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## Article

# Bulk gels for permeability reduction in fractured and matrix reservoirs

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## Review article

## Bulk gels for permeability reduction in fractured and matrix reservoirs

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## ABSTRACT

Having a high water cut reduces the economic viability of oil production. Water production increases, as less-viscous water tends to flow through high-permeability zones, leaving behind large volumes of unswept oil. Since the 1920s, different materials have been used in order to plug high-permeability thief zones. Gels are often preferred for this purpose, as they provide deeper penetration than cement or mud suspensions. Moreover, some gels reduce permeability to water more than that to oil. And can be economically feasible at low oil prices if applied correctly. This article reviews permeability reduction of several widely used inorganic and organic bulk gels, with separate discussions of their application in fractures and matrix rocks of sandstone and carbonate reservoirs. The presented information is to help with proper well treatment design.

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## 1. Introduction

Handling water produced along with oil and gas costs the petroleum a significant amount each year (Seright et al., 2001a). High water cuts shorten the production life of wells (Lockhart and Burrafato, 2000) and cause a great deal of corrosion to equipment (Brondel et al., 1994; Popoola et al., 2013). Excess water production can result from fractures and large permeability contrasts between different matrix layers (Al-Ghanim and Al-Nufaili, 2010; Vicente et al., 2001). This is an urgent problem for mature reservoirs in which super high permeability zones are created by mineral dissolution and sand production, resulting from continuous water flooding (Delshad, 2013; Goudarzi et al., 2014).

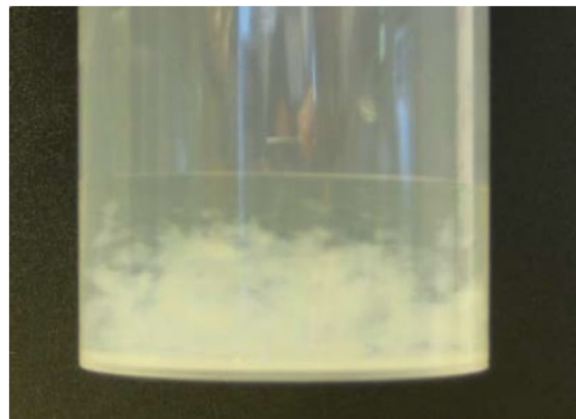
Polymer-augmented flooding has been practiced since the 1960s in an effort to improve water flooding sweep efficiency through the increase of water viscosity (Pye, 1964; Mungan, 1969). However, plugging using bulk gels is more effective in specific cases, as polymer solutions tend to channel through fractures and fracture-like features (Seright et al., 2011c). The first uses of gels for permeability reduction date back to the 1930s (Kennedy, 1936). However, the real era of gel treatments began after the first successful applications of polyacrylamide gels in the 1970s (Borling et al., 1994).

This work summarizes laboratory and field tests of sodium silicate and polyacrylamide/chromium (III) bulk gels, as they are the most used and cost-effective materials. Several relatively new brine- and temperature-activated gels are also discussed as an alternative to sodium silicate and polyacrylamide gels. These gels are applicable in elevated temperature conditions and when the make-up water and reservoir brine are of high salinity.

For each material, the article shortly mentions the chemical composition, acceptable reservoir temperature, and salinity range of make-up water and reservoir brine. The main distinguishable feature of this article is that it presents an overview of the current state of the subject by providing some facts about issues of placement and stability of different bulk gels for fractures and matrices separately. The placement and stability of plugs in fractures are discussed not only in view of ambient conditions but also in view of whether the plug was injected in the form of solution (gelant) or mature gel. This is an important factor, as gelants, unlike mature gels, tend to leak off from the fracture faces into the matrix as well as slump due to the gravity force. For matrices, the issues of selective and disproportionate permeability reduction as well as in-depth placement of gel plugs are explained. The explanation is supported by selected laboratory and field tests results. The conclusions made at the end can be of help for proper design of successful well treatment operations.

## 2. Sodium silicate gels

Sodium silicate gels are the oldest gel technology ever applied in permeability reduction (Hills, 1992; Kennedy, 1936; Sydansk and Romero-Zeron, 2011), and are usually formed by mixing an aqueous solution of sodium silicate ( $(\text{SiO}_2)_n:\text{Na}_2\text{O}$ ,  $n < 4$ ) with HCl (Amiri, 2014). Gelation takes place at a pH below 11 (Pham and



**Fig. 1.** Precipitate in 4.5 wt% sodium silicate solution after addition 25 wt% sea water at 20 °C.

Source: Hamouda and Akhlaghi Amiri (2014).

Hatzignatiou, 2016). A number of natural minerals have been successfully tested as gelation activators in place of hazardous HCl, including NaCl at 30–60 °C (Pham and Hatzignatiou, 2016) and by-products of urea thermal decomposition at above 70–95 °C (Nasr-El-Din and Taylor, 2005).

Sodium silicate gels proved to be stable inside of pressure chambers at 300 °C and 1250psi for a period of 12 weeks (Bauer et al., 2005). However, a study that would describe the stability of gel plugs placed in porous rocks at temperatures close to 300 °C was not found in the literature.

The presence of different solids in make-up water affects the gelation time and stability of sodium silicate solution. In fact, sodium silicate may start to precipitate at 40–80 ppm of divalent ion content in make-up brine (Pham and Hatzignatiou, 2016). Thus, fresh water with a minimal content of dissolved solids is preferred for gelant preparation. The Table 1 summarizes the make-up water composition and silicate gelling solution recipes as described in different works. As it can be seen distilled or low salinity water is usually used, since the presence of Mg and Ca ions cause immediate precipitation and viscosity increase in sodium silicate solutions (Fig. 1).

### 2.1. Fractured reservoirs

#### 2.1.1. Gel placement issues

If injection time of gelant exceeds gel onset time, as is often the case, simultaneous propagation of gel and gelant will take place inside of a treated fracture, which is why below the propagation of gelants and gels through fractures is reviewed separately.

**2.1.1.1. When placed as a gelant.** Since sodium silicate gelants possess water like viscosity, their effective placement in fractures is questionable due to the slumping and leaking effects (Fig. 2). To tackle this problem, combined application of sodium silicate with polymer additives should be tested. For example, in a study by Hatzignatiou et al. (2015), the addition of 0.45–0.75 wt%

**Table 1**  
Silicate gel recipes used by different researcher.

Mixing water composition	Silicate recipe	Gelation activator	pH	Aging temperature, °C	Gel onset time	Work
DW	SiO <sub>2</sub> 1.9 mol/L SiO <sub>2</sub> /K <sub>2</sub> O	15.7 wt% of acetic acid 1M	11.41	40	500 min	Fleury et al. (2017)
Fresh water	4 wt% SiO <sub>2</sub> /Na <sub>2</sub> O = 3.1	HCl 0.6–0.75 wt%	7	20–65	1–11 hr	Starkovskiy (2013)
Fresh water	Silicate solution	NA	NA	60	85 min	Vidick et al. (1988)
0.5 wt% NaCl	9 wt% SiO <sub>2</sub> /Na <sub>2</sub> O = 3.29	Urea 3.6 wt%	11.6–11.7	95	2 hr	Nasr-El-Din and Taylor (2005)
1 wt% KCl	4–6 wt% sodium silicate	HCl	11.1–11.9	60	0.5–3.5 days	Rolfsvag et al. (1996)
3 g 0.1M CaCl <sub>2</sub> and 5.78 g DW	9.22 g of sodium silicate	2 g 10 wt% citric acid	NA	40 60 80	42 min 16 min 8 min	Sachdeva (2015)
0.2 wt% Na <sub>2</sub> CO <sub>3</sub> 0.1 wt% NaOH 0.1 wt% Na <sub>2</sub> S 1.2 wt% CaCO <sub>3</sub>	Na <sub>2</sub> SiO <sub>3</sub> 0.05–1.5 wt%	9 wt% NaCl	10	NA	NA	Jafarov et al. (2018)

of synthetic and biopolymers to sodium silicate solutions provided significant a viscosity increase in the gels from 1.2cp to 20–30cp, at 1 s<sup>-1</sup> and 20 °C.

The effect of gelant leaking can have a significant negative effect on post treatment gel stability unless sodium silicate gelants can quickly form an impermeable barrier on the fracture face. This is possible if: 1-contact with rock results in pH decrease, which causes coagulation of silicate oligomers; 2-rock has polyvalent cations (Ca<sup>2+</sup>, Mg<sup>2+</sup>, Al<sup>3+</sup>) on its surface, which causes the formation of insoluble precipitate (Van Oort et al., 1996). These two phenomena are likely to occur in high buffering capacity and significant clay content rocks and are worth to be studied in future.

