processes

MDPI

Article

Study on the Wellbore Instability Mechanism in the Longtan Formation with Soft/Hard Thin Interlayers in the South Sichuan Basin

Jianhua Guo [1], Yu Sang [1], Beiqiao Meng [1], Lianbin Xia [1], Yangsong Wang [1], Chengyu Ma [2], Tianyi Tan [1] and Bin Yang [3,*]

[1] Engineering and Technology Research Institute, PetroChina Southwest Oil & Gas Field Company, Chengdu 610017, China; g_jh@petrochina.com.cn (J.G.); sangy@petrochina.com.cn (Y.S.); mengbq@petrochina.com.cn (B.M.); xialianbing@petrochina.com.cn (L.X.); swpuwys@163.com (Y.W.); tantianyi2022@petrochina.com.cn (T.T.)
[2] Sichuan-Chongqing Shale Gas Frontline Command, PetroChina Southwest Oil & Gas Field Company, Chengdu 610015, China; machengyu@petrochina.com.cn
[3] College of Energy, Chengdu University of Technology, Chengdu 610059, China
* Correspondence: yangbin19@cdut.edu.cn

Abstract: The lithology of the transitional facies of the Longtan Formation in the southern Sichuan Basin is complex, with soft/hard thin interlayers of mud shale, sandstone, and limestone. Drilling this layer often results in wellbore instability, including frequent blockages, tripping resistance, and sticking. This study focuses on a shale gas block in the Longtan Formation in Zigong, where a geomechanical profile was established by integrating ground stress, rock parameter tests, and logging data. The critical collapse pressure was calculated, and wellbore instability was simulated using the Mohr–Coulomb failure criterion and the discrete element method. Results indicate significant variability in the mechanical strength of the rocks, with notable longitudinal heterogeneity and a high risk of wellbore instability. The critical collapse pressure equivalent density ranges from 1.05–1.69 g/cm^3. Under low-density conditions, wellbore expansion and reduction coexist due to local shear and dropping. Even when the drilling fluid density exceeds the collapse pressure equivalent, stress imbalance can still cause localized dropping at lithologic interfaces. These findings offer valuable insights into the mechanical mechanisms behind wellbore instability in formations with soft/hard thin interlayers and provide guidance for the prevention and control of wellbore instability and associated risks.

Keywords: Longtan formation; thin interlayer; wellbore instability; discrete element method

check for updates

Academic Editor: Carlos Sierra Fernández

Received: 6 December 2024
Revised: 11 February 2025
Accepted: 24 February 2025
Published: 3 March 2025

Citation: Guo, J.; Sang, Y.; Meng, B.; Xia, L.; Wang, Y.; Ma, C.; Tan, T.; Yang, B. Study on the Wellbore Instability Mechanism in the Longtan Formation with Soft/Hard Thin Interlayers in the South Sichuan Basin. *Processes* **2025**, *13*, 727. https://doi.org/10.3390/pr13030727

Copyright: © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

Wellbore collapse and the instability of wellbores may lead to pump blockages and wellbore pressure fluctuations, as well as complications such as tripping resistance, ream, circulation loss, sticking, and buried pipe issues [1,2]. These are among the key constraints for achieving safe and efficient drilling. The Permian Longtan Formation in the Zigong area of southern Sichuan is a marine–terrestrial transitional depositional system, specifically characterized by fluvial overbank and tidal flat deposits [3]. The formation exhibits complex and variable lithology, including bauxite mudstone, gray-black shale, siltstone, fine sandstone, limestone, and coal, with multiple thin interlayer lithologies. For a long time, wellbore instability in the Longtan Formation has been a common challenge in drilling the Upper Permian in the eastern and southern Sichuan Basin. In recent years, during the

large-scale development of shale gas in the southern Sichuan region, frequent wellbore instability and sticking incidents in the Longtan Formation have become key obstacles to accelerating drilling in the upper formations.

The primary causes of frequent wellbore instability are believed to be the unbalanced stress around the wellbore after its formation, hydration of the shale, and weak structural planes such as natural fractures [4–7]. Correspondingly, scholars have successively established various constitutive models for wellbore instability, including the linear elastic analytical model [8], the elastoplastic model [9], the thermo-poroelastic model [10], and the chemo-poroelastic model [11]. Additionally, they have developed multi-field coupling wellbore instability models considering single or grouped weak planes, such as fluid–solid, fluid–solid–chemical, thermo–fluid–solid, and fluid–solid–chemical–thermal models [2,12,13]. Although these models have made progress in predicting wellbore stability, most assume homogeneous or simple layered formations, making it difficult to accurately describe the impact of soft/hard thin interlayers on wellbore stability [14–17]. While significant advancements have been made in wellbore stability, several critical limitations remain. Most existing models rely on the assumption of homogeneous or simplified layered formations, which fail to adequately capture the effects of frequent vertical lithological variations and soft/hard thin interlayers that significantly influence wellbore stability. Additionally, conventional failure criteria such as the Mohr–Coulomb and Drucker–Prager models, while effective for assessing overall stability, are insufficient in accurately modeling localized stress concentrations, shear failure, and block detachment at lithological interfaces [18–20]. Furthermore, traditional approaches that focus on increasing drilling fluid density to mitigate instability have proven to be inadequate [21]. Logging data shows that the Longtan Formation commonly exhibits characteristics of shale interspersed with hard sandstone/limestone. The existing wellbore instability models have not adequately explained this wellbore instability phenomenon and its control mechanisms.

This paper takes the Longtan Formation in the Zigong area of southern Sichuan as its research object. Through laboratory experiments on rock mechanics and in situ stress parameters, combined with logging data, a single-well geomechanical profile of a typical well is established to analyze the potential wellbore instability characteristics of the Longtan Formation. Furthermore, the discrete element method is used to simulate the wellbore instability characteristics under conditions of thin interbeds in the complex lithology of the Longtan Formation. This approach allows for a more accurate representation of localized shear failure, stress redistribution, and block detachment at lithological interfaces, which are typically overlooked by conventional models. This study innovatively integrates geomechanical profiling with numerical simulation to address the limitations of traditional wellbore stability models that fail to capture the effects of lithological heterogeneity. Additionally, by analyzing the impact of drilling fluid density variations, this paper provides new insights into the limitations of conventional mud weight control strategies. The results offer valuable support for safe and efficient drilling operations in the Longtan Formation, as well in as other formations with similar complex lithological characteristics, thereby advancing the understanding of wellbore instability mechanisms and improving practical drilling strategies.

