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Polymer Composition for Reducing Permeability in a Fractured High-Viscosity Oil Reservoir

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Abstract

In fractured reservoirs, water from injection wells quickly moves through the reservoir and enters to the production well. As part of this research, a polymer composition for fractured reservoirs was developed. The polymer composition consists of polyacrylamide, lignosulfonates, hydrochloric acid and salt. Dependences for assessing the properties of the composition on the content of the components are obtained. Laboratory experiments were carried out to evaluate the results of the interaction of the gel-forming composition with formation water. It has been established that a layer of the composition with a thickness of less than 1 mm, upon contact with water, dissolves after 48 hours, while the rest of the gel volume remains intact, that is, the gel-forming mass is preserved. Core experiments prove that the polymer composition reduces fracture permeability by up to 99%. The composition has a high viscosity and therefore penetrates shallowly into rocks with low permeability. In such rocks, the composition blocks the filtration channels at a short distance from the inlet surface. During the day, the composition is converted into a gel and blocks the movement of formation water through the filtration channels. By changing the content of components in the composition, you can increase or decrease the rate of gel formation and its viscosity.

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1. Introduction

To maintain reservoir pressure, various agents are pumped into oil deposits, mainly water. Water injection into wells makes it possible to achieve high values of oil recovery factors[1]. This helps prevent rock deformation.[2,3] During stationary injection, advanced watering of production wells occurs due to water breakthrough through more permeable channels. (Fig. 1).[4] To improve the efficiency of deposit exploitation, change the direction of filtration flows and involve previously non-drained reserves in the development, various technologies are used, including non-stationary waterflooding, surfactant injection, *etc*.[5-8] One of the effective methods for increasing reservoir coverage by flooding and reducing the water cut in producing wells is the injection of polymers.[9,10] Polymer flooding will be most effective if applied early in oil production while mobile oil saturation is still high. Polymer flooding improves the mobility coefficient by increasing the viscosity of the injected water.[11,12]

In waterflooding, the increase in sweep volume and the increase in oil displacement efficiency are interdependent, but their contribution to enhanced oil recovery is different. The pore structure of the reservoir is the main factor affecting waterflooding, while the physical properties and initial oil saturation have a relatively small effect.[13]

Using high viscosity polymers and maintaining a high injection rate are two desirable but competing properties that affect the success of polymer flooding. The low viscosity of the polymer near the wellbore and the high viscosity of the polymer away from the wellbore leads to an increase in sweep efficiency.[14]

Laboratory studies of polymer compositions make it possible to determine the optimal composition for waterflooding in order to achieve maximum efficiency.[15]

Increasing water saturation reduces oil recovery regardless

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Fig. 1 Movement of water from a reservoir pressure maintenance system in an oil reservoir.

of wettability conditions. In addition, an increase in the mineralization of injected fluids reduces the efficiency of production due to a decrease in the viscosity of the polymer.[16] The use of polymers in waterflooding is limited by the reservoir temperature.[17]

During polymer injection, polymer retention on the rock surface is one of several important mechanisms involved in the waterflooding process.[18] Generally, synthetic polymers such as biopolymers and xanthan type are widely used as mobility agents in chemical EOR.[19] Viscoelastic polymers with higher elasticity provide higher oil displacement efficiency.[20]

Currently, research is mainly focused on polymer flooding for enhanced oil recovery due to its ease of operation, availability, low cost, mature technology and associated results.[21]

The world's heavy oil resources are estimated at about ten trillion barrels, which is almost three times the reserves of conventional oil.[22]

In this study, the task was to develop an effective polymer for injection into wells in formations with highly viscous oil. The parameters of the studied reservoirs are shown in Table 1.

Table 1. Geological parameters of the Tournaisian carbonate reservoirs (Nozhovskaya group of fields).

Index	Range of values
Oil-saturated thickness, m	4.2-7.5
Permeability, μm^2	0.032-0.628
Initial reservoir temperature, C	28-33
Oil viscosity in reservoir conditions, mPa·s	48.8-87.1

Tournaisian deposits are characterized by a low temperature - up to 33 degrees Celsius, so the issue of thermal stability of the polymer under these conditions will not be significant. However, when choosing the components of the composition, one should take into account its adaptation to highly mineralized media and mechanical strength.

The salinity of formation water for Tournaisian deposits reaches 260 g/l. The polymer solution is subjected to rather severe mechanical stresses during its preparation and transport to the bottomhole formation zone. As a result, macromolecules are destroyed and the viscoelastic properties of the solution decrease.