Unfortunately, no laboratory studies of sodium silicate gelant propagation through fractures were found in the literature. Nevertheless, there are a number of works which demonstrated that sodium silicate solutions can quickly form precipitates which fill pores and prevent fluid invasion and leaking (El Essawy et al., 2004; Jafarov et al., 2018; Soric et al., 2004). This phenomenon is worth to be studied on fractured core models.

**2.1.1.2. When placed as a gel.** Taking into account the small yield stress values of silicate gels (0.01–0.2 kPa for 12 wt% sodium silicate/0.7–1.2 wt% NaCl gels), gel extrusion pressure gradients in fractures are expected to be in the range of 1–20psi/ft at 30–40 °C. However, such values may be underestimated, as they were calculated using a simple force balance equation (Pham and Hatzignatiou, 2016):

$$dp = \frac{2 \cdot G \cdot dL}{w} \quad (1)$$

where dp represents gel extrusion pressure drop, G is yield stress of the gel, dL shows fracture length, and w is fracture width.

No experimental studies of sodium silicate gel extrusion through fractures that would account for water leaks into the matrix, the rough surfaces of fracture walls, variable flow rates, and ambient temperatures were found in the literature.

### 2.1.2. Gel stability in fractures

Because silicate gels are brittle, they may not be stable in fractures (Krumrine and Boyce, 1985). For example, in the work of Amiri (2014), the maximum strength of gels achieved by varying the sodium silicate content and pH was only 2.8 kPa. Whereas, the strength of polyacrylamide gels varies between 9 and 880 kPa (Ferruzzi et al., 2000). In fact, back-production of silicate gels from a production well was detected at Gullfaks oilfield (North Sea)

after the reservoir was unintentionally fractured during the injection of 25,300 bbls of 5 wt% of sodium silicate gelant (Rolfsvag et al., 1996).

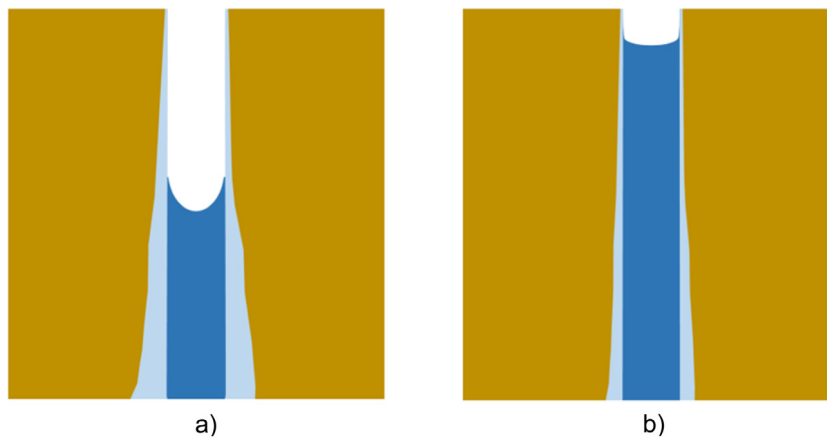
The stability of gels can be improved by the increase of sodium silicate content (Amiri, 2014). For example, in the work of Pham and Hatzignatiou (2016), 550psi/ft were required to extrude 22 wt% sodium silicate/0.52 wt% NaCl gel from a 4.8 mm-width tube, at 20 °C. Moreover, Hatzignatiou et al. (2015) reported no shrinkage of 13 wt% sodium silicate/0.65 wt% NaCl gel placed inside a 5 mm-width channel drilled into a carbonate core and aged for 70 days at 60 °C (Pham and Hatzignatiou, 2016). As a result, permeability of the channel was reduced from 2·10<sup>6</sup> D to 2.3 mD. However, as no pressure gradient was applied during the aging, these results may severely underestimate any syneresis expected under reservoir conditions.

The stability and elasticity of sodium silicate gels can be improved by the addition of polymers. For example, Hatzignatiou et al. (2015) added 0.45 wt% of a biopolymer to 13 wt% sodium silicate gelant (Pham and Hatzignatiou, 2016). As a result, an increase in the chase water injection rate caused a reduction in post-treatment fracture permeability from 30 to 1.6 mD, due to radial expansion of the elastic gel. However, long-term stability of sodium silicate/polymer gels under dynamic aging conditions has not yet been studied. Nevertheless, sodium ortho-silicate/HPAM gels have been successfully tested in Omani faulted reservoirs with extreme permeabilities (Lakatos et al., 2011). In Alberta (Canada) silicate-based polymer slurries were injected into 200 producers in order to seal-off cement fractures in wells. As a result, water production decreased from 24,850 to 400 bbls/day, while oil rates increased by 660 bbls/day (Samari et al., 1998).

## 2.2. Matrix reservoirs

### 2.2.1. In-depth propagation and selective placement of gelants

In-depth propagation of sodium silicate gelants firstly depends on gel time. By varying sodium silicate content (10–13 wt%) and NaCl (activator) concentrations (0.6–1.74 wt%) at temperatures up to 40 °C, the gel onset time can be regulated over a wide range (1–100 h). A further increase in temperature by 10 °C caused the reduction of gel onset time by a factor of 2 (Pham and Hatzignatiou, 2016). For longer gel onset times, at above 70 °C, urea ((NH<sub>2</sub>)<sub>2</sub>CO) is recommended for use instead of HCl or NaCl. For example, the gel time of 9 wt% sodium silicate/1–25 wt% urea gelants occurs within 1–30 h at 95 °C (Nasr-El-Din and Taylor, 2005).



**Fig. 2.** The effect of gravity and leaking on low viscous (a) and (b) high viscous gelling solutions placement in a fracture. ■ – gelling solution placed inside the fracture; ■ – leaked gelling solution; ■ – matrix rock.

In spite of the water-like viscosity of sodium silicate gelants (Krumrine and Boyce, 1985; Liang et al., 1993), their in-depth propagation and selective placement may be problematic due to the immediate precipitation of calcium and magnesium silicates upon contact with reservoir brine. In fact, 800 ppm was reported as the maximal acceptable  $\text{CaCl}_2$  concentration for silicate/urea gelant (Nasr-El-Din and Taylor, 2005). In rocks with high cation exchange capacity, such as sandstones, even the presence of 20 ppm of calcium in the pre-flush water may cause untimely plugging (Stavland et al., 2011a). Thus, proper design of the preflush is critical (Lakatos et al., 2015; Skrettingland et al., 2012).

The concentration of HCl (activator) and volume of cold pre-flush also influence the depth of sodium silicate gelant placement (Krumrine and Boyce, 1985). Cold water preflush creates a time delay in the onset of gelation by cooling down a reservoir below the gel activation temperature. Table 2 demonstrates the effect of HCl concentration decrease and an increase in the volume of the cold water (30 °C) preflush on the reduction in RFs during the injection of sodium silicate gelants with gel activation temperature set around 70 °C at Snorre field (reservoir temperature is above 90 °C) (Skrettingland et al., 2012, 2014). High RFs may cause the gelant to penetrate into low permeability zones.

In addition, it should be noted that if the injection velocity falls below a certain value, the propagation of sodium silicate gelant will stop due to the silicate deposition. For instance, in the work of Stavland et al. (2011a), this value was found to be 20 ft/d ( $7 \cdot 10^{-5}$  m/s). Taking into account that flow velocities in matrix formations vary from around 100 ft/d at the sand face of a vertical well to 0.1–1 ft/d deep inside of the reservoir, the distance at which sodium silicate will start precipitating can be predicted using flow velocity distribution curves.

### 2.2.2. Gel stability in matrix

The Table 3 presents results of different researchers showing maximal pressure gradients registered during water post flush of core samples treated with sodium silicate gelants.

From the data in Table 3 it is obvious that sodium silicate gels provide high stability in matrix rocks at wide range of permeabilities and temperatures. However, it is also seen that in unconsolidated porous media the gels fail to provide plugging. Moreover, in rocks of greater grain sizes, the syneresis of sodium silicate gels is higher compared with low grain size rocks (Table 4). Thus, the gels are not recommended for unconsolidated sand treatments.

Stability of low-volume (6–230 bbl) sodium silicate/HCl gel plugs in high permeability near wellbore zones at high draw-downs (1800psi) and temperatures (90 °C) was proved by the

treatment of two producers at Prudhoe Bay field. The treatment resulted in the reduction of GOR on 57% (Herring et al., 1984). Moreover, sodium silicate/HCl gel plugs were proved to be stable during 10–14 months in the bottomhole zones of the producers subjected to cyclic steam treatments (Starshov et al., 1999). Other examples of successful applications of sodium silicate in matrix reservoirs can be found elsewhere (Lakatos et al., 2011, 2015).

