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# Analysis of Experience With Preformed Particle Polymer Gels in High-Water-Cut Production Facilities in Low-Temperature Oil Reservoirs

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**Abstract:** International practices in high-water-cut oil production suggest the use of preformed particle gel (PPG) suspension injection into wells. Upon swelling, these polymer particles become elastic, allowing them to move through highly permeable, water-saturated zones into deeper reservoir sections, creating a polymer "plug." Domestic applications of this technology have largely involved testing foreign products. This study explores the potential of PPG technology in the specific geological and technological settings of high-water-cut fields in Perm Krai, identifying effective PPG reagents for low-temperature reservoirs (20-35 °C) with high salinity (over 200 g/l). We analyzed global PPG application practices to establish optimal injection protocols and assess how particle morphology can be adjusted during synthesis to match reservoir characteristics. A crucial aspect of this technology is the ability to remove PPG particles post-treatment; tests with a sodium persulfate breaker compound and synergistic additives were conducted for this purpose. PPG technology shows promise in reservoirs with significant permeability variation. Two types of high-water-cut production facilities suitable for PPG implementation in Perm Krai were identified: carbonate Tournaisian-Famennian reservoirs with notable macrofractures and terrigenous Visean deposits with varying oil viscosity (5 to 100 mPa·s) and high permeability (> 0.5 μm²). Specific areas within these reservoir types have been highlighted as viable for PPG technology application.

**Keywords:** high-water-cut production; injectivity profiles; injection wells; preformed particle gel; permeability; injection pressure.

**Introduction:**In the later stages of oil field exploitation, waterflooding leads to the creation of washed-out zones that facilitate the escape of injected water, resulting in premature watering out of production wells and leaving behind recoverable oil in less permeable areas. This issue is particularly severe in oil fields with high permeability variability and increased oil viscosity. Reducing water cut in wells in aging oil and gas regions is crucial for prolonging the lifespan of the well stock and boosting production efficiency. Enhanced oil recovery methods, particularly tertiary methods, are essential for the rational development of such fields. Currently, the predominant method for improving water injection efficiency in domestic fields involves using polymer solutions. However, standard polyacrylamide (PAA) solutions often prove ineffective in high-salinity formation water, as polymers can be adsorbed onto rock surfaces and interact with metal ions, altering their rheological properties. Studies indicate that adsorption can hinder the movement of polymer solutions, thereby not significantly affecting the water phase mobility and resulting in delayed polymer displacement behind the oil front. To address reservoir injectivity profiles in mature fields, recent global practices have adopted the injection of PPG suspensions into wells. Upon swelling, these polymer particles can bypass the bottom-hole zone (BHZ) and penetrate into remote formation zones (RFZ), forming effective plugs.

**Problem Statement.** Russian applications of PPG technology have primarily focused on foreign compounds, with limited domestic development. Noteworthy examples include the Temposcreen reagent, which is cross-linked PAA requiring specialized production equipment, and the water-

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swelling AK-639 polymer, which has constraints due to its high swelling temperature. In Perm Krai, these polymers' effectiveness is limited due to low absorption capacities at reservoir temperatures (20-35 °C) and high salinity levels. Research shows that in such conditions, PPG particles remain rigid, reducing their ability to penetrate RFZs due to the formation of a double electric layer around the particles. This impedes the mobility of polymer chains, leading to diminished absorption capacity. Studies conducted at the Kalamkas field in Kazakhstan and various Perm Krai fields indicate an overall effectiveness of 80% for PPG technology, with optimal results seen in paleochannel zones. However, standard PAA treatments in Perm Krai have been inefficient due to low residual resistance factors.

