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AZƏRBAYCAN DÖVLƏT NEFT VƏ SƏNAYE UNİVERSİTETİ

MINISTRY OF SCIENCE AND EDUCATION
REPUBLIC OF AZERBAIJAN
AZERBAIJAN STATE OIL AND INDUSTRY UNIVERSITY



“NEFTİN, QAZIN GEOTEXNOLOJİ PROBLEMLƏRİ VƏ KİMYA”

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Derivation and validation of a generalized Darcy law for Herschel-Bulkley fluids in porous media

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Abstract. Large resources of heavy and highly viscous crude oil exhibit non-Newtonian behavior that cannot be represented adequately by the classical Darcy law. A particularly important feature of many structured oils is the existence of a yield stress and, consequently, a threshold pressure gradient below which macroscopic filtration does not occur. This study develops an analytical generalized Darcy relation for a Herschel-Bulkley fluid flowing through a homogeneous porous medium. The derivation starts from the laminar tube-flow solution and introduces porosity, an equivalent hydraulic radius, and a pore-channel tortuosity coefficient to obtain a porous-medium velocity equation. The resulting relation is nonlinear and explicitly includes yield stress, consistency index, flow-behavior index, permeability, and porosity. Its limiting forms are examined for power-law, Newtonian, and Bingham fluids. The analytical equation is then compared with a widely used simplified semi-empirical relation for permeability values of 1.0×10^{-13} , 2.0×10^{-13} , and 3.0×10^{-13} m² and flow-behavior indices of 0.90, 1.05, and 1.20. The two formulations show similar trends over the investigated engineering range, although the deviation becomes more noticeable near the onset of flow and for stronger departures from Newtonian behavior. An explicit expression for the threshold pressure gradient is also obtained, eliminating the need to treat the corresponding coefficient as purely empirical. The proposed formulation can support screening calculations and reservoir-flow models involving yield-stress oils and other Herschel-Bulkley fluids.

Keywords: Herschel-Bulkley model; generalized Darcy law; non-Newtonian fluid; porous-medium flow; threshold pressure gradient; heavy oil.

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1. Introduction. The progressive depletion of conventional petroleum resources has increased interest in heavy oils, bitumen, and other unconventional hydrocarbons. These resources represent a substantial part of the remaining hydrocarbon base, but their development is complicated by high viscosity, complex composition, and non-Newtonian flow behavior [1-4].

High viscosity reduces well deliverability and may make production uneconomic unless the fluid mobility is improved. Thermal enhanced-oil-recovery methods are frequently applied because viscosity generally decreases strongly with increasing temperature [5, 6]. Nevertheless, reliable reservoir calculations still require a constitutive flow relation that remains valid before, during, and after thermal or chemical treatment.

The rheology of structured oils is governed by the formation, deformation, and breakdown of internal networks associated with asphaltenes, resins, waxes, and dispersed phases. These effects have been discussed in rheological studies of anomalous oils [7], reviews of enhanced recovery from non-Newtonian reservoirs [8], and experimental investigations of threshold pressure gradients in porous media [9].

Accounting for non-Newtonian behavior is essential in field-development forecasting. A model based on the classical Darcy law may overestimate mobility, drainage radius, and ultimate recovery when a fluid possesses a yield stress. In such systems, the local pressure gradient must exceed a finite threshold before continuous flow begins. Regions in which this condition is not

satisfied become stagnant or weakly mobilized zones, particularly far from producing wells. Neglecting these zones in reservoir simulation can produce optimistic recovery predictions [10].

For a Newtonian fluid, shear stress is proportional to shear rate:

$$\tau = \mu \dot{\gamma}. \quad (1)$$

where τ is shear stress, μ is dynamic viscosity, and $\dot{\gamma}$ is shear rate. Fluids that do not satisfy this linear relation are classified as non-Newtonian. The Bingham, Ostwald-de Waele (power-law), and Herschel-Bulkley models are commonly written as follows [11]:

$$\tau = \tau_0 + \mu_B \dot{\gamma}, \quad (2)$$

$$\tau = K \dot{\gamma}^n, \quad (3)$$

$$\tau = \tau_0 + K \dot{\gamma}^n. \quad (4)$$

Here τ_0 is the yield stress, μ_B is the Bingham plastic viscosity, K is the consistency index, and n is the flow-behavior index. The Herschel-Bulkley equation is the most general of these three expressions: it reduces to the power-law model when $\tau_0 = 0$, to the Bingham model when $n = 1$, and to the Newtonian model when $\tau_0 = 0$ and $n = 1$.

Porous-medium flow of Bingham fluids has been treated analytically and numerically [12], whereas power-law filtration has received broader attention through packed-bed, pore-network, and continuum formulations [13, 14]. The yield-stress term makes Herschel-Bulkley flow substantially more difficult, especially under transient conditions, because the mobile region itself depends on the pressure field.

The Herschel-Bulkley model is widely used for drilling fluids, polymer solutions, emulsions, and structured crude oils because it captures both a finite yield stress and nonlinear post-yield behavior [15, 16]. Pipe-flow formulations and explicit approximations for pressure loss have been developed for operational calculations [17-19].

Chevalier et al. [20] experimentally investigated yield-stress-fluid flow through beds of glass beads with diameters from 0.26 to 2 mm. A Carbopol solution and a water-in-oil emulsion were both described satisfactorily by the Herschel-Bulkley model. Reported parameter ranges included $\tau_0 = 8$ -89 Pa and $K = 3.6$ -49 Pa·sⁿ for the Carbopol system, and $\tau_0 = 54$ -71 Pa and $K = 12.7$ -13.4 Pa·sⁿ for the emulsion, with $n \approx 0.36$. Related rheological behavior has also been reported for emulsions and asphaltene-rich oils [21, 22].

The objective of the present work is to derive a generalized Darcy law for Herschel-Bulkley fluids from the laminar capillary-flow solution, evaluate its limiting cases, obtain an analytical threshold-gradient condition, and compare the result with a simplified semi-empirical relation used in engineering practice.

2. Methodological part. The derivation is based on steady, laminar, single-phase flow of an incompressible Herschel-Bulkley fluid through a homogeneous and isotropic porous medium. Fluid properties, porosity, and permeability are assumed constant over the representative elementary volume. Inertial effects, compressibility, gravity segregation, and time-dependent rheology are neglected. The pressure coordinate is selected so that $G = -dP/dz > 0$ in the direction of flow.

Porous-medium flow relations

The classical Darcy equation relates superficial velocity to pressure gradient through permeability and viscosity:

$$v = -\frac{k}{\mu} \frac{dP}{dx}. \quad (5)$$

For a packed bed, the Blake-Kozeny relation can be written as

$$v = -\frac{D_p^2 \phi^3}{150 (1-\phi)^2} \frac{dP}{dx}. \quad (6)$$

and comparison with Darcy's law gives

$$k = \frac{D_p^2 \phi^3}{150 (1-\phi)^2}. \quad (7)$$

A more general pore-geometry representation introduces a coefficient C that accounts for tortuosity and deviations from an ideal bundle of straight capillaries [23]:

$$k = \frac{D_p^2 \phi^3}{72C(1-\phi)^2}. \quad (8)$$

At low velocities, viscous forces dominate. At higher velocities, the inertial contribution represented by the Ergun equation may become important [24]:

$$\frac{dP}{dx} = \frac{150\mu v(1-\phi)^2}{D_p^2 \phi^3} + \frac{1.75\rho v^2(1-\phi)}{D_p \phi^3}. \quad (9)$$

Only the viscous regime is considered below; therefore, the second term in Eq. (9) is omitted in the derivation.

Simplified semi-empirical relation

A frequently used generalized Darcy relation for Herschel-Bulkley fluids is [25]

$$v = \left[\frac{k}{\mu_{ef}} \left(-\frac{\partial P}{\partial x} - \alpha_0 \right) \right]^{\frac{1}{n}}, \quad (10)$$

where the mobility factor is

$$\frac{k}{\mu_{ef}} = \frac{1}{2K} \left(\frac{n\phi}{1+3n} \right)^n \left(\frac{8k}{\phi} \right)^{\frac{n+1}{2}}, \quad (11)$$

and the threshold pressure gradient is commonly represented as

$$\alpha_0 = \frac{\beta \tau_0}{\sqrt{k}}, \quad (12)$$

The coefficient β is usually established experimentally. A corresponding expression for a Bingham fluid was proposed in the form [26]

$$v = \frac{k}{\mu_B} \left(-\frac{\partial P}{\partial x} - \alpha_0 \right). \quad (13)$$

In Eqs. (10) and (13), the subtraction of α_0 from the applied gradient introduces the onset-of-flow condition, but the coefficient itself is not obtained directly from the constitutive equation.

For a power-law fluid with zero yield stress, Christopher and Middleman [27] derived the analytical packed-bed relation

$$v = \left(\frac{k}{\mu_{ef}} \frac{dP}{dx} \right)^{\frac{1}{n}}, \quad (14)$$

with the effective viscosity

$$\mu_{ef} = \frac{K}{12} \left(9 + \frac{3}{n} \right)^n (150k\phi)^{\frac{1-n}{2}}. \quad (15)$$

Derivation of the generalized Darcy law

The volumetric flow rate of a Herschel-Bulkley fluid in a circular tube of radius R can be expressed as [15, 16]

$$Q = \frac{\pi n}{K^{\frac{1}{n}}} \frac{\left(-\frac{RdP}{2dz} - \tau_0 \right)^{1+\frac{1}{n}}}{\left(-\frac{1dP}{2dz} \right)^3} \left(\frac{\left(-\frac{RdP}{2dz} - \tau_0 \right)^2}{3n+1} + \frac{2\tau_0 \left(-\frac{RdP}{2dz} - \tau_0 \right)}{2n+1} + \frac{\tau_0^2}{n+1} \right). \quad (16)$$

Dividing Eq. (16) by the tube cross-sectional area gives the mean velocity

$$v = \frac{n}{K^{\frac{1}{n}} R^2} \frac{\left(-\frac{RdP}{2dz} - \tau_0 \right)^{1+\frac{1}{n}}}{\left(-\frac{1dP}{2dz} \right)^3} \left(\frac{\left(-\frac{RdP}{2dz} - \tau_0 \right)^2}{3n+1} + \frac{2\tau_0 \left(-\frac{RdP}{2dz} - \tau_0 \right)}{2n+1} + \frac{\tau_0^2}{n+1} \right). \quad (17)$$

To transfer Eq. (17) from a single capillary to a porous medium, three geometric corrections are introduced. First, the velocity is multiplied by porosity ϕ to obtain a superficial, or Darcy, velocity. Second, the pressure gradient is divided by C to account for pore-path tortuosity. Third, the tube radius is replaced by an equivalent pore radius. Since the hydraulic radius of a circular tube is $r_h = R/2$ and the mean hydraulic radius of a packed bed is $r_h = D_p \phi / [6(1-\phi)]$, the equivalent radius is $R = D_p \phi / [3(1-\phi)]$. Combining this result with Eq. (8) gives $R = \sqrt{\frac{8kC}{\phi}}$.

After these substitutions, Eq. (17) becomes

$$v = \frac{\phi n}{K^{\frac{1}{n}} \left(\sqrt{\frac{8kC}{\phi}} \right)^2} \frac{\left(-\sqrt{\frac{8kC}{\phi}} \frac{dP}{2C dz} - \tau_0 \right)^{1+\frac{1}{n}}}{\left(-\frac{1}{2C} \frac{dP}{dz} \right)^3} \left(\frac{\left(-\sqrt{\frac{8kC}{\phi}} \frac{dP}{2C dz} - \tau_0 \right)^2}{3n+1} + \frac{2\tau_0 \left(-\sqrt{\frac{8kC}{\phi}} \frac{dP}{2C dz} - \tau_0 \right)}{2n+1} + \frac{\tau_0^2}{n+1} \right). \quad (18)$$

Algebraic simplification yields the generalized Darcy relation

$$v = \frac{\phi^2 n}{8K^{\frac{1}{n}} kC} \frac{\left(-\sqrt{\frac{2k}{\phi C}} \frac{dP}{dz} - \tau_0 \right)^{1+\frac{1}{n}}}{\left(-\frac{1}{2C} \frac{dP}{dz} \right)^3} \left(\frac{\left(-\sqrt{\frac{2k}{\phi C}} \frac{dP}{dz} - \tau_0 \right)^2}{3n+1} + \frac{2\tau_0 \left(-\sqrt{\frac{2k}{\phi C}} \frac{dP}{dz} - \tau_0 \right)}{2n+1} + \frac{\tau_0^2}{n+1} \right). \quad (19)$$

Equation (19) is the principal analytical result of this study. It explicitly links the superficial velocity to the applied pressure gradient, permeability, porosity, pore-geometry coefficient, and all three Herschel-Bulkley rheological parameters.

Limiting cases and flow-onset condition

When $\tau_0 = 0$ and $n \neq 1$, Eq. (19) reduces to the generalized power-law form

$$v = \frac{\phi^2 C^2 n}{(3n+1)kK^{\frac{1}{n}}} \left(\frac{2k}{\phi C} \right)^{\frac{3n+1}{2n}} \left(-\frac{dP}{dz} \right)^{\frac{1}{n}}. \quad (20)$$

For $C = 25/12$, Eq. (20) is consistent with the packed-bed expression in Eq. (14). Setting $n = 1$ additionally recovers the classical Darcy equation

$$v = -\frac{k}{K} \frac{dP}{dz}. \quad (21)$$

where K becomes the Newtonian viscosity. If $n = 1$ while $\tau_0 \neq 0$, the Herschel-Bulkley model reduces to the Bingham model, and Eq. (19) gives

$$v = \frac{\phi^2 C^2}{kK} \frac{1}{\left(-\frac{dP}{dz} \right)^3} \left(\frac{\left(-\sqrt{\frac{2k}{\phi C}} \frac{dP}{dz} - \tau_0 \right)^4}{4} + \frac{2\tau_0 \left(-\sqrt{\frac{2k}{\phi C}} \frac{dP}{dz} - \tau_0 \right)^3}{3} + \frac{\tau_0^2 \left(-\sqrt{\frac{2k}{\phi C}} \frac{dP}{dz} - \tau_0 \right)^2}{2} \right). \quad (22)$$

which can be rearranged as

$$v = \frac{k}{K} \left(-\frac{dP}{dz} - \frac{2}{3} \sqrt{\frac{2\phi}{k}} \tau_0 + \frac{\phi^2 C^2}{12} \tau_0^4 \frac{1}{\left(-\frac{dP}{dz} \right)^3} \right). \quad (23)$$

A necessary condition for nonzero flow follows directly from the requirement that the yielded annular region exist:

$$-\frac{dP}{dz} > \sqrt{\frac{\phi C}{2k}} \tau_0 \approx \sqrt{\frac{\phi}{k}} \tau_0. \quad (24)$$

Accordingly, the threshold pressure gradient is

$$\alpha_0 = \sqrt{\frac{\phi C}{2k}} \tau_0 \approx \sqrt{\frac{\phi}{k}} \tau_0. \quad (25)$$

Comparison of Eqs. (12) and (25) gives an analytical estimate of the empirical coefficient

$$\beta = \sqrt{\frac{\phi C}{2}} \approx \sqrt{\phi}. \quad (26)$$

Thus, β is related primarily to porosity and the pore-geometry coefficient rather than being an unrestricted fitting parameter.

3. Results and discussion. The analytical relation in Eq. (19) was compared with the simplified semi-empirical equation, Eq. (10). The parameter set used for the calculations is summarized in Table 1. The selected permeability values represent low-permeability porous media,

while the three flow-behavior indices cover mildly shear-thinning, near-linear, and shear-thickening post-yield responses.

Table 1

Parameter	Value
Yield stress, τ_0	0.3 Pa
Consistency index, K	$5 \times 10^{-3} \text{ Pa} \cdot \text{s}^n$
Pore-geometry coefficient, C	25/12
Porosity, ϕ	0.10
Flow-behavior index, n	0.90; 1.05; 1.20
Permeability, k	1.0×10^{-13} ; 2.0×10^{-13} ; $3.0 \times 10^{-13} \text{ m}^2$

Figure 1 presents the velocity-pressure-gradient curves for $k = 1.0 \times 10^{-13} \text{ m}^2$.

The solid curves correspond to Eq. (19), whereas the black dashed curves represent Eq. (10). The results confirm that the apparent mobility is highly sensitive to n. Over the plotted range, changing n from 0.90 to 1.20 alters the predicted velocity by several times, even though all other properties remain fixed.

The simplified and analytical equations produce the same overall ordering of the curves and comparable engineering trends. Their agreement is closest for the larger value of n and decreases as the rheology departs more strongly from the near-linear case. The largest relative differences occur close to the threshold gradient, where both predicted velocities approach zero and small absolute changes produce large percentage deviations. Therefore, Eq. (10) is suitable for preliminary calculations within the investigated range, whereas Eq. (19) is preferable when the onset of flow or the detailed nonlinear response is important.

The dotted reference curves illustrate the response obtained when yield-stress and nonlinear effects are omitted. Their departure from the Herschel-Bulkley solutions demonstrates that the classical Darcy law cannot represent the combined influence of a threshold gradient and a non-unit flow-behavior index.

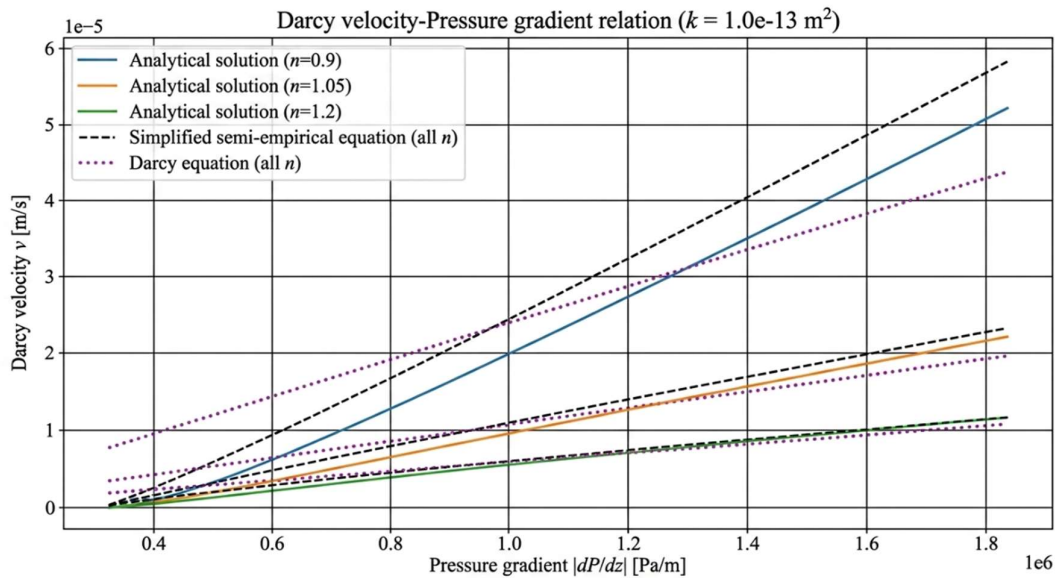


Figure 1. Darcy velocity as a function of pressure gradient for $k = 1.0 \times 10^{-13} \text{ m}^2$, calculated using Eqs. (10) and (19)

Figures 2 and 3 show the corresponding results for permeabilities of 2.0×10^{-13} and 3.0×10^{-13} m². Increasing permeability raises the Darcy velocity and shifts the flow-onset gradient to lower values, in agreement with Eq. (25), which gives $\alpha_0 \propto 1/\sqrt{k}$. Thus, a more permeable medium not only provides greater mobility after yielding but also requires a smaller pressure gradient to initiate filtration.

The consistent pattern across the three permeability levels supports the internal correctness of the derived scaling. At the same time, the comparison should not be interpreted as universal validation for all porous structures and rheological states. The derivation treats the porous medium through an equivalent capillary radius and a single geometric coefficient C ; experimental calibration remains advisable for highly heterogeneous rocks, broad pore-size distributions, thixotropic fluids, or regimes in which inertial effects become significant.

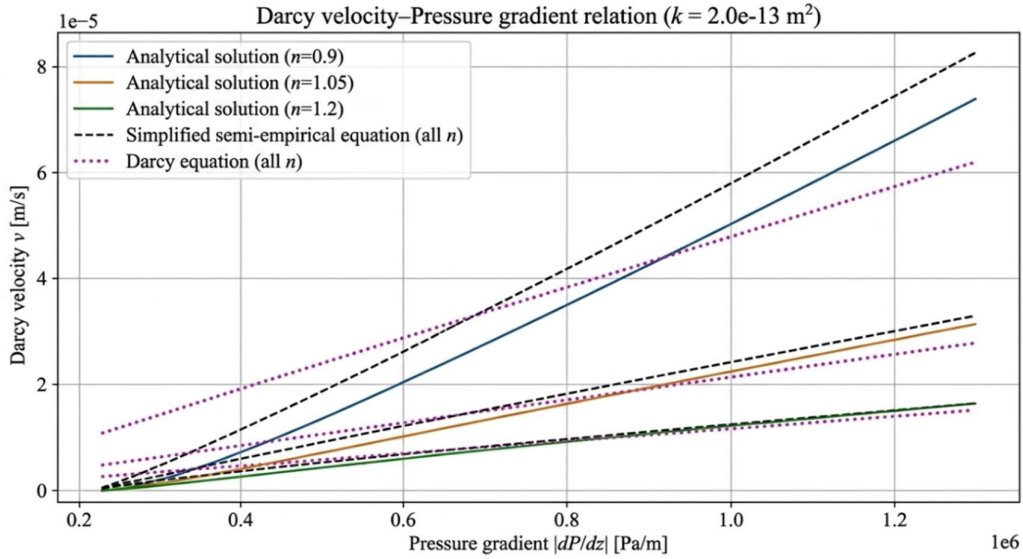


Figure 2. Darcy velocity as a function of pressure gradient for $k = 2.0 \times 10^{-13}$ m², calculated using Eqs. (10) and (19)

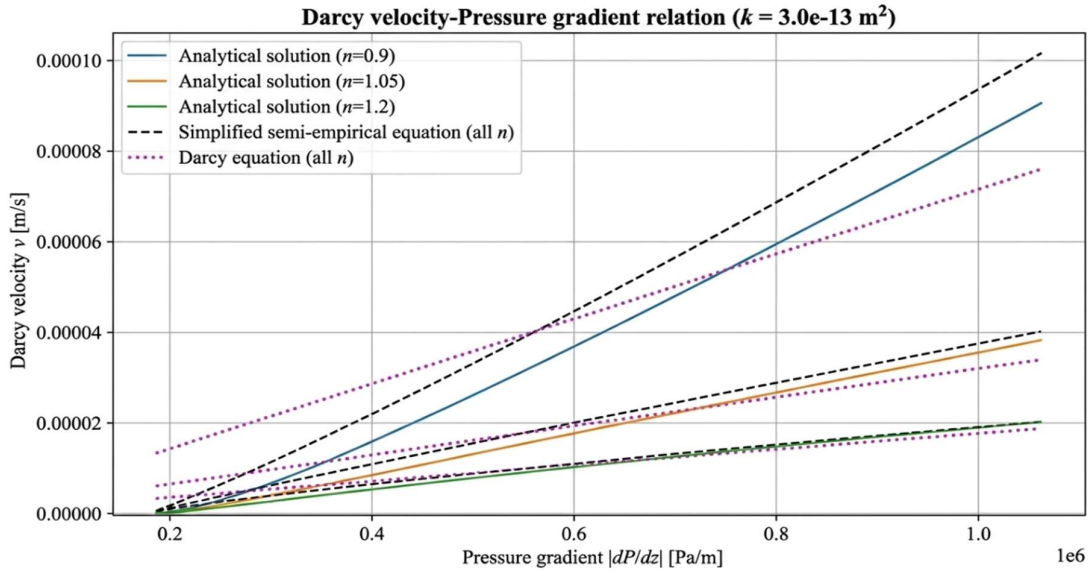


Figure 3. Darcy velocity as a function of pressure gradient for $k = 3.0 \times 10^{-13}$ m², calculated using Eqs. (10) and (19)

4. Conclusions. An analytical generalized Darcy law has been derived for steady laminar flow of a Herschel-Bulkley fluid through a homogeneous porous medium. The main findings are summarized below.

1. The resulting equation includes permeability, porosity, a pore-geometry coefficient, yield stress, consistency index, and flow-behavior index in a single nonlinear relation between Darcy velocity and pressure gradient.

2. The formulation correctly reduces to the generalized power-law expression, the classical Newtonian Darcy law, and a Bingham-fluid relation under the corresponding limiting assumptions.

3. A closed-form condition for the onset of filtration was obtained. The threshold gradient is proportional to yield stress and porosity and inversely proportional to the square root of permeability.

4. Comparison with a simplified semi-empirical equation showed similar engineering trends for $k = 1.0 \times 10^{-13} - 3.0 \times 10^{-13} \text{ m}^2$ and $n = 0.90 - 1.20$. The simplified equation can be used for screening calculations in this range, but the analytical relation is more informative near the flow threshold and for strongly nonlinear rheology.

5. The proposed equation provides a physically interpretable basis for estimating stagnant zones and mobility in reservoirs containing structured heavy oils. Further validation should include core-scale experiments and extension to heterogeneous, transient, and temperature-dependent conditions.

Conflict of interest.

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

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Drawdown-driven sand production in gas-lift wells

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Abstract. Gas-lift operation in weak consolidated sandstone can increase drawdown and exaggerate sand-related completion impairment, while sparse surveillance often prevents mechanism attribution. This study develops an evidence-graded, field-constrained workflow for screening drawdown-driven sand response, scenario-based screen impairment, and potential casing-integrity consequences in a dual-tubing, packerless gas-lift well. The workflow supports surveillance prioritization pending calibration with downhole pressure, screen differential pressure, intervention outcomes, and caliper data.

Keywords: gas-lift well; drawdown; sand production; screen plugging; weak consolidated sandstone; well integrity; production sustainability.

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1. Introduction. In mature oil wells completed in weakly consolidated sandstone reservoirs sand production is a major operational problem [1, 2, 3]. Grain-size distribution influences both the mobilization of formation solids and the retention performance of sand-control screens [4,5]. Laboratory and modeling researches relate sanding onset to the evolving near-wellbore effective-stress state and the mechanical strength of the formation [6,7]. Reservoir depletion, high water cut, and artificial-lift operation can alter effective stress, solids transport, and flowing-pressure conditions. When the drawdown between reservoir pressure and flowing bottom hole pressure reaches the formation-failure condition, grains may detach from the rock matrix and enter the wellbore with the produced fluid [2,6,7].

Gas-lift injection reduces the hydrostatic contribution of the produced-fluid column and changes the flowing-pressure profile of the well [8]. In dual-string gas-lift systems, the distribution of injected gas between the available flow paths can further influence production and pressure behavior [9]. If these changes reduce the flowing bottomhole pressure while reservoir pressure remains comparable, the resulting drawdown increases. In weakly consolidated sandstone, increasing drawdown may move the near-wellbore stress state toward the sanding-failure condition [2,6,7]. Gas-lift adjustment can therefore improve lifting performance while reducing the available drawdown margin; however, the operating change alone does not confirm sand influx or screen impairment.

Dual-tubing gas-lift completions contain interacting tubing and annular flow paths, and the allocation of injected gas between these paths affects lift performance and production response [9]. Field experience with high-rate gravel-packed wells shows that sand-control completion performance should be assessed together with the corresponding production response [10]. In gas-lift wells, abnormal pressure behavior and operational complications can be screened using wellhead data [11], while statistical monitoring and choke-response signatures provide additional surveillance indicators [12,13]. These surface observations are useful for diagnosis, but they cannot independently locate solids accumulation or confirm screen plugging.

Formation instability and screen plugging are related but mechanically distinct phenomena. Near-wellbore formation instability involves grain debonding, displacement, or shear when the local

effective-stress state reaches the formation-failure condition [2,6,7]. Screen plugging is a hydraulic and completion response in which transported grains or fines accumulate on or within the screen medium, reducing its effective flow area [14,15,16]. Neither formation instability nor screen plugging alone demonstrates that casing deformation has occurred.

A reduction in effective screen area redistributes flow through the remaining openings and may increase local velocity and pressure loss [14,15,16]. Studies of sand-control screen erosion show that concentrated sand-laden flow can increase erosion susceptibility under unfavorable velocity and particle-loading conditions [17,18]. However, these studies address screen erosion and do not provide direct evidence of casing deformation in the investigated well.

Casing deformation is a separate structural response that may result from non-uniform external loading, formation displacement, or loss of radial support [19,20,21].

Analysis of operating curves can provide indirect diagnostics of casing-deformation risk [22], but the confirmation of a geometric change requires direct downhole measurement. Because multifinger-caliper, downhole-imaging, and drift or passage records were unavailable, this study reports a predicted casing integrity concern rather than observed casing deformation.

Previous research has examined sand-production mechanisms and prediction [1,2,23], screen selection and clogging [14,15,16], screen erosion [17,18], and casing integrity [19,20,21,22] as largely separate topics. However, fewer studies integrate gas-lift-induced pressure changes, observed sand response, scenario-based screen impairment, and conditional casing-integrity concern within a single field-surveillance workflow.

Accordingly, this study develops an evidence-graded, field-constrained workflow that integrates pressure–production behavior and surface sand response with a geomechanical drawdown framework, scenario-defined reductions in effective screen area, and a conditional casing-integrity pathway. Changes in surface pressure, liquid rate, gas-injection rate, and sand concentration are evaluated separately from the scenario-based hydraulic response to declining effective screen area.

2. Materials and methods. The methodology comprises four linked components: definition of the field case and evidence hierarchy, interpretation of gas-lift pressure–production behavior, geomechanical screening of sanding tendency, and separate evaluation of field-response indicators and scenario-based screen impairment. It is applied to an anonymized dual-tubing, packerless gas-lift well completed in weakly consolidated Balakhany sandstone. The six records represent selected stages from one operating sequence; all disclosed values were anonymized and rounded.

To preserve the hierarchy of evidence, all inputs are classified as field-recorded, calculated, or scenario-defined. Field-recorded variables include wellhead pressure, P_{WH} ; inter-tubing pressure, P_{IT} ; casing-annulus pressure, P_{cp} ; gas-injection rate, g ; liquid production rate, $Q_{l,m}$; and wellhead sand concentration, C_s . Completion geometry and the reported gas-lift configuration are treated as field inputs. Stage-specific reservoir pressure, P_{res} ; flowing bottomhole pressure, P_{wf} ; effective open-area ratio, λ ; differential pressure across the screen, ΔP_{scr} ; and casing deformation were not measured directly. Consequently, drawdown is retained as a geomechanical screening variable, λ is prescribed in the sensitivity analysis, and casing deformation remains an unverified integrity concern rather than a calculated field outcome.

Representative Dual-Tubing Gas-Lift Completion. The investigated completion represents mature offshore dual-tubing, packerless gas-lift well completed in a weakly consolidated sandstone interval. The well configuration reflects mature offshore production conditions where sand influx, high water cut, and unstable gas-lift performance occur at the same time.

The completion comprises a $9^{5/8}$ in production casing and two concentric tubing strings. The $2^{7/8}$ in inner tubing and the $4^{1/2}$ in outer tubing terminate at 2450 and 1800 m MD, respectively. The producing interval extends from 2480 to 2520 m MD and consists of an uncemented open-hole section equipped with a premium-mesh standalone screen; the total measured depth is 2520 m. No packer isolates the annular flow path between the production casing and the tubing strings. Figure 1 presents the conceptual pressure–flow configuration; the schematic is not drawn to scale.

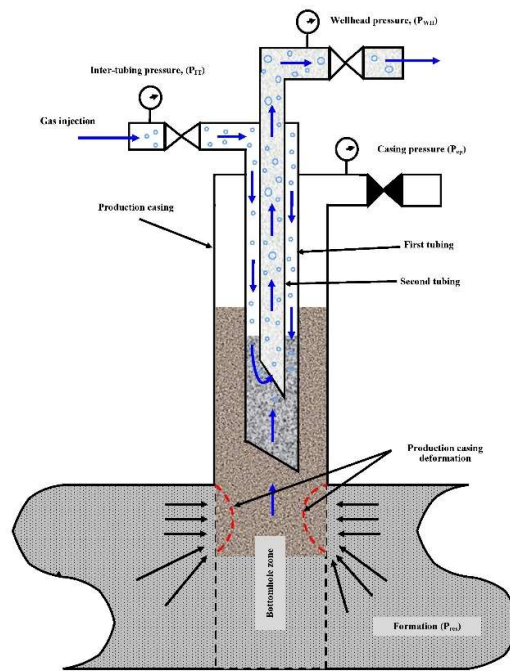


Figure 1. Conceptual pressure-flow configuration of the dual-tubing, packerless gas-lift system, and the hypothesized casing-integrity pathway

Gas is injected through the annular flow path between the $9^{5/8}$ in casing and the $4^{1/2}$ in outer tubing. The injected gas moves downward through this annular space and enters the production flow path at depth. The gas then mixes with the produced liquid and reduces the average density of the fluid column. This reduction lowers the flowing bottomhole pressure and supports the upward movement of the gas-liquid mixture through the lift tubing.

The well is completed across the producing sandstone with a standalone premium mesh screen. The screen interval length is 40 m, and the initial open area is 5.5%. The screen is assumed to provide distributed inflow under clean conditions. During sand production, part of the screen surface becomes impaired by retained grains, compacted solids, and fines migration. This reduces the effective open area and changes the inflow pattern from distributed to localized. The field-constrained completion, reservoir, and reference-fluid inputs are summarized in Table 1, together with the evidentiary basis of each value.

Table 1. Field-constrained completion, reservoir, and reference-fluid inputs used in the screening workflow

Parameter	Value	Status or Basis
Well type	Dual-tubing, packerless gas-lift well	Field record
Production casing	$9^{5/8}$ in, 47.0 lb/ft; N80/P110 designation	Field record; exact depthwise grade schedule unavailable
Inner lift tubing	$2^{7/8}$ in, 6.5 lb/ft; J55/N80 EUE	Field record; exact grade unavailable
Outer lift tubing	$4^{1/2}$ in, 12.6 lb/ft; J55/N80 BUE	Field record; exact grade unavailable
Inner tubing depth	2450 m MD	Field record
Outer tubing depth	1800 m MD	Field record
Packer condition	No packer in the active completion	Field record
Producing interval	2480–2520 m MD; open-hole	Field record

Production-casing shoe depth	Not available	No assumed field value assigned
Open-hole diameter	Not available	No assumed field value assigned
Screen type	Premium-mesh standalone screen	Field record
Initial screen open area	5.5%	Design specification
Screen material	316 L stainless steel	Completion description
Nominal screen aperture	Not available for the case screen	A provisional 0.100–0.150 mm range is examined only in sensitivity analysis
Formation	Weakly consolidated Balakhany sandstone	Field description
Porosity	33.5%	Field-constrained reservoir input
Permeability	850 mD	Field-constrained reservoir input
Sand-grain density	2660 kg/m ³	Engineering input
Reservoir-pressure range	16.5–28.0 MPa	Field operating range; not available by individual stage
Flowing bottomhole-pressure range	12.0–15.0 MPa	Calculated operating range; not available by individual stage
Reservoir-temperature range	70–85 °C	Field operating range
Water cut	80–92%	Field operating range
Oil density	840 kg/m ³	Reference value at 25 °C and standard pressure
Formation-water density	1004 kg/m ³	Reference value at 25 °C and standard pressure
Reference liquid-mixture density	971–991 kg/m ³	Calculated from phase densities over the 80–92% water-cut range
Oil viscosity	3.5 cP	Reference value at 25 °C and standard pressure
Formation-water viscosity	1.03 cP	Reference value at 25 °C and standard pressure
Injected-gas relative density	0.65, air = 1	Field-constrained gas-property input
Standard gas conditions	101.325 kPa and 15.56 °C	Reference conditions for reported gas rate
Median formation-grain size, d ₅₀	Not available for the case well	A non-regional value of 0.209 mm is used only as a literature-based sensitivity input [24]
Uniformity coefficient, U _c	Not available for the case well	U _c = 5.0 is used only in the same non-regional sensitivity case [24]

Because case-specific particle-size-distribution data and the manufacturer-certified screen aperture were unavailable, plugging plausibility was examined through a non-regional sensitivity case rather than a reconstructed field measurement. The sensitivity case uses $d_{50} = 0.209$ mm and a uniformity coefficient $U_c = d_{60}/d_{10} = 5.0$ from Reference [24], together with a provisional screen-aperture range of 0.100–0.150 mm. The resulting aperture-to-median-grain-size ratio is 0.48–0.72. This range places the assumed aperture below the median grain size, whereas $U_c = 5.0$ represents a relatively broad particle-size distribution in which finer particles may penetrate and accumulate within the screen medium even when coarser grains are retained. Because screen performance also depends on the complete PSD curve, fines and clay content, mesh architecture, and flow conditions,

this sensitivity case supports the physical plausibility of partial impairment but does not validate the selection or actual plugging state of the case-well screen [4,16].

