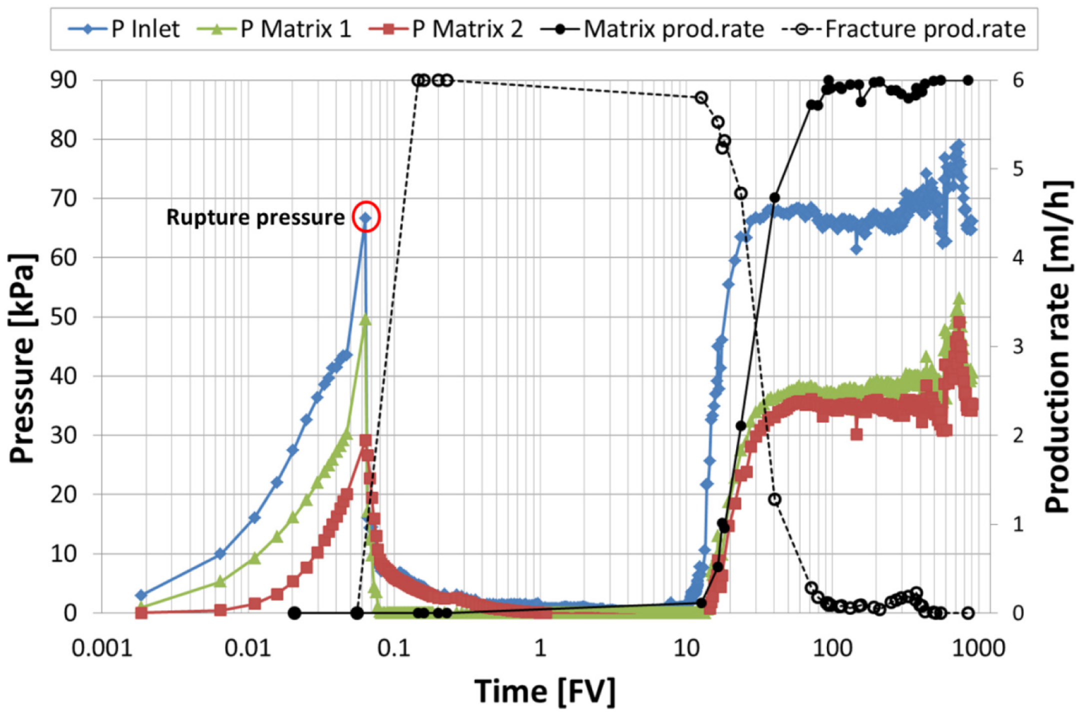

Figure 7—Measured differential pressures (left y-axis) and production rates (right y-axis) across the fracture and matrix core halves during low-salinity water flooding of Core 2_EDW. The x-axis is given in a logarithmic scale for improved viewing of early waterflood characteristics.

In 1_EDW_BS, water injection continued after gel rupture using varying injection rates to measure the gel blocking characteristics. The pressure trends measured at the inlet and in the respective core halves are shown in Figure 6. The gel ruptured shortly after waterflood initiation and water production from the fracture outlet was observed. The differential pressure rapidly decreased when the rupture pressure was reached, and all production of fluids was subsequently through the fracture. By varying the water injection rate, peaks in pressure were seen, followed by swift pressure drops. This is a characteristic behavior of the gel owing to erosion of wormholes, and is expected at higher injection rates (Brattekås et al. (2014b)). Reducing the injection rate to 6 mL/h (the lowest water injection rate used), the pressures across the core and in both core halves were reduced to close to zero. So far, the results did not suggest quantitative differences between gel behavior during short-term high-salinity (Brattekås et al. (2014b)) and low-salinity waterflooding. *LowSal3* injection continued at 6 mL/h for 100 FV of water injected, corresponding to an injection time of approximately 44 hours. Between t=28-32 FV, pressures remained low and water production was only observed through the fracture. From t=32 FV injected (≈4.5 h), the pressure drop across the core increased, as did the pressure in both core halves. From t=60 FV injected (t≈20 h), the pressures remained constant at a value twice as high as the initially measured rupture pressure. The matrix production rate in this time period totaled 2.8 mL/h, which is slightly below 50% of the total production rate: the remaining water volume was produced through the fracture.