To block cracks in rocks under the previously listed conditions, a search was made for a component for a new gel composition. Polyacrylamide, technical lignosulfonates, hydrochloric acid and magnesium chloride were chosen as the basis of the composition. Studies have been conducted to determine the properties of the composition depending on the content of the components. After determining the most effective composition of the composition, filtration studies were carried out on rocks. Research has confirmed the high efficiency of the new composition and the possibility of its use.

2. Experimental section

2.1 The choice of components of the polymer composition

Analyzing the advantages and disadvantages of existing polymer compositions, the following requirements for them can be identified:

- selectivity of influence;
- availability of reagents included in the composition;
- low initial viscosity, high penetrating power;
- ability to clog (isolate) highly permeable layers;

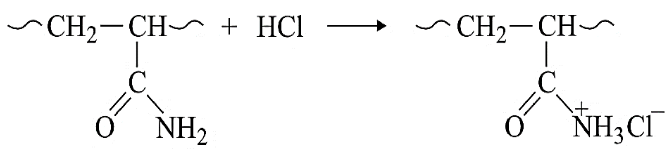
• ability to form a homogeneous insulating mass;
• the ability to regulate the timing of gelation or hardening;
• no shrinkage.

Research has shown that among the group of polymers, hydrophobically bonded polyacrylamide polymers have attracted more researchers in both academic and industrial laboratories in the field of polymer flooding.[23] This is due to their unique structure and properties, such as thickening properties, shear thinning, relative permeability modifiers, sweep efficiency, *etc*.[24] Accordingly, it has been extensively investigated in petrochemical additives such as mobility control agents and rheology modifiers.[25]

As noted earlier, one of the promising directions in the development of flow equalizing compositions is the use of gel-forming compositions based on polyacrylamide and lignosulfonates.

Polyacrylamide solutions have become widespread in the oil industry to reduce the permeability of filtration channels as a basis for the formation of gel systems at a relatively low cost and high efficiency. Gelation is the process of transition of a colloidal solution into a gelatinous state. There is a significant variety of grades of polyacrylamide, which differ in their properties and effectiveness in reservoir permeability reduction processes. By creating compositions from a solution of polyacrylamide, salt and hydrochloric acid, it is possible to obtain homogeneous low-viscosity compositions.[26] At the same time, after injection into the reservoir, hydrochloric acid reacts with carbonate rocks, the pH of the medium increases, and crosslinking of the polymer occurs in pores and cracks. In laboratory experiments, it was shown that with an increase in the concentration of polyacrylamide to 5%, the displacement coefficient additionally increases by 15%. Based on the foregoing, to block highly permeable filtration channels, highly concentrated polymer compositions should be used that can create a strong water-insulating system in the reservoir. To reduce the initial viscosity of the polymer composition, low molecular weight polyacrylamide can be used, however, reducing the molecular weight requires increasing the concentration of polyacrylamide in the solution to achieve the necessary physicochemical and structural-mechanical properties of the polymer compound. Currently, polyacrylamide brand DP9-8177, which is a hygroscopic dry white powder, highly soluble in water, has become widespread. This polyacrylamide has a low molecular weight and is adapted to highly mineralized environments. Polyacrylamide type DP9-8177 was used as the basis for preparing the waterproofing composition.

The creation of a reliable waterproofing screen is achieved not only due to the strength of the material, but also due to the completeness of filling the reservoir with it. When the composition is injected into the well, it is important to slow down the dissolution of the main gelling component. This will allow you to adjust the viscosity and gelation rate and provide a deeper penetration of the composition into the reservoir. The dissolution retarder of the polyacrylamide may be a salt solution. Produced waters are mainly calcium chloride type, so the best option is to use chlorides, such as magnesium chloride. Magnesium chloride is presented in the form of crystals, we will well dissolve in water, it is ecologically safe. To improve the adhesion of the resulting composition with the rock, it is necessary to use reagents with surface-active properties. Improving the adhesion will increase the duration of the effect from the injection of the polymer composition in the well. One of the substances with surface-active properties are lignosulfonates. Technical lignosulfonates are a homogeneous viscous liquid of dark brown color. Lignosulfonates belong to the class of colloidal surfactants.[27] Hydrochloric acid is used to regulate the acidity of the medium and enhance the intermolecular interaction inside the solution. The process of hydrolysis of a low-concentration acid proceeds slowly at a low temperature (20, 32 degrees) and does not cause an imidization process (precipitation of reaction products), enhances intermolecular interaction within the solution, which leads to the formation of stronger bonds within the system. When hydrochloric acid and polyacrylamide react, structures of the following structure are formed:



The addition of hydrochloric acid also slows down the rate of gelation.[28]

As a result, polyacrylamide grade DP9-8177, technical lignosulfonates, dilute hydrochloric acid and magnesium chloride were used as reagents for obtaining a flow-leveling and water-insulating composition. Information about polyacrylamide grade DP9-8177 is given in Table 2.

