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## LABORATORY STUDY OF INFLUENCE OF RHEOLOGICAL CHARACTERISTICS OF CROSS-LINKED POLYMER SYSTEMS ON PERMEABILITY AND OIL DISPLACEMENT COEFFICIENTS

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## ЛАБОРАТОРНЫЕ ИССЛЕДОВАНИЯ ВЛИЯНИЯ РЕОЛОГИЧЕСКИХ ХАРАКТЕРИСТИК СШИТЫХ ПОЛИМЕРНЫХ СИСТЕМ НА КОЭФФИЦИЕНТЫ ПРОНИЦАЕМОСТИ И ВЫТЕСНЕНИЯ НЕФТИ

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enhanced oil recovery methods, permeability coefficient, oil displacement coefficient, linear filtration rate, viscosity and temperature characteristics of polymer compositions, acrylamide polymer.

In development of hard-to-recover hydrocarbon reserves, enhanced oil recovery methods are applied on a massive scale, chemical methods being the most common ones. Each formation stimulation technology is associated with certain application conditions which depend on the initial geological and physical formation parameters and current state of its development.

Methodological approach is provided for determination of permeability coefficient and coefficient of oil displacement from rock during testing of compositions of technologies of physical and chemical enhanced oil recovery methods on the basis of laboratory studies of rheological properties of various brands of acrylamide polymer. The methods have been developed according to the requirements to core analysis. The study provides a list of equipment and basic characteristics of the filtration system, as well as the procedure for preparation of working fluids and laboratory formation to laboratory study.

Laboratory study of gel systems' rheological properties is performed on the basis of the technological process for preparation of components of viscoelastic compound recipe at the wellhead and its further injection into the formation. To this end, in order to determine the rheological properties of gel systems, a special-purpose rheometer was used, with a capability to dynamically register the changing viscosity data of the tested polymer systems prepared on the analogues of fresh, produced and Cenomanian waters in "well – formation" thermobaric conditions. Based on the laboratory studies, it has been shown that trial injections of cross-linked compositions on the basis of polyacrylamide (PAA) of brands FP-107 and Poly-T-101, possessing the capability of multifold increase of final viscosity of the polymer composition (by 2–3 times and more) in conditions of increasing temperature in low salinity waters (produced, Cenomanian), enable higher technological effectiveness compared to brand FP-307 polyacrylamide presently used in the company's oilfields.

### Ключевые слова:

методы увеличения нефтеотдачи, коэффициент проницаемости, коэффициент вытеснения нефти, линейная скорость фильтрации, вязкостно-температурные характеристики полимерных композиций, полимер акриламида.

При разработке трудноизвлекаемых запасов углеводородов нефтяных месторождений массово применяются методы увеличения нефтеотдачи, основными из которых являются химические. Каждая технология воздействия на пласт обладает определенными условиями применения, зависящими от исходных геолого-физических параметров пласта и текущего состояния его разработки.

Представлен методологический подход к определению коэффициентов проницаемости и вытеснения нефти из пород при испытании составов технологий физико-химических методов увеличения нефтеотдачи на основе лабораторных исследований реологических свойств различных марок полимера акриламида. Методики разработаны в соответствии с требованиями по исследованию керна. Приведен перечень оборудования и основные характеристики фильтрационной системы, а также порядок подготовки рабочих жидкостей и моделей пласта к проведению лабораторных исследований.

Осуществление лабораторных исследований реологических свойств гелевых систем выполнено исходя из особенностей технологического процесса приготовления компонентов рецептуры вязкоупругого состава на устье скважины и последующей его закачки в пласт. С этой целью для определения реологических характеристик гелевых систем использовался специализированный реометр, который позволяет в динамическом режиме фиксировать данные изменения вязкостных свойств испытываемых полимерных систем, приготовленных на моделях пресной, подтоварной и сеноманской вод в термобарических условиях «скважина – пласт». На основании лабораторных исследований показано, что проведение опытных закачек сшитых композиций на основе полиакриламида (ПАА) марок FP-107 и Poly-T-101, обладающих способностью кратного повышения конечной вязкости полимерного состава (в 2–3 раза и более) с ростом температуры в слабоминерализованных водах (подтоварная, сеноманская), позволяет получить большую технологическую эффективность по сравнению с применяемым в настоящее время на месторождениях компании полимером акриламидом марки FP-307.