2. Basic Characteristics of Formation

During the Late Paleozoic era, influenced by the Caledonian and Dongwu orogenies, the Longtan Formation of the Upper Permian in the Zigong area of southern Sichuan experienced several transgressions and regressions [3,22]. During regression periods, the Upper Permian was characterized by coastal swamp, continental lake, localized riverbed, and coal-bearing swamp deposits. The lithology mainly consisted of bauxite mudstone,

tuffaceous sandstone, and shale. During transgression periods, it was characterized by shallow marine deposits, with lithologies primarily consisting of limestone, bioclastic limestone, and shale. The base is marked by a boundary between gray bauxite mudstone and the underlying light gray-brown limestone of the top of the fourth section of the Maokou Formation, presenting an unconformable contact. This depositional background created the lithological characteristics of the Longtan Formation, which includes interlayers of mudstone, shale, tuffaceous sandstone, limestone, and thin coal.

Logging data (Figure 1) similarly indicates that the lithology of the Longtan Formation in the Zigong area of southern Sichuan is complex, with a significant occurrence of wellbore collapse. The average wellbore enlargement rate is 8.17%, with the lower sections averaging 11.3% and reaching a maximum of 41.5%. Additionally, comparing the true formation resistivity (Rt) and flushed zone resistivity (RXO) reveals minimal differences between the two curves, suggesting that natural fractures in the formation are relatively underdeveloped. The main causes of wellbore instability are most likely low-strength, easily hydrated shale and coal formation, as well as the instability of thin interlayer strata.

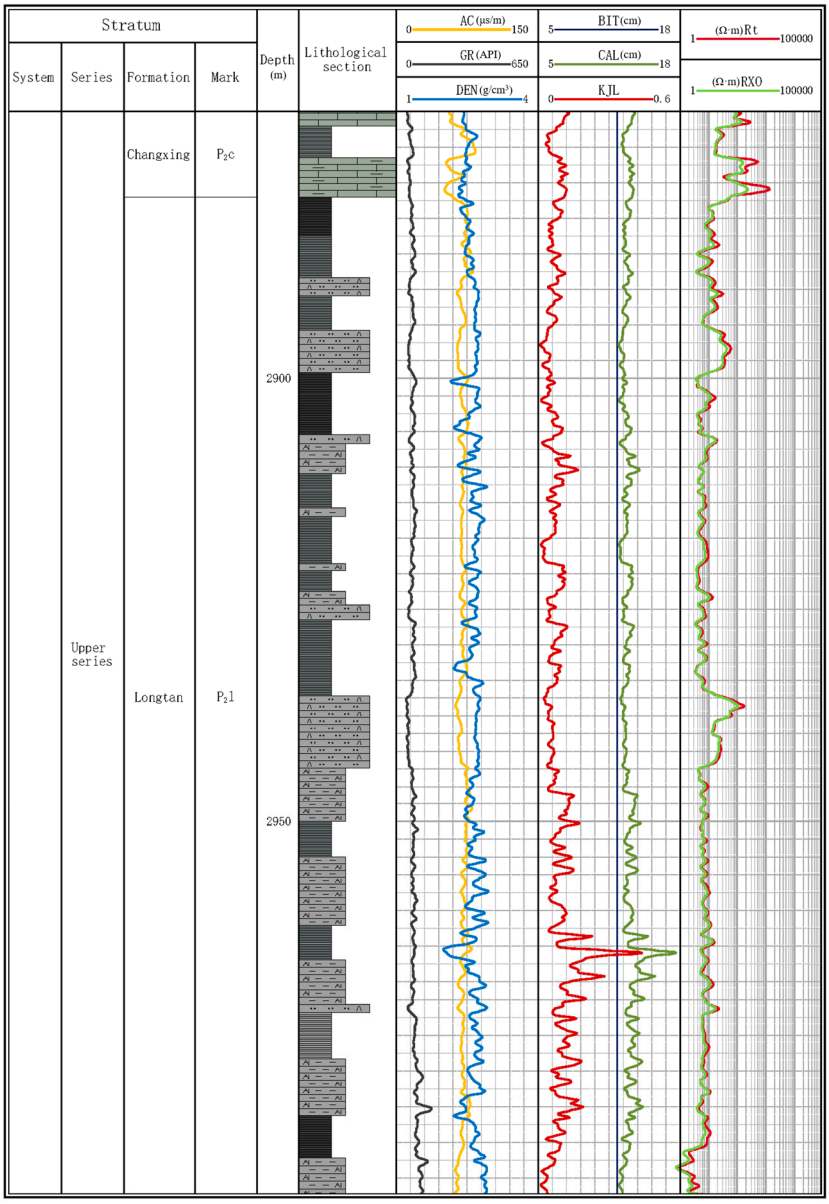


Figure 1. Lithology and logging curve diagram of the Longtan Formation in a shale gas well in southern Sichuan.

