

Biopolymer consolidation of the near-wellbore zone and mobility control in the ACG field: A coupled two-phase hydrodynamic-geomechanical model

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Abstract. This study presents a coupled two-phase hydrodynamic–geomechanical model of biopolymer treatment in fluvio-deltaic sandstones of the Azeri–Chirag–Gunashli (ACG) field. Unlike conventional polymer flooding models, which consider only changes in filtration properties and fluid mobility control, the proposed model incorporates the mechanism of mechanical stabilization of weakly cemented formations through biopolymer adsorption. The model integrates the governing equations of two-phase oil–water flow, accounting for concentration-dependent viscosity and permeability, adsorption kinetics based on the Langmuir isotherm, and a geomechanical component based on the Mohr–Coulomb failure criterion. Rock strengthening is implemented through an increase in effective cohesion proportional to the level of adsorbed biopolymer. The coupled system is solved numerically using the finite volume method (TPFA) and the IMPES scheme. Simulations performed for representative ACG reservoir conditions demonstrate that biopolymer concentrations of 300–400 mg/L reduce near-wellbore permeability from 500 mD to 70–120 mD and decrease the failure index by 25–40%. An optimal concentration of approximately 320 mg/L provides a balance between sweep efficiency improvement, fluid mobility control, and mechanical stability without significant injectivity impairment. The results demonstrate that the proposed model can be effectively applied for designing sand production prevention treatments and optimizing biopolymer flooding parameters in high-salinity, high-temperature reservoirs such as those of the ACG field.

Keywords: Biopolymer flooding, Sand production control, Near-wellbore consolidation, Coupled hydrodynamic–geomechanical model, Polymer adsorption, ACG field, Fluvio-deltaic sandstones, Reservoir geomechanics.

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1. Introduction. Polymer flooding is one of the most effective enhanced oil recovery (EOR) methods due to its ability to improve the mobility ratio and increase reservoir sweep efficiency [1,2]. Conventional approaches primarily focus on increasing the viscosity of the aqueous phase, which slows the propagation of the water front and reduces early breakthrough through high-permeability channels. However, under offshore reservoir conditions such as those of the Azeri–Chirag–Gunashli (ACG) field, the application of synthetic polymers is limited by high salinity and elevated temperatures, which lead to chemical degradation, viscosity loss, and accelerated macromolecular breakdown [1,3]. This reduces the effectiveness of polymer flooding and necessitates the development of alternative materials and advanced modeling approaches.

ACG reservoirs consist of layered fluvio-deltaic sandstones with permeability ranging from 100 to 1000 mD and pronounced heterogeneity, resulting in early water breakthrough through high-permeability intervals and reduced displacement efficiency [5,11]. An additional challenge is the presence of weakly cemented zones susceptible to sand production under high filtration velocities and significant pressure gradients [9,10]. Under such conditions, conventional sand control methods—including mechanical screens, cementation, and filtration materials—are often insufficient or economically inefficient, particularly when large-scale treatment of the near-wellbore zone is required [10].

Biopolymers such as xanthan and scleroglucan offer several advantages over synthetic polymers, including high resistance to salinity and temperature, shear stability, and strong adsorption capacity on grain surfaces [3,7,8]. These properties make biopolymers particularly suitable for offshore reservoirs, where both mobility control and stability under harsh conditions are

critical. Furthermore, biopolymer adsorption on grain surfaces can provide additional mechanical stabilization by increasing intergranular cohesion and reducing the risk of sand production [3,8].

Despite these advantages, existing models [1,2,5] do not simultaneously account for two-phase flow hydrodynamics, adsorption kinetics, changes in filtration properties, and geomechanical strengthening of the rock.

In this work, a coupled two-phase hydrodynamic–geomechanical model of biopolymer treatment is proposed for ACG reservoir conditions. The model incorporates: (1) two-phase oil–water flow with concentration-dependent viscosity and permeability [5,11]; (2) kinetic adsorption of biopolymer based on the Langmuir isotherm; (3) a geomechanical component based on the Mohr–Coulomb failure criterion, in which adsorbed biopolymer increases the effective cohesion of the rock; and (4) a stability criterion linking filtration-induced shear stresses with the mechanical properties of the formation [9,10]. This integrated approach enables evaluation of both flooding efficiency and sand production risk as functions of injection conditions and biopolymer concentration [6,7].

