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Review of Injection Profile Reversal during Polymer Flooding

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Abstract: As a core enhanced oil recovery technology, polymer flooding has been widely applied in the mid-to-late stages of reservoir development, particularly during high-water-cut production phases. This technique increases the viscosity of injected water and optimizes the mobility ratio between water and oil, thereby expanding the sweep efficiency of the displacing fluid within the reservoir and effectively suppressing water channeling through high-permeability zones. However, the migration of polymers in heterogeneous reservoirs can lead to significant redistribution of fluid uptake capacity across different layers—a phenomenon commonly known as waterflood profile reversal. During polymer flooding, polymers preferentially enter high-permeability layers, where they adsorb and become trapped, creating residual resistance that gradually reduces permeability in these zones and subsequently drives more injected fluid into medium- and low-permeability layers. Moderate profile reversal can enhance vertical sweep efficiency and mobilize residual trapped oil; however, excessive polymer retention may cause formation damage and result in inefficient fluid redistribution. This study systematically investigates the fundamental causes and key influencing parameters of waterflood profile reversal during polymer flooding, including reservoir heterogeneity, permeability variation coefficient, polymer rheological behavior, adsorption/trapping characteristics, polymer solution concentration, injection rate, and depositional facies architecture. Based on this analysis, practical technical approaches for profile adjustment and reservoir adaptive management are further explored. To improve overall development efficiency in polymer flooding, this paper proposes an integrated technical framework combining high-resolution geological modeling, numerical simulation of polymer displacement, real-time monitoring of waterflood profiles, spatially resolved estimation of residual oil, and iterative optimization of development strategies.

Keywords: Polymer Flooding; Injection Profile Reversal; Reservoir Heterogeneity; Polymer Retention; Profile Control; Sweep Efficiency; Enhanced Oil Recovery.

1. Introduction

n the actual applications of major oil fields in China, polymer flooding has become the most common chemical enhanced oil recovery method in mature waterflooded reservoirs. In simple terms, it achieves this by adding polymers to the injection water [1-3], making the water thicker and thus slowing down the flow rate of water relative to oil, preventing water from migrating through the oil layer and forming ineffective flow, and expanding the swept volume. The practices of Daqing, Shengli, Henan and other oil fields have proved that in the high water cut stage, this technology can significantly recover a considerable amount of oil[4-6].

However, due to the non-Newtonian fluid characteristics of polymers and their interactions with rocks such as adsorption, retention, and mechanical blockage, their flow in underground porous media is much more complex than that of clear water. The properties of the fluid are also affected by various factors such as shear rate, concentration, molecular structure, and pore shape.

In particular, when the reservoir is uneven and there are multiple layers, these factors can significantly alter the original water injection distribution. Usually during water flooding, high-permeability layers are more prone to water migration, and injected water is likely to flow along the high-permeability layers. This situation often persists when polymer injection begins. However, as the polymer continuously enters these advantageous channels, its adsorption and retention effects will gradually block subsequent flow, causing the polymer solution to shift to the previously less-injected medium and low-permeability layers.

Once these layers that were not fully displaced originally contribute more to fluid absorption than the high-permeability layers, a phenomenon known as "water injection profile reversal" occurs. This phenomenon is crucial - it is not only an important mechanism for using polymers to control the oil displacement profile, but also may be the root cause of new flow problems in the later stage of polymer flooding..

2. Concept of Injection Profile Reversal

The water injection profile refers to the distribution of the injected fluid among different reservoirs, small layers, or individual sand bodies underground. The injection ratio of a certain layer is the proportion of the injected volume that enters that layer out of the total injected volume. During ordinary water flooding oil production, due to the low flow resistance, high-permeability layers often absorb most of the injected water[7].

However, when using polymer flooding, the polymer not only increases the viscosity of the water phase but also generates additional flow resistance through adsorption and retention on the rock surface, thereby changing the flow path of the fluid. Generally, the changes in the water injection profile can be divided into three stages:

The first stage is the dominance of high-permeability layers, where the distribution of the fluid is mainly controlled by the initial permeability gradient; the second stage is the readjustment of the water absorption profile. As the polymer continuously enters the high-permeability layers, its adsorption, retention, and the resulting residual resistance gradually accumulate, leading to a decrease in the water absorption ratio of the high-permeability layers and more injected water beginning to flow to the medium and low-permeability layers.