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## Introduction

Today more than 90 % of the remaining recoverable reserves in commercial category oilfields are hard-to-recover (high watercut, gas-oil, complex structure, low production, etc.). According to the native and global experience, effective development of hard-to-recover reserves by waterflooding is impossible without massive application of enhanced oil recovery (EOR) methods, chemical (CEOR) methods being the most common ones. Starting from the stage of advancing water production, CEOR methods enable cost-effective improvement of oil recovery ratio by 3–15 % and more and significantly extend the period of cost-effective formation development [1–10].

Each formation stimulation technology has its own application conditions which depend on the initial geological and physical formation parameters and current state of its development. Failure to observe these conditions (applicability criteria) can lead to a failure to obtain the expected amount of incremental oil and oil recovery ratio [11–14].

In order to maintain and improve specific effectiveness of the technologies, and to achieve higher recovery in uninvaded zones of formations, the solution volume of the injected plugs of flow diverter compounds is planned to be increased by 10–15 % annually, with an increase in chemical reagents concentration [15, 16].

Structural scheme of formation stimulation chemical methods is shown in fig. 1.

CEOR methods can be provisionally divided into two groups:

- bottom hole treatment (BHT) of the well in order to stimulate the formation (formation BHT);
- flow diverting methods of enhanced oil recovery (FDEOR) [17–20].

BHT methods can be provisionally divided into two subgroups:

- using acid compositions;
- using hydrocarbon solvent and surfactants.

Based on the formation stimulation mechanism, flow diverting enhanced oil recovery methods can be provisionally divided into three subgroups:

- methods for stabilizing the injection well water intake profile with emulsion compounds (emulsion-based SWIP) [26–31];
- methods for stabilizing the water intake profile and front of oil displacement with water (SWIP and FODW) based on polymers, gels and particulate fillers [21–25];
- surfactant-based methods assisting residual oil sweeping [11, 32, 33].

Further discussed are the methods for stabilizing the water intake profile and front of oil displacement with

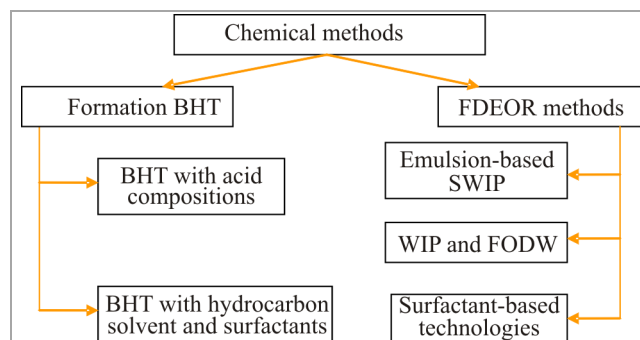


Fig. 1. Classification of chemical enhanced oil recovery methods

water (SWIP and FODW). According to the current concepts of oil displacement mechanics in porous media, front of oil displacement with water is configuration, by section and formation area, of the conventional interface line between zones with oil saturation approximating the initial state and zones containing injected water in the composition of saturating fluids. Such definition does not contradict the established fact of outpacing water saturation increase up to the critical value in uninvaded purely oil-filled formation zones long before entry of injection water. This phenomenon is most apparent in low permeability reservoirs and can be explained by high mobility of residual water caused by differential pressure increase (start of oil injection in injection wells). Depression cone expansion in producing wells leads to “squeezing” of loosely bound water from underlying and overlying clays. In the initial period of formation development (formation pressure equal to initial pressure) this phenomenon can be neglected, taking into account water permeability of clays ( $10^{-6}$ – $10^{-7}$   $\mu\text{m}^2$ ), but within the depression cone, at shale streak thickness of 2 m, the volume of additional water penetrating through it into the well can amount to 20  $\text{m}^3/\text{day}$  (at maximum formation potential recovery values). Due to these factors, product watercut in low output wells may be substantial, which can lead to misconceptions regarding the displacement front configuration at the initial stages of formation development.

Stabilization of the front of oil displacement with water suggests activities aimed at ensuring maximally uniform distribution of injected water flows, in the section and across the area of the zones distant from the injection wells, in order to ensure maximum ultimate oil recovery. Since the effect of compositions on the formations starts in the immediate vicinity of BHZ, FODW technology doesn't exist in pure form. Initially these technologies facilitate SWIP and further, as the plug progresses through the formation, in the uninvaded interwell space – FODW. Methods stabilizing the water intake profile and front of oil displacement with water are, primarily, polymer-based technologies [15, 16, 21–25].

