

Article

Genesis and Prediction Method of Local Abnormal Pressure in Carbonate Strata Controlled by Strike–Slip Faults: A Case Study of the Fudong Block, Fuman Oilfield, Tarim Basin

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Abstract

Ultra-deep Ordovician carbonates in the Tarim Basin are a major target for oil and gas exploration in China. Localized overpressure, however, creates substantial well-control risks and impairs drilling safety and exploration performance. This study investigates the Fudong Block of the Fuman Oilfield using drilling, seismic, and well-test data. We develop a high-resolution, layer-specific formation-pressure prediction workflow that integrates well and seismic data through a stress–fracture–pressure framework. The workflow combines geomechanical modeling, prediction of the in situ stress field and fracture distribution, stress–fracture matching, Biot-theory-based pressure prediction, and iterative calibration against drilling observations. The results show that: (1) overpressure is concentrated near secondary faults, branch faults, and NW-trending faults. It is jointly controlled by tectonic compression, pressure retention within fracture–vug bodies, and fluid charging. Multiple vertically separated pressure systems are common, and their marked heterogeneity is closely related to secondary-fault development and fracture–vug connectivity; (2) drilling disturbance can generate apparent overpressure and lead to erroneous pressure interpretation. Overpressured wells commonly exhibit a kick followed by lost circulation or simultaneous kick and loss. Drilling-fluid invasion into confined fracture–vug bodies causes pressure buildup; and (3) formation pressure is a key parameter in integrated geological and engineering sweet-spot evaluation and is closely linked to wellbore stability. Field applications confirm the accuracy of the proposed workflow. The method strengthens integrated geology–engineering evaluation and provides a practical basis for the safe and efficient development of ultra-deep carbonate reservoirs.

Keywords: carbonate reservoir; localized overpressure; strike-slip fault; formation-pressure prediction; geomechanical modeling; Fuman Oilfield



Academic Editor: Suzanne Golding

Received: 14 June 2026

Revised: 26 July 2026

Accepted: 31 July 2026

Published: 6 August 2026

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1. Introduction

Ultra-deep carbonate reservoirs are frontier targets for global oil and gas exploration. Major discoveries have been made in the Tarim, Sichuan, and other basins [1]. Overpressure in these reservoirs is generally controlled by tectonic compression, fluid charging, and sealing conditions, although the dominant controls vary among tectonic settings [2,3]. In China, the ultra-deep carbonates of the Tarim Basin are a principal exploration target. Fracture–vug reservoirs in the Ordovician Yijianfang and Yingshan formations at depths

greater than 7000 m have considerable resource potential and are central to reserve and production growth [4,5]. Localized overpressure nevertheless occurs frequently and can cause kicks, lost circulation, and wellbore blockage. These events severely compromise drilling safety and exploration performance [6,7].

Overpressure in the carbonate succession of the Tarim Basin has been widely studied. Tectonic compression, hydrocarbon charging, disequilibrium compaction, and fluid expansion are generally regarded as the principal geological mechanisms [8–11]. Wu et al. [12] demonstrated the role of strike–slip faults in hydrocarbon accumulation and showed that fault activity and sealing capacity strongly affect pressure distribution. Zhu et al. [13] proposed that the late, large-scale hydrocarbon charging of Ordovician fracture–vug reservoirs displaced connate water and raised formation pressure under closed conditions. Wu et al. [14] identified a hydrocarbon-generation–sealing–pressurization chain in successions sealed by evaporite and tight limestone, with particularly strong pressurization in small, isolated fracture–vug bodies. Duan et al. [15] attributed the long-lived deep overpressure to rapid burial and impeded dewatering beneath thick mudstone and evaporite seals. Shao et al. [16] further clarified how gas–liquid displacement regulates pressure in constant-volume carbonate bodies.

Most previous studies have focused on basin-scale systems or major fault zones. The mechanisms responsible for local overpressure near the secondary branches of strike–slip faults, horsetail splays, and fault-poor areas remain poorly resolved, limiting explanations of interwell pressure variability [17–19]. Geological overpressure has also not been adequately distinguished from drilling-induced apparent overpressure. In particular, diagnostic criteria are lacking for the apparent pressure increases caused by the gravity displacement of drilling fluid and by loss–pressure–buildup cycles in confined reservoirs [20–22]. Common prediction methods include the Eaton method, seismic inversion, and finite-element simulation [23–27]. These methods have been used widely in clastic successions. In fracture–vug carbonates, however, extreme heterogeneity, the weak pressure sensitivity of acoustic velocity, and fracture effects can lead to erroneous estimates [28–30]. Conventional approaches therefore struggle where multiple pressure systems overlap, fracture–vug bodies are hydraulically confined, and faults compartmentalize pressure [31]. A higher-resolution method is needed for ultra-deep, strike–slip fault-controlled reservoirs.

To address these limitations, we develop a high-resolution, layer-specific pressure prediction workflow for the eastern Fuman Oilfield (Fudong Block) by integrating well and seismic data. Drilling histories and test data are first used to distinguish geological overpressure from drilling-induced apparent overpressure. Seismic data are then used to model the in situ stress field and quantitatively predict fracture distribution. The spatial distribution of overpressure is inferred from the coupled fault–stress–fracture relationship, and vertically stacked pressure systems are predicted by depth interval. This workflow improves pressure-prediction resolution in ultra-deep carbonates and supports integrated geological and engineering sweet-spot evaluation, efficient exploration, and the safe development of fracture–vug reservoirs in the Tarim Basin.

2. Geological Setting

The Fuman Oilfield lies in the transition between the Awati and Manjiaer depressions of the Tarim Basin and forms part of a Paleozoic ultra-deep carbonate hydrocarbon province (Figure 1a) [32,33]. The area records superimposed Caledonian, Hercynian, and Himalayan tectonic events that produced a complex fault network. The F15 fault divides the network: NW-trending faults such as F13 and F14 occur to the west, whereas major NE-trending faults including F116, F117, F119, and F120 occur to the east. Secondary faults and small fault clusters are developed around and between the major faults [34,35]. The principal targets

are the Ordovician Yijianfang and Yingshan formations. Fault damage and karstification created pores, vugs, and fractures that form fault-controlled fracture–vug reservoirs [36,37].

The eastern Fuman Oilfield, here termed the Fudong Block, includes the FI20 fault zone and areas farther east (Figure 1b). The target interval is the Ordovician Yingshan Formation, a carbonate succession deposited mainly as high-energy grain shoals along a platform margin. Dolomite and grainstone constitute the principal reservoir rocks. Subsequent diagenesis removed much of the primary porosity, and reservoir quality is generally poor (Figure 2) [38,39]. The FI20 fault zone is comparatively large, whereas secondary faults to the east are smaller, mostly less than 100 m long, and provide limited reservoir connectivity.

By March 2025, 15 wells had been completed in the Fudong Block. Nine wells in the FI20 fault zone generally yielded commercial oil and gas flows. Six wells on secondary faults or in inter-fault areas showed overpressure. Drilling-based pressure coefficients for wells FD1, FD2, FD101, and MS1C ranged from 1.96 to 2.17. These overpressured wells either were not brought on stream or produced at low rates and with poor efficiency. Thus, overpressure in the study area does not necessarily correspond to high productivity.

