

Original Paper

Dynamic evolution of stress interference during the multi-layer exploitation of sand-shale interacted continental shale oil reservoirs



Qi-Xing Zhang^{a,b,*}, Bing Hou^{b,c,**}, Liao-Yuan Zhang^d, Bin-Tao Zheng^d, Zhen-Yu Wang^e

^a College of Mechanical and Electrical Engineering, Beijing University of Chemical Technology, Beijing, 100029, China

^b National Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum, Beijing, 102249, China

^c Department of Petroleum Engineering, China University of Petroleum (Beijing) at Karamay, Karamay, 834000, Xinjiang, China

^d Shengli Oilfield Company, SINOPEC, Dongying, 257000, Shandong, China

^e ZhenHua Oil Company Limited, Beijing, 100031, China

ARTICLE INFO

Article history:

Received 7 December 2025

Received in revised form

1 February 2026

Accepted 14 April 2026

Available online 21 April 2026

Edited by Jia-Jia Fei

Keywords:

Hydraulic fracturing

Multi-layer exploitation

Sand-shale interbedded layers

Geomechanical modeling

Interlayer stress interference

ABSTRACT

Accurate prediction of stress evolution induced by production pressure depletion after hydraulic fracturing is essential for efficient development of stacked continental shale reservoirs. This study establishes a three-dimensional stress sensitivity and flow coupling framework to characterize intra-layer and interlayer stress evolution during shale oil development. A 3D discrete fracture network (DFN) integrating hydraulic and natural fractures was reconstructed from microseismic data obtained during multi-layer fracturing. Based on this, a stress sensitivity model for interbedded sandstone–shale reservoirs and a V-shaped well layout flow model was developed to simulate single-layer (three-well) and three-layer (nine-well) production scenarios. The reconstructed fracture network revealed that hydraulic fractures propagate laterally away from the zipper fracturing side and vertically upward toward low-pressure zones. During multi-layer development on Platform H, fracture intersections between the middle and adjacent layers produced 0–3 MPa pore pressure interference under different production schedules, indicating the need for optimized inter-well and interlayer spacing. Sandstone layers, characterized by higher permeability and porosity, exhibited a greater increase in horizontal stress difference (2.61 MPa) than shale layers (<0.5 MPa). Stress reorientation angles ranged from 5° to 38° in shale and from 16° to 64° in sandstone layers. These results demonstrate that well spacing should be larger in sandstone layers, whereas infill drilling is more suitable within shale intervals. The proposed modeling and analysis approach provides a theoretical and technical basis for optimizing well pattern deployment and maximizing energy utilization in shale oil reservoir development.

© 2026 The Authors. Publishing services by Elsevier B.V. on behalf of KeAi Communications Co. Ltd. This is an open access article under the CC BY-NC-ND license (<http://creativecommons.org/licenses/by-nc-nd/4.0/>).

1. Introduction

Oilfield development practices in shale oil and gas plays such as Eagle Ford and Bakken in North America, as well as Fuling and Changning–Weiyuan in China, have demonstrated that hydraulic fracturing technology is evolving from single-layer multi-well volumetric fracturing to stereoscopic fracturing (Patel et al., 2016; Sun et al., 2023). Stereoscopic fracturing can effectively stimulate

low-permeability formations, significantly enhance shale resource utilization and recovery while also reducing operational costs, shortening construction cycles, improving equipment utilization, and minimizing land use (Barbosa et al., 2025). By deploying multiple horizontal wells within a single well pad and simultaneously developing multiple reservoir layers, petroleum engineers can maximize the areal coverage of well patterns (Zhang et al., 2022). Typically, a single pad involves 2 to 5 stacked layers with 16 to 65 wells. For example, the Wolfcamp shale, with an average thickness of approximately 350 m, is commonly developed using V- and W-shaped well trajectories with same-layer well spacing of about 200 m and interlayer spacing of 100 m, enabling efficient three-layer development (Zhang et al., 2025a).

Wood et al. (2018), Ajisafe et al. (2017), and Guo et al. (2025) reported that the lateral migration distance of proppant in

* Corresponding author.

** Corresponding author.

E-mail addresses: 2024700038@buct.edu.cn (Q.-X. Zhang), binghou@cup.edu.cn (B. Hou).

Peer review under the responsibility of China University of Petroleum (Beijing).

List of symbols			
DFN	Discrete fracture network	$\mathbf{u}$	Flow velocity vector
DFM	Discrete fracture model	Q_m	Source term
DBSCAN	Density-based spatial clustering of applications with noise	k_m	Matrix permeability
RANSAC	Random sample consensus	μ	Fluid viscosity
SRV	Stimulated reservoir volume	g	Gravitational acceleration
LGR	Local grid refinement	ε_v	Volumetric strain
DOFs	Degrees of freedom	t	Production time
Constant a	Seismicity parameter, representing the level of seismic activity	S_m	Total compressibility of the rock
b -value	Proportional coefficient in the magnitude–frequency relationship	χ_L	Compressibility coefficients of the fluid
M	Earthquake magnitude	χ_m	Compressibility coefficients of the solid
N	Frequency of events with magnitude greater than M	χ_f	Compressibility coefficients of the fracture
σ_{ij}	Stress component.	d_f	Fracture aperture
ε_{ij}	Strain component	∇_T	Tangential gradient operator along the fracture
ε_{kk}	Volumetric strain of the rock	k_f	Fracture permeability
δ_{ij}	Kronecker delta, which is equals to 1 when $i=j$ and 0 when $i \neq j$	Q_f	Source term in the fracture
G	Shear modulus	ϕ_{ss}	Porosity of sandstone
K	Bulk modulus	ϕ_{ss0}	Initial porosity of sandstone
α	Biot coefficient	α_{ss}	Effective stress coefficient of sandstone
p	Pore pressure	ε_{vss}	Volumetric strain of sandstone
$p_{,i}$	Partial derivative of pore pressure p with respect to the i -direction	k_{ss}	Permeability of sandstone
$u_{i,j}$	Partial derivative of the displacement component u_i with respect to the j -direction	k_{ss0}	Initial permeability of sandstone
$u_{j,i}$	Partial derivative of the displacement component u_j with respect to the i -direction	ϕ_s	Porosity of shale
f_i	Component of the body force in the i -direction	ϕ_{s0}	Initial porosity of shale
$\sigma_{ij,j}$	Partial derivative of the stress component σ_{ij} with respect to the j -direction	α_s	Effective stress coefficient of shale
$u_{j,ji}$	Second-order partial derivative of the displacement component u_j with respect to j - and i -directions	ε_{vs}	Volumetric strain of shale
$u_{i,jj}$	Second-order partial derivative of the displacement component u_i with respect to j -direction	k_s	Permeability of shale
ϕ_m	Matrix porosity	k_{s0}	Initial permeability of shale
ρ	Fluid density	d_{f0}	Initial fracture aperture
		p_f	Fluid pressure inside the fracture
		p_{f0}	Initial fluid pressure inside the fracture
		S_{Hmax}	Maximum horizontal in situ stress
		S_{Hmin}	Minimum horizontal in situ stress
		$S_{Hmax}-S_{Hmin}$	Horizontal stress difference
		S_v	Overburden in situ stress
		θ	Angle between the minimum horizontal principal stress and the x -axis
		σ_H	Maximum horizontal principal stress
		σ_h	Minimum horizontal principal stress
		p_p-p_0	Pore pressure variation

hydraulic fractures of shale formations is typically around 20–30 m, while the vertical migration height of most proppant is about 10–20 m. This indicates that thick shale formations have substantial potential for multi-layer development. Huang et al. (2019, 2022) explored the characteristics of fracture geometry and the vertical penetration behavior of hydraulic fractures under varying geological conditions and operational parameters. Multi-layer development can be categorized into two main types. The first type targets shale reservoirs such as Haynesville and Bossier, where multiple sweet spots are vertically dispersed over large intervals (greater than 80 m); in such cases, wells are drilled separately in different sweet-spot layers (Defeu et al., 2019). The second type targets formations like the Wolfcamp shale, characterized by thick sweet spot intervals interbedded with multiple limestone and sandstone layers, where stereoscopic staggered well placement is adopted. All planned wells are drilled from the same surface location, and multiple productive layers are accessed simultaneously through multilateral horizontal well and commingled production technologies (Kaufman et al., 2019). Unlike North American marine shale multi-layer development, which typically involves multiple stacked layers across multiple

formations, China's marine shale gas is older, occurs at greater depths, and exhibits high temperatures, high pressures, and complex structural–lithological characteristics. The vertical distribution of shale layers is often discontinuous and interbedded with thin sandstone intervals, resulting in a “single formation–multilayer” development pattern (Guo et al., 2024; Yang, 2024). Continental shale oil reservoirs are characterized by large depositional thickness and well-developed sedimentary rhythms, with rapid vertical and lateral variations in lithology, oil-bearing properties, and interlayer distribution, as well as relatively low thermal maturity, making multi-layer development even more challenging (Lv and Hou, 2024).

Stereoscopic fracturing and conventional multi-stage/multi-cluster fracturing of a horizontal well lead to significantly different patterns in local stress field evolution, fracture propagation behavior, and fluid flow regimes (Marongiu-Porcu et al., 2016). In practice, zipper fracturing and simultaneous fracturing are commonly applied to maximize the stimulated reservoir volume by enhancing stress interference between wells and clusters and activating pre-existing natural fractures (Zhang et al., 2025b). Wang et al. (2023), Zhang et al. (2021a), and Wang et al. (2026)

established three-dimensional fully coupled perforation-fracturing models to quantitatively describe fracture competition and growth dynamics among multiple perforation clusters. During multi-well fracturing, when the stress fronts generated by two wells intersect head-on, stress neutralization may occur, thereby suppressing further fracture propagation (Abdelaziz et al., 2023; Zhang et al., 2026). In contrast, oblique intersection of stress fronts can generate new fractures through shear effects, improving stimulation effectiveness (Chang and Hou, 2023; Hou et al., 2024). Li et al. (2025) found that optimizing the fracturing sequence can enhance stimulation performance by leveraging inter-fracture stress interference. Wu et al. (2017) observed fracture deflection and attraction between wells, which tends to cause fracture coalescence and inter-well connectivity. Sesetty and Ghassemi (2015) pointed out that the closure behavior of early-stage fractures significantly affects induced stress field evolution and the geometry of subsequent fractures. Wang et al. (2022) argued that although high stress anisotropy can effectively reduce fracture deflection caused by inter-well stress interference, asymmetric fracture propagation and insufficient reservoir stimulation between wells can still occur. Pei et al. (2023) and Yin et al. (2025) demonstrated that both orthogonal and inclined well patterns are susceptible to enhanced asymmetric fracture growth in child wells when the parent-child well spacing is reduced or the production period is prolonged. Qiu et al. (2015) demonstrated that there exists an optimal well and cluster spacing during hydraulic fracturing, and zipper fracturing generally achieves better reservoir stimulation than sequential fracturing. Dontsov and Peirce (2015) investigated proppant transport during dynamic single-fracture propagation and found that proppant accumulation within the fracture reduces fluid conductivity. Wang et al. (2018) integrated a proppant transport model into the PKN fracture propagation model and evaluated the effects of proppant distribution on fracture closure width and fracture conductivity.

The development of unconventional oil and gas reservoirs has entered a stage characterized by the large-scale application of stereoscopic well pattern development, with gradually reduced well spacing and interlayer spacing. However, production-induced stress interference has resulted in significant variability in development performance (Luo et al., 2021; Pei and Sepehrnoori, 2022). Sawadogo et al. (2020) evaluated the effects of well spacing and layer settings on inter-well connectivity and production dynamics throughout the entire wellbore interval. Alimahomed et al. (2018) investigated stereoscopic well stacking and staggered development strategies and demonstrated that a bottom-up completion sequence combined with a well spacing of 660 ft can significantly enhance oil and gas production. Bommer and Bayne (2020) employed an integrated geological-engineering simulation combined with microseismic monitoring, tracer tests, and inter-well pressure interference measurements to optimize the well spacing, identifying 300 m as the optimal value. Guo et al. (2018) developed a two-dimensional multi-phase flow-geomechanics coupled model to investigate stress reorientation during production in the Eagle Ford shale gas reservoir. Curnow and Tutuncu (2016) applied a dual-porosity dual-permeability model to analyze stress field evolution during horizontal well production in the Eagle Ford shale oil reservoir, enabling optimization of fracturing and production strategies. Morales et al. (2016) established a three-dimensional hydro-mechanical coupling model to study stress evolution during production from hydraulically fractured horizontal wells in shale oil reservoirs, analyzing its effects on refracturing and infill well stimulation. Sangnimmuan et al. (2019) incorporated reservoir stacking features into a coupled reservoir-geomechanics-EDFM model to investigate the spatiotemporal evolution of the stress field in the Permian Basin, demonstrating

that vertical well pattern deployment induces less stress perturbation than infill drilling in horizontal well patterns. Wei et al. (2021) found that as formation pressure decreases during production, the orientation of principal stresses changes, with stress reversal occurring near hydraulic fractures. Zhang et al. (2021b) and Hou et al. (2022) used the RANSAC algorithm to reconstruct complex three-dimensional fracture networks for both primary and infill wells in shale gas reservoirs, and applied dual-porosity dual-permeability modeling to investigate stress interference between hydraulic fractures and between wells.

Many existing studies examine the dynamic evolution of reservoir stress fields using fracture geometries derived primarily from numerical simulations. Moreover, most models are limited to production-induced stress variations under different well-pattern deployments involving only two or three horizontal wells, whereas the coupled effects of well-pattern and fracture-network configurations in multi-layer, multi-well development are often overlooked. During multi-layer development of continental shale oil reservoirs, the three-dimensional distribution of fracture networks and fluid flow behaviors are the two key factors governing the evolution of the in-situ stress field. In this study, we first reconstructed the post-stimulation hydraulic fracture network geometry for Platform H using microseismic events recorded during multi-layer fracturing operations. This allowed a clear visualization of the fracture network morphology for nine wells after stimulation. Then, according to the distribution characteristics of “sweet spots” in different continental shale oil reservoirs and considering interlayer spacing and layer thickness, a 3-layer, 9-well hydro-mechanical coupling model was established, as shown in Fig. 1. A series of numerical simulations of interlayer multi-horizontal well fracturing and production with a V-shaped well layout were performed to investigate the dynamic evolution of both horizontal and vertical in-situ stress under vertical heterogeneity conditions.

2. Geological background of continental shale oil multi-layer development in the X Depression

2.1. Stereoscopic well pattern configuration and microseismic monitoring

The X Depression is a typical representative of continental faulted basins in China, characterized by strong vertical heterogeneity. The target formation consists of thin interbedded layers with well-developed lamina fractures and multiple types and scales of microfractures. Due to variations in mineral composition, different interbeds exhibit either brittle or ductile mechanical behavior. The shale oil reservoirs are deeply buried, with depths ranging from 3000 to 5000 m, and are subject to high horizontal stress anisotropy and abnormally high pore pressure. The fracture system is well developed, and the differential horizontal stress ranges from 4.9 to 6.9 MPa, with an average of 5.7 MPa. The reservoir lithology is primarily composed of mudstone and sandstone, with a typical lithological assemblage of thick mudstone interbedded with thin sandstone. Porosity generally ranges from 4% to 10%. The reservoir is characterized by limited lateral continuity and discontinuous vertical distribution. The target intervals exhibit good brittleness, with brittleness indices ranging from 0.35 to 0.45 (average 0.38), and Poisson's ratios ranging from 0.25 to 0.30 (average 0.28).

Taking Well H-1-A as an example, the stage length ranges from 60 to 67 m, with an average of 61.5 m. The cluster spacing ranges from 8 to 11 m, with an average of 9.5 m. The proppant and fluid injection intensities are 3.3 and 38.5 m³/m,

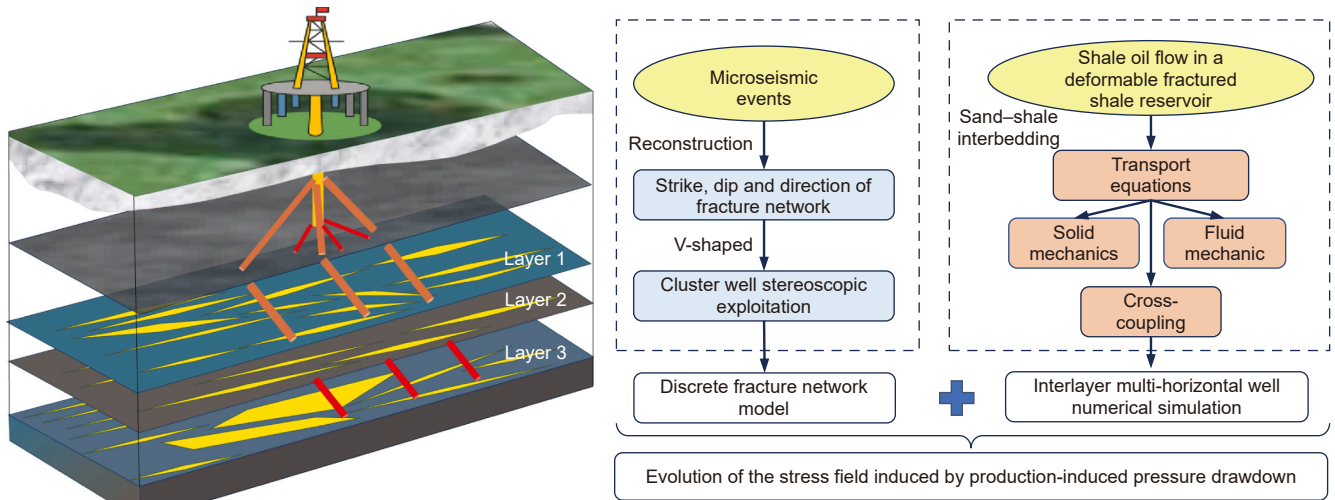


Fig. 1. Schematic diagram of stereoscopic fracturing and the research workflow.

respectively. The well is completed at a depth of 3200–3434 m, with a reservoir temperature of 135 °C, an average porosity of 5.3%, and an average permeability of 0.848 mD. During hydraulic fracturing, a surface microseismic monitoring system was deployed on Platform H using an array of three-component geophones. The monitoring network consisted of 95 three-component intelligent seismic nodes. Microseismic signals were acquired, denoised, and then processed through event location and interpretation workflows. Due to the influence of faults and pre-existing natural fractures, Well H-1-A exhibited a significant accumulation of microseismic events near the wellbore, forming a distinct angle with the dominant fracture propagation direction. Large-scale natural fractures were detected on the left side of Stage 20 and the right side of Stage 21. In contrast, the natural fracture response was weaker in Wells H-1-B and H-1-C. The microseismic events in these two wells showed a strip-like distribution pattern, forming a certain angle with the wellbore and exhibiting asymmetric spatial distribution along the well, as illustrated in Fig. 2.