### 2.2.3. Disproportionate permeability reduction

Very few papers have been dedicated to the study of the DPR effect provided by sodium silicate gels. Askarinezhad et al. (2016) have shown that the sodium silicate solution should be injected along with oil, otherwise full blockage in 0.7–0.8 D Berea cores may occur. Additionally, a pronounced DPR effect only occurred in oil-wet rocks ( $\text{RRF}_w = 129$  and  $\text{RRF}_o = 20$  at 78% water cut), while in water-wet media no positive effect was observed ( $\text{RRF}_w = 100$  and  $\text{RRF}_o = 460$ ) (Askarinezhad et al., 2016).

In fact, a number of successful examples of sodium silicate gels application in production wells can be found in the literature. For example, the gels were successfully applied in 99% water cut producer at Mardovo–Karmalsky bituminous sand field. 30 m<sup>3</sup> of sodium silicate/HCl solution alternated with brine and cement slurry were injected to block water inflow from the underlying aquifer. As a result, 30%–40% water cut decrease and 145 tons of incremental bitumen production were achieved in 14 months (Starshov et al., 1999).

## 3. HPAM/ $\text{Cr}^{+3}$ gels

HPAM aqueous gels crosslinked with  $\text{Cr}^{+3}$ -carboxylate-complex have been the most frequently applied plugging material since the 1970s (Gall James and Lanning William, 1972). Some examples of field application of HPAM/ $\text{Cr}^{+3}$  at wide variety of conditions can be found in the literature (Arangath and Mkpassi, 2002; Marin et al., 2002).

Successful application of HPAM gels was proved to be possible at temperatures up to 80 °C in fractures and 120 °C in matrices (Albonico et al., 1993; Seright, 2003a; Sydansk and Romero-Zeron, 2011). The chemical composition of the make-up brine is also critical (Moradi-Araghi and Doe, 1987). For many laboratory studies, the salinity of the make-up water was about 1 wt% of NaCl and  $\text{CaCl}_2$ . For field applications, the use of technical water with a low content of divalent cations is preferred, as at 75 °C precipitation of HPAM may occur if the content of divalent cations is 2000 ppm (Seright et al., 2010).

**Table 2**  
Parameters of sodium silicate treatments at Snorre field (offshore Norway).

Parameters	1st treatment (Skrettingland et al., 2012)	2nd treatment (Skrettingland et al., 2014)
Volume of the preflush, bbls	2,500	715,200
Volume of the gelant, bbls	4,800	1,520,000
Na-silicate concentration, ppm	40,000	40,000
HCl concentration, ppm	4,300	2,000
<b>RF at the end of the injection</b>	<b>10</b>	<b>1–1.3</b>

**Table 3**  
Review of silicate gel stability in matrix rocks.

Gelling agent recipe	Rock type	Permeability, D	Temperature, °C	Maximal registered pressure gradient, psi/ft	Literature source
4 wt% Sodium silicate/0.6 wt% HCl	Sandstone	0.036	Not reported	960	Starkovskiy (2013)
Sodium silicate 9 wt%/urea 3.6 wt% gel	Carbonate	0.517	95	2,500	Nasr-El-Din and Taylor (2005)
NA	Sandstones and carbonates	1–6	40–80	1200–1500	Vidick et al. (1988)
Sodium silicate 5 wt% adjusted to pH 10.7 with HCl	Sand pack	60	50	1–3	Amiri (2014)

**Table 4**  
Ultimate syneresis of sodium silicate gel when placed in flask and porous media of different grain sizes (Patrick Powers et al., 2007).

Syneresis, %	60 wt% Sodium silicate-ethyl acetate gel
73	In a flask
23	Placed inside of 8–10 mm gravel pack
3	Placed inside of 0.06–1.25 mm sand pack

### 3.1. Fractured reservoirs

The most successful production well treatments conducted throughout the 1970s and 1980s targeted fractured reservoirs (Seright and Liang, 1994). However, if fractures connect oil and water zones, even relatively small volumes of plugging agent injected (10–900 bbls) may invade oil matrix and reduce oil production (Sydansk and Moore, 1990). Thus, fractures connected with aquifers or located in low matrix permeability reservoirs are the best candidates for HPAM/Cr<sup>3+</sup> treatments, as plugging of the oil-saturated matrix under such conditions is not likely.

Plugging fractures through injection wells with moderate volumes (around 100–2000 bbls) of HPAM/Cr<sup>3+</sup> gelant is less risky (Sydansk and Moore, 1990), and can greatly increase oil production in low temperature (40 °C) reservoirs with matrix permeability around 5 mD, making the project economically feasible even at low oil prices (\$10/bbl) (Ricks and Portwood, 2000).

#### 3.1.1. Gel placement issues

Different injection behaviors and plugging effects are observed depending on whether HPAM/Cr<sup>3+</sup> gels are placed in fractures as mature gels or gelants (Brattekkås et al., 2015b). Actually, the injection periods of HPAM/Cr<sup>3+</sup> gelants often exceed their gelation times by a factor of 100 (Seright, 2000). Thus, even if a gel plug was intended to be placed as a gelant, the simultaneous extrusion of gel and gelant would take place in fractures during the treatment (McCool et al., 2007).

**3.1.1.1. When placed as a gel.** Because HPAM/Cr<sup>3+</sup> gels exhibit elastic behavior even at high strain values (Liu and Seright, 2000), their propagation through fractures is supported by the “slip effect”. For example, the pressure gradients during the extrusion of 0.5 wt% HPAM/0.0417 wt% Cr<sup>3+</sup> gel through a 1 mm-width fracture were unaltered by an increase of the flow rate from

200 cm<sup>3</sup>/hr (413 ft/d) to 16,000 cm<sup>3</sup>/hr (33,100 ft/D), and varied between 28 and 18psi/ft, respectively (Brattekkås et al., 2015b). Moreover, high molecular weight HPAM gels are more suitable for deeper placement into a fracture, as 12–14·10<sup>6</sup> Da HPAM gel was extruded through 1 mm-width fracture at a pressure gradient 7 times lower than the 5·10<sup>6</sup> Da gel (Seright, 2000).

However, for fixed fracture widths, an increase in polymer concentration results in an exponential rise in gel extrusion pressure gradients, which can be described by the following formula:

$$\frac{dp}{dl} = \frac{4.15 \cdot [e^{2.27 \cdot C}]}{w_f^2} \quad (2)$$

where dp/dl represents pressure gradient in psi/ft, C is polymer concentration in %, and  $w_f$  shows fracture width in mm (Seright, 2003a, 2001a).

Furthermore, in fractures with a width of less than 2.54 cm, the extrusion of gels may slow down due to water leak-off from pressurized gel into the matrix, resulting in gel film accumulation that is higher for longer injection periods (Seright, 1999). For example, at 413 ft/d, 15FVs of gel had to be injected into a fracture of 48 ft in length before the gel appeared at the outlet of the model, while at 33,100 ft/d it required only 1.7FVs (Seright, 2000). In fact, after the extrusion of 80FVs of gel at 200 cm<sup>3</sup>/hr, the whole fracture volume was occupied with 20–40 times concentrated immobile gel (Seright, 1999). Additionally, all further injected gel propagated at a stabilized pressure through wormholes inside of the dehydrated gel (Seright, 2003a).

Of importance is that the dehydration behavior and extrusion pressure gradients of the gel were shown to be similar for a wide range of matrix permeabilities (1.5–650 mD) and temperatures (20–80 °C) (Seright, 1997, 2003a). The probable reason for this is that the properties of HPAM gels and rate of water leak-off do not change considerably within this range of conditions.