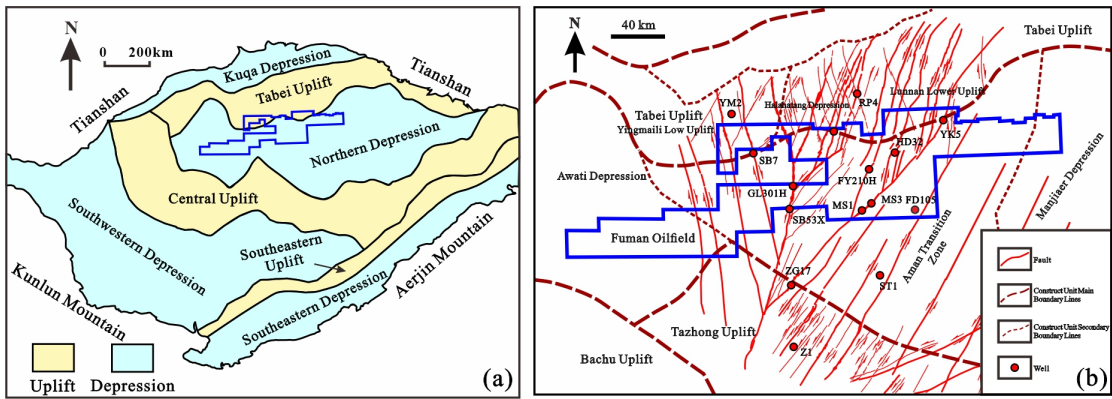


Figure 1. Regional tectonic location of the Fuman Oilfield (a) and structural map of the Fudong area (b). (after Xu et al.) [40].

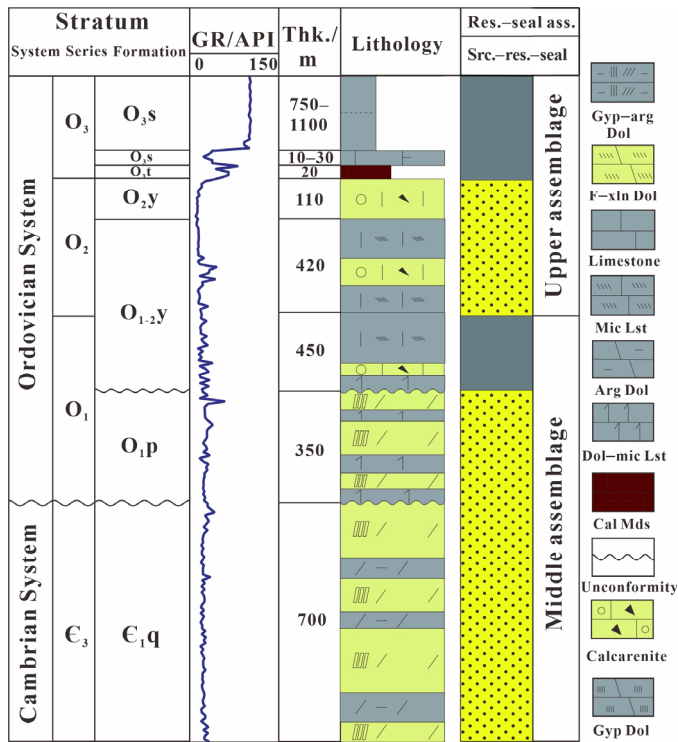


Figure 2. Lower Paleozoic stratigraphic column of the Fuman Oilfield (after Song et al.) [35].

3. Overpressure Prediction Method and Application

3.1. Theoretical Basis

The Fudong Block contains multiple pressure systems, highly heterogeneous fracture–vug reservoirs, and substantial drilling disturbance. To address these challenges, we integrate well and seismic data in a high-resolution, layer-specific prediction method. The method combines Biot theory with geomechanical modeling to predict pressure by depth interval. It is designed to improve the accuracy and applicability of overpressure prediction and to support safe drilling, mud-weight optimization, and well-control risk management.

Under Biot theory, formation pressure depends primarily on rock deformation and on the fraction of applied stress transferred to the pore fluid. Pore pressure is therefore related to the bulk modulus of the rock and the applied in situ stress. In fractured carbonates, fracture intensity also changes the bulk compressibility and effective stress coefficient. Fracture parameters must therefore be included explicitly in the pressure calculation. The Biot-based relationship is expressed as follows Equation (1) [41,42]:

$$P_p = \frac{(K_f \times \sigma + 4)}{(K_{sat} + G \times POR)} \quad (1)$$

where P_p is the pore pressure (MPa); K_f is the bulk modulus of the pore fluid (GPa); K_{sat} is the bulk modulus of the rock (GPa), σ is the in situ stress (MPa); G is the consolidation coefficient (taken as 20 for carbonate rocks); and POR is rock porosity (%).

To simplify the calculation and clarify the parameter relationships, the volumetric compressibility, defined as the reciprocal of the bulk modulus, is introduced. This yields the following relationship (Equation (2)) [43]:

$$P_p = \left(\frac{(1 - POR) \times C_b \times \sigma_z}{(1 - POR) \times C_b - POR \times C_p} \right)^s \quad (2)$$

where C_b is the bulk compressibility (unitless); C_p is the pore-fluid compressibility (unitless); σ_z is the overburden stress (MPa); and s is an empirical coefficient ranging from 0.8 to 1.0.

The Gassmann equation is a fundamental rock–physics relation for the elastic properties of fluid-saturated porous media. It links the bulk moduli of saturated rock, the dry-rock frame, the mineral matrix, and the pore fluid. The pore-fluid bulk modulus can therefore be estimated from the elastic properties of saturated rock, dry rock, and the mineral matrix [44].

Application of the Gassmann equation requires the porous medium to be macroscopically homogeneous and isotropic; the pore space to be fully and uniformly saturated; the solid frame and pore fluid to behave elastically; static conditions with no fluid-flow effect and uniform pore pressure; and equal shear moduli for saturated and dry rock. The classical form is given by Adam et al. [45] (Equation (3)). Rearrangement provides an expression for the pore-fluid bulk modulus (Equation (4)) [46,47]. Physically, the saturated-rock bulk modulus is governed jointly by the dry-frame modulus, mineral properties, pore-fluid properties, and porosity. The influence of the pore fluid enters through the fluid-modulus terms in the numerator and denominator.

$$K_{sat} = K_{dry} + \frac{\left(1 - \frac{K_{dry}}{K_{min}}\right)^2}{\frac{POR}{K_{fluid}} + \frac{1 - POR}{K_{min}} - \frac{K_{dry}}{K_{min}^2}} \quad (3)$$

where K_{dry} is the bulk modulus of the dry rock frame (GPa); K_{min} is the bulk modulus of the rock mineral grains (GPa); and K_{fluid} is the bulk modulus of the pore fluid (GPa).

$$K_{\text{fluid}} = \frac{POR \cdot K_{\text{min}}^2}{\frac{(K_{\text{min}} - K_{\text{dry}})^2}{K_{\text{sat}} - K_{\text{dry}}} - [(1 - POR) \cdot K_{\text{min}} - K_{\text{dry}}]} \quad (4)$$

Within this Biot–Gassmann pressure-prediction framework, the dry-frame bulk modulus and Biot effective stress coefficient α link rock deformation to pore pressure. Because ultra-deep fracture–vug carbonates are highly heterogeneous, K_{dry} cannot be measured directly throughout the model. It is instead estimated from rock-mechanical and fracture parameters using the following procedure.

(1) Conversion between Dynamic and Static Rock-Mechanical Properties

P- and S- wave slowness and density from seismic interpretation and conventional logs are used to calculate dynamic elastic modulus (Equation (5)) [48], dynamic Poisson's ratio (Equation (6)), and dynamic bulk modulus (Equation (7)).

$$E_d = G \cdot \frac{3(\Delta t_s)^2 - 4(\Delta t_p)^2}{(\Delta t_s)^2 - (\Delta t_p)^2} \quad (5)$$

$$\mu_d = \frac{1}{2} \frac{(\Delta x)^2 - 2(\Delta y)^2}{(\Delta x)^2 - (\Delta y)^2} \quad (6)$$

$$K = \frac{E_d}{3(1 - 2\mu_d)} \quad (7)$$

where Δt_s are the P-wave and S-wave slowness ($\mu\text{s}/\text{m}$); E_d the dynamic elastic modulus (GPa); ν_d is dynamic Poisson's ratio (unitless); and K is the dynamic bulk modulus (GPa).