2.2. Evaluation of microseismic activity during zipper fracturing on a cluster well platform

In seismological prediction studies, a sudden decrease in the b -value is generally considered an indicator of stress release and a potential precursor to seismic events. The Gutenberg-Richter law describes the relationship between M and N , as shown in the following equation, where N represents the number of events with magnitude greater than M , and a and b are constants (Lei and Ma, 2014). The parameter b is commonly called the b -value.

$$\log N = a - bM \quad (1)$$

For the three horizontal wells in Layer H-1, a total of 19,917 microseismic events were recorded during 74 hydraulic fracturing stages. The magnitude distribution of microseismic events ranged from -2.6 to -0.2 . The Gutenberg-Richter relationship for the three wells is shown in Fig. 3(a). The calculated b -values for the three wells are 2.58, 2.86, and 2.64, respectively. For comparison, the b -value for natural earthquakes is typically close to 1, while

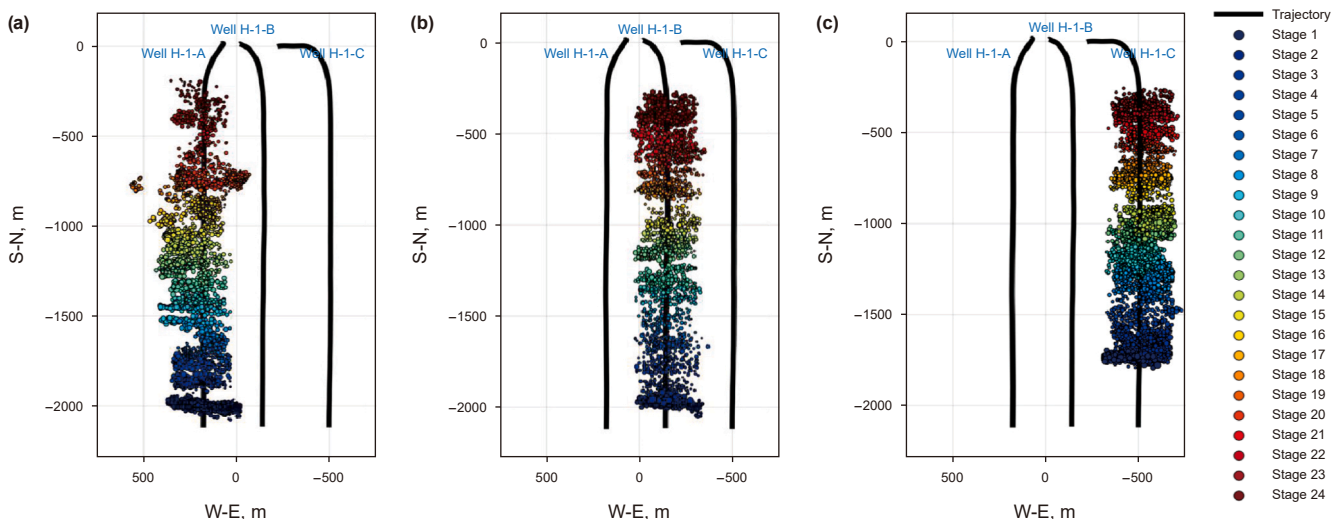


Fig. 2. Plan view of microseismic event distribution for the three wells in Layer H-1. The diameter of each event marker corresponds to the event magnitude.

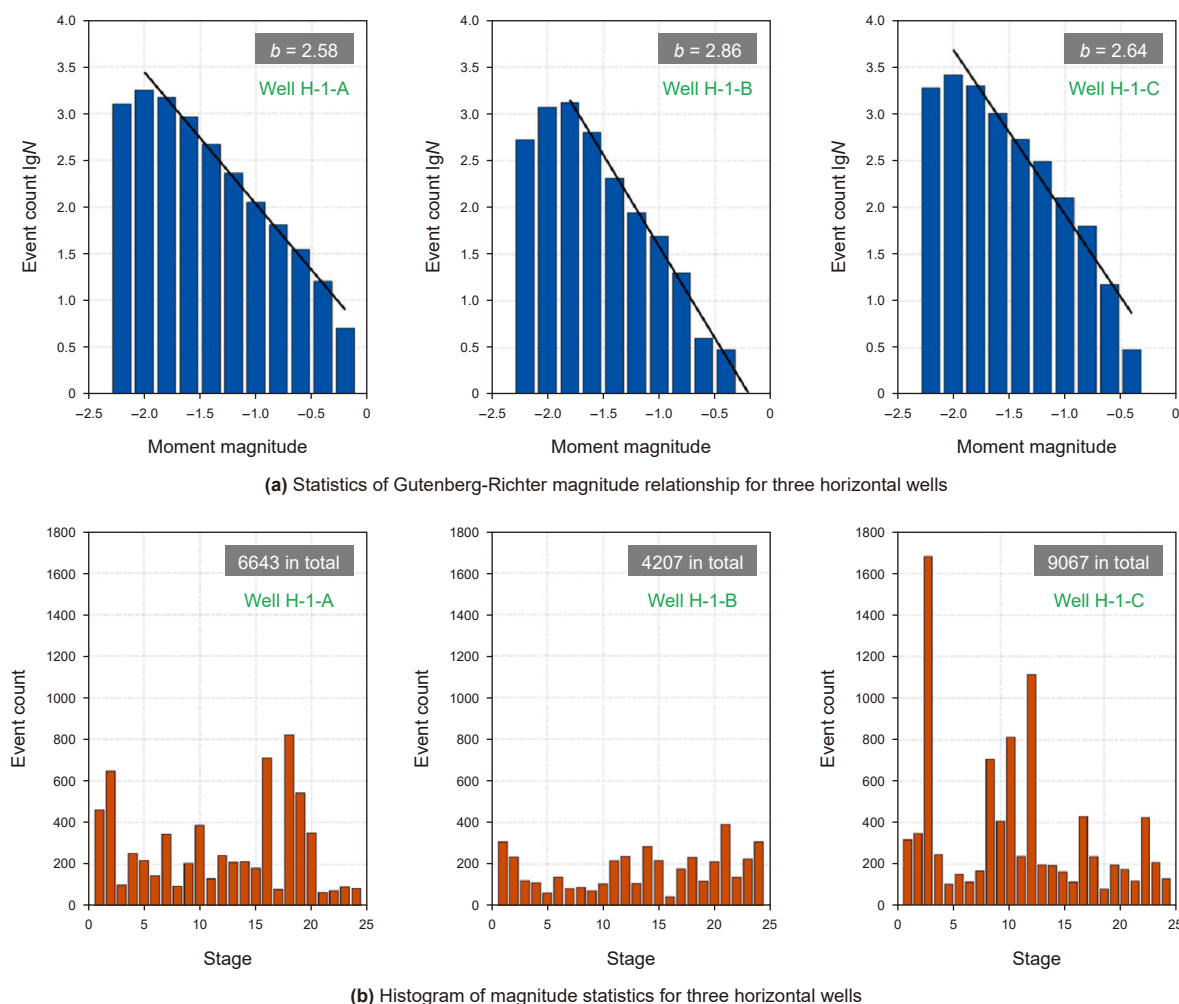


Fig. 3. Gutenberg-Richter magnitude–frequency relationship and event magnitude histogram.

that for induced events in tight sandstone fracturing is around 2.4. The average b -value of 2.67 for the H well group indicates that the number of larger-magnitude events is relatively small, which is consistent with the monitoring results. The histogram of event magnitudes for the three horizontal wells is presented in Fig. 3(b). The total number of monitored events for Wells H-1-A, H-1-B, and H-1-C is 6,643, 4,207, and 9,067, respectively. The number of events recorded by Well H-1-C is approximately 1.36 and 2.15 times that of the other two wells, indicating stronger microseismic activity during fracturing operations.

Wang et al. (2009) suggested that the b -value can be used to infer reservoir stress and lithological characteristics, and that the b -value is closely related to rock brittleness. A smaller b -value after fracturing indicates the formation of a more complex fracture network. In general, tectonic stress within the rock mass is inversely correlated with b -value, and low- b -value zones are typically associated with higher stress accumulation. Fig. 4 shows the comparison between the average event magnitude and b -value for each fracturing stage of Well H-1-A. It can be observed that stages 2, 3, 6, 7, 10, 11, and 19–22, where strong-magnitude events are concentrated, correspond to smaller b -values, mostly below 1. This indicates that the reservoir in these zones tends to be more brittle and capable of higher stress accumulation than surrounding intervals, resulting in a greater number of large-magnitude microseismic events.

2.3. Three-dimensional discrete fracture network reconstruction and stimulation effectiveness evaluation

The spatial distribution of dry microseismic events within each fracturing stage and cluster exhibits an isolated, scattered pattern (Shakiba and Sepehrnoori, 2015). To effectively identify the density distribution of microseismic event clusters, the DBSCAN algorithm was applied. This approach allows for the identification of dry events generated during reservoir stimulation and removes noise points, thereby eliminating blank zones in the fracture network caused by noise and improving the accuracy of hydraulic fracture orientation identification and SRV calculation. Given the multi-stage, multi-cluster design of horizontal wells, the RANSAC algorithm, known for its high robustness, was employed to reconstruct the hydraulic fracture network using both core point sets and boundary point sets. This process enabled the extraction of fracture surface geometries and the characterization of intersection points between hydraulic and natural fractures. Details of the algorithm implementation can be found in (Zhang et al., 2025c).

The hydraulic fractures created by the three horizontal wells effectively interacted with the pre-existing natural fracture network, forming a high-complexity fracture system that aligns well with the observed microseismic event distribution. For each fracturing stage, the reconstructed fracture propagation envelope

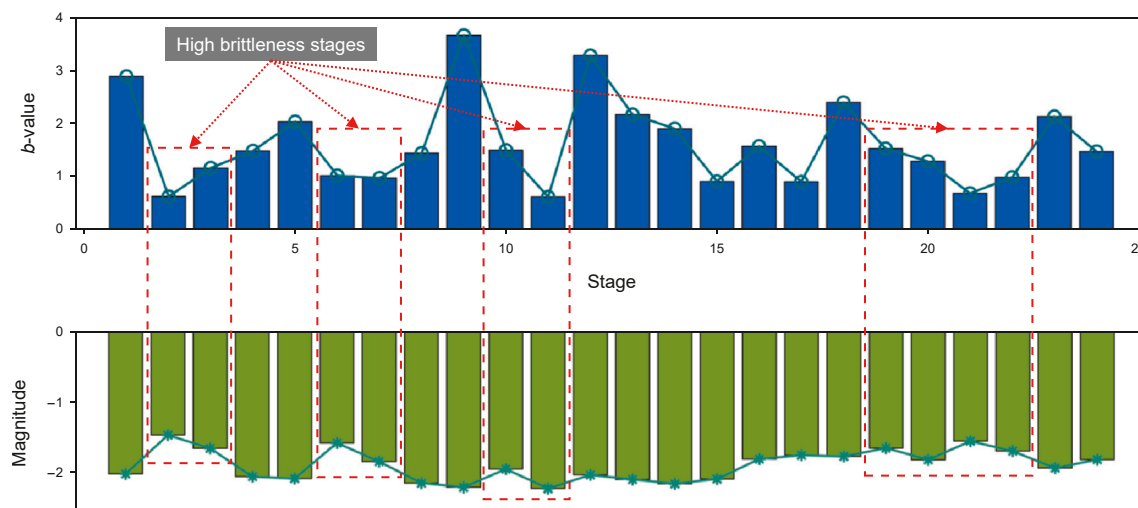


Fig. 4. Comparison of average event magnitude and b -value for each fracturing stage of Well H-1-A.

corresponds closely to the spatial distribution of its associated microseismic signals. Spatially, the fracture network primarily extends laterally along the maximum principal stress direction, forming an intersection angle with the wellbore, while the vertical propagation remains relatively narrow, as illustrated in Fig. 5. In addition, most hydraulic fractures are not perfectly perpendicular to the wellbore. The reconstructed hydraulic fracture geometries are highly complex, influenced mainly by stress interference induced by zipper fracturing and the presence of strip-shaped natural fracture belts. From the perspective of the three wells: Well H-1-A is strongly influenced by surrounding natural

fractures. Pressure transmission during fracturing stimulated fractures in the far-well region, resulting in a large number of low-density events distributed away from the wellbore. Natural fractures are more developed in Stages 19–24, with shorter reconstructed natural fracture lengths and smaller intersection angles with the wellbore. Well H-1-B exhibits a more symmetric fracture distribution, with dominant hydraulic fractures between Stages 8 and 12 that are nearly perpendicular to the wellbore. Well H-1-C shows the most uniform event distribution and the widest overall coverage. Due to the influence of faults and natural fractures, fractures in Stages 3 and 9–13 are particularly complex.

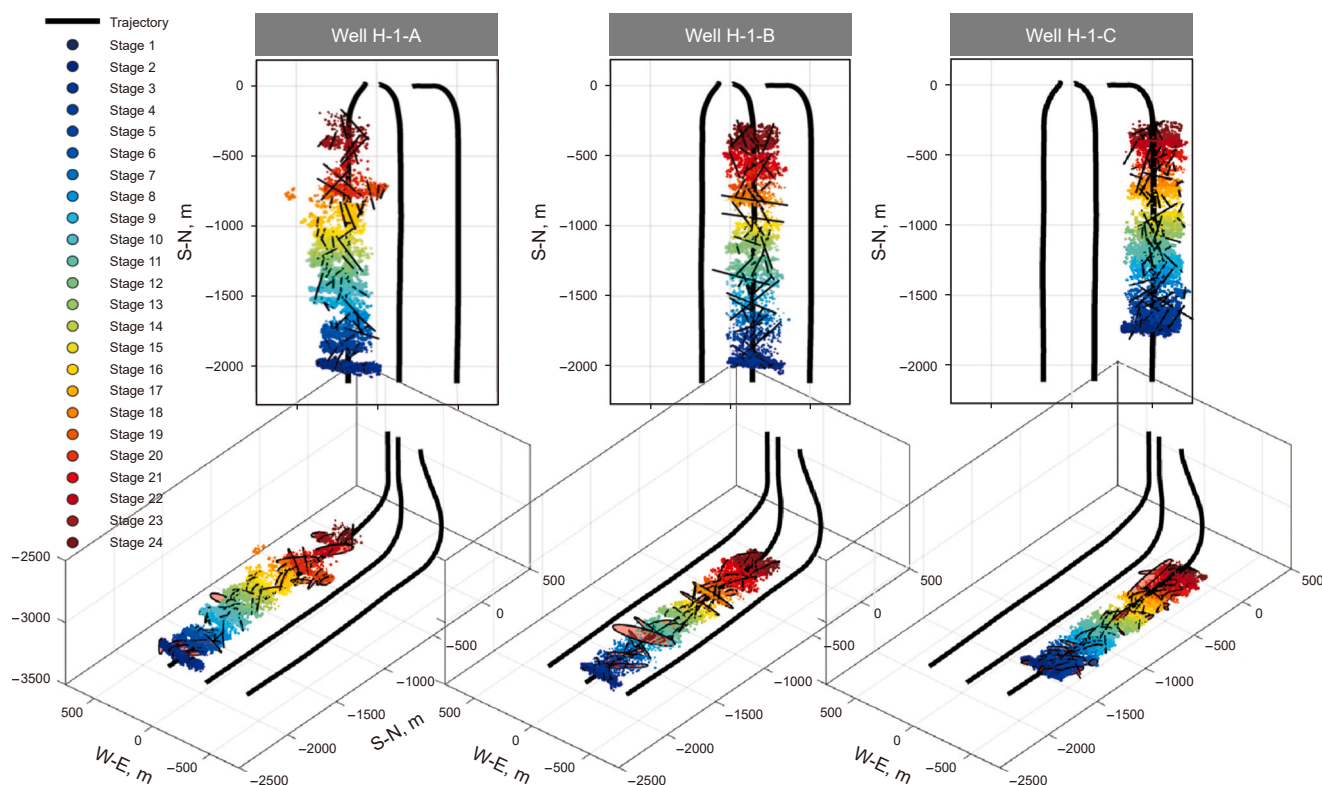


Fig. 5. Reconstructed hydraulic fracture network for the three horizontal wells in Layer H-1 based on microseismic events.

The hydraulic fracture network serves as the main flow pathway for shale oil and gas production, and fracture length and height are key indicators for evaluating stimulation effectiveness and production potential. Taking Well H-1-A as an example, Fig. 6 presents a bar chart comparing the fracture length, fracture height, half-fracture length, and half-fracture height. The distribution of fracture length and height is highly uneven, with large standard deviations, indicating strong heterogeneity in fracture propagation. For Well H-1-A, the average fracture length and average fracture height are 239 and 83 m, respectively, both showing asymmetric propagation characteristics. The left and right half-fracture lengths are 129 and 109 m, respectively, with the wing away from the zipper fracturing well showing stronger development. This suggests that, under the influence of zipper fracturing, injection pressure from adjacent wells increases effective stress in the fracture zone, enhancing fracture complexity and deflection on the zipper side while promoting greater half-fracture length growth on the opposite side. In the vertical direction, the upper fracture height and lower fracture height are 48 and 36 m, respectively. This indicates that the hydraulic fracture network tends to propagate upward toward regions of lower pore pressure,

reflecting the preferential fracture growth direction in vertically heterogeneous formations.