**3.1.1.2. When placed as a gelant.** Moderate viscosity gelling mixture (gelants) with prolonged gelation onset times (Albonico et al., 1993; Burrafato and Lockhart, 1989; Natarajan et al., 1998) may be considered the best choice for deep placement into a fracture. Unfortunately, partial penetration of a gelant or preflushing crosslinker into the matrix is necessary to prevent the diffusion of Cr<sup>3+</sup> and to gel the polymer (Ganguly et al., 2002; Brattekkås

et al., 2015b; Wilton and Asghari, 2007). For example, after the increase of matrix preflush distance from 1 to 1.5 cm, by direct injection of 300 ppm chromium solution into rock slabs, RRFs inside of the fracture rose from 154 to 5790 (Wilton and Asghari, 2007). However, in field conditions, chromium solution or gelant penetration into a matrix can be accomplished only by leak-off from a fracture, and will be problematic in high-permeability fractures, as well as in oil-wet and/or tight matrix reservoirs (Brattekkås et al., 2015b). Thus, placement of a gelant at chromium overload would be a better choice under such conditions. The work of Wilton and Asghari (2007) has been the only study that has compared the plugging efficiency of the “matrix preflush” and “chromium overload” gel placement techniques. However, due to great differences between fracture permeabilities, as well as an unrealistic preflush simulation, the effectiveness of “chromium overload” gel placement may have been underestimated.

Under actual conditions, the flow velocity in open conduits might be around several thousand ft/d, which roughly corresponds to shear rates between 10 and 100  $s^{-1}$ , thus the effect of shearing on gelation should always be considered (Huang et al., 1986; Sydansk, 1988). The gelation time and gel strength of HPAM/chromium acetate gels were shown to be unaffected by very high shear rates (50,000  $s^{-1}$ ), if applied for short time periods (0.005 s) inside of a 1.6-mm-wide tube at 22 °C. Such conditions may exist only in the vicinity of a well (Sydansk, 1988).

Indeed, during the injection of inline mixed gelants at 1000–4000 ft/d (20–100  $s^{-1}$ ), the time required to create a gel screen inside of a treated conduit may exceed that of bulk gelation by several times, depending on gelant content and temperature. Furthermore, at increased injection/shear rates, pressure gradients tend to decrease (McCool et al., 2007), the reason for which is the continuous breaking of gel aggregates by the shearing force. For example, the shearing of  $5 \cdot 10^6$  Da HPAM/ $Cr^{+3}$  gelant during 27 h at 100 and 316  $s^{-1}$  and 25–30 °C prevented its gelation, and the viscosities stabilized at 500 and 100cp respectively (Broseta et al., 2000). However, in a real fracture, the gel particles would filter out at the fracture face, while the water entered the porous media. The gel filter film in the fracture face could build up over time and restrict flow into the fracture (Seright, 2003a).

Additional systematic research is required in order to study the effect of shearing on the gelation time in long fractures (10–100 ft), utilizing different flow rates, temperatures, and gelant mixtures.

### 3.1.2. Gel stability in fractures

The poor stability of HPAM gels in fractures may be part of the reason behind a number of failed treatments (White et al., 1973; Seright, 2003a).

In fact, when the volume of a gel is less than 0.6MPV, spontaneous imbibition (SI) of water from gel into oil-saturated water-wet matrix causes a reduction of up to 98% in the volume of a gel over 1–5 days. As fractures occupy a small volume of the overall reservoir volume, the negative influence of SI on gel stability is expected to be high (Brattekkås et al., 2012). SI is higher with gels that are placed as gelants, as during gel extrusion through fractures low permeability (around 0.3  $\mu$ D) dehydrated gel film accumulates at the fracture-matrix interface (Brattekkås et al., 2015b; Seright, 1999, 2001b). In fact, in 1 mm-width fractures, gel plugs placed as mature gels provide 8 times larger RRFs than those placed as gelants (Brattekkås et al., 2015b). The application of surfactants was suggested to reduce SI from gels, though no experimental results have been made available so far (Brattekkås et al., 2012).

The influence of shear stress on HPAM gel stability should also be considered. McCool et al. (2007) exposed gelants with a gel onset time of around 5 h to shearing over a period of 20 h. As

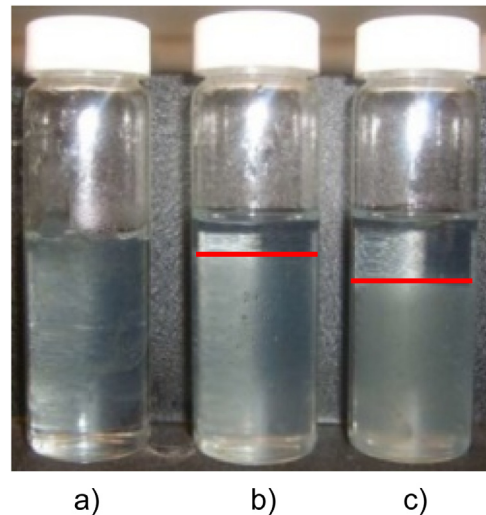


Fig. 3. 0.5 wt% HPAM/0.01 wt%  $Cr^{+3}$  gels after being sheared at 1  $s^{-1}$  (a), 10  $s^{-1}$  (b) and 100  $s^{-1}$  (c) during their gelation and aged for 130 days (McCool et al., 2007). The red lines show the appearance of syneresis.

a result, those gels exposed to higher shear rates demonstrated more pronounced syneresis (Fig. 3).

Thus, though injection at high rates provides deeper placement (Seright, 2000), it also exposes gels to higher shear stresses, thus causing more syneresis, less concentrated gel film accumulation, and lower RRFs. In fact, gels placed inside of 1 mm wide fractures at 826 ft/d demonstrated 5 times higher RRFs than those placed at 4130 ft/d (Seright, 2003b).

Salinity of water used in chase flooding also influences the stability of HPAM gels in fractures (Lamedo et al., 2005). For example, Brattekkås et al. (2015a) observed 0.5 wt% HPAM/0.0417 wt%  $Cr^{+3}$  acetate gel rupture at 20psi/ft and 40 °C during the injection of 80,000 ppm brine, containing 4 wt% of NaCl, 3.4 wt% of  $MgCl_2 \cdot 6H_2O$  and 0.05 wt% of  $CaCl_2 \cdot 2H_2O$ , with the result that no fluid diversion was achieved. Whereas, during the injection of distilled water the ruptured gel swelled and 100% fluid diversion into the matrix occurred at 100psi/ft. However, 0.3–0.9 wt% HPAM/0.025–0.075 wt%  $Cr^{+3}$  gels were successfully applied in a horizontal production well to stop water influx from an aquifer with brine salinity of around 17,000 ppm. The reservoir temperature was around 90 °C (Holstein and Warner, 1994; Lane and Sanders, 1995). The highest water salinity and temperature at which HPAM gels can be applied in fractures needs to be determined in the future. Furthermore, it was noted that in wide fractures (more than 3–4 mm) the plugging effect provided by HPAM gels is very poor (Seright, 2003b).

With regards to water salinity and fracture width, Table 5 summarizes results of different researchers.

As it can be seen from Table 5, almost all experimental work was conducted at low and moderate temperatures. No experimental results were found for the temperature beyond 100 °C. The increase of fracture width generally results in poorer stability of a gel plug. It can be seen from Fig. 4, which was built by using the data presented in Table 5, post flush pressure gradients decreases exponentially with the increase in fracture width.

The Eq. (3) presented at the graph (Fig. 4) can be used to assess maximal brine postflush pressure gradients in fractures filled with 0.5 wt% HPAM/0.05 wt% CA gels.

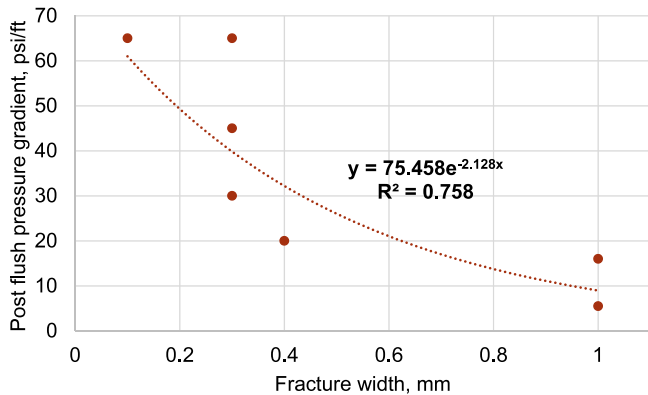
$$\frac{dp}{dl} = \frac{75.46}{[e^{2.13 \cdot w}]} \quad (3)$$

**Table 5**  
Maximal water post flush pressure gradient for different fracture widths and brine salinities.

Recipe	Concentrations	Post flush brine salinity, g/L	Temperature, °C	Fracture width, mm	Post flush pressure gradient, psi/ft	Source	
1	FP-107 (15 mln. Da, 13%–18% hydrolysis) and chromium acetate	0.5 wt% FP-107/0.05 wt% CA	264.4	25–26	0.1	More than 65	Belyh et al. (2017)
2	((Low Mw PAA with inorganic crosslinker))	–	186.2	25	0.3	45	Kornienko (2017)
3	((High Mw PAA with inorganic crosslinker))	–	186.2	25	0.3	65	Kornienko (2017)
4	HPAM (5 mln. Da, 5%–10% hydrolysis) with chromium acetate <sup>b</sup>	0.5 wt% HPAM /0.047 wt% CA	10	25–30	0.3	30	Ganguly et al. (2002)
5	HPAM (5 mln. Da, 5%–10% hydrolysis) with chromium acetate <sup>b</sup>	0.5 wt% HPAM /0.047 wt% CA	10	25–30	0.4	20	Ganguly et al. (2002)
6	HPAM (5 mln. Da, 5%–10% hydrolysis) with chromium acetate <sup>b</sup>	0.5 wt% HPAM /0.047 wt% CA	10	25–30	1	5.5	Ganguly et al. (2002)
7	HPAM (5 mln. Da, 5%–10% hydrolysis) with chromium acetate <sup>a</sup>	0.5 wt% HPAM /0.047 wt% CA	10	40	1	16	Seright (2003a,b)

<sup>a</sup>The formulation was placed in the fracture as a mature gel.