Biot theory requires static elastic properties to describe deformation of the rock frame. We therefore used triaxial mechanical tests on cores from the study area to establish dynamic-to-static conversion relationships for Yingshan carbonates (Equations (8) and (9)) [49]. The corrected properties provide input for geomechanical modeling and calibration of the effective stress coefficient.

$$E_s = 1.6765E_d - 71.36 \quad R^2 = 0.8014 \quad (8)$$

$$\mu_s = -1.4122\mu_d + 0.7201 \quad R^2 = 0.7558 \quad (9)$$

where E_s the dynamic elastic modulus (GPa); ν_s is dynamic Poisson's ratio (unitless).

(2) Estimation of K_{dry} Using a Fractured-Rock Physics Model

In fault-controlled carbonate reservoirs, the dry-frame bulk modulus is governed by both the mineral matrix and the fracture system. To incorporate fracture predictions quantitatively, we apply the Schoenberg linear-slip model [50]. Fracture density (FDI), derived from seismic attributes and image-log interpretation, is represented as an increment in the dry-rock compliance tensor. The effective compliance tensor is given in Equation (10).

$$S_{\text{dry}} = S_{\text{min}} + \Delta S_f \quad (10)$$

where S_{dry} , S_{min} and ΔS_f are the compliance tensors of the fractured dry-rock frame, mineral matrix, and fracture-induced increment, respectively (GPa^{-1}). S_{min} is constructed from the bulk modulus K and shear modulus G , both in GPa. ΔS_f depends on the normal compliance Z_N and tangential compliance Z_T of fractures, both in m/Pa . Both Z_N and Z_T are proportional to fracture density and are calibrated against quantitative fracture predictions in the study area. The model yields the bulk modulus K_{dry} and shear modulus

G_{dry} of the fractured dry frame, both in GPa. The Biot effective stress coefficient α is dimensionless and is calculated directly from K_{dry} (Equation (11)).

$$\alpha = 1 - \frac{K_{\text{dry}}}{K_{\text{min}}} \quad (11)$$

(3) Parameter Coupling and Pore-Pressure Calculation

After K_{dry} , α , and the static bulk modulus have been obtained, the parameters are entered into the Gassmann equation to calculate K_{sat} , and pore pressure is then solved using the Skempton relationship. For three-dimensional application, P-wave velocity, S-wave velocity, and density are obtained from seismic impedance inversion and converted from dynamic to static properties. These volumes are combined with fracture-density-driven K_{dry} and α volumes in the Biot–Gassmann workflow to generate a three-dimensional formation-pressure coefficient volume.

These equations are derived under static, no-flow conditions. Their application to dynamic conditions, such as seismic-wave propagation, requires a Biot-theory correction for fluid-flow effects. Compared with conventional approaches, the Biot-based method has a strong theoretical basis, relatively few restrictive assumptions, and broad applicability. It is not tied to a particular lithology or overpressure mechanism and directly relates formation pressure to fluid-wave velocity. It therefore provides a suitable theoretical basis for overpressure prediction under the complex conditions of the study area.

3.2. Workflow

The high-resolution, layer-specific workflow integrates well logs and seismic data with geomechanical modeling and iterative calibration against drilling observations. It focuses on coupled stress–fracture-pressure prediction and comprises the following steps.

Step 1: Geomechanical Modeling

A regional geomechanical model is constructed from drilling, well-log, and rock-mechanical data and is constrained by the regional tectonic history. Elastic modulus, Poisson's ratio, and related properties are integrated to characterize the intensity of tectonic compression and the distribution of secondary faults. The model provides the mechanical basis for stress, fracture, and pressure prediction.

Step 2: Seismic Inversion and In Situ Stress Prediction

The one-dimensional geomechanical models developed in Step 1 constrain post-stack impedance inversion and pre-stack simultaneous AVO inversion. The inversions yield three-dimensional P-wave velocity V_p , S-wave velocity V_s , and density volumes. A finite-element model then solves the three-dimensional in situ stress field, including stress magnitude, orientation, and spatial distribution. This stress field both controls the subsequent fracture prediction and supplies the effective-stress term used in pressure calculations.

Step 3: Fracture Prediction and Stress-Fracture Matching

Fracture development is predicted quantitatively from the simulated stress field and seismic elastic properties. Sensitive seismic attributes, including curvature, coherence, ant tracking, and the instantaneous-frequency attenuation gradient, are extracted. Image-log fracture density in cored wells is used as the target for a neural-network fusion model that generates a three-dimensional fracture development index (*FDI*). Fracture effectiveness is evaluated with the slip tendency $ST = \tau/\sigma_n$, where τ and σ_n are the shear and normal stresses acting on the fracture plane, respectively.

Step 4: Biot-Theory-Based Pressure Prediction

Empirical relationships are established between *FDI*, the Biot effective stress coefficient α , and the dry-rock bulk modulus K_{dry} . The saturated-rock bulk modulus derived from

acoustic-velocity inversion is then entered into the Biot–Gassmann equation to predict formation pressure.

Step 5: Calibration Against Drilling Observations

Measured pressures, well-control responses, and fracture intersections recorded during drilling are compared with the initial prediction. Prediction errors are calculated, and the model is iteratively calibrated to test and improve its validity and applicability (Figure 3).

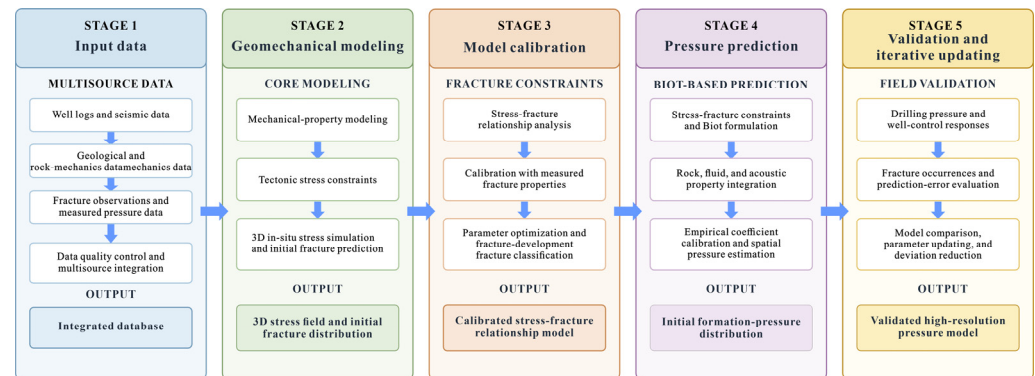


Figure 3. Technical workflow used in this study.

4. Application

Well FD105 is an appraisal well drilled on a lower-order fault zone in the Fudong Block, with the Ordovician Yingshan Formation as its target. Formation pressure is a key engineering parameter and an important criterion for geological sweet-spot evaluation. Its distribution is closely related to the fault-fracture system and compressive stress [31,51]. We apply the proposed workflow to evaluate reservoir geomechanics and pressure distribution around FD105 and assess prediction accuracy using multiple wells.