3. Flow model of fractured continental shale oil reservoirs

3.1. Solid mechanics governing equations

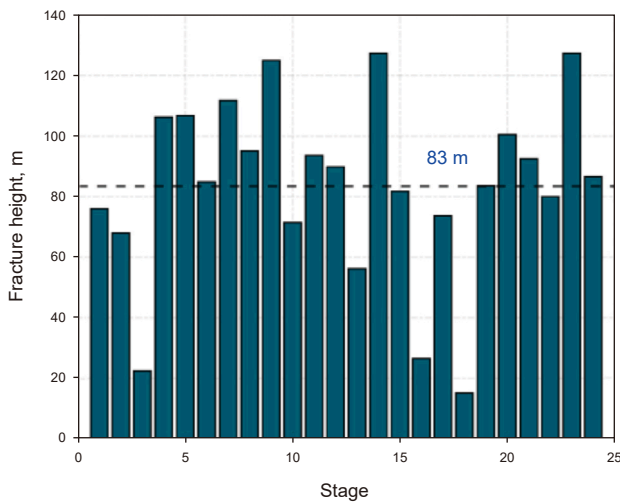
According to the elastic theory of porous media, the constitutive equation of an isotropic matrix saturated with fluid can be derived as follows (He et al., 2020):

$$\sigma_{ij} = 2G\varepsilon_{ij} + \left(K - \frac{2G}{3}\right)\varepsilon_{kk}\delta_{ij} - \alpha p\delta_{ij} \quad (2)$$

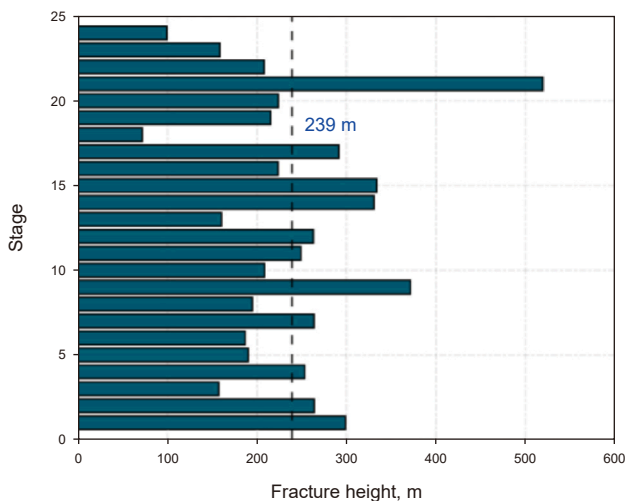
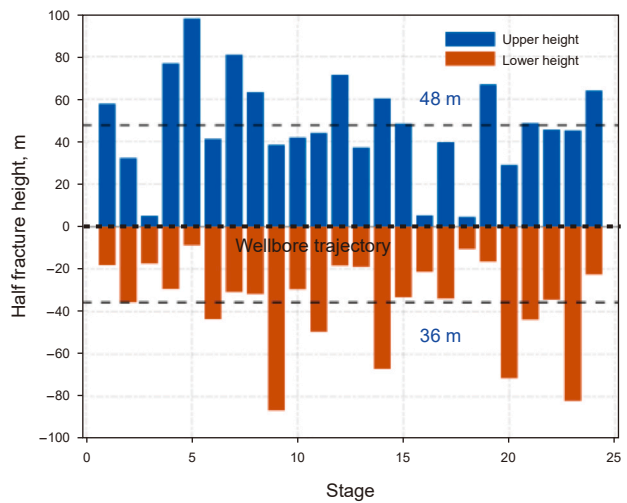
For a homogeneous, isotropic, and elastic medium, the geometric equation can be expressed as:

$$\varepsilon_{ij} = \frac{1}{2}(u_{i,j} + u_{j,i}) \quad (3)$$

Considering the deformation of the solid as a quasi-static process, the stress equilibrium equation can be expressed as:



(a) Bar chart of total and half fracture heights along the vertical direction



(b) Bar chart of total and half fracture lengths along the horizontal direction

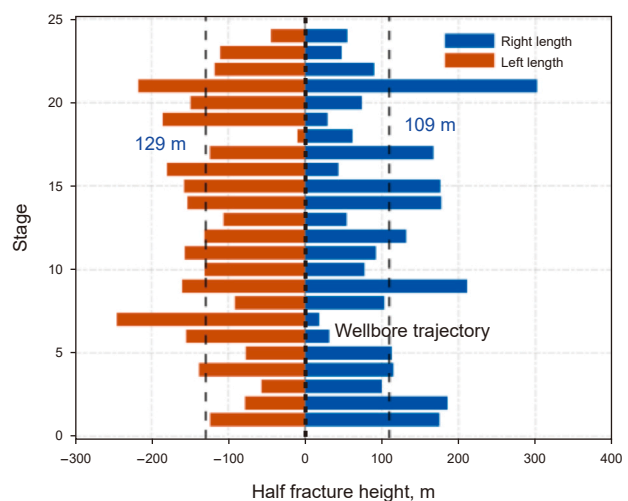


Fig. 6. Bar chart of fracture propagation length in horizontal and vertical directions for Well H-1-A.

$$\sigma_{ij,j} + f_i = 0 \quad (4)$$

Based on Eqs. (2)–(4), the governing equation for solid displacement can be derived as:

$$\left(K + \frac{G}{3}\right) u_{j,ji} + G u_{i,jj} - \alpha p_{,i} + f_i = 0 \quad (5)$$

In Eqs. (2)–(5), compressive stress is defined as negative.

3.2. Governing equations of fluid flow

3.2.1. Governing equations of fluid flow in the matrix

The continuity equation in the matrix pores can be expressed as (Kazemi et al., 1969):

$$\frac{\partial(\phi_m \rho)}{\partial t} + \nabla \cdot (\rho \mathbf{u}) = Q_m \quad (6)$$

$$\mathbf{u} = -\frac{k_m}{\mu} (\nabla p - \rho \mathbf{g}) \quad (7)$$

Considering solid deformation, fluid flow is driven by both production pressure differential and pore deformation, and the governing equation for fluid flow can be expressed as:

$$\rho S_m \frac{\partial p}{\partial t} - \rho(\alpha - \phi_m) \frac{\partial \varepsilon_v}{\partial t} + \nabla \cdot \left[-\frac{k_m}{\mu} \rho (\nabla p - \rho \mathbf{g}) \right] = 0 \quad (8)$$

$$S_m = \phi_m \chi_L + (1 - \phi_m) \chi_m \quad (9)$$

3.2.2. Governing equations of fluid flow in fractures

Since the length and height of fractures are much greater than their aperture, the fracture can be simplified as a two-dimensional plane in three-dimensional space. A discrete fracture model (DFM) is then adopted to describe fluid flow inside the fracture. By homogenizing the fracture aperture, the governing equation for fluid flow within the fracture can be expressed as (Yu et al., 2015):

$$d_f \chi_f \frac{\partial p}{\partial t} + \nabla_T \cdot \left[-d_f \rho \frac{k_f}{\mu} (\nabla_T p - \rho \mathbf{g}) \right] = Q_f \quad (10)$$

3.3. Cross-coupling equations

The reservoir consists of two lithologies: sandstone and shale. Due to significant differences in lithological properties between these layers, their porosity, permeability, and mechanical properties also differ markedly, leading to distinct flow behaviors. Consequently, the stress-sensitivity characteristics of sandstone and shale layers differ.

In sandstone reservoirs, matrix pore deformation is the dominant factor reducing porosity and permeability. The variation of porosity and permeability in sandstone interlayers under hydro-mechanical coupling can be expressed as (Wei et al., 2019):

$$\phi_{ss} = \phi_{ss0} + \alpha_{ss} \varepsilon_{vs} \quad (11)$$

$$k_{ss} = k_{ss0} \left(\frac{1 - \phi_{ss0}^2}{1 - \phi_{ss}^2} \times \frac{\phi_{ss}^3}{\phi_{ss0}^3} \right) \quad (12)$$

In shale formations, a large number of natural fractures exist. During production, fracture closure becomes the dominant factor influencing variations in shale porosity and permeability (Pan and Connell, 2007). From the perspective of poroelastic theory, the variation laws of shale porosity and permeability under hydro-mechanical coupling can be theoretically derived as follows:

$$\phi_s = \phi_{s0} + (\alpha - \phi_s) \varepsilon_{vs} + \frac{(\alpha_s - \phi_s)(1 - \alpha_s)}{k_s} \Delta p \quad (13)$$

$$k_s = k_{s0} (1 + \varepsilon_{vs})^2 \quad (14)$$

For a planar fracture, the aperture can be regarded as a function of the fluid pressure inside the fracture. Therefore, the fracture aperture can be expressed as:

$$d_f = d_{f0} e^{\frac{1}{2} \chi_f (p_f - p_{f0})} \quad (15)$$

In the direction parallel to fluid flow, the fracture permeability and fracture aperture can be related by the cubic law as follows:

$$k_f = \frac{d_f^2}{12} \quad (16)$$

3.4. Model parameter settings

Based on the distribution of sweet spots and the vertical heterogeneity of Platform H, a three-dimensional sandstone–shale interbedded stress-sensitive model was established, accounting for interlayer spacing and layer thickness. Logging interpretation, in-situ stress analysis, wellbore trajectories, and the 3D distribution of hydraulic fractures were incorporated to build a multi-layer development physical model. Furthermore, a production-induced stress evolution prediction model was developed based on poroelastic theory, and a multi-well, multi-layer flow model for shale oil development was constructed. As shown in Fig. 7, the 3D model has dimensions of 2200 m × 1600 m × 510 m, with sandstone and shale layers vertically stacked. The thickness of sandstone layers ranges from 10 to 20 m, while shale layers range from 60 to 140 m. It should be noted that the z-direction in the figure represents relative height rather than burial depth. The vertical relative height in the model ranges from 0 to 510 m, corresponding to burial depths of 3200–3710 m in the geological model.

A total of 248 fracturing stages and 56,294 effective micro-seismic events were recorded from nine horizontal wells, as shown in Fig. 8(a). Using the method described in Section 2.3, a three-dimensional DFN for the nine wells was reconstructed (Fig. 8(b)). During the well placement design of Platform H, structural features and favorable lithofacies distribution were considered. A “V-shaped” staggered well pattern was adopted for the well group, with vertical offsets for wells in the same layer and horizontal offsets for wells in different layers, resulting in three layers and nine horizontal wells. As shown in Fig. 8(c) and (d), partial fracture intersections are observed at the toe ends between Layers H-1 and H-2, with intersection heights of 2–4 m, and at the heel ends between Layers H-2 and H-3, with intersection lengths of 3–7 m. Large-scale volume fracturing promotes the formation of a complex fracture network with numerous branches in the reservoir. The induced natural fractures, triggered by hydraulic fracture propagation, are characterized by random and discrete distributions (indicated by blue ellipses in Fig. 8(e)). In contrast, the hydraulic fractures, shown as black ellipses in Fig. 8(e), are directly initiated by fluid injection and are typically connected to the horizontal wellbore. In the three-dimensional numerical model, both hydraulic and natural fractures are represented using LGR, as illustrated in Fig. 8(f).

The boundary conditions of the solid mechanics model in this study are defined in two parts. The lateral boundaries of the model are constrained by zero normal displacement (i.e., the normal displacement is set to zero), which represents the mechanical boundary condition of an infinite surrounding formation. This

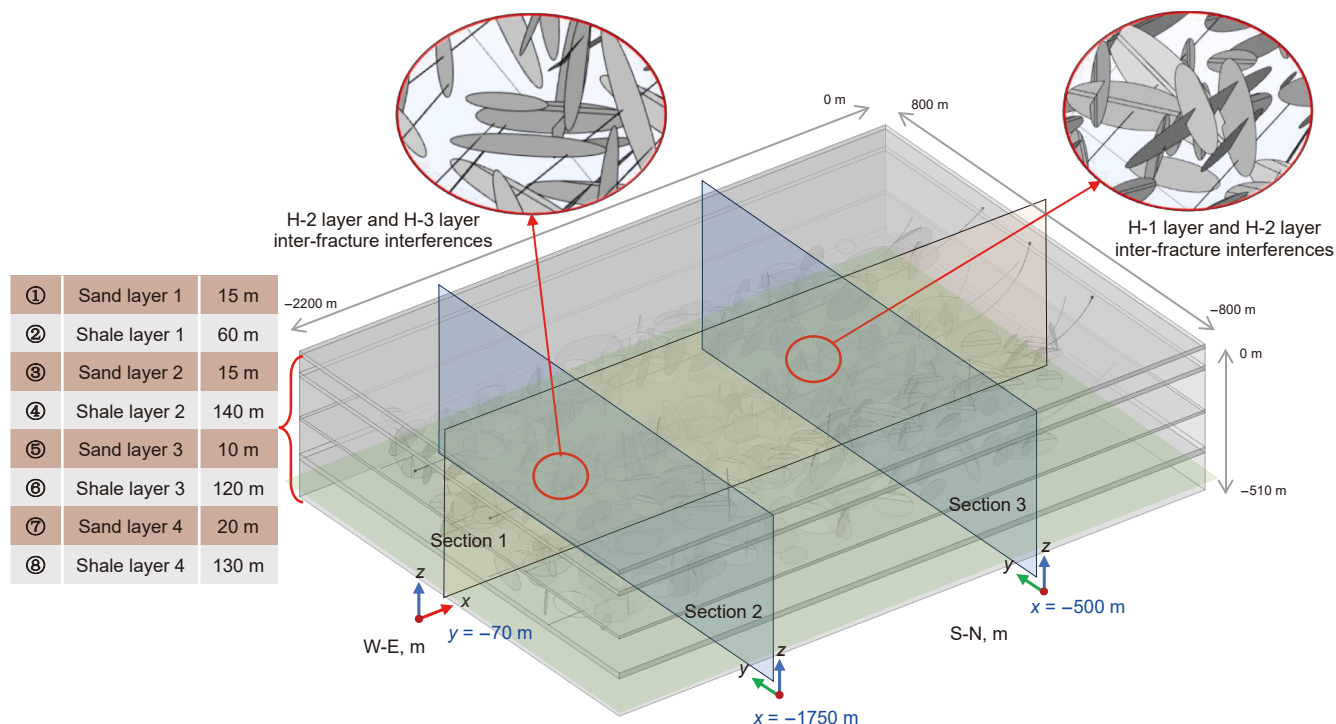


Fig. 7. Three-dimensional geological model for multi-layer development of a three-layer sandstone-shale interbedded reservoir.

setting prevents rigid-body motion of the model, ensures stress field stability, and avoids rigid-body drift and singular matrix issues during numerical computation. The upper boundary of the model is subjected to a constant pressure load of 78 MPa, corresponding to the overburden stress at a burial depth of 3200 m. This boundary condition is applied to account for the compaction effect of the overlying rock layers. The evolution of the three-dimensional stress field induced by production pressure depletion is governed by Eqs. (5–10). An implicit Euler finite difference scheme is employed for the time domain to ensure numerical accuracy and convergence. Spatial discretization is performed using the Galerkin finite element method, and nonlinearities in the system are handled using the Newton-Raphson method. All simulations were performed on a workstation equipped with an Intel 64-bit processor (consumer-grade P6 architecture, model 106, level 10), featuring 32 CPU cores and 256 GB of RAM. The three-layer model consists of 1,739,861 mesh elements and 9,447,298 degrees of freedom (DOFs), requiring 29,811 s of CPU time and a peak memory usage of 160.18 GB. In contrast, the single-layer model contains 493,183 mesh elements and 2,711,448 DOFs, with a CPU time of 6625 s and a peak memory consumption of 38.97 GB. These results indicate that although the computational cost of the three-layer model increases by approximately 3–5 times, the improved representation of sand-shale interlayering and fracture network complexity significantly enhances the applicability and scalability of the proposed method for field-scale reservoir simulations. This increase in computational cost represents an acceptable trade-off between modeling accuracy and computational efficiency.

In the model, the horizontal stages of all nine wells are in the middle of the reservoir. Each well contains 23–28 fracturing stages, with average fracture lengths and heights of 230 and 75 m, respectively. The vertical spacing between Layers H-1 and H-2 is 48 m, and between Layers H-2 and H-3 is 42 m. Table 1 summarizes the penetration of hydraulic fractures into reservoir layers at

different depths, showing the distribution of fractures and their corresponding layer intervals.

The simulation parameters for the three-layer development model are summarized in Table 2, including in-situ stress, physical properties, and pressure parameters. Based on field logging data and lithological distribution, the model is vertically divided into eight layers, comprising four sandstone layers and four shale layers. The sandstone layers are thinner and exhibit higher triaxial stress. The ranges of S_{Hmax} , S_{Hmin} , and S_v in the sandstone layers are 74–82, 69.5–75.5, and 78–86.44 MPa, respectively. For the shale layers, the corresponding stress ranges are 73–80.98, 67.5–74.91, and 75–83.56 MPa, respectively. The $S_{Hmax} - S_{Hmin}$ for the four sandstone layers and four shale layers is 4.75 and 5.76 MPa, respectively. Unlike many domestic and international shale oil reservoirs, the continental shale oil reservoir at Platform H is characterized by overpressure at depths greater than 3000 m, with pressure coefficients ranging from 1.2 to 1.8. In this study, the pore pressure coefficient is set to 1.5.

4. Stress interference evaluation of three horizontal wells in a single-layer stacked continental shale oil reservoir

4.1. Model validation

To verify the validity of the proposed model and to compare it with existing approaches, a stratigraphic model was constructed as shown in Fig. 9(a). The middle layer is a sandstone with relatively high porosity and permeability, while the upper and lower layers are shale with lower porosity and permeability. The simulation parameters of the sandstone layer are taken from the Sand 2 layer in Table 1, and those of the shale layers are taken from the Shale 2 layer in Table 2.

The Mandel effect is a classical benchmark problem for validating poroelastic and hydro-mechanical coupled models. It describes a phenomenon in which fluid is discharged from one

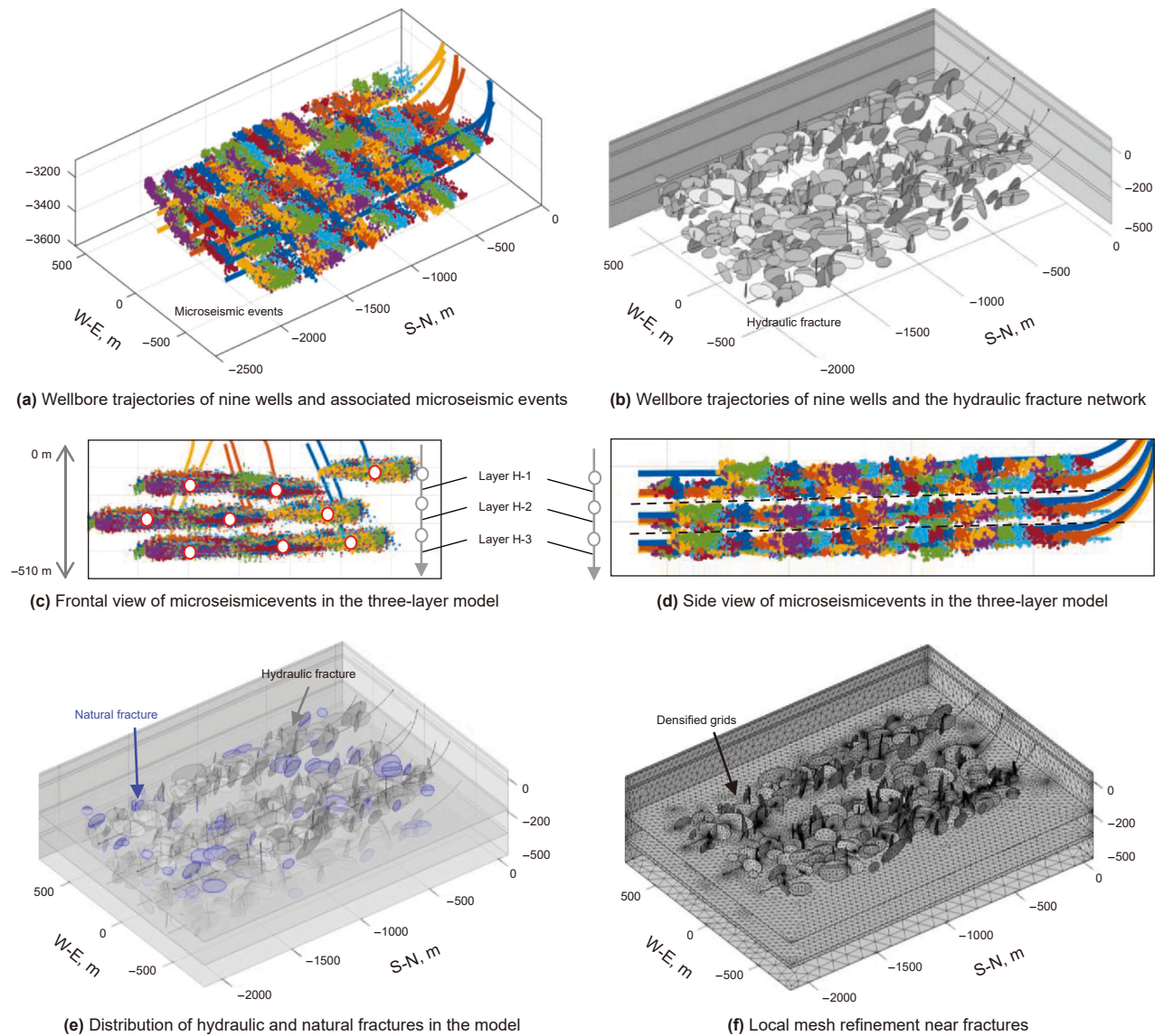


Fig. 8. Schematic diagram of V-shaped and W-shaped well patterns for three-layer development.