Table 2. Physico-chemical characteristics of DP9-8177.

Parameter	Value
Appearance	white powder
Gel formation time, hours	32.5
Dissolution time in fresh water at a temperature of 25 C, min	50
Dynamic viscosity of solution, cP	65.3
Molecular weight, Dalton	5.0
Insoluble residue,%	0.36
Degree of hydrolysis, % (mol.)	3.4

2.2 Experiments with polymer compositions

To assess the interaction of the components of the studied compositions in laboratory conditions, their sequential mixing was carried out. To prepare the gel-forming composition, the necessary volumes of water and technical lignosulfonates were preliminarily prepared, the mass of bulk components was determined using high-precision balances AND EJ - 300.

The components were mixed in glass beakers using a WiseStir HS-50A stirrer.

During the experiments, an aqueous solution of polyacrylamide was first prepared; for this, polyacrylamide powder was gradually added to the required amount of water with constant stirring.

A given amount of magnesium chloride in water, lignosulfonates, and hydrochloric acid were added to the resulting system. The mixing process of the components was carried out continuously. As a result of mixing, a light brown liquid composition was formed (Fig. 2).

Fig. 2 Polymer composition. Initial state.

The glass with the resulting solution was hermetically sealed and a timer was started to determine the gelation time. When studying the physicochemical properties of the obtained compositions, their dynamic viscosity and gelation time were determined.

2.3 Determination of the dynamic viscosity of the compositions

Viscosity is one of the main properties that should be taken into account when assessing the conditions for the effective use of the resulting composition for water-proofing and flow-leveling work. Dynamic viscosity was determined using a rotational viscometer "Rheotest" RV 2.1. The principle of operation of this device is based on the fact that the test substance is subjected to shear in the gap between two cylinders, one of which rotates (internal). The change in torque by adjusting the number of revolutions of the inner cylinder is interpreted as a relationship between shear stress and shear rate. The change in shear rate at each point of the investigated fluid depends on the width of the gap between the cylinders.

2.4 Gelation time determination

When determining the gelation time, the prepared composition was poured into a glass beaker and placed in an oven, where it was further kept at different temperature conditions (20 and 32°C), with the gelation time counted. The moment of gelation was determined visually by tilting the beaker at an angle of 45° every 5 min. If the angle did not change when tilted, the composition was considered to be gelled. The time from the moment of preparation of the composition to the formation of the gel was determined. If the gel did not structure within 24 hours, the experiment was terminated.

The data obtained during laboratory studies are shown in Table 3.

When mixing polyacrylamide and lignosulfonates under standard conditions, with an increase in the content of polyacrylamide in the composition, its initial viscosity increased and the gelation time decreased (Fig. 3). With an increase in the content of lignosulfonates in the composition, its viscosity decreased (Fig. 4). An increase in the content of hydrochloric acid in the composition led to a decrease in the initial dynamic viscosity, while the gelation time increased (Fig. 5). With an increase in the content of magnesium chloride in the composition, the viscosity of the system decreased, the gelation time increased.

Experiments have shown that the technological characteristics of the gel are significantly affected by the content of polyacrylamide and salt. By changing the content of reagents, it is possible to obtain systems with different gelation times. The duration of the gelation period for such systems can be from 30 to 1200 minutes.

Therefore, it is very important to have a balance between achieving higher recovery and avoiding severe formation damage and well plugging. Reservoir plugging can lead to loss of injectivity, leading to the failure of many polymer flooding projects.[29]

For gelation of the composition within the bottomhole formation zone and accelerated commissioning of wells after exposure, it is proposed to choose a composition with a gelation time of 3 to 4 hours.