4.1. Construction of the Three-Dimensional Geomechanical Model

A three-dimensional geological model covering approximately 200 km² was first constructed for the Fudong Block to provide a mechanical basis for stress and fracture prediction. To balance resolution and computational efficiency, the horizontal grid size was set to 20 × 20 m. The Yingshan and Yijianfang target intervals were divided into 40 vertical layers, giving approximately 2.1 million cells. Because the study area contains numerous faults and complex structures, the model was built in Petrel using a complex-structure modeling workflow.

One-dimensional geomechanical models from five key wells provided the initial mechanical properties. Elastic moduli, Poisson's ratio, density, internal friction angle, and other parameters were propagated through the three-dimensional grid by kriging (Figure 4). Formation heterogeneity was constrained by an empirical relationship between acoustic impedance and rock strength. Faults and fractures were represented as mechanically weakened zones.

The model base was constrained against normal displacement, the top was treated as a free surface, and horizontal compressive displacement was applied to all four lateral boundaries. Regional geology and image-log interpretation indicate that the present-day maximum horizontal principal stress in the ultra-deep carbonate reservoir is predominantly NNE–SSW-oriented. Differential-strain measurements and related data give average gradients of 0.0233 and 0.0191 MPa/m for the maximum and minimum horizontal principal stresses, respectively. Finite-element simulation under these constraints produced the present-day in situ stress field (Figure 5a).

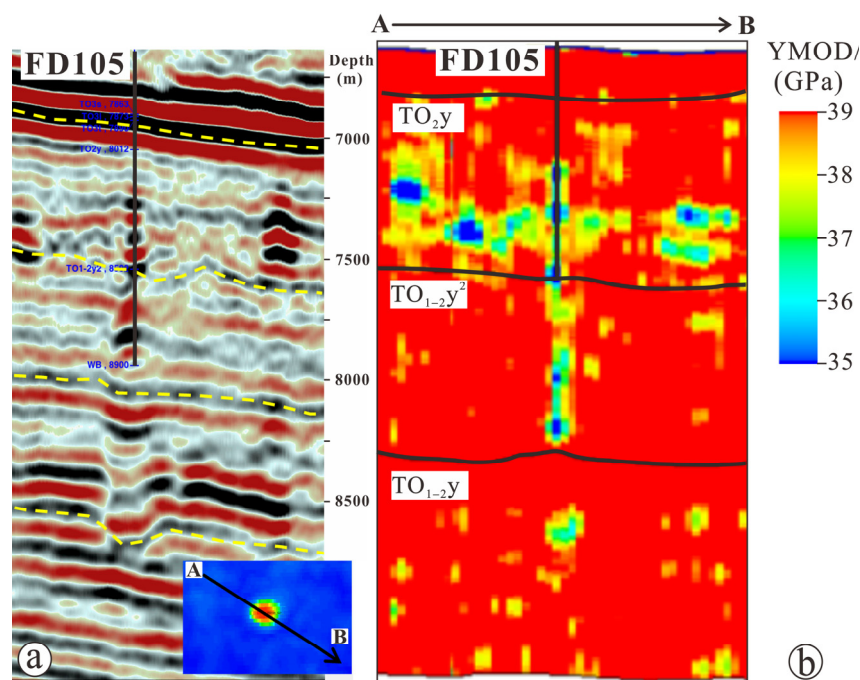


Figure 4. Distribution of elastic modulus around Well FD105. (a): Seismic section through Well FD105; (b): elastic-modulus distribution through Well FD105.

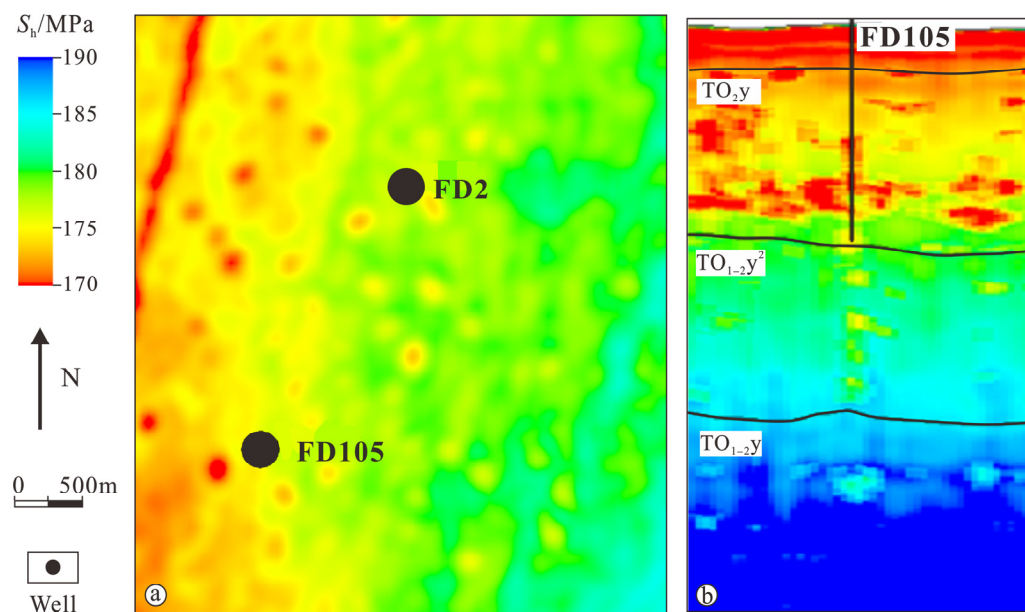


Figure 5. Simulated in situ stress field around Well FD105. (a): Map of minimum horizontal principal stress in the Yingshan Formation around FD105; (b): minimum horizontal principal stress along a section through FD105 (the location of FD2 well is also shown in the figure to verify the accuracy of stress simulation and provide stress state comparison).

In map view, FD105 lies in a lower-stress area than nearby wells (FD2), a setting favorable for reservoir preservation. Vertically, the Yijianfang Formation has a relatively uniform stress field and weak compression. The Yingshan Formation is more complex. Stress decreases by approximately 8 MPa in densely faulted and fractured intervals, and zones of strong compression and complex fracture architecture overlap closely with overpressured areas (Figure 5b).

4.2. Fracture Prediction and Mechanical Effectiveness

The ultra-deep carbonates are strongly compressed, hard, and brittle. Image-log fracture intensity was therefore used as the target variable and seismic ant-tracking, curvature, coherence, and related attributes as predictors in a probabilistic neural network. The resulting fracture-probability volume was converted to a three-dimensional fracture-density distribution. The simulated stress field and the shear-failure geometry of strike-slip faults indicate two dominant fracture sets in the Yingshan Formation, trending approximately N-S and NE. Fracture intensity varies markedly with depth at FD105. Fractures are sparse in the upper interval, are most abundant in Member 2 of the Yingshan Formation, where fault-fracture bodies are prominent, and gradually decrease through the lower parts of Members 3 and 4 (Figure 6a).