In Core 2_EDW the injection rate was not varied and water was injected at a constant injection rate of 6 mL/h for over 1000 hours. The results are shown in Figure 7. The rupture pressure was reached shortly after water injection start, after which the pressures across the core and in both core halves decreased. After gel rupture, the fracture production rate abruptly rose to 6 mL/h, meaning that all fluids were produced through the fracture. The pressure increased after an incubation period of approximately 8 FV (t≈12 h), during which *LowSal3* was continuously injected, and remained constant for a prolonged period of time (>1000 FV) at the level of the initial gel rupture pressure. The matrix production rate increased alongside the pressure profiles: a minor increase in matrix production was observed during the incubation time, with a steep increase from t=12.6- 93.8 FV. The matrix production rate remained stable from t=94 FV injected. At this point the fracture was efficiently sealed off by gel and all fluids were produced through the matrix. The injection pressure and matrix production rates remained stable at high levels for a prolonger period of time (t>1000 FV injected), reflecting a continued improved blocking ability for the gel residing in the fracture.

During waterflooding, non-uniform matrix production from the core halves, as well as differences in *in-situ* pressure profiles were seen, both in Cores 1_EDW and 1_BS (no conductivity contrast between the core halves), and in Cores 1_EDW_BS and Core 2_EDW_BS (measured conductivity contrasts between the core halves of 48.4 and 42.9, respectively- hence, the sandstone core half was more than forty times more conductive than its limestone counterpart in both assembled cores). When contrasts in conductivity between two media exist, Darcy’s law dictates that a higher pressure is required to reach a given flow rate in the low conductivity medium, compared to the medium of high conductivity. The distribution of flow through a core plug with an inherent conductivity contrast is therefore dictated by the differential pressure, and fluid channeling through the pathway of highest conductivity (e.g. fractures) expected. In our experiments, however, we often found that conductivity contrasts were reflected in *in-situ* pressure profiles, but not in the production rates. For example, in Core 2_EDW_BS (Figure 4 and Figure 5) the sandstone core half produced more than twice the fluids compared to the Edwards limestone core half during the first 120 FV of waterflooding, but during *LowSal3* injection a shift in production occurred and the lower permeability limestone conducted the majority of fluid flow for the remaining 1000 FV of waterflooding. Non-uniform fluid production from the core halves is believed to be caused by small scale differences at the inlet end faces of the core halves, due to: 1) differences in gel erosion during waterflooding, or 2) disintegration of core material during low-salinity waterflooding, causing small particles to lodge in pore throats and change the flow pattern- and will not be prominent on field scale, where matrix blocks are significantly larger compared to the fracture volume.

Figure 8 shows the average residual resistance factor (F_{rrw}) in the fracture. The residual resistance factor is the ratio of initial to post-gel treatment fracture conductivity, and provides a measure of the permeability reduction achieved by the gel. Figure 8 shows F_{rrw} measured at 6 ml/h for each brine composition during waterflooding of 1_EDW, 1_BS and 2_EDW_BS. Data from Brattekås et al. (2014b) is also included for comparison, and gives insight to conventional behavior of gel during waterflooding- where gel residual resistance factor is usually observed to decrease. The decreasing trend depended on the placement method and applied differential pressure during waterflooding when formation water with the same composition as the gel solvent was injected (Brattekås et al. (2014b)). In cores where low-salinity waterfloods were implemented after gel rupture, residual resistance factors increased with water through-put and decreasing salinity content in the injected water phase. Frrw values for each brine composition were not consistent between the cores, caused by differences in core material and solvent leakoff during gel placement. In Core 1_EDW and Core 1_BS, the average residual resistance factors during *LowSal3* waterflooding were 330 and 169 times higher than the end point residual resistance factor measured during *FW* injection. In Core 1_BS average Frrw was almost 5300 times higher, and converged towards infinity because the fracture was completely re-blocked (zero conductivity) during the LowSal3 waterflood.