Polymer gelling agent (PGA) technology is the basis for other polymer-based technologies and one of the most common flow diverting technologies that were and have been in use in Surgut region wells (9800 well jobs, or 20.8 % of all well jobs in 1991–2017). PGA injection volume varied from 50 to 550 m<sup>3</sup> per well job. The reagents in use are polyacrylamide (PAA) by Accotrol, GS-1, DKS and others, with concentrations of 0.2–0.6 %, cross-links – chromium acetate, chromium-potassium sulfate and others with concentrations of 0.02–0.07 % [34].

The technology aims to increase the sweep efficiency and stabilization of displacement front, which is achieved by creating excessive filtration resistances in water-swept intervals of the formation by way of polymer cross-linking in the formation. PGA effectiveness first of all depends on accuracy of computation of its optimum injection volume for each stimulated well. In case of insufficient volume, filtration resistance will be low, and SWIP will not be achieved; too high PGA injection volume can lead to temporary blocking of oil saturated formation intervals, which also impedes reaching SWIP.

#### **Methodological approach for determination of permeability coefficient and coefficients of oil displacement from rock during testing of compositions for technologies of physical and chemical EOR methods**

Methods for measurement of permeability coefficients and coefficients of oil displacement from reservoir rock during testing of compositions for the technologies of physical and chemical enhanced oil recovery methods have been developed according to the requirements of GOST 26450.0-85, GOST 26450.2-85 [36, 37], OST 39-195-86 [38] and OST 39-235-89 [39]. The methods are applied to oil-containing rock and establish the procedure for measurement of these coefficients in laboratory conditions.

The target of testing is laboratory formation made of cylindrical rock samples of correct geometrical shape drilled from whole core of the oil-bearing horizon under research. The testing conditions shall ensure replication of natural physical and chemical characteristics of the “rock-fluid” formation system, preservation of temperature and pressure values of the formation during the experiment. Linear flow rate of the tested fluids through the rock in time shall match its production values in the formation areas proximal to or distant from the well. During the test it is necessary to use reservoir oil and water or their laboratory analogues, as well as chemical compounds used as working agents in SWIP technologies [40, 41].

## **Equipment**

Filtration system (hereinafter the system) for testing of compositions of technologies of oil production stimulation and enhanced oil recovery shall consist of interrelated functional blocks ensuring performance of testing operations in thermobaric conditions simulating reservoir conditions (table 1).

Table 1

Basic characteristics of filtration systems

Parameter	Value
Maximum confining pressure, MPa	Minimum 68.0
Maximum pore pressure, MPa	Minimum 40.8
Maximum operating temperature, °C	Minimum 150
Permeability variation range, mD	0.001 to 5000
Pump discharge variation range, cm <sup>3</sup> /min	0.00001 to 50
Pore fluid contacting surface material	Hastelloy C-276, Titanium, Viton, Peek, Teflon

The system's principal arrangement includes the following main blocks:

- tested fluid injection;
- formation factors simulation;
- confining pressure control;
- back pressure control for filtration flow;
- system control and experiment data recording.

#### **Preparation of working fluids to testing**

Tests determining formation rock permeability and residual oil saturation use samples of pure oil and water, and process liquids used as working agents in development of a specific oil field facility (formation). In absence of formation fluid samples, their laboratory analogues are acceptable.

Physical analogues of formation oil can be degassed oil diluted with organic solvent (petroleum ether, hexane, gasoline, kerosene, etc.). The main criteria of analogue oil matching the reservoir gas-saturated oil is equality of their rheological characteristics (viscosity, density) in formation condition [34]

Formation water analogue is prepared by dissolving chloride salts (NaCl, CaCl<sub>2</sub>, etc.) in distilled water. Content of salts should correspond to total salinity of formation water. Qualitative and quantitative composition of salts is calculated on the basis of formation water chemical analysis results and salinity value assumed for the formation under study converted to sodium chloride.

Preparation of compositions of physical and chemical EOR methods to improve well productivity, stabilize well water intake profile, front of residual oil displacement and sweeping, as well as process liquids

used in well construction, testing and further operation, is performed under the requirements stipulated by guideline documents regulating respective geological and technical activities.