3. Geomechanical Parameter Test and Analysis

Selected rock samples from the Longtan Formation in the Zigong area of southern Sichuan were subjected to stress magnitude testing using the differential strain analysis method [23]. The differential strain analysis method operates on the principle that a core sample, under the influence of in situ stress in the formation, remains compressed, and naturally occurring fractures remain closed. Once the core is brought to the surface and the stress is released, the rock expands, generating microfractures whose opening magnitude and orientation are closely related to the original in situ stress field. To determine the magnitude of in situ stress, a complete core with a marked orientation is selected from the field. This core is then machined into a cubic sample, fitted with strain gauges, and placed into a pressure chamber. Various levels of confining pressure are applied, and the strain responses in each direction are recorded. Through tensor analysis of these strain measurements, the magnitudes and orientations of the principal stresses can be obtained. The experimental results, as shown in Table 1, indicate that the vertical, maximum horizontal, and minimum horizontal principal stress gradients of the Longtan Formation are 2.47 MPa/100 m, 2.72 MPa/100 m, and 2.34 MPa/100 m, respectively, indicating an overall strike-slip stress state. Principal stress gradients refer to the rate at which the three principal stresses change with respect to the true vertical depth (TVD). The magnitude of the principal stress gradient is calculated by dividing the principal stress (measured using the differential strain analysis method) by the TVD. Influenced by regional tectonics, the direction of the in situ stress in the Longtan Formation in this area is predominantly east–west, with the main distribution around 90° to 110°.

Table 1. Experiment on crustal stress of Longtan Formation in southern Sichuan.

Formation	Depth /m	Vertical Stress /MPa	Minimum Horizontal Principal Stress/MPa	Maximum Horizontal Principal Stress/MPa	Gradient of Vertical Stress /MPa	Gradient of Minimum Horizontal Principal Stress/MPa	Gradient of Maximum Horizontal Principal Stress/MPa
Longtan	3190	78.31	74.13	85.56	2.45	2.32	2.71
Longtan	3193	79.05	75.40	87.2	2.48	2.36	2.73
Ave.	\	78.68	74.77	86.88	2.47	2.34	2.72

Simultaneously, random outcrop samples from the Longtan Formation were selected for uniaxial rock mechanics testing. The test results, as shown in Figure 2, indicate that the uniaxial compressive strength of the samples ranges from 16.2 to 187.4 MPa, with an average value of 84.9 MPa. The compressive strength test values show significant fluctuations and exhibit a clear positive correlation with sample density. Combining this with the density and gamma logging in Figure 1, it is evident that changes in sample density to some extent reflect changes in formation lithology. Specifically, samples 3 to 23 are primarily shale, with relatively low rock compressive strength, while samples 24 to 26 and sample 31 are from limestone sections, exhibiting high rock mechanical strength with an average uniaxial compressive strength of about 178.2 MPa. Sample 27, taken from a coal interlayer, shows very low strength, displaying typical coal-rock mechanical characteristics.

Using the correlation formulas summarized by previous studies [24,25] on common sandstone, shale, and limestone rock mechanics parameters and sonic logging parameters in the Sichuan Basin, combined with the logging data of the target formation, a profile of the rock mechanics parameters of the target formation can be derived. As shown in Figure 3, the vertical rock mechanics parameters, including uniaxial compressive strength, elastic modulus, Poisson's ratio, cohesion, and internal friction angle, exhibit significant heterogeneity and large fluctuations. Specifically, the uniaxial compressive strength ranges

from 45.2 to 112.3 MPa, the elastic modulus ranges from 18,850 to 39,910 MPa, Poisson's ratio ranges from 0.213 to 0.315, cohesion ranges from 4.29 to 26.54 MPa, and the internal friction angle ranges from 27.7° to 38.4°. These results are generally consistent with the aforementioned mechanical testing and the lithological characteristics of the formation.

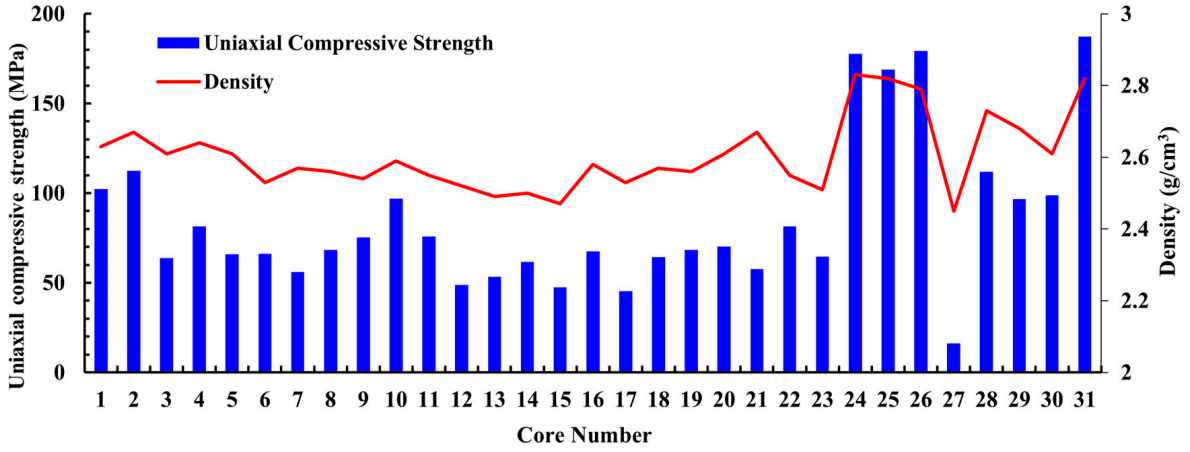


Figure 2. Uniaxial compressive strength test results of Longtan Formation.