Gas-Lift-Induced Drawdown Mechanism. At time t , drawdown, $\Delta P(t)$, is defined as the difference between reservoir pressure, $P_{res}(t)$, and flowing bottomhole pressure, $P_{wf}(t)$. Stage-specific P_{res} and P_{wf} measurements were unavailable for the six-stage field sequence; consequently, drawdown was treated as a model-based geomechanical screening variable rather than a directly observed stage parameter.

An increase in gas fraction reduces ρ_m and lowers P_{wf} . This improves lifting performance, but it also increases drawdown across the producing interval. In weakly consolidated sandstone, this effect narrows the safe operating window because excessive drawdown increases the probability of sanding [8, **Error! Reference source not found.**]. In gas-lift operation, injected gas reduces the average density and hydrostatic head of the produced-fluid column. For mechanistic interpretation, the local mixture density is represented by $\rho_m = \alpha_l \rho_l + \alpha_g \rho_g$, where $\alpha_l + \alpha_g = 1$, ρ_l and ρ_g denote the liquid-and gas-phase densities, and α_l and α_g denote their local volumetric fractions. The injected-gas relative density and the reference liquid-phase density and viscosity values used in the screening calculations are reported in Table 1.

This mixture relation is not treated as a depth-resolved multiphase PVT model. Gas density, phase holdup, formation-volume factors, and effective mixture viscosity vary with pressure, temperature, and flow regime, whereas stage-specific downhole pressure-temperature data and detailed injected-gas composition were unavailable. Consequently, the relation is used to explain the expected direction of the flowing-bottomhole-pressure response rather than to calculate stage-specific P_{wf} values. An increase in gas holdup may reduce P_{wf} and enlarge drawdown, but the magnitude of this response also depends on tubing-annulus interaction and the prevailing multiphase-flow regime [8, **Error! Reference source not found.**].

Screen Impairment and Local Inflow Response. Within the screening framework, the near-screen filtration response is interpreted using a Darcy-type relation consistent with coupled hydrodynamic–geomechanical sand-production modelling [23]. For otherwise comparable permeability and fluid properties, an increasing pressure gradient raises the superficial filtration velocity. Because the investigated well produces multiphase fluid and no direct near-screen velocity measurements were available, this relation is used only to establish the expected response direction rather than to calculate a stage-specific filtration velocity.

For operating stage t , the remaining effective screen area is represented as

$$A_{eff}(t) = \lambda(t)A_0, 0 < \lambda(t) \leq 1 \quad (1)$$

where A_0 is the active open area under the reference scenario, and $\lambda(t)$ is the prescribed effective-open-area ratio. A value of $\lambda = 1$ represents the reference condition, whereas $100[1 - \lambda(t)]\%$ represents the assumed loss of effective open area. The stage-specific λ values were selected through production matching to represent progressively restrictive sensitivity cases. However, because no screen inspection, screen differential pressure record, cleanout-volume reconciliation, or manufacturer-specific resistance calibration was available, the matching is non-unique and λ is not treated as a measured or uniquely inferred plugging fraction. Its role is limited to testing how a prescribed reduction in active flow area would affect the normalized local-inflow response.

The liquid rates in the field sequence are reported as mass rates in t/d and cannot be inserted directly into a velocity expression. The corresponding volumetric rate is calculated as

$$q_l(t) = \frac{1000Q_{l,m}(t)}{86400\rho_{l,ref}} \quad (2)$$

where $Q_{l,m}(t)$ is the reported liquid mass rate in t/d, $q_l(t)$ is the volumetric liquid rate in m³/s, and $\rho_{l,ref}$ is the reference liquid-mixture density. Because stage-specific liquid densities were unavailable, a common reference value of 981 kg/m³, corresponding to the midpoint of the 971–991 kg/m³ range in Table 1, is applied to all stages.

The local velocity through the remaining active screen area is then expressed as

$$v_{loc}(t) = \frac{q_l(t)}{\lambda(t)A_0} \quad (3)$$

The screen outside diameter and base-pipe dimensions were unavailable; therefore, A_0 and the absolute value of v_{loc} cannot be determined uniquely for the case well. The field-stage analysis consequently uses the normalized local velocity ratio

$$I_v(t) = \frac{v_{loc}(t)}{v_{loc,0}} = \frac{q_l(t)}{q_{l,0}} \frac{\lambda_0}{\lambda(t)} \quad (4)$$

where subscript 0 denotes the stable reference stage and $\lambda_0 = 1$. Because the same reference density is used for all stages, $\frac{q_l(t)}{q_{l,0}}$ is equal to $\frac{Q_{l,m}(t)}{Q_{l,m,0}}$. Thus, the stage-specific velocity ratio accounts for both the observed change in liquid rate and the scenario-defined reduction in effective screen area.

For a constant total liquid rate, the expression reduces to $I_v = \frac{1}{\lambda}$; this limiting case is presented in Figure 2 only as a generic sensitivity illustration. For the field sequence, the observed liquid-rate ratio is retained. Local inflow acceleration occurs only when the fractional reduction in effective screen area exceeds the fractional decline in total liquid rate. Screen-erosion studies identify local velocity and particle loading as important controls on erosion susceptibility [17,18]. Accordingly, under otherwise unchanged fluid and opening conditions, the present sensitivity analysis represents wall-shear tendency as scaling approximately with I_v and the inertia-related dynamic-stress tendency as scaling approximately with I_v^2 . These are relative scenario indicators rather than absolute stress predictions because opening geometry and depth-resolved mixture rheology were unavailable.

The constant-rate sensitivity of normalized local velocity to effective open-area reduction is illustrated in Figure 2.

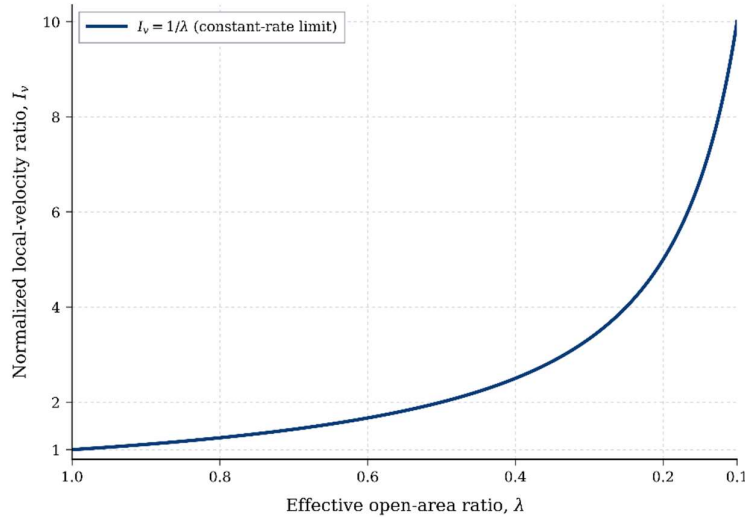


Figure 2. Constant-rate sensitivity of the normalized local velocity ratio to the prescribed effective open-area ratio

The curve represents $I_v = \frac{1}{\lambda}$ for $\frac{q_l}{q_{l,0}} = 1$ and is not a calibrated plugging threshold; the field-stage values reported in Table 2 additionally account for the observed changes in liquid rate.

Table 2. Stage-constrained effective-open-area sensitivity and normalized hydraulic response

Stage	$Q/Q_{1,0}$	Representative λ	Assumed Effective-Area Loss Relative to the Reference, $100(1 - \lambda)$, %	I_v	Normalized Screen-Pressure-Drop Tendency, $I_{\Delta P}$	Interpretation
1	1.000	1.00	0	1.00	1.00	Reference-area scenario
2	0.973	0.95	5	1.02	1.02–1.05	Minor impairment sensitivity
3	0.883	0.75	25	1.18	1.18–1.39	Moderate impairment sensitivity
4	0.500	0.25	75	2.00	2.00–4.00	Partial impairment sensitivity
5	0.333	0.10	90	3.33	3.33–11.11	Severe impairment sensitivity
6	0.000	n/a	n/a	n/a	n/a	Shut-in; hydraulic ratio not evaluated

Casing-Deformation Risk. The casing-integrity pathway considered in this study is conditional. Gas-lift operation may reduce P_{wf} and increase drawdown; if the near-wellbore stress state reaches the formation-failure condition, grain detachment and solids mobilization may occur [2,23]. Because stage-specific downhole pressures were unavailable, the investigated field sequence does not establish that the critical drawdown was actually exceeded.

Mobilized grains and fines may be transported toward the completion, where they can accumulate on or within the screen medium or contribute to screen erosion [14,15,16]. If the effective screen area decreases, the scenario model in Section 2.1.3 predicts redistribution of flow through the remaining openings and possible local velocity amplification. However, screen plugging, erosion, and near-wellbore void development were not directly measured in the case well. They are therefore treated as intermediate scenario-based or inferred steps rather than confirmed field events.

Previous casing-integrity studies identify non-uniform external loading, formation displacement, and loss of radial support as possible contributors to restriction, ovalization, local bending, and intervention-access problems [19,22]. The investigated well had no multifinger-caliper log, downhole image, restriction-depth survey, or drift and passage record. Accordingly, casing deformation is retained only as an unverified integrity concern at the end of the conditional pathway and is not reported as an observed outcome.

Geomechanical Sanding Criterion and Critical Drawdown Model. The hydrodynamic mechanism described in Section 2 explains how gas-lift operation reduces flowing bottomhole pressure, increases drawdown, and accelerates local inflow through the remaining open screen area during partial plugging. However, hydrodynamic acceleration alone does not fully explain sanding onset. Sand production starts when the near-wellbore stress state exceeds the mechanical strength of the weakly consolidated sandstone.

For this reason, the hydrodynamic model is coupled with a geomechanical sanding criterion. The geomechanical part of the workflow evaluates whether the drawdown imposed by gas-lift operation exceeds the critical drawdown pressure of the formation. If this limit is exceeded, the near-screen sandstone becomes unstable, and grains detach from the rock matrix.

The studied interval is represented by weakly consolidated Balakhany sandstone. The mechanical response of this formation is controlled by low compressive strength, limited cohesion,

high porosity, and sensitivity to depletion-induced effective stress increase. The geomechanical model therefore uses effective stress, Mohr–Coulomb failure, and critical drawdown concepts to define the onset of sanding [23].

Effective Stress Around the Producing Interval. Within Biot’s poroelastic framework, the effective stress carried by the rock skeleton is related to the total stress and pore pressure as follows [25]:

$$\sigma' = \sigma - \alpha P_p \quad (5)$$

where σ' is effective stress, σ is total stress, α is Biot coefficient, and P_p is pore pressure.

For the producing interval, this relation is applied to the vertical and horizontal stress components. As reservoir pressure declines during depletion, pore pressure decreases and effective stress increases around the near-wellbore zone. This effect is important in mature weakly consolidated sandstone because it reduces the safe drawdown margin and increases the probability of sanding.

Mohr–Coulomb Sanding Criterion

The Mohr–Coulomb failure criterion is used to evaluate shear failure in the weakly consolidated sandstone:

$$\tau = c + \sigma_n' \tan \varphi \quad (6)$$

where τ is shear stress, c is cohesion, σ_n' is effective normal stress, and φ is internal friction angle.

In terms of principal effective stresses, the failure condition may be expressed through a Mohr–Coulomb failure function:

$$F_{MC} = (\sigma_1' - \sigma_3') - (\sigma_1' + \sigma_3') \sin \varphi - 2c \cos \varphi \quad (7)$$

where σ_1' is maximum principal effective stress, and σ_3' is minimum principal effective stress. The formation remains stable when F_{MC} is below the failure limit. Sanding onset is expected when the operating drawdown increases the near-wellbore stress state to this limit [26,27].

Representative Geomechanical Inputs and Data Provenance. The representative geomechanical inputs were obtained from an existing one-dimensional mechanical-earth-model (MEM) database for the target interval rather than from new laboratory testing. Table 3 identifies the derivation basis and data-availability status of each parameter. The underlying raw logs, core-calibration records, test results, measurement counts, and statistical distributions were not available in the disclosed dataset.

Table 3. Representative geomechanical inputs and their derivation status for the 2480–2520 m MD interval

Parameter	Symbol	Representative Value	Derivation Basis in the Source MEM	Range and Measurement-Count Status
Unconfined compressive strength	UCS	14.44 MPa	Sonic-log-derived representative input	Raw sonic samples, calibration records, n, and min–max range unavailable
Cohesion	c	4.05 MPa	Calculated from representative UCS and friction angle using the Mohr–Coulomb relation	Derived quantity; independent n and measured range not applicable
Internal friction angle	φ	31.5°	Log-derived representative input in the source MEM	Underlying correlation record, n, and min–max range unavailable
Static Young’s modulus	E	2.40 GPa	Static-equivalent input converted from dynamic elastic response	Dynamic-to-static calibration dataset and range unavailable

Poisson's ratio	ν	0.28	Derived from compressional- and shear-wave response	Raw V_p/V_s samples, n, and range unavailable
Biot coefficient	α	0.78	Calculated poroelastic input based on static and grain bulk moduli	Underlying modulus values and propagated uncertainty unavailable
Vertical stress	σ_v	54.8 MPa	Representative source-MEM value based on bulk-density integration	Density-log integration record and uncertainty range unavailable
Maximum horizontal stress	σ_H	47.8 MPa	Model-derived representative horizontal-stress input	Calibration observations and uncertainty range unavailable
Minimum horizontal stress	σ_h	41.2 MPa	Field-constrained representative source-MEM input	Underlying LOT/mini-frac record, n, and uncertainty range unavailable

The values in Table 2 are deterministic screening inputs and should not be interpreted as sample means, measured min–max intervals, or statistically calibrated distributions. Cohesion was calculated from the representative UCS and friction angle as $c = \text{UCS}(1 - \sin\phi)/(2\cos\phi)$, which gives approximately 4.05 MPa. The reported stresses indicate a normal-faulting ordering, $\sigma_v > \sigma_H > \sigma_h$. As the source calibration files and uncertainty distributions could not be obtained, the classification of geomechanics and well casing integrity is conditional upon this representative set of parameters.

The stress regime is important for the depleted sandstone because a decrease in pressure causes an increase in effective stresses in this zone.

Critical Drawdown Definition and Calibration Requirement. Critical drawdown is the difference between reservoir pressure and the critical flowing bottomhole pressure at which the selected formation-failure criterion is first satisfied. Critical-drawdown prediction has been addressed using analytical and field-case methods [28,29], weak-sandstone and perforated-well models [30,31], and one-dimensional geomechanical or reservoir-specific numerical models [32,33,34]. These studies show that the critical value depends on formation strength, in situ stress, completion geometry, pressure conditions, and the selected failure criterion; it is therefore a well-specific parameter rather than a universal pressure limit.

For a well with the required pressure and geomechanical data, critical drawdown is defined as

$$P_{\text{res}}(t) - P_{\text{cwf}}(t) \quad (3)$$

where P_{cwf} is the critical flowing bottomhole pressure predicted from the calibrated formation-failure model. Proximity to this limit can then be expressed through

$$I_D(t) = \frac{\Delta P(t)}{\Delta P_{\text{crit}}(t)} \quad (4)$$

Operation at $I_D < 1.00$ remains below the modelled sanding threshold, whereas $I_D \geq 1.00$ indicates that the calibrated threshold has been reached or exceeded. No additional numerical warning boundary is assigned because a lower limit, such as 0.80, has not been established from statistical validation or documented intervention outcomes.

Stage-specific P_{res} , P_{wf} , and calibrated P_{cwf} values were unavailable for the six-stage field sequence. Consequently, I_D is retained as a future field-calibration variable and is not reported as a calculated stage-level result in the present case. Reaching the critical-drawdown condition would indicate an increased sanding tendency; it would not independently confirm screen plugging or casing deformation.

Conditional Coupling Between Sanding and Inferred Screen Impairment. The solids arriving at the wellhead are measured directly from the field as sand concentration at wellhead, C_s , but there is not unique interpretation that this C_s represents solely a near-wellbore mechanical failure event; C_s may represent a new grain detachment, accumulation remobilization, variable transport intermittency,

or a shift in liquid carrying capacity [31,32]. Hence the continuous increase of C_s from stage to stage is used here as an operator marker of instability rather than the individual occurrence confirming exceeding of Mohr–Coulomb failure limit.

The proposed coupling is conditional: drawdown-induced near-wellbore instability may mobilize formation grains, while transported grains and fines may subsequently accumulate on or within the screen medium and reduce its effective open area [14,16]. However, the surface sand concentration, C_s , cannot by itself confirm the presence, location, or severity of screen plugging. Accordingly, the operating stages described are not used to impose a one-to-one relationship between C_s and screen plugging; instead, they provide field constraints for the scenario-based hydraulic sensitivity analysis presented later in the manuscript.

For the field data, Stage 1 is used to represent initial stable operations, Stages 2–3 are designated as increasing sand production, and Stages 4–5 as consistent with screen plugging since both liquid rate-loss and wellhead surface pressure changes accompany increasing sand rates. The above designations are interpretations of observed operations and cannot prove the physical location, thickness, or internal configuration of any screen plug [35,36].

The conditional link between mechanics and hydraulics provides the conceptual basis for the two-axis screening framework developed in Section 4.

Field Case and Input Data. Case-Study Basis. The proposed workflow is applied to an anonymized single-well field case from a mature offshore dual-tubing, packerless gas-lift well completed in a weakly consolidated sandstone reservoir in the South Caspian Basin. The case reflects real operating behavior observed under high water cut, declining reservoir pressure, sand influx, screen impairment, and unstable pressure response.

The case is derived from confidential operational records of one monitored offshore gas-lift well. For confidentiality reasons, the well name, exact field identifier, coordinates, full raw time-series records, and intervention files are not disclosed. Instead, the pressure–production sequence, sand-concentration response, completion geometry, and geomechanical inputs are reported in anonymized, rounded, and engineering-interpretable form. This allows the diagnostic workflow to be tested on real field behavior while protecting operationally sensitive information.

The representative well configuration, completion geometry, and geomechanical inputs were defined in Sections 2 and 3. This section adds the pressure–production sequence used to test the model response during the transition from stable gas-lift production to sand-loaded flow, partial screen plugging, and predicted casing-deformation risk.

Operating-Stage Definitions. The field sequence is divided into six diagnostic stages to organize the observed pressure, production, and sand-concentration changes. These labels are interpretive and do not represent independently verified downhole conditions. Stage 1 defines the stable reference condition; Stage 2 represents an early transition; Stage 3 represents excited sanding; Stages 4 and 5 represent partial and severe impairment scenarios, respectively; and Stage 6 represents the shut-in or pre-intervention condition.

The Stage 2 label does not assert that drawdown was measured to increase because concurrent P_{res} and P_{wf} values were unavailable. Likewise, the Stage 4 and Stage 5 labels describe conditions consistent with progressive flow-path impairment under the assigned λ scenarios rather than screen states confirmed by inspection. The stage definitions are based on the combined evolution of liquid rate, wellhead sand concentration, and surface-pressure response.

Stage 1 serves as the stable reference. Stage 2 captures an early departure from that reference, whereas Stage 3 is identified by a measurable increase in wellhead sand concentration accompanied by a comparatively limited decline in liquid production. Stages 4 and 5 are evaluated as partial and severe impairment scenarios, respectively, because the corresponding downhole screen conditions were not directly measured. Stage 6 represents the shut-in or pre-intervention condition and is retained for operational context but excluded from the field-response-score calculation for the five flowing stages.

3. Results and discussion. The contrast between production decline and the sand-

concentration multiplier is illustrated in Figure 3.

Figure 3 shows that the sand-concentration response becomes pronounced before the largest production loss. At Stage 3, the sand multiplier reaches 15, while the liquid-rate decline remains 11.7%. At Stages 4 and 5, the sand multiplier increases to 80 and 150, respectively, while the corresponding production declines reach 50.0% and 66.7%. These measured field responses are used in the field-response branch, whereas the prescribed λ values and their hydraulic consequences are evaluated separately in Table 4. Their temporal co-variation supports diagnostic prioritization but does not independently confirm physical screen plugging or localized inflow redistribution.

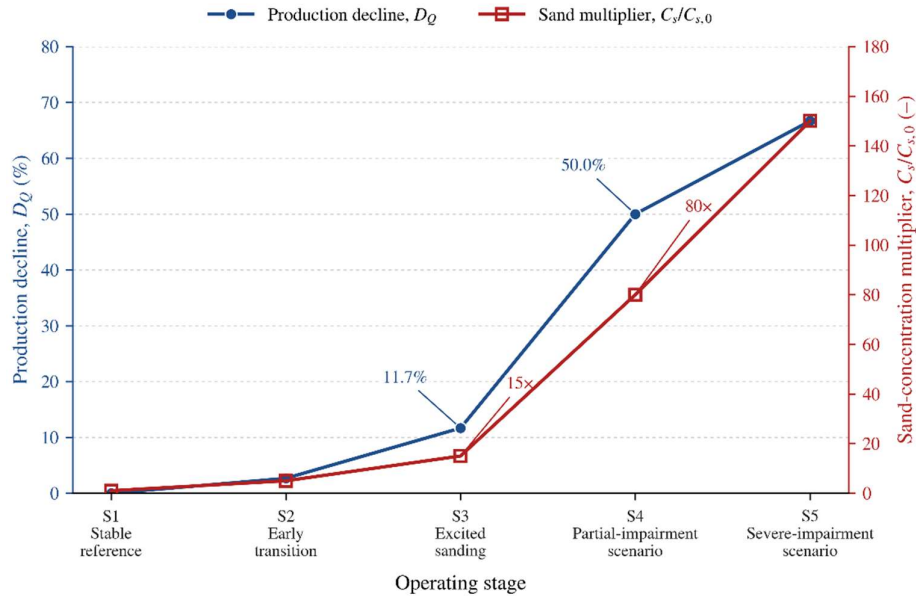


Figure 3. Production decline and sand-concentration multiplier across the five flowing stages.

Connecting lines are visual guides between selected stage-level records and do not represent a continuous or smoothed time series. The labels assigned to Stages 4 and 5 denote prescribed impairment scenarios rather than screen conditions verified by downhole inspection.

Stage-Level Pressure Response. The pressure records reported in Table 3 show an increase from the stable reference to Stage 4. Over this interval, P_{WH} increases from 3.5 to 5.9 MPa, P_{IT} from 4.2 to 6.5 MPa, and P_{cp} from 6.5 to 7.2 MPa. Stage 4 therefore has the largest combined pressure deviation from the reference condition in the evaluated sequence.

At Stage 5, P_{WH} , P_{IT} , and P_{cp} decrease to 3.2, 4.0, and 6.4 MPa, respectively, despite the further reduction in liquid rate and increase in sand concentration. This non-monotonic response indicates a change in the hydraulic state of the production system. The selected records, however, cannot determine whether the change resulted from restriction release, multiphase-holdup redistribution, altered gas-lift hydraulics, or another transient process.

Figure 4 presents the three pressure variables across the five flowing stages. The connecting lines are visual guides between selected stage records and should not be interpreted as a continuous pressure waveform.

Because the underlying high-frequency records are unavailable, the data do not support calculation of oscillation period, pulsation amplitude, or buildup-release cycle frequency. The pressure decrease at Stage 5 is therefore reported as a non-monotonic stage-level response rather than as confirmed collapse or release of a sand restriction.

Stage 6 represents a shut-in or pre-intervention condition in which both gas injection and liquid production are zero. Its casing-annulus pressure of 7.5 MPa may represent trapped or isolated

pressure under non-flowing conditions. Stage 6 is retained for operational context but is excluded from the flowing-stage pressure normalization and field-response-score calculation.

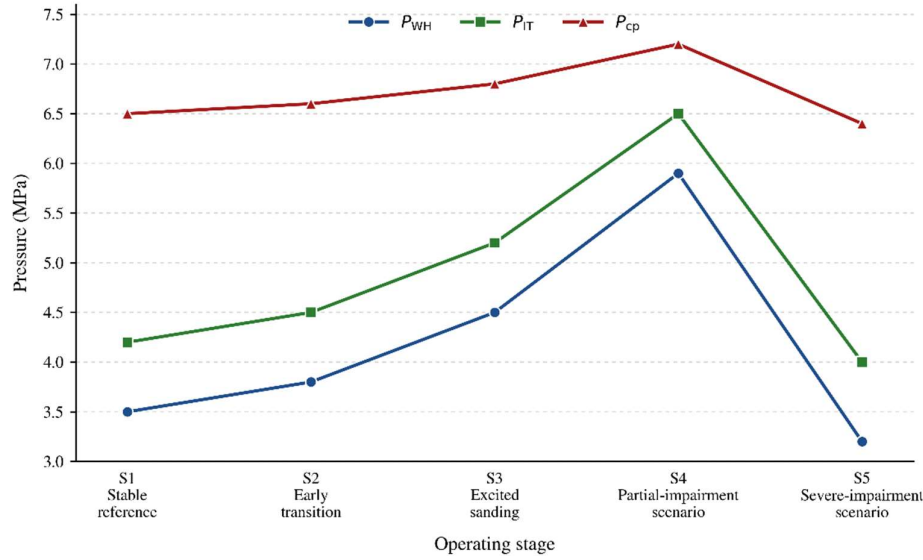


Figure 4. Stage-level wellhead, inter-tubing, and casing-annulus pressures across the five flowing stages.

Connecting lines are visual guides between selected operating records and do not represent a continuous pressure waveform.

Gravel packing may provide more durable sand retention than a standalone screen where formation PSD, fines content, and completion geometry permit effective placement [24]. Screen replacement or redesign should be based on measured PSD and screen-retention testing rather than on the regional sensitivity values used in the present study [16]. Chemical consolidation may be considered where mechanical remediation is impractical, but its use requires laboratory evaluation of retained permeability, consolidation strength, temperature stability, and compatibility with the produced fluids [**Error! Reference source not found.**].

A sustained departure of S_{FR} from the reference stage, when accompanied by persistent sand production or evidence of declining well accessibility, should prompt physical integrity verification before further production optimization. Choke or gas-injection adjustments made without confirming the condition of the flow path may temporarily alter the surface response while leaving a developing restriction unresolved. The selected response should therefore depend on the calibrated I_D ; the persistence of the measured pressure, production, and sand signals; and any direct evidence obtained during cleanout or downhole intervention.

4. Conclusions. This study developed an evidence-graded, field-constrained workflow for recognizing operational deterioration associated with sand production in a dual-tubing, packerless gas-lift well. The field-response score, (S_{FR}), combines normalized liquid-rate loss, surface sand response, and pressure deviation, whereas (λ) and (I_v) are retained as separate scenario-based sensitivity variables. This structure enables comparison of operating stages without treating prescribed impairment scenarios as measurements of the screen condition.

For field operation, drawdown should remain below the calibrated critical drawdown, ($\Delta P < \Delta P_{crit}$), corresponding to ($I_D < 1.00$). An upward trend in (I_D) toward 1.00 should prompt verification and intensified surveillance, whereas ($I_D \geq 1.00$) should initiate corrective drawdown management through choke and gas-injection review, subject to gas-lift stability constraints. A sustained (S_{FR}) departure accompanied by persistent sand production should prompt screen differential pressure measurement, cleanout-response evaluation, coiled-tubing passage checks, or multifinger-caliper

logging. Because stage-specific downhole pressures, measured screen pressure drop, complete PSD statistics, resolved tubular properties, and direct casing-deformation measurements were unavailable, the casing-integrity outcome remains unverified, and the workflow requires multi-well calibration before wider application.

Conflict of interest.

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

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Determination of the optimal hot water injection volume to enhance oil recovery in extra-heavy oil reservoirs

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Abstract. The growing global demand for petroleum and prevailing oil price dynamics have elevated the recovery of heavy oil resources to a matter of strategic importance for the energy sector. Addressing the technical challenges and operational complexities inherent to heavy oil production has been a primary focus of applied petroleum engineering research in recent years. A substantial proportion of hydrocarbon reserves remains unrecovered owing to the characteristically high viscosity of heavy crude oils, which severely impairs their mobility within the reservoir formation. Thermal enhanced oil recovery (EOR) technologies provide a viable pathway for reducing oil viscosity and augmenting oil displacement efficiency through the application of heat to subsurface formations.

Hot water injection constitutes a thermal EOR technique that involves the injection of heated water into hydrocarbon-bearing formations via injection wells. The injected thermal energy reduces the viscosity of heavy oil, thereby improving its mobility and facilitating displacement toward production wells. This study investigates the application of hot water injection in a Middle Eastern reservoir with substantial heavy oil reserves, characterized by an initial oil saturation of 75% and an in-situ heavy oil viscosity of 500 cP. Two-phase immiscible displacement experiments were conducted to evaluate system performance. The primary objective is to identify the optimal injection temperature and hot water slug size – in terms of pore volumes injected – that maximize oil recovery efficiency. The results of several design parameter combinations are analyzed, including hot water floods conducted at various injection volumes and slug sizes. Based on these findings, operational guidelines are established for designing effective hot water injection systems capable of efficiently recovering heavy oil from analogous reservoir conditions. The study also delineates the conditions under which specific design configurations yield superior recovery performance. A critical element of process optimization is the determination of the optimal hot water injection volume that maximizes incremental oil recovery.

Keywords: hot water injection, heavy oil, oil viscosity, enhanced oil recovery (EOR) methods, thermal recovery techniques, optimal injection volume, oil displacement efficiency.

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1. Introduction. Upon conclusion of primary oil recovery operations, a substantial fraction of the original oil in place (OOIP) remains unextracted within the reservoir formation. Enhanced oil recovery (EOR) encompasses a broad spectrum of techniques specifically designed to mobilize and produce this residual hydrocarbon resource from partially depleted reservoirs. EOR processes are conventionally classified into three principal categories: thermal methods, chemical methods, and miscible/immiscible displacement methods. Each approach targets a distinct mechanism governing fluid displacement efficiency and aims to address specific reservoir and fluid property limitations that constrain primary and secondary recovery performance.

Thermal recovery methods and their associated operational procedures have been the subject of extensive research within the petroleum engineering literature. The application of heat serves as the fundamental mechanism by which thermal recovery technologies mobilize subsurface hydrocarbons. Among all EOR strategies, thermal recovery methods represent the most widely deployed approach for enhancing production from heavy oil reservoirs, owing to their demonstrated effectiveness in reducing oil viscosity and improving displacement efficiency under a broad range of reservoir conditions.

1.1. Classification of Thermal EOR Techniques. Four distinct thermal injection techniques are recognized in petroleum engineering practice:

- Hot gas injection
- Hot water injection (HWI)
- Steam stimulation (cyclic steam injection)
- Steam displacement (steamflooding)

In-situ combustion – in which the fuel source is the reservoir oil itself and an oxidizing agent (air or oxygen - enriched gas) is injected into the formation – represents an alternative thermal production method. Heat can also be introduced externally by injecting hot fluids such as steam or hot water into the formation. In-situ combustion occurs less frequently than exogenous heat injection methods in field applications.

1.2. Fundamentals and Advantages of Hot Water Injection. Among all thermal injection methods, hot water injection (HWI) most closely resembles conventional cold water flooding in terms of operational simplicity and surface facility requirements. The fundamental concept is straightforward: water is heated at surface facilities and injected into the reservoir formation through designated injection wells. The thermal energy delivered to the formation serves to reduce oil viscosity, and the associated displacement mechanism – combined with the increased oil mobility – facilitates hydrocarbon flow toward production wells.

The relative mobility improvement achieved by hot water injection is particularly pronounced for heavy oils, because their viscosity decreases at a substantially faster rate with temperature than does water viscosity. As reservoir temperature increases, the oil-to-water mobility ratio improves favorably, resulting in a more efficient displacement front and higher incremental oil recovery compared to cold water flooding at equivalent injection volumes.

It has been established that the energy content of saturated steam is approximately three times that of hot water at temperatures below 423°F (217°C). Consequently, hot water injection generally achieves lower maximum energy injection rates than steam injection. However, practical field experience has demonstrated that a steam flood followed by a hot water flood can yield greater total oil recovery than a steam flood alone. In such hybrid operations, steam follows the preferential flow channels established by the preceding hot water flood – rather than overriding toward the reservoir crest – thereby contacting previously bypassed oil in the lower portions of the formation.

Conversely, when a steam flood project is converted to hot water injection, the advancing hot water front mobilizes and displaces oil that had been bypassed by the steam phase. This operational strategy reduces fuel consumption, mitigates the risk of formation compaction during steam production, and minimizes the probability of sand production. Additionally, steam in a steamflood project has a tendency to migrate preferentially toward the upper portions of the reservoir due to gravity segregation, resulting in non-uniform volumetric sweep. When hot water is subsequently injected into the thermally affected zone, heat is transferred from the swept region to the unswept portions of the reservoir, thereby recovering thermal energy that would otherwise be stranded.

2. Field Background and Research Methodology

2.1. Field Description and Reservoir Characteristics. This research was conducted with reference to the Western Absheron (Qərbi Abşeron) heavy oil field, located in the South Caucasus petroleum province. The field is classified as a heavy oil reservoir, with in-situ crude oil viscosity ranging between 20 and 28 cP under reservoir conditions. For heavy oil accumulations of this type, thermally enhanced oil recovery methods represent the most appropriate and technically justified production strategy.

Oil is principally recovered from two producing horizons, designated the QA and QD formations. The field currently supports 59 active production wells. A supplementary development program has been planned that includes the drilling of 14 injection wells to support the proposed hot water injection scheme. The primary research objective is to determine the optimal daily hot water injection volume that maximizes oil recovery efficiency, and to this end, a comprehensive sensitivity analysis was performed as a function of injection volume.

2.2. Sensitivity Analysis: Effect of Injection Volume on Daily Oil Production. A series of simulation scenarios was designed and executed in which the daily hot water injection volume was systematically varied across a range of values. The simulation results for daily oil production as a

function of hot water injection volume are presented in Figure 1. Each scenario was evaluated under identical reservoir and operational conditions, with the sole variable being the daily hot water injection rate.

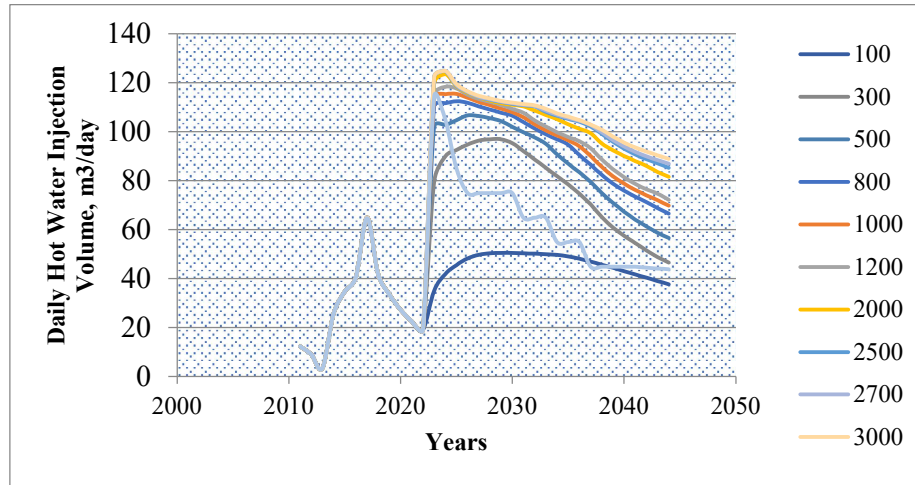


Figure 1. Daily Oil Production Rate as a Function of Hot Water Injection Volume

Table 1.