Numerical simulations conducted using representative ACG reservoir parameters demonstrate that biopolymer concentrations of 300–400 mg/L can significantly reduce near-wellbore permeability while simultaneously improving mechanical stability. The model sensitivity to injection rate Q_1 was also investigated, allowing identification of optimal operating conditions that provide a balance between sweep efficiency, injectivity, and rock stability. The proposed model can be applied for the design and optimization of biopolymer flooding programs and sand production prevention treatments in complex fluvio-deltaic reservoirs.

2. Reservoir and Fluid Properties. Lithological and Structural Characteristics of the Reservoir. The reservoirs of the Azeri–Chirag–Gunashli (ACG) field are predominantly composed of layered fluvio-deltaic sandstones of Pliocene age, characterized by:

- pronounced stratigraphic heterogeneity;
- interbedding of high- and medium-permeability layers;
- presence of weakly cemented intervals;
- local anisotropy of filtration properties.

The grain size distribution corresponds to fine- to medium-grained sandstones, with a median grain diameter of $d_{50} \approx 0.1\text{--}0.35\text{ mm}$.

Clay content ranges from 5 to 20%, predominantly composed of illite–chlorite minerals.

The degree of cementation is weak to moderate (quartz and carbonate cement), which contributes to the susceptibility of the formation to sand production under increased drawdown pressure.

Petrophysical Properties

Parameter	Typical range	Notes
Porosity, ϕ	0.20–0.25	Effective porosity
Absolute permeability, k	100–1000 mD	Locally up to 1500 mD
Vertical permeability	0.1–0.5 k_h	Indicates anisotropy
Initial water saturation, S_{wr}	0.20–0.30	Lithology-dependent
Residual oil saturation, S_{or}	0.15–0.25	After water flooding

Capillary pressure is described using a modified Brooks–Corey function with exponent $\lambda = 2\text{--}3$.

The high permeability of individual layers creates preferential flow channels, resulting in early water breakthrough.

Thermobaric Conditions

Parameter	Range
Depth	2500–3500 m
Reservoir pressure	30–45 MPa
Temperature	70–90 °C
Overburden stress	55–75 MPa

Reservoir temperature significantly affects:

- oil viscosity;
- degradation of synthetic polymers;
- biopolymer adsorption kinetics.

Reservoir Fluid Properties

Oil

- Density at reservoir conditions: 780–820 kg/m³
- Viscosity: 1.5–5 mPa·s
- Gas content: moderate
- Oil type: light to medium

The relatively low oil viscosity results in an unfavorable mobility ratio during conventional water flooding.

Formation Water

- Salinity: 50–150 g/L
- Water type: Na–Cl
- Density: 1050–1150 kg/m³
- pH: 6.5–7.5

High salinity represents a critical factor affecting the stability of polymer solutions, particularly synthetic polymers.

Biopolymer Properties. This study considers xanthan and scleroglucan with the following characteristics:

- Concentration: 200–500 mg/L
- Base water viscosity, μ_{w0} : 0.4–0.6 mPa·s at 80 °C
- Thickening coefficient, α : 0.003–0.006 L/mg
- Maximum adsorption, S_{max} : 0.5–1.5 mg/g of rock
- Langmuir constant, K : 0.5–2 L/g

Biopolymers exhibit:

- stability at salinity levels up to 150 g/L;
- high shear stability;
- strong adsorption on quartz surfaces.

Geomechanical Properties of the Rock

Parameter	Value
Young's modulus, E	3–8 GPa
Poisson's ratio, ν	0.20–0.30
Initial cohesion, c_0	~10 kPa
Internal friction angle, ϕ	~30°
Biot coefficient, α_B	0.8–1.0
Bulk density, ρ_b	2500–2650 kg/m ³

The low initial cohesion and moderate internal friction angle explain the susceptibility of the formation to failure under increased filtration-induced shear stresses.

3. Hydrodynamic and Geomechanical Basis for Model Development. The key characteristics of the ACG reservoirs that justify the use of a coupled hydrodynamic–geomechanical model include:

1. High permeability → unfavorable mobility ratio.
2. Layered heterogeneity → early water breakthrough.
3. Weak cementation → increased risk of sand production.
4. High salinity → limitations on synthetic polymer stability.
5. Elevated temperature (70–90 °C) → accelerated chemical degradation.

Under these conditions, biopolymer treatment performs two simultaneous functions:

- Hydrodynamic function: mobility control through increased viscosity and reduced permeability.
- Geomechanical function: enhancement of effective cohesion due to adsorption on grain surfaces.