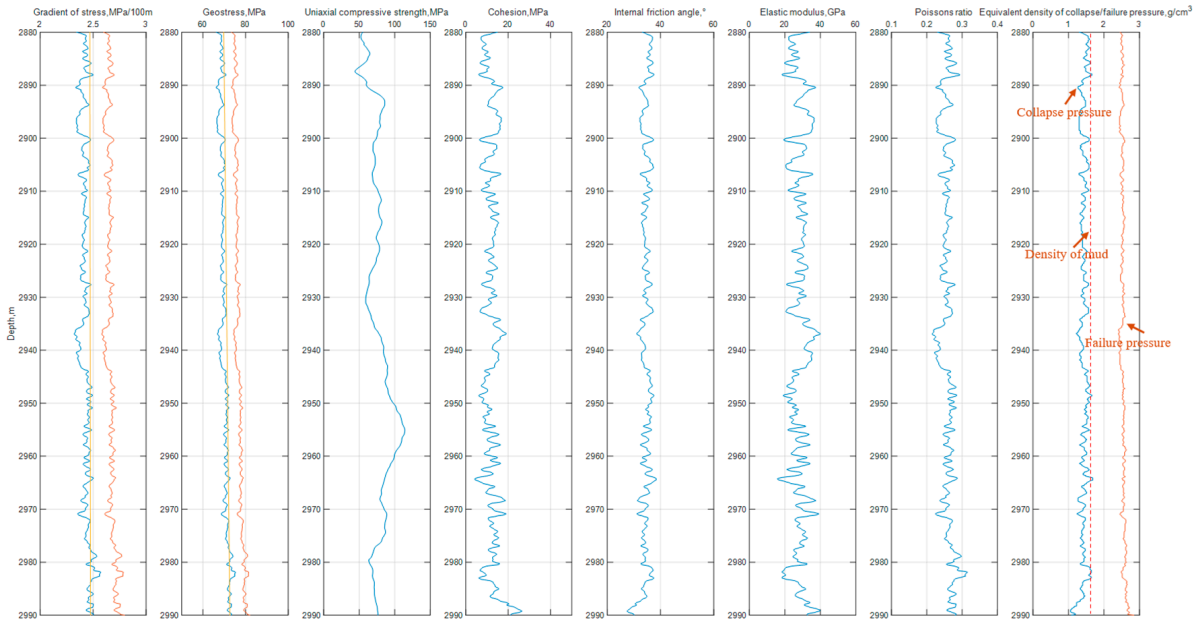


Figure 3. Geomechanical parameters and collapse pressure equivalent density interpretation results of the Longtan Formation.

Based on the depth of stress testing samples and the experimental data on in situ stress magnitudes combined with the rock physical parameters interpreted from logging data, the horizontal tectonic stress coefficient for the target formation was calculated using the structural stress coefficient method proposed by Huang Rongzun [26] with the following formula.

$$\sigma_H = \frac{\mu}{1-\mu}(\sigma_v - \alpha P_p) + \alpha P_p + \frac{E}{1-\mu}\xi_H + \frac{E\mu}{1-\mu}\xi_h \quad (1)$$

$$\sigma_h = \frac{\mu}{1-\mu}(\sigma_v - \alpha P_p) + \alpha P_p + \frac{E\mu}{1-\mu}\xi_H + \frac{E}{1-\mu}\xi_h \quad (2)$$

In the formula, σ_v, σ_H, and σ_h represent the vertical, maximum horizontal, and minimum horizontal in situ stresses, respectively, in MPa. μ is Poisson's ratio of the rock (dimensionless). E is the elastic modulus of the rock in MPa. P_p is the formation pressure in MPa. α is the Biot coefficient of the rock. ξ_H and ξ_h are the tectonic stress coefficients in the directions of the maximum and minimum horizontal stresses, respectively (dimensionless). Based on experimental data, the horizontal tectonic stress coefficients for the target interval were determined to be 7.9504×10^{-4} and 6.1258×10^{-4}, respectively.

Given the known in situ stress and rock mechanics parameter profiles for a single well, the critical collapse pressure equivalent density of the wellbore can be calculated using the Mohr–Coulomb failure criterion for vertical wellbore rock. As shown in Figure 3 (right), the collapse pressure equivalent density of the Longtan Formation wellbore ranges from 1.05 to 1.69 g/cm^3, with an average value of 1.44 g/cm^3. This is generally lower than the density of the drilling fluid used in practice (1.53 g/cm^3). The critical collapse pressure density of the lower Longtan Formation is relatively higher, locally exceeding the drilling fluid density, making it a potential high-risk area of instability. This is consistent with the borehole enlargement rate profile calculated from the logging data (Figure 1).

4. Discrete Element Simulation of Wellbore Instability in Thin Interlayer Formation

The discrete element method, also known as the granular element method, is a numerical simulation method proposed by Cundall [27] and widely used in the fields of geotechnics, mining, and petroleum engineering to study the mechanical behavior of granular or cemented materials. In discrete element method (DEM) simulations, several basic assumptions were made to simplify the model. These include the following: (1) each particle is modeled as a rigid body with finite mass and is either spherical (3D) or circular (2D); (2) particles can independently translate and rotate; (3) interactions occur only at point contacts; (4) small overlaps between particles are allowed, with contact forces determined by a force-displacement law; and (5) bonds can form at particle contacts, with bond strength defined by the user [27,28]. These assumptions, based on conventional DEM frameworks, ensure the computational efficiency and feasibility of simulating large systems [29,30]. In recent years, some scholars have introduced discrete element methods, such as particle flow code (PFC), into the study of wellbore stability [31–33]. These methods demonstrate significant advantages in aspects such as large wellbore deformations, weak plane cementation, discrete fracture networks, and micro-mechanical analysis. Considering the characteristics of the thin interlayer lithologies in the Longtan Formation, this paper employs the discrete element method to establish a numerical model for wellbore instability in the Longtan Formation.

As shown in Figure 4, an open hole section is established based on the actual size of the borehole, with the formation consisting of thin interlayer structures of shale, sandstone, limestone, and coal. The discrete element model for wellbore instability consists of 29,980 particles, primarily simulating rock mineral particles. The bonding between particles is represented using the linear parallel bond model, with different bonding strengths set between particles to characterize the degree of rock cementation. Specifically, particles are grouped, and differentiated mechanical parameters are assigned to different groups of particles and their bonds to represent the rock mechanical properties of various lithologies. Detailed information can be found in Table 2.