The temperature affects the gelation, with its increase, the process accelerates. Heating increases the movement of molecules within the system, which leads to an increase in the rate of adhesion between molecules. The dynamic viscosity decreases slightly in this case. When interacting with highly mineralized formation water, which acts as an electrolyte in

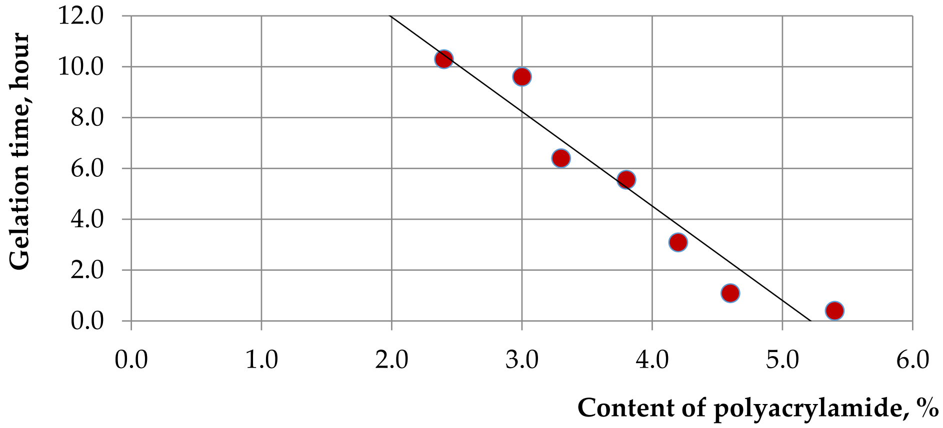


Fig. 3 Dependence of the gelation time on the content of polyacrylamide. Content of components: magnesium chloride 10.6%, hydrochloric acid (12%) 20.1%, lignosulfonates 31.2%

Table 3. The main results of studies of compositions under standard conditions.

No	The content of polyacrylamide, mass.,%	The content of magnesium chloride, mass.,%	Content of hydrochloric acid (12%), mass.,%	The content of lignosulfonates, mass.,%	Initial dynamic viscosity, mPa*s	Dynamic viscosity after 1 hour, mPa*s	Gelation time, min
1	1.3	10.6	20.1	31.2	114	758	-
2	2.4	10.6	20.1	31.2	143	956	618
3	3.0	10.6	20.1	31.2	179	1235	576
4	3.3	10.6	20.1	31.2	194	1524	384
5	3.8	10.6	20.1	31.2	235	1789	333
6	4.2	10.6	20.1	31.2	259	2536	186
7	4.6	10.6	20.1	31.2	357	2987	66
8	5.4	10.6	20.1	31.2	506	3400	24
9	4.2	8.9	20.1	31.2	311	2548	153
10	4.2	9.7	20.1	31.2	281	2541	164
11	4.2	10.1	20.1	31.2	269	2539	181
12	4.2	12.1	20.1	31.2	204	2529	246
13	4.2	13.8	20.1	31.2	150	2523	317
14	4.2	14.8	20.1	31.2	107	2515	360
15	4.2	16.5	20.1	31.2	96	2498	376
16	4.2	10.6	2.7	31.2	480	2583	38
17	4.2	10.6	7.7	31.2	428	2575	57
18	4.2	10.6	10.0	31.2	384	2569	98
19	4.2	10.6	12.3	31.2	370	2562	108
20	4.2	10.6	15.0	31.2	347	2548	131
21	4.2	10.6	23.5	31.2	175	2526	292
22	4.2	10.6	26.7	31.2	126	2517	423
23	4.2	10.6	20.1	27.4	319	2552	76
24	4.2	10.6	20.1	29.4	285	2544	151
25	4.2	10.6	20.1	33.0	224	2532	336
26	4.2	10.6	20.1	34.6	210	2530	512
27	4.2	10.6	20.1	35.5	205	2527	598
28	4.2	10.6	20.1	36.2	190	2527	710
29	4.2	10.6	20.1	37.7	175	2525	864
30	4.2	10.6	20.1	39.0	158	2522	923