Daily Oil Production Rate as a Function of Hot Water Injection Volume

Years	Hot Water Injection Volume, m ³ /day										
	100	300	500	800	1000	1200	2000	2500	2700	3000	3500
2023	135.20	146.06	152.90	157.43	158.85	159.18	160.08	160.23	160.24	160.24	158.78
2024	149.59	177.66	190.78	197.73	200.56	201.97	205.13	205.79	205.84	205.84	198.51
2025	165.60	211.03	228.52	238.71	242.76	245.13	249.19	250.02	250.12	250.18	235.25
2026	182.82	245.20	267.28	279.67	284.61	287.53	291.89	292.83	292.99	293.15	264.99
2027	200.74	280.15	306.16	320.20	325.84	329.18	333.83	334.86	335.04	335.28	292.31
2028	219.08	315.56	344.94	360.32	366.63	370.43	375.32	376.42	376.66	377.04	319.70
2029	237.50	350.96	383.26	399.87	406.81	411.14	416.22	417.51	417.83	418.30	347.02
2030	255.93	386.10	420.85	438.95	446.46	451.32	456.83	458.30	458.68	459.25	374.33
2031	274.32	420.24	457.63	477.35	485.54	490.94	497.21	498.84	499.29	499.96	400.73
2032	292.69	453.27	493.72	514.85	523.72	529.73	537.35	539.30	539.82	540.59	424.46
2033	310.95	484.96	528.92	551.36	560.83	567.41	576.66	579.11	579.85	580.84	448.13
2034	329.13	515.39	562.74	587.06	597.11	604.22	615.34	618.25	619.16	620.39	469.35
2035	347.13	544.58	595.09	622.03	632.65	640.24	653.31	656.87	657.94	659.35	489.36
2036	364.90	572.57	626.18	655.84	667.55	675.69	690.67	695.14	696.35	697.95	509.43
2037	382.23	598.98	655.93	688.07	701.16	710.22	727.30	732.77	734.17	735.78	528.84
2038	399.11	623.58	684.00	718.89	733.22	743.42	762.68	769.48	771.13	772.98	545.21
2039	415.52	646.48	710.57	748.22	763.71	774.98	796.86	805.03	806.92	809.28	561.57
2040	431.50	668.07	735.82	776.47	793.05	805.33	830.24	839.59	841.76	844.68	577.98
2041	446.94	688.45	759.74	803.68	821.27	834.50	862.73	873.09	875.61	879.15	594.35
2042	461.88	707.74	782.59	830.08	848.64	862.76	894.49	905.80	908.72	912.96	610.63
2043	476.33	725.98	804.45	855.58	875.28	890.30	925.38	937.85	941.22	946.18	626.77
2044	490.33	743.38	825.50	880.30	901.17	917.13	955.56	969.39	973.29	978.95	642.86

As illustrated in Figure 1, daily oil production increases progressively with increasing hot water injection volume up to a threshold value of 3,000 m³/day. Beyond this critical injection rate, however, further increases in injection volume yield diminishing marginal returns, and the production rate begins to decline. This behavior is consistent with the well-established principle that beyond an

optimal injection volume, excessive water injection can result in premature water breakthrough, unfavorable mobility ratios, and reduced displacement efficiency.

Table 1.

Annual Oil Production at Various Hot Water Injection Volumes

Hot Water Injection Volume (m ³ /day)	Recovery Performance
500	Below optimal – insufficient thermal energy
1,000	Progressive improvement in recovery
1,500	Continued improvement
2,000	Approaching optimal range
2,500	Near-optimal performance
3,000	Optimal – maximum oil recovery rate achieved
> 3,000	Diminishing returns – production rate declines

Note: Specific annual production values for each injection scenario are presented in the corresponding simulation output figures. The table above summarizes the qualitative performance trend observed across the injection volume range investigated.

The simulation results demonstrate that the optimal daily hot water injection volume for the Western Absheron field is 3,000 m³/day. At this injection rate, the maximum daily oil production rate is achieved. This finding indicates that a well-defined injection volume threshold exists, beyond which the incremental benefits of additional hot water injection are outweighed by adverse displacement dynamics, including increased water cycling, thermal dilution, and unfavorable sweep efficiency.

3. Discussion

3.1. Mechanisms Governing Optimal Injection Volume. The existence of an optimal hot water injection volume is a consequence of competing physical mechanisms operating within the reservoir. At sub-optimal injection rates, the thermal energy delivered to the formation is insufficient to reduce oil viscosity to levels that enable effective displacement, resulting in poor sweep efficiency and low recovery. As injection volume increases toward the optimal threshold, viscosity reduction improves progressively, mobility ratio becomes more favorable, and the displacement front advances more uniformly through the reservoir.

Beyond the optimal injection volume, however, the thermal front moves faster than the oil bank, leading to early thermal breakthrough at production wells. Excessive injection rates can also result in unfavorable pressure gradients that promote channeling through high-permeability streaks, bypassing significant volumes of oil in less permeable zones. Additionally, the energy efficiency of the process degrades as an increasing proportion of the injected thermal energy is produced without contributing to oil displacement.

3.2. Design Parameters Influencing Hot Water Injection Performance. The overall effectiveness of a hot water injection program is governed by a complex interplay of reservoir

characteristics and operational design parameters. The primary factors influencing hot water injection performance include the following:

- Oil recovery factor and residual oil saturation distribution within the reservoir
- Well spacing geometry and the pattern of injection and production wells
- Daily hot water injection rate and total cumulative injection volume
- Injection water temperature and associated thermal energy content
- Reservoir permeability distribution and heterogeneity
- In-situ oil viscosity and its temperature-dependence
- Reservoir geometry, structural configuration, and net pay thickness

Understanding and optimizing these parameters – both individually and in combination – is essential to the design of an economically and technically efficient hot water injection project. Sensitivity analysis, as employed in this study, provides a systematic and rigorous methodology for quantifying the relative importance of each parameter and identifying the combination of design variables that yields the highest recovery performance.

4. Conclusions. Heavy oil has long been recognized as one of the world's most significant unconventional hydrocarbon resources, owing to its vast reserve volumes and the growing global demand for petroleum. However, the inherently high viscosity of heavy crude oil – governed by reservoir properties such as permeability, reservoir pressure, and in-situ oil viscosity – presents substantial technical challenges to efficient production. Hot water injection represents a technically appropriate and commercially viable thermal EOR technology for recovering heavy oil from reservoirs with characteristics similar to those studied in this investigation. The principal conclusions of this research are as follows:

1. The optimal daily hot water injection volume for the Western Absheron heavy oil field has been quantitatively determined to be 3,000 m³/day. Below this threshold, increasing injection volume produces a consistent and progressive improvement in daily oil production, attributable to enhanced viscosity reduction and improved oil-to-water mobility ratio.

2. Beyond the optimal injection volume of 3,000 m³/day, further increases in hot water injection rate yield no additional improvement in oil production rate, and in some scenarios result in a measurable decline in recovery performance. This confirms the existence of a well-defined optimal injection volume beyond which the displacement process becomes increasingly inefficient.

3. The sensitivity analysis demonstrates that hot water injection is a highly effective thermal EOR strategy for extra-heavy oil reservoirs, provided that injection parameters are carefully optimized. Suboptimal injection volumes result in insufficient thermal energy delivery, while excessive injection leads to premature breakthrough and reduced volumetric sweep efficiency.

4. The findings of this study provide a quantitative basis for the design and operational planning of hot water injection programs in analogous heavy oil reservoirs, and underscore the critical importance of injection volume optimization as a central element of thermally enhanced recovery project design.

5. Future work should investigate the combined effects of injection temperature, well spacing geometry, and reservoir heterogeneity on recovery performance, as well as the potential economic benefits of hybrid thermal strategies combining hot water flooding with steam injection phases.

Conflict of interest

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

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Technology and mechanism of residual oil extraction using in-situ combustion

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Abstract. The article provides detailed information on the mechanism of residual oil extraction using the technology of intra-layer combustion. Here, the history of the emergence of this exploitation method, the stages of its development are discussed, and mainly the most widely used and the maximum achievement of annual oil production are presented. It has been theoretically proven that the speed of thermal convection is less than the speed of movement of the combustion front. In this method of development, air is used as an oxidizer, which is injected into the formation through air injection wells. An electric heater is lowered to the bottom of the well and turned on; oil vapors at the bottom of the well ignite and create a combustion group; then compressed air is injected into the formation to move it forward to the production wells. When checking the formation and progress of the combustion flame, temperatures are measured in existing wells.

The chemical formula for the combustion of petroleum residue-coke is given in two forms. The formula for calculating the volume of air required for the combustion of coke in 1m³ of the layer is given. The rate of the oxidation reaction within the layer is expressed by the Arrhenius law; based on this, the rate of oxygen entering the reaction is calculated. The combustion rate of the combustion group and its formula for any time t and for the radial case are given.

Keywords: in-situ combustion, residual oil, coke, extraction mechanism, technology, underground degassing, compressed air, combustion front, electric heater.

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1. Introduction. The modern oil production industry faces a key challenge: declining production from traditional fields and an increasing share of hard-to-recover oil reserves. Researchers estimate that up to 60–70% of initial geological oil reserves remain in the subsurface after primary and secondary development methods. This requires the implementation of innovative technologies aimed at increasing the ultimate oil recovery factor. Among the most promising areas, in-situ combustion (ISC) - a thermochemical method based on controlled oxidation-reduction reactions in the oil-bearing formation - occupies a special place.

Historical origins of this method are linked to D.I. Mendeleev's (1888) idea of underground coal degassing, which served as the theoretical basis for the development of thermochemical methods for influencing formations. In the 1930s, Soviet scientists A.B. Sheinman and K.K. Dubrovay first proposed using a similar principle to enhance oil recovery - initiating in-situ oxidation of oil followed by combustion. Although the first attempts to implement this method at fields in the Krasnodar Territory were unsuccessful, their research became the starting point for the development of this field.

In the late 1950s and early 1960s, interest in this technology increased significantly. Laboratory and industrial tests conducted in the USSR, USA, Hungary, France, the Netherlands, and other countries confirmed that, with a properly managed combustion process, commercial-grade oil can be recovered even from low-permeability and water-saturated formations. Experiments have shown that a combustion front can propagate stably in the subsurface if a balance is maintained between the air supply rate, reaction temperature, and the composition of the oil residue (coke).

The purpose of this study is to analyze and theoretically substantiate in-situ combustion technology as one of the most effective methods for enhancing oil recovery, as well as to identify the factors influencing combustion front stability and the kinetics of oxidation reactions.

2. Materials and Methods. Accumulated global experience demonstrates that in-situ combustion is not only an effective but also a fairly versatile method applicable to various types of oil reservoirs, including heavy and highly viscous oils [1-6].

In the process of developing an oil field by the in-situ combustion method, air is mainly used as an oxidizer, which is injected into the formation from special air injection wells. Oil is taken from the producing wells, along with combustion products and water, which can also be injected into the formation; into these air injection wells or into special water injection wells. To do this, a heater assembly is lowered into the wellbore and air is injected, partially compressing the oil and water from the formation into the producing wells. Then a depth heater assembly is connected and heat is introduced into the formation. As a result, the temperature in the formation increases, the rate of oil oxidation increases, and oxidation proceeds to combustion [7-9].

The chemical formula for the combustion of oil residue - coke is written as follows:



(1)

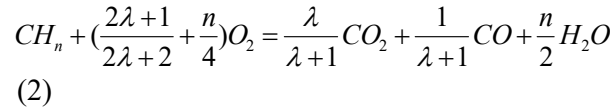
In the reaction according to formula (1), all hydrogen atoms are converted to water. Therefore, $d=n/2$. Then, by equating the hydrogen atoms on the left and right sides of formula (1), we get:

$$(\lambda + 1)b = 1; b = \frac{1}{\lambda + 1}$$

We obtain on oxygen:

$$a = \lambda b + \frac{b}{2} + \frac{d}{2} = \frac{2\lambda + 1}{2\lambda + 2} + \frac{n}{4}$$

Thus, the chemical formula for combustion (1) takes the form:



From formula (2) it can be seen that for one mole of coke to burn, $\frac{2\lambda + 1}{2\lambda + 2} + \frac{n}{4}$ mol O₂ is required.

The molar mass of the CH_n group of coke is 12+n. Thus, $\frac{2\lambda + 1}{2\lambda + 2} + \frac{n}{4} / (12 + n)$ kg/mol O₂ is required for 1 kg of coke.

An important parameter of the layer affected by combustion is the amount of coke in its unit volume. This quantity is denoted by z. Thus, the volume of air required for the combustion of coke

in 1m³ of the layer (brought to standard conditions) is:

$$V_{air} = \frac{22,4 \left(\frac{2\lambda + 1}{2\lambda + 2} + \frac{n}{4} \right)}{a_1 a_2 (12 + n)}$$

(3)

Here, a_1 is the amount of oxygen in the air; a_2 is the degree of oxygen utilization.

It should be noted that according to expression (2), or from 1 kg/mol of coke in the developed combustion process in the formation, $\lambda/(\lambda + 1)$ kg·mol of CO₂ and $n/2$ kg/mol of water are released.

3. Results and discussion. Let us quantitatively evaluate the formation of various substances during intensive combustion in the formation. Let us assume that $n=2$ and, according to experimental data, a significantly small amount of CO is formed as a result of combustion. In this case, $\lambda=10$. The amount of coke in the rock is $z_t=25 \text{ kg/m}^3$, $a_1=0.21$, $a_2=0.9$, and

$$V_{air} = \frac{22,4 \left(\frac{2 \cdot 10 + 1}{2 \cdot 10 + 2} + 0,5 \right)}{0,21 \cdot 0,9(12 + 2)} \approx 308 \text{ m}^3/\text{m}^3$$

Thus, for the combustion of 1 m^3 of coke from the bed, 308 m^3 of air will be required under standard conditions. For the combustion of 1 kg of coke, 21.31 m^3 of air is required under standard conditions. As it can be seen from expression (2), the following amount of CO_2 gas is formed in the reservoir for 1 kg of burnt coke:

$$\frac{44\lambda}{(\lambda + 1)(12 + n)} = 2,86 \text{ kg}.$$

And the water:

$$\frac{9n}{12 + n} = 1,286 \text{ kg}$$

An important characteristic of the combustion process within the formation is the rate of oxidation reaction w , i.e. the rate of reaction of oxygen with coke per unit volume of the formation. This rate can be multiplied by certain coefficients to obtain the rate of temperature drop in 1 m^3 of the formation.

Studies of oil oxidation in porous media show that the rate of oxidation reaction within the formation is expressed by the Arrhenius law. Thus, according to this law, the following formula exists for the reaction rate of oxygen w_{ox} :

$$w_{ox} = a_0 P_{ox}^n \cdot e^{-\frac{E}{RT}} \quad (4)$$

Here, a_0 , n are the coefficients determined experimentally for various oils and oil reservoirs; P_{ox} is the partial pressure of oxygen in the oxidizer; E - the activation energy; R - the gas constant; T - the absolute temperature, in K^0 .

To determine the constants a_0 , n and $B=E/R$, laboratory studies of the oxidation kinetics of specific oils are carried out on natural and artificial samples of mountain rocks.

It was found experimentally that the oxidation kinetics constants of oils included in formula (4) have the following order: $E/R=(8-9)103$; $n=0.5-1.0$; $a_0=(1-5)104 \text{ (kgO}_2 \cdot \text{MPa)} \cdot n/\text{kg coke} \cdot \text{s}$). The dimension $[w_{ox}]=\text{kgO}_2/(\text{kg coke} \cdot \text{s})$. Let us estimate the value of w_{ox} according to formula (4). Let us assume that $A/R=8.5 \cdot 103 \text{K}$; $n=1.0$; $a_0=3 \cdot 104 \text{ kgO}_2/(\text{kg oil} \cdot \text{s} \cdot \text{MPa})$; $P=10 \text{ MPa}$; $P_{ox}=0.21 \cdot 10=2.1 \text{ MPa}$; $T=313.15 \text{ K}$ (40°C). We get:

$$w_{ox} = 3 \cdot 10^4 \cdot 0,21 \cdot 10e^{\frac{8,5 \cdot 10^3}{313,15}} = 10,27 \cdot 10^{-8} \text{ kgO}_2/(\text{kg coke} \cdot \text{s}) = 8,87 \cdot 10^{-3} \text{ kgO}_2/(\text{kg coke} \cdot \text{day}).$$

Oxidation reaction $T=473,15 \text{ K}$ (200°C) temperaturda sürətini hesablayıb, alırıq:

$$w_{ox} = 3 \cdot 10^4 \cdot 0,21 \cdot 10e^{\frac{8,5 \cdot 10^3}{473,15}} = 9,954 \cdot 10^{-4} \text{ kgO}_2/(\text{kg coke} \cdot \text{s}) = 86 \text{ kgO}_2/(\text{kg coke} \cdot \text{day}).$$

Unit of measure $[w_T]=\text{kJoule}/\text{m}^3 \cdot \text{s}$; then we write:

$$w_T = w_{ox} \cdot H_T \cdot Z_T = 8,87 \cdot 10^{-3} \cdot 10,5 \cdot 10^3 \cdot 25 = 2328 \text{ kJoule} / \text{m}^3 \text{ day}$$

If we assume that the average heat capacity of the layer $C_{for}=2.5 \cdot 103 \text{ kJoule}/(\text{m}^3 \text{K})$, then at this rate the temperature will rise by $(2.238 \cdot 103)/(2.5 \cdot 103) \approx 1 \text{ K}$ during the day. We assume the temperature $T=473.15 \text{ K}$ and calculate:

$$w_T = 9,954 \cdot 10^{-4} \cdot 10,5 \cdot 10^3 \cdot 25 = 261,3 \frac{\text{kJoule}}{\text{m}^3 \text{ s}} = 225,8 \cdot 10^5 \text{ kJoule} / \text{m}^3 \text{ day}$$

If air is injected to move the combustion front in a straight layer, then the combustion speed of the front is:

$$w_f = q_{air} / R_{air} \cdot bh \quad (5)$$

Here, q_{air} is the air flow rate in the layer element; b is the width of the layer; h is the thickness of the layer covered by combustion.

At any time t , the state of the combustion front X_f is:

$$X_f = \frac{\int_0^t q_{air}(t) dt}{R_{air}bh} \quad (6)$$

In the radial case:

$$2\pi r_f dr_f h R_{air} = q_{air} dt; w_f = \frac{q_{air}}{2\pi r_f h R_{air}}$$

Then

$$\pi h R_{air} r_f^2 = \int_0^t q_{air}(t) dt \quad \text{yaxud}$$

$$r_f = \left[\frac{\int_0^t q_{air}(t) dt}{\pi h R_{air}} \right]^{1/2} \quad (7)$$

Let us assume that in the radial case, under standard conditions, $q_{air}=30 \cdot 10^3 \text{ m}^3/\text{day}$; $Z_t=25 \text{ kg/m}^3$;

$h=10\text{m}$; $R_{hava}=308 \text{ m}^3/\text{m}^3$. Then, after 1 year=365 days, the combustion front will advance to the following distance from the well.

$$r_f = \left[\frac{30 \cdot 10^3 \cdot 365}{3,14 \cdot 10 \cdot 308} \right]^{1/2} = 33,65\text{m}$$

Thus, all the main indicators of the considered method are analyzed and determined. This proposed technology and mechanism are effective in designing the field development system.

4. Conclusion. The study outlines the key mechanisms and calculation relationships that characterize in-situ combustion processes for recovering residual oil. It is shown that the combustion front is formed by injecting compressed air and initiated by an electric heater, while its movement is controlled through temperature measurements in the reservoir. The chemical equations of coke combustion, the calculation of the air volume required for its oxidation, and Arrhenius-based formulas describing the reaction kinetics and the combustion front velocity are presented. The results refine the physicochemical parameters of the process and confirm the potential of in-situ combustion as an effective enhanced oil recovery method.

Conflict of interest

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

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Formation of crystalline hydrates of hydrocarbon gases and selection of methods for combating it

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Abstract. The article presents the results of the analysis and study of hydrate vapors and considers the formation of hydrates in hydrocarbon gases, starting from pentane and moving upwards (hexane, heptane, octane, etc.).

The formation of hydrates in hydrocarbon gas is considered the most important complication in its transportation through pipelines. Methods of combating this complication are carried out in two directions: the development and application of measures to prevent the formation of hydrates; the development and application of measures to eliminate already formed hydrates.

As one of the first directions, methanol injection into the gas flow is carried out in the pipeline. At the beginning of the pipeline, gas heating is applied in order to prevent hydrate formation. At the same time, the turbulent motion of the gas flow creates certain conditions for the formation of hydrates. The equilibrium constants of gas hydrates were determined based on the experimental data of Carson and Katz.

As the second direction, the regulation of cleaning of hydrates deposited in the pipeline by various mechanical methods is carried out.

The formation of hydrocarbon gas hydrates is considered the most important complication in its transportation through pipelines. Methods of combating this complication are carried out in two directions: 1) development and application of measures to prevent the formation of hydrates;

2) development and application of measures to eliminate already formed hydrates.

As the first direction, methanol is injected into the gas flow in the pipeline; the gas is heated at the beginning of the pipeline where hydrate formation begins.

The turbulence of gas movement contributes to the formation of hydrates.

As the second direction, hydrate deposited in the pipeline is cleaned by various mechanical method. Three types of methods for combating hydrate plugs in gas pipelines are shown and five different methods for drying gas are mentioned.

Keywords: gas pipeline, crystalline hydrate, gas condensate, thermodynamic research, fractional composition of gas, flow turbulence.

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1. Introduction. Hydrocarbon gases saturated with water vapor at certain pressure and temperature form chemical compounds of hydrocarbons with water called gas hydrates. When water is present in the liquid phase of the gas hydrates are formed.

Gas hydrates were discovered in 1810 by G. Davy, and their properties were studied in depth much later.

Thermodynamic studies have shown that methane molecules combine with 7 (or 6) water molecules to form methane hydrate $-CH_4 \cdot 7H_2O$, respectively: ethane hydrate $-C_2H_6 \cdot 8H_2O$; propane hydrate $-C_3H_8 \cdot 18H_2O$; carbon dioxide hydrate $-CO_2 \cdot 7H_2O$; propane hydrate $-C_3H_8 \cdot 18H_2O$ are formed.

As a result of the analysis and study of hydrate vapors, it has been determined that starting from pentane and higher (hexane, heptane, octane, etc.), hydrocarbons do not form hydrates [1,6].

The peculiarity of hydrate formation is that its formation temperature is much higher than the ice formation temperature ($0^\circ C$). Each hydrocarbon, starting from methane to butane, has a certain

temperature limit at which hydrates can form, for example, $CH_4 - O \div 22^\circ C$; $C_2H_6 - 0 \div 14,5^\circ C$; $C_3H_8 - 0 \div 5,5^\circ C$; izzo $C_4H_{10} - 0 \div 2,5^\circ C$; normal $C_4H_{10} - 0 \div 1^\circ C$.

At the indicated limits, hydrates are gaseous, slightly saturated and quickly decompose. At temperatures higher than these limits, hydrates do not form, even at high pressures [2,8].

2. Methodological part. The article also mentions five different methods of drying gas and explains their purposes. Hydrate is a yellowish solid substance resembling wet snow, which is formed in the form of crystals inside pipes and pipelines and settled on their walls, reducing their cross-sectional area and pipeline productivity [3,7].

The formation of hydrocarbon gas hydrates is considered the most important complication in its transportation through pipelines. Methods of combating this complication are carried out in two directions: 1) development and application of measures to prevent the formation of hydrates; 2) development and application of measures to eliminate already formed hydrates.

As the first direction, methanol is injected into the gas flow in the pipeline; the gas is heated at the beginning of the pipeline where hydrate formation begins.

3. Results and discussion. As the second direction, hydrate deposited in the pipeline is cleaned by various mechanical methods.

The following empirical formula was proposed by Gammer-Schmidt to determine the melting temperature of hydrates depending on pressure:

$$t = 10,633 \cdot p^{0,285} - 17,78,^\circ C$$

(1)

However, the formation of hydrates depends not only on pressure and temperature, but also on the fractional composition of the gas, its humidity, the physical conditions of the gas, that is, the flow velocity, pulsation, flow turbulence, the presence of CO_2 , N_2 , H_2S and other gases in its composition.

The temperature of the gas in the pipeline is found by the following formula [4,9]:

$$\lg \frac{t_i - t_g}{t_i - t_g} = -10,4 \frac{k\pi DL}{V\gamma C_p} \quad (2)$$

where t_g - the temperature of the gas pipeline at a distance L m from the first temperature measurement point, $^\circ C$; c - the coefficient of heat transfer from the gas pipeline to the soil surrounding the pipe, in $kkal / saat \cdot m^2$, D - the outer diameter of the gas pipeline in m ; V - the volume flow of gas in m^3 / day ; γ - the specific gravity of the gas, in kq / m^3 ; C_p - the heat capacity of the gas at constant pressure, in $kkal / kq$.

The law of pressure change, i.e. (dispersion) through the gas pipeline is expressed by this equation:

$$P_x = \sqrt{P_1^2 - (P_1^2 - P_2^2) \cdot X}$$

(3)

where P_1 is the pressure at the beginning of the pipeline, atm; P_2 pressure at a distance of X atm.

The distance of hydrate fall in a gas pipeline, depending on its temperature of fall is determined by the following formula of V.G. Shukhov:

$$t_x = t_g + \frac{t_i - t_g}{l \frac{k\pi DX}{V\gamma C_p}}$$

(4)

Where $l = 7,22$ is the base of the natural logarithm.

Formula (4) can also be written as

$$\lg \frac{t_1 - t_g}{t_x - t_g} = 0,434 \frac{k\pi DX}{V\gamma C_p}$$

(5)

Methods of combating hydrate plugs in gas pipelines can be divided into the following three groups:

1. Methods of only decomposing crystalline hydrates by reducing the pressure in the gas pipeline.
2. Methods of preventing decomposition of hydrates and their formation by heating the gas pipeline and injecting chemical reagents into the pipeline.
3. Methods of warning against the formation of hydrate plugs, that is, methods of partially drying the gas before feeding it into the pipeline [5,10].

The methods of drying gas are as follows:

- 1) The method of using the throttle effect (choke) in the expansion of the gas (or cooling it to a low temperature).
- 2) The method of compressing and cooling the gas.
- 3) The method of absorption by wet hygroscopic products.
- 4) The method of absorption by wet solid sorbents.
- 5) The method of drying the gas by injecting a hygroscopic liquid into the gas flow.

Gas drying has the following purposes:

The presence of water vapor condensate in the gas creates the following complications:

1. Formation or increase of water vapor condensate in gas pipelines;
2. Formation of ice plugs in gas pipelines;
3. Formation of crystal hydrates in gas pipelines;
4. Corrosion and erosion of metal parts of pipes, apparatus and devices.

4. Conclusion.

1. The article provides detailed information on the development of effective measures to combat crystalline hydrates formed during the transportation of hydrocarbon gases through main pipelines.

2. It is shown that hydrates are formed as a result of a chemical reaction between hydrocarbon gases and the water vapor contained in them.

3. Gas hydrates are formed by combining one molecule of each of methane, ethane, propane, isobutane and normal borosilicate gases with various numbers of water molecules, and carbon dioxide hydrates are also formed.

4. Hydrates are not formed from pentane and higher natural hydrocarbons.

5. Each hydrocarbon gas, from methane to butane, has a temperature limit at which hydrates are formed. At temperatures higher than these, hydrates are not formed.

6. The Gammer-Schmidt formula determines the pressure-dependent melting temperature of hydrates.

7. The turbulence of gas movement contributes to the formation of hydrates.

8. The article provides a formula for determining the temperature of gas in pipelines.

9. The formula for the law of pressure dispersion in a gas pipeline is also provided.

10. The distance at which hydrate begins to fall in a gas pipeline, based on the temperature of its fall, is determined by the formula of V.G. Shukhov, for this purpose, the second formula is also presented.

11. Three types of methods for combating hydrate blockages in gas pipelines are shown.

12. The article also mentions five different methods of drying gas and explains their purposes.

Conflict of interest

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

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Enhancement of oil and gas production efficiency through expansion of well drainage area

Jabrayil Eyvazov, Togrul Aslanov, Malik Allahverdiyev

Abstract. This study investigates the influence of several key reservoir and well parameters on production performance in the context of increasing drainage area across different well types. The primary objective is to quantitatively determine and compare the production operating points of vertical and deviated (directional) wells, recognizing that deviated wells inherently encompass a larger drainage area than their vertical counterparts. A central component of this investigation involves the derivation and comparative analysis of Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves for both well configurations. These curves are computed using specialized petroleum engineering software (PROSPER), and their intersection point defines the well's production operating point. Since the drainage areas of the two well types differ fundamentally, their respective IPR curves – and consequently their operating points – yield distinct production outcomes.

Furthermore, this research employs sensitivity analysis to evaluate the effect of varying tubing diameter and wellhead pressure on the VLP curves. The results of this sensitivity study elucidate how the production operating point responds to changes in these critical operational parameters across the two well configurations, thereby providing practical guidance for production optimization and well design.

Keywords: IPR (Inflow Performance Relationship), VLP (Vertical Lift Performance), Nodal Analysis, production operating point, drainage area, tubing diameter, wellhead pressure, deviated well, vertical well, PROSPER.

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1. Introduction. The physical drainage area of a well is governed either by impermeable physical boundaries within the reservoir or by no-flow boundaries that arise from interference between adjacent producing wells. During transient flow conditions, however, a well does not drain its entire physical drainage area; consequently, the physical drainage boundaries do not exert a controlling influence on flow characteristics or production performance during this period. Two complementary interpretations of transient flow are particularly useful for the purposes of this study: (1) the distance reached by the pressure transient within the wellbore – as a result of production – remains smaller than the distance from the well to the drainage boundary; and (2) the cumulative fluids withdrawn from the well have been sourced from a region that is smaller than the total distance to the drainage boundary.

It is not uncommon for unconventional wells to reach the end of their economic life while still operating under transient flow conditions, rendering their physical drainage areas largely inconsequential to production performance assessment. In order to apply conventional recovery-estimation methods to evaluate ultimate recovery and recovery factors, it is analytically advantageous to define a transient drainage area – one that is smaller than the physical drainage area and is an explicit function of time.

The two interpretations of transient flow presented above lead to distinct conceptual frameworks: the first gives rise to the concept of the investigation radius, while the second provides the basis for defining an effective transient drainage area. Before elaborating on the concept of transient drainage during transient flow, it is instructive to first review the pertinent literature concerning the drainage areas of horizontal and deviated (directionally drilled) wells.

When a well is produced until the pressure transient reaches all boundaries of the reservoir (boundary-dominated flow), the area enclosed within those boundaries is defined as the drainage area. The boundaries of a well's drainage area may consist of physical barriers such as faults and formation discontinuities, or they may be established by the no-flow boundaries created by adjacent producing wells operating under interference conditions.

The reservoir model employed in this study considers a two-phase system comprising oil and water; however, the fluid system was modeled as entirely oil-saturated for the purpose of simplification. The fluid viscosity model adheres to Newtonian fluid behavior. No artificial lift mechanism is incorporated into the production system, and the well is completed with a protective casing configuration. Furthermore, no sand control measures are implemented in the wellbore.

2. Experimental Methodology. This study was conducted using the PROSPER well performance simulation software. The following data categories were entered as input parameters: PVT (pressure-volume-temperature) data characterizing reservoir fluid properties, petrophysical data describing reservoir rock properties, deviation survey data defining the well trajectory, surface equipment specifications, and downhole equipment configurations. All input parameters were maintained identical for both the vertical and deviated well models, with the sole distinction being that the deviated well was assigned a larger drainage area than the vertical well. Based on these parametric inputs, the software computed the Inflow Performance Relationship (IPR) curve for each well configuration independently, yielding distinct IPR values corresponding to each well type.

2.1. PVT Data and Reservoir Properties. The primary PVT data utilized as model inputs are summarized in Table 1 below.

Table 1. Primary PVT Data of the Reservoir

Parameter	Value
Reservoir Pressure (psig)	3,150
Reservoir Temperature (°F)	200
Oil Gravity (°API)	30
Gas Specific Gravity	0.75
Water Salinity (ppm)	80,000
Water Cut (%)	0
Total GOR (scf/STB)	400

Additional PVT properties measured at 200°F across various pressure levels are presented in Table 2.

Table 2. Matched PVT Data at 200°F

Pressure (psig)	GOR (scf/STB)	Oil FVF (rb/STB)	Oil Viscosity (cP)
1,500	237	1.138	1.34
2,000	324	1.178	1.15
2,500	400	1.214	1.01
3,000	400	1.207	1.05
4,000	400	1.198	1.11

2.2. Well System Equipment Configuration. The equipment section of the system model is subdivided into five principal sub-sections:

- Deviation survey measurement

- Wellhead equipment specifications
- Downhole equipment configuration
- Geothermal gradient profile
- Average heat capacity parameters

The deviation survey datum can be defined at any reference point, including the wellhead, seabed, platform deck, or mean sea level. The critical requirement is that all downhole equipment descriptions are referenced consistently to the selected datum origin. It is important to note that the wellhead depth does not necessarily coincide with the datum origin. Any deviation between these two reference points will influence the pressure gradient calculations for the mixed-phase flow arriving at the surface. The contribution of each lateral section and its corresponding impact on the downhole pressure drop is incorporated into the IPR model calculations.

Table 3. Deviation Survey Data for Vertical (lower) and Deviated (upper) Wells

Measured Depth (m)	True Vertical Depth (m)	Cumulative Displacement (m)	Inclination Angle (°)
0	0	0	0
1,665	1,665	0	0
1,680.23	1,680	2.64	9.97
1,696.78	1,695	9.63	25.00
1,714.10	1,710	18.29	30.00
1,733.68	1,725	30.87	40.00
1,757.52	1,740	49.40	51.01
1,900	1,775	187.52	75.78
2,500	1,775	787.52	90.00
2,700	1,775	987.52	90.00

Downhole equipment encompasses all components situated between the wellhead and the completion interval, including production tubing strings, casing strings, tubing joints, subsurface safety valves (SSSVs), and associated accessories. Consistent with the deviation survey reference framework, this sub-section provides a complete description of all downhole equipment from the wellhead datum to the completion point.

Table 4. Downhole Equipment Specifications

Equipment Type	Measured Depth (m) [Vert./Dev.]	Inner Diameter (in)	Roughness (m)
Christmas Tree	0	N/A	1.52E-05
Tubing	260	3.5	1.52E-05
SSSV	N/A	2.875	1.52E-05
Tubing	1,750 / 2,100	3.5	1.52E-05
Casing	1,800 / 2,700	7.0	1.52E-05

The geothermal gradient represents the rate of temperature increase per unit depth and is considered independent of the well's flow rate. When employing the approximate temperature prediction method, the geothermal gradient is entered as a function of measured depth. PROSPER internally converts measured depth to true vertical depth and applies a true vertical depth-based temperature gradient throughout its calculations.