**International Experience** and **Methodology.** Internationally, the application of PPG technology has been more extensive, with successful implementations in China, the USA, and Canada. Preformed particle gels have been utilized for selective blocking of reservoir intervals with higher permeability and for microgels targeting conformance control in lower-permeability zones. The PPG technology has been applied effectively across a range of reservoir temperatures and formation water salinities. Treatment volumes typically range from 2000 to 4500 m$^3$, requiring 5 to 15 tons of dry PPG powder. Treatment effects can result in significant increases in oil flow rates and reductions in water cut over several months. The Perm Krai region, characterized by low reservoir temperatures, presents an opportunity for applying PPG technology to enhance oil recovery, particularly as many fields experience water cuts exceeding 75% in a majority of wells. The need for complex technologies to control fluid movement and engage previously unrecoverable reserves is evident. The mineralization of formation water (200-230 g/l) is typical for the Perm Krai region. The recommended PPG reagents for this area need to be adjusted for the conditions of low-temperature formations with high salinity. Due to these factors, the absorption capacity of PPG decreases significantly, rendering many imported formulations ineffective. To address this, the authors have developed a unique PPG gel formulation that is cross-linked with imide functional groups formed during the synthesis of polyacrylamide chains. This new composition exhibits an absorption capacity of 35-40 g/g, which is twice that of existing alternatives. Optical microscopy reveals that the gel particles swell to 4-6 times their original size. Strength tests indicate that these gel particles can compress and pass through openings that are 20 times smaller than their swollen diameter. Filtration core tests have been conducted using this reagent on carbonate fractured and terrigenous pore-type reservoirs. X-ray tomography has shown that the PPG suspension effectively colmatizes fractures and highly permeable porous intervals, redistributing filtration flows into less permeable channels. The treatment process is influenced by three main parameters: injection rate, suspension concentration, and gel particle size, which are also affected by the permeability of the bottomhole formation zone and the injectivity of the wells. If there's an increase in pump outlet pressure during the initial treatment phase, the injection rate and PPG concentration should be reduced. Adjustments are made to ensure that the injection pressure does not exceed 80% of the design rock fracture pressure. The size of the gel particles is chosen based on the characteristics of the void spaces and the gel's properties, such as strength and absorption capacity. The common approach is to start with smaller PPG fractions and gradually increase the size if no changes in injection pressure occur. For reservoirs with completely flushed "superchannels," treatment begins with larger PPG fractions to colmatize the area, followed by smaller fractions. During injection, PPG gel particles may adhere to the rock surface, forming a crust, necessitating a method to remove the reagent from the bottomhole zone after treatment. Core studies have demonstrated that swollen PPG particles can release 60-85% of their water when exposed to hydrochloric acid. The dehydration of PPG particles leads to significant shrinkage, thus restoring core permeability and porosity. To improve injectivity after treatment, a breaker is typically injected into the well. Breakers, which can be enzymes or oxidizing agents, are used to disrupt the preformed gel structure. Enzymes can break down polymer chains into shorter fragments but are limited by their effectiveness at certain temperatures and pH levels, as well as their cost. More promising are breakers that act through redox processes. Research has shown that sodium persulfate-based breakers are particularly effective. In a study, PPG particles were kept in model formation water until they reached equilibrium absorption capacity. Afterward, a 20 g sample of gel was introduced to the breaker solution, leading to 85% of the PPG gel dissolving

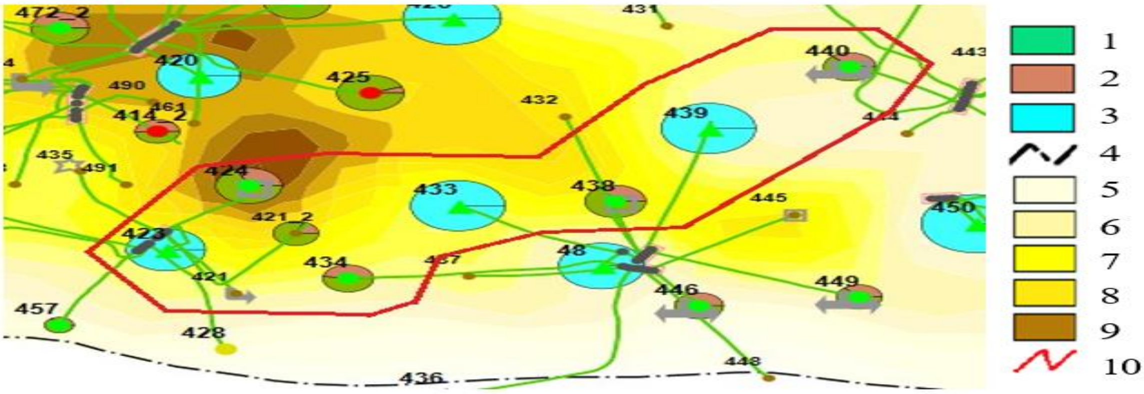


Fig.2. Example of a fractured reservoir development site.
Facility T. Opalikhinskoe oil field
1, 2 – current withdrawals, tons per day (1 – water flow rate, 2 – oil flow rate); 3 – injectivity, m³/day; 4 – outer oil bearing contour; 5-9 – density of reserves, t/m² (5 – 0.03-0.17; 6 – 0.17-0.32; 7 – 0.32-0.46; 8 – 0.46-0.61; 9 – 0.61-0.75); 10 – PPG area

within 24 hours, which is considered a successful outcome. The final efficiency of the PPG technology depends on correctly selecting the development system, which includes the injection and production wells. High injectivity is essential for the injection wells. Successful implementation requires significant permeability heterogeneity (ranging from 10–3 μm² to single digits) and a stable hydrodynamic connection between injection and production wells, which can be verified through tracer studies. Based on the analysis of PPG technology experiences, certain geological and technological conditions can be identified for selecting promising sites. Economic feasibility should be supported by sufficient residual recoverable oil reserves, assessed through 3D geological and technological models. Ideal conditions include production wells with a water cut exceeding 50% and high injectivity in injection wells. A stable hydrodynamic connection between these wells should be established through comprehensive hydrodynamic studies.The effectiveness of PPG technology also benefits from high anisotropy in reservoir permeability, both vertically and horizontally. This approach is suitable for both fractured and pore-type reservoirs with complex geological structures. In Perm Krai, it is particularly applicable to carbonate reservoirs from the Tournaisian-Famennian age, such as the Opalikhinskoe field, which has high-viscosity oil and reduced matrix permeability. The area selected for PPG implementation has a dense oil reserve and a water cut exceeding 50%, with existing hydrodynamic studies indicating high reservoir permeability. The injection wells show signs of fracturing, suggesting a suitable environment for this technology.