<sup>b</sup>The formulation was placed in the fracture as a gelant, allowing 100% matrix saturation before the shut-in.



**Fig. 4.** Post flush pressure gradient versus fracture width measured by different researchers (see Table 5).

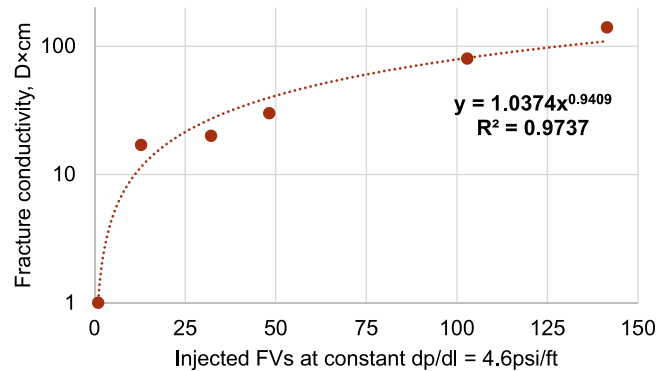
where  $\frac{dp}{dl}$  – post flush pressure gradient, psi/ft;  $w$  – fracture width, mm.

Long term stability of HPAM gels in fractures was studied by Ganguly et al. (2002). The Fig. 5 presents a graph which was built on the basis of the results obtained by Ganguly et al. (2002).

The Fig. 5 shows that at constant pressure gradients permeability of 1 mm fracture recovers at a large rate during the injection of first 60FVs of water. After that point the rate of permeability recovery (gel wash out) reduces substantially. Probably this dynamics can be explained by the wash out of mobile gel from the fracture during the early stage of water post flush (Seright, 2003b).

### 3.2. Matrix reservoirs

The extrusion of gels through porous rocks or fractures filled with proppant at realistic pressure drops is not possible (Seright, 1999). Therefore, gel placement as a gelant is the only variant. Authors of this paper conducted their own test in order to get a visual qualitative evidence. The Fig. 6 below shows 6 Darcy marble pack model after the injection of mature gel. 1PV of 0.5wt% HPAM/0.05 wt% chromium acetate aged for 24 h at 40 °C



**Fig. 5.** Fracture conductivity versus injected water volume at constant pressure gradient 4.6psi/ft. Temperature 25–30 °C. Fracture length 61 cm, width 1 mm, height 5.1 cm. 0.5 wt% HPAM (5 mln. Da, 5%–10% hydrolysis)/0.047 wt% CA. Makeup and postflush water salinities 10g/L NaCl. Pretreatment fracture conductivity is 8000 D×cm. Source: Ganguly et al. (2002).



**Fig. 6.** Screening out of HPAM/chromium acetate gel within the first section of 6 Darcy marble pack. Length of the model – 8.6 cm, diameter – 4.3 cm.

gel was injected into the model at 1 cm<sup>3</sup>/min. As it can be seen, the gel concentrated and screened out within the first section of the model and did not penetrated any sufficient distance. The inlet injection pressure stabilized at 6psi during the injection process.



### 3.2.1. Gel stability in matrix

By varying polymer/crosslinker content in the range of 0.75–5 wt%/0.03–0.4 wt% it is possible to achieve sufficient stability of HPAM/Cr<sup>3+</sup> gels and high RRFs (above 1000) at high pressure gradients (up to 4000psi/ft), temperatures (up to 124 °C) and injected brine salinity (up to 120 g L<sup>-1</sup>) in porous rocks with permeabilities as high as 15–20 Darcy over extended periods of time (more than 1 month) (Asghari and Taabbodi, 2004; Bryant et al., 1996; Kuzmichonok et al., 2007; Liang et al., 1992; Sydansk, 1990). The Table 6 provides data on experimental conditions and results of different researchers.

As it can be seen from the first 4 lines in Table 6, the presence of residual oil saturation results in lower range of measured RRFs. Another good example, in fully water saturated Berea core RFF for 5000–7500 ppm HPAM/15 mM CrMa<sub>3</sub>/0.6M acetate gels were as high as 16,000 at 90 °C. However, when residual oil saturation was present inside of the core RFF was as low as 170 (Kolnes and Nilsson, 1996).

### 3.2.2. In-depth propagation and selective placement of gels

Longer gel onset times support deeper placement of gels. HPAM/Cr acetate gels can be formulated to gel after several weeks at 22 °C. Unfortunately, at 60 °C, the gelation process may be accelerated by 80 times (Sydansk, 1990). The replacement of chromium acetate with chromium malonate (CrMa<sub>3</sub>) is one way to achieve a significant delay in gel onset time at high temperatures (up to 18 days at 120 °C) (Bartosek et al., 1994; Lockhart and Albonico, 1994).

The effect of shearing on gelation time is also notable. In fact, gelation in porous media can be accelerated by 3 times at a flow velocity of around 2 ft/day (2.3 s<sup>-1</sup>) (Huang et al., 1986). However, a study that would systematically cover a wide range of experimental conditions was not found in the literature. Rotational viscometers are not suitable for this purpose, as the rotational speed may break apart gel aggregates, thus preventing them from growing beyond a certain size. That size may be too small for a viscometer to detect any significant viscosity increase, but large enough to plug pore throats in a rock. Therefore, in matrix rocks, the real/practical gelation time is reached when the gel particles approach the size of the pore throats, and therefore can no longer pass through them.

The gel onset time is also influenced by the retention of chemicals (Garver et al., 1989). In sandstone, polymer retention can be reduced by using anionic or neutral polymers (Sorbie, 1991), though chromium retention is a serious problem, especially at temperatures above 50 °C. More importantly, retained Cr<sup>3+</sup> may accelerate in-situ gelation of any gelant that is later injected by around 6 times (Bartosek et al., 1994; Kolnes and Nilsson, 1996). At 90–120 °C chromium malonate (CrMa<sub>3</sub>) was shown to be more resistant to retention than chromium acetate and glycolate (Bartosek et al., 1994). However, in rocks with notable clay content, the use of buffering agents is still required (Bartosek et al., 1994; Kolnes and Nilsson, 1996).

The presence of carbonate minerals is also crucial, as fluid-rock contact may result in the increase of pH and chromium precipitation as (Cr(OH)<sub>3</sub>) (Kolnes and Nilsson, 1996). In fact, at pH 9 and salinity higher than 50 g/L the precipitation of chromium can be almost instantaneous (Zou et al., 2000). The pH value at which the interaction between polymer and Cr(III) cannot prevent the precipitation of Cr(III) as chromium hydroxide salt should be determined for each reservoir specifically (McCool et al., 1995). However in general, it was demonstrated that for reliable plugging in-situ pH of the gelant should not be higher than 7, otherwise the gelation is unlikely to happen (Fig. 7) (Kolnes and Nilsson, 1996).