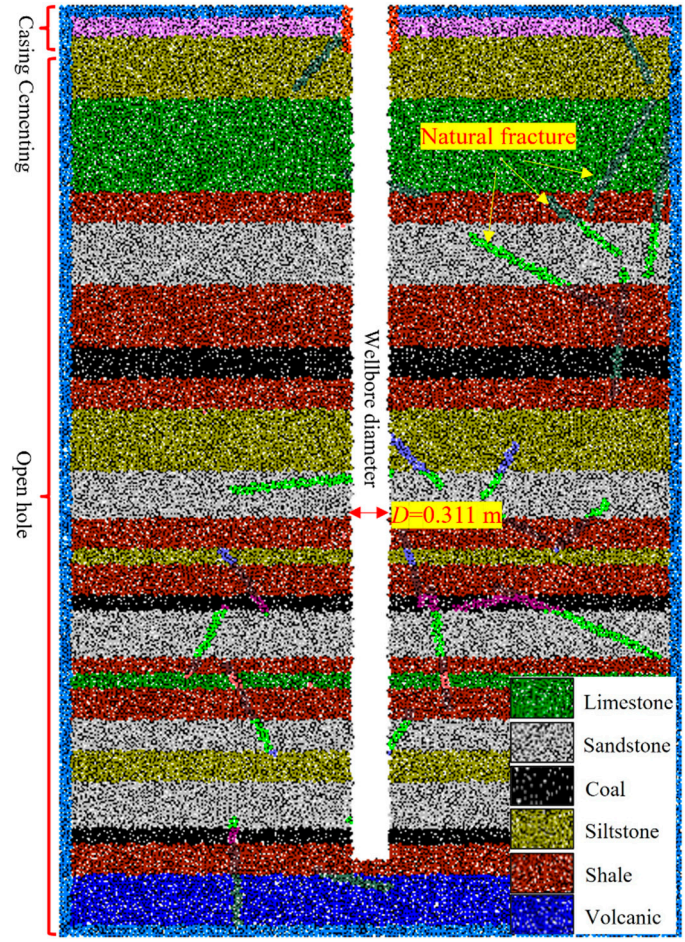


Figure 4. Discrete element model of wellbore instability in the Longtan Formation.

Table 2. Particle and cementation parameter assignment for the discrete element model of wellbore instability [29,34,35].

Parameter	Value				
	Shale	**Siltstone**	**Sandstone**	**Limestone**	**Coal**
Density of particle (g/cm^3)	2.7	2.7	2.7	2.7	1.8
Mean particle radius of particle (mm)	7.5	7.5	7.5	7.5	7.5
Contact modulus of particle (MPa)	20,000	30,000	35,500	40,000	8000
Stiffness ratio of particle	2.6	2.0	1.5	1.5	2.0
Friction coefficient of particle	0.45	0.55	0.6	0.52	0.35
Effective modulus of parallel bond (MPa)	20,000	30,000	35,500	10,000	8000
Stiffness ratio of parallel bond	2.6	2.0	1.5	1.5	2.0
Tensile strength of parallel bond (MPa)	2.0	5.0	6.0	6.0	1.0
Cohesion strength of parallel bond (MPa)	10	20	30	25	4
Friction angle of parallel bond (°)	30	35	40	38	25

Based on the numerical model, stress boundaries are applied to the model in accordance with the in situ stress test results for the Longtan Formation as shown in Table 1. Additionally, fluid pressure is assigned between the particles in the model according to the actual pore pressure coefficient (1.32 g/cm^3), and the wellbore fluid column pressure is assigned based on the actual drilling fluid density (1.53 g/cm^3). The flow of formation fluids and drilling fluids follows Darcy's law. The stress exerted on the particles directly affects the size of the flow channels, and the fluid pressure between the particles simultane-

ously acts back on the rock particles, influencing particle movement and the cementation failure behavior between particles. This simulation process is a fluid–solid coupling process, detailed in references [36,37].

As shown in Figure 5, under the combined control of the in situ stress field, fluid pressure field, and rock mechanical strength in the open hole section, the wellbore exhibits characteristics of local instability in weak formations such as shale and coal seams. The primary cause of instability and falling blocks in the upper thin coal layers is probably the low strength of the rock itself. In the lower thin interlayer sections of shale, sandstone, and limestone, wellbore instability is more pronounced, particularly at lithological interfaces. It is believed that instability and falling blocks in the shale layers at lithological interfaces can disrupt the stress equilibrium, potentially triggering the collapse of relatively high-strength sandstone and limestone formations. Because these types of blocks have high mechanical strength, they are not easily fragmented. Once fallen, they tend to form local ledges, often leading to difficulties in tripping and stuck pipe incidents. When drilling through the Longtan Formation and other formations with thin interbeds of hard and soft layers is carried out, irregular hard blocks are frequently returned, and the wellbore tends to form ledges, consistent with the simulation results. Meanwhile, the right image shows that micro-scale shear failure events occur in the rock mass around the wellbore at heights consistent with the unstable layers, indicating that shear failure of the rock is the primary mechanical mechanism inducing wellbore instability and falling blocks.

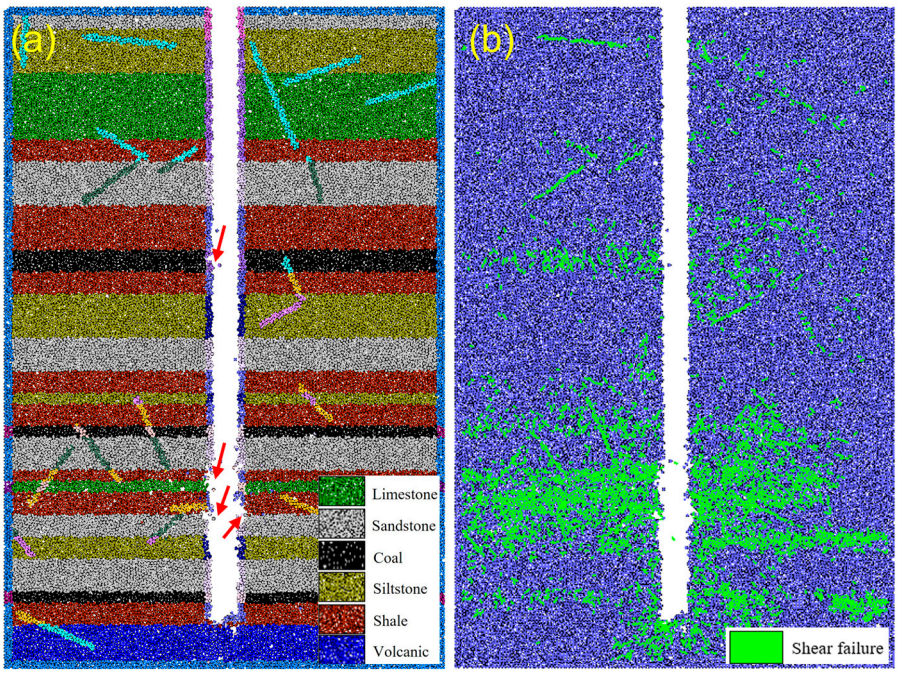


Figure 5. Simulation results of wellbore instability in the thin interbedded formations of the Longtan Formation: (**a**) instability characteristics of different lithological sections; (**b**) distribution of shear failure bands in particle cementation.