### Laboratory formation preparation to testing

Filtration tests of compositions of physical and chemical stimulation of the formation use cylindrical rock samples of correct geometrical shape drilled from whole core, 30 and 38 mm in diameter and at least 27 mm long. Prior to the tests, samples are extracted in alcohol-benzene mixture for complete removal of hydrocarbons from their void space and, in case of high (more than 50–100 g/L) salinity of formation (residual) water, are desalted in Soxhlet apparatus. Next, samples stripped of hydrocarbons and formation water salts are dried to constant weight with accuracy up to  $\pm 0.001$  g in a drying oven at  $105 \pm 2$  °C during 12 h. The dried samples of rock are cooled in the desiccator above tempered calcium chloride to ambient temperature during 2–3 h, followed by determination of their porosity and permeability. Based on the known values of permeability of individual core samples to gas (nitrogen, helium) they are arranged in the laboratory formation, based on the condition that each subsequent sample in the composite column is less permeable than the previous, provided that the permeability variance between the two adjacent samples shall not exceed 10–15 %. Depending on the tasks solved during simulation of processes of stimulation of well bore zone or uninvaded zone of the formation with chemical reagent solutions, determination of rock permeability to liquid (to water – in case of water displacement, to oil or water – in case of change in rock fluid conductivity) is performed in the course of its filtration through the laboratory formation in the direction of porous medium permeability reduction.

Water saturation of the laboratory formation arrangement prior to the tests is created using centrifuging method ensuring conformity of residual water content in the void space of individual samples to its quantity in reservoir conditions. The method consists in displacement of excessive water from the fully water-saturated sample by centrifuging due to creation of capillary pressure at the air-water phase interface in rock pores. The ultimate stage of laboratory formation preparation is saturation of core samples bearing replicated residual water with kerosene in the desiccator by vacuum treatment during at least 4 h.

### Filtration system preparation to testing

The procedure of system preparation activities prior to testing includes:

- filling the reservoirs with tested fluids (formation samples of oil, water or their laboratory analogues, chemical reagent solutions);
- loading the laboratory formation made up of core samples into the rubber collar of the core holder, connection of fluid conducting tubes;
- leakage check of the system's hydraulic circuit by way of creating confining (rock) pressure and pore (formation) pressure in the core holder corresponding to oil formation factors;
- heating up system components (reservoirs, core holder, separator, etc.) to formation temperature;
- customizing the software and experiment sequence, creating log file;
- displacement of kerosene with oil by way of its pumping through the laboratory formation in the amount not less than 3–4 pore volumes in constant flow maintenance mode, not exceeding linear filtration rate of 1 m/day;
- laboratory formation dwell period for 12–16 h at thermobaric conditions to stabilize “rock-fluids” system.

### Measurement of permeability coefficient

The measurement method is based on assessment of reservoir rock permeability to the filtered fluid (water, oil, or their laboratory analogues) before and after its treatment with chemical reagent solutions. The method consists in testing the compositions of technologies for production stimulation and enhanced oil recovery of reservoirs in composite columns consisting of core samples, whose effectiveness, depending on the purpose of use (well productivity increase, well water intake profile and displacement front stabilization, residual oil sweeping, etc.) is determined by the change in rock fluid conductivity.

During tests, filtration of the tested fluids (oil, water, chemical reagent solutions) through the laboratory formation is performed with constant flow rate throughout the experiment. The flow rate is determined on the basis of linear flow rate in the zones proximal to and distant from the well (1) [42–45]:

$$V = \frac{864Q}{F \cdot m(1 - S_{w.resid} - S_{o.resid})}, \quad (1)$$

where  $V$  – linear filtration rate, m/day;  $Q$  – filtered liquid flow,  $\text{cm}^3/\text{s}$ ;  $F$  – laboratory formation cross-section area,  $\text{cm}^2$ ;  $m$  – laboratory formation porosity, decimal quantity;  $S_{w.resid}$ ,  $S_{o.resid}$  – residual water and oil saturation of laboratory formation in formation conditions, respectively, decimal quantity.

Measurement of coefficient of the laboratory formation permeability to liquid (oil, water) is

performed after its pumping through the rock in the minimum amount of 4–6 pore volumes and in presence of pressure gradient at composite column face ends.

Calculation of the coefficient of formation rock permeability to liquid is performed on the basis of a formula of Darcy's linear filtration law (2):

$$K = \frac{QL\mu}{\Delta PF}, \quad (2)$$

where  $K$  – rock permeability to liquid,  $\mu\text{mD}$ ;  $Q$  – liquid volumetric flow rate,  $\text{cm}^3/\text{s}$ ;  $L$  – length of sample part on which pressure differential is measured,  $\text{cm}$ ;  $F$  – sample cross-section area in the sample's measured part,  $\text{cm}^2$ ;  $\mu$  – liquid viscosity in the experiment conditions,  $\text{mPa}\cdot\text{s}$ ;  $\Delta P$  – pressure differential in the sample's measured part at the given filtration mode,  $10^5 \text{ Pa}$ .