Table 1
Vertical propagation characteristics of hydraulic fractures in different lithologies.

No.	Layer	Fracture penetration	Depth interval, m
1	Sandstone 1	No penetration	0–15
2	Shale 1	Partial penetration	15–75
3	Sandstone 2	Partial penetration	75–90
4	Shale 2	Full penetration	90–230
5	Sandstone 3	Full penetration	230–240
6	Shale 3	Full penetration	240–360
7	Sandstone 4	Full penetration	360–380
8	Shale 4	Partial penetration	380–510

boundary, and under the action of overburden stress, pore compaction occurs, leading to a transient increase in pore pressure at certain locations. For a two-dimensional homogeneous medium, the Mandel effect has an analytical solution and is therefore widely used for model verification in coupled flow–geomechanics studies (Guo et al., 2019). In this study, the model proposed by Wei et al. (2019) was used to simulate a single-layer sandstone model, where pressure drawdown was applied at the left boundary and all

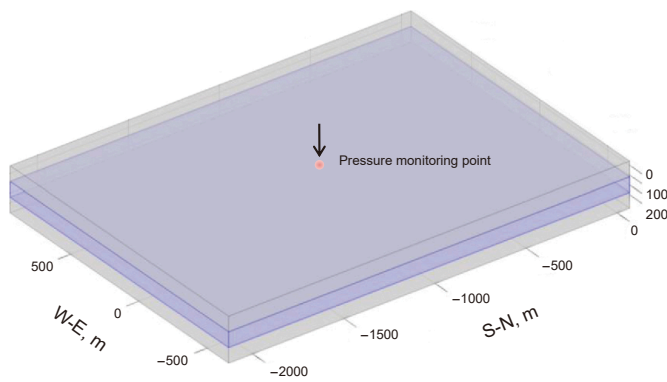
other boundaries were sealed. In contrast, the proposed model was applied to the sand–shale interbedded system shown in Fig. 9(a), with all boundaries sealed except for pressure draw-down applied only at the left boundary of the sandstone layer. The pore pressure evolution at the center of the sandstone layer was then compared between the two models. As shown in Fig. 9(b), the homogeneous model of Wei et al. (2019) exhibits a faster pore pressure increase than the heterogeneous model proposed in this study. This difference arises because the homogeneous model neglects interlayer fluid exchange, and the higher porosity and permeability of the sandstone result in a more rapid pore pressure decline compared with the heterogeneous sand–shale system.

4.2. Analysis of horizontal stress evolution induced by simultaneous production in a single layer

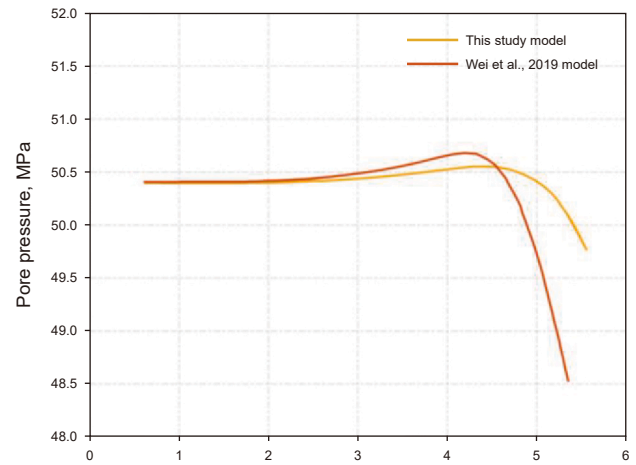
During the simulation of three horizontal wells in a single-layer development model, a fixed bottom-hole pressure of 40 MPa was applied over a three-year production period, allowing characterization of the spatiotemporal evolution of pore pressure and

Table 2
Model parameters for three-layer development simulation.

Parameter	Shale 1	Sandstone 1	Shale 2	Sandstone 2	Shale 3	Sandstone 3	Shale 4	Sandstone 4
S_{Hmax} , MPa	74.00	73.00	75.00	74.64	78.00	77.92	82.00	80.98
S_{Hmin} , MPa	69.50	67.50	71.50	69.02	73.50	72.07	75.50	74.91
Matrix porosity, %	4	6	4	6	4	6	4	6
Density, $g \cdot cm^{-3}$	2.2	2.0	2.2	2.0	2.2	2.0	2.2	2.0
Permeability, mD	0.25	10	0.25	10	0.25	10	0.25	10
Poisson's ratio	0.23	0.15	0.23	0.15	0.23	0.15	0.23	0.15
Young's modulus, GPa	20	40	20	40	20	40	20	40
Effective stress coefficient	0.75	0.80	0.75	0.80	0.75	0.80	0.75	0.80
Hydraulic fracture porosity	0.30	Hydraulic fracture permeability, D	1000	Hydraulic fracture aperture, mm	5	Reservoir pore pressure, MPa	48	
Natural fracture porosity	0.001	Natural fracture permeability, mD	500	Natural fracture aperture, mm	0.5	Bottom-hole pressure, MPa	40	
Shale oil viscosity, mPa·s	57.7	Shale oil density, $g \cdot cm^{-3}$	0.94	Fracture compressibility, 1/Pa	1×10^{-8}			



(a) Model validation reservoir setting



(b) Comparison of Mandel effect pressure

Fig. 9. Comparison between homogeneous sandstone and heterogeneous sand–shale interbedded models.

in-situ stress. Because of significant differences in porosity and permeability among sublayers and varying hydraulic fracture propagation in each sublayer, the pore pressure evolution patterns also exhibit considerable heterogeneity. Fig. 10 presents the spatial distribution of pore pressure in sandstone and shale layers after two years of production. As production progresses, the area of pore pressure depletion expands. In regions far from the SRV, the pore pressure change is negligible due to the extremely low matrix permeability, which restricts pressure transmission away from the production wells.

In comparison, both the magnitude and spatial extent of pore pressure variation in sandstone layers are significantly larger than those in shale layers. This is mainly attributed to the higher porosity and permeability of sandstone. Since the hydraulic fractures in the three wells did not penetrate the Sandstone 1 layer, pressure variation in this layer is primarily due to pressure propagation, resulting in a maximum pore pressure drop of only 1.1 MPa. In the other five layers where hydraulic fractures are present, the maximum pore pressure changes in Sandstone 2 and Sandstone 3 are 9.1 and 11 MPa, respectively. For the shale layers, the maximum pore pressure changes in Shale 1, Shale 2, and Shale 3 are 7.6, 10, and 4.7 MPa, respectively. As shown in Fig. 10(a) and (f), the pressure-depletion zone in sandstone exhibits a striped distribution pattern extending outward from the fracture network due to its higher permeability, whereas in shale layers, pore pressure variation is confined to areas near the hydraulic fractures.

During production, the in-situ horizontal principal stress within the layer rotates by a certain angle. The angle between the minimum horizontal principal stress and the x -axis in the plane can be calculated using the following equation (Guo et al., 2019):

$$\tan\theta = \frac{\tau_{xy}}{\sigma_H - \sigma_x} \quad (17)$$

Fig. 11 shows the distribution of the minimum horizontal principal stress and its orientation in three sandstone layers and three shale layers after two years of production. It can be observed that within a 200 m radius from the horizontal wellbore, a clear stress rotation occurs. The stress rotation angle at the tips of hydraulic fractures is larger than in other regions, and the rotation angle in sandstone layers is greater than that in shale layers. Far away from the discrete fracture network, the maximum principal stress rotation is almost negligible, with the stress direction remaining aligned with the initial minimum principal stress direction. This is because the pressure-depletion front does not effectively propagate into these areas. The maximum stress rotation angles in Sandstone 1, Sandstone 2, and Sandstone 3 are 16°, 64°, and 57°, respectively, while those in Shale 1, Shale 2, and Shale 3 are 14°, 38°, and 5°, respectively. A smaller stress rotation angle indicates a lower interference between adjacent fractures during refracturing, reducing the likelihood of fracture crossing and enabling longer fracture propagation.

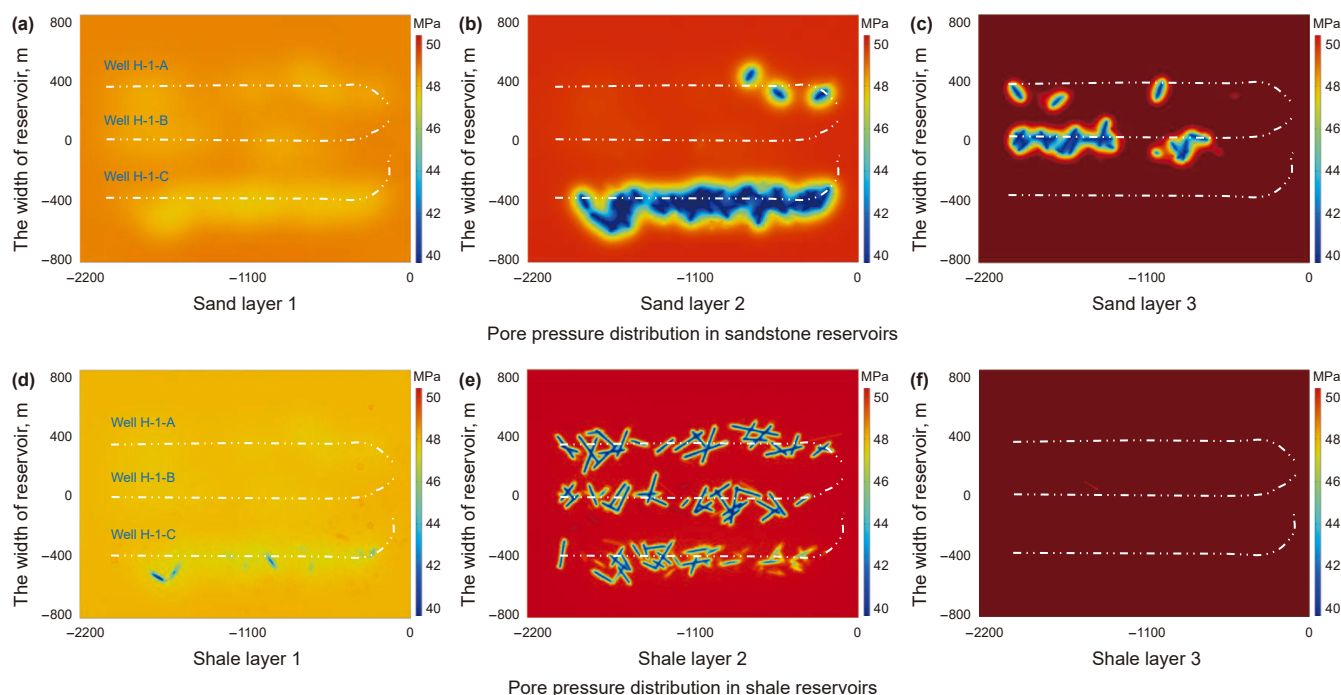


Fig. 10. Pore pressure distribution in three shale and sandstone layers after two years of production. The pressure contour maps correspond to the mid-depth of each layer, with vertical coordinates of -7.5 , -45 , -82.5 , -160 , and -235 m.

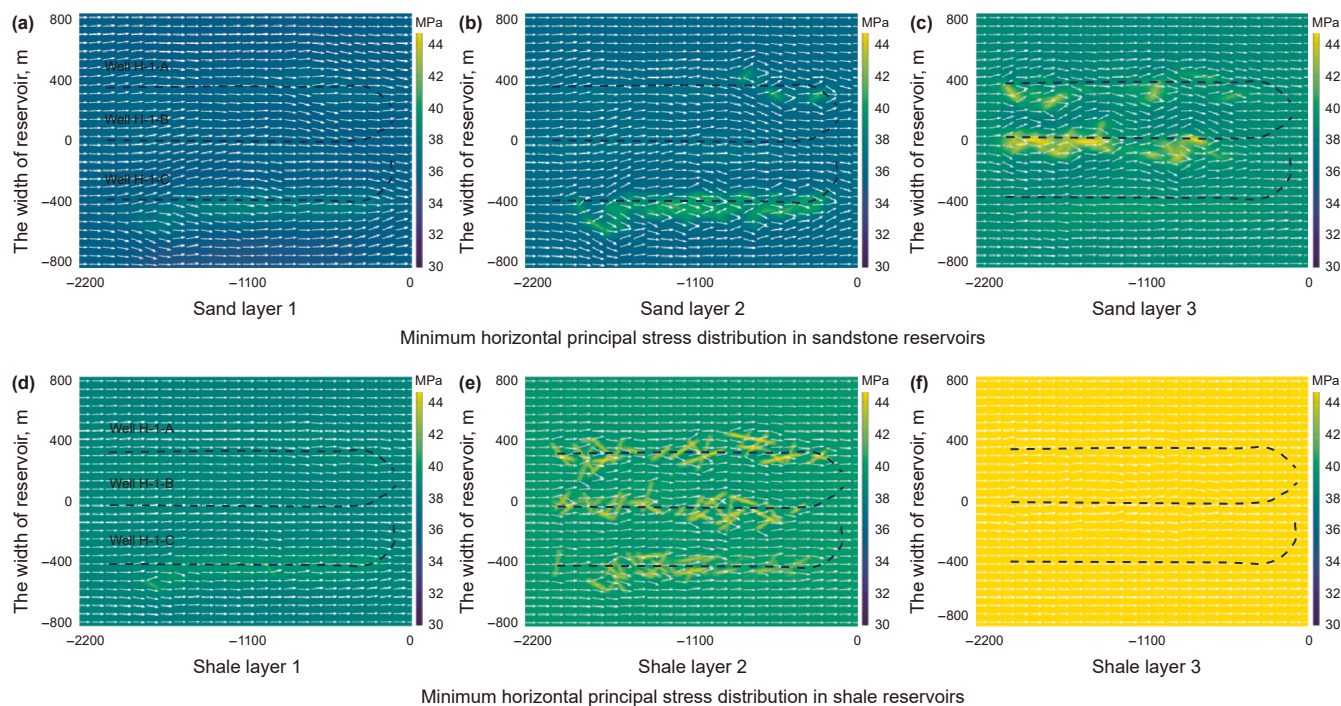


Fig. 11. Contour maps of minimum horizontal principal stress and stress rotation angle in three sandstone and shale layers after two years of production.

Hydraulic fractures mainly propagate in Sandstone 2, the lower part of Shale 3, and the upper part of Shale 2. These zones also show more pronounced changes in both the increase and decrease of effective minimum horizontal principal stress compared with other layers. Although Shale 1 and Shale 2 have similar initial horizontal stress differences (5.5 and 5.62 MPa, respectively), hydraulic fractures propagate more extensively in Shale 2. The range

and magnitude of stress rotation in Shale 3 are greater than those in Shale 1, indicating that hydraulic fractures intensify stress rotation. The degree and range of stress rotation in Sandstone 2 are also greater than those in Sandstone 3, primarily because hydraulic fractures penetrate Sandstone 2 more extensively. However, the initial horizontal stress difference in Sandstone 3 (6.5 MPa) is larger than that in Sandstone 2 (4.5 MPa). This

demonstrates that the initial horizontal stress difference strongly influences stress rotation, and the larger the initial stress difference, the smaller the rotation angle under the same production period.

4.3. Evolution of vertical stress induced by simultaneous production in a single layer

In the regions penetrated by the hydraulic fracture network, pore pressure responds more significantly to production. Even in areas not intersected by hydraulic fractures, changes in both the magnitude and direction of in-situ stress, though limited, still lead to local stress field alterations, which may influence the drilling, completion, and fracturing performance of adjacent wells in vertical well spacing during development (Fig. 12). As shown by the flow streamlines, when the pore pressure depletion front induced by hydraulic fractures in the shale layer reaches the sandstone layer, the higher permeability of sandstone causes the depletion zone to propagate horizontally, resulting in a “T-shaped” pressure depletion pattern. Furthermore, if a hydraulic fracture in the shale layer intersects this T-shaped zone, it establishes hydraulic communication between the shale fracture and the sandstone layer, thereby enhancing shale oil recovery. For the unfractured regions of sandstone, shale oil first migrates into Shale layer 2 under the combined effect of gravity and pressure gradient, and is then produced through the hydraulic fracture network. Fig. 12(b) shows the pore pressure curves along line X ($Z = -50$ m) at the 1st, 2nd, and 3rd production years. The pressure depletion range induced by hydraulic fractures is typically 40–62 m, and the depletion zone is relatively narrow and elongated. This is mainly because shale oil has relatively low maturity, high density and viscosity, and is primarily adsorbed on the internal surface, resulting in poor flowability in the subsurface. Additionally, the pressure depletion magnitude generated by the main hydraulic fracture network is largest in the first year and decreases in the second and third years, reflecting a gradual decline in pressure gradient and flow intensity over time.

The interlayer stress difference is a key factor influencing the vertical propagation of hydraulic fractures. Experimental results by (Tan et al., 2017) have shown that when the horizontal stress difference between layers reaches 4–6 MPa, the vertical propagation of hydraulic fractures can be effectively constrained. However,

this critical horizontal stress difference may vary for different formations. The horizontal principal stress can be expressed as:

$$\sigma_{H,h} = \frac{\sigma_x + \sigma_y}{2} \pm \sqrt{\left(\frac{\sigma_x - \sigma_y}{2}\right)^2 + \tau_{xy}^2} \quad (18)$$

In the poroelastic model, tensile stress is defined as positive, and for convenience. In this study, the minimum horizontal principal stress, minimum horizontal stress, and horizontal stress difference were extracted at the toe and heel of the horizontal wellbore, as well as at near-wellbore and far-field locations. These stress curves were then used to characterize the spatial and temporal variations of in-situ stress at different positions along the horizontal well.