In the third stage, which is the so-called profile reversal stage, the contribution of medium and low-permeability layers to the fluid absorption may exceed that of the original high-permeability layers. This reversal can occur within the same layer or between different layers. The internal structure of the reservoir will significantly affect the manifestation of the reversal. According to oilfield development research, in cut-valley sedimentary deposits or river channel sand bodies, the water injection profile may show large or periodic changes, while in relatively homogeneous layered sandstones, the changes may be relatively smooth..

3. Mechanisms of Profile Reversal

3.1. Reservoir Heterogeneity

Reservoir heterogeneity constitutes the essential geological prerequisite for the occurrence of injection-profile reversal. Differences in permeability, porosity, net pay thickness, inter-layer baffles and sand-body connectivity lead to significant disparities in fluid-absorption capacity across reservoir units. High-permeability zones serve as dominant flow pathways at the initial water-injection stage. Such flow superiority can be gradually weakened during polymer flooding owing to increased flow resistance within these zones[8]. Accordingly, reservoirs with stronger initial heterogeneity tend to exhibit more remarkable redistribution of injected fluids. It is noteworthy that reservoir heterogeneity cannot be fully described merely using average permeability values. The spatial distribution and connectivity of high-permeability geobodies, interbeds and individual sand-body units are also critical influencing factors.

3.2. Polymer Adsorption and Retention

Profile reversal is largely governed by two key mechanisms: polymer adsorption on rock surfaces and polymer retention inside pore-space networks. Polymer molecules can be trapped in porous media through three pathways, namely surface adsorption, mechanical entrapment and hydrodynamic retention. The permeability impairment and residual flow resistance generated by these processes can remain stable even after polymer injection ceases. Since polymer solutions preferentially enter high-permeability zones in the early flooding period, the flow resistance of these strata rises considerably, which supplies the primary driving force for later-stage fluid redistribution. Nevertheless, polymer retention has potential adverse impacts. Excessive polymer retention may decrease formation injectivity[9-10], elevate well-head injection pressure and limit the effective exploitation of target reservoirs.

3.3. Polymer Rheology

Aqueous polymer solutions typically display non-Newtonian rheological properties, and their apparent viscosity is dependent on both polymer concentration and shear rate. Inside high-permeability flow channels, relatively high flow velocity and shear stress can induce molecular deformation and mechanical degradation of polymer chains. By comparison, polymer transport within low-permeability formations occurs under distinct shear environments. For this reason, polymer viscosity and mobility-control performance should not be treated as constant parameters across the entire reservoir. The coupling effect between polymer rheological characteristics and heterogeneous pore architecture leads to the dynamic evolution of injection-profile reversal.

3.4. Mobility Control

The core objective of polymer-flooding technology is to optimize the water-oil mobility ratio. By raising the viscosity of the injected aqueous phase, the mobility superiority of water within high-permeability flow channels can be weakened, enabling a larger fraction of injected fluid to penetrate zones that were not effectively swept in earlier stages. Accordingly, profile reversal can be regarded as a key indicator of successful mobility control. Moderate fluid redistribution demonstrates that polymer flooding has suppressed preferential flow pathways and achieved improved vertical sweep efficiency.

4. Factors Controlling Profile Reversal

4.1. Permeability Contrast

Permeability contrast strongly affects the timing and magnitude of profile reversal. A large permeability contrast causes severe preferential flow during water flooding. Polymer injection subsequently has a greater opportunity to modify this flow pattern. However, the relationship is not necessarily linear. Extremely strong heterogeneity may result in persistent dominant channels that cannot be effectively controlled by conventional polymer concentrations.

4.2. Polymer Concentration

Polymer concentration determines solution viscosity and resistance to flow. Increasing concentration generally enhances mobility control but may also increase injection pressure and polymer retention. Therefore, polymer concentration should be optimized according to reservoir permeability, temperature, pore structure, salinity, polymer molecular properties, and injection pressure.

4.3. Injection Rate

The injection rate exerts a notable impact on polymer-shear performance and its transport efficiency in porous media. Over-high injection velocities tend to aggravate polymer shear degradation and sustain dominant fluid flow within preferential channels. On the contrary, an excessively low injection rate restricts the propagation of polymer fronts and lowers oil-displacement efficiency in the target reservoir.

4.4. Polymer Slug Size

The scale of the injected polymer slug determines how long and to what extent injection-profile modification lasts. In the initial flooding period, polymer solutions primarily act on high-permeability flow channels. As the pore-volume of injected polymer rises, fluid diversion toward medium- and low-permeability layers gradually plays a dominant role. Consequently, the optimum polymer-slug size ought to be identified on the basis of laboratory tests and reservoir-simulation results, instead of blindly enlarging the total injection volume of polymer solutions.