### Measurement of oil displacement coefficient

The measurement method suggests determining oil recovery ratio from laboratory formation by means of filtration of displacing agents (water, chemical reagent solutions) through its void space until saturated watercut of the fluid being recovered is reached. The method consists in simulation of the process of waterflooding productive horizons. Combining waterflooding with injection of plug compositions of flow correcting technologies helps establish additional increment of residual oil displacement.

Oil displacement from laboratory formation is performed at constant flow for all injected liquids, which has to correspond to real or project (expected) linear rate (1) of their filtration in the formation zone distant from the well.

Procedure for measurement of oil displacement coefficients in the course of technology compositions testing consists of the following stages:

- continuous displacement of oil with water until saturated watercut of liquid discharged from the core holder, but not less than 4–6 pore volumes of laboratory formation. Initial volume of water-displaced oil is determined by indications of the acoustic separator;

- injection into laboratory formation of plug compositions of flow correcting technologies from 0.5 to 4 pore volumes, whose quantity during testing is assumed on the basis of the actual process of chemical reagents injection into the formation;

- injection into laboratory formation of water plug in the amount of 4–6 rock pore volumes. Final volume of incrementally displaced oil after filtration of plugs of technology compositions is determined using the retort method.

The achieved increment of residual oil recovery  $\Delta K_{displ}$  after use of technology compositions is

determined from the difference between final  $K_{displ.fin}$  and initial  $K_{displ.init}$  displacement coefficients (3):

$$\Delta K_{displ} = K_{displ.fin} - K_{displ.init}. \quad (3)$$

Initial (oil displacement with water) and final (after injection of technology compositions) oil displacement coefficients are calculated by formulas (4), (5):

$$K_{displ.init} = \frac{V_{o.sep}}{V_{o.init}} 100 \%, \quad (4)$$

$$K_{displ.fin} = \frac{V_{o.ret}}{V_{o.init}} 100 \%, \quad (5)$$

where  $K_{displ.init}$ ,  $K_{displ.fin}$  – oil displacement coefficients before and after injection of technology compositions through the laboratory formation, respectively, %;  $V_{o.sep}$ ,  $V_{o.ret}$  – displaced oil volumes according to the acoustic separator and extraction retort indications, respectively, normalized to testing conditions,  $\text{cm}^3$ ;  $V_{o.init}$  – oil volume initially contained in the laboratory formation, determined by the difference between void volume and residual water, normalized to testing conditions,  $\text{cm}^3$ .

Residual oil content in laboratory formation after injection of technology compositions is determined by formula (6):

$$S_{o.resid} = \frac{V_{o.init} - V_{o.ret}}{V_n} 100 \%, \quad (6)$$

where  $S_{o.resid}$  – residual oil saturation of laboratory formation after injection of technology compositions, %;  $V_n$  – pore volume of laboratory formation made up of core samples,  $\text{cm}^3$ .

### Acrylamide polymer brands laboratory analysis results

A series of laboratory analyses was conducted in order to establish the declared rheological characteristics of cross-linked polymer systems on the basis of acrylic polymer (PAA) brands accepted for testing and laboratory assessment of effectiveness of the viscoelastic composition technology (VEC) intended for redistribution of injected water flows during stabilization of water intake profile and displacement front of injection wells in compartmentalized and non-uniform permeability formations. The first stage of the works was studying rheological properties of polymer systems with simulation of thermobaric parameters of the technological process of VEC recipe preparation at the wellhead and its further injection into the formation.

Another subject of this series of tests was impact of salinity of water used for makeup of gel systems. The second stage consisted in filtration tests of cross-linked gel structures on highly permeable core analogues of VK<sub>1</sub> horizon of field R. Laboratory works were comparative and based on the juxtaposition of technological indicators – those of the reagents proposed for the pilot test (Poly-T-101, FP-107, FP-207 and PoLEOR ATC N800) and of the PAA brands already tested in the compositions of flow diverting technologies in PJSC Surgutneftegaz fields (FP-307, Accotrol S-622).