Unfortunately, selective placement of viscous HPAM gelants in multilayered reservoirs with minimal variations in permeability

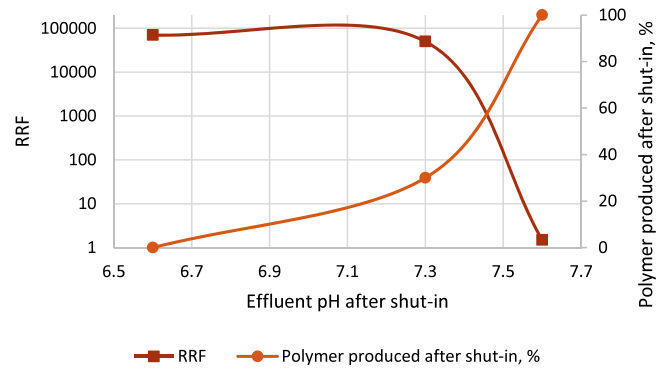


Fig. 7. Effect of initial gelant pH on permeability reduction of 1 Darcy Bentheimer core at 90 °C with 7.5 mM CrMa<sub>3</sub> and 6000 ppm HPAM AF935. Derived from the results of Kolnes and Nilsson (1996).

is often not achievable (Seright and Liang, 1994; Zaitoun et al., 1999). In this respect, identifying the extent of the DPR effect that can be provided by HPAM/Cr<sup>3+</sup> gels is of high importance.

### 3.2.3. Disproportionate permeability reduction

In laboratory tests conducted by Liang et al. (1992), the treatment of Berea sand cores by bulk gels, including HPAM/Cr<sup>3+</sup>, resulted in 2–100 and 2–15 fold reduction of water and oil permeability, respectively. Seright et al. (2004) demonstrated that regardless of rock wettability, HPAM/Cr<sup>3+</sup> gels reduced permeability to water by 80–90 times more than that to oil. In a study by Willhite et al. (2002), this value varied between 100 and 1000.

X-ray microtomography demonstrated that in water-wet rocks, DPR occurs due to the coalescence of oil droplets caused by a 55% reduction in HPAM gel volume, due to dehydration of the gel induced by oil flow. While in oil-wet rocks, DPR was explained by the ability of oil to slip along the interface between oil-wet pore walls and the gel (Seright et al., 2001b, 2004; Willhite et al., 2002; Sydansk and Romero-Zeron, 2011).

RRFs to oil and water measured in water-wet sand packs treated with HPAM/Cr<sup>3+</sup> gels were independent of pressure gradients in the range of 1–50psi/ft (Nguyen et al., 2006). Thus, DPR by HPAM gels does not depend on the distance at which a gel has been placed inside of a reservoir.

However, for Berea core treated with HPAM gel, it may require more than 100 PVs of oil throughput before permeability to oil will recover from 2–5 to several hundred mD. This suggests that a notable DPR effect can be provided only when gel penetration into oil bearing rock is limited (less than few feet) (Seright, 2006). Aside from that, the oil bearing layer must be drained at 100% oil cut (Sydansk and Romero-Zeron, 2011). In fact, gelants that decrease permeability to water by a factor of 10 are not recommended for application in multilayered matrix reservoirs with vertical cross-flows (Zaitoun et al., 1999).

When injectors are treated, near wellbore geology is less critical, as oil permeability damage occurs far away from producers. For example, in 2008 at Guarda oilfield (Colombia) 25,736 bbls of HPAM/Cr<sup>3+</sup> solution were injected into an injection well located in a two-layered reservoir with severe cross-flows. The treatment was paid off in 6 months, IOR calculated in 2011 was equal to 172,600 bbls (Montoya Moreno et al., 2014). Another good example is the treatment of 7 producers at Big Horn Basin (USA) in 2009 by the injection of 8200–11,400 bbls of HPAM/Cr<sup>3+</sup> gelant. Despite the isolation of the oil-bearing zone by a packer, it was damaged; and, as a result, both water and oil rates decreased by 72% and 56% respectively. However, the treatment changed the fluid dynamics of the reservoir and increased the average oil flow

**Table 6**  
RRFs measured by different researchers for HPAM/Cr(III) gels.

Gel recipe	Polymer Mw/hydrolysis degree	Rock type	Pretreatment permeability to brine, mD	Residual oil saturation	Temperature, °C	Pressure gradient, psi/ft	RRF	Reference
7500 ppm/300 ppm Cr(III) in 1% NaCl	7mln Da/30%	Crushed carbonate	14,740	Not present	40	NA	19,000–76,000	Asghari and Taabbodi (2004)
7500 ppm/300 ppm Cr(III) in 1% NaCl	7mln Da/30%	Crushed carbonate	2,430	Present	40	NA	111–445	
7500 ppm/300 ppm Cr(III) in 1% NaCl	7mln Da/30%	Crushed carbonate	37,000	Not present	NA	NA	49,500–1,370,370	Kuzmichonok et al. (2007)
7500 ppm/300 ppm Cr(III) in 1% NaCl	7mln Da/30%	Crushed carbonate	10,700	Present	NA	NA	9,640–254,762	
1.39% HPAM/212ppm Cr(III) in 1% NaCl	2mln Da/2%	Berea sandstone	180	Present	41	NA	52,954	Liang et al. (1992)
2.2 wt% HPAM/0.02752t% Cr(III)	11mln Da/2%	Ottawa sand pack	20,000	Not present	85	1,000	434,780	Sydansk (1990)
2.2wt% HPAM/0.02752t% Cr(III)	11mln Da/2%	Core plug	NA	Not present	124	4,000	250,000	

rate of 22 surrounding wells from 1270 to 1340 bbls/day (Turner et al., 2010). This suggests that under the existing geological conditions, treatment of the injectors would have been a better choice.

Sydansk and Seright (2006) provide guidance on the application of permeability modification treatments in both injectors and producers with regard to different geological conditions of a reservoir, as well as some more detailed explanation of pre- and post-treatment hydrodynamic processes.

#### 4. Brine initiated gels

Some polymer solutions can be crosslinked by cations found in brine. For example, hydroxypropylcellulose (HPS) and sodium dodecyl sulfate (SDS) dissolved in fresh water instantly gel after mixing with brine. The gel thoroughly plugs sand cores at 30–54 °C. For reservoir brines, gelation does not occur if the concentration of divalent cations exceeds 5000 ppm, unless SDS is partially substituted with sodium lauryl ether sulfate (SLES) (Naae and Whittington, 1991; Whittington and Naae, 1992; Whittington et al., 1994). No reports on field application of HPS/SDS gels were found in the literature.

In this context, it is worth mentioning that biopolymers gellan and i- or k-carrageenan dissolved in fresh water gel upon contact with all types of reservoir brines (Ibragimov et al., 2013; Iglauer et al., 2011; Kudaibergenov et al., 2015). In fact, gelation of gellan gum was found to be enhanced by divalent cations (Kudaibergenov et al., 2015; Nurakhmetova et al., 2015). Gellan gum has been successfully tested in laboratory and field conditions at temperatures up to 60 °C and at brine salinities below 120 g L<sup>-1</sup> (Gussenov et al., 2014). No reports on field application of carrageenan gels were found in the literature.

##### 4.1. Fractured reservoirs

###### 4.1.1. Gel placement issues

If the gelant is injected without a fresh water preflush, a mature gel plug will result, as the gel forms immediately upon contact with reservoir brine.

**4.1.1.1. When placed as a gel.** Due to the high Young's modulus of gellan and k-carrageenan gels (50–90 kPa), their placement should require higher pressure gradients than those of i-carrageenan gels (1–2 kPa) (Stevens et al., 2013). In fact, the injection of 760 bbls of 1 wt% gellan solution into a production well located in a reservoir with fracture controlled water flow caused a rapid injection pressure increase from 90 to 200 bars (Gussenov, 2017).

**4.1.1.2. When placed as a gelant.** If gelant is injected after a fresh water preflush, the gel will not form during the injection procedure. In this case, the gel will form only after a brine post-flush. No laboratory studies of gellan or carrageenan solution propagation through fractures were found in the literature.

###### 4.1.2. Gel stability in fractures

Due to the low rigidity of HPC/SDS gels, they are not effective for plugging fractures and unconsolidated sands with permeability of around 70 D (Whittington et al. 1994). As for carrageenan gels, they cannot be applied when plugging fractures at temperatures close to 60 °C, as they become flowable at this temperature (Gussenov, 2017; Stevens et al., 2013).

Laboratory tests with 0.5 wt% gellan solutions on 20 cm long 1 mm wide fractures with impermeable matrix showed that at 90 °C brine post flush pressure gradient grow linearly with the flow rate until 60psi/ft is reached (Fig. 8) (Gussenov, 2017). This value can be considered as a maximal water breakthrough pressure gradient. For the comparison 0.5 wt% HPAM gels 1 mm wide in fractures provided only 5.5–30psi/ft at 25–40 °C (see Table 5) (Seright, 2003b).