Figure 6 illustrates the impact of drilling fluid density changes on the wellbore stability of thin interlayer formations with varying hardness. When the drilling fluid density is 1.3 g/cm^3, severe collapse and enlargement occur in the lower part of the wellbore, with a maximum enlargement rate of 40.8%. In the middle and upper parts of the borehole, insufficient support from the drilling fluid leads to a certain necking, with a maximum necking rate of 15.8%. As the drilling fluid density increases to 1.5 g/cm^3, the phenomena of falling blocks and collapse are effectively curbed. Localized block falls mainly occur in the coal and the thin interlayer sections of lower shale and hard sandstone/limestone, with

a maximum enlargement rate of 34.1%. Simultaneously, under these conditions, a certain necking also occurs in the borehole near the block fall positions, with a necking rate of 6.4%. The analysis suggests that the dilatancy effect during the shear instability process of the rock and local deformation caused by stress imbalance are significant reasons for the coexistence of borehole enlargement and necking in unstable areas. This also aligns with field feedback, where wellbore instability areas in vertical sections often experience tripping resistance and back-reaming issues.

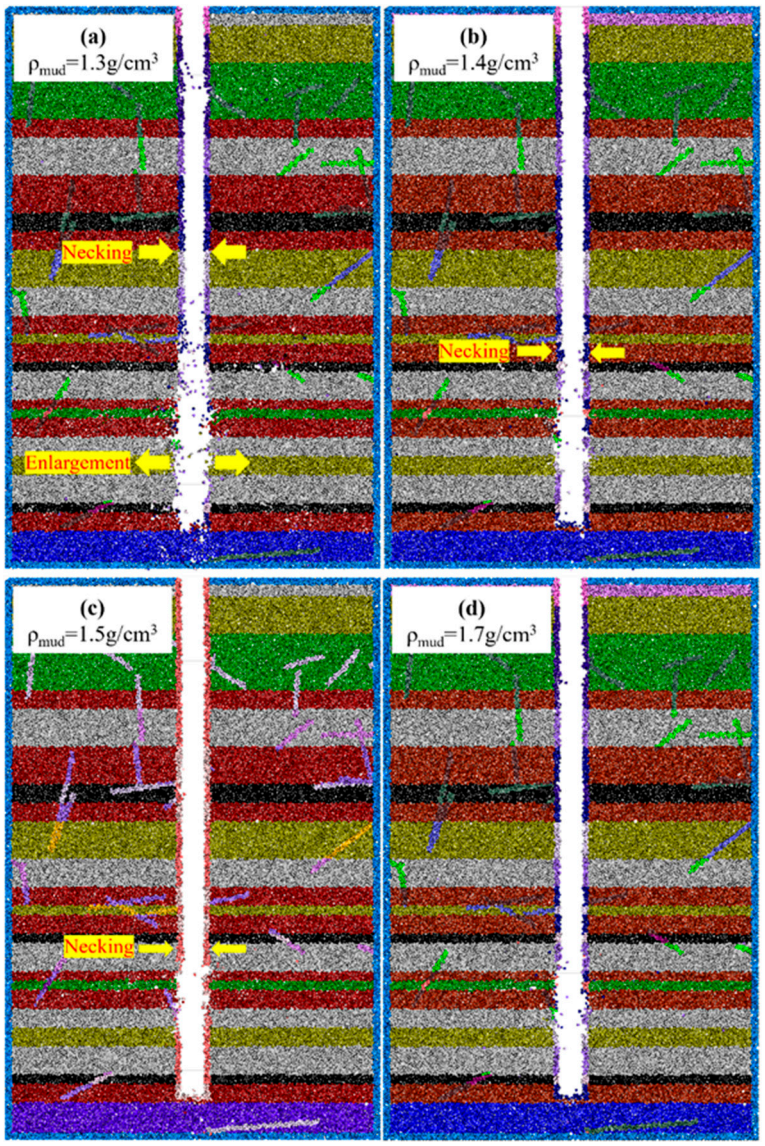


Figure 6. Variation trends of wellbore instability characteristics under different drilling fluid densities.

As the drilling fluid density increases to 1.7 g/cm^3, the simulation results show that the wellbore remains stable overall, with no significant necking phenomena. However, localized falling blocks still occur at the lithological interfaces in the lower thin interlayer sections of soft and hard formations. This indicates that insufficient support from fluid column pressure is no longer the primary cause of wellbore block falls. Instead, the stress imbalance at lithological interfaces, caused by the differences in macroscopic in situ stress, fluid pressure field, and rock mechanical strength, is most likely the main reason for block falls. These wellbore block falls are often difficult to prevent by increasing the fluid density and are a significant risk factor in inducing sticking during drilling. Finally, through the overall analysis of Figure 6, it is observed that wellbore block falls and instability in

long open hole sections with thin interlayer formations tend to occur in the middle and lower parts of the borehole. This area is often where large-diameter drilling collars and downhole tools are located, further increasing the risk of tripping resistance and sticking. These factors need to be considered when preventive measures for sticking during drilling are implemented.