Efficiency calculations indicate that the average fracture openness within the perforation interval is between 30 to 50 µm. The application of PPG technology is expected to fill the most open fractures, and considering the change in particle size upon swelling, the minimum PPG particle size is estimated to be 250 µm. In pore-type reservoirs, advanced waterflooding is more noticeable in areas with higher oil viscosity. Figure 4 illustrates the relationship between well watercut and oil recovery for various viscosity ranges in pore-type reservoirs. For viscosities below 2 mPa·s, wells only begin to show significant waterflooding after recovering more than 75% of reserves. In these cases, the oil displacement front is uniform across the reservoir thickness, with water cut remaining below 45% during the main development phase.

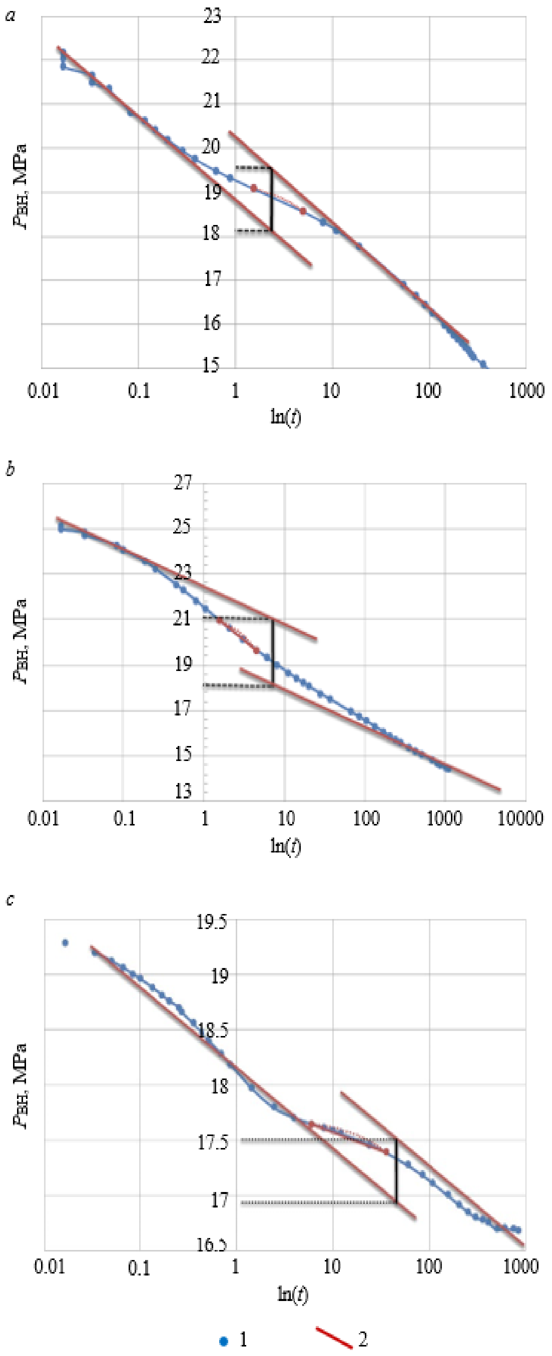


Fig.3. Pressure drop curves for injection wells
N 423 (*a*), 433 (*b*), 439 (*c*)
1 – pressure drop curve measurements;
2 – interpretation by Warren – Root model