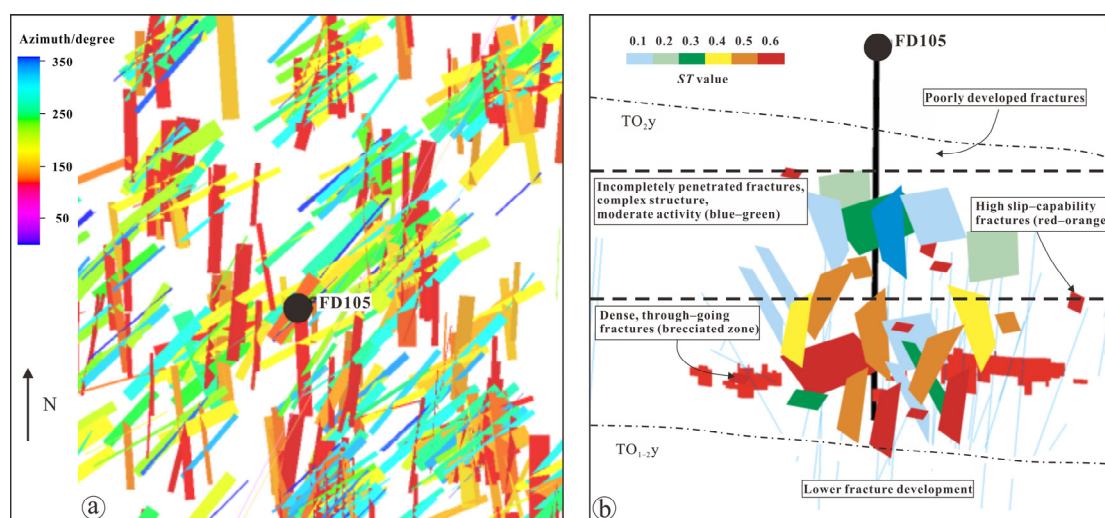


Figure 6. Predicted natural fractures and their mechanical activity along a section through Well FD105. (a): Three-dimensional natural-fracture prediction around FD105; (b): ST value distribution along a section through FD105.

Mechanical effectiveness was evaluated from the orientation of the secondary fault at FD105 and its slip tendency (ST). Fractures in the upper part of Yingshan Member 2 form a large angle with the present NNE-trending stress direction and are comparatively unfavorable for slip, with ST values of approximately 0.2–0.3. In the lower part of Member 2, fractures form a smaller angle with the present stress direction. Fault-fracture architecture is more pronounced, mechanical effectiveness is higher, and ST values increase to approximately 0.6–0.7, corresponding to improved reservoir quality (Figure 6b).

The upper part of Yingshan Member 2 is thus a complex fractured zone under relatively strong horizontal compression. Fractures are not fully connected, the architecture is complex, and mechanical activity is moderate, providing conditions favorable for overpressure. In the lower part of Member 2, fractures are more abundant and better connected, mechanical activity is greater, and pressure can dissipate more readily. Overpressure is therefore less likely.

4.3. Reservoir-Pressure Prediction and Multiwell Validation

Based on the in situ stress field and fracture parameters described above, reservoir pressure prediction was performed. The results show that the formation pressure coefficient of the Yijianfang Formation is approximately 1.20 (Figure 7a). The Yingshan Formation exhibits pronounced vertical heterogeneity and can be subdivided into ten subzones with pressure coefficients of: ① 1.20, ② 1.90–2.00, ③ 1.50–1.60, ④ 1.95–2.05, ⑤ 1.35–1.45, ⑥ 1.60–1.70, ⑦ 1.30–1.40, ⑧ 1.60–1.70, ⑨ 1.35–1.45, and ⑩ 1.50–1.60 (Figure 7a). Overall, the Yingshan

Formation displays an alternating pattern of high-pressure zones (ca. 1.9–2.05) and moderately high-pressure zones (ca. 1.3–1.7), reflecting the vertical stacking and partitioning of multiple independent pressure systems. Figure 7b shows a pressure-coefficient profile through Well FD105, directly illustrating the lateral variation and vertical segmentation of pressure along the wellbore, and clearly revealing the spatial coincidence of overpressured zones with intensely faulted and fractured intervals. The high pressure in subzones such as ② and ④ is closely linked to an increase in the effective Biot coefficient and a decrease in the dry-rock bulk modulus caused by elevated fracture density, quantitatively reflecting the contribution of fracture development to local overpressure. Considering that adjacent wells FD1, FD101, and FD2 experienced pressure-coefficient increases of 0.3–0.7 owing to pressure build-up in isolated fracture-cavity bodies and lost-circulation effects, it is predicted that the dynamic pressure in Well FD105 may further increase during drilling.

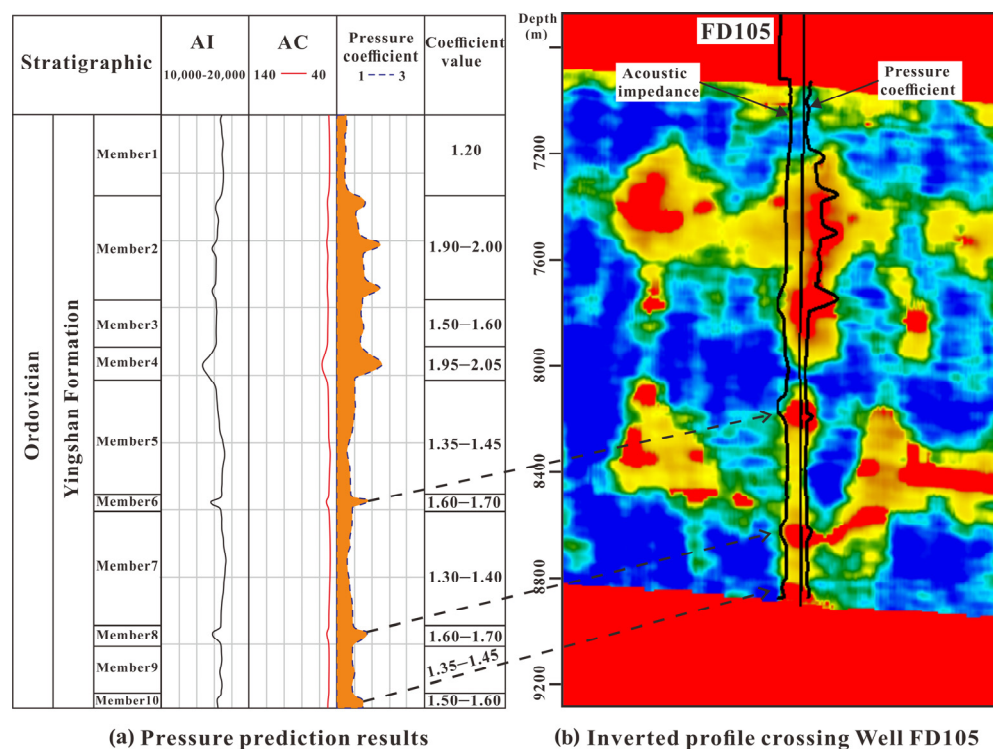


Figure 7. Formation-pressure prediction for Well FD105. (a) Reservoir-pressure prediction profile for FD105; (b) formation-pressure distribution along a section through FD105.

Blind validation was performed using completed wells with measured pressure data. In the Yingshan Formation of FD1, the measured pressure coefficient is 1.54, compared with a predicted value of 1.47, giving a relative error of 4.55%. At FD101, the measured and predicted coefficients are 1.71 and 1.78, respectively, giving an error of 4.09% (Table 1).

Table 1. Comparison of predicted pressure coefficients with post-drilling measurements.

Well	Formation	Predicted Pressure Coefficient	Measured Pressure Coefficient	Error Rate
FD2	O ₂ y	1.80	1.72	4.65%
FD101	O ₂ y	1.78	1.71	4.09%
FD1	O ₂ y	1.47	1.54	4.55%
MS11	O ₂ y	1.35	1.45	6.90%
MS1C	O ₂ y	1.45	1.53	5.23%

To illustrate multiwell applicability and vertical resolution, Figure 8a,b present integrated pore-pressure panels for FD1 and FD101. Each panel includes the normal-compaction trend, acoustic impedance, porosity, predicted pressure coefficient, mud-weight window, and recorded losses, kicks, and gas influxes. At FD1, the sharp rise in pressure coefficient coincides with lower acoustic impedance, higher porosity, and dense fracturing. The mud-weight window narrows abruptly in the same interval, where a kick was recorded. At FD101, gas influx and lost circulation are concentrated in intervals with coefficients greater than 1.7. These observations support a causal link among fracturing, localized overpressure, and a narrow safe operating window.