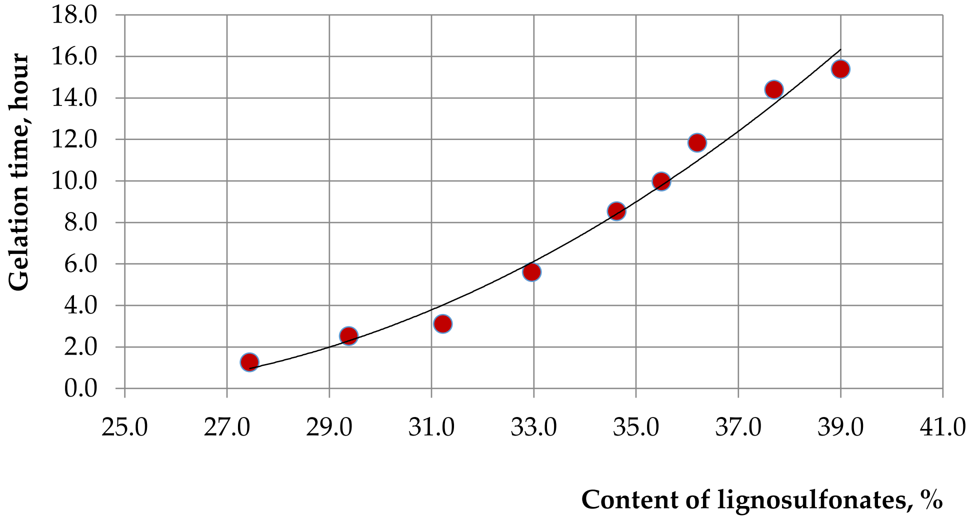


Fig. 4 Dependence of gelation time on the content of lignosulfonates. Component content magnesium chloride 10.6%, HCl (12%) 20.1%, polyacrylamide 4.2%.

the process of gel formation, a slight decrease in the viscosity of the system does not have a significant effect on gel formation.

With an increase in the content of polyacrylamide, the dynamic viscosity of the composition increases. The dynamic viscosity of the composition decreases with an increase in the content of magnesium chloride solution and lignosulfonates.

Reservoir pressure maintenance systems use wastewater separated from oil during its field preparation, which is mineralized to one degree or another, *i.e.* contains reservoir waters. Produced water produced along with oil at Tournaisian reservoir has the composition presented in Table 4.

In the process of flow equalization works in injection wells with a gel-forming composition, it interacts with the water injected to maintain reservoir pressure. In this regard, laboratory experiments were performed to evaluate the results of the interaction of the gel-forming composition with reservoir water (Fig. 6). It has been established that a thin layer of the composition in contact with this water after 48 hours has minor structural damage, while the gel volume remains intact, that is, the integrity of the gel-forming mass is preserved.

Table 4. Reservoir water properties.

Parameter	Average value
Volumetric coefficient, shares of units	0.9999
Viscosity, mPa*s	1.49
General mineralization, g/l	260.29
Density under standard conditions, kg/m^3	1.182
Density in reservoir conditions, kg/m^3	1.179
Compressibility factor, 1/MPa	$2.74 \cdot 10^{-4}$

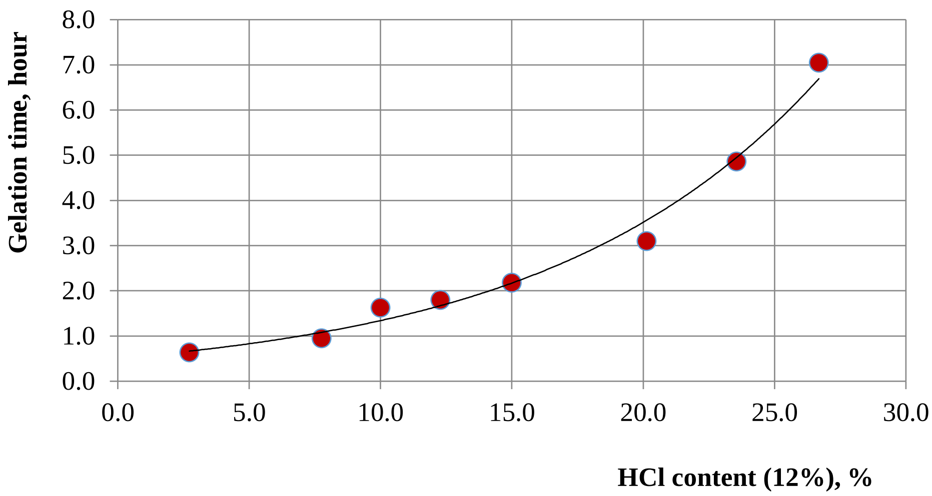


Fig. 5 The dependence of the gelation time on the HCl content. Content of components: magnesium chloride 10.6%, lignosulfonates 31.2%, polyacrylamide 4.2%.