Table 5. Perforation Intervals for Vertical and Deviated Wells

Perforation Interval	Vertical Well	Deviated Well
Measured Depth (m)	1,750–1,800	2,100–2,700
True Vertical Depth (m)	1,750–1,800	1,775–1,775

Table 6. Reservoir Parameters

Parameter	Value
Horizontal Permeability (md)	200
Net Pay Thickness (m)	50
Drainage Area (acres)	200
Reservoir Top Depth (m)	1,750
Vertical Permeability (md)	20

3. Nodal Analysis of Oil and Gas Wells. Nodal analysis – formally defined as a systematic approach to the optimization of oil and gas well production systems – is employed to conduct a comprehensive evaluation of the entire production system. This methodology enables the optimization of individual components within a producing well, as well as the collective performance of all wells operating within a given production system. As an integrated systems analysis technique, nodal analysis provides a rigorous framework for simultaneously evaluating reservoir inflow performance and wellbore/surface outflow performance.

3.1. Objectives of Nodal Analysis. The principal objectives of nodal analysis are as follows:

1. Determination of the production flow rate achievable by an existing oil or gas well, accounting for the well's geometric configuration and completion-imposed constraints (natural first flow).
2. Identification of the flow conditions – which may be time-dependent – under which the well will experience loading or flow cessation.
3. Selection of the economically optimal timing for artificial lift installation and facilitation of the most suitable lift method selection.
4. Optimization of the overall production system to achieve the most economically justified target flow rate.
5. Diagnostic evaluation to identify individual system components that unnecessarily restrict the achievable flow rate.
6. Facilitation of rapid identification – by operating and engineering personnel – of potential avenues for production rate enhancement.

It is noteworthy that a substantial number of oil and gas wells worldwide have not been optimized to achieve efficient target production rates. Indeed, many wells may have been completed in configurations that preclude attainment of their maximum production potential. System analysis is applicable to both naturally flowing wells and wells operating under artificial lift conditions, and provides valuable insight at the initial completion design stage. Even with limited data availability, a qualitative evaluation of anticipated well behavior can be obtained by screening multiple completion scenarios. This approach proves particularly useful in the analysis of producing wells, enabling the identification of flow restrictions and opportunities for productivity enhancement.

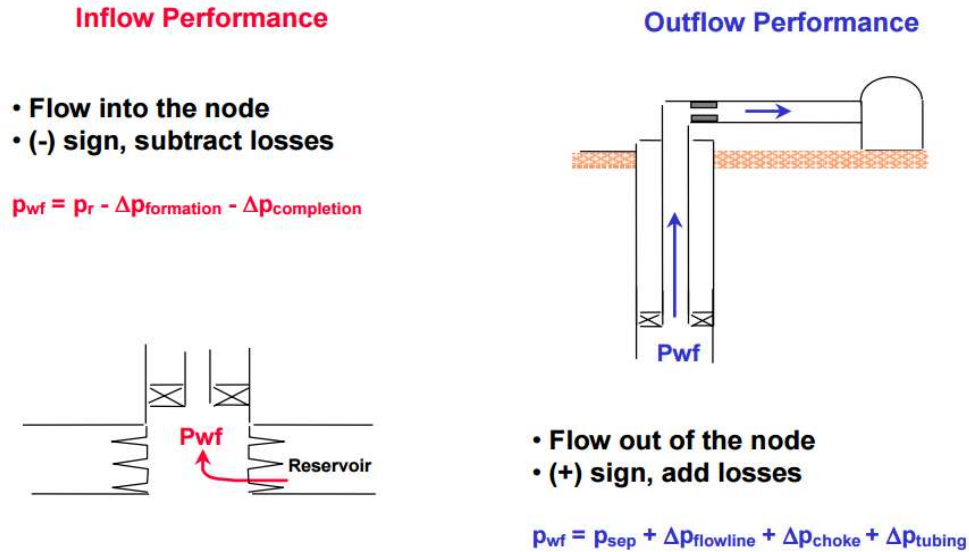


Figure 1. Schematic Representation of Inflow and Outflow Performance Relationships

3.2. Typical Applications of Nodal Analysis. Primary applications of nodal analysis include the following:

- Flow rate estimation and production capacity assessment
 - Tubing string sizing and selection
 - Flowline and surface pipeline sizing
 - Wellhead pressure optimization and surface choke sizing
 - Evaluation of the effects of reservoir pressure depletion
 - Identification and quantification of flow restrictions
- Additional specialized applications include:*
- Sizing of subsurface safety valves (SSSVs)
 - Optimization of perforation density and shot phasing
 - Gravel pack completion design
 - Artificial lift system design and selection
 - Optimization of injection gas-liquid ratio for gas lift operations
 - Evaluation of the effects of reduced wellhead pressure or compression installation
 - Assessment of well stimulation treatment effectiveness

4. Results and Discussion. Following the determination of the IPR curves for both well configurations, the corresponding VLP (Vertical Lift Performance) parameters were entered into the PROSPER model to compute the tubing performance curves. A sensitivity analysis was subsequently conducted by varying the wellhead (first node) pressure and tubing internal diameter across a range of specified values. Based on these parametric variations, the software identified the distinct production operating points corresponding to each parameter combination.

The IPR curve computed from the input parameters clearly demonstrates that the production performance outcomes differ between the vertical and deviated wells. As established by nodal analysis theory, the intersection of the IPR and VLP curves defines the well's production operating point – the stabilized flow rate and corresponding bottomhole flowing pressure at which the well operates under steady-state conditions. Since the drainage areas of the two well configurations differ fundamentally, their operating points are inherently distinct. This study further characterizes the sensitivity of the production operating point to variations in tubing diameter and wellhead pressure for both well types.

4.1. Sensitivity Analysis: Wellhead Pressure (Deviated Well)

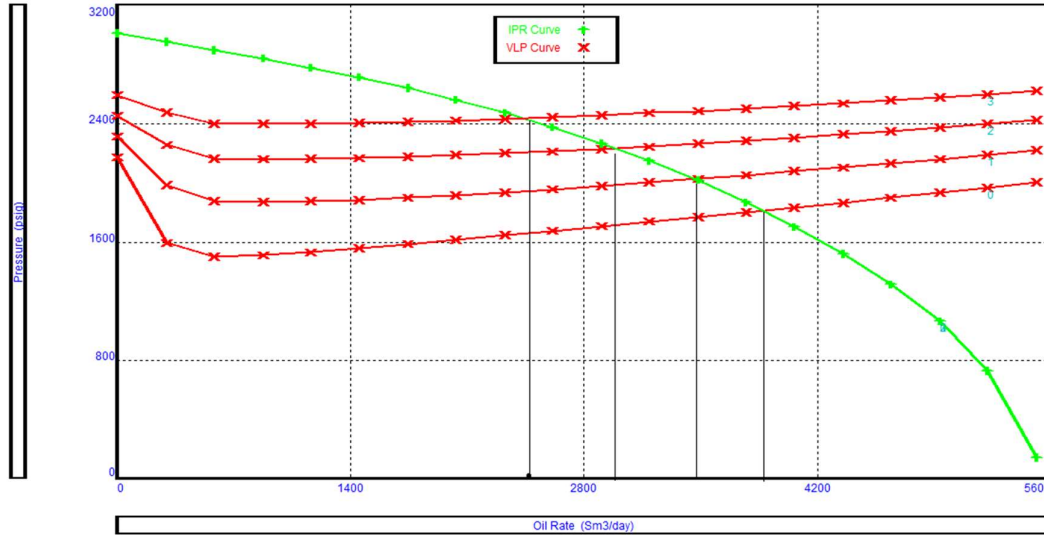


Figure 2. IPR/VLP Curves for the Deviated Well at Various Wellhead Pressures

Figure 2 illustrates the production response of the deviated well as a function of increasing wellhead (tubing head) pressure. The VLP curves at each pressure level are represented by distinct colored lines, while the red curve represents the baseline VLP at a wellhead pressure of 275.4 psig, yielding an estimated production operating point of 3,878 m³/day. This operating point corresponds to the stabilized flow rate and associated bottomhole flowing pressure achieved when a steady-state flow condition is established between the reservoir and the wellbore.

The sensitivity results demonstrate a consistent inverse relationship between wellhead pressure and the estimated production operating point – as wellhead pressure increases, the operating flow rate decreases correspondingly. The specific results are summarized as follows:

- Case 0 – Wellhead pressure: 275.4 psig → Operating point: 3,878 m³/day
- Case 1 – Wellhead pressure: 420.4 psig → Operating point: 3,465 m³/day
- Case 2 – Wellhead pressure: 565.5 psig → Operating point: 2,968 m³/day
- Case 3 – Wellhead pressure: 710.5 psig → Operating point: 2,443 m³/day

4.2. Sensitivity Analysis: Wellhead Pressure (Vertical Well)

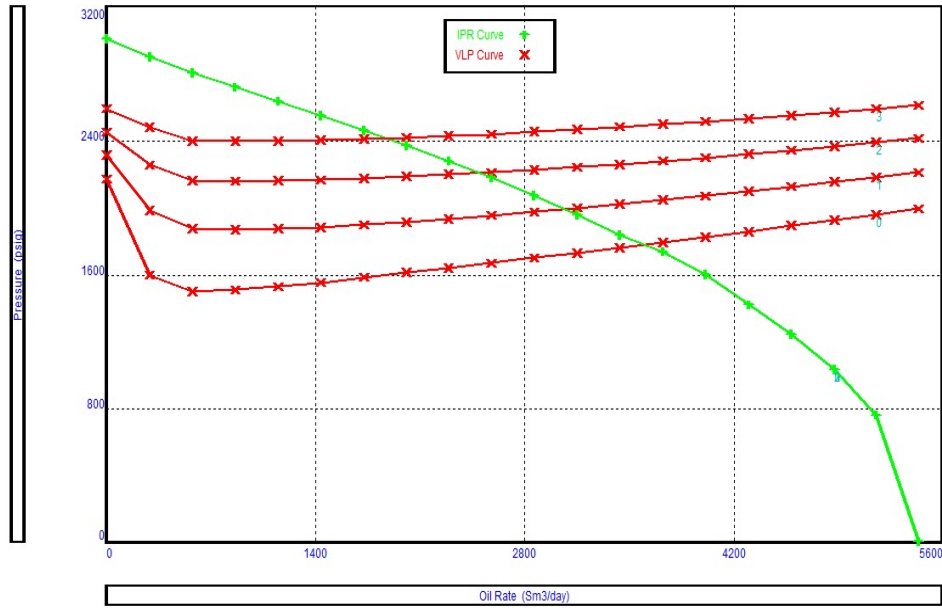


Figure 3. IPR/VLP Curves for the Vertical Well at Various Wellhead Pressures

Figure 3 presents the analogous wellhead pressure sensitivity results for the vertical well configuration. At the baseline wellhead pressure of 275.4 psig, the estimated production operating point for the vertical well is 3,598 m³/day – lower than that of the deviated well at the same pressure, reflecting the smaller drainage area of the vertical well. The results confirm that increasing wellhead pressure similarly reduces the production operating point for the vertical well configuration, as follows:

- Case 0 – Wellhead pressure: 275.4 psig → Operating point: 3,598 m³/day
- Case 1 – Wellhead pressure: 420.4 psig → Operating point: 3,066 m³/day
- Case 2 – Wellhead pressure: 565.5 psig → Operating point: 2,478 m³/day
- Case 3 – Wellhead pressure: 710.5 psig → Operating point: 1,862 m³/day

4.3. Sensitivity Analysis: Tubing Diameter (Deviated Well)

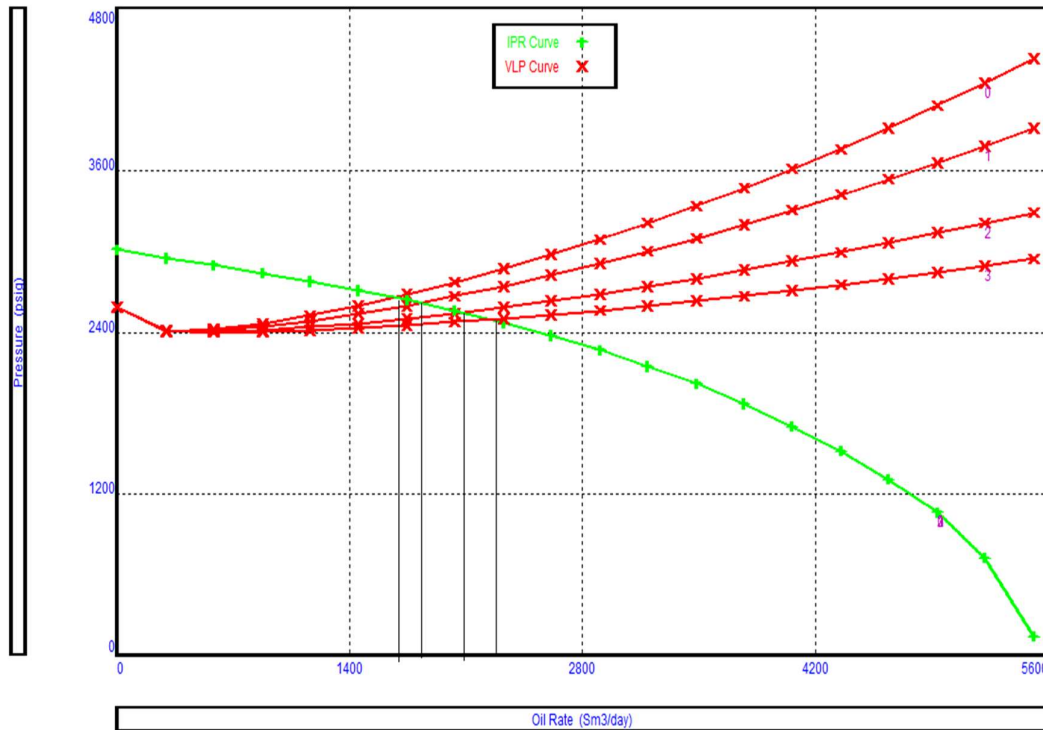


Figure 4. IPR/VLP Curves for the Deviated Well at Various Tubing Diameters

Figure 4 illustrates the production response of the deviated well as tubing internal diameter is progressively increased. The baseline case (Case 0) employs a tubing diameter of 3.75 inches, yielding an estimated production operating point of 1,673 m³/day. The results demonstrate that increasing the tubing diameter produces a consistent positive effect on the production operating point – a physically expected outcome attributable to the reduction in frictional pressure losses within the tubing string as diameter increases. The full sensitivity results are as follows:

- Case 0 – Tubing diameter: 3.75 in → Operating point: 1,673 m³/day
- Case 1 – Tubing diameter: 4.00 in → Operating point: 1,813 m³/day
- Case 2 – Tubing diameter: 4.50 in → Operating point: 2,100 m³/day
- Case 3 – Tubing diameter: 5.00 in → Operating point: 2,226 m³/day

4.4. Sensitivity Analysis: Tubing Diameter (Vertical Well)

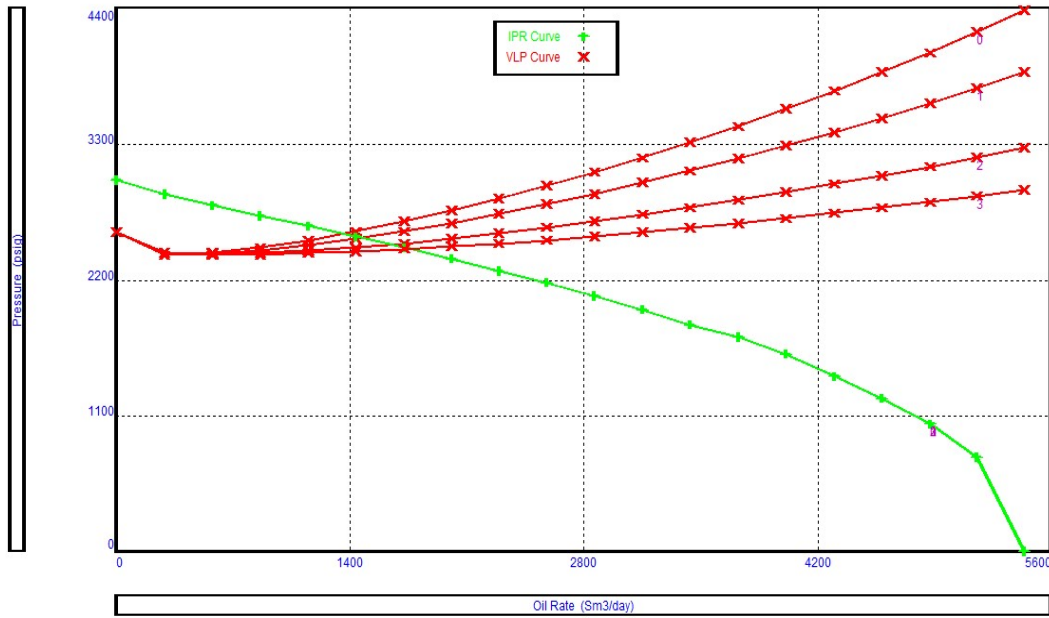


Figure 5. IPR/VLP Curves for the Vertical Well at Various Tubing Diameters

Figure 5 presents the tubing diameter sensitivity results for the vertical well. The baseline case with a tubing diameter of 3.75 inches yields a production operating point of 1,365 m³/day – again lower than the corresponding deviated well value, consistent with the smaller drainage area of the vertical well. Increasing the tubing diameter produces a qualitatively identical positive effect on production performance, as detailed below:

- Case 0 – Tubing diameter: 3.75 in → Operating point: 1,365 m³/day
- Case 1 – Tubing diameter: 4.00 in → Operating point: 1,477 m³/day
- Case 2 – Tubing diameter: 4.50 in → Operating point: 1,645 m³/day
- Case 3 – Tubing diameter: 5.00 in → Operating point: 1,723 m³/day

5. Conclusions. This study has successfully demonstrated the production performance differential between vertical and deviated well configurations when PVT data and petrophysical parameters are held constant. The key findings and conclusions are as follows:

1. The deviated well encompasses a significantly larger drainage area relative to the vertical well, which directly translates into a higher production operating point as determined through nodal analysis.

2. The intersection of the IPR and VLP curves – as computed by PROSPER – consistently confirms that the production operating point of the deviated well exceeds that of the vertical well under equivalent operational conditions, demonstrating the production advantage conferred by the larger drainage area of the deviated well configuration.

3. The sensitivity analysis reveals that increasing tubing diameter yields a positive effect on oil production rates in both well types, attributable to the reduction in frictional pressure drop within the production string.

4. Conversely, increasing wellhead pressure exerts a detrimental effect on production performance in both the deviated and vertical well configurations, as it shifts the VLP curve and consequently reduces the production operating point.

5. The primary conclusion of this investigation is that oil production from the deviated well is substantially greater than that from the vertical well under identical reservoir and operational conditions, confirming the production efficiency advantage of deviated well completions in

Conflict of interest

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

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Evaluation of the effectiveness of physicochemical methods for enhanced oil recovery in Azerbaijan oil fields at the late stage of development

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Abstract. Mature oil fields in Azerbaijan are characterized by high depletion of recoverable reserves, declining reservoir pressure, increasing water cut, and declining economic performance. Under these conditions, the implementation of physicochemical methods to enhance oil recovery, aimed at bringing hard-to-recover and residual oil reserves into production, is particularly relevant.

This article presents a comprehensive analysis of the geological and physical conditions of Azerbaijani fields, the theoretical foundations of physicochemical reservoir stimulation, and practical experience with polymer, surface-active, alkaline, combined (ASP), and microbiological methods.

Calculated relationships, reservoir models, waterflooding schemes, and tabulated oil recovery indicators are presented. The environmental aspects and prospects for digitalization of EOR technologies are discussed.

It is shown that the integrated application of physicochemical methods can increase oil recovery by 10–15%, extend the profitable life of fields in the late stages of development by 10–20 years, and ensure the sustainable development of the Azerbaijani oil industry.

Keywords: enhanced oil recovery, physicochemical methods, polymer flooding, ASP technologies, Azerbaijani fields.

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1. Introduction. Azerbaijan is rightfully considered one of the historical centers of the global oil industry. Commercial oil production on the Absheron Peninsula began in the 19th century and has since led to a high degree of depletion of the country's main oil deposits. Most of the country's fields are in the late or final stages of development, which is reflected in declining well flow rates, increasing water cut, and an increasing share of hard-to-recover reserves.

According to various estimates, the average oil recovery factor at such fields in Azerbaijan is 0.25–0.30, while a significant portion of the oil (up to 60–70% of geological reserves) remains in the subsoil. Given the limited potential for discovering new large fields, enhancing oil recovery at existing sites has become a strategic objective.

Physicochemical methods for enhancing oil recovery represent one of the most promising tools for solving this problem. These methods are based on targeted modification of the physicochemical properties of the rock-oil-water system and allow for increased oil displacement efficiency and reservoir coverage.

2. Methodological part. Geological and physical characteristics of Azerbaijani fields in the final stages of development.

Major oil and gas regions. The key oil and gas regions of Azerbaijan include:

- 1) The Absheron oil and gas region.
- 2) The Baku Archipelago.
- 3) Nizhnekura Depression.
- 4) South Caspian Depression.

The fields of the Absheron Peninsula, such as Balakhany-Sabunchu-Ramany, Bibi-Heybat, and Surakhany, which are in the late stages of development, have been in production for over 100 years.

These fields are characterized by:

- 1) an oil recovery factor (ORF) of 0.28–0.38;
- 2) a water cut of up to 85–95%;
- 3) increasing permeability heterogeneity;
- 4) colmatation of the bottomhole zone.

Under these conditions, traditional pressure maintenance methods are insufficient, requiring the optimization of physical and chemical stimulation technologies.

Reservoir properties of formations. Typical geological and physical parameters of Azerbaijani fields are presented in Table 1.

Table 1

Reservoir characteristics of Azerbaijani fields
in the late stage of development

Parameter	Value range
Porosity, %	15–28
Permeability, mkm ²	0.05–0.8
Effective thickness, m	5–25
Formation temperature, °C	40–90
Formation water salinity, g/L	100–180
Oil viscosity, mPa·s	20–200

High reservoir heterogeneity and fractures result in uneven flow distribution during flooding and premature water breakthrough [1, 2].

Theoretical foundations of enhanced oil recovery. Filtration model.

Darcy's law of filtration rate:

$$v = \frac{k \Delta P}{\mu L}$$

where: k – is the permeability;
 μ – is the fluid viscosity;
 ΔP – is the pressure drop;
 L – is the filtration length.

With an increase in permeability from 120 to 190 mD after acid treatment:

$$\frac{v_2}{v_1} = \frac{190}{120} = 1.58$$

The increase in filtration capacity is $\approx 58\%$.

The oil recovery factor is determined by the expression:

$$K_{OR} = \frac{Q_{extr.}}{Q_{geol.}}$$

where: $Q_{extr.}$ – is the cumulative oil production;

$Q_{geol.}$ – is the geological reserves.

The increase in oil recovery during physicochemical treatment [3] can be estimated as:

$$\Delta K_{OR} = \frac{\Delta Q}{Q_{geol.}}$$

Incremental production is calculated as:

$$\Delta Q = (q_2 - q_1)t$$

where: q_1 – is the flow rate before treatment;

q_2 – is the flow rate after treatment;

t – is the effect period.

The formation recovery factor is determined by the expression:

$$K_{OR} = K_{displ.} \cdot K_{coverage}$$

where: K_{OR} – is the oil recovery factor;

$K_{displ.}$ – is the oil displacement factor;

$K_{coverage}$ – is the formation sweep efficiency.

Physicochemical methods of enhanced oil recovery (EOR) affect both factors, increasing both the efficiency of oil displacement from pore space and the degree of formation sweep by the working fluid.

Fluid mobility is determined by the formula:

$$\lambda = \frac{k_r}{\mu}$$

where: k_r – is the relative permeability;

μ – is the dynamic viscosity.

Water to oil mobility ratio:

$$M = \frac{\left(\frac{k_{rw}}{\mu_w} \right)}{\frac{k_{ro}}{\mu_o}}$$

Unfavorable displacement conditions are observed at $M > 1$, typical for most fields in the final stages of development.

Acidizing: calculating the optimal volume. Hydrochloric acid treatment is effective for terrigenous reservoirs in Azerbaijani fields [4÷7].

Acid volume:

$$V_{HCl} = \pi r^2 h \varphi \beta$$

where: r – is the penetration radius (m);

h – is the effective thickness (m);

φ – is the porosity;

β – is the reaction saturation coefficient.

Calculation example. Parameters:

$$r = 1.5 \text{ m}$$

$$h = 12 \text{ m}$$

$$\varphi = 0.22$$

$$\beta = 0.8$$

$$V = 3.14 \cdot (1.5)^2 \cdot 12 \cdot 0.22 \cdot 0.8$$

$$V \approx 14.9 \text{ m}^3$$

The optimal acid volume is 15 m³.

Table 2 shows the oil flow rates before and after treatment.

Table 2

Flow rate effect

Indicator	Before treatment	After treatment
Oil flow rate, tons/day	4.2	6.8
Water cut, %	88	80

Incremental production over 180 days:

$$\Delta Q = (6.8 - 4.2) \cdot 180 = 468 \text{ tons}$$

Polymer flooding. Physical principle of the method. Polymer flooding involves injecting aqueous solutions of high-molecular-weight polymers (most often polyacrylamides) into the reservoir, increasing the viscosity of the displacing agent and reducing its mobility [8].

Polymer flooding reduces water mobility. When using polymer systems, phase mobility is determined by the formula:

$$M = \frac{\lambda_w}{\lambda_o}$$

where: λ – is the phase mobility.

With the introduction of the polymer, water viscosity increases:

$$\mu'_w = \mu_w \cdot (1 + Ck)$$

C – is the concentration;

k – is the swelling coefficient.

Example: The initial viscosity of water is 1 mPa·s, the concentration is 0.15%, and the swelling coefficient is 6.

$$\mu'_w = 1 \cdot (1 + 0.15 \cdot 6) = 1.9 \text{ mPa} \cdot \text{s}$$

A 35% decrease in the water mobility coefficient is observed.

Surface-active agents (surfactants). The use of surfactants is aimed at reducing the interfacial tension between oil and water to values of approximately 10⁻³–10⁻⁴ mN/m, which ensures the mobilization of residual oil retained by capillary forces [9÷11].

Interfacial tension reduction:

$$\sigma = \sigma_0 \cdot e^{-kC}$$

At $\sigma_0 = 30 \text{ mN/m}$, $C = 0,3 \%$ and $k = 4$

$$\sigma = 30e^{-1.2} \approx 9 \text{ mN/m}$$

A 3.3-fold reduction in interfacial tension is observed.

Integrated technologies. The most promising for Azerbaijan are: ASP technologies; microbiological-chemical methods; adaptive flooding systems [12].

Combination: acid + surfactant, polymer + alkali. Additional recovery factor increase:

$$\Delta K_{OR} = 0.04 - 0.07$$

For a reservoir with reserves of 25 million tons: $\Delta Q = 25 \cdot 0.05 = 1.25$ million tons

Alkaline and ASP technologies. The essence of the ASP method. ASP technology combines the injection of alkali, surfactant, and polymer, providing simultaneous reduction in interfacial tension, changes in rock wettability, and control of displacement agent mobility [12].

Calculated data are presented in Table 3.

Table 3

Oil flow rate dynamics

Year	Before EOR, tons/day	After EOR, tons/day
1	3.2	5.8
2	3.0	5.6
3	2.8	5.4
4	2.5	5.2
5	2.3	5.0
6	2.1	4.8
7	1.9	4.6

Promising development directions. Digitalization of EOR: digital hydrodynamic models; machine learning for reagent selection; intelligent injection control.

Environmental aspects. The use of physical and chemical methods requires strict environmental safety monitoring, especially in the Caspian zone. Biodegradable polymers and microbiological technologies are considered the most promising.

Numerical hydrodynamic modeling. A two-phase model was used:

$$\begin{aligned} \frac{\partial}{\partial t}(\varphi S_o) + \nabla \cdot (v_o) &= 0 \\ \frac{\partial}{\partial t}(\varphi S_w) + \nabla \cdot (v_w) &= 0 \end{aligned}$$

The following boundary conditions should be considered:

- 1) constant injection rate;
- 2) isothermal system;
- 3) rock incompressibility.

The modeling results show:

- 1) an 18% increase in reservoir coverage;
- 2) a decrease in residual oil saturation from 0.32 to 0.24;
- 3) an increase in the final oil recovery factor from 0.34 to 0.41.

Optimization Algorithm

- 1) Geological and field analysis of the reservoir.
- 2) Laboratory modeling and core studies.
- 3) Selection of composition or reagents.
- 4) Volume and concentration calculation.
- 5) Hydrodynamic modeling.
- 6) Pilot implementation and processing.
- 7) Flow Rate and Water Cut Monitoring.

3. Results and discussion. Azerbaijani fields in the final stages of development have significant residual oil potential.

Physicochemical methods for enhanced oil recovery (EOR) are a key tool for achieving this goal.

Integrated application of these technologies allows for an increase in oil recovery by 10–15%. The introduction of EOR ensures the sustainable development of the country's oil industry.

Physicochemical treatments increase flow rates by 50–70%.

The implementation of combined reagent technologies is feasible at Azerbaijani fields, as they can additionally extract over 1 million tons of oil. The economic efficiency is positive with a duration of effect exceeding 6 months.

4. Conclusion. Physicochemical methods for enhanced oil recovery are the main tool for increasing the efficiency of Azerbaijani field development and represent a strategically important area for the development of the Azerbaijani oil industry. Their implementation requires a comprehensive approach, including laboratory research and pilot testing. It also ensures production growth, economic analysis, and the efficiency and environmental sustainability of Azerbaijan's mature fields.

With traditional reserves depleted, these technologies could become a key factor in the sustainable development of the country's oil industry.

Conflict of interest

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

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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
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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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Enhancing oil recovery in heterogeneous reservoirs with CO₂ flooding

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Abstract. This research explores the key challenges associated with CO₂-enhanced oil recovery (EOR), emphasizing the influence of fine-scale reservoir characteristics, viscous and interfacial dynamics, and dispersion effects driven by concentration gradients. The focus is on understanding how these microscale parameters affect oil extraction efficiency during CO₂ injection.

A series of simulation models reflecting different heterogeneity configurations was created and tested under varying pressure conditions, both above and below the Minimum Miscibility Pressure (MMP). A basic two-dimensional reservoir model was constructed as a compositional oil simulation using Eclipse 300. The grid comprises 100 cells along the x-axis and 20 cells along the z-axis, totaling 2000 cells. To replicate injection and production processes, two vertical wells were positioned at opposite ends of the model, fully penetrating the z-direction. This setup enables CO₂ to displace oil effectively from the injection well toward the production well.

Following 21 simulation runs, the findings indicated that when operating below the Minimum Miscibility Pressure (MMP), gravitational forces dominated the displacement process, leading to gas overriding oil, while permeability had a relatively minor influence. In contrast, at pressures above the MMP, viscous forces triggered fingering and premature breakthrough. All scenarios demonstrated enhanced oil recovery due to miscibility, with the kv/kh ratio emerging as a key parameter. Increased horizontal permeability, or simultaneous increases in both horizontal and vertical permeabilities, negatively affected recovery performance. Gas override was governed by both permeability directions, contributing to fingering in cases with randomly distributed permeability. Variations in horizontal permeability, even when vertical permeability remained constant, had the most pronounced effect on recovery efficiency. Moreover, the study highlighted that relying solely on the coefficient of variation (Cv) was insufficient to describe heterogeneity, as models sharing identical Cv values yielded recovery rates ranging from 62% to 95.9%.

The unique contribution of this study lies in its quantitative assessment of how reservoir heterogeneity influences CO₂-enhanced oil recovery (EOR). The results highlight the complex interplay between reservoir characteristics and CO₂ miscible flooding, providing valuable guidance for refining EOR approaches in heterogeneous formations.

Keywords: CO₂-enhanced oil recovery, Vertical permeability, Horizontal Permeability, Minimum Miscibility Pressure (MMP), Heterogeneous Reservoirs.

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1. Introduction. In recent decades, global oil production has surged in response to rising energy demand worldwide (Bello et al., 2023). To satisfy this growing need, various recovery techniques have been implemented to extract additional oil from mature and depleted reservoirs (Leonhard Ganzer et al., 2017). Despite the use of primary recovery methods that rely on natural reservoir energy and secondary techniques such as water flooding, a substantial volume of oil remains trapped within the fine pores of reservoir rocks. Enhanced Oil Recovery (EOR) technologies have long been employed to boost extraction efficiency and reduce residual oil saturation (Bello et al., 2023). The primary aim of EOR is to improve the mobility ratio between injected and displaced fluids, thereby enhancing sweep efficiency or modifying interfacial tension and capillary pressure (Xiao Deng et al., 2020). As a result, EOR continues to be recognized as a critical technological frontier in the petroleum sector (Mostafa Iravani et al., 2023).

Enhanced Oil Recovery (EOR) techniques are generally categorized into three main types: chemical, thermal, and miscible approaches (Alvarado and Manrique, 2010). Chemical EOR methods include polymer flooding, alkaline flooding, and surfactant flooding (Ragab and Mansour, 2021; Razman Shah et al., 2023). These techniques improve oil displacement by introducing specific chemicals into the injected water to alter fluid viscosity or modify interfacial properties, thereby achieving a more favorable mobility ratio (Pashapouryeganeh et al., 2022). Thermal EOR strategies

involve processes such as cyclic steam stimulation, steam flooding, and in-situ combustion (Antolinez et al., 2023). These methods utilize heat to lower oil viscosity (Pan et al., 2023), and in some cases, vaporize lighter hydrocarbon fractions into the gas phase, making the oil less dense and easier to mobilize (Zhao et al., 2020; 2021). Miscible EOR techniques rely on injecting substances like Liquefied Petroleum Gas (LPG), Nitrogen, or Carbon Dioxide (CO₂). Miscible displacement was defined as “*the displacement of oil by fluids with which it mixes in all proportions without the presence of an interface*” (Carcoana 1992).

CO₂ stands out as a highly effective agent in Enhanced Oil Recovery (EOR) due to its distinctive miscibility characteristics. As such, CO₂-EOR offers a dual advantage—boosting energy output while promoting environmental stewardship—making it a vital technology for optimizing resource extraction and reducing carbon emissions in the oil and gas sector (Fahad I. Syed et al., 2022). In aging reservoirs, traditional recovery methods often leave a considerable amount of oil trapped within the formation (Zhengxiao Xu et al., 2020). The injection of supercritical CO₂ into these reservoirs mobilizes the remaining oil through several key mechanisms (Jin et al., 2017). First, CO₂ dissolves into the oil, leading to expansion and reduced viscosity, which enhances its movement toward production wells. This process, known as “miscible displacement,” yields significantly higher recovery rates compared to water flooding. Second, CO₂ interacts with reservoir rock surfaces, modifying wettability and facilitating oil release. Additionally, CO₂-EOR provides further advantages: it serves as a long-term storage solution for captured CO₂, helping to mitigate greenhouse gas emissions, and adds economic value by revitalizing depleted oilfields (Abubakar Isah et al., 2022).

Deploying CO₂-EOR in mature oil reservoirs presents several challenges that can potentially compromise the feasibility of such projects (Pimenta et al., 2022). These obstacles include fine-scale reservoir characteristics, viscous and interfacial forces that influence fluid dynamics, and dispersion effects arising from concentration gradients between fluids (Mohamad Yousef Alklih et al., 2021). A key factor affecting reservoir performance during CO₂ injection is heterogeneity, which refers to the spatial variation in rock attributes such as porosity, permeability, facies distribution, and layer thickness (Ahmed, 2006). Such heterogeneities may lead to early CO₂ breakthrough, resulting in channeling and dispersion that hinder effective oil displacement and reduce project efficiency. Addressing these issues requires thorough reservoir evaluation, the use of sophisticated simulation tools, and detailed risk analysis (Muataz Alshuaibi et al., 2018). Professionals involved in CO₂-EOR must consider how heterogeneity influences fluid movement and recovery efficiency (Mohamad Yousef Alklih et al., 2019). Adjustments in injection strategies, well positioning, and operational settings may be necessary to overcome these limitations. Continued innovation and research in EOR technologies are essential for enhancing the effectiveness of CO₂-EOR, especially in aging oilfields (Seyedeh Hosna Talebian et al., 2014).