Two-Phase Flow Model

Mass Conservation Equations

For incompressible phases:

$$\begin{aligned}\frac{\partial(\phi S_w)}{\partial t} + \nabla \cdot u_w &= 0 \\ \frac{\partial(\phi S_o)}{\partial t} + \nabla \cdot u_o &= 0 \\ S_w + S_o &= 1\end{aligned}$$

Darcy Velocities

$$\begin{aligned}u_w &= -\frac{k(c)k_{rw}(S_w)}{\mu_w(c)} \nabla p \\ u_o &= -\frac{k(c)k_{ro}(S_w)}{\mu_o} \nabla p\end{aligned}$$

Relative Permeability model (Brooks–Corey)

$$\begin{aligned}k_{rw} &= k_{rw0} \left(\frac{S_w - S_{wr}}{1 - S_{or} - S_{wr}} \right)^{n_w} \\ k_{ro} &= k_{ro0} \left(\frac{1 - S_w - S_{or}}{1 - S_{or} - S_{wr}} \right)^{n_o}\end{aligned}$$

Biopolymer Transport Model

Transport Equation

$$\frac{\partial(\phi c S_w)}{\partial t} + \nabla \cdot (c u_w) = \nabla \cdot (\phi D \nabla c) - \rho_b \frac{\partial s}{\partial t}$$

Adsorption Model (Langmuir Isotherm with Kinetics)

Equilibrium adsorption:

$$\begin{aligned}s &= \frac{s_{max} K c}{1 + K c} \\ \frac{\partial s}{\partial t} &= k_a c (s_{max} - s) - k_d s\end{aligned}$$

Concentration-Dependent Properties

$$\begin{aligned}\mu_w(c) &= \mu_{w0} \exp(\alpha c) \\ k(c) &= k_0 \exp(-\beta c)\end{aligned}$$

Geomechanical Consolidation Model [5,11].

Effective Stress

$$\sigma' = \sigma - \alpha_B p$$

Mohr–Coulomb Failure Criterion

$$\tau = c_{eff} + \sigma' \tan \varphi$$

Biopolymer-Induced Strengthening

$$c_{eff} = c_0 + \gamma s$$

Biopolymer adsorption directly increases rock cohesion.

Filtration-Induced Shear Stress

$$\tau_f = \mu_w(c) \frac{|u_w|}{\sqrt{k(c)}}$$

Stability Index

$$\Psi = \frac{\tau_f}{c_0 + \gamma s + \sigma' \tan \varphi}$$

Stability conditions:

- $\Psi < 1 \rightarrow$ stable formation
- $\Psi > 1 \rightarrow$ failure and sand production

Numerical Implementation. The coupled system is solved using the finite volume method (TPFA) and the IMPES scheme:

1. Implicit pressure solution
2. Explicit saturation update
3. Implicit concentration solution
4. Adsorption update
5. Stability index calculation

Convergence is achieved using Picard iteration with a tolerance of 10^{-6} .

Hydrodynamic Effects

For an initial permeability $k_0 = 500\text{mD}$:

Concentration (mg/L)	Permeability k(c) (mD)
0	500
300	111
320	100
400	68

Permeability reduction improves the mobility ratio and delays water breakthrough.

Mechanical Stabilization [3,8,9,10].

For representative ACG parameters:

- $c_0 = 10\text{kPa}$
- $\varphi = 30^\circ$
- $\gamma = 5 \times 10^3 \text{Pa} \cdot \text{g/Mg}$

The failure index is reduced by:

- approximately 25% at 300 mg/L
- approximately 40% at 400 mg/L

Optimal Biopolymer Concentration

An optimal concentration of approximately 320 mg/L provides:

- sufficient permeability reduction;
- acceptable injectivity;
- significant mechanical strengthening;
- moderate pressure increase.

4. Conclusions

1. A coupled hydrodynamic–geomechanical model of biopolymer treatment in ACG sandstones has been developed [1–11].

2. Biopolymer adsorption provides simultaneous permeability reduction and mechanical strengthening of the formation through increased rock cohesion [3,7–10].

3. Biopolymer concentrations of 300–400 mg/L reduce permeability by up to 85% and decrease the failure index by 25–40% under representative ACG reservoir conditions [5,6].

4. An optimal concentration of approximately 320 mg/L provides a balance between sweep efficiency, injectivity, and rock stability [5,9].

5. The proposed model can be applied for the design of sand production prevention treatments and optimization of polymer flooding in weakly consolidated reservoirs such as ACG [1–11].

Conflict of interest

The authors declare that they have no conflict of interest in relation to this research.

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