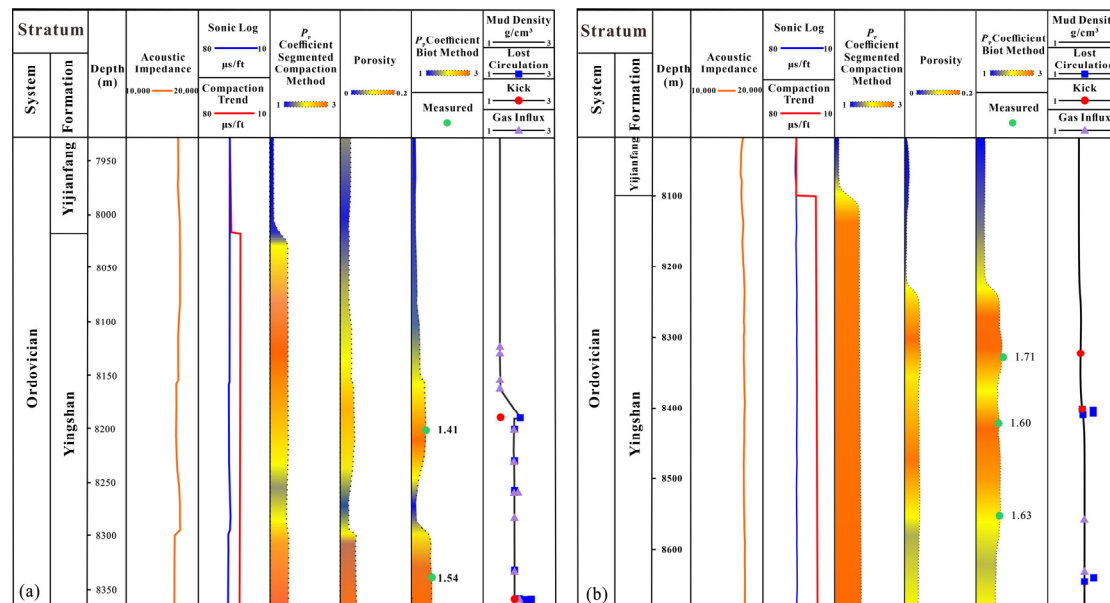


Figure 8. Formation-pressure prediction profiles. (a): Reservoir-pressure prediction profile for Well FD1; (b): reservoir-pressure prediction profile for Well FD101.

Post-drill pressure-while-drilling data from Well FD105 show a main high-pressure zone with a pressure coefficient of approximately 1.65, consistent with the predicted high-pressure intervals. These multi-well validation results demonstrate that the proposed well-seismic integrated high-precision layered pressure-prediction method can effectively identify the boundaries of multiple vertical pressure systems with significantly higher accuracy than conventional trend-based approaches, providing a reliable basis for pre-drill hazard assessment in ultra-deep carbonate rocks.

4.4. Wellbore-Stability Evaluation

Wellbore stability at FD105 was evaluated using the predicted pressure field. A vertical trajectory provides the greatest overall stability. The Yijianfang Formation is comparatively stable and presents a low drilling risk. The upper part of Yingshan Member 2 combines moderate overpressure with relatively high stress and is less stable; mud weight should be increased appropriately to balance formation pressure. The lower part of Member 2 has lower stress but is highly fractured and well connected. Mud weight must therefore be optimized to maintain wellbore stability without inducing losses.

5. Mechanisms of Overpressure

5.1. Geological Causes

Geological processes provide the fundamental controls on overpressure in the study area. Tectonic evolution, reservoir architecture, and fluid charging jointly govern its

generation and distribution. The most important processes are tectonic compression, development of the fault-fracture network, and charging-related pressurization [52,53].

(1) Tectonic-Stress Accumulation

In the Riedel shear model, movement on a principal strike-slip fault generates lower-order secondary shears, including R shears that intersect the principal displacement zone at a small angle and oppositely oriented R' shears (Figure 9a). These structures occupy specific quadrants around the principal fault, and their dimensions, continuity, and connectivity depend on fault displacement and the history of reactivation. Secondary faults near wells such as FD105 can be interpreted as R shears generated early during Caledonian movement on the principal strike-slip faults. They terminate within the Yingshan-Penglaiba interval and are formed relatively early. By contrast, the major faults remained active into the Hercynian and cut the Cambrian–Carboniferous succession. Repeated movement produced well-connected damage zones along the major faults, whereas secondary faults were not substantially reworked and remained unconnected or partly connected. Their complex architecture, poor connectivity, and low activity are consistent with the early formation and limited late reactivation of subsidiary Riedel shears (Figure 9b). Poor reservoir development in the overlying Yijianfang Formation further restricts upward stress-release pathways. Tectonic stress therefore cannot dissipate effectively along the secondary faults and accumulates in local weak zones. Continued stress transfer to reservoir fluids gradually raises formation pressure. This mechanism explains why overpressured wells cluster near secondary faults and in fault-poor areas, where strain is incompletely accommodated within the Riedel network.

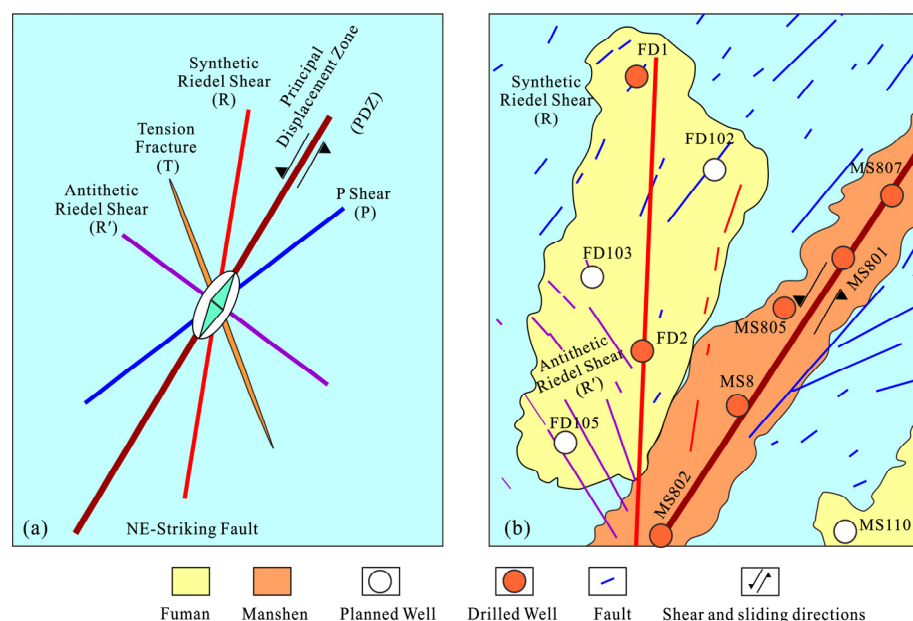


Figure 9. Fault distribution in the Fudong Block. (a): Riedel shear model; (b): distribution of secondary fault zones in the Fudong Block.

(2) Pressure Retention in Constant-Volume Reservoir Bodies

Overpressured reservoirs are dominated by isolated, bead-like reef–shoal bodies. The seismic section through FY1 shows well-developed reservoirs in the Yingshan Formation but poor reservoir development in the overlying Yijianfang Formation. Individual bodies are generally small and produce isolated bead-like seismic reflections, indicating a relatively constant-volume geometry. Although the reflections are strong, internal fracture–vug connectivity is poor and communication with the regional fault system is limited. The result

is a set of independent, constant-volume pressure compartments. These compartments retain pressure because reservoir fluids cannot discharge effectively through the fault network, allowing pressure to accumulate over time (Figure 10a).