As shown in Fig. 13, a slight fluctuation in the minimum horizontal principal stress occurs at locations where lithological transitions are present. As production progresses, the effective minimum horizontal principal stress increases, while the minimum horizontal stress decreases at the toe of the horizontal well, with different trends observed at different positions. Hydraulic fractures are mainly distributed in the lower part of Shale layer 1, Sandstone layer 2, Shale layer 2, and the middle part of Sandstone layer 3. Consequently, the increase in effective minimum horizontal principal stress and the decrease in minimum horizontal stress in Shale 2, Sandstone 3, and the upper part of Shale 3 are more pronounced than in other layers. Because the permeability of Shale 2 is lower than that of the overlying and underlying sandstone layers, fluid within Shale 2 is squeezed into the adjacent high-permeability sandstone layers during production. This leads to a larger minimum horizontal principal stress variation in Shale 3, resulting in a slope-shaped stress profile. In interbedded sandstone–shale reservoirs, the interlayer stress difference controls whether hydraulic fractures can propagate across multiple thin layers, while the magnitude of the minimum horizontal principal stress determines the required fracture extension pressure. With continued production, the horizontal stress differences between Sandstone 3 and the adjacent layers increase to 6.32 and 6.51 MPa, respectively, which are unfavorable for the vertical propagation of hydraulic fractures across layer interfaces.

As shown in Fig. 14, at the heel and near-wellbore section of the horizontal well, the effective minimum horizontal principal stress in all sublayers increases slightly, by approximately 0.5 MPa, with a larger increase in sandstone layers (0.8 MPa) than in shale layers.

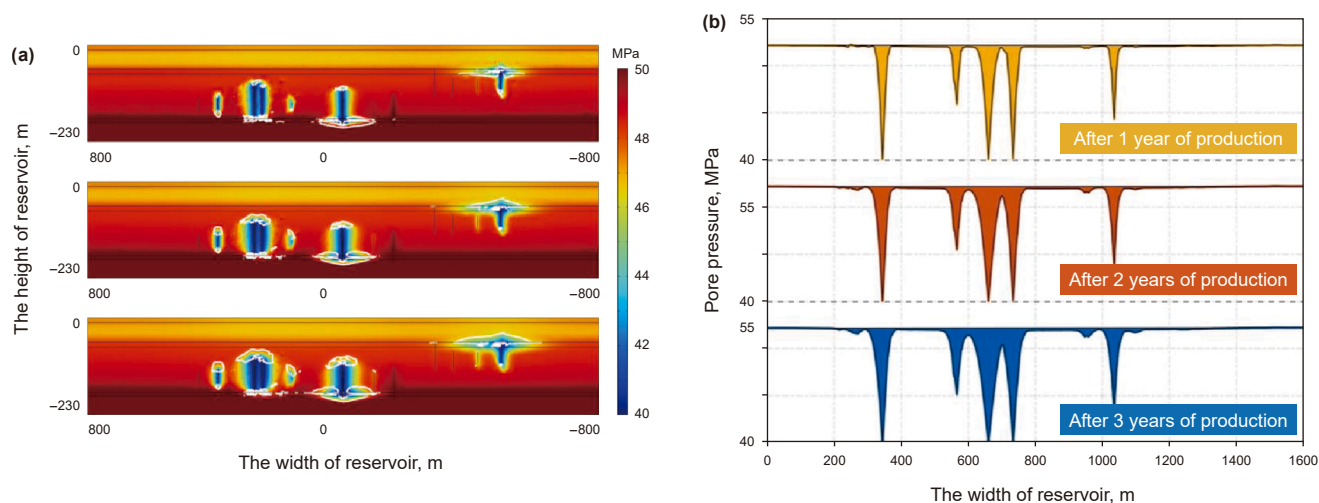


Fig. 12. Pore pressure contour maps and pore pressure profiles along section 2 ($x = -1750$) during three years of production. The white dashed lines in panel (a) represent flow streamlines.

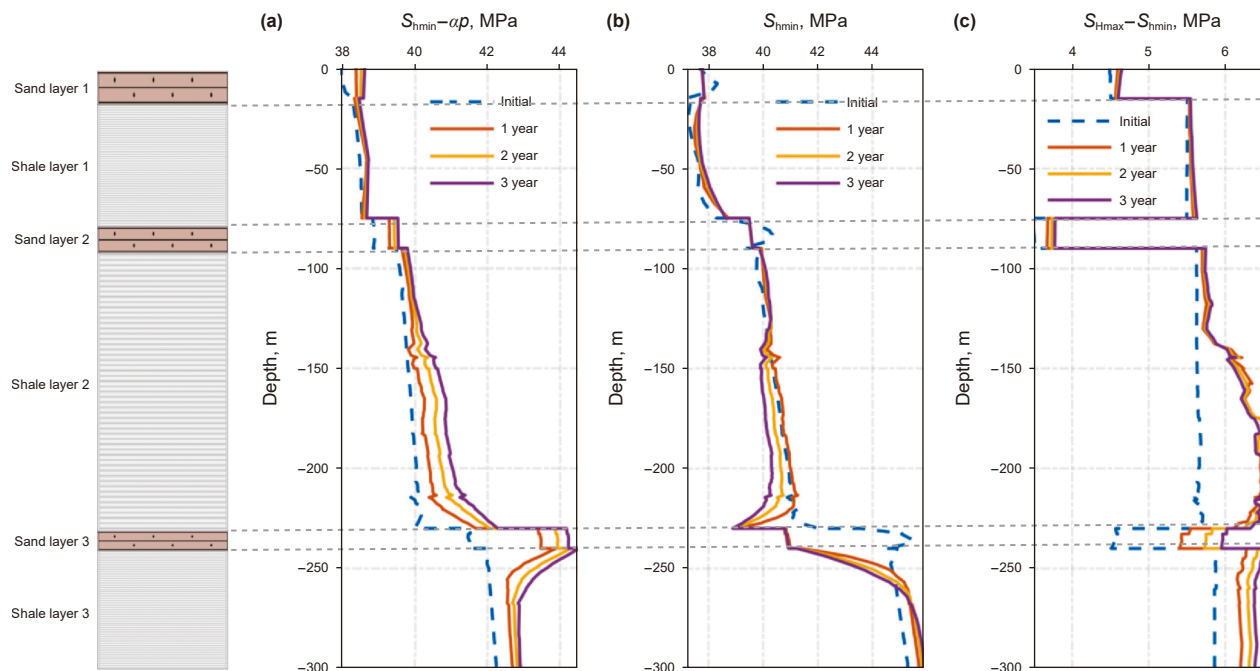


Fig. 13. Stress curves at the toe end and near-wellbore section of three horizontal wells.

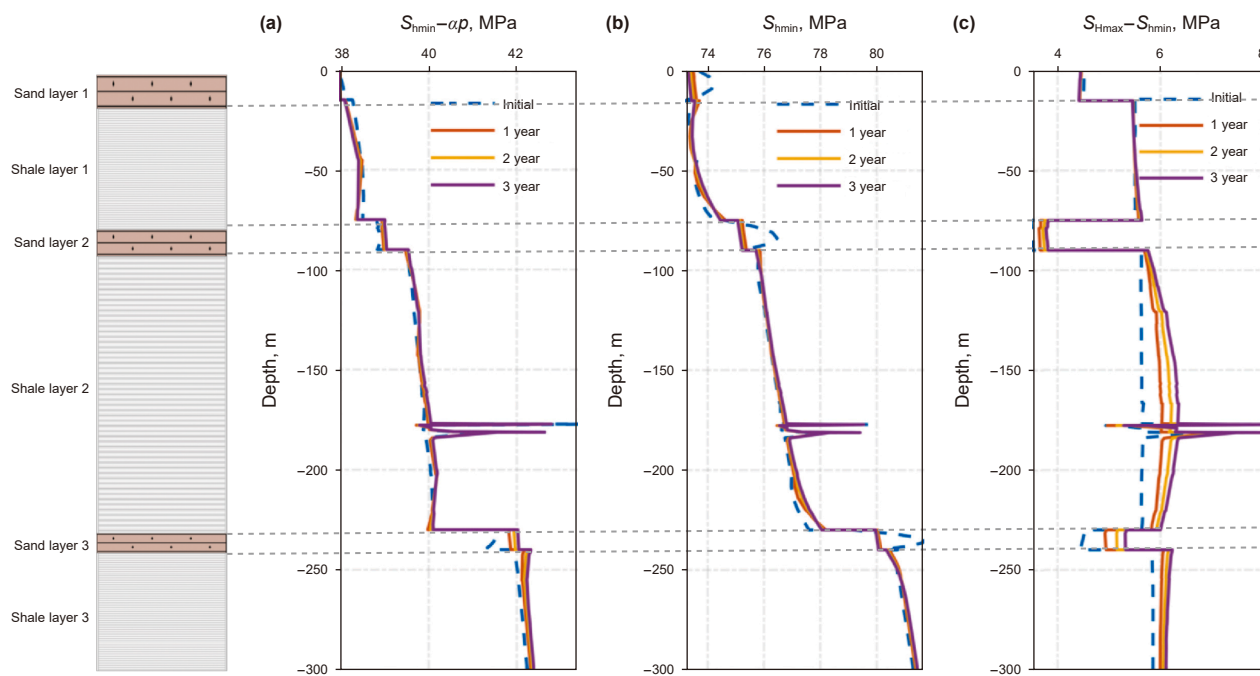


Fig. 14. Stress curves at the heel end and near-wellbore section of three horizontal wells in a single layer.

The minimum horizontal stress in all sublayers decreases, with Sandstone 2 and Sandstone 3 showing a greater reduction than the adjacent layers. This leads to increases in the horizontal stress difference of approximately 0.3 and 0.9 MPa, respectively, which, to some extent, weaken the vertical fracture propagation capacity. As shown in Fig. 14(c), the horizontal stress difference in the sandstone layers increases significantly, while that in the shale layers increases slightly. In Shale 2, sawtooth-like fluctuations can be observed in the minimum horizontal principal stress, minimum horizontal stress, and horizontal stress difference, with

amplitudes of 3.11, 3.02, and 2.33 MPa, respectively. However, the vertical thickness of these fluctuations is relatively small, mainly because of the low porosity and permeability of shale, which limit the vertical propagation range of the pressure-depletion front.

4.4. Production performance evaluation under simultaneous single-layer production

Fig. 15 shows the cumulative oil production per unit thickness of each sublayer as a function of production time. Overall,

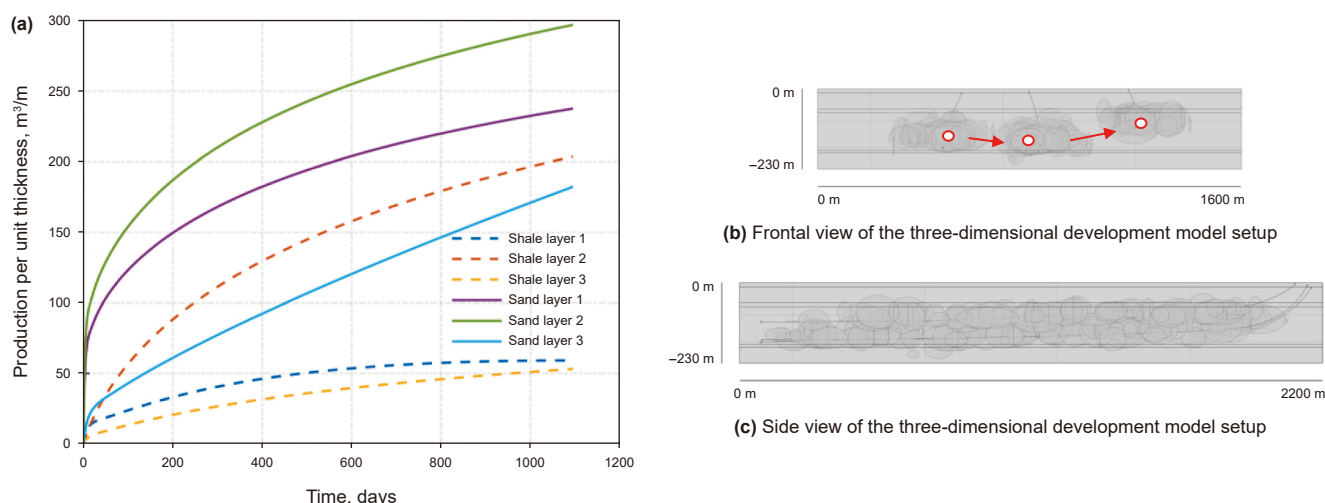


Fig. 15. Cumulative oil production per unit thickness of each sublayer over time.

sandstone layers exhibit higher production than shale layers, with the cumulative production ranking of the three sandstone layers being Sandstone 2 > Sandstone 1 > Sandstone 3, and that of the shale layers being Shale 2 > Shale 1 > Shale 3. For the sandstone layers, oil production increases most rapidly during the first 150 days, with growth rates of 0.92, 1.14, and 0.34 m³/m/d, respectively. After 200 days, the production growth rate becomes more gradual. In contrast, shale layers show a relatively stable, slower rate of production increase, approximately 0.14 m³/m/d. Notably, Shale 2 outperforms Sandstone 3, with a cumulative production of 203.46 m³/m after three years. This is primarily because the hydraulic fractures are mainly distributed within Shale 2. The highest production is achieved in Sandstone 2, mainly due to its higher porosity and permeability, and because the upper part of the hydraulic fracture network of Well H-1-A is located within this layer. These findings suggest that during stereoscopic well pattern deployment, layer selection should be optimized to place more hydraulic fractures in high-permeability layers and to allow them to propagate vertically across layers, thereby contacting a larger reservoir volume and enhancing shale oil recovery.

5. Vertical stress interference in a three-layer well pattern within interbedded sandstone–shale reservoirs

5.1. Horizontal stress evolution induced by three-layer development

During three-layer development, stress interference between layers caused by vertical hydraulic fractures is a key concern in field-scale shale oil development. The well interference phenomenon discussed in this paper specifically refers to the interference between adjacent horizontal wells induced by reservoir depletion and large-scale reservoir stimulation during the development of low-permeability shale oil and gas reservoirs. This is conceptually different from the well interference caused by injection–production well patterns and infill drilling in conventional reservoirs. Such interference, also known as fracturing-induced interference, can occur in both horizontal and vertical directions. At the early stage of production, the pore pressure in the dominant hydraulic fracture network—which is directly connected to the wellbore—declines first, leading to pressure perturbation in both the same layer and the adjacent layers, with a magnitude of approximately 2 MPa, as shown in Fig. 16.

The fracture density and fracture permeability during stereoscopic fracturing determine the fracture–reservoir contact area and the fluid flow velocity within the fractures, thereby directly influencing the production characteristics of shale oil horizontal wells. The pore pressure variation ranges in Sandstone layers 1–4 are 1.2, 9.3, 12, and 15.3 MPa, respectively, while those in Shale layers 1–4 are 7.7, 10.4, 12.6, and 15.5 MPa, respectively. Compared with the single-layer three-well development scenario shown in Fig. 10, the pore pressure changes induced by three-layer nine-well three-layer development are more pronounced. Moreover, in contrast to single-layer well patterns, the shale layers are more susceptible to vertical stress interference from the sandstone layers in three-layer development. Specifically, Shale 3 is affected by the induced pressure depletion from hydraulic fractures in Sandstone 3 and Sandstone 4, while hydraulic fractures in Sandstone 3 influence Shale 4. As a result, Shale 3 and Shale 4 experience combined intra-layer and inter-layer pore pressure perturbations. In contrast, the impact of shale layers on the sandstone layers is weaker, with only Sandstone 4 being affected by Shale 3 and Shale 4. These findings indicate that three-layer development planning must consider not only optimized interlayer spacing but also fracture height propagation across different lithologies to maximize reservoir stimulation and production efficiency.

As shown in Eq. (5), during the three-layer development of continental shale oil reservoirs, fluid flow reduces pore pressure, which in turn increases the effective stress carried by the rock skeleton, leading to rock deformation and ultimately changes in both the magnitude and direction of the in-situ stress field. Fig. 18 presents the minimum horizontal effective stress contour maps of four sandstone layers and four shale layers after two years of production. It can be observed that, with increasing depth, the minimum horizontal effective stress in both shale and sandstone layers increases continuously, ranging from 0 to 4.2 MPa. In comparison, the pore pressure variations are more pronounced in sandstone layers. As production time increases, the effective stress fluctuation range in the hydraulic fracture network gradually propagates outward from the wellbore, and connectivity along the wellbore direction becomes more significant. However, as shown in Fig. 17, the spatial extent of the effective stress perturbation is smaller than that of the pore pressure perturbation. This is mainly because rock deformation is related to pore pressure change through a cubic relationship, resulting in a more localized stress response compared with pressure depletion.

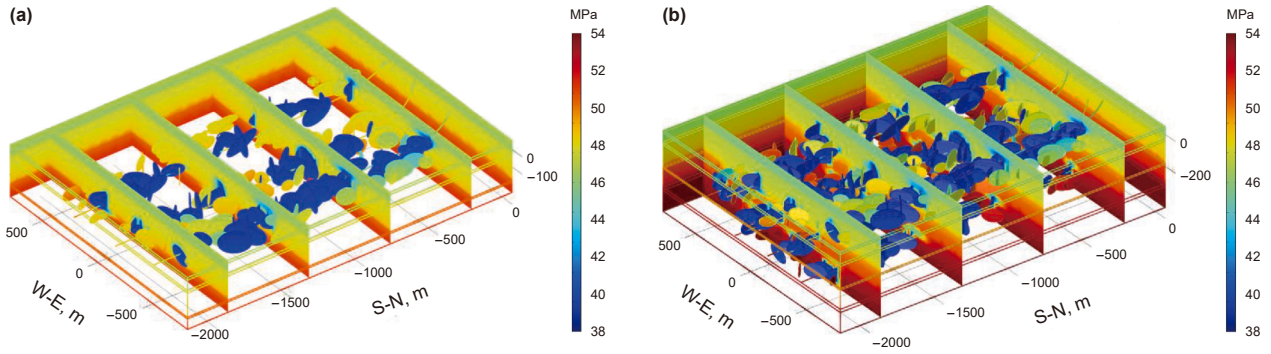


Fig. 16. Stress disturbance in the same and adjacent layers during three-layer development.