**First stage.** Until now, there is no commonly accepted method of laboratory testing of acrylic polymer compositions at oil deposit thermobaric conditions of occurrence. This is caused by absence of justified theory and single opinion concerning the mechanism of spatial cross-linking of PAA water soluble molecules by ions of polyvalent metals in pore space of reservoir rocks. To this end, in order to determine rheological characteristics of gel systems, a special-purpose rheometer was used to capture the dynamics of viscosity properties of the tested polymer systems mixed on the analogues of fresh, produced, and Cenomanian waters in “well-formation” thermobaric conditions. The following conditions were observed during the experiments for simulation of thermobaric parameters of the technological process of VEC recipe makeup:

1. Dissolution of gelling agent in the solvent at constant stirring with an agitator (300 rpm) during 30 minutes at 22–25 °C with further addition of a cross-linking agent to the solution.

2. Temperature intervals of heating of the cross-linked polymer system in the experiment:

– heating from 25 to 40 °C during 30 minutes;

– conducting the experiment with uniform temperature increase to 70 °C during 24 h.

3. Establishing dynamic viscosity values of the tested composition at shear rate 100 1/s (117.6 rpm) and liquid pressure in the viscosity meter system 7 MPa.

Adherence to these conditions was replicated by actual makeup time of linear gel and cross-linking agent

(30–40 min), their mixing in the turbulent flow during feeding through the well tubing string (WTS) to well bottom (20–30 min) and further dwell period of the polymer system required to form the cross-link in the formation (at least 12–24 h). In the experiments, special focus was made on the temperature intervals of heating of cross-linked gel samples:

– for polymer composition injection into the formation – temperature increase from 20 to 40 °C during 30 minutes.

– for spatial cross-linking of PAA molecules in rock void space – uniform temperature increase to 70 °C during 24 h. This corresponds to the polymer system heating rate to formation temperature in the area of the well bottom hole zone cooled by the injected water.

Provided that the stipulated concentrations of gelling agent ( $C_{PAA} = 0.4$  wt. %) and cross-linking agent ( $C_{CA} = 0.04$  wt. %) are observed, polymer structures demonstrate high values of initial dynamic viscosity (40 to 80 mPa·s), which is caused by the final stage of cross-linking microgel complexes due to nearly complete dissolution of PAA in distilled water over a relatively short period of time (30–40 minutes). Among the tested PAA brands, an exception is PoLEOR ATC N800, which does not manifest high thermal stability in fresh water and loses its viscosity properties by more than 2.5 times when the tested sample heating temperature increases up to 50–60 °C.

During makeup of VEC technology compositions on analogue types of produced and Cenomanian water, except for the solution based on Accotrol S-622 reagent ( $C_{NaCl} = 5$  g/L), on the contrary, the primary factor influencing maintenance of stable viscosity and temperature characteristics of hydrogels is detrimental influence of low mineralization of salts contained in solvents. This is caused by low initial viscosity values of the systems (10 to 17 mPa·s) due to the time lag of intramolecular cross-linking processes in the entire bulk of polymer compositions whose intensity grows not earlier than after 4–6 h. Besides, in the course of testing it was noted that kinetics of spatial formation of gel in acrylamide polymers in saline solutions and in fresh

Table 2

Viscosity and temperature characteristics of polymer compositions based on samples of polyacrylamide cross-linked with chromium acetate ( $C_{PAA} = 0.4$  wt. %,  $C_{CA} = 0.04$  wt. %)

Analogue water (solvent) type	Poly-T-101	Poly-T-101	FP-107	FP-207	FP-307	Accotrol S-622	PoLEOR ATC N800
	Polymer system dynamic viscosity (mPa·s) at shear rate 100 1/s (117.6 rpm)						
Fresh (distilled)	48.87*/37.01**	61.20*/38.79**	47.69*/33.51**	44.74*/35.39**	47.32*/46.51**	68.82*/55.94**	28.55*/11.21**
Produced ( $C_{NaCl} = 5$ g/L)	10.19*/42.95**	17.33*/44.13**	15.24*/47.69**	16.49*/21.64**	15.80*/17.84**	69.41*/67.65**	6.62*/10.19**
Cenomanian ( $C_{NaCl} = 15$ g/L)	9.68*/32.18**	13.76*/31.58**	11.33*/22.08**	8.39*/17.58**	11.09*/13.25**	9.68*/11.72**	0.56*/6.73**

Note: \* – initial dynamic viscosity of the tested polymer composition at 20–25 °C; \*\* – final dynamic viscosity of the polymer composition after 24 h at 70 °C.