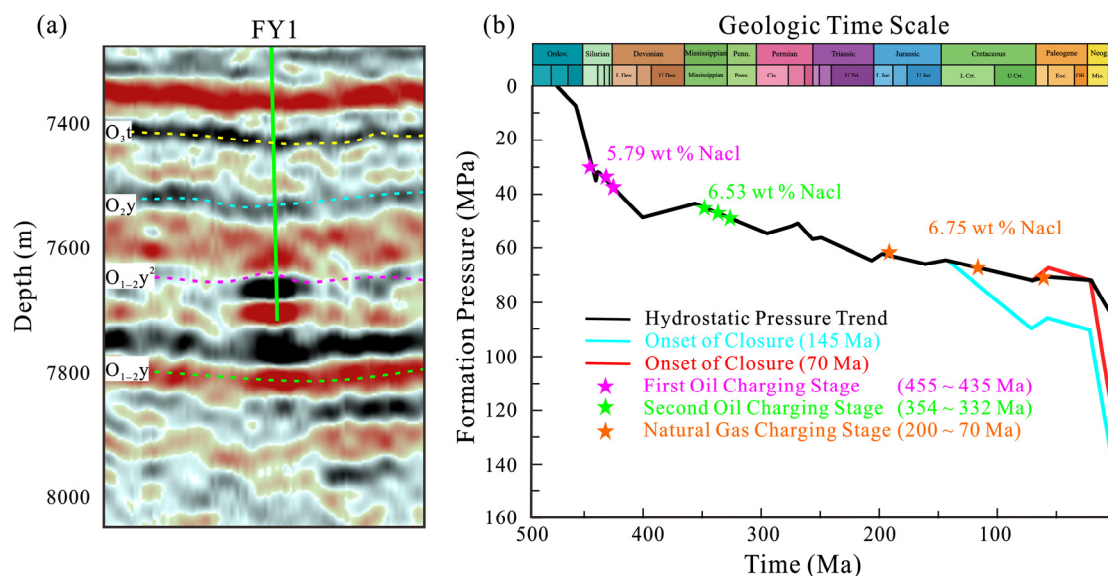


Figure 10. Seismic section through Well FY1 (a) and modeled reservoir-pressure evolution at Well FD2 (b).

(3) Pressurization by Fluid Charging

Himalayan dry-gas charging was an important pressurization mechanism. Regional dry-gas migration is spatially associated with the overpressure system. Continued gas charging after high-temperature cracking produced volumetric expansion and widespread overpressure in dry-gas reservoirs. Core fluorescence and fluid-inclusion analyses at FD2 identify two episodes of oil charging and one episode of gas charging. Products of the first two oil-charging episodes exhibit bright-blue fluorescence and occur mainly in early dolomite, calcite cement that fills dissolution vugs, and secondary cracks in oblique, high-angle calcite veins. The third episode introduced natural gas mainly into secondary cracks in the high-angle calcite veins. Fluid charging and the regional tectonic history indicate a pressure of 129–147 MPa and a coefficient of 1.47–1.68 at FD2. The overpressure therefore has a mixed origin: post-accumulation gas charging was followed by rapid Himalayan subsidence, and disequilibrium compaction and thermal expansion of confined fluids jointly raised pressure (Figure 10b).

(4) Multiple Pressure Systems Generated by Tectonic Compression

The platform-basin region of the Tarim Basin remains under strong tectonic compression. Network stylolites are common in cores and provide direct evidence of intense compression. Their formation is also associated with hydrocarbon-driven dilation and fracturing under tectonic stress (Figure 11). Strong compression promotes stress partitioning and fluid compartmentalization within fault-fracture bodies. Combined with their intrinsic heterogeneity, this process creates multiple independent pressure systems and helps explain the complex pressure response and concurrent kicks and losses observed during drilling.

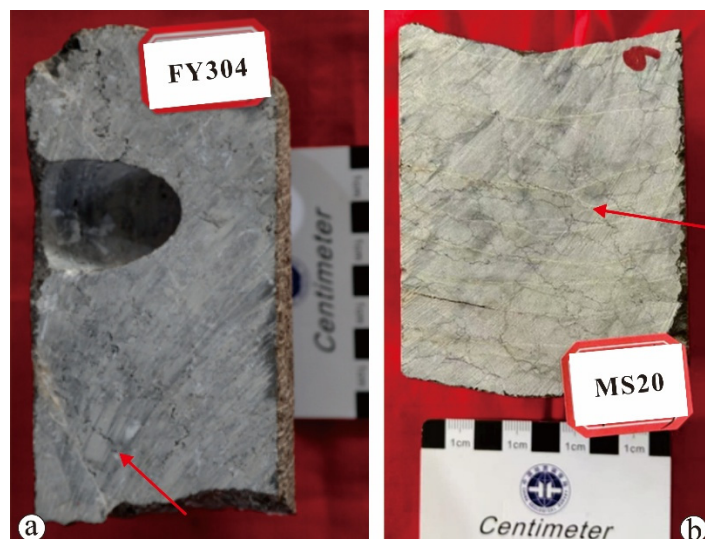


Figure 11. Core observations from the study area. (a): Network stylolites, Well FY304, O₁₋₂y, 8035.4 m; (b): network stylolites, Well MS20, O₂y, 7379.4 m.

5.2. Drilling-Related Causes

Drilling operations can amplify apparent overpressure and lead to misinterpretation of true formation pressure. The principal external control is fluid disturbance during drilling. In particular, pressure buildup caused by drilling-fluid losses into constant-volume fracture–vug bodies is closely related to the narrow safe pressure window of these carbonate reservoirs.

(1) Pressure Buildup Induced by Gravity-Displacement Influx

Gravity-displacement influx and the associated apparent overpressure form a complex fluid-dynamic process characteristic of fractured carbonates. The process depends on fracture connectivity and the density contrast between the drilling fluid and formation fluid. When the drilling fluid is denser than the formation fluid and the fractures are sufficiently connected, buoyant formation fluids such as gas or oil migrate upward and displace the denser drilling fluid from the wellbore, producing a kick. At the same time, the denser drilling fluid invades deeper parts of the fracture network, causing simultaneous kick and loss. This behavior is consistent with gas–liquid displacement in constant-volume carbonate bodies of the Tarim Basin.

The resulting apparent overpressure reflects both pressure locking in the fracture network and pressure imbalance between the wellbore and fractures. Where fractures are largely closed and poorly connected to the surrounding formation, lost drilling fluid occupies fracture space, displaces the resident fluid, and compresses the gas. Because the resident fluid cannot discharge rapidly into lower-pressure regions, a transient overpressure develops and local pressure rises quickly. The influx associated with gravity displacement also lowers the fluid-column height and bottomhole pressure, further increasing the wellbore-to-formation pressure difference. Additional formation fluid then enters the wellbore, producing a self-sustaining feedback that intensifies the apparent overpressure.

(2) Pressure Buildup Caused by Fracture–Vug Volume And Drilling-Fluid Loss

The constant-volume character of fracture–vug bodies and the volume of drilling-fluid loss control drilling-induced pressure buildup and apparent overpressure. The mechanism is the pressure increase produced when fluid is forced into a confined volume. We quantified these effects using geological and engineering parameters from the study area: gas formation volume factor, 0.00214; gas compressibility, $17.5 \times 10^{-4} \text{ MPa}^{-1}$; rock

compressibility, $19.4 \times 10^{-4} \text{ MPa}^{-1}$; well depth, 8000 m; initial pressure coefficient, 1.2; and initial formation pressure, 94.1 MPa.