The treatment of a production well at the Karabulak oilfield and two injectors at the Kumkol oilfield (Kazakhstan) with 0.2–1 wt% gellan solutions demonstrated effective permeability reduction in fractured reservoirs at 60 °C (Gussenov, 2017). Water cut rapidly increased at the beginning of production, though instantly declined from 80% to 0% following the injection of a small volume (760 bbls) of gellan solution, which suggests that fracture-controlled water flow existed in the vicinity of the production well. Also at the Kumkol oilfield, incremental production of 5890 tons of oil occurred within 11 months following the injection of 1000 and 1480 bbls of gellan into two injectors, most probably as a result of fractures being plugged by the gel (Gussenov et al., 2014; Gussenov, 2017; Kudaibergenov et al., 2015).

##### 4.2. Matrix reservoirs

###### 4.2.1. Gel stability in matrix

In general, HPC/SDS gels are likely to be stable in sandstones with permeability below 7–8 D. In Berea cores with permeability of 0.3–0.4 D, HPC/SDS gels reduced water permeability by 95% at pressure gradients of 10–15psi/ft and a temperature of 54 °C. After aging the treated core for 6 months, the permeability recovered by 12% (Naae and Whittington, 1991; Whittington and Naae, 1992; Whittington et al., 1994).

At 60 °C, it requires 1000–2000 psi/ft in order to extrude gellan and carrageenan gels through oil saturated and water flooded

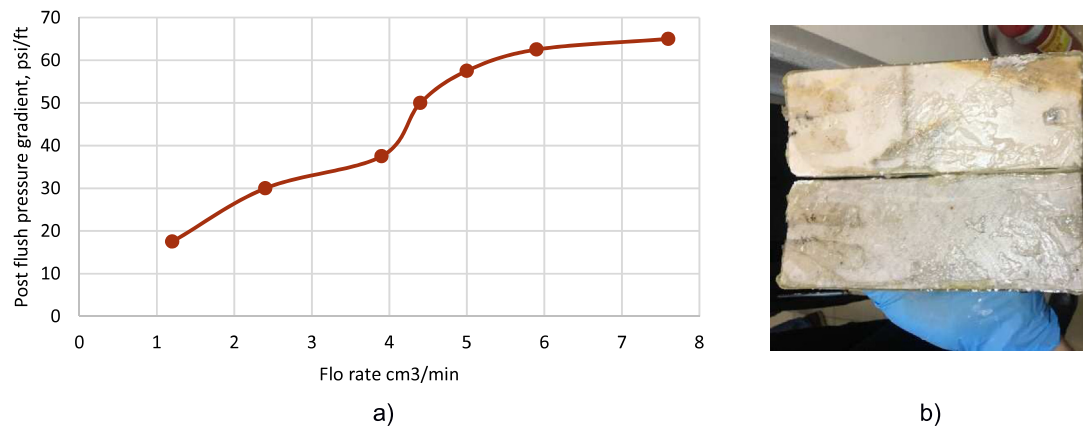


Fig. 8. 150 g/L brine post flush in 1 mm wide fracture filled with gellan gel at 90 °C (a) and gel appearance in fracture after the test (b) Gussenov (2017).

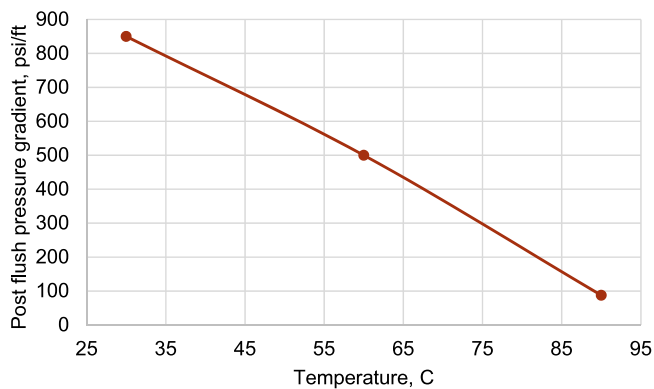


Fig. 9. 90 g/L brine post flush after 0.5 wt% gellan injection in 2.8 and 7 Darcy two-layered sand pack models. Residual oil saturation is present. Oil viscosity 330cp (Gussenov, 2017).

sand packs with air permeability of 2–2.3 D. No significant difference between the plugging behaviors of i- and k-carrageenans has been noted. When sand packs with air permeability of 20D were tested, the gel extrusion pressure gradient decreased to 240psi/ft (Gussenov, 2017).

Gellan solutions may not plug high permeability sand packs if injected at temperatures close to 90 °C (Fig. 9) (Gussenov, 2017). The same is expected for carrageenan gels.

However, a limited amount of laboratory research data has been found in the literature. Laboratory studies of dynamic aging of gellan and carrageenan gels in matrix rocks for different temperatures and permeabilities should be conducted in the future.

#### 4.2.2. In-depth propagation and selective placement of gelants

The continuous injection of HPC/SDS gelants into water flooded cores does not cause notable plugging. Severe plugging has been observed when the gelant is injected in small slugs alternated with similar slugs of brine in order to allow for sufficient mixing (Whittington et al., 1994). Thus, constant injection mode is better for the treatment of injection wells in order to plug thin thief layers (less than 1 m thick). Whereas, alternated injection mode is better for plugging thick thief layers and production well treatments, as this method ensures high resistance to flow in the reverse direction.

The injection of gellan and carrageenan solutions into water flooded sand packs causes a rapid pressure gradient increase (up to 2000 psi/ft) due to gel formation upon contact with brine (Gussenov, 2017). Experiments on two-layered sand packs

demonstrated a modest oil recovery increase (around 5%–9%) (Gussenov et al., 2017); however, unrealistically high pressure gradients (730psi/ft) required for the 0.5PV gellan slug and chase water injection throw doubts on successful application of this polymer in matrix reservoirs, unless sufficient preflush is applied to prevent premature gelation. In fact, it required only around 3psi/ft in order to inject 2PVs of 0.5% gellan solution at 8.6 cm/hr and 25 °C through 14 Darcy (air permeability) porous media saturated with distilled water (Gussenov, 2017). Therefore, propagation of gellan and carrageenan solutions through matrix rocks preflushed with fresh water ought to be studied in the future.

#### 4.2.3. Disproportionate permeability reduction

When injected into matrix layers at an initial oil saturation 75%–80% and 54 °C, HPC/SDS gelants do not gel (Whittington et al., 1994). The injection of gellan into an oil saturated sand pack resulted in the decrease of oil permeability by a factor of 3 (Gussenov, 2017). In general, DPR effect provided by gellan and carrageenan gels was not studied thoroughly. The minimal value of connate water saturation at which the gelation can occur should be determined for each gelant exclusively. This information will help to forecast whether the injected gelant can gel in oil-bearing zones or not.

### 5. Thermo-activated inorganic Galka and organic Metka gels (widely applied in Russia)

Galka, an inorganic gel system, consists of aluminate, carbamide, and surfactant dissolved in water. The heating of carbamide releases CO<sub>2</sub> and ammonia, increasing pH from 2.5–3.5 to 3.8–4.2, as well as initiating the hydrolysis of alumina ions. As a result, aluminum hydroxide gel forms. The gels can be used at temperatures from 20 to 320 °C, regardless of brine salinity (Altunina and Kuvshinov, 2007).

Metka, an organic gel system, consisting of aqueous solutions of cellulose ethers (CE) and electrolytic or non-electrolytic complexes, exhibits a viscosity increase at elevated temperatures and salinities. According to laboratory studies, the gels are stable at temperatures below 220 °C and makeup water salinity of 0–20,000 ppm. Gelation temperature may be regulated within a range of 40–120 °C with inorganic and/or organic additives. Moreover, gelation was found to be reversible if ambient temperature drops by 20–30 °C below the gel onset temperature (Altunina and Kuvshinov, 2007).

Galka and Metka bulk gels have been successfully utilized at Russian, Chinese, Vietnamese, and Omani reservoirs (Altunina et al., 2013, 1995; Altunina and Kuvshinov, 2002).

### 5.1. Fractured reservoirs

A number of field tests proved the suitability of Galka and Metka gelants for the plugging in fractures. During 2007–2011 87 producers were treated by 550–1000 bbls of Galka gelants in a naturally fractured carbonate reservoir at the Usinskoe oilfield. As a result, oil flow rates increased on 20%–30% and water cuts decreased from 70 to 34% (Altunina et al., 2015; Taraskin et al., 2012). Metka gelants were successfully used in fractured injection wells at Urevskoe field for the plugging in lower parts of the fractures. As a result, over the next 22 months, due to the increased sweep efficiency the subsequent chemical flooding yielded more than 4400 tons of incremental oil production (Altunina et al., 2014).