The primary objective of this research is to examine how fine-scale reservoir characteristics influence oil recovery during CO₂ injection. This includes replicating the slim tube experiments originally conducted by Holm and Josendal through high-resolution simulation models (Holm and Josendal, 1974). It is well established that CO₂ becomes miscible with oil in one-dimensional systems under sufficient pressure. However, actual reservoir formations are complex and exhibit heterogeneity, with fluid flow occurring in three dimensions. It remains unclear whether miscibility effects diminish or intensify under such conditions. Additionally, gravity override may cause CO₂ to bypass oil zones, limiting interaction and mixing. To identify the dominant factors affecting recovery, a range of models with varying static heterogeneity patterns has been developed. Sensitivity analyses have been performed to evaluate how reservoir heterogeneity impacts gas miscibility, oil recovery, and the role of the coefficient of variation in influencing recovery outcomes.

2. Methodology

2.1. Base Case Description. To investigate the influence of fine-scale geological features on CO₂-EOR performance, a basic 3D grid model was developed using the Eclipse reservoir simulator (E-300). The model spans dimensions of 10 m × 1 m × 2 m and comprises 2000 cells, each measuring 0.1 m × 0.1 m × 0.1 m, arranged as 100 cells along the x-axis and 20 cells along the z-axis. The reference case is a compositional oil model with uniform rock properties, detailed in Table A.1 of Appendix A. Fluid characteristics, including density and formation volume factors, were initially calculated using the Peng-Robinson equation of state for a seven-component reservoir fluid system (see Table A.2), while Table A.3 presents the oil-gas relative permeability curves. For simulating injection and production, two vertical wells were positioned—an injector at grid cell (1,1) and a producer at (100,1). Both wells were completed across all 20 layers to ensure vertical coverage, enabling CO₂ to displace oil from the injection point to the production well. The producer was set to operate at a minimum Bottom Hole Pressure (BHP) equal to the reservoir pressure (50 bar), which was later increased above the Minimum Miscibility Pressure (MMP). The injector was configured to deliver 1.2 pore volumes (PV) of CO₂ at a rate of 0.48 m³/day over a 12-hour period. Figure 1 illustrates the initial gas saturation distribution within the model.

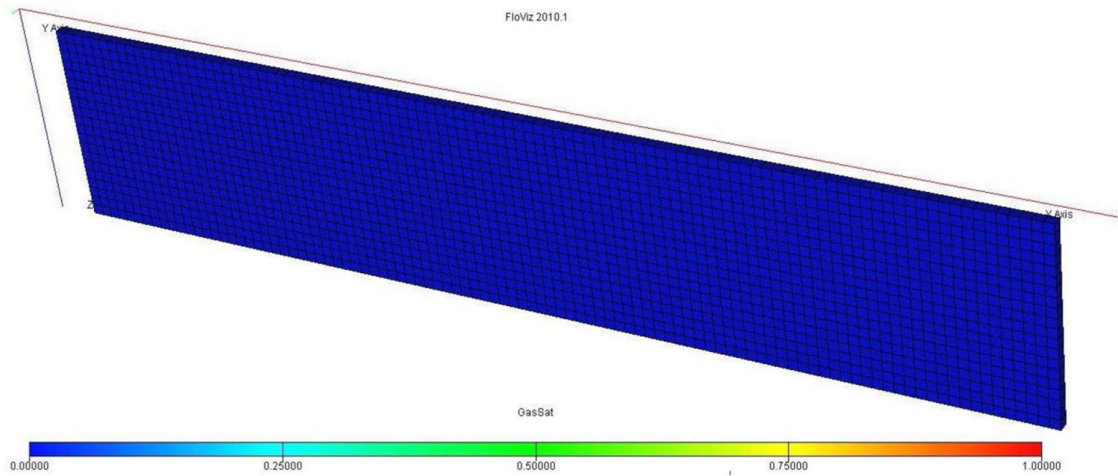


Figure 1. shows the initial gas saturation of the base case model (i.e., Model 1).

2.2. Scenarios Investigated. To evaluate the impact of reservoir heterogeneity, multiple scenarios were developed, each featuring distinct permeability distributions across the layers. Simulations were conducted at varying reservoir pressures ranging from 50 to 300 bars. Following this, 1.2 pore volumes (PV) of CO₂ were injected, and oil recovery was plotted against pressure to identify the Minimum Miscibility Pressure (MMP). Additionally, gas saturation patterns were analyzed at pressures both above and below the MMP. For every scenario, the coefficient of variation was computed, and oil recovery results were compared to a homogeneous reference model—designated as Model 1—which featured uniform horizontal and vertical permeabilities of 500 mD.

To assess the influence of anisotropy on CO₂ recovery, Models 2 through 4 were designed as homogeneous cases with varying kv/kh ratios. In these models, horizontal permeability was altered while vertical permeability remained fixed. Although the permeability values were uniform across all cells within each model, they varied between models. Notably, the kv/kh ratios in these three cases exceeded 1, which is relatively uncommon unless horizontal fissures or natural fractures are present. Conversely, Models 5 to 7 were developed to examine the impact of modifying vertical permeability while maintaining a constant horizontal permeability. It is important to highlight that in all six of these models, permeability values were consistent throughout each model but differed from one model to the next.

In a separate set of scenarios, Model 8 was designed with horizontal permeability increasing upward through the layers, while vertical permeability remained unchanged. Conversely, Model 9 featured vertical permeability that coarsened upward, with horizontal permeability held constant. In Model 10, both horizontal and vertical permeabilities were configured to coarsen upward simultaneously, resulting in isotropic conditions across each layer. To explore the impact of upward fining on CO₂-EOR performance, Models 11 through 13 were developed with grain sizes decreasing with height, leading to higher permeability at the base compared to the top of the model. Additionally, the influence of stratification on CO₂ recovery was examined by constructing models with alternating high and low permeability layers. For instance, Model 14 included layers of 500 mD and 100 mD, while Model 15 incorporated layers of 500 mD and 250 mD.

In an additional set of scenarios, Model 16 was configured with horizontal permeability randomly varying across layers, while vertical permeability remained unchanged. In contrast, Model 17 featured random variation in vertical permeability, with horizontal permeability held constant. The influence of diverse horizontal permeability values was further examined in Model 19, where these values were randomly assigned across layers, keeping vertical permeability fixed. Similarly, Model 20 utilized the same set of permeability values, but allowed variation in both horizontal and vertical directions. For Models 21 and 22, permeability was also randomly distributed among layers; however, each layer was isotropic, meaning horizontal and vertical permeabilities were equal. Table 1 provides a summary of the permeability configurations used across all models in this study.

Table 1. Summarizes the permeability distributions of all cases in this study.

Model No.	Horizontal Permeability Kh	Vertical permeability Kv	Kv/Kh ratio	Comments
1	500	500	1	Homogeneous
2	125	500	4	Homogeneous
3	250	500	2	Homogeneous
4	375	500	1,333	Homogeneous
5	500	125	0,25	Homogeneous
6	500	250	0,5	Homogeneous
7	500	375	0,75	Homogeneous
8	coarsening upward	500		
9	500	coarsening upward		
10	coarsening upward	coarsening upward		
11	fining upwards	500		
12	500	fining upwards		
13	fining upwards	fining upwards		
14	alternating layers of 500 and 100 mD	alternating layers of 500 and 100 mD		
15	alternating layers of 500 and 250 mD	alternating layers of 500 and 250 mD		
16	Random	500		
17	500	random		
18	Random	500		
19	Random	random		Isotropic
20	Random	random		Isotropic
21	Random	random		Isotropic

3.Results and Discussion

3.1. Investigation of Minimum Miscibility Pressure (MMP). The initial step involved determining the Minimum Miscibility Pressure (MMP) by running simulations for Models 2 through 14 under varying pressure conditions. Oil recovery was then plotted against pressure on a Cartesian scale after injecting 1.2 pore volumes (PV) over a 12-hour period. Models 2 to 4 were designed to assess the impact of reducing horizontal permeability relative to vertical permeability. As pressure increased, oil recovery improved until it stabilized around 175 bars, which was identified as the MMP. When these models were compared to the base case (Model 1), they exhibited a similar trend and the same MMP, indicating that a k_v/k_h ratio greater than 1 does not significantly influence recovery or MMP, as illustrated in Figure 2.a. In contrast, Models 5 through 7 explored the effect of lowering vertical permeability while keeping horizontal permeability constant, resulting in k_v/k_h ratios below 1. These models also showed increasing recovery with pressure until it leveled off at approximately 175 bars, reaffirming the MMP, as shown in Figure 2.b. Despite sharing the same MMP, the recovery rates varied among the models. A noticeable trend was that lower vertical permeability led to higher recovery. This is attributed to reduced vertical crossflow, which enhances horizontal displacement and improves sweep efficiency.

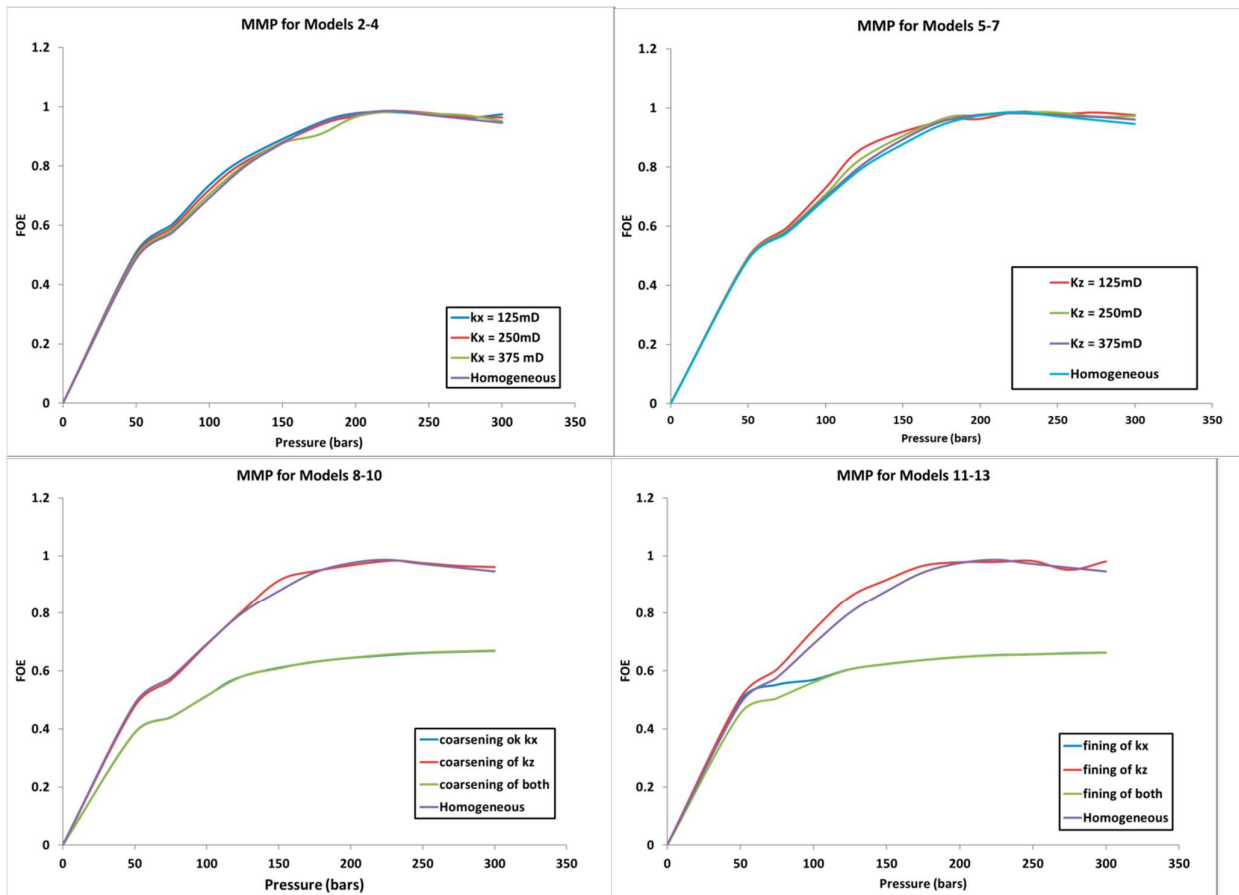


Figure 2. Shows the recovery versus pressure for a) Models 2-4, b) Models 5-8, c) Models 9-11, and d) Models 12-14.

Additionally, Models 8 through 10 were designed to examine the impact of upward coarsening in horizontal permeability, vertical permeability, and both simultaneously. Models 8 and 10 exhibited similar recovery trends with increasing pressure, identifying the Minimum Miscibility Pressure (MMP) within the range of 150 to 200 bars. These models also demonstrated lower recovery compared to Model 1 and Model 9, primarily because horizontal permeability was greater at the top of the reservoir than at the bottom. With vertical permeability held constant at 500 mD, increased

crossflow redirected fluid into upper layers, causing oil bypass and early CO₂ breakthrough. In contrast, Model 9 achieved higher recovery than Models 8 and 10, as its vertical permeability increased upward while horizontal permeability remained fixed at 500 mD, as illustrated in Figure 2.c. This configuration reduced vertical crossflow due to lower permeability at the base, promoting more effective horizontal displacement and improved sweep efficiency. Across all models, the MMP consistently fell between 150 and 200 bars, and was ultimately determined to be 175 bars.

Additionally, Models 12 to 14 were used to examine the impact of upward fining in horizontal permeability, vertical permeability, and both simultaneously. Upward fining refers to a permeability profile where values decrease from the bottom to the top of the model. In Model 12, oil recovery was notably high and closely matched that of the homogeneous base case. This is attributed to the lower vertical permeability at the top of the model, while horizontal permeability remained constant at 500 mD. As a result, vertical crossflow was minimized in the upper layers, allowing CO₂ to effectively sweep oil from those zones. Gravity also played a supportive role by promoting upward gas migration, enhancing sweep efficiency across most layers.

In contrast, Model 11, which featured only horizontal permeability fining upward and maintained vertical permeability at 500 mD, exhibited significantly lower recovery, as illustrated in Figure 2.d. This is because vertical permeability is much higher than horizontal permeability and so cross flow occurs, and flow is diverted into lower layers only keeping the top layers unswept. The same occurs with Model 13 since both horizontal and vertical permeability are both fining so flow is diverted into lower layers with higher permeability.

3.2. Effect of heterogeneity on gas saturation. The following figures illustrate gas saturation in each model after six hours of CO₂ injection. Simulations were conducted at two pressure levels—100 bars and 250 bars—to observe behavior before and after achieving miscibility. Figure 3 presents the gas saturation profile for the homogeneous case (Model 1) at both pressure conditions. At 100 bars, where miscibility has not yet been reached, gas flow is primarily governed by gravity, causing the lighter CO₂ to rise and override the oil. As pressure increases to 250 bars, approaching the Minimum Miscibility Pressure (MMP), the extent of gas override diminishes, eventually forming a more uniform displacement front.

Figure 4 displays the gas saturation in Model 3 after six hours of injection. Similar to the homogeneous case, gas movement below the MMP is dominated by gravity, with CO₂ rising due to its lower density relative to oil. However, once the MMP is attained, the fluids become miscible, their densities converge, and the degree of gas override is significantly reduced.

Moreover, the extent of gas override diminishes as horizontal permeability is reduced. This occurs because, with a constant injection rate, lower horizontal permeability leads to increased pressure at the injector. As a result, the displacement becomes more miscible due to the elevated pressure and reduced permeability. When comparing Figure 4 to Figure 3, it is evident that gas fingering at the top of the model is absent, unlike in the homogeneous case, and the gas distribution appears more uniform. A similar behavior is observed in Models 2 and 4. Figure 5 illustrates gas saturation in Model 6 at both pressure levels. Once again, the same trend is noted—at pressures below the MMP, gas rises due to its lower density, driven by gravity. As pressure increases, the degree of override gradually declines until a nearly uniform displacement front is established. It is also clear that decreasing vertical permeability reduces gas override, eventually resulting in a stable front, similar to scenarios with minimal crossflow.

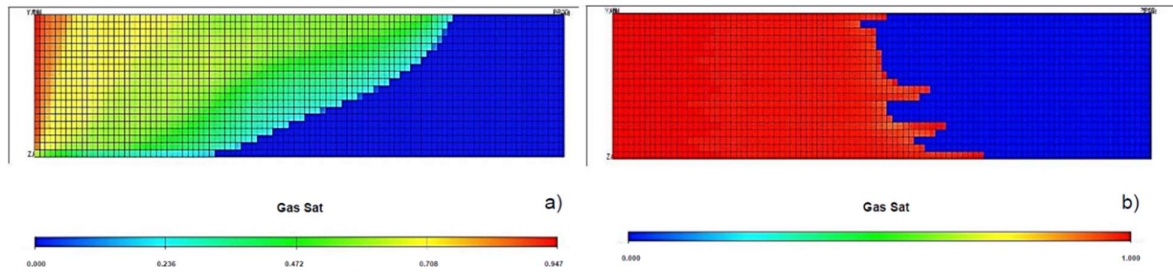


Figure 3. Shows gas saturation in Model 1 at a) 100 bars and b) 250 bars.

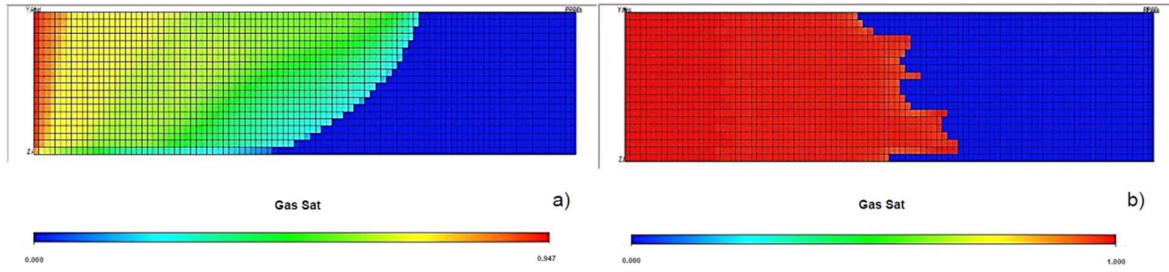


Figure 4. Shows gas saturation in Model 3 at a) 100 bars and b) 250 bars.

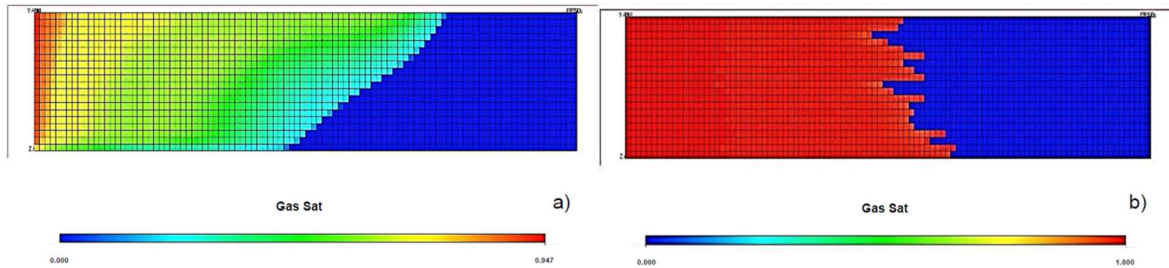


Figure 5. Shows gas saturation in Model 6 at a) 100 bars and b) 250 bars.

In Model 8, a significant degree of gas override is observed due to the natural tendency of gas to rise, driven by its lower density. This effect is further intensified by the high vertical permeability, which facilitates upward gas movement. As a result, the upper layers of the model exhibit nearly complete gas saturation, while the lower layers remain largely unswept. This behavior is consistent across all pressure levels but is more pronounced at pressures below the Minimum Miscibility Pressure (MMP). Figure 6 illustrates the gas saturation distribution in Model 8 at 100 and 250 bars.

Figure 7 presents the gas saturation for Model 10, where both horizontal and vertical permeabilities increase upward. Once again, gas override is evident, primarily due to the relatively low permeability at the base compared to the top layers. The low density of CO_2 contributes to its upward migration, and this pattern persists across all pressures, with a stronger effect observed below the MMP.

Figure 8 shows the gas saturation after six hours of injection in Model 12, which features upward fining of horizontal permeability—meaning the top layers have lower horizontal permeability than the bottom. This configuration causes the gas to slump downward. Although CO_2 naturally tends to rise, the limited horizontal permeability at the top restricts upward flow, and the higher vertical permeability redirects the gas downward. At pressures below the MMP, gas saturation spans more layers due to gravity-driven flow attempting to override, but being hindered by low permeability at the top. At or above the MMP, the flow becomes viscosity-dominated, allowing gas to move efficiently through the more permeable lower layers.

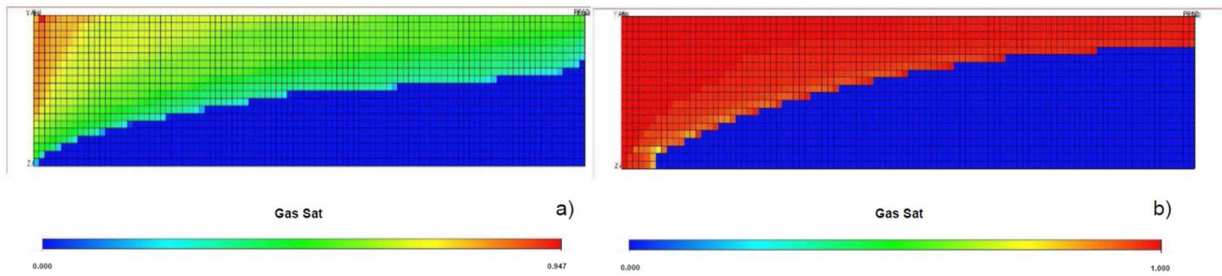


Figure 6. Shows gas saturation in Model 8 at a) 100 bars and b) 250 bars.

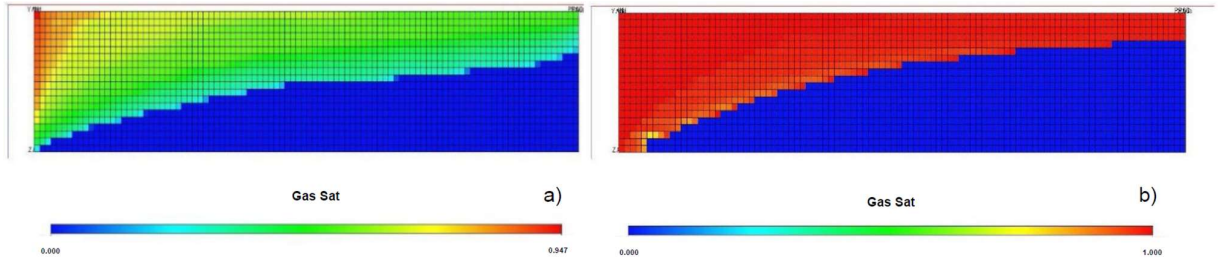


Figure 7. Shows gas saturation in Model 10 at a) 100 bars and b) 250 bars.

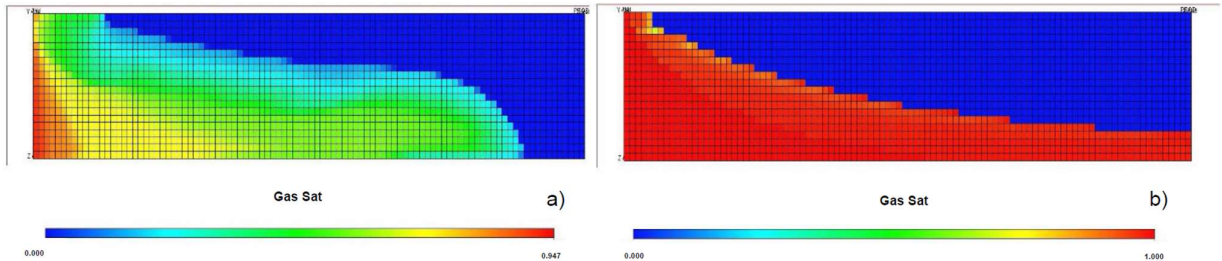


Figure 8. Shows gas saturation in Model 12 at a) 100 bars and b) 250 bars.

In Model 14, gas is observed to migrate downward due to the higher permeability at the bottom of the model compared to the top. Figure 9 illustrates the gas saturation profile for Model 14, where both horizontal and vertical permeabilities decrease upward. At pressures below the Minimum Miscibility Pressure (MMP), gas saturation spans a wide portion of the model, driven by the natural tendency of gas to rise because of its lower density. However, at elevated pressures, the flow becomes less influenced by gravity and instead follows the path of higher permeability, moving more rapidly into the lower layers.

Figure 10 presents the gas saturation in Model 15, which consists of uniform layers alternating between permeabilities of 500 mD and 100 mD. At pressures below the MMP, the stratification has minimal impact on the saturation profile, and gas override dominates, with early breakthrough occurring in the upper layers. Once the MMP is reached, the flow becomes viscosity-driven, and gas preferentially moves through the high-permeability layers, resulting in near-complete saturation in those zones and minimal saturation in the low-permeability layers—producing a fingering effect.

Figure 11 shows the gas saturation in Model 16 at pressures below, at, and above the MMP. Similar behavior to Model 15 is observed; however, the saturation in the lower-permeability layers is higher in Model 16 due to the smaller contrast in permeability values compared to Model 14.

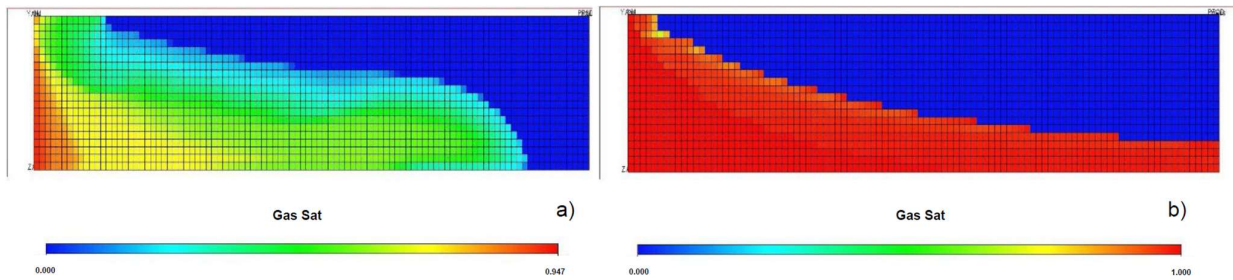


Figure 9. Shows gas saturation in Model 14 at a) 100 bars and b) 250 bars.

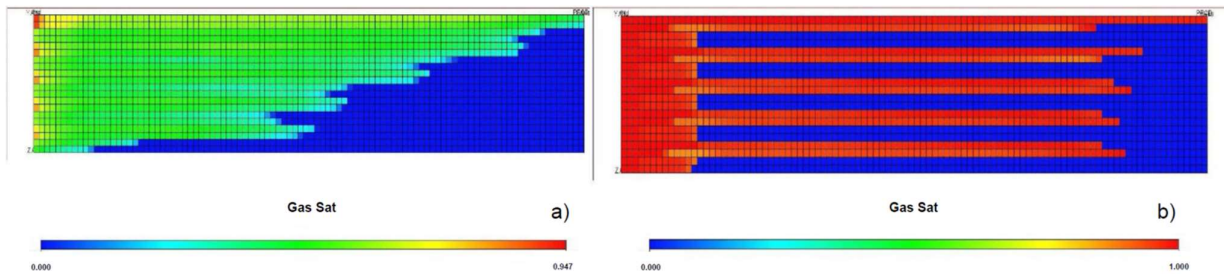


Figure 10. Shows gas saturation in Model 15 at a) 100 bars and b) 250 bars.

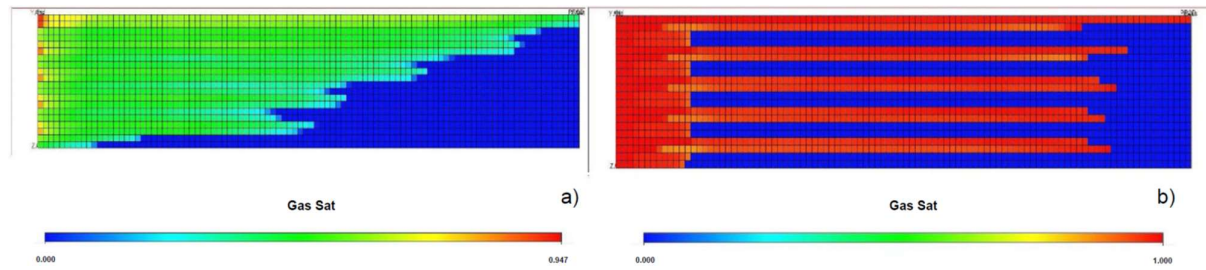


Figure 11. Shows gas saturation in Model 16 at a) 100 bars and b) 250 bars.

In Model 17, at a pressure of 100 bars, gas saturation extends across the entire model, exhibiting a near piston-like displacement. Figure 12 illustrates the gas saturation profile for this model, where horizontal permeability is randomly assigned to each layer, while vertical permeability remains fixed at 500 mD. Due to the reduced horizontal permeability and constant vertical permeability, gas tends to rise because of its lower density but is restricted from spreading laterally. At the Minimum Miscibility Pressure (MMP), gas override is no longer observed, and the flow becomes viscosity-dominated, favoring movement through high-permeability layers and bypassing others. This results in fingering and early breakthrough in those high-permeability zones.

Figure 13 displays the gas saturation for Model 19, where horizontal permeability varies randomly with depth, and vertical permeability is again held constant at 500 mD. At 100 bars, the flow is gravity-driven, with gas rising and overriding, leading to early breakthrough in the upper layers. As pressure increases, the override effect diminishes, and gas preferentially flows through the more permeable layers, causing fingering and early breakthrough in those zones.

Figure 14 presents the gas saturation for Model 20, which shares the same permeability values as Model 19, but allows variation in both horizontal and vertical directions. At lower pressures, gas override is less pronounced compared to Model 19, due to the presence of very low vertical permeability layers that inhibit crossflow. At MMP and above, the effect is the same as in Model 19, and the flow is viscous-dominated and moves through the high permeability layers faster.

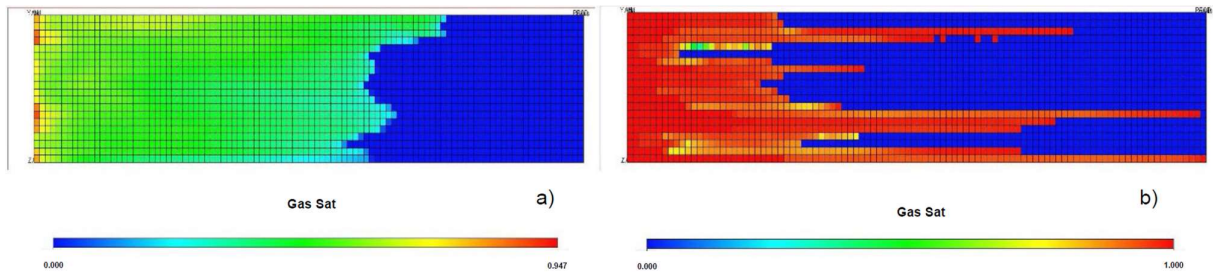


Figure 12. Shows gas saturation in Model 17 at a) 100 bars and b) 250 bars.

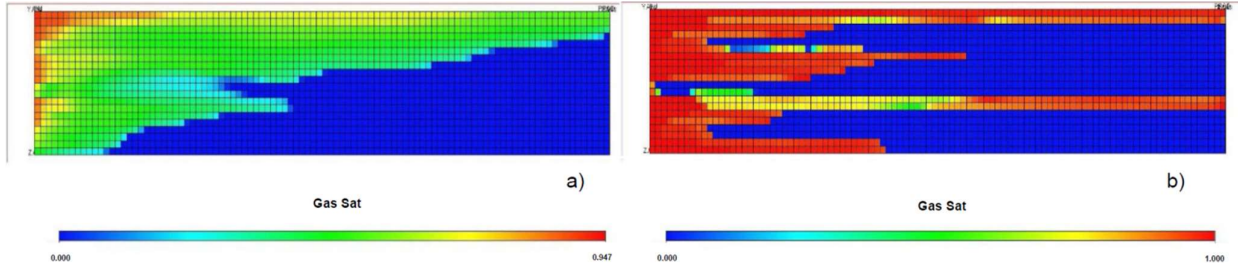


Figure 13. Shows gas saturation in Model 19 at a) 100 bars and b) 250 bars.

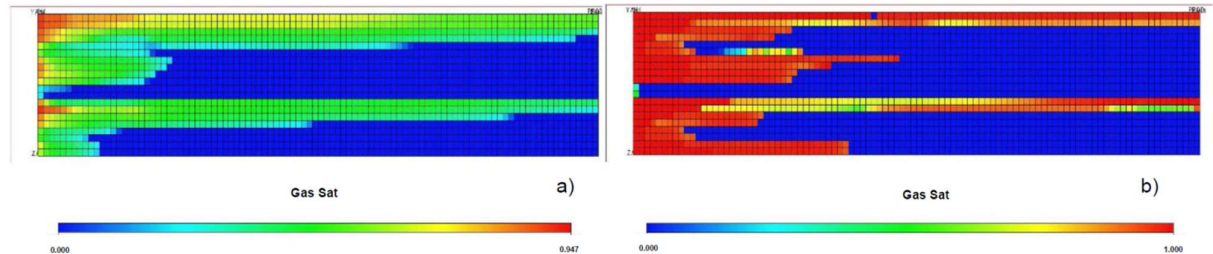


Figure 14. Shows gas saturation in Model 20 at a) 100 bars and b) 250 bars.

3.3. Effect of Heterogeneity on Oil Recovery. It has become evident that reservoir heterogeneity and fine-scale geological features significantly influence gas saturation patterns, thereby impacting overall oil recovery. Table 2 provides a summary of oil recovery results for each of the 22 models discussed earlier. Recovery values are recorded both before and at the Minimum Miscibility Pressure (MMP) following the injection of 1.2 pore volumes (PV) of CO₂. The improvement in recovery attributed to miscibility is also quantified. Additionally, the table includes the coefficient of variation for each scenario, serving as an indicator of the degree of heterogeneity present in the model.

It is evident that for the first eight models, oil recovery at the Minimum Miscibility Pressure (MMP) closely matches that of the homogeneous base case. Specifically, Models 2 to 4, which feature reduced horizontal permeability, yielded recovery rates comparable to the homogeneous model at MMP. In contrast, Models 5 to 7—where vertical permeability was decreased—exhibited a modest improvement in recovery, approximately 1–2% higher. These seven models have a coefficient of variation equal to zero, indicating uniform permeability across all layers. While the models are homogeneous in terms of permeability distribution, they differ in their kv/kh ratios, making them anisotropic. At pressures below the MMP, these models showed significantly lower recovery, with miscibility contributing to an approximate 22% increase in oil recovery.

It is observed that Model 9 achieves significantly higher oil recovery at the Minimum Miscibility Pressure (MMP) compared to Models 8 and 10. In Model 9, vertical permeability increases upward while horizontal permeability remains constant, resulting in reduced crossflow at the bottom and enhanced flow at the top, which contributes to improved recovery. In contrast, Models 8 and 10—where horizontal permeability was designed to coarsen upward—show notably lower recovery rates, around 63.1%. This indicates that upward coarsening of horizontal permeability has a

pronounced negative impact on recovery. Below the MMP, all three models follow a similar trend, though overall recovery is lower. Model 9 exhibits a 25% improvement in recovery due to miscibility, while Models 8 and 10 show only an 11% increase.