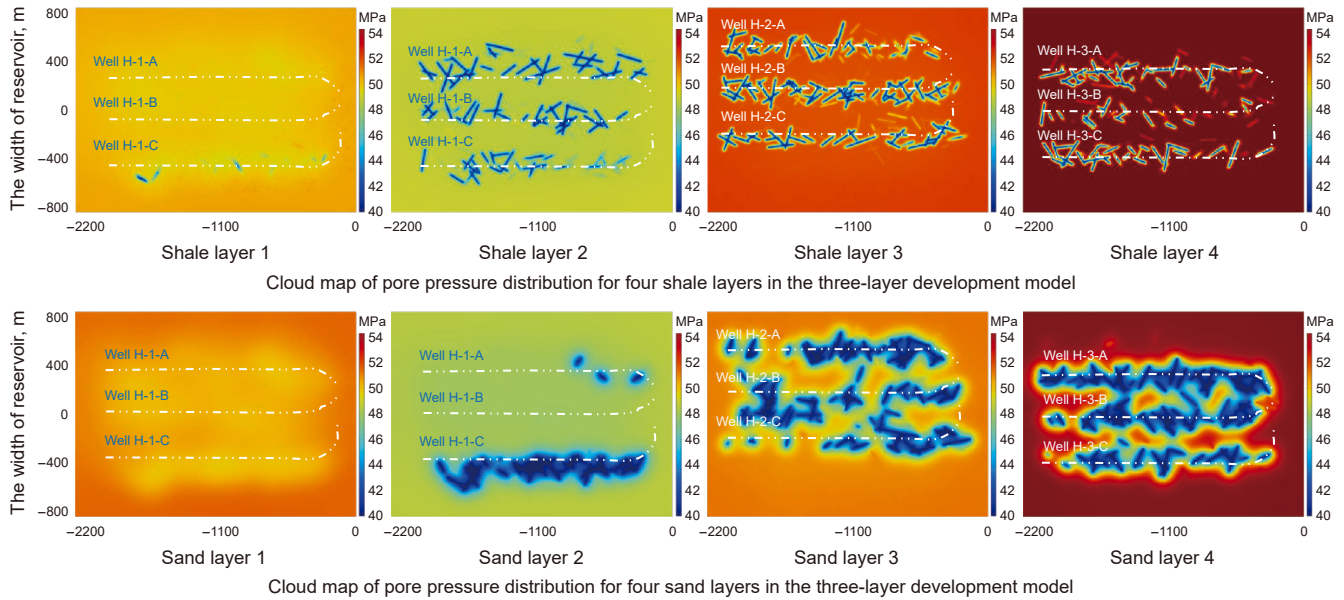


Fig. 17. Pore pressure contour maps of four sandstone and shale layers after two years of production.

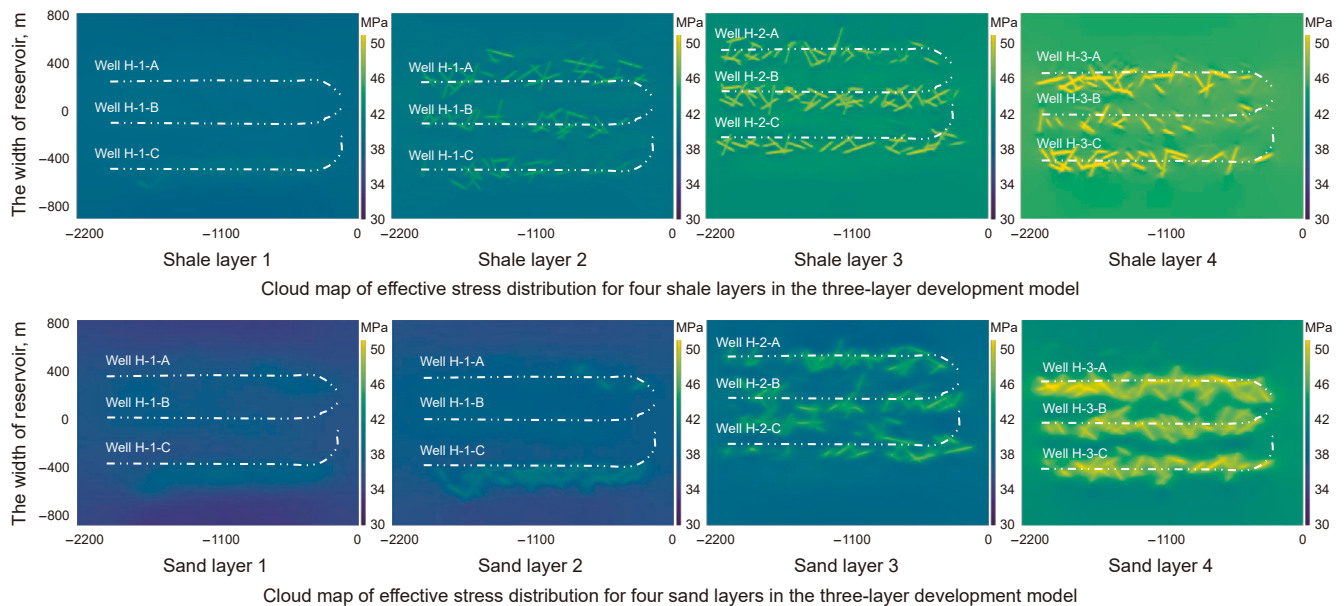


Fig. 18. Contour maps of minimum horizontal principal stress and stress rotation angle in four sandstone and shale layers after two years of production.

5.2. Analysis of vertical stress evolution induced by three-layer development

Due to significant differences in porosity–permeability parameters, initial in-situ stress, and rock mechanical properties

between sandstone and shale on the H platform, the reservoir exhibits large interlayer stress differences and strong vertical geomechanical heterogeneity, resulting in notable variations in stress evolution patterns across sublayers during production. As shown in Fig. 19(a), the effective minimum horizontal principal

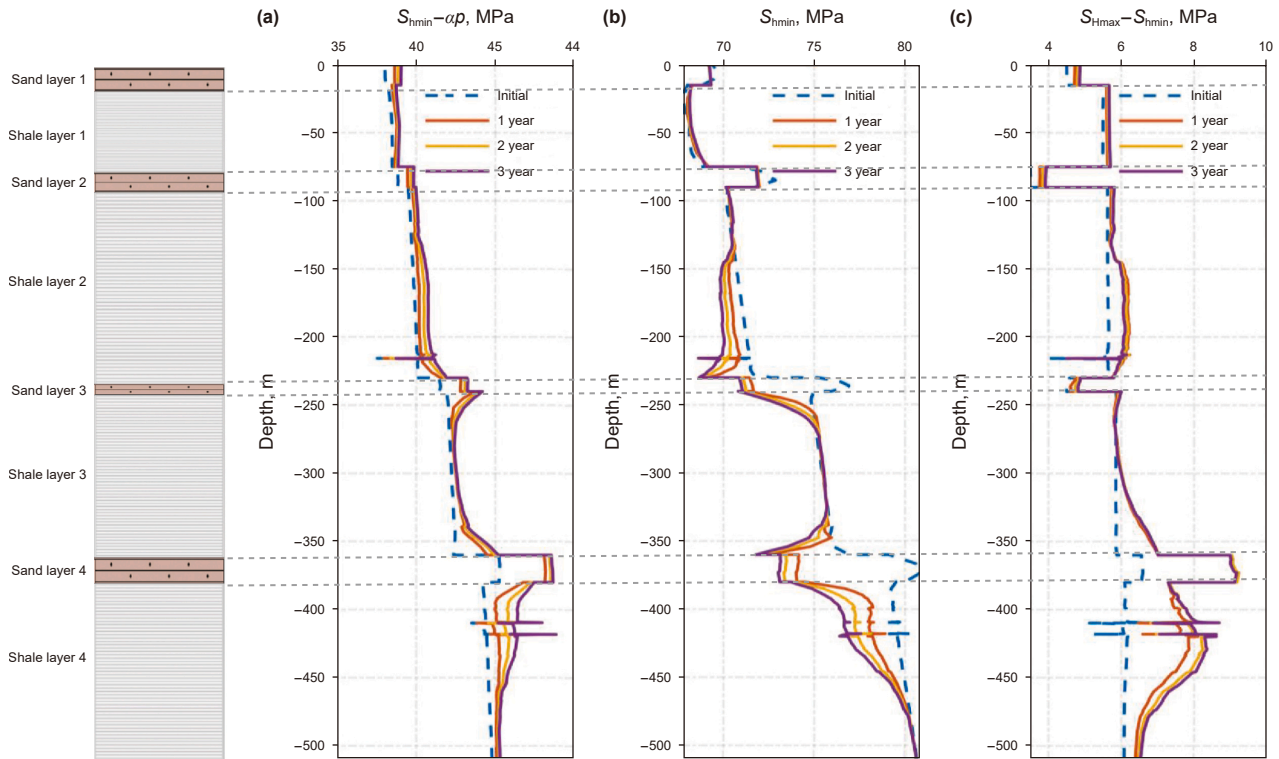


Fig. 19. Line chart of stress variation near the toe of the horizontal wellbore during three-layer nine-well development.

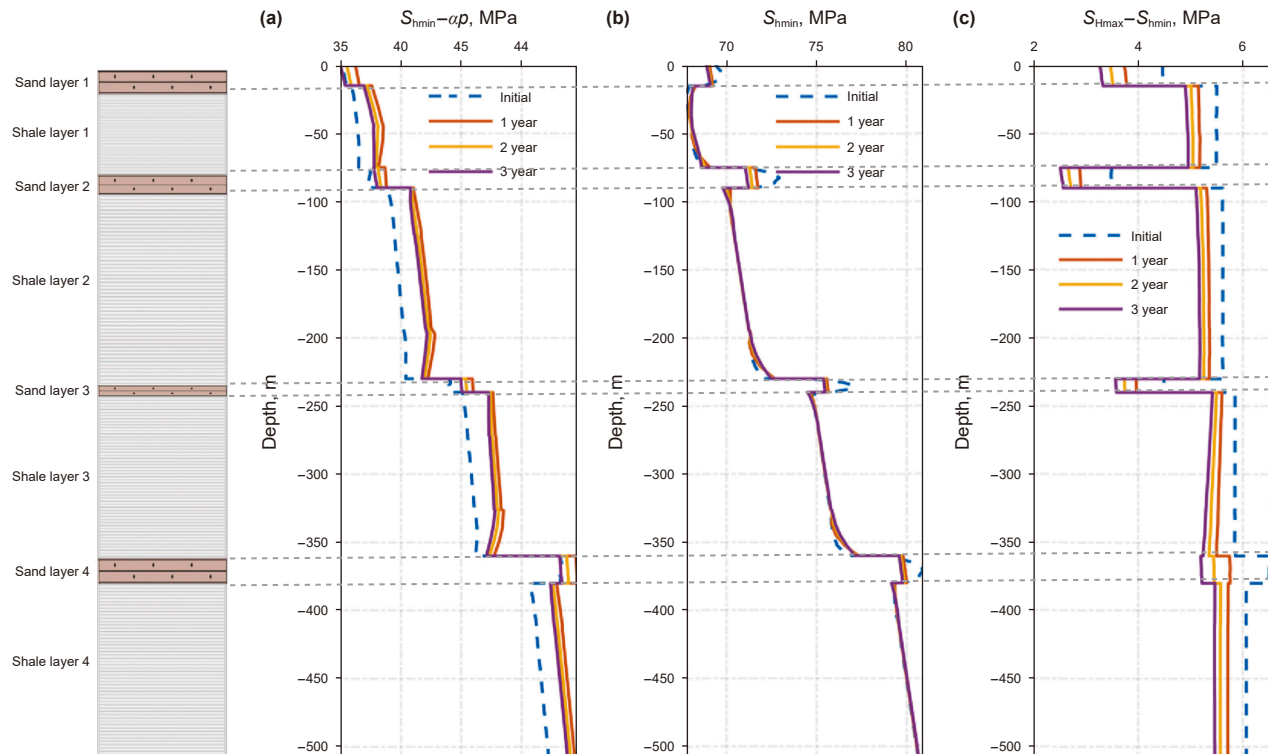


Fig. 20. Stress variation in the far-field region near the toe of the horizontal wellbore during three-layer nine-well development.

stress near the toe of the horizontal wellbore increases in all sublayers, with sandstone layers exhibiting a larger increase than shale layers. Specifically, Sandstone 4 and Sandstone 2 increase by 1.77 and 3.24 MPa, respectively, and their adjacent shale layers (Shale 3 and Shale 4) also show a noticeable increase. Fig. 19(b) shows that the minimum horizontal principal stress decreases in all sublayers, with Sandstone 2 and Sandstone 3 exhibiting larger reductions (5.75 and 7.47 MPa, respectively) than neighboring layers. This results in an increased horizontal stress difference between these sandstone layers and adjacent layers, which is unfavorable for vertical hydraulic fracture propagation. As shown in Fig. 19(c), the horizontal stress differences in the sandstone layers increase significantly, with Sandstone 4 increasing by 2.61 MPa, while shale layers show a more minor increase. Notably, in Shale 4, the reservoir near the hydraulic fracture zone exhibits a 2.16 MPa increase. These results indicate that when planning vertical infill fracturing, it is advisable to avoid sandstone layers with both high permeability and high initial in-situ stress, as they may amplify stress barriers and limit fracture vertical growth.

As shown in Fig. 20, in the far-field region, the effective minimum horizontal principal stress of the reservoir increases with production time, while the minimum horizontal stress and horizontal stress difference decrease slightly, since fluid in this region has not yet been produced and pore pressure changes remain small. In addition, as shale oil is produced, the total stress

continuously decreases. The horizontal stress difference decreases near the horizontal well but shows a slight increase in the far-field. Interlayer fracture propagation significantly enhances the drainage volume of a single well, thereby increasing well productivity. Whether hydraulic fractures can propagate across layers primarily depends on the interlayer stress difference. The interlayer horizontal stress difference decreases over time near the middle section of the horizontal well, while it increases at the toe and in the far-field. Therefore, refracturing should be preferentially performed near the middle section of the horizontal well.

During the three-layer development process, in addition to the effects of hydraulic and natural fractures, the distribution of high-permeability sandstone layers also induces interlayer stress interference. Fig. 21 shows the p and pore pressure variation contour maps for Cross-section 1 and Cross-section 2 after three years of production. Compared with shale layers, the width of the lateral pore pressure variation zone induced by a single fracture in sandstone is approximately 2–3 times larger. The sandstone layers (Sand 3 and Sand 4) that are directly connected to hydraulic fractures exhibit faster lateral seepage rates, and as production continues, the pressure-decline zones tend to become inter-connected. This finding partially explains why Shale 3's oil production is higher than Sand 1's.

During shale oil development, various forms of vertical interwell interference can occur, primarily governed by the hydraulic

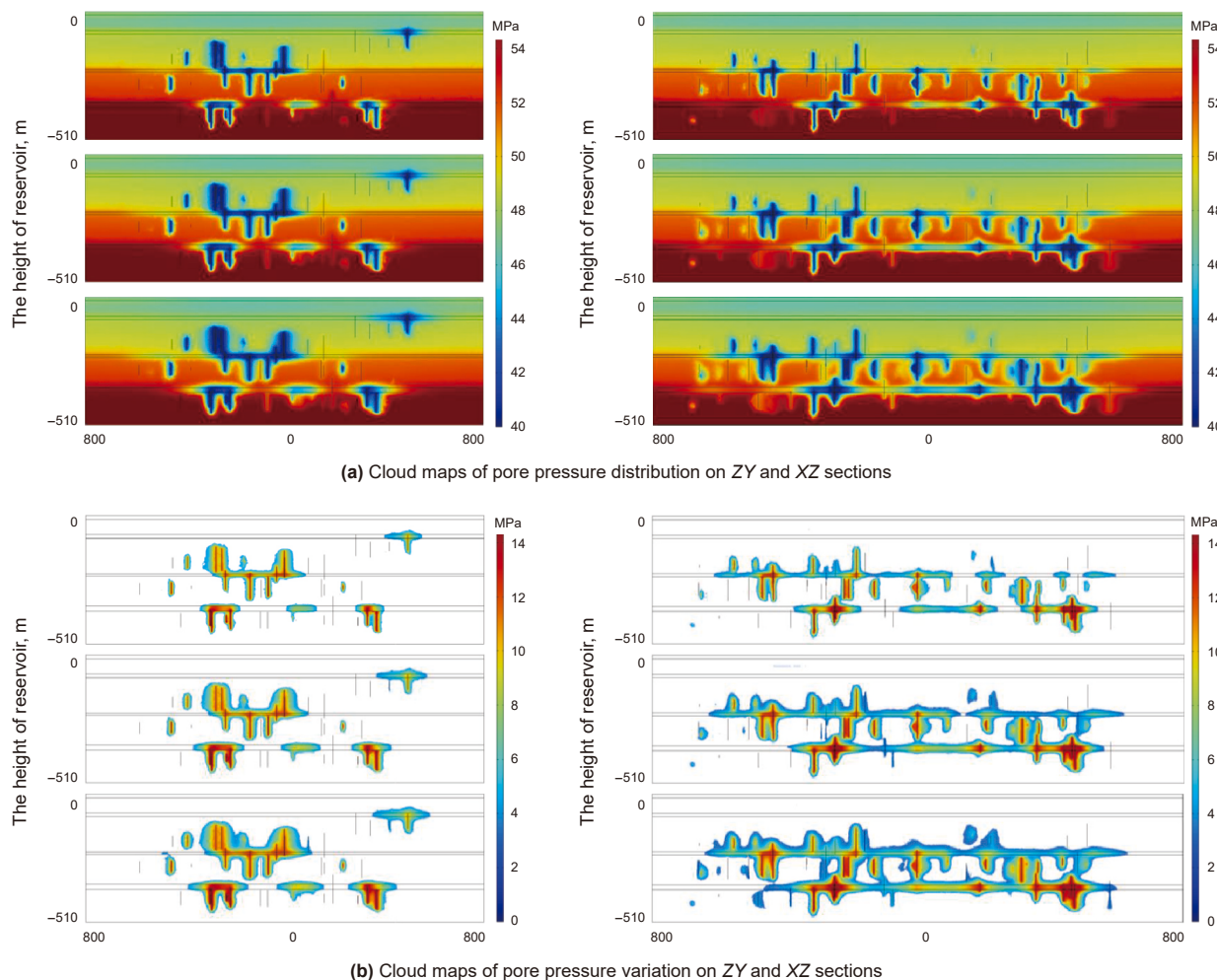


Fig. 21. Pore pressure and pore pressure variation contour maps of Cross-section 1 and Cross-section 2 during three-layer development. Cross-section 1 corresponds to the YZ plane ($x = 1750$), and Cross-section 2 corresponds to the XZ plane ($y = 0$).

and natural fracture connectivity between wells. The degree of such interference is primarily determined by the extent of natural-fracture development within the reservoir and the effectiveness of hydraulic stimulation applied to each well. According to the dominant fracture connection patterns, the interference mechanisms can be classified into four main types: (a) direct connectivity between the hydraulic fractures of Wells A and B; (b) communication between secondary hydraulic fractures from Well A and main hydraulic fractures from Well B; (c) communication between natural fractures or secondary hydraulic fractures of Well A and hydraulic fractures of Well B; and (d) interaction between natural or secondary hydraulic fractures from both Wells A and B. In addition to these fracture-induced pathways, three-layer development introduces another form of vertical coupling. The presence and spatial distribution of high-porosity and high-permeability sandstone layers can induce interlayer stress interference (e), acting as mechanical conduits for stress transmission between adjacent strata. This lithological stress coupling, superimposed on fracture-induced connectivity, further complicates the multi-layer geomechanical response during production, as illustrated in Fig. 22.