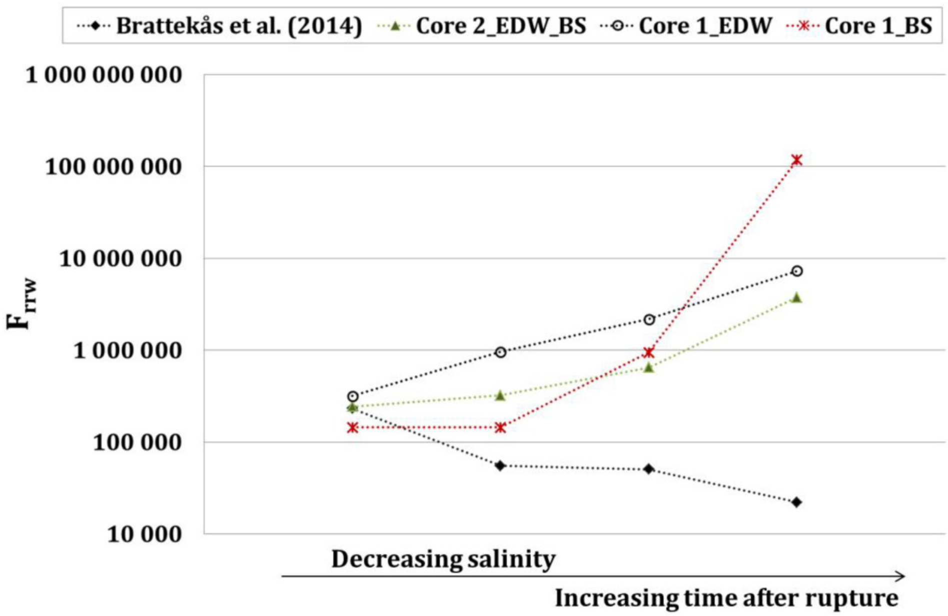

Figure 8—The residual resistance factor measured in the fracture during waterflooding at 6 ml/h as a function of decreasing salinity and increasing time after gel rupture. Core 3 from Brattekås et al. (2014b) is shown for comparison, where formation water was continuously injected.

Discussion

The increase of fracture flow capacity caused by gel dehydration and rupture during chase waterflooding is generally irreversible. Gel treatments may, however, still be efficient in reducing fracture flow after rupture due to the inherent elasticity of the gel, which allow wormholes to collapse and re-open corresponding to the applied differential pressure (Wilton and Asghari (2007, Brattekås et al. (2014b)), although common belief still dictates that the rupture pressure is the ultimate pressure achievable during water chase floods and that fracture production after gel rupture cannot be easily remedied. We have presented experimental work that shows how gel blocking capacity may be controlled by varying the salinity of the injected water relative to the gel solvent. Some important distinctions of this system must be clarified to distinguish where and when low-salinity waterflooding may be successfully applied to improve the conformance control of polymer gel.

Gel vs gelant

In this work, mature gel was injected to reduce flow in open fractures. Previous published work demonstrated that mature gel will only progress through open fractures, and that its concentration and rigidity increase during extrusion, because solvent leaves the gel in a leakoff process (Seright (1999), (2001), (2003a)). Fresh gel flows through the concentrated gel in wormholes, which are believed to be the weakest part of the gel during chase floods, and likely where the gel ruptures. The occurrence of wormholes is largely responsible for a gel's ability to significantly reduce flow after it ruptures, as injected fluids are contained in the narrow flow channels constituting the wormholes through the concentrated gel. When gelant is placed in a fracture, solvent does not separate from the polymer, and the gel concentration filling the fracture remains constant. Gelant solution may enter the matrix adjacent to the fracture during injection, which may cause bonds to form between the gel in the fracture and the gel in the matrix during crosslinking, resulting in an increased initial rupture pressure (Ganguly et al. (2002)). During continued waterflooding after gel rupture, gel blocking capacity is, however, reduced compared to mature gel placed in fractures, because larger sections of the fracture has opened to flow (Brattekås et al. (2014b)).

Very narrow wormholes are present when formed gels are extruded into a fracture. These narrow wormhole pathways probably provide the water pathway when brine ruptures the gel. Because these wormholes are quite narrow and the gel is quite concentrated (due to dehydration during placement), mature gel may respond better to low-salinity waterflooding after placement in a fracture than gel placed in its immature state, i.e., a small degree of swelling of the concentrated gel more effectively constricts the wormhole. In contrast, in fractures where gel was placed in its immature state, the aperture of the rupture path may be quite wide- both because the brine/gel mobility contrast was less and the gel was more pliable than the concentrated pre-formed gel. Consequently, less pronounced effects may be seen during low-salinity brine injection, because the gel must experience a higher degree of swelling to fill a comparable section of the fracture. Injection pressures during low-salinity waterfloods were measured to be above the initial rupture pressures in all experiments, and frequently 2-3 times as high as the measured rupture pressures. These are significant effects, particularly for 1-mm wide fractures, and indicate that gel blocking efficiency due to gel swelling may also be significantly improved in fractures with wider rupture apertures, for example experienced after immature gel placement.