Table 3

Conditions and observed parameters  
of filtration tests on highly permeable core  
analogues of VK<sub>1</sub> horizon field R

Parameter	Value
Check conditions	
Experiment temperature, °C	70
Confining pressure, MPa	31
Pore pressure, MPa	10
Fluid injection rate, cm <sup>3</sup> /h	2.4
Formation oil analogue viscosity, mPa·s	4.07
Formation water analogue viscosity, mPa·s	0.54
Formation water analogue salinity, g/L	12
Observed parameters	
Grad P during saturation of laboratory formation with oil, MPa/m	0.041
Phase permeability to oil at $K_{\text{init. sat.}}$ , $\mu\text{m}^2 \cdot 10^{-3}$	96.56
Grad P during displacement of oil with water until filtration of technology compositions of physical and chemical EOR methods, MPa/m	0.130
Phase permeability to water before treatment at $K_{\text{resid. sat.}}$ , $\mu\text{m}^2 \cdot 10^{-3}$	4.07
Grad P during displacement of oil with water after filtration of technology compositions of physical and chemical EOR methods, MPa/m	10.330
Phase permeability to water after treatment at $K_{\text{resid. sat.}}$ , $\mu\text{m}^2 \cdot 10^{-3}$	0.05

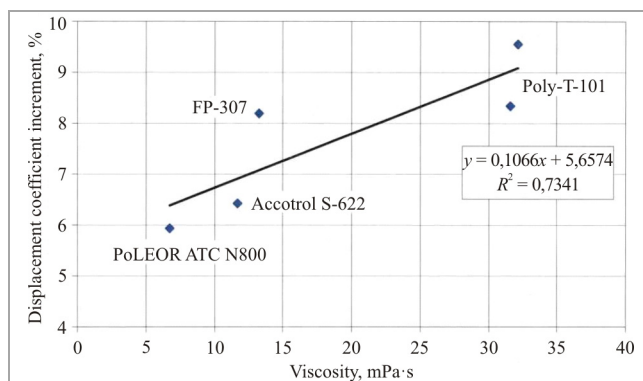


Fig. 2. Dependence of incrementally displaced oil dynamics on final viscosity of polymer compounds based on PAA brands under test injected through laboratory formation VK of field R, mixed on analogue of produced water

waters is limited by the experiment temperature (maximum 50–60 °C). This phenomenon is demonstrated by further drop in viscosity properties of the tested compounds caused by thermal destruction of interchain bonds of cross-linked gels, in which final stabilization of rheological properties only occurs after 16–20 h.

The performed rheological tests have established that out of all control assays of PAA samples under test, negative influence of the aforementioned factors (sensitivity to brines, thermal stability) is less evident in polymer compositions based on FP-107 and Poly-T-101 reagents, whose final solution viscosities (after 24 h at 70 °C) exceed initial values by more than 2–3 times and are comparable to viscosity of gels prepared using fresh water (table 2).

In case of testing of cross-linked systems based on such PAA brands as FP-207, FP-307, Accotrol S-622, and PoLEOR ATC N800, no multiple increase of final viscosity of polymer systems occurred. The findings can be explained by high sensitivity to low salinity brines in combination with lower thermal destruction threshold (see table 2).

**Second stage.** Performance of filtration tests to determine permeability coefficient and oil displacement coefficient in use of cross-linked gel structures in highly permeable core analogues of VK<sub>1</sub> horizon of field R (table 3).

The identified variances in behavior of viscosity and temperature curves for chromium acetate cross-linked PAA brands fully match the results of their filtration tests on laboratory formation VK<sub>1</sub> of field R, where salinity of pore (residual) water and displacement agent amounted to  $C_{\text{NaCl}} = 12$  g/L. The obtained increments of coefficients of oil displacement with water are located in the interval from 5.94 to 9.55 % and directly depend on final values of polymer systems' dynamic viscosity.

The experiments also established a relative reduction in residual oil saturation of composite columns made up of core samples after treatment with polymer compositions based on the tested polyacrylamide brands, which amounted to: Poly-T-101 – 5.29 and 6.13 %; Accotrol S-622 – 4.23 %, FP-307 – 5.70 %, and PoLEOR ATC N800 – 3.91 % (table 4).