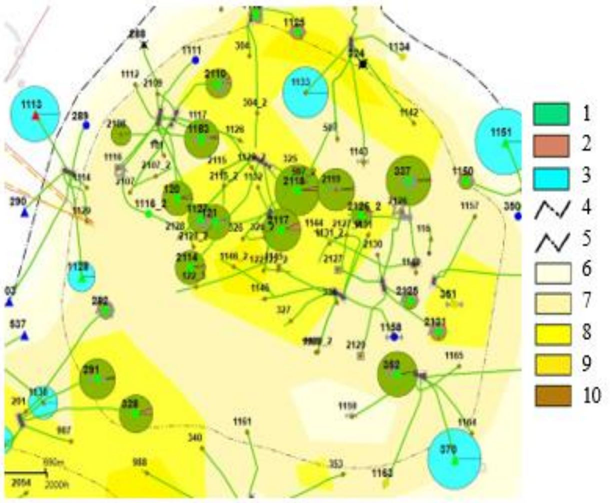


Fig.5. Example of a pore reservoir development site.
Tl-Bb facilities. Shagirtsko-Gozhanskoe field
1, 2 – current withdrawals, tons per day (1 – water flow rate, 2 – oil flow rate); 3 – injectivity, m³/day; 4 – inner oil bearing contour; 5 – outer oil bearing contour; 6-10 – density of reserves, t/m²
(6 – 1.23-3.97; 7 – 3.97-6.71; 8 – 6.71-9.44; 9 – 9.44-12.18; 10 – 12.18-14.92)

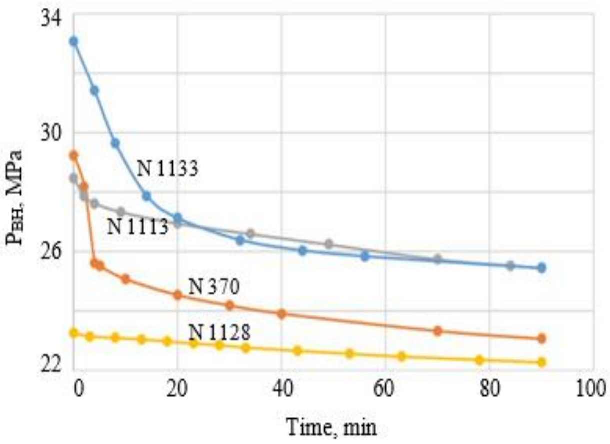


Fig.6. Pressure drop curves of injection wells
N 370; 1113; 1128; 1133 for *PI* calculation

In contrast, for viscosities above 5 mPa·s, the water cut can exceed 50% at just 40% recovery. Therefore, reservoirs with higher oil viscosity ($\mu \geq 5$ mPa·s) in highly permeable pore reservoirs (k ≥

0.5 μm²) are promising candidates for PPG application. An analysis of Perm Krai deposits reveals that most of these reservoirs belong to the terrigenous Visean strata (Tl, Bb, Ml – 41 sites) within the platform area of Perm Krai. Notably, areas with k ≥ 0.5 μm² may exist in deposits with lower average permeability, making them potential targets for PPG use. The Tl-Bb reservoir of the Shagirtsko-Gozhanskoe field (μ = 38 mPa·s, k = 1.2 μm², η = 60.9%) is considered a promising candidate for PPG technology. In this facility, under sufficient rates of return (ROR), producing wells exhibit a water cut exceeding 80% (Fig. 5). International best practices suggest that candidate wells for PPG reagent injection should be identified using the pressure index (PI), which is derived from a pressure drop curve based on measurements taken every 5-10 minutes during a 90-minute shut-in of the injection well [14, 23, 41]. The PI is calculated from the pressure changes over time when the injection well is closed. Wells with PI values deviating more than 5 MPa below the average site value are prioritized for PPG injection. Short-term efficiency measurements conducted by the authors revealed the following PI values for specific wells: N 370 – PI = 83.5 MPa; 1113 – PI = 104.8; 1128 – PI = 113.8; 1133 – PI = 78.9. This analysis indicates a high degree of heterogeneity (with a PI range of about 35 MPa), suggesting selective isolation of highly permeable intervals. Wells N 370 and 1133, which show a significant decline in efficiency, are prioritized for reagent injection.

**In conclusion.** based on international PPG technology applications and research on low-temperature oil deposits in Perm Krai, the authors developed a cross-linked PPG reagent with imide functional groups formed during polyacrylamide synthesis. This PPG has an absorption capacity of 35-40 g/g, double that of existing alternatives. The effectiveness of this compound for sealing fractures and permeable porous intervals is supported by core filtration tests, while optical microscopy has shown that swollen gel particles can expand 4-6 times in size. Gel particle strength tests indicate that these particles can compress and passthrough openings significantly smaller than their swollen diameter. Two primary applications of PPG technology have been identified for high-water-cut oil production in Perm Krai: in carbonate reservoirs with established fracturing and in terrigenous reservoirs with geological heterogeneity. For carbonate deposits, PPG application aims to seal the most open fractures, while in terrigenous reservoirs, it is particularly effective for oil with viscosity over 5 mPa·s and permeability above 0.5 μm². PI calculations for selecting injection wells showed a high degree of heterogeneity, leading to recommendations for wells demonstrating a sharp pressure drop. Research also identified sodium persulfate as the most effective breaker for PPG, dissolving 85% of the gel within a day.

Overall, the research outlines essential measures for effective PPG technology application, establishes a primary reagent injection scheme, and identifies promising operational sites that could enhance long-term oil recovery in mature fields.

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