The pore pressure and interlayer connectivity characteristics during three-layer development of three-layer and single-layer well patterns are illustrated in Fig. 23. In the three-layer, nine-well development model, the fracture network is dense and vertically interconnected across multiple layers, forming a pronounced pressure gradient. Local interlayer pore pressure differences reach 1–2 MPa, and in zones where fractures intersect, the pressure communication between layers becomes significant. The pore pressure drop between the H-2 and H-3 layers reaches approximately 2–3 MPa, indicating strong vertical stress interference. In contrast, the single-layer, three-well model exhibits a more moderate pore pressure decline, primarily confined to

200–300 m around the hydraulic fractures, with a maximum pressure drop of less than 2 MPa. Overall, the three-layer development substantially enhances vertical pressure transmission and interlayer fluid communication, expanding the effective pressure-depletion zone by approximately 1.5–2 times. This improved connectivity provides more favorable flow channels and energy release conditions, thereby facilitating more efficient volumetric exploitation of shale oil resources.

5.3. Production evaluation of three-layer development

Fig. 24 presents the cumulative oil production per unit thickness for four sandstone and four shale layers over a three-year production period. It can be observed that in the first 220 days, the initial production from Shale 3 and Shale 4, which are directly connected to the hydraulic fractures, is significantly higher, reaching 174.88 and 146.67 m³/m, respectively. This indicates that three-layer development can substantially enhance resource recovery and improve oil production efficiency. After approximately 250 days, both sandstone and shale layers enter a stable production stage, during which cumulative oil production increases linearly at rates of 0.23 m³/m/d for sandstone layers and 0.08 m³/m/d for shale layers. Shale 1 and Sandstone 1 exhibit the lowest production among their respective lithologies, primarily because no hydraulic fractures are distributed within these layers. Therefore, in three-layer development, increasing the complexity and density of the fracture network is essential to improve overall shale oil flow capacity and enhance ultimate recovery.

Fig. 25(a) presents the overall production evolution of Well H-1-C during the first year after hydraulic fracturing. Shale oil production exhibits a relatively high initial rate of approximately 110–120 m³, followed by a rapid decline over the first 14 days, then

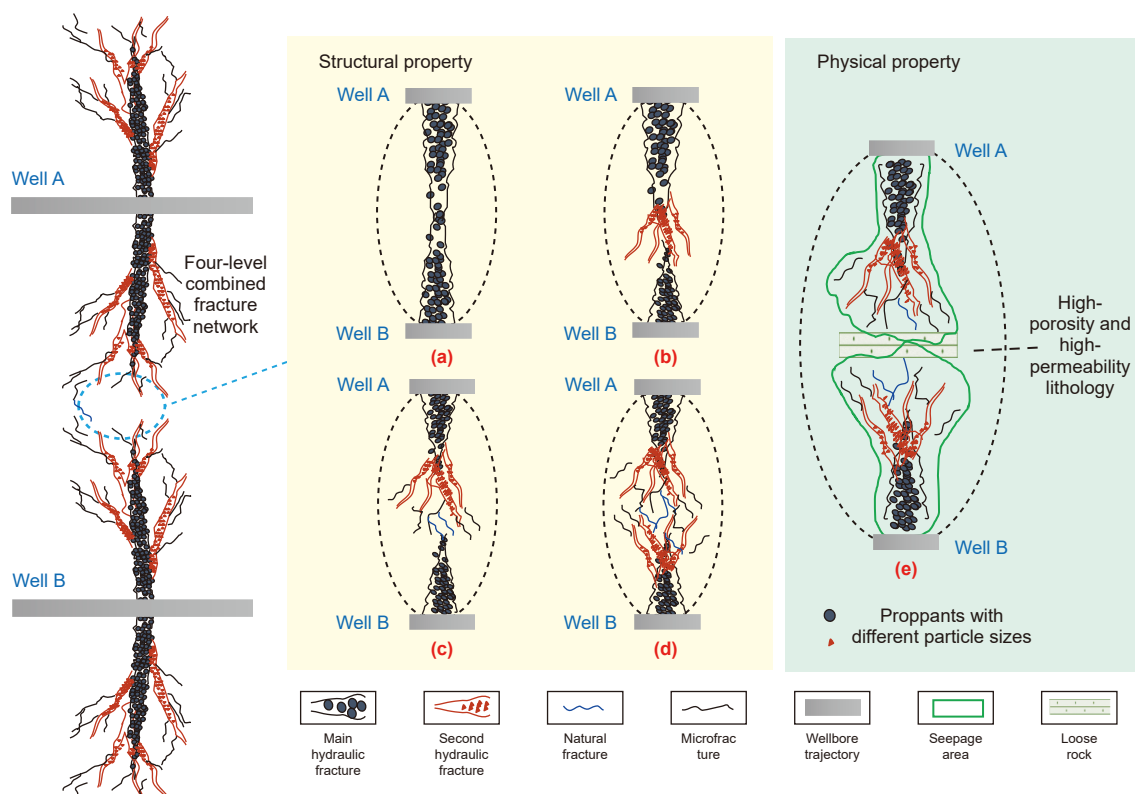


Fig. 22. Schematic diagram of vertical stress interference induced by four-level combined fracture networks in multi-layer horizontal wells.

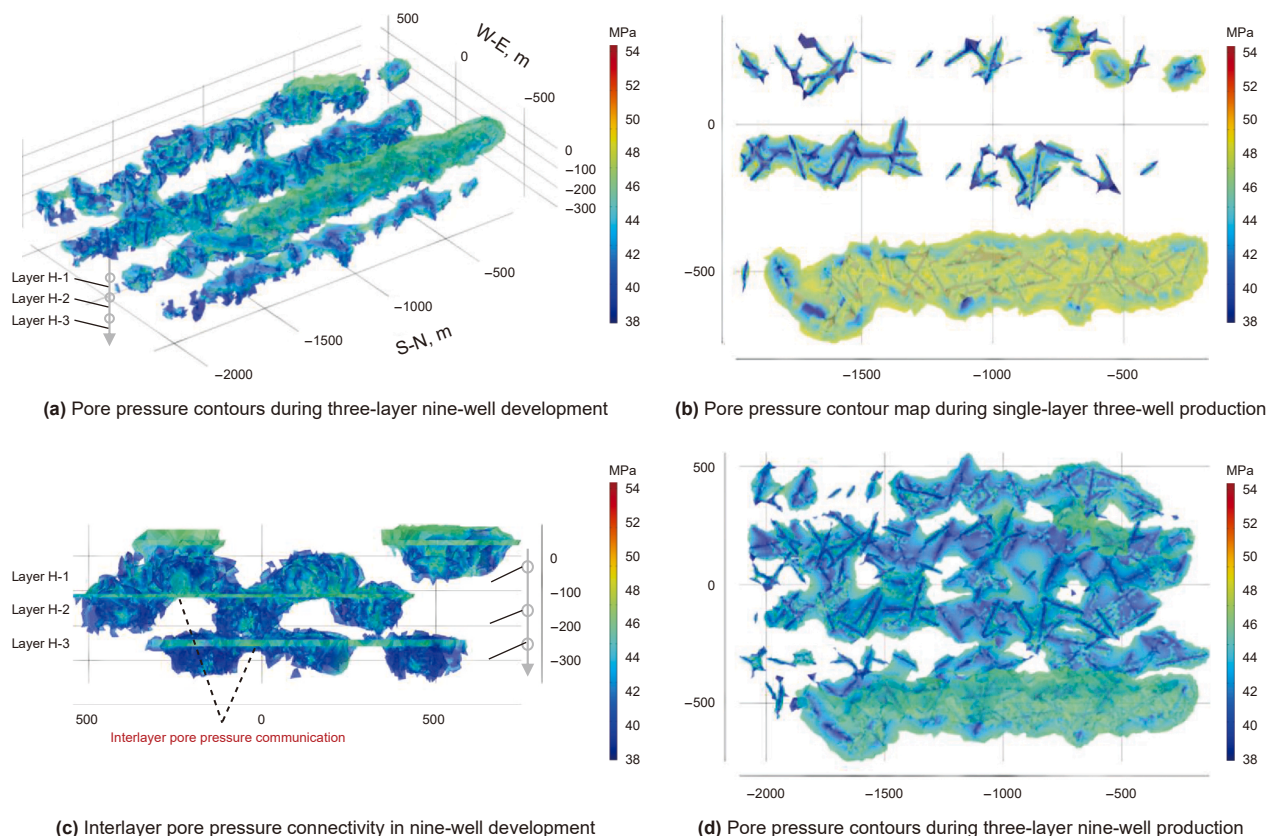


Fig. 23. Comparison of pore pressure distribution and interlayer connectivity characteristics between three-layer and single-layer developments.

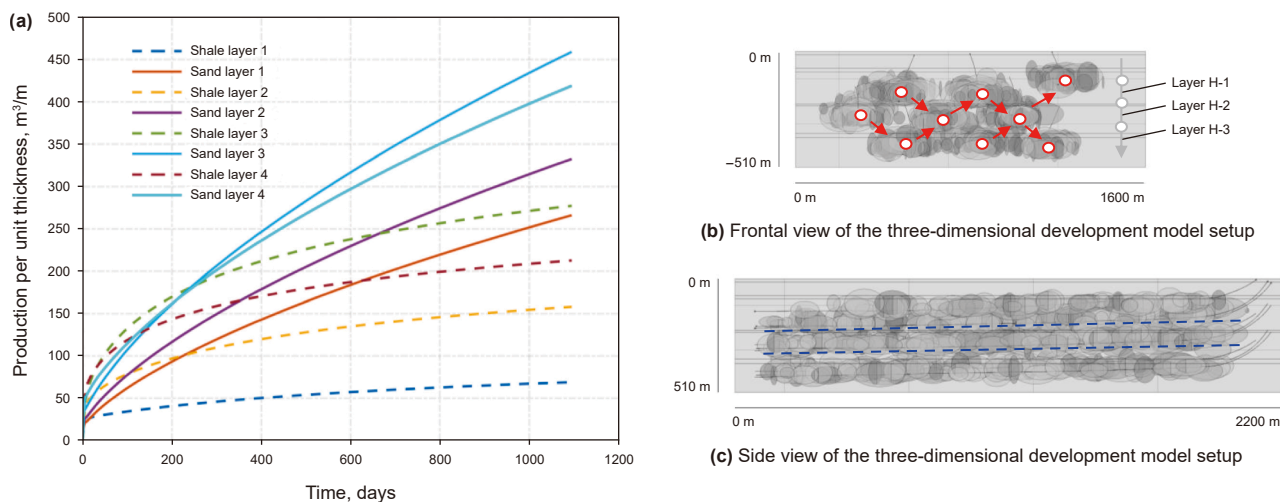


Fig. 24. Cumulative oil production per unit thickness of each sublayer during three-layer development.

gradually transitioning to a slower decline. The simulated results show good agreement with the measured production data in terms of the overall trend, successfully capturing the typical production behavior of unconventional reservoirs characterized by a rapid early decline followed by a more stable depletion stage. Fig. 25(b) provides a zoomed-in view of the first 60 days, offering a clearer comparison between the simulated and observed data during the early production period. Although the simulated production is slightly lower than the measured data in the first few days, the two curves converge after approximately 15 days,

indicating that the proposed model can accurately reproduce early-time production decline and its dynamic evolution, demonstrating good predictive reliability and applicability.

6. Further discussion

- (1) In this study, two multi-layer development models were constructed: a single-layer three-well model and a three-layer nine-well model. For future work, it is necessary to establish fracture interference charts under different

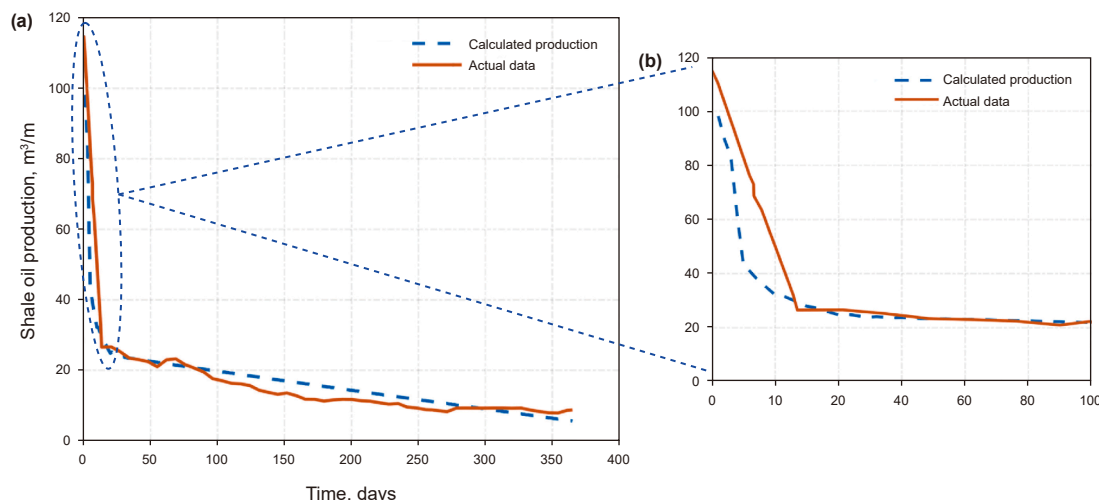


Fig. 25. Comparison between simulated and field shale oil production for Well H-1-C after history matching.

interlayer spacing, well spacing, and stage-cluster spacing to guide field operations. Such charts can facilitate batch-scale multi-layer development, promote standardization of surface facilities, and enable systematic production management.

- (2) Stereoscopic well group development can effectively increase the recovery factor. Appropriate interlayer and well spacing are crucial to ensure the economic efficiency of well groups. When the interlayer spacing is too large, resource control between layers is weakened, resulting in unrecovered reserves. Conversely, when the spacing is too small, fracture communication between layers may cause overlapping drainage areas, leading to competitive production and reduced ultimate recovery. Therefore, it is essential to determine the optimal interlayer spacing, which can superimpose interlayer pressure, suppress outward pressure propagation, and fully utilize reservoir energy, thereby enhancing ultimate recovery across different layers.
- (3) Multi-layer stimulation and development involve multiple types of wells, including producing wells, fractured wells awaiting production, drilled wells awaiting fracturing, wells under drilling, and planned wells. Multi-layer development involves different production sequencing strategies, which are typically categorized into horizontal-then-vertical and vertical-then-horizontal “Tank” operating modes. In this study, the model in Section 5 was used to simulate top-down and bottom-up production scenarios (Fig. 26). The results indicate that when interlayer fracture communication occurs, different production sequences can induce 0–4 MPa of interlayer stress interference, and the range of pore pressure depletion varies at the end of the third year. Future studies should evaluate the impact of these production sequence strategies on interlayer and interwell stress interference, and explore their effects on reservoir recovery efficiency.

7. Summaries and conclusions

This study focuses on continental shale oil reservoirs with vertically interbedded sandstone and shale, clarifying the

deployment and distribution characteristics of stereoscopic fracturing well patterns and fracture networks. It further investigates the dynamic evolution of in-situ stress induced by production under vertical heterogeneity of continental shale reservoirs. The main conclusions are as follows:

- (1) The distribution of microseismic events near the wellbore of the H platform shows limited vertical extension, with a narrow spatial range and high spatial density. The reconstructed average fracture length and height of the nine wells are 230 and 75 m, respectively. Under zipper fracturing-induced stress disturbance from neighboring wells, the fracture length tends to extend 20 m from the fracturing side, whereas in high-pore-pressure shale reservoirs, the fracture height preferentially propagates upward toward lower-pore-pressure zones.
- (2) The intersection lengths between fractures in Layer H-2 and the toe of Layer H-1 and the heel of Layer H-3 are approximately 2–4 and 3–7 m, respectively. Different production sequences between layers induce pore pressure variations of approximately 3 MPa in the interlayer connected fracture zones. Therefore, stereoscopic fracturing well pattern design should consider not only the favorable vertical distribution of sweet spots to minimize interlayer interference and maximize reservoir recovery, but also fracture geometry, orientation, complexity, and stimulated reservoir volume (SRV) to optimize well spacing and interlayer spacing for effective volumetric control.
- (3) Because sandstone layers have higher porosity and permeability than shale layers, during three-layer development, the horizontal stress difference in high-permeability sandstone layers increases significantly by 2.61 MPa, whereas in low-permeability shale layers the increase is less than 0.5 MPa. The stress rotation angle in sandstone is also greater than in shale. To reduce stress interference from existing wells during infill fracturing, the well spacing in sandstone layers should be larger than that in shale layers, and shale layers are more suitable for infill well deployment.
- (4) Compared with single-layer, three-well production, three-layer, nine-well development induces more pronounced pore pressure changes, effectively improving shale oil

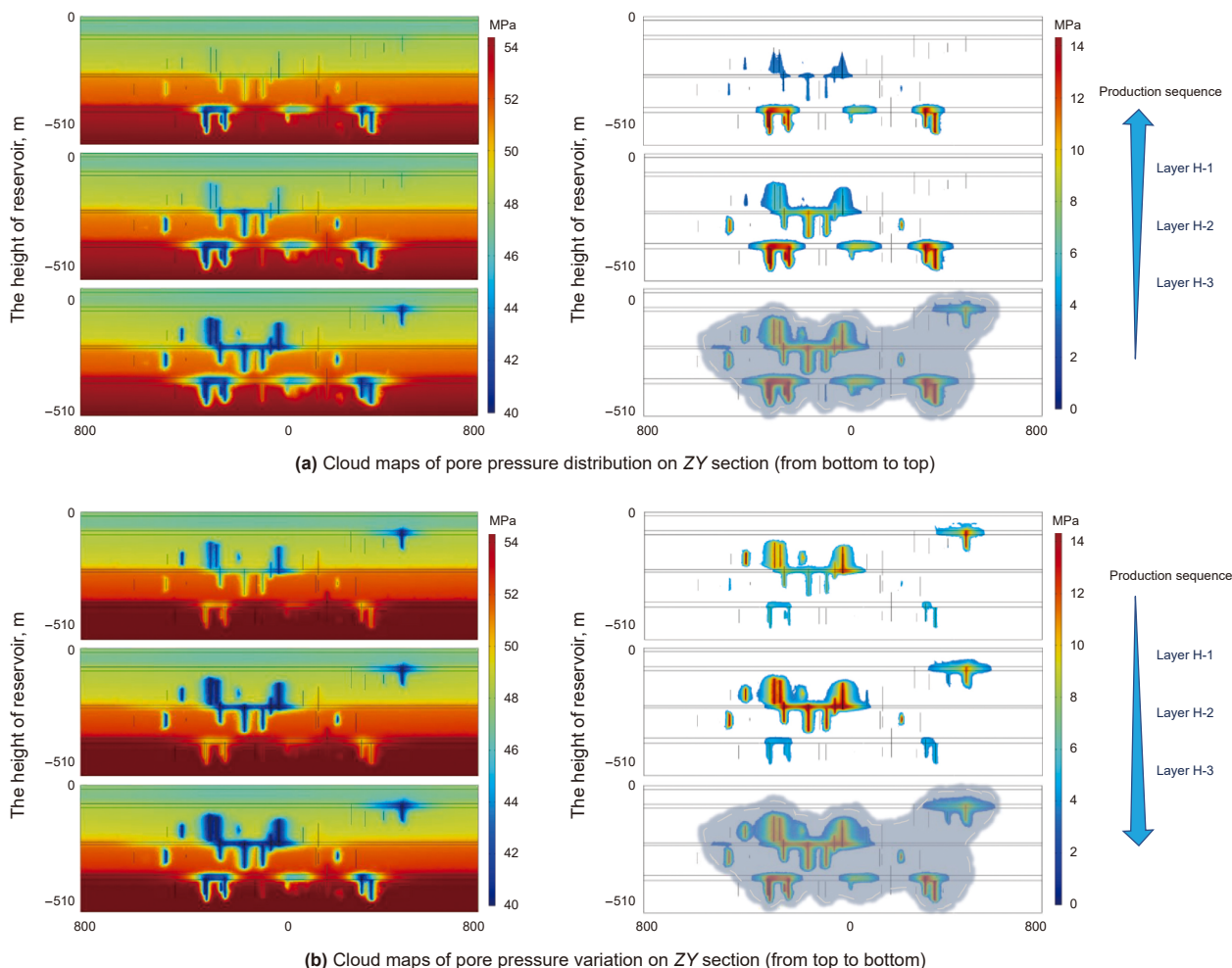


Fig. 26. Pore pressure variation contour maps induced by bottom-up and top-down production sequences.

recovery. To achieve efficient development of continental shale oil, stereoscopic fracturing must be employed to break the tight shale reservoir and establish high-conductivity flow channels between shale pore throats and the wellbore, enabling efficient hydrocarbon flow and improved recovery.