### 5.2. Matrix reservoirs

Between 1989 and 2014, Galka was tested in different Siberian reservoirs, including those subjected to steam injection. The volumes injected varied between 80 bbls and 1000 bbls. As a result, there were 3%–45% reductions in water cut and increases in oil flow rates of up to 4.8 times (Altunina and Kuvshinov, 2007; Altunina et al., 2011, 2013).

Lukoil, the Russian oil company, has applied Metka gels since 1998. During the period of 1998–2000, 158 wells, including steam injectors, were treated with Metka. On average, one treatment allowed incremental production increases of 1630 tons of oil (Altunina et al., 2011; Altunina and Kuvshinov, 2007).

#### 5.2.1. Gel stability in matrix

Galka and Metka gels are claimed to be stable in sandstones and carbonate matrix rocks with permeabilities  $\geq 20$  D, at pressure gradients of 450psi/ft, and at temperatures up to 350 °C (for Galka) and 200 °C (for Metka). However, Metka gels become unstable when they come into contact with reservoir brine with salinity higher than 200,000 ppm (Altunina et al., 2011).

#### 5.2.2. In-depth propagation and selective placement of gelants

As the gel on-set time of Galka and Metka solutions does not exceed several hours, rapid plugging was most probably the main reason for small volumes of gelants (not larger than 1300 bbls) injected in all field treatments (Altunina et al., 2011). In order to place a gel plug at a distance from a well component-wise injection of Galka gelant and gel-initiating carbamide solution was simulated and tested at an oilfield in Germany. However, due to the small volumes of the injected buffering and chase water slugs the gel plug was placed only 4 m away from the wellbore (Kuvshinov and Kuvshinov, 2013).

The increase of reservoir sweep efficiency from 10 to 38% after the injection of 760bbls of Galka gelant into steam injector at Usinskoye oilfield (Russia) proved that selective permeability reduction by Galka gels in near wellbore zone is possible (Altunina et al., 2013; Altunina and Kuvshinov, 2007).

#### 5.2.3. Disproportionate permeability reduction

Metka gels were claimed to provide DPR effect, since they allowed RRFs to oil 2–3 times lower than that to water inside of sand pack with permeability around 11 D. However, it required 670psi/ft in order to pump 3PVs of oil through the model (Altunina and Kuvshinov, 2007). Such high pressure gradients are not achievable in real conditions. Nevertheless, if Metka gel placed wrongly 100% permeability recovery by cooling down the plugged area is possible (Altunina et al., 2006). This makes Metka a good candidate to be applied as an agent for temporary bridging in drilling, directed injection and fracturing (Herring et al., 1984; Sorbie, 1991; White, 1958).

Results of tests of DPR by Galka gels were not found in the literature.

## 6. Conclusion

In this work, several bulk gels are reviewed as materials for permeability reduction in fractures and matrix rocks. In fractures, gel stability is a major concern. While in matrix rocks, the main issues are in-depth propagation and selective placement of gelants, as well as the disproportionate permeability reduction effect.

Inorganic gels do not seem to be effective for the plugging of fractures, unless used in combination with polymers, and in-depth permeability reduction in matrix rocks. However, their high stability in matrix rocks at elevated temperatures (up to 300 °C for Galka gel) makes them a suitable choice for the treatment of steam injection wells.

HPAM/Cr<sup>+3</sup> and brine initiated gels are effective for the plugging of fractures at temperatures up to at least 80 °C. In cases where HPAM/Cr<sup>+3</sup> gels cannot be applied due to the high salinity of chase flooding water brine initiated gels may be a better choice. HPAM/Cr<sup>+3</sup> and brine initiated are also effective for the plugging of matrix rocks at temperatures up to at least 90–120 °C. However, their in-depth selective placement may be problematic. HPAM/Cr<sup>+3</sup> gels always reduce permeability to oil by at least a factor of two, and may not be effective in multi-layered reservoirs with sufficient cross-flows. The DPR effect provided by brine initiated gels promises to be reliable and should be studied in the future.

Galka and Metka gels can also be applied for the plugging of fractures and matrix rocks if the salinity of the makeup brine and reservoir temperature are too high to use other gelling materials. However, there is not enough laboratory research to explain the behavior of these gels inside of a reservoir.

The Table 7 presents the most important info on the bulk gels review in this paper.

The information presented in this review can help with choosing proper plugging material with regards to reservoir conditions and determine future research works which have to be conducted in order to acquire more understanding of permeability reduction by gels.

## Abbreviations

CA	Chromium Acetate
Cr	Chromium
D	Darcy
DPR	Disproportionate Permeability Reduction
IOR	Incremental Oil Recovery
GOR	Gas Oil Ratio
HD	Hydrolysis Degree
HPAM	Hydrolyzed Polyacrylamide
Ma	Malonate
MPV	Matrix Pore Volume
Mw	Molecular Weight
PV	Pore Volume
RF	Resistance Factor
RRF	Residual Resistance Factor
RRF <sub>o</sub>	RRF to oil
RRF <sub>w</sub>	RRF to water
WOR	Water Oil Ratio

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**Table 7**  
General information on the application of the reviewed bulk gels.

Bulk gel type	Make up water requirements	Placement and stability		Reservoir temperature requirements	DPR effect
		Fractured reservoirs	Matrix reservoirs		
Sodium silicate gels	Fresh water with minimal content of divalent cations (Nasr-El-Din and Taylor, 2005; Pham and Hatzignatiou, 2016; Stavland et al., 2011a).	More reliable if applied in combination with polymers (Hatzignatiou et al., 2015; Pham and Hatzignatiou, 2016; Lakatos et al., 2011; Samari et al., 1998).	In-depth selective propagation of gels can be improved by regulating preflush volumes and activator content. The gels are stable at high pressure drops (Herring et al., 1984; Nasr-El-Din and Taylor, 2005).	The gels were proved to be stable in fractures and matrices at 60 and 95 °C, respectively. Bulk gels are stable at 300 °C (Nasr-El-Din and Taylor, 2005; Pham and Hatzignatiou, 2016).	DPR effect can be achieved in oil-wet rocks. The gels should be injected along with oil (Askarinezhad et al., 2016).
HPAM/Cr <sup>+3</sup> gels	Low salinity water with maximal content of divalent cations around 10 g/L is preferable (Moradi-Araghi and Doe, 1987); (Seright et al., 2010).	More reliable if the plugging agent is injected as mature gel. High salinity postflush decreases gel stability and is not recommended (Brattekkås et al., 2015a,b; Liu and Seright, 2000; Seright, 2000).	In reservoirs with notable carbonate mineral content the increase of pH up to 6–7 may prevent gelation. The gels are stable at high pressure drops (Lockhart and Albonico, 1994; Bartosek et al., 1994; Kolnes and Nilsson, 1996; McCool et al., 1995).	Were proved to be stable in fractures and matrices at 80 and 120 °C (Albonico et al., 1993; Seright, 2003a; Sydansk and Romero-Zeron, 2011).	DPR effect is reliable in both water- and oil-wet rocks. However, oil permeability is always reduced by a factor of 2 or much greater (Seright et al., 2004; Sydansk and Romero-Zeron, 2011).
Brine initiated gels	Fresh water with minimal content of dissolved solids (Kudaibergenov et al., 2015; Whittington et al., 1994).	Gellan gum gels provide good plugging at 90 °C compared with HPAM gels (Gussenov, 2017).	Fresh water preflush is necessary to avoid premature plugging. The gels are stable at high pressure drops (Gussenov, 2017; Whittington et al., 1994).	HPS/SDS gels were proved to be stable in matrices at 54 °C. Gellan gels were proved to be stable at 60–90 °C in matrices and fractures (Gussenov, 2017; Kudaibergenov et al., 2015; Whittington et al., 1994).	Depending on water saturation the gels may or may not gel. Additional research is required (Nae and Whittington, 1991; Whittington and Nae, 1992; Whittington et al., 1994).
Thermo-activated inorganic Galka and organic Metka gels	Galka gelants can be prepared at any salinity, while salinity limit for Metka is 20,000ppm (Altunina and Kuvshinov, 2007).	Additional studies are required. However, a number of field trials proved the efficiency of the gels in fractured reservoirs (Altunina et al., 2015, 2014; Taraskin et al., 2012).	Sufficient cold water preflush may be required to achieve in-depth selective placement of gels. The gels are stable at high pressure drops (Altunina et al., 2011).	300 °C for Galka and 200 °C for Metka in matrices. Additional research is required for fractured reservoirs (Altunina and Kuvshinov, 2007).	Additional research is required.

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