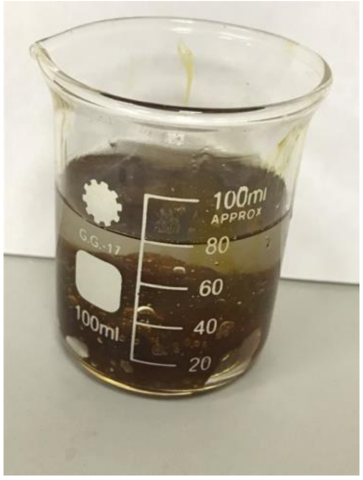


Fig. 6 Composition in interaction with reservoir water.

2.5 Dependence of composition properties on the content of components

For the mathematical processing of the data in Table 2, the classical multiple linear regression model was used. It was assumed that the relationship between the parameters could be described by a linear relationship of the form:

$$Y = \beta_1 x_1 + \beta_2 x_2 + \cdots + \beta_i x_i + u, \quad (1)$$

where Y is the dependent variable, u is a random component of the model, x_i represents the independent variables and β_i represents the regression coefficient.

The relationship between the dependent variable μ_0 and independent variables C_{pol}. C_{MgCl}. C_{lig}. C_{HCL} were determined via regression. Where the least squares method was used in the regression analysis. Dependences for assessing the properties of the composition on the content of the components are obtained:

Dependence of the initial viscosity of the composition on the content of the components

$$\mu_0 = 48 \cdot C_{pol} - 30 \cdot C_{MgCl} - 12 \cdot C_{\text{lig}} - 14 \cdot C_{\text{HCL}} + 1050, \quad (2)$$

The dependence of the gelation time on the content of the components (minutes)

$$T = 29 \cdot C_{MgCl} - 103 \cdot C_{pol} + 83 \cdot C_{\text{lig}} + 17 \cdot C_{\text{HCL}} - 2544, \quad (3)$$

when changing the content of components within the following limits:

polyacrylamide (C_{pol}),%: 1.3-4.5

magnesium chloride (C_{MgCl}),%: 10-15

lignosulfonates (C_{lig}),%: 31-38

hydrochloric acid (12%),%: 10-22.

The developed composition should be used to reduce the permeability of washed high-permeability reservoirs.

Calculations of pressures at wellheads were performed when gel-forming compositions were injected at a rate of 2 l/s, sufficient for injection of up to 10 cubic meters of the composition into the reservoir for 1 hour. The calculations were performed for a vertical well 1600 m deep, equipped with tubing with a diameter of 73 mm, at a formation pressure of 16 MPa. Wellhead pressures are calculated up to 21 MPa. The average value of the injectivity index for the injection wells of the Tournaisian facilities is 6.5 m^3/(day*MPa) with an average bottomhole zone permeability of 0.015 μm^2. Based on the calculations performed. compositions with an initial viscosity not exceeding 300-400 mPa*s should be used. The gelation time when filling the pore volume of the bottomhole formation zone with a gel-forming composition in a volume of 10 cubic meters should be 3-4 hours.

The above conditions (limitations) corresponds to the composition with the following content of components, %:

- magnesium chloride 10.6;
- lignosulfonates 31.2;
- hydrochloric acid (12%) 20.1;
- polyacrylamide 4.2;
- water remain.

2.6 Coreflood experiments of the gel-forming composition

Dynamic polymer retention is typically measured using in-line coreflood experiments.[30]

To determine the properties of the developed composition, filtration studies were carried out on carbonate core samples of the Tournaisian object. The studies were carried out according to the principle: constant flow – change in pressure drops. The main controlled parameter during the experiments was the change in the phase permeability of the liquid, which was used to evaluate the effectiveness of the composition.

Gelling systems containing polyacrylamide are recommended for use primarily in injection wells. During waterproofing operations in producing wells, compositions with polyacrylamide can be used to reduce permeability in washed layers, including in formations with fractured or fractured-porous carbonate reservoirs. Isolation of washed layers should be based on the analysis of the results of hydrodynamic and geophysical field studies. The filling of such rock layers in production wells should be carried out with the adoption of measures to prevent the entry of the composition with polyacrylamide into oil-saturated layers.

The direction of injection of the formation water model and composition corresponded to the direction of fluid movement in the reservoir. Direct filtration corresponds to the process of fluid inflow from the reservoir into the well, including well development after water shut-off measures, and reverse filtration simulates the process of blocking the watered interval in the bottomhole formation zone.