Salinity- how high can we go?

In gel applications in fractured reservoirs, a high-salinity gel solvent may be desired, to 1) avoid reactions between the gel and formation water during and after gel placement, and 2) to be able to improve gel conformance by reducing the salinity of the chase water relative to the gel solvent. Concerns about the long-term stability of polymer gels with high-salinity solvent must therefore be addressed. An increased degree of syneresis has previously been pointed out as a good reason to stay below certain concentrations of mono- and multivalent cations in the gel solvent (Aalaie et al. (2009)), and detailed studies of gel solvent compositions and their effects on gel stability may be required before field applications. The short-term behavior of high-salinity gel, as used in this study, was comparable to gel containing 5% NaCl only, both during and after injection into an open fracture (Brattekås et al. (2014b), Seright (2003a)). In Core 2_EDW and Core 2_EDW_BS high-salinity gel blocking capacity was also demonstrated to remain stable for more than a thousand hours of low-salinity waterflooding.

If reduction of injection-water salinity is mainly intended to improve gel blocking capacity only, it may be possible to place gel of extra high salinity in the reservoir. Subsequently, the gel may swell after contacting formation water (if the salinity of the gel solvent exceeds formation water salinity). More specifically, injection of sea water may have the same gel swelling benefits that low-salinity waterflooding demonstrated in this study. The added advantages from low-salinity flooding will, however, not be experienced in such cases, because sea water will enter and flood the matrix.

Our work did not suggest that the injection order of the different water compositions were important to achieve improved blocking. On the contrary, our studies showed that the gel swelling effect caused by low-salinity waterflooding was reversible and only dependent on continuous injection of a given water composition- thus, gel was de-swelled and fracture production commenced when formation water with the same composition as the gel solvent was injected. Two observations were made which require further investigations: 1) the rupture pressures achieved by injecting low-salinity water did not differ from P_R achieved during high-salinity waterflooding. This statement does, however, require further experiments to provide a wider basis for comparison, and 2) When *LowSal3* was injected into the cores directly, the most severe swelling effect and consequent improvement in gel blocking was observed after a longer time period (4.5-10.7FV) compared to experiments where the salinity of the injected water phase was gradually reduced (0.5-1.9FV after *LowSal3* initiation). One explanation may be that for a time while water is eroding the gel, small gel particles can pass through the rupture path and exit the core unhindered. During low-salinity waterflooding loose gel particles may get re-lodged in the rupture path, thereby clogging it. If there is enough area upstream in the fracture to allow effective leakoff of the water without re-rupturing a path through the gel, the fracture remains blocked. The mechanism of re-lodging of gel particles will be further investigated experimentally. For now, we can only speculate that re-lodging of gel particles may be aided by their swelling, and the swelling of the concentrated gel layer which create narrower rupture paths. Thus, the long induction time seen in Core 1_EDW_BS and Core 2_EDW may be caused by short fractures, where the gel particles are initially washed out before they are able to swell and clog the rupture paths through the fracture.

Oil recovery

In the experiments presented in this work, outcrop rock core samples were used, which are generally understood to be strongly water-wet. The core plugs were saturated by mineral oil, and was at the residual oil saturation at waterflood initiation. Additional recovery of oil during waterflooding was therefore not expected. In some experiments (e.g. using Core 2_EDW) a few drops of oil were produced during long term *LowSal3* waterflooding, often alongside rock particles, suggesting that the minor oil recovery resulted from dissolution of core material and following collapse of pores and throats caused by the injection of several hundred pore volumes of water. In systems at less water-wet conditions, saturated by complex crude oils, increased oil recovery may be expected from low-salinity flooding of an oil saturated matrix (Morrow and Buckley (2011)), and is an added benefit to the improved blocking capacities of the gel.

Future work

The discussion section above points out that the formation of wormholes influence the success of a low-salinity waterflood to improve gel blocking capacity. It is therefore also of importance to investigate leakoff characteristics during gel propagation through fractured, oil-saturated media. Experiments should also be performed where gelant is placed in fractured core plugs and cross-linked after placement, to reveal the effects of low-salinity chase floods on the gel blocking capacities after gel rupture when wider segments of the fracture are open to flow. Experiments concentrating on revealing the mechanisms of gel particles possibly re-lodging in the fracture and clogging the wormholes are also being planned.