4.5. Sedimentary Architecture

Injection-profile reversal is strongly affected by sedimentary architecture. Channel sands usually have high connectivity and tend to develop thief flow channels. Mouth-bar sediments show complex intra-formational heterogeneity, and sheet sand bodies present different connectivity characteristics. Accordingly, profile-reversal analysis must incorporate sedimentary facies, sand-body architecture and interlayer connectivity information. Single-layer evaluation based solely on average permeability cannot accurately reflect actual flow dynamics..

5. Effects on Reservoir Development

Injection-profile reversal yields both favorable and adverse reservoir responses. A moderate-magnitude reversal is normally advantageous, as it mitigates over-flow within high-permeability channels and diverts injected fluids into medium- and low-permeability intervals. Such fluid redistribution improves vertical sweep efficiency and recovers previously bypassed crude oil. Nevertheless, severe polymer retention may trigger formation damage and cause injectivity decline. Furthermore, new dominant flow pathways are likely to emerge after the initial high-permeability channels are effectively plugged. Consequently, the occurrence of profile reversal cannot be treated as sufficient evidence for optimum sweep performance.

The effectiveness of profile reversal should therefore be evaluated using multiple indicators, including injection profile, injection pressure, polymer concentration in produced fluids, water cut, oil production rate, and remaining-oil distribution.The key criterion should be whether profile redistribution produces effective sweep-volume expansion and incremental oil recovery.

6. Profile-Control and Development-Adjustment Strategies

6.1. Separate-Layer Injection

Separate-layer injection can be used to control fluid allocation among heterogeneous layers. Injection rates can be reduced in dominant high-permeability layers and appropriately increased in under-swept medium- and low-permeability layers.This approach is particularly useful in reservoirs with strong vertical heterogeneity and clear differences in remaining-oil distribution.

6.2. Profile Control and Water Shutoff

Profile-control treatments can selectively reduce flow through dominant high-permeability channels and redirect subsequent injected fluid toward unswept zones.Gels, polymer-based plugging agents, preformed particle gels, and polymer microspheres have been investigated for this purpose. The performance of these treatment agents is largely governed by particle-size characteristics, reservoir permeability, plugging capacity, injectivity, and inter-layer reservoir connectivity.

6.3. Deep Profile Control

Deep-depth profile-control operations become especially critical when preferential flow channels propagate deep into the reservoir interior. Traditional near-wellbore regulation treatments can merely deliver short-term plugging performance. By contrast, deep diverting agents are capable of migrating deep inside thief zones before constructing blocking structures or increasing flow resistance. Consequently, the follow-up injected fluids can be diverted toward poorly swept reservoir intervals..

6.4. Post-Polymer-Flooding Chemical EOR

Considerable residual oil and leftover polymer may persist in the reservoir upon the completion of polymer flooding operations. The combined application of profile-control agents and follow-up chemical-flooding technologies (e.g., ASP flooding or alternative mobility-control systems) provides a feasible approach to further enhance oil-recovery performance. The primary technical difficulty lies in striking a reasonable balance between macroscopic sweep optimization and microscopic displacement efficiency.

7. Conclusion

(1) Injection-profile reversal represents a critical dynamic phenomenon occurring in heterogeneous reservoirs during polymer flooding. It is essentially generated by the redistribution of injected fluid across different reservoir strata and sand-body units.

(2) The evolution of profile reversal is governed by a set of dominant controlling factors, including reservoir heterogeneity, inter-layer permeability contrast, polymer adsorption and retention, polymer rheological properties, polymer concentration, injection rate and injected polymer-slug volume.

(3) Appropriate profile reversal can suppress preferential flow within high-permeability formations and expand the sweep coverage of medium- and low-permeability zones. Nevertheless, over-accumulated retained polymer may lead to formation damage, injectivity decline and the generation of new inefficient flow pathways.

(4) Spatiotemporal behaviors of injection-profile reversal are strongly influenced by sedimentary architecture. For this reason, injection-profile evaluation should be carried out in combination with sedimentary-facies interpretation and reservoir-architecture characterization.

(5) Future optimization strategies for polymer-flooding projects ought to integrate high-resolution geological modeling, polymer-transport numerical simulation, production dynamic monitoring, remaining-oil distribution prediction and deep profile-control techniques.

In summary, injection-profile reversal is far more than a simple outcome of polymer retention; instead, it reflects the dynamic feedback of heterogeneous reservoirs to polymer-based mobility-control processes. Revealing its internal mechanisms and evolutionary rules is indispensable for optimizing polymer-flooding schemes, enhancing sweep efficiency and raising the ultimate oil-recovery factor.

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