From the point of view of fixing the composition in the filtration channels, the conditions for injection wells, when the directions of injection of water and gel-forming compositions coincide, are simpler than in production wells. Therefore, the results of filtration studies obtained for the conditions of production wells can be transferred to flow-equalizing processes in injection wells.

The methodology for conducting filtration studies was as follows:

1. The prepared natural core sample was saturated under vacuum with the formation water model (Fig. 7). After

Fig. 7 Saturated core sample.

saturation, the pore volume of the sample was determined by weighing by the magnitude of the mass change.

2. The saturated sample was placed in the core holder of the filtration unit, where the pressure was created corresponding to the actual reservoir conditions. The temperature was set at 32 °C based on the average formation temperature of the Tournaisian deposits.

3. Filtration was carried out through a sample of formation water in the constant flow mode until the pressure gradient stabilized at a temperature of 32 °C and formation pressure. The direction of filtration in this case is direct.

In the constant flow mode, the studied water-insulating composition was injected. The injection volume, measured at the outlet of the sample, was 1 pore volume of the core sample. The direction of filtration in this case is the opposite.

5. After the completion of the process of pumping the waterproofing composition into the sample, the system was kept at rest for 24 hours.

6. After keeping the core sample at rest, its phase permeability for formation water was determined in the constant flow mode until the pressure gradient stabilized. The direction of filtration in this case is direct.

The studied composition was prepared by mixing the calculated amount of components until a homogeneous mass was obtained (Fig. 8).

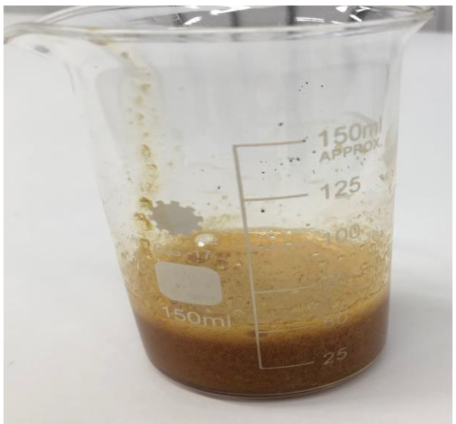


Fig. 8 Gelling composition before experience.

The results of filtration after a daily exposure of the sample with the composition pumped into it are shown in Table 5.

Table 5. Results of filtration experiments.

No	Sample water permeability, 10^{-3} μm²		Permeability reduction, %
	before composition injection	after composition injection	
1	36.0	28	23
2	21661	4.57	99
3	9086	36.8	99
4	1024	51.8	95
5	78	49.9	39
6	54	36	37
7	284	31	89

Experiment No 1 showed that the composition penetrated shallowly into the low-permeability rock of the carbonate reservoir. When the composition was injected into a low-permeability sample. The pressure gradient reached 200 MPa/m. After keeping the composition for 24 hours and filtering the formation water in the opposite direction. The pressure gradient dropped sharply, the permeability of the sample was restored by 77%.

For the second experiment, a core sample with wormholes was selected, which was previously used for modeling acid treatment. The water permeability of the sample before the experiment was 21.661 μm².

The main results of filtration experiment № 2 are shown in Fig. 9 and Table 6.

Table 6. Results of filtration experiment No 2.

Parameter	Unit of measurement	Before the injection of the composition	After downloading the composition
Pressure gradient during water injection	MPa/m	0.00025	7.504
Sample water permeability	10^{-3} μm²	21661	4.57
Permeability reduction	%		99
Residual resistance factor	Unit		300

When treated with the composition of a highly permeable carbonate core sample, the residual resistance factor was 300 units.

For the third experiment, a core sample was selected with a sample water permeability before the experiment of 9.086 μm². For experiment No. 4, a core sample was selected with a water permeability of the sample before the experiment of 1.024 μm².