Conclusions

- Low-salinity waterfloods of fractured core plugs where mature gel was placed in fractures improved the blocking capacity of the gel.
- Gel blocking capacity improved when the injected water salinity was reduced with respect to the gel solvent.
- When water with a salinity that was almost 80000-ppm lower than the gel solvent was injected, the injection pressure increased to above the initially measured rupture pressure in all cores, frequently stabilizing at a value 2-3 times higher than the rupture pressure.
- The fractures were efficiently blocked due to gel swelling during low-salinity waterflooding. In some cores, fracture flow was completely inhibited and fluid flow occurred only through the fracture adjacent matrix.
- The blocking capacity achieved by injection of low-salinity water remained stable for long periods of time, providing that low-salinity water was continuously injected into the fractured cores.
- When gel solvent was injected into the fractured cores after low-salinity waterflooding, gel de-swelled and the blocking characteristics were reduced to the original level.

Nomenclature

S_{or}:	residual oil saturation
FV:	fracture volume
PV:	pore volume
P_R:	gel rupture pressure

F_{rrw}: residual resistance factor

References

Aalaie, J., A. Rahmatpour and E. Vasheghani-Farahani (2009). "Rheological and swelling behavior of semi-interpentrating networks of polyacrylamide and scleroglucan." *Polym. Adv. Technol.* **20**: 1102–1106.

Akstinat, M. H. (1980). Polymers For Enhanced Oil Recovery In Reservoirs Of Extremely High Salinities And High Temperatures. SPE 8979, SPE Oilfield and Geothermal Chemistry Symposium. Stanford, CA, Society of Petroleum Engineers.

Al-Sharji, H. H., C. A. Grattoni, R. A. Dawe and R. W. Zimmerman (1999). Pore-Scale Study of the Flow of Oil and Water through Polymer Gels. SPE 56738, SPE Annual Technical Conference and Exhibition. Houston, TX, Society of Petroleum Engineers.

Bai, B. J., L. X. Li, Y. Z. Liu, H. Liu, Z. G. Wang and C. M. You (2007). "Preformed particle gel for conformance control: Factors affecting its properties and applications." SPE 89389, *SPE Reservoir Evaluation & Engineering* **10**(4): 415–422.

Brattekås, B., Å. Haugen, G. Ersland, Ø. Eide, A. Graue and M. A. Fernø; (2013). Fracture Mobility Control by Polymer Gel- Integrated EOR in Fractured, Oil-Wet Carbonate Rocks. SPE 164906, EAGE Annual Conference & Exhibition incorporating SPE Europec. London, UK.

Brattekås, B., Å. Haugen, A. Graue and R. S. Seright (2014a). "Gel Dehydration by Spontaneous Imbibition of Brine from Aged Polymer Gel." SPE 153118, *SPE Journal* **19**(01): 122–134.

Brattekås, B., S. G. Pedersen, H. T. Nistov, Å. Haugen, A. Graue, J.-T. Liang and R. S. Seright (2014b). "The effect of Cr(III) Acetate-HPAM Gel Maturity on Washout from Open Fractures". SPE 169064, SPE IOR, Tulsa, OK, USA.

Choi, S. K., M. M. Sharma, S. Bryant and C. Huh (2010). "pH-Sensitive Polymers for Novel Conformance-Control and Polymer-Flood Applications." SPE 121686, *SPE Reservoir Evaluation & Engineering* **13**(06).

Ganguly, S., G. P. Willhite, D. W. Green and C. S. McCool (2002). "The Effect of Fluid Leakoff on Gel Placement and Gel Stability in Fractures." SPE 79402, *SPE Journal* **7**(03): 309–315.

Horkay, F., I. Tasaki and P. J. Basser (2000). "Osmotic Swelling of Polyacrylate Hydrogels in Physiological Salt Solutions." *Biomacromolecules* **1**: 84–90.

Johannesen, E. B. (2008). "NMR characterization of wettability and how it impacts oil recovery in chalk". Dept. of Physics and Technology. Bergen, University of Bergen. PhD thesis: 71.

Klein, E. and T. Reuschle (2003). "A Model for the Mechanical Behaviour of Bentheim Sandstone." *Pure applied Geophysics* **160**: 833–849.

Krishnan, P., K. Asghari, G. P. Willhite, C. S. McCool, D. W. Green and S. Vossoughi (2000). "Dehydration and Permeability of Gels Used in In-Situ Permeability Modification Treatments". SPE 59347, SPE/DOE Improved Oil Recovery Symposium. Tulsa, OK, Society of Petroleum Engineers.