Table 2. Summary of Cv and oil recovery for each model

Model No.	Coefficient of variation (Cv)	Overall Oil Recovery (%) at MMP (175 bars)	Overall Oil Recovery (%) at 100 bars	Increase in oil Recovery due to miscibility (%)
1	0	94	69.2	24.8
2	0	94.6	73.6	21
3	0	93.6	72	21.6
4	0	94.4	70.4	24
5	0	95.6	72.8	22.8
6	0	96.2	70.7	25.5
7	0	95.4	69.9	25.5
8	0.44	63.1	51.4	11.7
9	0.44	94.7	69	25.7
10	0.44	63.1	51.4	11.7
11	0.44	63.6	56.9	6.7
12	0.44	96.5	74	22.5
13	0.44	63.8	56.1	7.7
14	0.56	84.5	51.6	32.9
15	0.28	70	55.2	14.8
16	0.54	76.3	59.3	17
17	0.54	95.7	59.6	36.1
18	0.79	70.7	56.6	14.1
19	0.79	61.5	47.2	14.3
20	0.65	65.5	59.2	6.3
21	0.34	77.6	68.4	9.2

Model 12 achieved a recovery of 96.5%, significantly higher than the 63.6% and 63.8% observed in Models 11 and 13, respectively. This enhanced performance is attributed to the upward fining of vertical permeability in Model 12, while horizontal permeability remained constant. In contrast, Model 11 featured upward fining of horizontal permeability with constant vertical permeability, and Model 13 had both horizontal and vertical permeabilities fining upward. At a pressure of 100 bars, the same recovery pattern was observed, albeit with lower values. Additionally, Model 12 showed a 22% improvement in recovery due to miscibility, whereas Models 11 and 13 exhibited only a 7% increase.

Models 14 and 15 consist of alternating layers with high and low permeability. Model 14 achieved an oil recovery of 84.5%, whereas Model 15 reached only 70%. This difference is attributed to the greater contrast in permeability in Model 14, which features layers of 500 mD and 100 mD, compared to Model 15's layers of 500 mD and 250 mD. Consequently, Model 14 has a coefficient of variation (Cv) of 0.56, while Model 15 has a lower Cv of 0.28. The higher recovery in Model 14 is due to the isotropic nature of the layers—where vertical and horizontal permeabilities are equal—resulting in reduced vertical flow and limited gas crossflow, thereby enhancing horizontal sweep efficiency. Additionally, Model 14 shows a greater improvement in recovery due to miscibility (32.9%) compared to Model 15, which exhibits only a 14.8% increase.

Models 16 and 17 were designed with randomly distributed permeability—Model 16 in the horizontal direction and Model 17 in the vertical. Model 16 yielded a significantly lower oil recovery of 76.3%, whereas Model 17 achieved a much higher recovery of 95.7%. This outcome highlights

that altering horizontal permeability while keeping vertical permeability constant leads to reduced recovery, as it promotes greater gas override. Consequently, more oil is bypassed, resulting in lower efficiency. This trend is consistent at pressures below the Minimum Miscibility Pressure (MMP) as well.

Model 18 achieved an oil recovery of 70.5%, notably higher than the 61.7% recorded for Model 19. Both models explored the impact of randomly distributed permeability; however, Model 18 featured random variation in horizontal permeability while maintaining a constant vertical permeability. In contrast, Model 19 had randomness in both horizontal and vertical directions, which contributed to its lower recovery. Despite the differences in configuration, both models experienced a similar improvement in recovery due to miscibility, with an increase of approximately 14%.

Models 20 and 21 exhibit different recovery outcomes—65.5% and 77.6%, respectively—despite both having randomly distributed permeability in both horizontal and vertical directions. The variation in recovery is attributed to the difference in their coefficient of variation (Cv), with Model 20 having a Cv of 0.65 and Model 21 a lower Cv of 0.34. Since Model 21 is more homogeneous, it achieves better recovery performance. However, the improvement in recovery due to miscibility is relatively modest for both cases, with Model 20 showing a 6.3% increase and Model 21 a 9.2% increase.

3.4. Effect of Coefficient of Variation on Recovery. To explore whether a correlation exists between the coefficient of variation (Cv) and oil recovery, a comparative analysis is conducted across the different models. For meaningful comparison, the models are categorized based on the direction in which permeability varies. This section evaluates the impact of modifying horizontal permeability alone, vertical permeability alone, and both simultaneously. As an illustration, Table 3 presents the recovery values at 175 bars along with the corresponding Cv for models where horizontal permeability was varied while vertical permeability remained constant at 500 mD.

Table 3. Oil recovery for variation in horizontal permeability

Model	Cv	Oil Recovery
8	0.44	63.1
11	0.44	63.6
16	0.54	76.3
18	0.79	70.7

Moreover, Table 4. shows the recovery and Cv for the models in which vertical permeability was made to vary and horizontal permeability was made constant at 500mD.

Table 4. Oil recovery for variation in vertical permeability

Model	Cv	Oil Recovery
10	0.44	94.7
13	0.44	96.5
18	0.54	95.7

Furthermore, Table 5. shows the recovery and Cv for the models in which both the horizontal and vertical permeability was made to vary simultaneously.

Table 5. Oil recovery for variation in both k_x and k_z

Model	Cv	Oil Recovery
11	0.44	63.1
14	0.44	63.8
15	0.56	84.5
16	0.28	70
20	0.79	61.5
21	0.65	65.5
22	0.34	77.6

4. Conclusions. Knowing what happens to the flow of CO₂ and hydrocarbon in the presence of fine-scale geological structures is important to determine the amount of CO₂ needed and how much hydrocarbon will be recovered. Understanding whether the flow is viscous-dominated or gravity-dominated could give some economic indications on the project and prevent the bypass of valuable oil. After running 21 models and analyzing the different outputs, the following were concluded:

1. The MMP for all models was found to be between 150 bars and 200 bars and was taken to be 175 bars. At pressures below the MMP, flow tends to be gravity-dominated and is affected mostly by gravity and less by permeability and tends to override. At pressures higher than the MMP, the oil and gas become one phase and the flow is viscous-dominated and takes the path of least resistance or highest permeability first. As a result, fingering occurs, and early breakthroughs occur in these layers.

2. All models show an increase in recovery due to miscibility. Having a k_v/k_h ratio greater than unity does not affect oil recovery and yields a similar recovery as that of the homogeneous. On the other hand, having k_v/k_h ratio less than unity affects oil recovery. As the ratio decreases, the recovery increases, with the best recovery being at $k_v=0$ (i.e., no cross flow).

3. Coarsening of the vertical permeability only does not have significant effect on oil recovery but the coarsening of the horizontal or both horizontal and vertical permeabilities reduces recovery greatly. Also, fining of vertical permeability does not affect oil recovery but fining of either horizontal permeability or both reduces recovery by a great amount.

4. The degree of gas override increases or decreases depending on both horizontal and vertical permeability. For example, having random permeability distribution distorts the flood front and causes fingering and the effect of gas override diminishes.

5. The variation of horizontal permeability has the most effect on oil recovery, regardless of whether vertical permeability is constant or varying as well. However, the coefficient of variation cannot be used alone as a measure of heterogeneity in CO₂ flooding, since two models with the same Cv value can yield different recoveries. No relation between Cv and recovery could be determined from the current available data.

Conflict of interest

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

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Appendix A

Table A.1: Component Fluid Properties

Component	Critical Temperature (K)	Critical Pressure (bars)	Acentric Factor	Molecular Weights	Boiling Points (K)	Initial oil Composition
CO ₂	304.2	72.80	0.225	44.010	194.7	0.0118
N ₂ -CH ₄	189.67	45.24	0.0084	16.208	113.656	0.1170
C ₂ -NC ₄	338.44	41.92	0.1481	44.793	259.432	0.1945
IC ₅ -C ₇	556.92	31.31	0.2485	83.458	340.618	0.2202
C ₈ -C ₁₂	667.51	23.86	0.3279	120.524	415.671	0.2815
C ₁₃ -C ₁₉	769.00	17.23	0.5672	210.743	543.642	0.0940
C ₂₀ -C ₃₀	801.51	11.9	0.9422	401.926	735.01	0.0809

Table A.2: Reservoir Properties data

Parameter	Value	Units
Porosity	0.1	-
Permeability in the x-direction	500	mD
Permeability in the z-direction	500	mD
Rock Compressibility	5x10-5	Bars-1
Temperature	53	C
Capillary Pressure	0	Bars
Wellbore Diameter	0.02	m
CO ₂ injection rate	0.48	m ³ /day

Table A.3: Relative permeability

Sg	Krg	Krog	Pc
0	0	1	0
0.02	0	1	0
0.045	9.21E-05	0.8538	0
0.07	0.000642	0.7233	0
0.095	0.002	0.6076	0
0.12	0.0045	0.5056	0
0.145	0.0084	0.4164	0
0.17	0.0139	0.3388	0
0.195	0.0214	0.2721	0
0.22	0.0312	0.2152	0
0.245	0.0433	0.1673	0
0.27	0.0582	0.1275	0
0.295	0.076	0.0948	0
0.32	0.097	0.0686	0
0.345	0.1214	0.048	0
0.37	0.1494	0.0321	0
0.395	0.1813	0.0204	0
0.42	0.2172	0.0121	0
0.445	0.2574	0.0065	0
0.47	0.302	3.05E-03	0
0.495	0.3514	1.15E-03	0
0.52	0.4057	2.89E-04	0
0.545	0.4651	0	0
0.57	0.5298	0	0
0.595	0.6001	0	0
0.62	0.6761	0	0
0.645	0.758	0	0
0.67	0.846	0	0
0.71	1	0	0
0.77	1	0	0
0.83	1	0	0

Table A.4 Permeability distribution for models 2-4

Model no.	Horizontal permeability (mD)	Vertical permeability (mD)	Kv/kh ratio
2	125	500	4
3	250	500	2
4	375	500	1.333

Table A.5: Permeability distribution for models 5-7

Model no.	Horizontal permeability (mD)	Vertical permeability (mD)	Kv/kh ratio
5	500	125	0.25
6	500	250	0.5
7	500	375	0.75

Table A.6: Permeability distribution for model 8

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	450	500
3	400	500
4	350	500
5	300	500
6	250	500
7	200	500
8	150	500
9	100	500
10	50	500

Table A.9: Permeability distribution for model 11

Table A.7: Permeability distribution for model 9

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	500	500
3	40	500
4	350	500

Table A.8: Permeability distribution for model 10

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	450	450
3	400	400
4	350	350
5	300	300
6	250	250
7	200	200
8	150	150
9	100	100
10	50	50

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	50	500
2	100	500
3	150	500
4	200	500
5	250	500
6	300	500
7	350	500
8	400	500
9	450	500
10	500	500

5	500	300
6	500	250
7	500	200
8	500	150
9	500	100
10	350	50

Table A.10: Permeability distribution for model 12

Table A.12: Permeability distribution for model 14

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	50
2	500	100
3	500	150
4	500	200
5	500	250
6	500	300
7	500	350
8	500	400
9	500	450
10	500	500

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	100	100
3	500	500
4	100	100
5	500	500
6	100	100
7	500	500
8	100	100
9	500	500
10	100	100

Table A.11: Permeability distribution for model 13

Table A.13: Permeability distribution

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	50	50
2	100	100
3	150	150
4	200	200
5	250	250
6	300	300
7	350	350
8	400	400
9	450	450
10	500	500

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	250	250
3	500	500
4	250	250
5	500	500
6	250	250
7	500	500
8	250	250
9	500	500
10	250	250

Table A.14: Permeability distribution for model 16

Table A.15: Permeability distribution for model 17

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	150
2	500	300
3	500	50
4	500	200
5	500	100
6	500	200
7	500	400
8	500	250
9	500	50
10	500	500

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	150	500
2	300	500
3	50	500
4	200	500
5	100	500
6	200	500
7	400	500
8	250	500
9	50	500
10	500	500

Table A.16: Permeability distribution for model 18

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	200	200
3	65	65
4	250	250
5	180	180
6	10	10
7	800	800
8	150	150
9	60	60
10	200	200

Table A.17: Permeability distribution for model 19 Table A.18: Permeability distribution for model 20

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	500	500
2	200	500
3	65	500
4	250	500
5	180	500
6	10	500
7	800	500
8	150	500
9	60	500
10	200	500

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	46	46
2	656	656
3	200	200
4	365	365
5	789	789
6	365	365
7	62	62
8	200	200
9	652	652
10	50	50

Table A.19: Permeability distribution for model 21

Layer no.	Horizontal Permeability (mD)	Vertical Permeability (mD)
1	250	250
2	220	220
3	500	500
4	320	320
5	700	700
6	400	400
7	200	200
8	300	300
9	500	500
10	600	600

Hybrid AI-assisted multi-criteria optimization of horizontal well trajectories under representative Caspian offshore conditions

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Abstract. A hybrid artificial-intelligence workflow is proposed for multi-criteria optimization of a horizontal well trajectory and its drilling set-points under representative Caspian offshore conditions. The method combines a physics-based trajectory generator, engineering indicators for dogleg severity, mechanical specific energy, drilling time, effective target contact and screening-level operational risk, an extremely randomized trees surrogate, and a weighted composite-objective search. A transparent synthetic case with a target true vertical depth of 3200 m, a landing departure of 2200 m, a 20 m productive interval and a 3° reservoir dip was evaluated. The surrogate was trained on 10,000 Latin-hypercube designs and used to screen 180,000 additional combinations within predefined engineering bounds. For the independent test set, the coefficient of determination for the penalized composite objective was $R^2 = 0.996$ and the mean absolute error was 0.104 objective units. Relative to the conventional reference design, the verified optimized solution reduced measured depth by 1.1%, maximum dogleg severity by 32.0%, mechanical specific energy by 20.9%, estimated drilling time by 26.0% and the integrated screening risk index by 16.6%. Predicted rate of penetration increased by 33.7%, while effective in-zone contact increased by 57.5%. The results are illustrative outputs of a reproducible synthetic model rather than disclosed field-performance data. The workflow is intended as an engineering decision-support layer that screens feasible alternatives and updates recommendations from MWD/LWD information while retaining expert control.

Keywords: artificial intelligence; horizontal well; well trajectory; geosteering; multi-criteria optimization; drilling optimization.

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1. Introduction. Horizontal wells increase reservoir contact, improve drainage of laterally heterogeneous intervals and allow offshore accumulations to be developed from a limited number of platform slots. Their benefit depends directly on trajectory quality. A geometrically short path may still be unacceptable if it produces excessive dogleg severity, high mechanical loading, poor hole cleaning or insufficient target exposure. Conversely, an overly conservative path may increase measured depth, drilling time and cost without improving useful reservoir contact [1, 2].

Trajectory planning is therefore a multi-criteria engineering problem. The planned path must reach the geological target, remain inside a defined drilling corridor, satisfy the maximum dogleg-severity limit and provide acceptable mechanical and hydraulic operating conditions. Within the reservoir, the lateral must follow the local dip and be updated when MWD/LWD information changes the interpreted formation boundary. Figure 1 presents the principal well architectures used as planning context; the numerical study reported here is restricted to a single horizontal well.

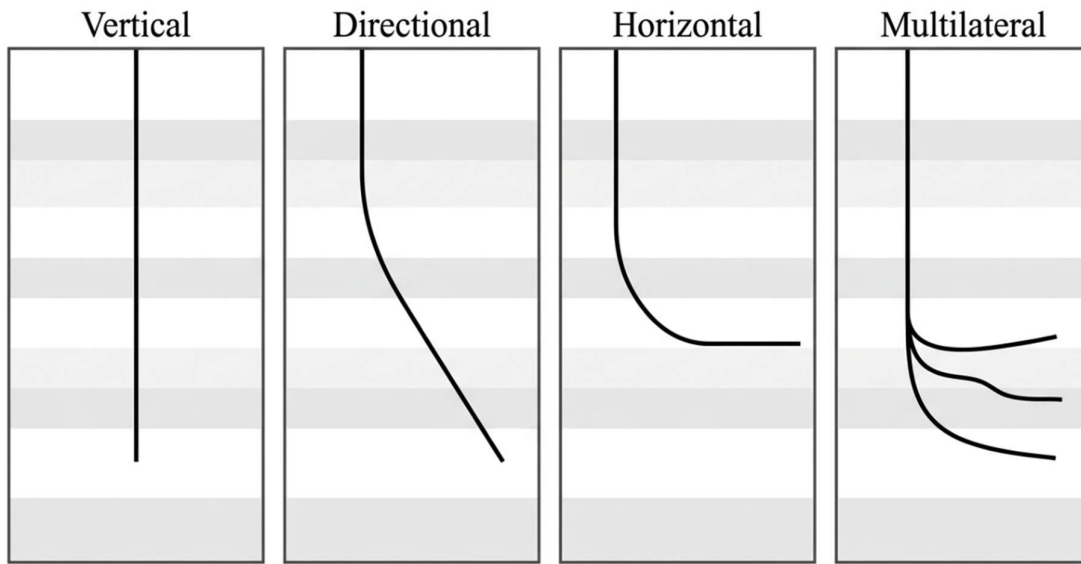


Figure 1. Representative well architectures considered during trajectory planning

Classical trajectory design relies on deterministic survey calculations, engineering constraints and the experience of the directional-drilling team. The minimum-curvature method remains the standard basis for survey reconstruction [2], while mechanical specific energy (MSE) is widely used to relate drilling inputs to rock-removal efficiency [3, 4]. Optimization methods have also been applied to trajectory length, torque, drag, buckling and operational risk [5, 6]. Their repeated application becomes computationally expensive when a large number of geological and operating combinations must be screened.

Artificial intelligence can reduce this computational burden by learning a surrogate of the engineering model inside a predefined design space. Data-driven planners have been used to adapt trajectories to reservoir geometry [7], and real-time AI-assisted geosteering has been investigated using LWD information [8]. Deep reinforcement learning and automated horizon interpretation have further extended trajectory-control research [9–14]. Nevertheless, an AI recommendation is acceptable only when it satisfies explicit engineering constraints and can be checked by the drilling team.

The objective of this study is to develop a transparent surrogate-assisted workflow for optimizing a horizontal well trajectory and drilling set-points under representative Caspian offshore conditions. The case is deliberately synthetic and fully methodological: it does not disclose or reproduce operating data from a specific field. The emphasis is on numerical consistency, constraint handling and human-in-the-loop implementation.

2. Methodological part. The workflow integrates trajectory geometry, operating-parameter selection, target contact and screening-level risk assessment in one closed optimization cycle. Geological and geomechanical information defines the target and exclusion zones; trajectory and BHA limits define constructability; historical and real-time drilling data define the operating envelope; the AI surrogate evaluates candidate combinations; and all shortlisted solutions are recalculated with the original engineering model before a recommendation is issued.

Hybrid AI-assisted trajectory optimization workflow

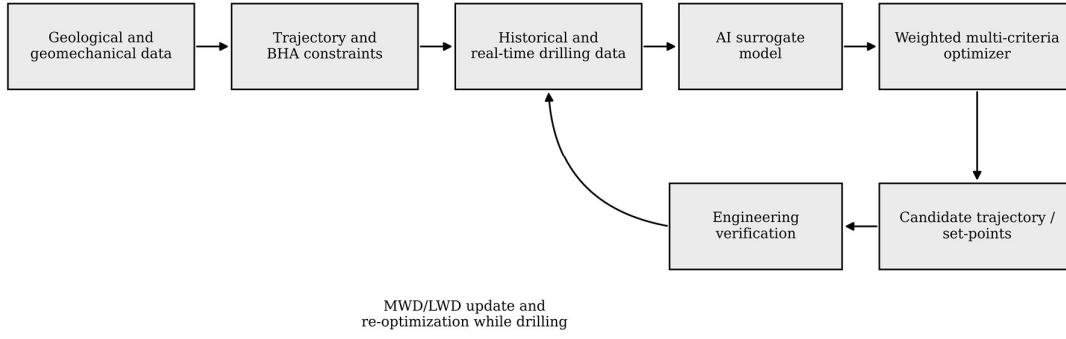


Figure 2. Hybrid AI-assisted trajectory optimization workflow

Trajectory representation and engineering constraints

The well path is represented by a smooth three-dimensional centerline. The build-and-land section is controlled by two engineering lengths, L_1 and L_2 , measured along the initial and terminal tangents of the parametric trajectory. For numerical reconstruction and plotting, the calculated survey-control stations are connected by shape-preserving cubic interpolation, which prevents oscillation and preserves monotonic depth increase. The reservoir section is described by lateral inclination, azimuth correction and lateral length. The eight decision variables are L_1 , L_2 , lateral inclination, lateral length, weight on bit (WOB), rotary speed, flow rate and azimuth correction.

Dogleg severity was calculated between adjacent survey stations from the minimum-curvature relationship:

$$DLS = \frac{30}{\Delta MD} \cos^{-1}[\cos I_1 \cos I_2 + \sin I_1 \sin I_2 \cos(A_2 - A_1)] \quad (1)$$

where I_1 and I_2 are the inclinations at two adjacent stations, A_1 and A_2 are their azimuths, and ΔMD is the measured-depth interval. The factor 30 scales the dogleg angle to degrees per 30 m; the inverse-cosine result is expressed in degrees. Survey stations were evaluated at 30 m measured-depth intervals. The hard constraint was $DLS \leq 3^\circ/30 \text{ m}$.

The target centerline was defined by a true vertical depth of 3200 m at a horizontal departure of 2200 m and a reservoir dip of 3° downward in the preferred drainage direction. The target window had a total thickness of 20 m. The target-contact coefficient was defined as $C_t = L_{in}/L_{lat}$, where L_{in} is the lateral length located inside the target window and L_{lat} is the nominal lateral length. Two elliptical exclusion zones represented a gas-prone interval and a mechanically weak interval. For zone j , normalized clearance was defined as $c_j = d_j/r_j$, where d_j is the minimum trajectory-to-zone distance in the normalized ellipse metric and r_j is the corresponding boundary value. Feasible solutions required $c_j > 1$.

Mechanical efficiency and synthetic operating response

Mechanical specific energy was calculated in SI units as:

$$MSE = \frac{WOB}{A_b} + \frac{2\pi NT}{A_b v} \quad (2)$$

where A_b is the bit area, N is rotary speed in revolutions per second, T is bit torque and v is rate of penetration in metres per second. A bit diameter of 0.216 m was used. Before substitution, $N = \text{RPM}/60$ and $v = \text{ROP}/3600$. Before substitution, WOB was converted from kN to N and torque

from kN·m to N·m. For the synthetic case, bit torque was generated by $T = 1.9484 + 0.010581(\text{WOB} - 90) + 0.003(\text{RPM} - 100) + 0.15\text{DLS}$, with T in kN·m, WOB in kN and DLS in degrees/30 m.

The ROP response was intentionally defined as a bounded synthetic surface rather than a field-calibrated correlation. The normalized variables were $w = (\text{WOB} - 90)/55$, $n = (\text{RPM} - 100)/60$, $q = (Q - 28.5)/6$, $d = \text{DLS}/3$, $a = |\Delta A|/5$ and $p_c = \max(c_j^{-2})$. The illustrative ROP model was:

$$\text{ROP} = 15.17 + 7.44w + 4n + 4q - 3w^2 - 2n^2 - 2d^2 - 1.5a^2 - 2p_c c \quad (3)$$

where ROP is in m/h. The negative quadratic terms prevent unlimited improvement when WOB or RPM is increased. The model is used only to compare candidates inside the bounds of Table 1 and must not be interpreted as a transferable field ROP correlation.

The operational screening index combined a hole-cleaning component and a stability/trajectory component:

$$R = 0.60R_{hc} + 0.40R_{st} \quad (4)$$

The hole-cleaning component R_{hc} was obtained by min-max normalization over the generated candidate set of $(\text{ROP}/Q)(1 + 2\sin^2 I)$. The stability/trajectory component R_{st} was the min-max normalized value of $(\text{DLS}/\text{DLS}_{lim})^2 + (\Delta A/A_{max})^2 + (1 - C_t)^2 + \max(c_j^{-2})$. Both components therefore lie between 0 and 1. The index is a comparative screening measure and does not replace a detailed hydraulics, wellbore-stability or anti-collision calculation.

AI surrogate and weighted multi-criteria search

A database of 10,000 candidate designs was generated by Latin hypercube sampling within the engineering bounds in Table 1. Each candidate was evaluated with the exact synthetic geometry and operating model. An extremely randomized trees ensemble with 400 trees, a minimum leaf size of 2 and a fixed random seed of 42 was trained to predict the penalized composite objective from the eight decision variables. Eighty percent of the cases were used for training and 20% for testing. The surrogate was used only for interpolation inside the predefined bounds.

For every minimized quantity x , the normalized component was

$$f_x = \frac{x - x_{min}}{x_{max} - x_{min}}$$

using the minimum and maximum values of the 10,000-case design database. Target-contact loss was represented by $1 - C_t$. The composite objective was:

$$J = 0.11f_{MD} + 0.14f_{DLS} + 0.16f_{MSE} + 0.15f_t + 0.22f_R + 0.22(1 - C_t) + P \quad (5)$$

The penalty was

$$P = 10 \left[\max \left(0, \frac{\text{DLS}}{\text{DLS}_{lim}} - 1 \right)^2 + \sum_j \max(0, 1 - c_j)^2 + \max(0, C_{min}^2 - C_t) + \max \left(0, \frac{|\Delta A|}{A_{max}} - 1 \right)^2 \right]$$

The minimum target-contact coefficient was $C_{min} = 0.50$ and $A_{max} = 5^\circ$. The weights sum to 1.00 and are listed in Table 2.

The trained surrogate screened 180,000 additional combinations. The 120 candidates with the lowest predicted objective values were recalculated with the exact model, and the best verified candidate was refined by differential evolution in a narrow neighbourhood. This two-stage procedure prevents the optimizer from exploiting local surrogate errors and ensures that the reported solution satisfies the original model.

3. Results and discussion. The surrogate reproduced the nonlinear penalized objective with high accuracy inside the sampled design space. For the independent test set, $R^2 = 0.996$ and $\text{MAE} = 0.104$ objective units. Figure 3 compares predicted and exact values. The largest deviations occurred

for strongly penalized infeasible cases, whereas the feasible low-objective region controlling the engineering decision remained close to the one-to-one line.

Table 1

Parameter	Range or value	Role in the model
Target true vertical depth, m	3200	Landing depth
Horizontal departure to landing, m	2200	Geometric target
Productive interval thickness, m	20	Target window
Reservoir dip, degrees	3	Preferred lateral direction
Bit diameter, m	0.216	MSE calculation
First control length L_1 , m	950–2100	Build-section shape
Second control length L_2 , m	650–1500	Landing smoothness
Lateral inclination, degrees from vertical	85.5–89.5	Target tracking
Lateral length, m	1200–1500	Reservoir contact
WOB, kN	90–145	Drilling load
Rotary speed, rpm	100–160	Rotational input
Flow rate, L/s	28.5–34.5	Screening hydraulics
Azimuth correction, degrees	–5 to +5	Drainage direction
Maximum DLS, degrees/30 m	3.0	Hard constraint
Minimum normalized clearance	1.0	Hard constraint

Table 2

Objective component	Weight	Optimization direction
Measured depth	0.11	Minimize
Maximum dogleg severity	0.14	Minimize
Mechanical specific energy	0.16	Minimize
Estimated drilling time	0.15	Minimize
Integrated screening risk	0.22	Minimize
Target-contact loss	0.22	Minimize

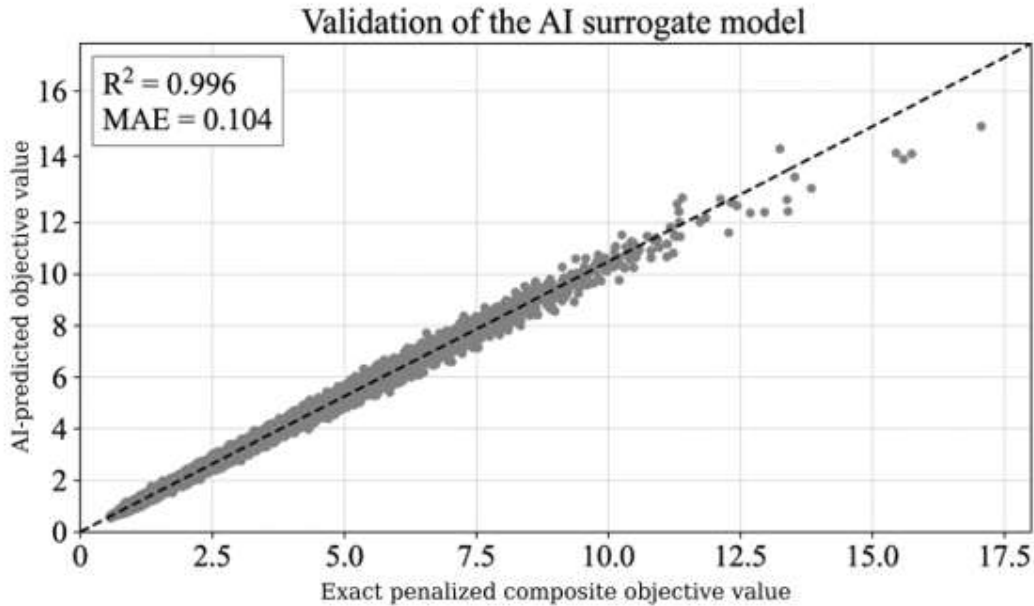


Figure 3. Validation of the AI surrogate against exact penalized composite-objective calculations.

Optimized trajectory and drilling parameters

The conventional reference design used $L_1 = 1350$ m, $L_2 = 1250$ m, a lateral inclination of 87.75° from vertical, a lateral length of 1350 m, WOB = 108 kN, rotary speed = 118 rpm, flow rate = 30.0 L/s and an azimuth correction of 3.0° . The verified optimized design used $L_1 = 1680$ m, $L_2 = 980$ m, a lateral inclination of 87.00° from vertical, a lateral length of 1200 m, WOB = 143.1 kN, rotary speed = 110.0 rpm, flow rate = 34.5 L/s and an azimuth correction of 0.2° .

The geometric effect is shown in Fig. 4. The conventional trajectory passed closer to both exclusion zones and followed a 2.25° downward lateral, whereas the optimized trajectory followed the 3° target centerline. The conventional path therefore remained inside the 20 m target window for approximately 762 m before leaving through the upper boundary. The optimized 1200 m lateral remained inside the target for its full displayed length. Figure 4 is a vertical-section reconstruction from the verified survey-control stations.

Table 3

Decision variable	Conventional design	AI-optimized design
First control length L_1 , m	1350	1680
Second control length L_2 , m	1250	980
Lateral inclination, degrees from vertical	87.75	87.00
Lateral length, m	1350	1200
WOB, kN	108.0	143.1
Rotary speed, rpm	118	110
Flow rate, L/s	30.0	34.5
Azimuth correction, degrees	3.0	0.2

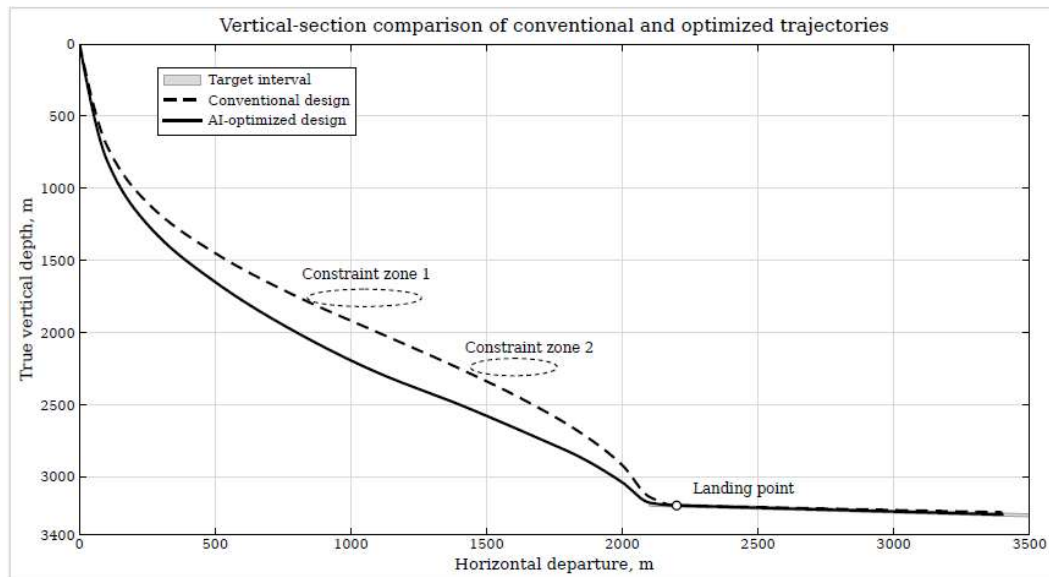


Figure 4. Vertical-section comparison of the conventional and AI-optimized trajectories.

The maximum dogleg severity decreased from 1.28 to $0.87^\circ/30$ m, while measured depth decreased by 1.1%. The main geometric gain was therefore improved smoothness and target placement rather than unrealistic shortening of the well. Effective target contact increased from 762 to 1200 m even though the nominal lateral length decreased by 11.1%.

Table 4

Indicator	Conventional design	AI-optimized design	Relative change, %
Measured depth, m	5557	5497	−1.1
Maximum DLS, degrees/30 m	1.28	0.87	−32.0
Target exposure, %	56.4	100.0	+77.3
Effective target contact, m	762	1200	+57.5
Predicted ROP, m/h	17.8	23.8	+33.7
Synthetic bit torque, kN·m	2.38	2.67	+12.2
MSE, MPa	165.6	130.9	−20.9
Estimated drilling time, h	311.5	230.5	−26.0
Integrated screening risk index	0.313	0.261	−16.6

The optimized operating point increased the synthetic ROP from 17.8 to 23.8 m/h. Although WOB increased, the combined effect of a smoother path, moderate rotary speed, higher flow rate and lower proximity penalty reduced MSE from 165.6 to 130.9 MPa. Estimated drilling time decreased by 81.0 h. Within the screening model, the higher flow rate and lower trajectory severity also reduced the normalized hole-cleaning and stability components of the integrated risk index.

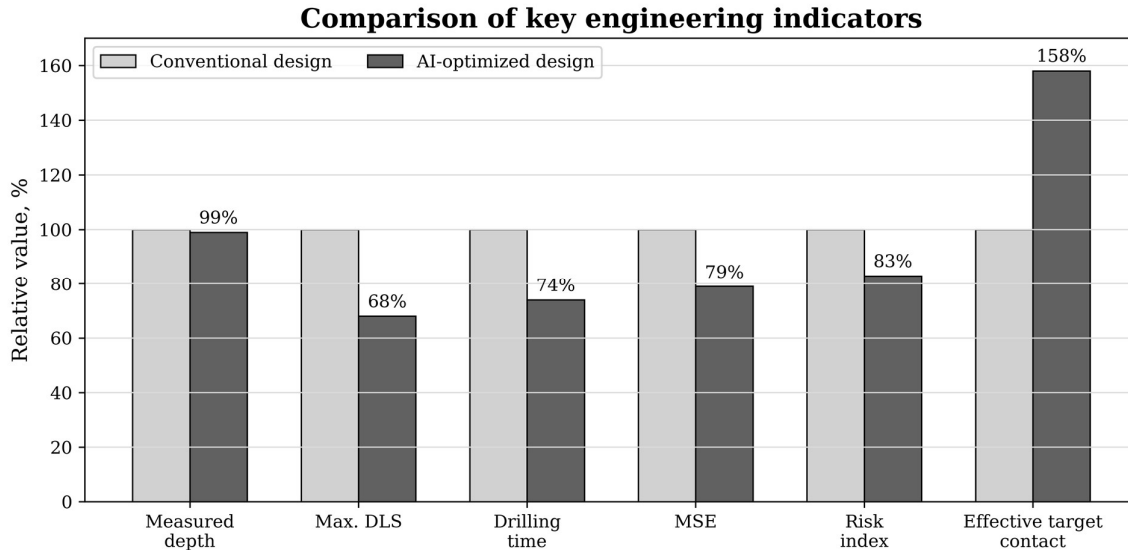


Figure 5. Relative comparison of selected engineering indicators. The conventional design is 100%; values below 100% indicate reductions in length, severity, time, energy or risk, whereas the value above 100% indicates increased effective target contact

Engineering interpretation and real-time application

Three practical implications follow. First, trajectory and drilling-parameter optimization should not be separated: a smoother path permits more efficient operating set-points without violating the DLS constraint. Second, reservoir placement should be evaluated by effective in-zone length rather than nominal lateral length alone. Third, the surrogate should operate in a closed loop. After each survey or LWD interpretation update, the remaining design space can be regenerated from the current bit position and revised formation boundary.