## Conclusions

1. Provided that the stipulated concentrations of gelling agent ( $C_{\text{PAA}} = 0.4$  wt. %) and cross-linking agent ( $C_{\text{CA}} = 0.04$  wt. %) are observed, polymer structures demonstrate high values of initial dynamic viscosity (40 to 80 mPa·s), which is caused by the final stage of cross-linking microgel complexes due to nearly complete dissolution of PAA in distilled water over a relatively short period of time (30–40 minutes). Among the tested PAA brands, an exception is PoLEOR ATC N800, which does not manifest high thermal stability in fresh water and loses its viscosity properties by more than 2.5 times when the tested sample heating temperature increases up to 50–60 °C.

Table 4

Results of determination of residual oil saturation in VK<sub>1</sub> laboratory formations of field R for oil displacement with water before and after filtration of plugs of VEC technology compositions ( $C_{CA} = 0.04$  wt. %,  $C_{PAA} = 0.4$  wt.%) based on various PAA brands

Test No.	PAA brand	Sample No.	Gas permeability, $\mu\text{m}^2 \cdot 10^{-3}$	Porosity, %	Initial oil saturation, %	Before injection of chemical reagent solutions		After injection of chemical reagent solutions		Reduction of residual oil saturation of laboratory formation after cross-linked PAA filtration, %	Incremental oil displacement with water after filtration of cross-linked PAA solution, %	Linear rate as per OST 39-195-86, m/day
						$S_{o, \text{resid}}$ (separation method), %	Coeff. of oil displacement with water, %	$S_{o, \text{resid}}$ (retort method), %	Coeff. of oil displacement with water, %			
1	POLY-T-101"	2860-06	236.40	27.32	64.01	26.00	59.43	20.07	68.64	6.13	9.55	0.82
		8016-06	233.45	26.43	65.49			19.70	69.92			0.81
		2913-06	230.40	27.39	62.75			19.84	68.38			0.84
		Wtd.av.val.	233.43	27.05	64.09			19.87	68.98			<b>6.13</b>
2	POLY-T-101	2912-06	225.55	27.16	61.88	27.50	56.63	21.01	66.05	5.29	8.35	0.90
		8003-06	218.11	29.31	63.18			22.96	63.66			0.81
		7861-07	205.15	26.85	65.01			22.61	65.22			0.84
		Wtd.av.val.	215.93	27.75	63.41			22.21	64.98			<b>5.29</b>
3	FP-307	2828-06	908.26	30.72	69.10	28.19	59.42	24.01	65.26	5.70	8.19	0.68
		2833-06	896.57	28.52	70.61			21.24	69.92			0.71
		2839-06	879.51	28.71	68.69			22.22	67.65			0.74
		Wtd.av.val.	894.90	29.32	69.47			22.49	67.60			<b>5.70</b>
4	Accotrol S-622	2843-06	884.84	27.94	65.70	26.86	59.65	18.71	71.53	4.23	6.43	0.79
		2821-06	872.70	28.20	67.58			29.61	56.19			0.75
		2820-06	862.61	28.61	66.47			19.80	70.22			0.76
		Wtd.av.val.	873.43	28.25	66.57			22.63	66.08			<b>4.23</b>
5	PoLEOR ATC N800	2861-06	249.95	27.17	66.13	30.22	54.13	25.60	61.28	3.91	5.94	0.88
		2910-06	243.71	26.89	67.68			27.85	58.85			0.85
		2911-06	241.18	26.79	63.82			25.50	60.04			0.95
		Wtd.av.val.	244.96	26.95	65.87			26.31	60.06			<b>3.91</b>

2. The performed laboratory tests of rheological properties have established that out of all control assays of PAA samples under test, negative influence of the aforementioned factors (sensitivity to brines, thermal stability) is less evident in polymer compositions based on FP-107 and Poly-T-101 reagents, whose final solution viscosities (after 24 h at 70 °C) exceed initial values by more than 2–3 times and are comparable to viscosity of gels prepared on fresh water.

3. According to the laboratory analysis findings, we believe that trial injections of cross-linked compositions based on such PAA brands as FP-107 and Poly-T-101 which are capable of causing multiple increase in final viscosity of polymer compositions (by 2–3 times and more) in conditions of temperature increase in low salinity water (produced, Cenomanian), will result in higher process effectiveness than the one obtained with FP-307 acrylamide polymer brand that is presently used at the company fields, previously tested Accotrol S-622 and brands proposed for use – FP-207, PoLEOR ATC N800.

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