Liang, J.-T., R. L. Lee and R. S. Seright (1993). "Gel Placement in Production Wells." SPE 2021, *SPE Production and Facilities* **8**(November): 276–284.

McCool, C. S., X. Li and G. P. Wilhite (2009). "Flow of a Polyacrylamide/Chromium Acetate System in a Long Conduit." SPE 106059, *SPE Journal* **14**(01): 54–66.

Morrow, N. and J. Buckley (2011). "Improved Oil Recovery by Low-Salinity Waterflooding." *Journal of Petroleum Technology* **63**(05): 106–112.

Romero-Zeron, L. B., F. M. Hum and A. Kantzas (2008). "Characterization of Crosslinked Gel Kinetics and Gel Strength by Use of NMR." SPE 86548, *SPE Reservoir Evaluation and Engineering* **11**(03): 439–453.

Schutjens, P. M. T. M., M. Hausenblas, M. Dijkshorn and J. G. van Munster (1995). "The Influence of Intergranular Microcracks on the Petrophysical Properties of Sandstone- Experiments to Qantify Effects of Core Damage. International Symposium of the Society of Core Analysts, San Francisco, CA.

Seright, R. S. (1995). "Gel Placement in Fractured Systems" SPE 27740, *SPE Production & Facilities* **10**(4): 241–248.

Seright, R. S. (1999). "Polymer Gel Dehydration During Extrusion Through Fractures." SPE 56126, *SPE Production & Facilities* **14**(2): 110–116.

Seright, R. S. (2001). "Gel Propagation Through Fractures" SPE 74602, *SPE Production & Facilities* **16**(4): 225–231.

Seright, R. S. (2003a). "An Alternative View of Filter-Cake Formation in Fractures Inspired by Cr(III)-Acetate-HPAM Gel Extrusion" SPE 81829, *SPE Production & Facilities* **18**(1): 65–72.

Seright, R. S. (2003b). Washout of Cr(III)-Acetate-HPAM Gels from Fractures. SPE 80200, International Symposium on Oilfield Chemistry. Houston, TX, Society of Petroleum Engineers.

Tie, H. (2006). "Oil Recovery by Spontaneous Imbibition and Viscous Displacement from Mixed-Wet Carbonates". Department of Chemical and Petroleum Engineering. Laramie, Wyoming, The University of Wyoming. PhD thesis: 238.

Tu, T. N. and B. Wisup (2011). Investigating the Effect of Polymer Gels Swelling Phenomenon under Reservoir Conditions on Polymer Conformance Control Process. International Petroleum Technology Conference. Bangkok, Thailand, IPTC.

Uhl, J. T., T. Y. Ching and J. H. Bae (1995). "A Laboratory Study of New, Surfactant-Containing Polymers for High-Salinity Reservoirs." SPE 26400, *SPE Advanced Technology Series* **3**(01).

Vossoughi, S. (2000). "Profile Modification Using In Situ Gelation Technology- A Review." *Journal of Petroleum Science and Engineering* **26**(1-4): 199–209.

Wilton, R. and K. Asghari (2007). "Improving Gel Performance in Fractures: Chromium Pre-Flush and Overload." *Journal of Canadian Petroleum Technology* **46**(02).

Witherspoon, P. A., J. S. Y. Wang, K. Iwai and J. E. Gale (1980). "Validity of Cubic Law for Fluid Flow in a Deformable Rock Fracture." *Water Resour. Res.* **16**(6): 1016–1024.

Wu, Y., A. Mahmoudkhani, P. Watson, T. R. Fenderson and M. Nair (2012). Development of New Polymers with Better Performance under Conditions of High Temperature and High Salinity. SPE 155653, SPE EOR Conference at Oil and Gas West Asia. Muscat, Oman, Society of Petroleum Engineers.

Young, T. S., J. A. Hunt, D. W. Green and G. P. Willhite (1989). "Study of Equilibrium Properties of Cr(III)/Polyacrylamide Gels by Swelling Measurement and Equilibrium Dialysis." SPE 14334, *SPE Reservoir Engineering* **4**(03): 348–356.

Zhang, H. and B. Bai (2011). "Preformed-Particle-Gel Transport through Open Fractures and Its Effect on Water Flow." *SPE Journal* **16**(2): 388–400.