5. Conclusions

1. In the Longtan Formation of the Zigong area in southern Sichuan, the vertical, maximum horizontal, and minimum horizontal principal stress gradients are 2.47 MPa/100 m, 2.72 MPa/100 m, and 2.34 MPa/100 m, respectively, indicating a strike-slip stress state. Vertically, the formation consists of thin interlayer structures of various lithologies, with significant differences in rock mechanical strength between layers, resulting in marked heterogeneity and a high risk of wellbore structural–mechanical instability.
2. Based on the geomechanical parameter profile of the Longtan Formation, the Mohr–Coulomb failure criterion was used to calculate the critical collapse pressure equivalent density of the wellbore, which ranges from 1.05 to 1.69 g/cm^3. At certain weak layers such as shale or lithological interfaces, the wellbore collapse pressure exceeds the actual drilling fluid density (1.53 g/cm^3), making these points potential triggers for wellbore instability and falling blocks.
3. A fluid–solid coupled discrete element model of wellbore instability was established for the multi-lithology thin interlayer structure of the Longtan Formation. The instability simulation results with varying drilling fluid densities show that under low-density conditions, both wellbore enlargement and necking coexist. Under high-density conditions, due to stress imbalance, localized block falls may still occur at the lithological interfaces of the soft and hard thin interlayer formations. These findings are significant for revealing the mechanical mechanisms of wellbore instability in thin interlayer formations during actual drilling and for guiding the prevention and control of wellbore instability and associated risks.

6. Discussion

While this study provides new insights into wellbore instability mechanisms in the Longtan Formation, several aspects warrant further investigation to improve the applicability of the proposed approach. Future research could focus on the following key directions:

1. The current study is based on a single-well geomechanical profile and numerical simulations. To enhance its applicability, future work could extend this approach to multi-well case studies and field-scale analyses, incorporating real-time drilling data to validate the model's predictive accuracy under varying geological conditions.
2. This study primarily considers stress redistribution and lithological heterogeneity. However, the inclusion of anisotropy, thermal effects, and chemical interactions could further refine wellbore stability predictions. For instance, thermal expansion and hydration effects may significantly alter the mechanical behavior of rock, particularly in formations with high clay content.
3. With advancements in big data analytics and artificial intelligence, future studies could integrate machine learning algorithms with geomechanical modeling to develop real-time, data-driven wellbore stability forecasting systems. By training models on large datasets from different well conditions, predictive accuracy and drilling risk mitigation strategies could be significantly improved.

Author Contributions: Conceptualization, J.G.; Methodology, B.M.; Software, C.M. and T.T.; Investigation, Y.S.; Data curation, Y.S.; Writing—original draft, B.Y.; Writing—review & editing, B.Y.; Visualization, L.X.; Supervision, Y.W.; Project administration, J.G. and B.M. All authors have read and agreed to the published version of the manuscript.

Funding: This work was supported by the National Natural Science Youth Foundation of China (No. 52104003), the National Natural Science Foundation of China (No. 52374005), and the Natural Science Youth Foundation of Sichuan Province (No. 2023NSFSC0930).

Data Availability Statement: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Authors Jianhua Guo, Yu Sang, Beiqiao Meng, Lianbin Xia, Yangsong Wang, Chengyu Ma, and Tianyi Tan were employed by the PetroChina Southwest Oil & Gasfield Company. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

References

1. Wang, W.; Li, D.; Jin, J. Technical problems and measures of wellbore stability of broken formation in Shunbei oil and gas field. *Sci. Technol. Eng.* **2022**, *22*, 5205–5212.
2. Liu, Z.; Chen, M.; Jin, Y.; Yang, X.; Lu, Y.; Xiong, Q. Calculation model for bore-hole collapse volume of a horizontal openhole in multiple-weak-plane formation. *Pet. Explor. Dev.* **2014**, *41*, 102–107. [CrossRef]
3. Yang, Y.M.; Zhang, S.M.; Jin, T.; Ming, Y.; Guo, R.Y.; Wang, X.Z.; Han, L.Y. Characteristics and exploration potential of shale reservoirs of Permian Longtan Formation in southern Sichuan Basin. *Lithol. Reserv.* **2023**, *35*, 1–11.
4. Yew, C.; Wang, O. Wellbore stress distribution produced by moisture adsorption. *SPE Drill. Eng.* **1990**, *5*, 311–316. [CrossRef]
5. Huang, R.Z.; Chen, M.; Deng, J.G.; Wang, K.P.; Chen, Z.X. Study on shale stability of wellbore by mechanics coupling with chemistry method. *Drill. Fluid Complet. Fluid* **1995**, *28*, 18–24.
6. Kang, Y.; Yang, B.; Li, X.; Jian, Y.; Lijun, Y.; Qiang, C. Quantitative characterization of micro forces in shale hydration and field applications. *Pet. Explor. Dev.* **2017**, *44*, 301–308. [CrossRef]
7. Jin, Y.; Chen, M.; Chen, Z. Mechanics model of sidewall stability of straight wells drilled through weakly consolidated formations. *Drill. Prod. Technol.* **1999**, *97*, 13–14.
8. Hubbert, M.K.; Willis, D.G. Mechanics of hydraulic fracturing. *Trans. AIME* **1957**, *210*, 153–168. [CrossRef]
9. Westergaard, H.M. *Plastic State of Stress Around a Deep Well*; Harvard University: Cambridge, MA, USA, 1940.
10. Gao, J.; Deng, J.; Lan, K.; Feng, Y.; Zhang, W.; Wang, H. Porothermoelastic effect on wellbore stability in transversely isotropic medium subjected to local thermal non-equilibrium. *Int. J. Rock Mech. Min. Sci.* **2017**, *96*, 66–84. [CrossRef]
11. Yu, M.; Chenevert, M.E.; Sharma, M.M. Chemical–mechanical wellbore instability model for shales: Accounting for solute diffusion. *J. Pet. Sci. Eng.* **2003**, *38*, 131–143. [CrossRef]
12. Aadnoy, B.S. Modeling of the stability of highly inclined boreholes in anisotropic rock formations. *SPE Drill. Eng.* **1988**, *3*, 259–268. [CrossRef]
13. Ding, Y.I.; Luo, P.; Liu, X.; Liang, L. Wellbore stability model for horizontal wells in shale formations with multiple planes of weakness. *J. Nat. Gas Sci. Eng.* **2018**, *52*, 334–347. [CrossRef]
14. AlBahrani, H.; Morita, N. Risk-controlled wellbore stability criterion based on a machine-learning-assisted finite-element model. *SPE Drill. Complet.* **2022**, *37*, 38–66. [CrossRef]
15. Ma, T.; Zhang, Y.; Qiu, Y.; Liu, Y.; Li, Z. Effect of parameter correlation on risk analysis of wellbore instability in deep igneous formations. *J. Pet. Sci. Eng.* **2022**, *208*, 109521. [CrossRef]
16. Panchal, M.; Raghavendra, G.; Bhargav Alamgir, M.; Ojha, S.; Babu, V.S.; Ben, B.S. Spectroscopic analysis of natural fiber/epoxy composites. In *Handbook of Epoxy/Fiber Composites*; Springer: Singapore, 2022; pp. 1–36.
17. Ma, Y.; Yu, R. New analytical methods to evaluate uncertainty of wellbore stability. *J. Pet. Sci. Eng.* **2019**, *180*, 268–277. [CrossRef]
18. Khatibi, S.; Aghajanpour, A.; Ostadhassan, M.; Farzay, O. Evaluating single-parameter parabolic failure criterion in wellbore stability analysis. *J. Nat. Gas Sci. Eng.* **2018**, *50*, 166–180. [CrossRef]
19. Aslannezhad, M.; Keshavarz, A.; Kalantariasl, A. Evaluation of mechanical, chemical, and thermal effects on wellbore stability using different rock failure criteria. *J. Nat. Gas Sci. Eng.* **2020**, *78*, 103276. [CrossRef]
20. Liu, C.; Han, Y.; Liu, H.; Abousleiman, Y.N. Wellbore-stability analysis by integrating a modified hoek-brown failure criterion with dual-porochemoelectroelastic theory (includes associated erratum). *SPE J.* **2019**, *24*, 1957–1981. [CrossRef]
21. Darvishpour, A.; Seifabad, M.C.; Wood, D.A.; Ghorbani, H. Wellbore stability analysis to determine the safe mud weight window for sandstone layers. *Pet. Explor. Dev.* **2019**, *46*, 1031–1038. [CrossRef]