For field use, the workflow should operate in advisory mode. It should return a small set of feasible candidates together with predicted gains, active constraints and sensitivity to uncertain

inputs. The directional driller and geosteering team would then accept, modify or reject the recommendation. This human-in-the-loop arrangement preserves engineering responsibility.

The study has explicit limitations. It is a synthetic methodological verification and does not use a complete dynamic torque-and-drag model, transient hydraulics, drillstring vibration, probabilistic geological uncertainty or a field-calibrated ROP correlation. The integrated risk index is a screening indicator and must not replace detailed hole-cleaning, wellbore-stability or anti-collision analyses. Before deployment, the trajectory generator, torque and ROP responses, target uncertainty and surrogate must be recalibrated using offset-well and real-time data for the relevant formation, BHA and mud system.

4. Conclusions. A hybrid AI-assisted multi-criteria workflow for horizontal well trajectory optimization has been developed and tested on a transparent representative Caspian offshore synthetic scenario. The main conclusions are as follows:

1. The combination of an explicit engineering model, an Extra Trees surrogate and exact recalculation of shortlisted candidates provides a transparent method for screening large trajectory and operating-parameter design spaces while retaining hard DLS, clearance, azimuth and target-contact constraints.

2. The surrogate predicted the penalized composite objective with $R^2 = 0.996$ and $MAE = 0.104$ objective units on the independent synthetic test set; this measures reproduction of the internal engineering model and is not a field-accuracy claim.

3. Relative to the conventional design, the verified optimized solution reduced maximum dogleg severity by 32.0%, estimated drilling time by 26.0%, MSE by 20.9% and the integrated screening risk index by 16.6%, while the synthetic ROP increased by 33.7%.

4. Effective target contact increased from 762 to 1200 m, or by 57.5%, despite a shorter nominal lateral. This confirms that in-zone placement is a more informative criterion than drilled lateral length alone.

5. The appropriate implementation is an advisory closed-loop system that updates candidate trajectories and drilling set-points from MWD/LWD information while leaving the final operational decision with drilling and geosteering specialists.

Conflict of interest.

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

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Integrated geomechanical framework for wellbore stability management in horizontal drilling

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Abstract. Wellbore instability is a major challenge in horizontal drilling, especially in anisotropic and unconventional formations. Factors such as stress concentrations, pore pressure anomalies, and reactive shales contribute to borehole collapse, stuck pipe, and reduced drilling efficiency. Advanced approaches-integrating Mechanical Earth Models (MEMs), real-time monitoring, and optimized mud weight-are essential for predicting and preventing instability. This paper also considers the impact of well trajectory, drilling fluid selection, and delayed integration of geomechanics into well planning. A case study from the V. Filanovsky field (North Caspian Sea) demonstrates the use of 3D geomechanical modeling for casing design, sidetrack planning, and drilling fluid optimization. Implementation of casing-while-drilling (CWD) significantly reduced open-hole exposure and improved borehole integrity. These strategies support safer, more efficient well construction under complex geological conditions. The integration of data-driven modeling and engineering decisions enhances well longevity, reduces non-productive time, and contributes to more resilient and sustainable drilling operations.

Keywords: wellbore instability; stress concentration; geomechanical modeling; safe mud-weight window; horizontal drilling; casing while drilling.

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1. Introduction. Horizontal drilling has become a primary method for accessing unconventional hydrocarbon reservoirs. It provides significant advantages in terms of reservoir contact, productivity, and economic efficiency, particularly in low-permeability formations such as tight gas, shale, and coalbed methane [1,2]. However, as well trajectories increase in length and complexity, issues related to borehole integrity and stability have also significantly intensified.

One of the most critical challenges in horizontal drilling is wellbore instability, which can lead to severe operational problems such as stuck pipe, excessive torque and drag, loss of circulation, and borehole collapse. Compared to vertical wells, horizontal wells present a higher risk of instability due to greater exposure to weak formations, longer open-hole sections, and complex in-situ stress interactions. This is especially relevant when drilling through laminated shale formations or highly anisotropic zones, where bedding planes or natural fractures may intersect the well path at unfavorable angles [3].

International research highlights that borehole failure is strongly influenced by the orientation of the wellbore relative to the principal stress directions, the presence of anisotropic rock fabric, and the selection of drilling fluid properties [4]. Studies have demonstrated the importance of geomechanical modeling [5–7] and real-time wellbore stability analysis to reduce these risks [8]. For instance, the use of Mechanical Earth Models (MEMs) and anisotropic failure criteria has become a standard practice in planning horizontal wells in formations such as the Barnett, Eagle Ford, and Marcellus shales [9].

In addition, pore pressure anomalies, thermal effects, and chemical interactions between drilling mud and rock formations have been identified as destabilizing factors in horizontal wells [10]. In HPHT (high-pressure, high-temperature) environments, temperature gradients can significantly

alter stress distribution and rock strength, potentially leading to unexpected collapse or fracturing [10].

To address these challenges, a growing body of international literature supports the integration of advanced monitoring tools (e.g., LWD, borehole imaging), inhibitive mud systems, and real-time MEM updating techniques [6,11]. Moreover, ongoing research continues to explore the role of machine learning and artificial intelligence in predicting instability events and optimizing mud weight in real time [12].

Recent advancements in horizontal drilling-such as underbalanced drilling (UBD), slim hole completions, lateral sidetracks, and multilateral wells-have improved reservoir contact and field development efficiency. However, these techniques introduce new mechanical and operational risks. For instance, slim hole completions may reduce annular space, limit mud circulation and affecting hole cleaning, while lateral sidetracks and multilateral junctions introduce complex stress interactions that can destabilize the borehole. These innovations necessitate more advanced geomechanical planning and real-time stability assessment tools to address the compounded risks introduced by non-traditional well architectures.

This paper builds upon that foundation by examining key mechanisms of instability, evaluating geomechanical modeling strategies, and highlighting best practices from global case studies. The goal is to support safer and more efficient horizontal well construction in complex and anisotropic formations.

2. Mechanisms and modeling approaches for wellbore instability. Wellbore instability is primarily caused by a range of geological, mechanical, and operational factors that interact along the borehole trajectory. One of the dominant contributors is the concentration of mechanical stresses around the wellbore wall due to the redistribution of the in-situ stress field during drilling. When the tangential or hoop stress exceeds the compressive or tensile strength of the surrounding rock, failure may occur in the form of shear collapse or tensile fracturing. This risk is amplified in formations exhibiting anisotropy in their mechanical properties. Transversely isotropic rocks, such as laminated shales, demonstrate directional variation in strength and deformability based on bedding orientation. Ignoring such anisotropy in geomechanical models can result in incorrect predictions of failure zones and ineffective well trajectory design. Another critical factor is the presence of abnormal pore pressures. Both overpressured and underpressured intervals affect the effective stress acting on the wellbore and may lead to loss of circulation or structural collapse if not properly accounted for. Furthermore, the interaction between drilling fluids and formation minerals, especially clays, can significantly weaken the rock matrix. Incompatible fluids may trigger hydration and swelling, which further destabilize the wellbore. To address these issues, comprehensive geomechanical modeling strategies are employed. The development of a Mechanical Earth Model (MEM) integrates well log data, core testing, seismic surveys, and drilling history to characterize key elastic and strength parameters. In this context, advanced modeling approaches for multiphase flow systems-such as those that account for phase transitions-demonstrate the value of integrating thermodynamic behavior into stability prediction models [13]. This model provides the basis for stress analysis and stability forecasting. Failure criteria such as Mohr-Coulomb, Drucker-Prager, and Mogi-Coulomb are applied to evaluate the likelihood of shear and tensile failures, considering various borehole inclinations and azimuths. An essential output of the MEM is the determination of a safe mud weight window, which defines the pressure range necessary to maintain wellbore integrity without inducing collapse or fracturing. In addition, temperature variations and chemical reactions between the mud and formation are factored into stability analysis, especially in high-pressure, high-temperature (HPHT) environments. Thermal modeling and mud compatibility testing are therefore integrated into the geomechanical workflow to provide more accurate predictions and safer drilling operations.

The chart (Fig. 1) illustrates the relationship between drilling mud weight and the associated wellbore stability risks. The red zone on the left represents the collapse risk region, where the mud weight is insufficient to counteract the in-situ stresses, potentially leading to shear failure or borehole collapse. On the right, the orange zone indicates the fracture risk region, where excessive mud weight

can induce tensile failure or hydraulic fracturing of the formation. The green zone between these two extremes represents the safe mud weight window - the optimal range where the borehole is most stable, minimizing both collapse and fracturing risks. Determining and maintaining mud pressure within this window is critical for avoiding non-productive time and ensuring safe drilling operations.

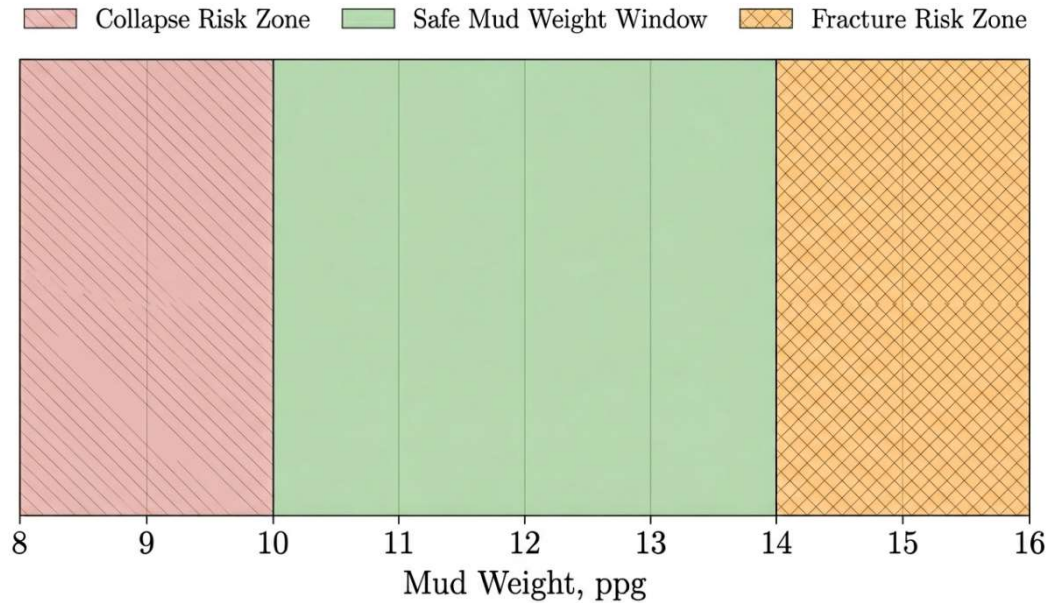


Figure 1. Safe mud-weight window and associated wellbore-stability risk zones

One of the most frequently cited operational risks is the delayed integration of geomechanical analysis into the well planning process. When MEMs are developed late or not fully calibrated, options for adjusting casing depth, mud program, or trajectory may be limited or costly. Early incorporation of MEMs-ideally during field development planning-enables proactive mitigation of risks and allows for safer, more efficient design decisions.

3. Trajectory optimization, fluid strategy and real-time adaptation. The design of the well trajectory plays a pivotal role in ensuring mechanical wellbore stability, particularly in horizontal and extended-reach drilling operations. One of the most effective strategies for minimizing the risk of borehole collapse or failure is to align the well path with the direction of the minimum horizontal stress. This alignment reduces hoop stress around the borehole wall, thereby minimizing the risk of shear or tensile failure. Deviating from this principle, especially in anisotropic or fractured formations, can introduce complex stress interactions that significantly degrade well integrity.

Another key consideration in trajectory planning is the avoidance of unfavorable intersections with geological features such as bedding planes, faults, or fracture networks. Crossing these features at oblique angles can trigger delamination or slippage along weak planes, leading to instability and borehole enlargement. Therefore, trajectory planners must assess bedding orientation and structural geometry when designing well paths. Additionally, tortuosity-the degree of curvature and deviation in the wellbore-should be minimized. High tortuosity not only increases mechanical drag and tool wear but also concentrates stress in localized zones, which can result in borehole deformation or tool sticking. An example of a planned trajectory with overlaid geomechanical risk zones is shown in Fig. 2.

Modern geomechanical and reservoir modeling software such as Petrel, Landmark, and JewelSuite provides robust 3D visualization capabilities that allow engineers to overlay stress field data with lithological and geomechanical property distributions. These tools enable more informed decision-making in path selection, casing setting depths, and the prediction of potential instability zones before drilling begins.

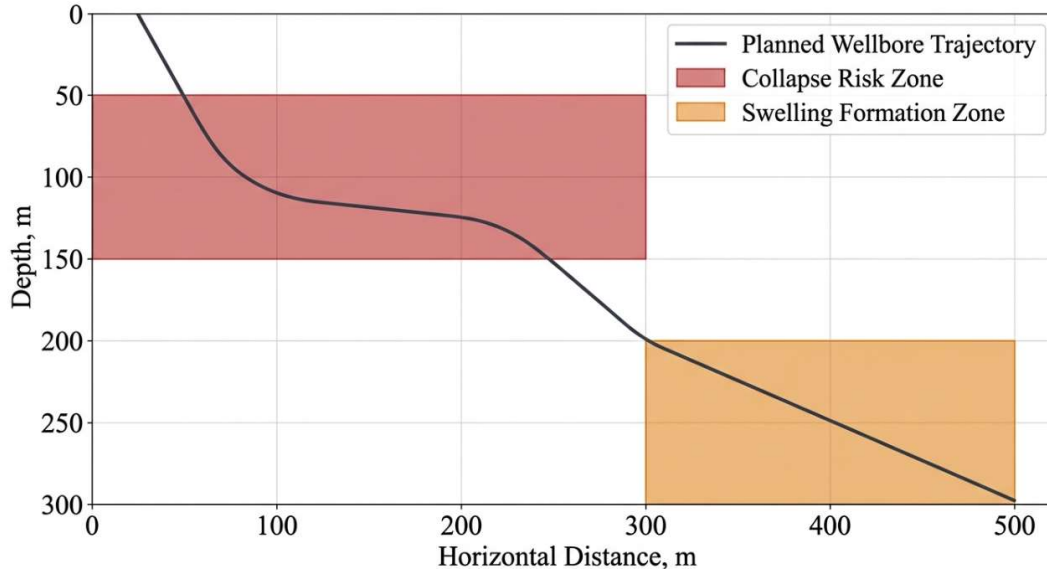


Figure 2. Planned well trajectory with collapse-risk and swelling-formation zones

Equally important is the management of drilling fluids, which serve as both a mechanical support and chemical buffer during drilling. The mud system must maintain a pressure regime within the safe operating window to counteract formation pressures without fracturing the surrounding rock. In reactive shale environments, oil-based or potassium-based muds are preferred due to their inhibitive properties that mitigate clay swelling and hydration. Maintaining a consistent mud weight helps prevent pressure surges and swab effects, which can destabilize the borehole. Techniques to suppress pressure pulsations in multiphase systems [14] may also be conceptually extended to manage transient pressure loads in drilling annuli and circulation systems. The addition of chemical inhibitors further stabilizes reactive formations and reduces the tendency for dispersion or caving. The rheological properties of the mud are also essential in transporting cuttings efficiently, especially in high-angle or horizontal sections where gravitational transport is limited. High viscosity and optimized flow characteristics ensure that cuttings do not accumulate and contribute to pack-offs or stuck pipe events. As drilling operations become more complex, the importance of real-time monitoring and adaptive control systems has grown significantly. Logging-while-drilling (LWD) technologies provide continuous feedback on borehole conditions, enabling early detection of enlargement, breakouts, or washouts. Borehole imaging tools offer high-resolution insights into the structure and integrity of the borehole wall, revealing features such as fractures, bedding planes, or instabilities in formation contact. Additionally, downhole pressure sensors monitor equivalent circulating density (ECD) and annular pressure variations, which are critical for detecting abnormal pressure regimes or surge/swab conditions. All of these real-time data streams are increasingly being fed into integrated drilling management systems, which update the Mechanical Earth Model (MEM) and enable dynamic adjustment of drilling parameters. This feedback loop enhances decision-making and supports a predictive, rather than reactive, approach to instability mitigation. The integration of real-time monitoring, optimized trajectory design, and adaptive fluid management forms the backbone of a modern, risk-informed drilling strategy.

Selecting the optimal stability strategy often requires trade-offs with other drilling and completion goals. For example, increasing mud weight may improve borehole support but also increase the risk of differential sticking or lost circulation. Similarly, trajectory optimization to avoid stress concentration zones may lengthen the well path or reduce reservoir exposure. Engineers must balance these factors-ROP, hole cleaning efficiency, cuttings transport, wellbore size, and stimulation potential-within an integrated design framework to ensure both structural integrity and operational feasibility.

4. Case studies and future perspectives. Practical implementation of geomechanical strategies in various drilling environments has demonstrated significant improvements in wellbore stability and overall operational efficiency. Numerous case studies across different geological basins illustrate how localized modeling and real-time decision-making contribute to mitigating instability-related risks (see Table 1).

Table 1

Case Study	Key Challenges	Geomechanical Strategy	Outcome
Bakken Formation, USA	Anisotropy, stuck pipe risk	Anisotropic MEM, optimized mud weight	Reduced stuck pipe incidents; improved prediction accuracy
South China Shale Gas Field	Structural complexity, shale instability	Trajectory aligned with Shmin, LWD tools, oil-based mud	Stabilized borehole; enhanced real-time decisions
North Sea HPHT Field	High pressure and temperature (HPHT)	Thermo-mechanical modeling, casing and mud design	Maintained integrity in HPHT conditions; improved safety and pressure containment
V. Filanovsky Field, North Caspian Sea	Complex tectonic stress, instability zones	3D geomechanical model, CWD implementation, optimized trajectory and mud system	Improved wellbore integrity; reduced open-hole exposure; optimized casing and fluid design

In the Bakken Formation (USA), operators confronted challenges typical of anisotropic shale formations, where conventional models often failed to predict borehole behavior accurately. To address this, advanced anisotropic geomechanical models were developed, which incorporated the orientation of bedding planes into the stress analysis. These models allowed for better prediction of failure envelopes and optimized trajectory design. By calibrating mud weights to local collapse and fracture gradients, operators significantly reduced the incidence of stuck pipe and improved drilling efficiency in horizontal sections.

In the South China Shale Gas Field, the complex stratigraphy and structural heterogeneity of the formations demanded a more dynamic drilling approach. Directional wells were strategically aligned parallel to the minimum horizontal stress to minimize hoop stress and enhance mechanical stability. The deployment of oil-based drilling fluids, known for their superior shale inhibition properties, helped to preserve borehole integrity. Additionally, microseismic monitoring and logging-while-drilling (LWD) tools were employed in real time to adjust operational parameters based on formation behavior. This adaptive strategy reduced borehole enlargement and improved rate of penetration (ROP) across laterals.

The North Sea High-Pressure High-Temperature (HPHT) Fields presented another layer of complexity, where elevated bottomhole pressures and temperatures altered the mechanical behavior of formations significantly. Here, thermo-mechanical models were used to simulate the effects of

temperature changes on stress distribution and rock strength. Engineers tailored casing programs and mud weight schedules to accommodate thermal expansion and contraction, which proved essential in avoiding formation breakdown and maintaining annular integrity. The use of synthetic-based muds further supported pressure containment in deep, high-temperature zones.

An illustrative case from the V. Filanovsky field in the North Caspian Sea demonstrated the practical benefits of comprehensive geomechanical integration. A full 3D geomechanical model was developed to address the region's complex tectonic and lithological conditions. This model was instrumental in identifying instability-prone intervals along the planned well trajectories and provided a basis for critical well design decisions. Key engineering outcomes included optimized casing design, targeted trajectory adjustments to avoid geohazards, and the implementation of casing-while-drilling (CWD) and cementing technologies in the intermediate section. These measures significantly reduced open-hole exposure time and enhanced wellbore integrity. Additionally, the model guided the selection and density adjustment of drilling fluids to maintain wellbore pressure within the safe operational window.

These field-based applications underscore the value of localized, data-intensive geomechanical workflows, especially when dealing with anisotropy, high-pressure regimes, and chemically reactive formations. However, as horizontal drilling continues to expand into even more technically challenging environments, further advancements are necessary.

Looking to the future, the integration of machine learning and artificial intelligence is expected to transform wellbore stability forecasting. Predictive models trained on historical well data can rapidly identify patterns of failure and recommend real-time adjustments to mud weight, trajectory, or drilling parameters. Moreover, real-time MEM updating systems-capable of ingesting LWD, seismic, and pressure data-will allow dynamic refinement of geomechanical models during drilling. Another promising frontier is the development of basin-scale geomechanical models, which incorporate regional tectonics, structural geology, and reservoir properties to guide large-scale field development planning.

By coupling these innovations with continued investment in high-resolution data acquisition and interdisciplinary collaboration, the oil and gas industry can reduce instability-related non-productive time (NPT), improve safety margins, and extend the productive life of horizontal wells-particularly in deep, unconventional, and structurally complex basins.

Beyond operational efficiency, effective wellbore stability management contributes to broader environmental and sustainability goals. Reducing open-hole exposure and instability minimizes waste from sidetracks and collapse recovery operations. Techniques like casing-while-drilling (CWD) reduce formation damage and non-productive time (NPT), while optimized mud systems lower environmental impact. As the industry advances, resilient wellbore design will become a cornerstone of environmentally responsible hydrocarbon production.

5. Conclusions. The main conclusions are as follows:

1. Wellbore stability in horizontal drilling requires a multidisciplinary and data-driven approach, combining geomechanics, drilling engineering, and real-time analytics to manage complex formation behaviors effectively.

2. Early integration of geomechanical modeling-including the development of Mechanical Earth Models (MEMs)-is critical for predicting stress distributions and identifying instability-prone zones before drilling begins.

3. Optimized trajectory design, aligned with in-situ stress orientations and informed by anisotropic properties, significantly reduces the risk of borehole collapse and mechanical failure.

4. Proper mud system selection and management-such as maintaining appropriate mud weight and using chemically compatible fluids-enhances borehole support and minimizes formation reactivity, particularly in shale zones.

5. Real-time monitoring and adaptive drilling technologies, including LWD tools, borehole imaging, and downhole pressure sensors, enable early detection of instability indicators and allow proactive adjustments during operations.

6. The combination of these techniques reduces non-productive time (NPT), enhances operational safety, and improves the overall success rate and cost-efficiency of horizontal well construction.

7. State-of-the-art digital technologies and continuous feedback loops provide a robust foundation for confident decision-making in geomechanically challenging environments.

Conflict of interest.

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

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Technique and technology of drilling inclined wells with large deviation

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Abstract. The relevance this article looks at how to make deep well drilling more stable and efficient. The main aim the article looks at how the rate of descent of the drilling rig affects the stability of the wellbore. This article talks about the characteristics of igneous, metamorphic, and sedimentary rocks and how they affect drilling. Choosing the right drilling technologies is important because sedimentary rocks are the main places where hydrocarbons are stored. When you build mechanical models for drilling, you can figure out how much energy, vibration, and friction are lost. Modern technologies, real-time monitoring systems, and fluid flow control play an important role in reducing risks. Results. The study demonstrates that optimal outcomes are attained through a multi-stage approach, integrating both conventional methods and contemporary technologies.

Key words: Inclined wells, drilling technologies, modern technologies, modern tools, mechanical models.

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1. Introduction. The modern oil and gas industry requires an integrated strategy for controlling drilling activities, making sure that the wellbore stays stable, and improving fluid dynamics. This is because deep well drilling is a complicated and varied process. Effective drilling boosts production and keeps people safe, especially when the geology and operations are hard (Bulatov, 1981; Basarygin et al., 2001; Guliyev and Shirinov, 2009; Akhundov and Hasanov, 2015). There are many important factors that make drilling deep wells hard, such as the physical and mechanical properties of the drill string, the geology of the area, and the properties of the drilling mud and fluid. The main problems are keeping the wellbore stable, reducing the risks that come with hydraulic fracturing, and changing the way drilling is done to fit the situation. This article looks at the basic ideas and methods used to make drilling operations safer and more efficient. This research will investigate the relationship between the descent velocity of the drilling apparatus and the stability of the wellbore, along with the influence of advanced technology in mitigating challenges associated with deep drilling. We will look closely at how geological conditions affect the choice of equipment and technology, as well as drilling management methods that are meant to reduce risk and improve the process. Because drilling in unstable environments has its own set of problems, special attention will be paid to controlling the flow rate, mud pressure, fluid viscosity, and the use of additives. Real-time monitoring systems are very important because they help optimize drilling parameters and adjust to the changing conditions inside the well. We will look at an analytical approach to drilling, which will include figuring out pressure balancing equations and kinematic principles to give us a full understanding of how drilling tools move in turbulent situations. The objective of this study is to ascertain the most effective and secure drilling methodologies to ensure stable wellbores and prevent issues such as hydraulic fracturing or wellbore wall failure. A common thread runs through all of this research: drilling deep wells requires a complete, multi-tiered plan that uses both traditional methods and the latest technology. Every part of the drilling process has its own set of problems and choices that need careful study and planning. The speed at which tripping activities happen during well drilling depends on a number of factors, including the technical specifications of the equipment and other things. A summary of some of these criteria is given above.

2. Methodological part. The scientific novelty of this study lies in the study of the relationship between the speed of descent of the drilling rig and the stability of the wellbore. It is

proposed to achieve a more stable drilling method by using real-time monitoring and mechanical models together, taking into account the properties of the rock and the combination of drilling technologies.

Igneous rocks, sometimes referred to as igneous rocks, are generated during volcanic eruptions. Magma that ascends to the Earth's surface after a volcanic eruption experiences fast cooling. Nonetheless, inside the subterranean magma, this process continues gradually and under pressure. Consequently, igneous rocks are categorized as effusive and intrusive types. Common effusive rocks on Earth's surface include diabase, basalt, porphyry, volcaniclastics, pumice, obsidian, and trachyte. Intrusive igneous rocks, including granite, syenite, diorite, gabbro, and peridotite, are characterized by their density and limited permeability, solidifying gradually inside the Earth's subsurface [2]. Igneous rocks often have superior hardness compared to other rock types. Excavations are now conducted in rock formations for geological assessments and tunnel development. Metamorphic rocks are generated by metamorphism, which transpires when igneous rocks are subjected to extreme heat and pressure in proximity. Examples include crystalline schist, marble, quartzite, and analogous materials. denotes rocks with diverse qualities such as. Sedimentary rocks are created by the weathering and erosion of pre-existing igneous and metamorphic rocks that have experienced physical, chemical, and mechanical processes. These compounds have been disseminated throughout the Earth's surface by the actions of the sun, wind, glaciers, rivers, and floods, leading to the formation of substantial sedimentary strata over millions and billions of years. The production of sedimentary rocks is an ongoing and dynamic natural process. Their negligible micro-growth rate of around 0.3-3 mm per century renders this developmental process imperceptible to human observation of nature throughout time. Long-exposed sediments to geological activity have hydrocarbons derived from faunal and floral remnants. The exploration and extraction of oil and gas deposits mostly occur in areas characterized by sedimentary rock formations, and this is not a coincidental occurrence. Sedimentary rocks are categorized into three kinds based on their creation mechanisms:

1. Mechanical sediments.
2. Chemical sedimentation.
3. Organic sediments [1].

Mechanical sediments include both naturally cemented and uncemented particles, often referred to as grains. The hardness of mechanical sediments is influenced by particle interaction, particle size, porosity, cementation degree, and cementing material concentration. The density of these sediments typically ranges from 2.1 to 2.8 g/cm³ in most instances. Chemical sediments are generated when mineral particles in both normal and colloidal solutions undergo precipitation. Cemented rocks demonstrate superior hardness compared to uncemented rocks. The hardness of cemented rocks fluctuates based on variations in particle size and the characteristics of the cementing agent. Examples of naturally occurring sedimentary rocks include limestones, calcareous tuffs, dolomites, marls, and siderites. Organic sediments denote organic sedimentary rocks mostly generated by the biological activities of organisms. The composition comprises naturally occurring particles of herringbone limestone, chalk, diatomite, trefoil, and opal. Organogenic rocks are mostly created in the bottom of seas and lakes. During the drilling of oil and gas wells, heterogeneous rock formations are often encountered. This amalgamation induces changes in both the porosity (the volume of voids inside the rock) and the hardness of the rocks. The rock's density rises with depth owing to the pressure from the above layers. The disparity in rock density at varying depths is attributable to this issue. Rocks exhibiting uniform physical qualities, including thermal insulation, electrical conductivity, elasticity, and hardness, are termed isotropic rocks [4]. Anisotropic rocks exhibit uniform constants in parallel orientations while differing in other directions.

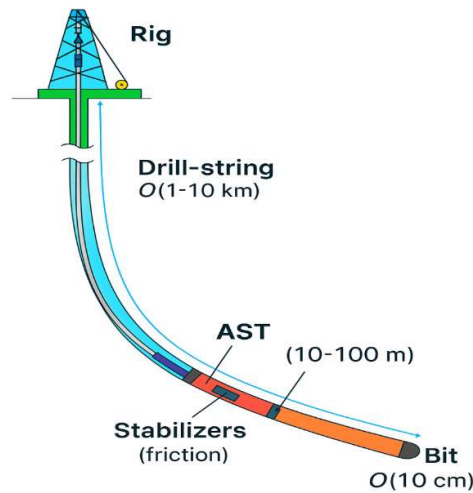


Figure 1. Schematic overview of a drilling system in an inclined well

The first image depicts the structure used in the process of drilling oil and gas wells. The drilling rig is located in the upper part. This device is the main center from which all equipment is controlled. A drill string (a set of drilling pipes), the length of which can vary between 1–10 km, is inserted into the well. Through these pipes, both the drilling fluid circulates and the rotational movement is transmitted to the bottom. At the bottom of the well is a part called BHA (Bottom Hole Assembly), the length of which is between 10–100 meters. The BHA provides the direction and stability of the well. Various devices and measuring equipment are installed there. The bit is located at the bottom and has a diameter of about 10 cm. It drills the well by breaking the rocks. Stabilizers are located on the pipes, which reduce friction and help the well to be drilled in a straighter direction. The image also shows the AST (actuator or special technical part). This part plays an important role in controlling rotation, direction and mechanical forces. Ultimately, this structure ensures a stable and controlled drilling process at depth [8].

Increasing hydrocarbon production by developing, for example, offshore fields, as well as further developing previously drilled areas, involves the implementation of complexly constructed design well profiles, the trajectories of which may contain curved sections with a limited (minimum possible) radius or inclined rectilinear sections of great length (more than 3000 m). The presence of such trajectories is due to the inaccessibility of oil and gas facilities located, for example, under populated areas, water bodies and nature conservation areas, as well as the remoteness of the shelf coastline [6]. The results of the analysis of practical data on drilling wells with a complex profile showed that the actual deepening trajectory in many cases differs significantly from the trajectory of the design profile. As a result, the wellbore is formed with the formation of large caverns and benches that hinder the advancement of the bottom hole assembly (BHA), and the intensity of the curvature and the radius of the sections of the build-up and decline of the zenith angle do not correspond to the permissible strength characteristics of the drill pipes. It is practically impossible to drill such sections using only a downhole motor (DDM) as a bit drive. This is primarily due to the high friction between the drill string (DS) and the rock. As a technological method for increasing the efficiency of drilling with a DDM, they use simultaneous periodic or constant rotation of the drill string by a rotor or top drive. Manufacturers call this method rotary-turbine or combined. Its implementation allows drilling wells of various depths with a wide range of changes in the type and properties of drilling fluids, drilling mode parameters, as well as using different designs and sizes of rock-cutting tools. However, with the current technology of combined drilling, there are problems associated with the instability of the DDM, their stops, as well as accidents (turning off, destruction of DDM elements) of the DS

assembly. The main disadvantage of using simultaneous rotation of the DDM and the BC is the impossibility of adjusting the well profile trajectory during the drilling of inclined straight (tangential) sections. In the case of drilling subsequent intervals located after the tangential section, for example, sections of the zenith angle increase or decrease, it is practically impossible to use the DDM without rotating the BC with simultaneous trajectory adjustment. This is due to the action of additional friction forces between the drilling tool and the rock.

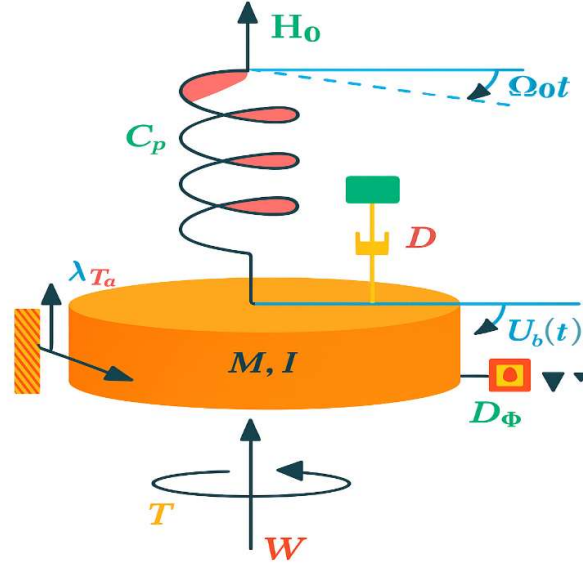


Figure 2. Schematic representation of the benchmark model

This figure depicts a mechanical model of the drilling process. Here, a disk marked M, I is taken as the main element. This disk symbolizes the rotating part of the drill string. The forces and moments acting on the disk are shown. The force denoted by H_0 and an elastic torsion spring called C_p are depicted from above. This spring models the elasticity of the drill pipes. The rotation of the disk is affected by the torque T , and the force W is the force arising from the weight directed downwards. Two important factors are also marked on the disk: λT_a and λT_i . These indicate the clamping and friction. On the side are the symbols $\Phi_b(t)$ and $U_b(t)$, which indicate the angular deformation and displacement occurring in the disk. The figure also shows the elements D and $D\Phi$, which model the shock absorber and friction forces. In short, this mathematical-mechanical model explains the rotational and elastic behavior of a part of the drill string. Its purpose is to calculate vibrations, friction, and energy losses that occur during drilling [8].