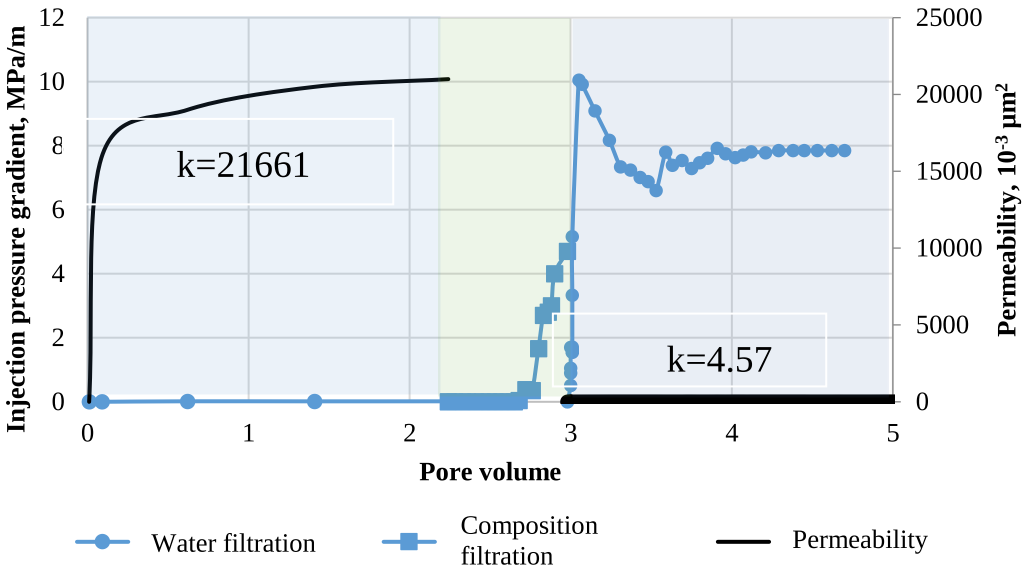


Fig. 9 Pressure gradient and pumping permeability for experiment No 2.

The dependence of the decrease in the water permeability of carbonate core samples on its initial (initial) value was obtained (Fig. 10). Natural core samples of porous type with a permeability of up to 0.1 μm^2 reduce their permeability to 40%. Samples with high permeability are almost completely blocked by the composition.

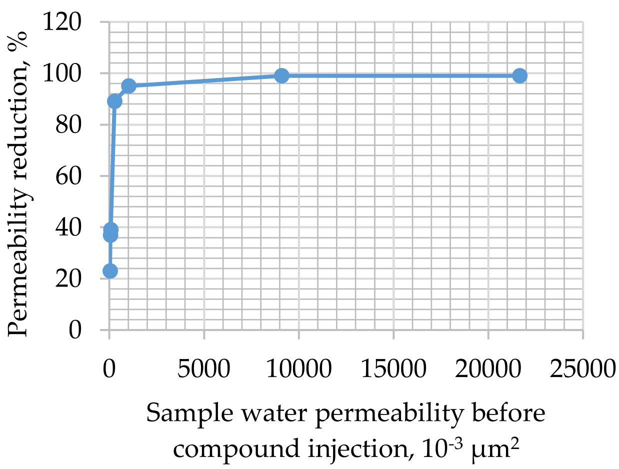


Fig. 10 Reducing the permeability of samples after injection of the composition.

The study developed a high viscosity gel formulation. Such a composition cannot be used for low-permeability pore reservoirs. The best area of application is rocks with cracks.

3. Summary and conclusions

In the presence of cracks in rocks, a rapid flow of water from injection wells to production wells is observed, in this case, water displaces little oil from the pores in rocks and the time for oil production to achieve the required oil recovery will increase. Polymer injection can be used to reduce fracture permeability. In the current study for rocks with high viscosity oil, a composition based on polyacrylamide, hydrochloric acid and lignosulfonates was developed. This composition will block the cracks and direct water from the cracks into the pores. This is confirmed by the results of filtration experiments. The composition, having an increased viscosity, penetrates shallowly into the rock with low permeability, clogging the pores at a short distance from the inlet surface. During the day, the composition during the formation of a gel-like structure blocks the movement of formation water along the cracks. By changing the content of the components in the composition, it is possible to increase or decrease its gelation rate and viscosity.

The study[31] also reported that the permeability reduction coefficients are inversely proportional to the permeability, which is confirmed by the results. The developed composition is most effective for highly permeable reservoirs. An additional increase in the permeability reduction coefficient is up to 10% compared to a low-permeability formation.

Acknowledgements

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Conflict of Interest

There is no conflict of interest.

Supporting Information

Not applicable.

Nomenclature

k	permeability	Y	dependent variable
C_{pol}	content of polyacrylamide, %	u	random component of the model

C_{MgCl}	content of magnesium chloride, %	x_i	represents the independent variables
C_{lig}	content of lignosulfonates, %	β_i	represents the regression coefficient
C_{HCL}	content of hydrochloric acid, %		

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