22. Wang, X.; Wang, Q.; An, X. Characteristics of sedimentary environment and evolution of Permian in southern Sichuan Basin: An example from the profile of Gulin Bajiaocun in Sichuan province. *Sediment. Geol. Tethyan Geol.* **2022**, *42*, 398–412.
23. Zoback, M.D. *Reservoir Geomechanics*; Cambridge University Press: Cambridge, UK, 2007.
24. Fan, Y.; Wang, J.; Liu, H.; Wu, P.C. Formation mechanical properties and wellbore stability of the whole well section in Luzhou block. *Sci. Technol. Eng.* **2020**, *20*, 6433–6439.
25. Zhao, Y.; Luo, Y.; Li, L.; Zhou, Y.; Li, L.; Wang, X. In-situ stress simulation and integrity evaluation of underground gas storage: A case study of the Xiangguosi underground gas storage, Sichuan, SW China. *J. Geomech.* **2022**, *28*, 523–536.
26. Deng, J.; Huang, R.; Tian, X. A New Method for Measuring in-situ Stress in Deep Formation. *J. Univ. Pet. China* **1997**, *34–37*, 115–116.
27. Cundall, P.A. A computer model for simulating progressive large-scale movements in blocky rock systems. In Proceedings of the Symposium of the International Society for Rock Mechanics, Nancy, France, 4–6 October 1971.
28. Cundall, P.A.; Strack, O.D.L. A discrete numerical model for granular assemblies. *Géotechnique* **1979**, *29*, 47–65. [CrossRef]
29. Jeoungseok, Y. Application of experimental design and optimization to PFC model calibration in uniaxial compression simulation. *Int. J. Rock Mech. Min. Sci.* **2007**, *44*, 871–889.
30. Potyondy, D.O. Simulating stress corrosion with a bonded-particle model for rock. *Int. J. Rock Mech. Min. Sci.* **2007**, *44*, 677–691. [CrossRef]
31. Hou, B.; Jin, Y.; Song, L.; Chao, Z. Failure mechanisms of borehole wall rocks in gravel beds with different grain sizes. *Nat. Gas Ind.* **2015**, *35*, 66–70.
32. Karatela, E.; Taheri, A. Three-dimensional hydro-mechanical model of borehole in fractured rock mass using discrete element method. *J. Nat. Gas Sci. Eng.* **2018**, *53*, 263–275. [CrossRef]
33. Park, N.; Olson, J.E.; Holder, J. Stress-corrosion cracking as an alternative time-dependent shale-stability model. *SPE Drill. Complet.* **2010**, *25*, 168–176. [CrossRef]
34. Wang, C.; Tannant, D.D.; Lilly, P.A. Numerical analysis of the stability of heavily jointed rock slopes using PFC2D. *Int. J. Rock Mech. Min. Sci.* **2003**, *40*, 415–424. [CrossRef]
35. Wu, S.; Xu, X. A study of three intrinsic problems of the classic discrete element method using flat-joint model. *Rock Mech. Rock Eng.* **2016**, *49*, 1813–1830. [CrossRef]
36. Yang, F. *Stability Analysis of End Soil of Tunnel in Sand Layer Based on PFC Fluid-Solid Coupling*; Changsha University of Science & Technology: Changsha, China, 2020.
37. Hu, J.X.; Bian, K.; Liu, J.; Xie, Z.Y.; Chen, M.; Li, B.Y.; Cen, Y.; Liu, Z.P. Discrete element simulation of shale softening based on parallel-bonded water-weakening model. *Chin. J. Geotech. Eng.* **2021**, *43*, 725–733.

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.