CRediT authorship contribution statement

Qi-Xing Zhang: Writing – original draft, Visualization, Validation, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Bing Hou:** Supervision. **Liao-Yuan Zhang:** Formal analysis. **Bin-Tao Zheng:** Project administration. **Zhen-Yu Wang:** Methodology, Investigation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

The authors are grateful for the financial support from the National Natural Science Foundation of China (No. 52504019), China Postdoctoral Science Foundation (No. 2025 M772961), the National Science and Technology Major Project of China (No. 2024ZD1404701), and the State Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum (Beijing) (No. PRE/open-2507). This paper is a substantially extended version of the work previously presented in abstract form at the InterPore 2026 Conference (Abstract ID: 536).

References

- Abdelaziz, A., Ha, J., Li, M., Magsipoc, E., Sun, L., Grasselli, G., 2023. Understanding hydraulic fracture mechanisms: from the laboratory to numerical modelling. *Adv. Geo-Energy Res.* 7, 66–68. <https://doi.org/10.46690/ager.2023.01.07>.
- Ajisafe, F.O., Solovyeva, I., Morales, A., Ejofodomi, E., Porcu, M.M., 2017. Impact of well spacing and interference on production performance in unconventional reservoirs, Permian basin. In: SPE/AAPG/SEG Unconventional Resources Technology Conference. <https://doi.org/10.15530/urtec-2017-2690466>.
- Alimahomed, F., Malpani, R., Jose, R., Defeu, C., Arteaga, E.I.V., Haddad, E., 2018. Development of the stacked pay in the Delaware Basin, Permian Basin. In: SPE/AAPG/SEG Unconventional Resources Technology Conference. <https://doi.org/10.15530/URTEC-2018-2875581>.
- Barbosa, L.G., Cleto, P.R., Maedo, M.A., Camargo, M., Rodrigues, E.A., Manzoli, O.L., 2025. Simulation of the natural fractures influence on hydraulic fractures

- propagation using high aspect ratio interface elements. *Comput. Geotech.* 179, 107026. <https://doi.org/10.1016/j.compgeo.2024.107026>.
- Bommer, P.A., Bayne, M., 2020. The effects of down-spacing in the Delaware Basin Wolfcamp play: A case history. In: SPE Hydraulic Fracturing Technology Conference and Exhibition. <https://doi.org/10.2118/199691-MS>.
- Chang, Z., Hou, B., 2023. Numerical simulation on cracked shale oil reservoirs multi-cluster fracturing under inter-well and inter-cluster stress interferences. *Rock Mech. Rock Eng.* 56, 1909–1925. <https://doi.org/10.1007/s00603-022-03145-7>.
- Curnow, J.S., Tutuncu, A.N., 2016. A coupled geomechanics and fluid flow modeling study for hydraulic fracture design and production optimization in an eagle ford shale oil reservoir. In: SPE Hydraulic Fracturing Technology Conference. <https://doi.org/10.2118/179165-MS>.
- Defeu, C., Williams, R., Shan, D., Martin, J., Cannon, D., Clifton, K., Lollar, C., 2019. Case study of a landing location optimization within a depleted stacked reservoir in the midland basin. In: SPE Hydraulic Fracturing Technology Conference and Exhibition. <https://doi.org/10.2118/194353-MS>.
- Dontsov, E.V., Peirce, A.P., 2015. Proppant transport in hydraulic fracturing: Crack tip screen-out in KGD and P3D models. *Int. J. Solid Struct.* 63, 206–218. <https://doi.org/10.1016/j.ijsolstr.2015.02.051>.
- Guo, W., Deng, S., Sun, Y., 2024. Recent advances on shale oil and gas exploration and development technologies. *Adv. Geo-Energy Res.* 11, 81–87. <https://doi.org/10.46690/ager.2024.02.01>.
- Guo, X., Wu, K., Killough, J., 2018. Investigation of production-induced stress changes for infill-well stimulation in eagle ford shale. *SPE J.* 23, 1372–1388. <https://doi.org/10.2118/189974-pa>.
- Guo, X., Wu, K., Killough, J., Tang, J., 2019. Understanding the mechanism of interwell fracturing interference with reservoir/geomechanics/fracturing modeling in eagle ford shale. *SPE Reservoir Eval. Eng.* 22, 842–860. <https://doi.org/10.2118/194493-pa>.
- Guo, X., Shen, B., Li, M., Liu, H., Li, Z., Zhang, S., Yang, Y., Guo, J., Liu, Y., Li, P., Ma, X., Zhao, M., Li, P., Zhang, C., Wang, Z., 2025. Research progress and key research directions of shale oil in lacustrine rift basins. *Petrol. Explor. Dev.* 52, 1113–1127. [https://doi.org/10.1016/S1876-3804\(25\)60629-X](https://doi.org/10.1016/S1876-3804(25)60629-X).
- He, J., Li, X., Yin, C., Zhang, Y., Lin, C., 2020. Propagation and characterization of the micro cracks induced by hydraulic fracturing in shale. *Energy* 191, 116449. <https://doi.org/10.1016/j.energy.2019.116449>.
- Hou, B., Zhang, Q., Lv, J., 2024. Distributed fiber optic monitoring of asymmetric fracture swarm propagation in laminated continental shale oil reservoirs. *Rock Mech. Rock Eng.* 57, 5067–5087. <https://doi.org/10.1007/s00603-024-03791-z>.
- Hou, B., Zhang, Q., Liu, X., Pang, H., Zeng, Y., 2022. Integration analysis of 3D fractures network reconstruction and frac hits response in shale wells. *Energy* 260, 124906. <https://doi.org/10.1016/j.energy.2022.124906>.
- Huang, L., Liu, J., Zhang, F., Dontsov, E., Damjanac, B., 2019. Exploring the influence of rock inherent heterogeneity and grain size on hydraulic fracturing using discrete element modeling. *Int. J. Solid Struct.* 176–177, 207–220. <https://doi.org/10.1016/j.ijsolstr.2019.06.018>.
- Huang, L., Dontsov, E., Fu, H., Lei, Y., Weng, D., Zhang, F., 2022. Hydraulic fracture height growth in layered rocks: Perspective from DEM simulation of different propagation regimes. *Int. J. Solid Struct.* 238, 111395. <https://doi.org/10.1016/j.ijsolstr.2021.111395>.
- Kaufman, P., McClure, M., Franciose, N., Owens, S., Srur, F., Russell, D., 2019. Optimizing completions in tank style development. In: SPE/AAPG/SEG Unconventional Resources Technology Conference. <https://doi.org/10.15530/urtec-2019-608>.
- Kazemi, H., Seth, M.S., Thomas, G.W., 1969. The interpretation of interference tests in naturally fractured reservoirs with uniform fracture distribution. *Soc. Petrol. Eng. J.* 9, 463–472. <https://doi.org/10.2118/2156-b>.
- Lei, X., Ma, S., 2014. Laboratory acoustic emission study for earthquake generation process. *Earthq. Sci.* 27, 627–646. <https://doi.org/10.1007/s11589-014-0103-y>.
- Li, Y., Yang, H., Li, B., Li, Z., 2025. Interference Behaviour between bedding planes and hydraulic fractures and its influence on the complex fracture network in shale. *Rock Mech. Rock Eng.* 58, 181–201. <https://doi.org/10.1007/s00603-024-04167-z>.
- Luo, A., Li, Y., Wu, L., Peng, Y., Tang, W., 2021. Fractured horizontal well productivity model for shale gas considering stress sensitivity, hydraulic fracture azimuth, and interference between fractures. *Nat. Gas Ind. B* 8, 278–286. <https://doi.org/10.1016/j.ngib.2021.04.008>.
- Lv, J.X., Hou, B., 2024. Fractures interaction and propagation mechanism of multi-cluster fracturing on laminated shale oil reservoir. *Pet. Sci.* 21, 2600–2613. <https://doi.org/10.1016/j.petsci.2024.02.007>.
- Marongiu-Porcu, M., Lee, D., Shan, D., Morales, A., 2016. Advanced modeling of interwell-fracturing interference: An Eagle Ford shale-oil study. *SPE J.* 21, 1567–1582. <https://doi.org/10.2118/174902-pa>.
- Morales, A., Zhang, K., Gakhar, K., Marongiu Porcu, M., Lee, D., Shan, D., Malpani, R., Pope, T., Sobernheim, D., Acock, A., 2016. In: Advanced modeling of interwell fracturing interference: An Eagle Ford shale oil study-refracturing. SPE Hydraulic Fracturing Technology Conference. <https://doi.org/10.2118/179177-MS>.
- Pan, Z., Connell, L.D., 2007. A theoretical model for gas adsorption-induced coal swelling. *Int. J. Coal Geol.* 69, 243–252. <https://doi.org/10.1016/j.coal.2006.04.006>.
- Patel, H., Cadwallader, S., Wampler, J., 2016. Zipper fracturing: Taking theory to reality in the Eagle Ford shale. In: SPE/AAPG/SEG Unconventional Resources Technology Conference. <https://doi.org/10.15530/urtec-2016-2445923>.
- Pei, Y., Sepehrnoori, K., 2022. Investigation of parent-well production induced stress interference in multilayer unconventional reservoirs. *Rock Mech. Rock Eng.* 55, 2965–2986. <https://doi.org/10.1007/s00603-021-02719-1>.
- Pei, Y., Wu, J., Chang, C., Liu, C., Wu, K., Yu, W., Miao, J., Mao, Z., Sepehrnoori, K., 2023. Parent-child well spacing optimization in deep shale gas reservoir with two complex natural fracture patterns: A Sichuan Basin case study. *Transport Porous Media* 149, 147–174. <https://doi.org/10.1007/s11242-022-01824-1>.
- Qiu, F., Porcu, M.M., Xu, J., Malpani, R., Pankaj, P., Pope, T.L., 2015. Simulation study of zipper fracturing using an unconventional fracture model. In: SPE/CSUR Unconventional Resources Conference. <https://doi.org/10.2118/175980-MS>.
- Sangnimmuan, A., Li, J., Wu, K., Holditch, S., 2019. Impact of parent well depletion on stress changes and infill well completion in multiple layers in permian basin. In: SPE/AAPG/SEG Unconventional Resources Technology Conference. <https://doi.org/10.15530/urtec-2019-972>.
- Sawadogo, J., Haggerty, M., Mallory, C., Huchton, J., DeAngelis, W., Price, C., 2020. Impact of completion design and well communication on well performance in full section development: A STACK case study using DNA based diagnostics. In: SPE Annual Technical Conference and Exhibition. <https://doi.org/10.1016/j.petrol.2015.04.020>.
- Sesetty, V., Ghassemi, A., 2015. A numerical study of sequential and simultaneous hydraulic fracturing in single and multi-lateral horizontal wells. *J. Petrol. Sci. Eng.* 132, 65–76. <https://doi.org/10.1016/j.petrol.2015.04.020>.
- Shakiba, M., Sepehrnoori, K., 2015. Using embedded discrete fracture model (EDFM) and microseismic monitoring data to characterize the complex hydraulic fracture networks. In: SPE Annual Technical Conference and Exhibition. <https://doi.org/10.2118/175142-MS>.
- Sun, H., Cai, X., Hu, D., Lu, Z., Zhao, P., Li, J., Wang, H., 2023. Theory, technology and practice of shale gas three-dimensional development: A case study of Fuling shale gas field in Sichuan Basin, SW China. *Petrol. Explor. Dev.* 50, 651–664. [https://doi.org/10.1016/S1876-3804\(23\)60417-3](https://doi.org/10.1016/S1876-3804(23)60417-3).
- Tan, P., Jin, Y., Han, K., Hou, B., Chen, M., Guo, X., Gao, J., 2017. Analysis of hydraulic fracture initiation and vertical propagation behavior in laminated shale formation. *Fuel* 206, 482–493. <https://doi.org/10.1016/j.fuel.2017.05.033>.
- Wang, C.L., Wu, A.X., Liu, X.H., Li, R., 2009. Study on fractal characteristics of b value with microseismic activity in deep mining. *Procedia Earth Planet. Sci.* 1, 592–597. <https://doi.org/10.1016/j.proeps.2009.09.094>.
- Wang, J., Elsworth, D., Denison, M.K., 2018. Propagation, proppant transport and the evolution of transport properties of hydraulic fractures. *J. Fluid Mech.* 855, 503–534. <https://doi.org/10.1017/jfm.2018.670>.
- Wang, X., Zhang, F., Zhu, H., Hou, B., 2026. Numerical simulation on fracture propagation of multilayer combined fracturing in coal-bearing strata: Analyzing perforation design effects. *Eng. Fract. Mech.* 332, 111807. <https://doi.org/10.1016/j.engfracmech.2025.111807>.
- Wang, X., Tang, M., Du, X., Zhang, F., Hou, B., Tang, J., 2023. Three-dimensional experimental and numerical investigations on fracture initiation and propagation for oriented limited-entry perforation and helical perforation. *Rock Mech. Rock Eng.* 56, 437–462. <https://doi.org/10.1007/s00603-022-03069-2>.
- Wang, Z., Yang, L., Gao, R., Xu, G., Liu, Z., Mo, S., Fan, M., Wang, X., 2022. Numerical analysis of zipper fracturing using a non-planar 3D fracture model. *Front. Earth Sci.* 10, 808183. <https://doi.org/10.3389/feart.2022.808183>.
- Wei, S., Xia, Y., Jin, Y., Chen, M., Chen, K., 2019. Quantitative study in shale gas behaviors using a coupled triple-continuum and discrete fracture model. *J. Petrol. Sci. Eng.* 174, 49–69. <https://doi.org/10.1016/j.petrol.2018.08.084>.
- Wei, S., Kao, J., Jin, Y., Shi, C., Xia, Y., Liu, S., 2021. A discontinuous discrete fracture model for coupled flow and geomechanics based on FEM. *J. Petrol. Sci. Eng.* 204, 108677. <https://doi.org/10.1016/j.petrol.2021.108677>.
- Wood, T., Leonard, R., Senters, C., Squires, C., Perry, M., 2018. Interwell communication study of UWC and MWC wells in the HFTS. In: SPE/AAPG/SEG Unconventional Resources Technology Conference. <https://doi.org/10.15530/urtec-2018-2902960>.
- Wu, K., Wu, B., Yu, W., 2017. Mechanism analysis of well interference in unconventional reservoirs: Insights from fracture-geometry simulation between two horizontal wells. *SPE Prod. Oper.* 33, 12–20. <https://doi.org/10.2118/186091-pa>.
- Yang, Y., 2024. Shale oil development techniques and application based on ternary-element storage and flow concept in Jiyang depression, Bohai Bay Basin, East China. *Petrol. Explor. Dev.* 51, 380–393. [https://doi.org/10.1016/S1876-3804\(24\)60030-3](https://doi.org/10.1016/S1876-3804(24)60030-3).
- Yin, Z., Zhang, Y., Zhang, F., Wang, X., Zhang, L., 2025. Dynamic evolution mechanisms of induced stresses in hydraulically fractured wells: Incorporating real gas characteristics. *Int. J. Rock Mech. Min. Sci.* 195, 106298. <https://doi.org/10.1016/j.ijsolstr.2025.106298>.
- Yu, W., Zhang, T., Du, S., Sepehrnoori, K., 2015. Numerical study of the effect of uneven proppant distribution between multiple fractures on shale gas well performance. *Fuel* 142, 189–198. <https://doi.org/10.1016/j.fuel.2014.10.074>.
- Zhang, F., Wang, X., Tang, M., Du, X., Xu, C., Tang, J., Damjanac, B., 2021a. Numerical investigation on hydraulic fracturing of extreme limited entry perforating in plug-and-perforation completion of dhale oil reservoir in changqing oilfield, China. *Rock Mech. Rock Eng.* 54, 2925–2941. <https://doi.org/10.1007/s00603-021-02450-x>.
- Zhang, G., Guo, T., Chen, M., Qu, Z., 2025a. Investigation of hydraulic fracture initiation and propagation behavior in glutenite reservoir using an improved global cohesive zone model. *Comput. Geotech.* 186, 107421. <https://doi.org/10.1016/j.compgeo.2025.107421>.
- Zhang, Q., Hou, B., Lin, B., Liu, X., Gao, Y., 2021b. Integration of discrete fracture reconstruction and dual porosity/dual permeability models for gas production analysis in a deformable fractured shale reservoir. *J. Nat. Gas Sci. Eng.* 93, 104028. <https://doi.org/10.1016/j.jngse.2021.104028>.

- Zhang, Q., Hou, B., Pang, H., Liu, S., Zeng, Y., 2022. A comparison of shale gas fracturing based on deep and shallow shale reservoirs in the United States and China. *Computer Modeling in Engineering & Sciences* 133, 471–507. <https://doi.org/10.32604/cmescs.2022.020831>.
- Zhang, Q., Zhang, Z., Zhang, B., Sun, T., Chen, X., Hou, B., 2025b. Research and application of self-suspending proppants based on block copolymer modification in coalbed methane wells. *Physics of Fluids* 37 (7), 077162. <https://doi.org/10.1063/5.0277558>.
- Zhang, Q., Hou, B., Jin, P., Zhang, B., Zhang, M., Yang, G., Sun, T., 2025c. Fracture morphology reconstruction and propagation behavior analysis of zipper fracturing in clustered well platforms based on microseismic monitoring. *Rock Mechanics Bulletin*, 100265. <https://doi.org/10.1016/j.rockmb.2025.100265>.
- Zhang, Q., Hou, B., Wu, A., Zhang, B., Chen, G., Yang, G., Sun, T., 2026. Feature identification in multi-cluster true triaxial hydraulic fracturing using integrated fiber optic and acoustic emission monitoring. *Measurement* 258, 119363. <https://doi.org/10.1016/j.measurement.2025.119363>.