For a fixed fracture–vug volume of $10,000 \text{ m}^3$, each 100 m^3 of drilling-fluid loss increases the pressure coefficient by 0.06. At a fixed loss volume of 1000 m^3 , the pressure response becomes stronger as the fracture–vug body becomes smaller. For volumes below $28,000 \text{ m}^3$, the coefficient can be raised above 1.4 by pressure buildup (Figure 12).

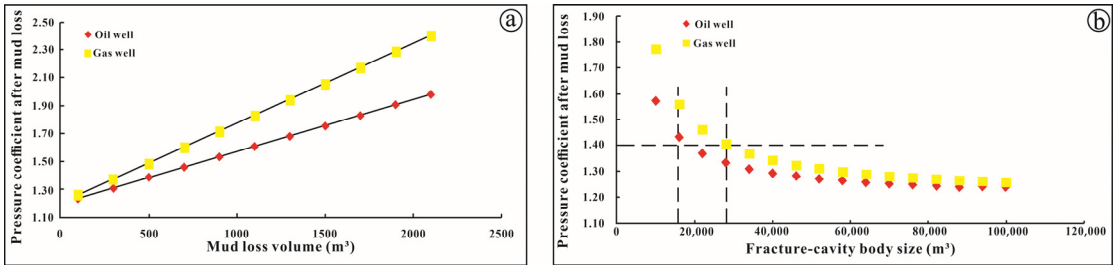


Figure 12. Effects of fracture–vug volume and lost-circulation volume on localized apparent overpressure. (a): Comparison of drilling-fluid-loss effects in oil and gas wells at different loss volumes; (b): comparison of drilling-fluid-loss effects in oil and gas wells for different fracture–vug volumes.

Fluid phase also affects the pressure response (Figure 12a). Under otherwise identical conditions, each 100 m^3 of drilling-fluid loss increases the pressure coefficient by 0.06 in a gas well but by only 0.04 in an oil well. In oil wells, the loss effect becomes appreciable only when the fracture–vug volume is below $15,000 \text{ m}^3$. In gas wells, a marked pressure anomaly develops below $28,000 \text{ m}^3$ (Figure 12b). Gas-filled bodies are therefore more susceptible than oil-filled bodies to difficult-to-control pressure buildup after drilling-fluid loss, consistent with the predominance of high-pressure gas indications in the study area.

(3) Drilling-Based Criteria for Diagnosing Apparent Overpressure

Quantitative criteria for identifying drilling-induced apparent overpressure were established from the mechanisms above and drilling responses in multiple Fudong wells (Table 2). If at least two of the following three criteria are met during an overpressure event, the event is interpreted as predominantly drilling induced.

Table 2. Drilling-based criteria for diagnosing drilling-induced apparent overpressure.

Diagnostic Indicator	Criterion/Threshold	Data Source
Pressure coefficient increment triggered by lost circulation (ΔP_c)	≥ 0.3 (relative to pre-drill static prediction)	Pressure-while-drilling monitoring and lost circulation statistics
Releasability of shut-in pressure	Pressure drop $\geq 15\%$ after shut-in	Well killing/gas venting records
Density window width under concurrent loss and gain	$< 0.05 \text{ g/cm}^3$	Daily drilling reports and mud logging

1. Loss-Triggered Pressure Increase: After cumulative drilling-fluid loss exceeds 100 m^3 , pressure-while-drilling measurements show an increase in $\Delta P_c \geq 0.3$ relative to the pre-drill static prediction at the same depth, and the increase is positively correlated with loss volume.
2. Releasable Pressure: Wellhead pressure falls by at least 15% within a short period after shut-in pressure measurement or circulation and gas venting. This response is inconsistent with rigid, persistent overpressure in a closed geological body.
3. Concurrent Kick and Loss with an Extremely Narrow Safe Window: Both influx and lost circulation occur in the same open-hole interval, and the effective mud-weight

window is less than 0.05 g/cm^3 . This behavior indicates a transient pressure imbalance caused by drilling disturbance.

6. Conclusions

- (1) Localized overpressure in the carbonate succession of the Fudong Block occurs mainly near secondary faults, branch faults, and NW-trending faults. It is controlled jointly by tectonic compression, pressure retention in constant-volume fracture–vug bodies, and fluid charging. Multiple vertically separated pressure systems are common, and their marked heterogeneity is closely related to secondary-fault development and fracture–vug connectivity.
- (2) The Yingshan Formation contains multiple vertically stacked pressure systems. The proposed method resolves three main intervals with coefficients of approximately 1.2 in the upper interval, 1.5–1.9 in the middle interval, and 1.3–1.7 in the lower interval. The middle interval contains three subintervals with coefficients of 1.7–1.9, 1.5–1.6, and 1.8–1.9. Abrupt pressure-coefficient boundaries coincide with changes in fracture density and the Biot effective stress coefficient α , confirming that the fracture network controls pressure-system boundaries.
- (3) Drilling disturbance can create apparent overpressure and cause true formation pressure to be misinterpreted. A kick followed by loss and concurrent kick and loss are common in the study area. Under constant-volume conditions, each 100 m^3 of drilling-fluid loss can increase the pressure coefficient of a gas well by approximately 0.06. When cumulative loss exceeds 100 m^3 and $\Delta P_c \geq 0.3$, releasable shut-in pressure and a concurrent kick-loss window narrower than 0.05 g/cm^3 provide diagnostic evidence of drilling-induced apparent overpressure.
- (4) Multiwell blind tests of the stress–fracture–pressure workflow yield errors of 4.09%–6.90% between predicted and measured pressure coefficients, demonstrating its practical value for drilling engineering.
- (5) The method remains subject to several limitations. Seismic inversion cannot resolve isolated fracture–vug bodies below its effective resolution. In addition, the relationships used to convert fracture density to poroelastic parameters were calibrated against a limited core dataset and may introduce error when extrapolated beyond the study area, particularly in sparsely explored regions. Future work should combine geostatistics with machine learning to improve the transferability of parameter calibration and should assimilate real-time drilling data to reduce uncertainty in dynamic pressure prediction.

Author Contributions: Conceptualization, Z.H. and Y.C.; methodology, W.J. and Z.Q.; software, Z.Q.; validation, Z.X. and R.L.; investigation, M.C.; resources, Z.X.; data curation, P.Z.; writing—original draft preparation, Z.H., W.J., Z.Q., K.X., P.Z. and Z.X.; writing—review and editing, Y.C., W.J.; visualization, M.C.; supervision, Y.C.; funding acquisition, K.X. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the National Science and Technology Major Project “Hydrocarbon Accumulation Mechanism and Exploration Technology in New Fields of the Basin-Mountain System in the Tarim Basin” (2025ZD1400500), the Youth Science and Technology Special Project of CNPC “Geomechanical Mechanism and Application of Ultra-deep Strike-slip Faults Controlling Reservoirs and Hydrocarbon Accumulations, Fuman Oilfield” (2024DQ03017), Scientific Research Project of Tarim Oilfield Company Research Center “Exploration Geomechanics Technology Research and Application” (YF202505). And the APC was funded by Youth Science and Technology Special Project of CNPC.

Data Availability Statement: All data, figures and tables required to support the findings are fully integrated within the main text of the paper.

Conflicts of Interest: Zhipeng Huan, Ziwei Qian, Ke Xu, Penglin Zheng, Zhou Xie, Mingjin Cai, Ruidong Liu are affiliated with PetroChina Tarim Oilfield Company. They declare that there are no conflicts of interest regarding the publication of this paper, and the company's role had no bearing on the research content or conclusions.

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