Contemporary drilling technology may be classified into two types according to their effect on rock. 1. Techniques using physical drilling. 2. Mechanical drilling techniques. Physical drilling techniques, referred to as shaftless drilling, contrast with mechanical drilling methods. Thermal drilling is a technology that use flame and plasma to fragment rock by the application of extreme heat and temperature. Explosive drilling entails the obliteration of subterranean rocks at the base of a well by detonation. Hydraulic drilling utilizes a high-pressure hydraulic pump to fracture rocks. Electrical impulse drilling entails the fragmentation of rock by the use of an electrical discharge. Chemical drilling use chemical substances to interact with rock, resulting in its degradation. Vibrating drilling employs a vibrodigger to execute drilling while the instrument functions under the surface. These drilling methods have not yet transcended the confines of laboratory study. Conversely, mechanical

drilling is often used due to its adaptability. At now, oil and gas wells are mostly drilled using mechanical techniques. Since the late 19th century, oil and gas wells have been mechanically dug, with depths progressively reaching 8,000 to 12,000 meters. Mechanical drilling methods are categorized into two types: percussive drilling and rotary drilling. Execute the percussion technique. Percussion drilling entails aggressively striking the well's bottom with an axe to fracture the rock. The resultant crushed rock pieces are then mixed with water and extracted from the well's bottom as a slurry or solid-liquid amalgamation. In this situation, the drilling apparatus is turned at a certain angle using keys at the wellhead to form a cylindrical wellbore. Percussion drilling entails the insertion of a substantial drilling implement into the rock, accompanied by periodic elevation and descent of the axe [3]. The drilling apparatus is elevated and descended by a crank-rod mechanism situated at the wellhead via a drilling rig. A crank mechanism transforms rotational momentum into reciprocating motion. A substantial rod connected to the axle aids in fracturing the underlying rock during descent. The process of rock destruction during hammer drilling consists of two independent processes executed sequentially. The first operation entails crushing the rock, followed by the removal of the excavated rock particles from the hole with a rod after elevating the rods. These methods are executed consecutively to enhance the drilling of the well. In this method, given that the well is devoid of contents, casing pipes are introduced into the wellbore to mitigate rock instability in the well wall, and the backside is then cemented. The rod drive method is used in drilling seismic research wells with depths of 10-15 meters, as well as in subterranean constructions, air exchange tunnels, and wells up to 100 meters deep, often utilized in water wells. The extraction of rocks from the well occurred concurrently with the drilling process. To accomplish this objective, all solid rods were substituted with rods (pipes) including internal channels, and the axes used for crushing rocks were replaced with axes containing holes for washing. Furthermore, a piston pump, a receiving tank, and troughs were erected at the wellhead. The presence of polluted drilling mud in the well caused a 3-4-fold decrease in the reinforcing of the hole with protective pipes. Consequently, drilling wells to higher depths became feasible. A concept was then presented to generate a hydraulic effect on the shaft to use the force of the circulating drilling mud solution during the drilling process. The intense impact of the fluid wave will generate significant vibrations at the well's bottom, therefore promoting rock fragmentation [7].

This figure shows a more expanded mechanical model than the previous one. There are now two disks: M_a, I_a and M_b, I_b . These disks represent different parts of the drill string. The upper part again depicts the spring C_p and the force H_0 . This spring represents the elasticity of the drill pipe, that is, the bending that occurs during rotation. The spring constant K_b and the shock absorber D_b are placed between the two disks. They indicate the energy transfer between the two parts and the vibration reduction. There are λT marks on both disks - these model the friction and limiting forces. The lower disk is affected by the torque T and the force W . The angular deformations - $\Phi(t)$, $\Phi_b(t)$ and their changes - $U(t)$, $U_b(t)$ are recorded on both the upper and lower disks. This model shows the dynamics of the drill string in more realistic conditions. Because not only one point at the depth of the well, but several segments are simultaneously affected. Through such models, vibrations, torsional waves, and mechanical loads generated in the well are analyzed and optimal parameters for more stable drilling are determined [8].

3. Results and discussions

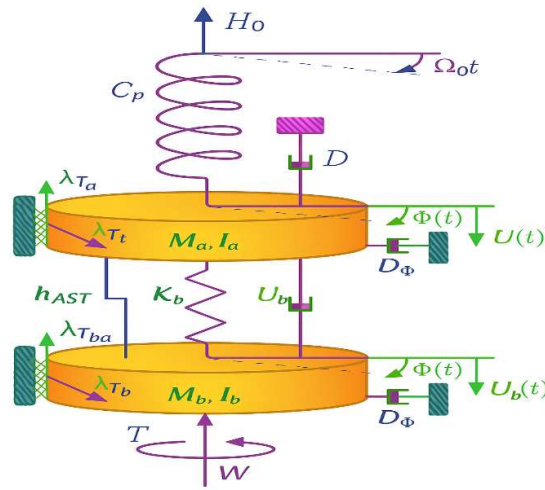


Figure 3. Schematic representation of the drill-string model including AST

The first attempt to create a specific fluid flow model for inclined wells was made (M. Mirkes et al., 2017). For this purpose, the turbulent Navier-Stokes equation was modeled in the inclined coordinate using a correction term $\tan(\beta) - 0.96 = \tan(\gamma)$ since the shear stress increases near the pipe wall during the anisotropic flow regime. The result was that the new model could more accurately estimate the friction coefficient and gas-liquid sliding velocity in inclined wells. However, the applicability of this fluid flow model through an inclined well for petroleum engineering purposes remained uncertain. Therefore, this work attempted to investigate the prediction of reservoir performance in inclined wells. Drilling processes are applied in the petroleum industry to penetrate soil layers and extract minerals (Elkatatny, 2020). During the development of a certain field, the well is directed in a curved line from the vertical direction towards the target node. This type of well is called a diversion well for an oil reservoir and is called a directional well because the wellbore is guided in a specific directional pattern to avoid hydrodynamic obstacles and limit the percentage of water cut. The purpose of drilling and logging is to reduce the cost of finding and extracting hydrocarbons from a geological reservoir. (Richard Chikabvumbwa et al., 2021). Approximately 70-80% of exploration costs are required only during the drilling of the well, so in many offshore oil reservoirs, it is very important to extract initial well parameters such as wellbore inclination and azimuth to determine whether to use logging. data depending on the financial potential of the reservoir [5].

4. Conclusion. The research identified that the primary challenges in deep well drilling pertain to wellbore stability, rock diversity, and the durability of drilling equipment under mechanical stress. The drilling speed and well quality are directly affected by the different mechanical properties of igneous, metamorphic, and sedimentary rocks. Sedimentary rocks are the main target areas because they have a lot of hydrocarbon deposits. At the same time, the drilling equipment's vibrations and friction cause energy to be lost. So, when using mechanical models, you should think about torque, elasticity, and friction forces. New technologies, like real-time monitoring, precise control of the well profile, and optimization of drilling fluid parameters, make drilling safer. The results indicate that drilling deep wells stably and safely is challenging when relying solely on traditional methods. Using a complicated strategy that includes managing technical equipment, rock properties, and drilling fluids is a good way to do things. This method both boosts production capacity and lowers the chance of accidents.

Conflict of interest

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

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Determining the bending intensity that ensures the free passage of the curved conductor assembly through the curvilinear barrel

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Abstract. In the article, in order to determine the free passage of the drilling tool through the curved interval of inclined wells, taking into account its elasticity, the intensity of the increase in the zenith angle was calculated accordingly.

Key words: zenith angle, flexibility, drilling tool, interline interval.

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1. Introduction. The geometrical dimensions and the diameter of the bit along with the drill collar of the curved transmission downhole motor allow to determine in advance the minimum curvature radius of the well or the minimum bending intensity. When you start bending the vertical well with this assembly, it stops in the position shown in figure 1. In this case, the body of the engine or the drill collar rests on the upper wall of the well at point S and exerts pressure on it with the force F_S . However, as the zenith angle increases, after reaching a certain value, the body of the engine or the drill collar breaks off (separates) from the upper wall at point S of the well due to its own weight and sits on the lower wall at point D and exerts pressure on it with the force F_D . Depending on the seating of the drill collars on the upper and lower walls of the well, the expected value of the bending intensity that ensures the normal passage of the indicated system through the inclined well pipe will also be different.

2. Methodological part. In the first case, that is, when the tool touches the wall of the well at point S, let's determine the value of the bending intensity that ensures the normal transition of the curved conductive assembly. For this, let us assume that the bit 1, the downhole motor 2, the drill collar 4 placed on it touch the well wall 5 at points A, B and S and the zenith angle DBO has an increasing tendency along the circular arc.

Therefore, the increase of the zenith angle in the interval from point D to point B will be $\Delta\alpha_0$, and in the drilling interval BO will be $\Delta\alpha_1$.

We assume that the well wall is absolutely rigid against lateral forces, and the shape of the elastic bits of the assembly in the interval from the bit to the point where the drill collar touches the wall is as shown in Figure 1.

To solve this problem, the lower part of the bent-conductor tool assembly can be viewed as a flexible beam mounted on three roller bearings.

Let's assume that the zenith angle accumulation intensity is $\Delta\alpha_k$.

The principle diagram of the transition of a curvilinear node from a curvilinear barrel

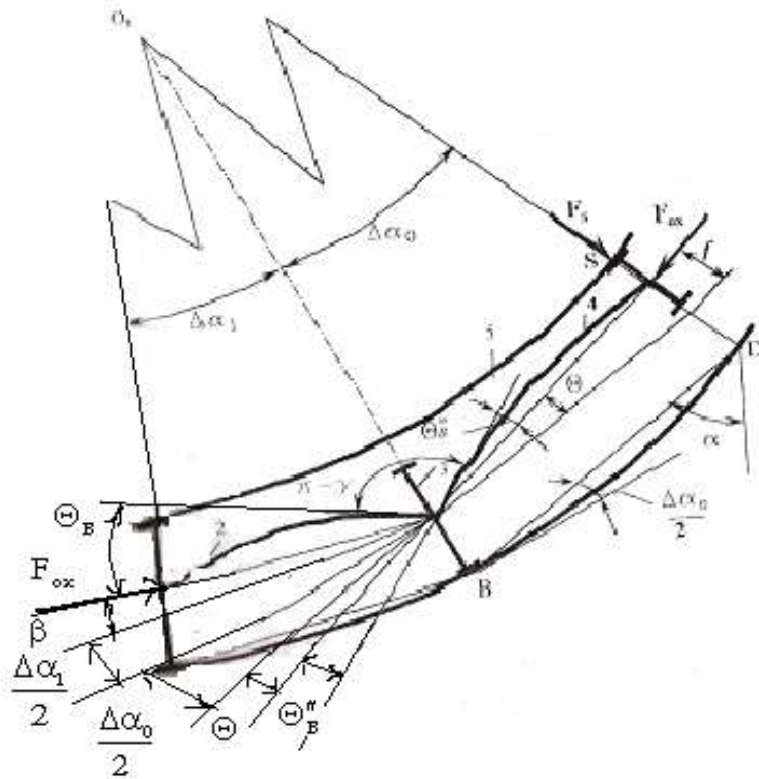


Figure 1.

In Figure 2, the following dependence can be written between the angles resulting from the deformation of the lower part of the drilling tool on the geometric dimensions of the assembly, the bending intensity and the curvature of the fuel in the section where the assembly is located with a curved conductor:

$$\theta'_B + \beta + \frac{\Delta\alpha_1}{2} + \frac{\Delta\alpha_0}{2} + \theta + \theta''_B \quad (1)$$

here, $\beta = \frac{D-D_x}{2L_T}$, $f = D - \frac{D_y+D_x}{2}$, D , D_x – the outer diameter of the bit and the curved conductor (mechanism), respectively, or if the downhole motor touches the wall of the well;

β - the inclination angle of the downhole motor with respect to the well bits;

L_T – the length of the downhole engine with the bit to the bending mechanism;

L – the distance from the curved conductor to where the assembly touches the wellbore wall,

α - zenith angle;

$\Delta\alpha_1$ – and $\Delta\alpha_0$ properly the increase of the zenith angle in the L_T and L interval;

γ - the angle of curvature of the curved conductor;

θ , θ'_B and θ''_B - O and B are the rotation angles of the bits of assembly at the supports.

Assuming that $\Delta\alpha_1 = \Delta\alpha_k \cdot L_T$ and $\Delta\alpha_0 = \Delta\alpha_k \cdot L$ depending on the bending intensity ($\Delta\alpha_k$) and if we substitute the values of these quantities in the expression (1) to determine the bending intensity ($\Delta\alpha_k$) we get this equation:

$$\Delta\alpha_k = \frac{2}{L_T+L} (\gamma - \beta - \theta - \theta'_B - \theta''_B) \quad \text{degrees/meters} \quad (2)$$

Since the quantities L , γ , θ'_B , θ''_B and θ in expression (2) are unknown, they must be determined.

Let's determine the quantities L , γ and θ for the case where the assembly with a curved conductor is located in a vertical barrel.

3. Results and discussion. When the shown system is located in a vertical wellbore, it undergoes elastic deformation and as a result, the bit is pressed against the well wall by the forces F_y and the drill collar by F_s . As a result of the presence of a curved conductor in the assembly and the arrangement of the assembly in a barrel with a limited diameter, an elastic moment M occurs in the section with a curved conductor, which causes the system to undergo elastic deformation. In this case, the situation where the assembly is located in the vertical wellbore can be considered as shown in figure 2. Taking the lower part of the assembly as a beam sitting on three absolutely rigid supports of different levels, determining the elastic moment M generated in the B-B section, the distance (L) from the bending plane to the point of the curved conductor, the fuel force F_y pressing the bit against the wall of the well, and the forces F_s pressing the drill collar against the wall can. If we consider the well wall to be absolutely rigid, then the value of the elastic bending moment M caused by the loads placed on the left side of the section B-B can be found with very little error from the following equation [79].

$$M = F_y L_T = F_s L \quad (3)$$

here, F_y – is the driving force (the force that presses the bit against the wall).

Layout of the bending assembly in a vertical well

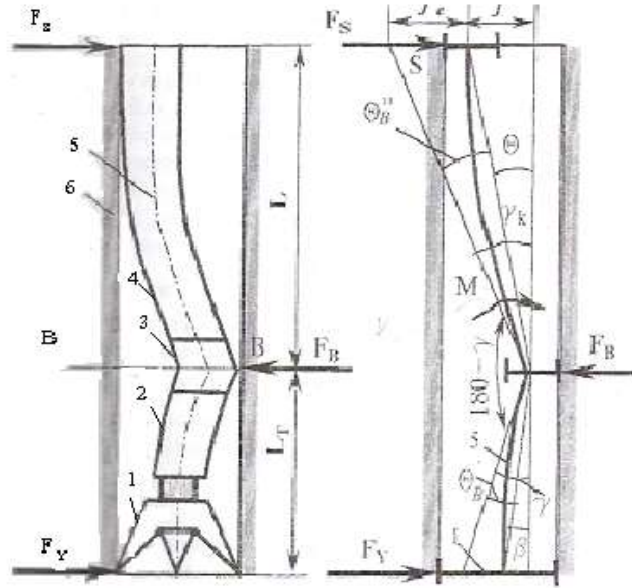


Figure 2. 1 – bit; 2 – well bottom engine; 3 - curved conductor; 4 – drill collar; 5 – elastic bits of assembly; 6 – well wall

To determine the driving force on the bit, the following relationship can be written between the angles of rotation resulting from the forces acting on the beam to the right and left of the B-B section and the angles resulting from the difference in the levels of the beam supports (i.e. for the case $\Delta\alpha_k = 0$).

$$\theta'_B + \theta''_B = \gamma - \theta - \beta \quad (4)$$

here, θ'_B, θ''_B -B-B are the turning angles of the beam on the left and right sides. If we ignore the weight of the downhole motor and the drill collar in the vertical barrel and the effect of the bit load applied to the bit, the turning angles θ'_B, θ''_B can be determined by the following formulas using known research works (4).

$$\begin{cases} \theta'_B = \frac{ML_T}{3EJ} \\ \theta''_B = \frac{ML}{3E_0} \end{cases} \quad (5)$$

here, EJ and EJ_0 – respectively the bending stiffness of the downhole motor and the drill collar placed on top of it; α - is the zenith angle.

To determine the distance L from the plane of curvature of the curved conductor to the point where the drill collar touches the top wall of the well, we write the equation of the beam angle θ at the support.

$$\theta = tg\theta = \frac{ML}{6EJ_0} = \frac{f}{L} \quad (6)$$

If we solve equations (6) – (7) together, we get:

$$\begin{aligned} L &= \frac{3f}{2\gamma_k} + \sqrt{\left(\frac{3f}{2\gamma_k}\right)^2 + \frac{2mfL_T}{\gamma_k}} = \frac{3f}{2\gamma_k} \left(1 + \sqrt{1 + \frac{8m\gamma_k L_T}{9f}}\right) \\ M &= \frac{6EJ_0 f}{L^2} = \frac{6EJ_0 \gamma_k}{3L + 2mL_T} \end{aligned} \quad (7)$$

(8)

here, $\gamma_k = \gamma - \beta$; $m = \frac{EJ_0}{EJ}$; $f = D - 0,5(D_y + D_x)$

To determine the angle of curvature of the bending mechanism (bend conductor), let's look at the parts BO and BS of the assembly as cantilever beams and use the deformation equations of the angles of rotation of the ends

$$\gamma_k = tg\gamma_k = \frac{F_y L_T^2}{2EJ} = \frac{ML_T}{2EJ} \quad (9)$$

$$\gamma_k = \frac{F_s L^2}{2E_0} = \frac{ML}{2EJ_0} \quad (10)$$

here, F_s – is the force pressing the pipe against the wall at point S.

We can solve the equations (8) - (10) together and determine the curvature angle of the curved conductor.

$$\gamma = \beta + \frac{3f}{mL_T} = \frac{1}{L_T} \left[\frac{D - D_y}{2} + \frac{3}{m} \left(D - \frac{D_2 + D_x}{2} \right) \right] \quad (11)$$

Substituting the value of the actual bending moment in the expression (11), we get the following equations to determine the propellant force F_y generated in the bit and the force F_s pressing the drill collar against the wall at point S.

$$F_y = \frac{M}{L_T} = \frac{6EJ_0 f}{L_T L^2} \quad (12)$$

$$F_s = \frac{M}{L} = \frac{6EJ_0 f}{L^3} \quad (13)$$

4. Conclusions. In order to determine the free passage of the drilling tool through the curved interval of inclined wells, taking into account its elasticity, the intensity of the increase in the zenith angle was calculated accordingly. Based on certain calculations, the free passage of the drilling tool through the curved interval is ensured.

Conflict of interest

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

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Integrated wellbore cleaning, near-wellbore stimulation, and water–air injection for restoring productivity and enhancing oil recovery in mature oil fields

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Abstract. Mature oil fields are commonly characterized by declining production rates, increasing water production, formation damage, near-wellbore plugging, sand accumulation, and decreasing efficiency of conventional reservoir-displacement processes. These factors act at different spatial scales, from the wellbore to the near-wellbore zone and the reservoir, and therefore require complementary technological solutions. This paper presents an integrated technological approach based on three complementary developments: a structured washing fluid for sand-plug removal and wellbore restoration; a piston-pump-driven impact-wave device for near-wellbore stimulation; and an ejector system for generating a water–air mixture without an external gas-supply system. The technologies are considered as sequential components of a unified production-restoration and oil-recovery concept. The first technology restores wellbore accessibility by improving the suspension and transport of sand particles. The second restores reservoir-to-well connectivity by generating pressure waves directed toward the perforated productive interval. The third extends the stimulation effect to the reservoir scale by injecting a water–air mixture to improve oil displacement. Laboratory studies associated with the ejector technology demonstrated final oil-displacement factors of 0.50 for formation water, 0.46 for air, and 0.62 for the water–air mixture. A field test of the impact-wave device increased oil production from 0.4 to 1.0 t/day while water production remained at 6 t/day. The washing-fluid technology was implemented in several production wells affected by sand-plug formation; quantitative production indicators are to be incorporated from the original field records. The integrated concept provides a basis for combining wellbore cleaning, near-wellbore stimulation, and reservoir-scale displacement improvement within a unified strategy for mature oil-field development.

Keywords: mature oil fields; wellbore restoration; sand-plug removal; washing fluid; sand transport; near-wellbore stimulation; impact waves; pressure-wave stimulation; ejector; water–air mixture; enhanced oil recovery; residual oil; production intensification.

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1. Aim

The aim of this study is to formulate a unified technological concept for restoring and intensifying oil production in mature fields by combining three complementary levels of intervention: wellbore cleaning, near-wellbore stimulation, and reservoir-scale oil-displacement enhancement.

The specific **objectives** are to:

1. develop a structured washing-fluid approach capable of suspending and transporting sand particles and removing sand plugs;
2. restore reservoir-to-well connectivity using directed impact-wave stimulation;
3. improve reservoir oil displacement by generating and injecting a water–air mixture using the hydraulic energy of injection water;
4. integrate the three technologies into a multiscale production-restoration strategy.

2. Introduction

The development of mature oil fields requires increasingly complex approaches to maintaining production and recovering remaining hydrocarbon reserves. During late-stage field development, production wells may experience declining productivity, increasing water production, sand accumulation, formation damage, and deterioration of reservoir displacement efficiency [1-21]. These restrictions may occur at different spatial levels. Sand accumulation and sand plugs primarily affect the wellbore. Formation damage and plugging can restrict flow in the near-wellbore zone. At the reservoir scale, incomplete sweep and residual oil reduce the effectiveness of conventional water flooding. Consequently, a single stimulation method may not address all dominant production limitations.

The present study therefore proposes a multiscale technological framework:

wellbore → near-wellbore zone → reservoir, (I)

with the corresponding interventions:

sand-plug removal → flow-connectivity restoration → displacement enhancement. (II)

This approach provides the scientific basis for integrating three technologies originally developed as separate engineering solutions [1-8].

3. Integrated Technological Concept

The proposed technological pathway is shown schematically in Figure 1.

The figure emphasizes that the three technologies act at different but interconnected levels of the production system.

The integrated sequence can therefore be represented as:

Wellbore obstruction → Near-wellbore restriction → Reservoir displacement limitation (III)

and:

Cleaning → Stimulation → Enhanced displacement. (IV)

The technologies are not necessarily intended for simultaneous application in every well. Rather, they form a complementary technological portfolio that can be selected according to the dominant production constraint.

4. Technology I – Structured Washing Fluid for Sand-Plug Removal

4.1. Problem and technological concept

Intensive sand production may occur in weakly cemented and unstable formations. Accumulation of sand particles can result in the formation of large sand plugs, restricting wellbore flow and potentially leading to well shutdown.

Conventional washing fluids may not provide sufficient carrying capacity for coarse particles or adequate control of fluid losses. The proposed washing-fluid technology addresses this problem through a structured, high-viscosity and micro-aerated system.

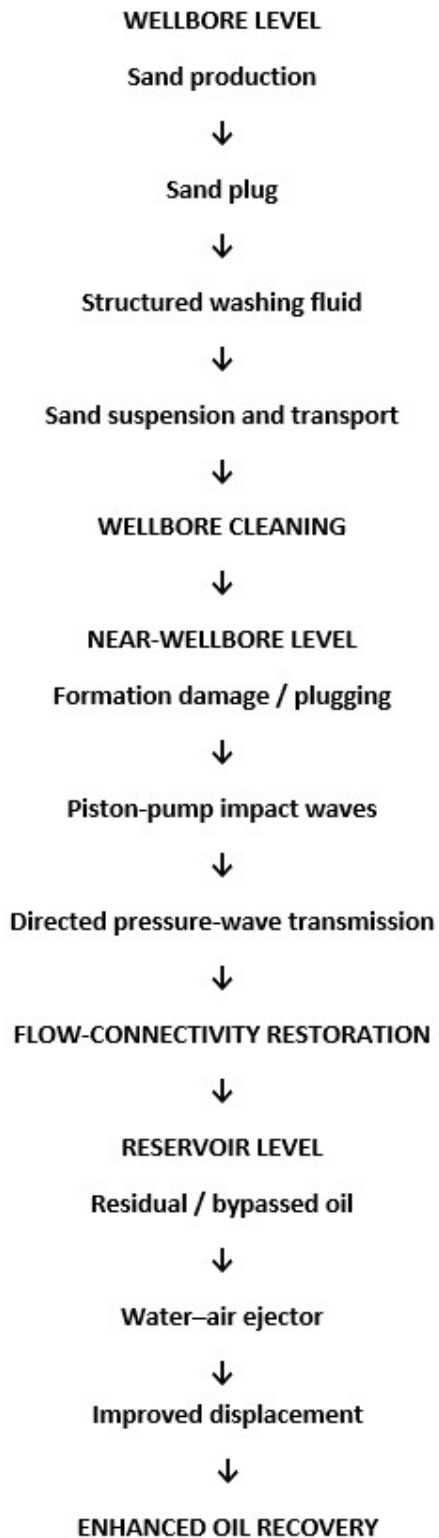


Figure 1. Multiscale technological pathway for restoration and enhancement of oil production in mature fields.

4.2. Composition

The optimal composition of the drilling fluid is given below.

Component wt. %	Concentration,
Quicklime (CaO)	0.5–1.0
Aluminium sulfate	0.5–1.0
Sodium silicate (liquid glass)	0.25–0.50
NIAGARA (AR–FFFP)	0.025–0.05
Technical or seawater	Balance

The functional architecture is:

$CaO + Al_2(SO_4)_3 \rightarrow$ dispersed/colloidal structure + liquid glass $\rightarrow$ structure strengthening + NIAGARA $\rightarrow$ micro-aeration. (V)

The resulting fluid combines structural strength, viscosity, micro-aeration and sand-carrying capacity.

4.3. Sand-transport criterion

An important engineering parameter is the relationship between the upward fluid velocity and the settling velocity of the transported sand particles.

The mean upward fluid velocity is:

$$v_f = \frac{Q}{A}, (1)$$

where Q is the washing-fluid flow rate and A is the effective flow area.

For a simplified particle-settling model, the terminal settling velocity can be estimated as:

$$v_t = \sqrt{\frac{4gd_p(\rho_p - \rho_f)}{3C_D\rho_f}}, (2)$$

where d_p – characteristic particle diameter; ρ_p – particle density; ρ_f – washing-fluid density; C_D – drag coefficient; g – gravitational acceleration.

A useful engineering transport criterion is therefore:

$$\frac{v_f}{v_t} > 1, (3)$$

which indicates that the upward flow velocity is greater than the characteristic settling velocity under the adopted simplified model.

The washing-fluid design is consequently related not only to chemical composition but also to flow velocity, density, viscosity and particle characteristics. In practical applications, the criterion should be evaluated together with the non-Newtonian rheology of the actual washing fluid.

4.4. Mechanism

The treatment sequence is:

washing-fluid injection → contact with sand plug → particle mobilization → suspension → upward transport → sand removal → wellbore restoration. (VI)

The principal controlled parameters include:

- effective viscosity; static shear stress; density; structural stability; mixing intensity; sand-carrying capacity; fluid-loss tendency.

The engineering objective is to maintain sufficient carrying capacity while avoiding excessive hydraulic resistance and undesirable fluid losses.

4.5. Field implementation

The technology was implemented in actual production wells, including wells of “Absheronneft” (781, 403, 1047 and 994), Well 1491 of A. J. Amirov, and Wells 1242 and 1196 of Z. A. Tagiyev.

For Well 1242: depth: 1570 m; filter interval: 1556–1566 m; oil production: 1.3 t/day; water production: 9 t/day; inter-repair period: 30 days.

Based on initial well data, the use of an optimal drilling fluid composition resulted in reduced flushing time and a longer post-treatment interval between workovers, as well as increased sand removal and post-treatment oil production.

5. Technology II – Impact-Wave Stimulation of the Near-Wellbore Zone

5.1. Problem

After removal of a sand plug, production may remain restricted by formation damage or plugging in the near-wellbore zone.

The second technology addresses this limitation through pressure-wave stimulation.

5.2. Device design

Figure 2 shows a schematic of the device for shock-wave treatment of the near-wellbore zone. The device includes:

1. tubing; 2. threaded coupling; 3. connecting pipe; 4. piston pump; 5. bottom support; 6. pipe with outlet openings; 7. outlet openings; 8. support pipe; 9. plug.

The assembly is prepared at the surface, connected by threaded joints and checked for leak tightness. The main engineering feature is the use of the piston pump as the impact-wave-generating mechanism.

5.3. Operating principle

The device is positioned so that the outlet openings correspond to the perforated productive interval. Reciprocating piston motion produces pressure fluctuations in the well fluid:

Piston motion → pressure fluctuations → pressure waves → perforations → near-wellbore zone. (VII)

The dynamic action can promote disruption and removal of plugging materials and improve reservoir-to-well flow connectivity.

Compared with the prototype [3] employing pneumatic piston control and multiple valves, the proposed device simplifies the wave-generation mechanism.

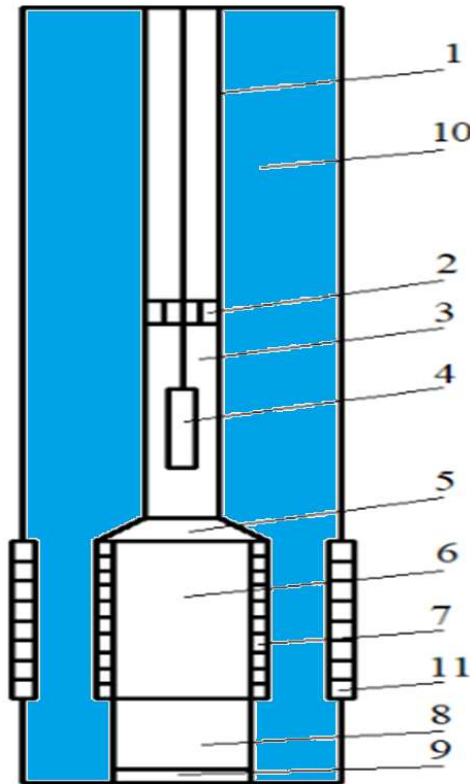


Figure 2. Schematic of the device for shock-wave stimulation of the near-wellbore zone.

5.4. Field test

The device was tested in Production Well No. 1510 at the Gala oil field in Azerbaijan.

Oil production increased from: 0.4 → 1.0 *t/day*, corresponding to a 2.5-fold increase and an absolute increase of 0.6 *t/day*.

Water production remained unchanged: 6 → 6 *t/day*.

The result demonstrates an increase in oil production without a simultaneous increase in water production during the reported test.

6. Technology III – Ejector-Based Water–Air Injection

6.1. Problem

At the reservoir scale, mature fields may contain substantial residual or bypassed oil because of incomplete sweep and declining displacement efficiency.

The third technology addresses this problem by generating a water–air mixture using the hydraulic energy of injection water.

6.2. Ejector design

A schematic diagram of the ejector design is shown in Fig. 3.

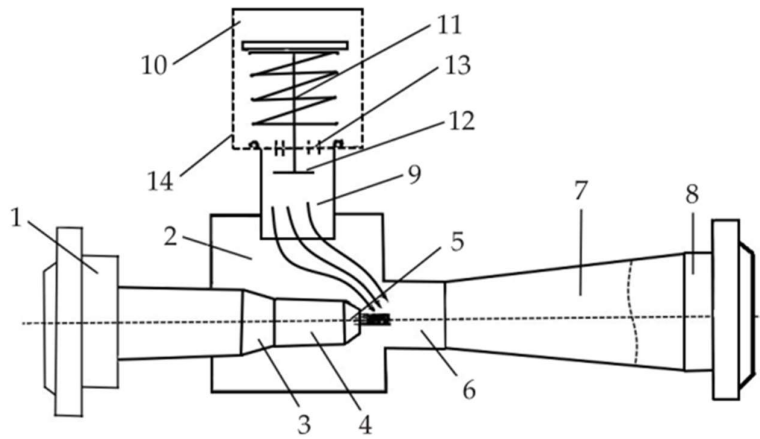


Figure 3. Schematic of the ejector assembly.

The ejector contains: 1. liquid inlet pipe; 2. receiving chamber; 3. confuser; 4. internal liquid pipe; 5. nozzle; 6. mixing chamber; 7. diffuser; 8. outlet pipe; 9. connecting branch pipe; 10. suction chamber; 11. spring; 12. dish-shaped valve; 13. air passage openings; 14. air intake openings.

The principal engineering innovation is the integration of a suction chamber and spring-loaded valve arrangement that enables atmospheric air to be entrained without a separate external gas-supply system.

6.3. Operating principle

The process is:

Pressurized water → velocity increase → pressure reduction → air suction → water–air mixing. (VIII)

The resulting mixture is delivered to the injection well and subsequently to the reservoir.

The ejection ratio is defined as:

$$R = \frac{V_{air}}{V_{water}}, \quad (4)$$

where V_{air} is the air volume and V_{water} is the water volume.

The reported optimum regime corresponded to approximately 60% air in the total mixture volume.

6.4. Laboratory results

Linear reservoir models had a length of 1.2 m and an internal diameter of 0.026 m. Quartz sand of different fractions with clay was used to reproduce heterogeneity. Initial model saturation consisted of 80% oil and 20% residual water.

Working agent factor	Final oil-displacement
Formation water	0.50
Air	0.46
Water + air	0.62

The water–air mixture produced the highest final oil-displacement factor.

6.5. Field test

The ejector was tested at Production Well No. 1781 in the second area of Siyazənneft and connected to Injection Well No. 349.

Before the test:

- oil production: 8 t/month;
- produced water: 174 m³/month.

After seven months:

- additional oil production: 130 t;
- produced water: 90 m³/month.

These results indicate the potential of the water–air injection approach for mature reservoirs with declining oil production and substantial water production.

7. Integrated Discussion

The three technologies address different production restrictions:

Scale	Main restriction	Technology	Main function
Wellbore	Sand plug	Structured washing fluid	Cleaning and sand transport
Near-wellbore	Formation damage / plugging	Impact-wave device	Connectivity restoration
Reservoir	Residual / bypassed oil	Water–air ejector	Displacement enhancement

This creates the central technological chain:

Wellbore cleaning → Near-wellbore stimulation → Reservoir displacement enhancement. (IX)

The technologies are complementary rather than redundant.

A well dominated by sand plugging may first require washing-fluid treatment. If productivity remains low after cleaning, near-wellbore stimulation may be considered. If wellbore and near-wellbore restrictions are adequately controlled but reservoir-scale displacement remains limiting, water–air injection may be considered.

Thus, the integrated concept provides a diagnostic and intervention framework rather than requiring universal simultaneous application.

8. Scientific Novelty

The scientific novelty of the present study lies in formulating three independent engineering developments as a unified multiscale production-restoration and oil-recovery system.

The novelty consists of:

1. establishing a spatial hierarchy connecting wellbore cleaning, near-wellbore stimulation and reservoir displacement enhancement;
2. connecting rheological sand transport, dynamic pressure-wave stimulation and water–air displacement within one production-restoration framework;
3. extending the conventional concept of well stimulation from a local intervention toward a multiscale wellbore–reservoir strategy;

4. providing a decision-oriented sequence for selecting technological intervention according to the dominant production constraint.

The novelty of the manuscript therefore concerns the integration and scientific interpretation of the three technologies, rather than claiming that each individual technology was invented within the present paper.

9. Practical Significance

The integrated technology portfolio can provide practical benefits at different stages of mature-field operation.

The washing-fluid technology can facilitate sand-plug removal and wellbore restoration.

The impact-wave device can provide a comparatively simple means of stimulating the near-wellbore zone.

The ejector can generate a water–air working mixture using the hydraulic energy of injection water, potentially reducing dependence on an external gas-supply system.

The combined approach may therefore contribute to:

- restoration of wellbore accessibility;
- improved near-wellbore filtration;
- increased oil inflow;
- maintenance or reduction of water production in appropriate cases;
- improved reservoir displacement;
- mobilization of residual oil;
- extension of productive well life;
- reduction of repeated intervention requirements.

The recommended operational strategy is:

Diagnose → Clean → Stimulate → Evaluate → Intensify → Monitor. (X)

10. Conclusions

A unified multiscale technological concept has been developed by combining structured washing-fluid treatment, piston-pump-driven impact-wave stimulation and ejector-based water–air injection.

The principal conclusions are:

1. The structured washing fluid addresses wellbore obstruction by improving sand suspension and transport and facilitating sand-plug removal.
2. The proposed impact-wave device addresses near-wellbore restrictions by generating pressure waves with a piston pump and directing them toward the perforated productive interval.
3. Field testing of the impact-wave device increased oil production from 0.4 to 1.0 t/day, corresponding to a 2.5-fold increase, while water production remained at 6 t/day.
4. The ejector converts hydraulic energy of injected water into an air-entrainment mechanism, enabling formation of a water–air mixture without a separate external gas-supply system.
5. Laboratory reservoir-model experiments produced a final oil-displacement factor of 0.62 for the water–air mixture compared with 0.50 for formation water and 0.46 for air.
6. The three technologies form a spatially hierarchical intervention pathway:

wellbore cleaning → near-wellbore stimulation → reservoir displacement enhancement.

7. The proposed concept is intended as a flexible technology-selection framework in which the intervention is matched to the dominant production limitation.

The resulting approach transforms three separate engineering developments into a coherent pathway from wellbore restoration to near-wellbore stimulation and finally to reservoir-scale oil-recovery enhancement.

Conflict of interest.

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

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